<table>
<tr><th></th><th>Utility and Review Committee Comments to Bechtel</th><th>Responses to Utility and Review Committee Comments</th></tr>
<tr><td colspan="3">Comments on Final Draft Report</td></tr>
<tr><td></td><td>
<u>The Costs of all Options are Significantly Underestimated</u>
Bechtel’s cost estimates provide only an order-of-magnitude estimate to compare the various options. In order for decision-makers to fully understand and evaluate the true financial obligations of each option and thus, the costs to our customers, the estimates must be as accurate and inclusive as possible for each technology option.

If many of the cost items listed as exclusions in section 7.12 are included in the estimates, it is clear that construction costs will be significantly higher. From a construction perspective, PG&E reviewed the final draft, including information on construction approaches and scheduling, and developed estimates for PG&E costs such as engineering and project oversight, security and other support costs, simulator upgrades, and plant shutdown and startup costs. Further, PG&E’s engineering review indicates that the screening technologies require revisions to the proposed construction approaches that will significantly increase costs.

From a finance perspective, PG&E developed estimates for both the cost of capital and an escalation factor in order to accurately reflect the long-term duration of between 8-14 years estimated by Bechtel for project permitting and construction.

The table below summarizes the difference between Bechtel’s estimates and those determined by PG&E, adding in the construction and financing costs described above.

<u>Comparison of Bechtel and PG&E Estimates</u>
<table>
<tr><th></th><th>Bechtel Construction Estimate</th><th>Bechtel Replacement Power Estimate</th><th></th><th>PG&E Revised Construction Estimate</th><th>PG&E Revised Replacement Power Estimate</th></tr>
<tr><td>Closed-Cycle Avg</td><td>$7.7B</td><td>$1.43B</td><td></td><td>$10.9B</td><td>$1.3B</td></tr>
<tr><td>Wedgewire</td><td>$314M</td><td>$0</td><td></td><td>$621M</td><td>$560M</td></tr>
<tr><td>Fine Mesh</td><td>$197M</td><td>$237M</td><td></td><td>$434M</td><td>$852M</td></tr>
</table>

Additionally, Bechtel’s estimates do not include increases to on-going plant maintenance and replacement power costs for station derates expected from the closed-cycle options. Additional increased station maintenance costs are expected to be on the order of $1 million annually for the screening options, and $6 million for the closed-cycle options. The station derates associated with the closed-cycle options (107 – 195 MW) would result in replacement power purchase costs in the range of $44-80 million annually.
</td><td>
Bechtel requested input from PG&E related to owner costs prior to issuing the draft report but was told that PG&E could not provide those costs until their team had reviewed the designs and the schedules. Bechtel has agreed to add Owner the Owner cost if that is the direction from the Review Committee.

Bechtel and the Review Committee agreed that Bechtel would not apply an escalation factor to our estimates.

Bechtel has agreed to add the Owner costs to our estimate and is waiting for those costs to be provided for inclusion in the report.

Bechtel requested input from PG&E related to owner costs prior to issuing the draft report but was told that PG&E could not provide those costs until their team had reviewed the designs and the schedules. Bechtel has agreed to add Owner the Owner cost if that is the direction from the Review Committee.
</td></tr>
</table>

<table>
<tr>
<td></td>
<td>Finally, mitigation cost estimates are not included. Mitigation for the closed-cycle options is likely to run in the hundreds of millions of dollars. The wedgewire option is likely to also require significant mitigation.</td>
<td>Bechtel agrees that mitigation costs could be significant but since they are typically negotiated with the various entities during the permitting process Bechtel was directed by the Review Committee to not consider a mitigation cost as part of our estimate. If the values are provided they could be added to the estimate. Per the Direction of the Review Committee Mr. Tom Luster will provide a position on Mitigation which will be added to the Final Report.</td>
</tr>
<tr>
<td></td>
<td><u>Permitting is likely to be significantly more time-consuming and costly than estimated, particularly for the closed-cycle options</u>

A critical concern is the continued underestimating of permitting challenges associated with the options, particularly the closed-cycle and wedgewire options. As an example, the permit application development timeframe for all options is estimated at one year. All technology options will require an EIR/EIS, but it is highly likely that the closed-cycle options (particularly the wet options) will require substantially more time and cost to develop the permit applications and supporting documentation. A one-year application development timeframe for a project the magnitude of the closed-cycle options – and likely the wedgewire option – is not realistic.

Further, the application review process is also estimated to be the same for all options – this is not likely to be the case. The closed-cycle and wedgewire options will raise serious environmental concerns and will very likely be subject to longer and more in-depth agency review, as well as challenges by various parties.

In reviewing estimated permitting costs, it seems unlikely that the dry-cooled closed-cycle options would cost less to permit than the fine mesh and wedgewire options. Further, based on prior permitting experiences for projects such as the Steam Generator Replacement Project and the Independent Spent Fuel Storage Installation, PG&E estimated in its CPUC cost recovery filing for Diablo Canyon's license renewal that coastal-related permitting costs would be approximately $12 million. Given the complexity and magnitude of construction, the permitting costs for the closed-cycle and wedgewire options would clearly be as much or more than the costs estimated for coastal-related license renewal approvals.

<u>Summary of Bechtel’s Permitting Schedule/Cost</u>

<table>
<tr><th>Option</th><th>Application Development</th><th>Application Review</th><th>Schedule Adder for Appeals</th><th>Cost</th></tr>
<tr><td>Fine Mesh Screens</td><td>1 year</td><td>2 years</td><td>+ 3 months</td><td>$3.1 million</td></tr>
<tr><td>Wedgewire Screens</td><td>1 year</td><td>2 years</td><td>+ 12 months</td><td>$3.9 million</td></tr>
<tr><td>Dry Closed-Cycle</td><td>1 year</td><td>2 years</td><td>+ 12 months</td><td>$2.9 million</td></tr>
<tr><td>Wet Closed-</td><td>1 year</td><td>2 years</td><td>+ 12 months</td><td>$4.3 million</td></tr>
</table>
</td>
<td>The permitting schedule associated with the various cooling technologies options were generally based on an examination of the statutory and/or expected permit review periods and the schedule logic associated with each specific permit or approval. In the case of the schedule bounding CEQA review process, additional review steps were included based on specific information on the CEQA schedule process documentation. More specifically, the CEQA process described in the report was composed of the standard initial 30-day completeness review, a 1-year EIR review, and a so-called 90-day “reasonable extension” triggered by compelling circumstances recognized by both the applicant and lead agency. While this 16 month period is clearly documented in published CEQA flowcharts, the process was further extended by conservatively adding an additional 8 months to cover “unreasonable delays” (CEQA terminology), which is ostensibly associated with the applicant’s difficulty in supplying requested information. The result is a two-year review period, which is subject to appeal. In response to the need to consider likely appeals, a specific final appeal period was selected which ranged from 3 months to a 1 year, depending on the cooling system technology and its attendant environmental impacts.

These schedules did not address NRC licensing process since NRC licensing matters are addressed separately in section 3 of the report. The schedule logic and associated assumptions for each cooling system technology assessment were clearly delineated in the report. Consequently, there is a credible basis for the permitting schedules.

As with any environmental permitting process, there are uncertainties in the process that are difficult to forecast to every organizations’ satisfaction. Most assuredly the time to prepare the permit applications and or comprehensive environmental assessment documentation, complexities associated with intervener actions and the length of the permit appeal process and associated legal processes can be the subject of much debate. The one-year period to develop the permit applications and CEQA-related EIR for the various options, which has been characterized as insufficient, was based in part are based on the assumption that that most of the conceptual engineering needed to support this permitting process has already been completed to support development of this report. Thus, the processes to prepare the EIR and associated permit applications have a significant head start, which would support immediate initiation of any appropriate related field investigation studies. In some cases, the significant amount of existing environmental information associated with this long-studied site will also serve to expedite this process. The two-year review period (CEQA review), as discussed above, has a specific basis that is aligned with the documented CEQA review process. Substantially longer review periods are not really directly dependent on the complexity of the project and the magnitude of its impacts, but rather on the nature of the iterative process to provide complete information to satisfaction of the reviewing CEQA entities. The two-year review process described is based on the applicant making a reasonable attempt to provide timely, creditable and complete responses to regulatory requests for supplemental information. The two-year review period, reflected in the report, did factor in some difficulty in getting through this process (8-month extension), However, the review period can increase more dramatically, if the responses systematically and repeatedly fail to provide complete information. . Finally, the length of the CEQA-related appeal periods do vary by cooling technology options, so the overall permitting periods are not the same for all of these technologies. The potentially more contentious wedge-wire and closed-cooling cycle options were assigned longer appeal periods. As noted earlier, the length of these appeal periods are subject to debate and there are no certain conclusions regarding the length of these periods.

While there are examples of projects (in California), which have boasted lengthier permitting schedules, there</td>
</tr>
</table>

	Cycle	are also numerous complex power projects (on California-based "Greenfield" sites) with CEQA or CEC permitting schedules that are supportive of the permitting schedules listed in the report. The bounding CEQA durations provided in the report are well aligned with this recent Greenfield project experience in California. Similarly, the cost estimates for the permitting process were also based on identification of statutory permit filing fees (if applicable), associated direct costs (e.g., emission offset fees) and specific assumptions regarding the number of job hours and cost per job hour associated with preparing the individual permit applications and the comprehensive environmental impact report. The assessment of permitting costs did not include legal costs and associated mitigation costs. The determination of these, not insignificant, cost considerations, were determined to be beyond the scope of this report - a point clearly delineated in the report. The rationale for this exclusion was specifically addressed with and approved by representatives of the PG&E and review board. Consequently, the report provided a specific, delineated and approved permit cost estimate methodology for the various cooling system technologies. The final permitting costs, inclusive of legal and mitigation costs, will likely be greater than the cost estimates reflected in the report. As discussed at the November 4th Review Committee meeting the durations for the permitting portrayed in the schedules are reasonable. Bechtel still believes that the criterion 10 evaluation supports that these changes would be able to be installed without the specific need for an LAR except for the fact that the modifications would likely require a change to the Environmental Protection Plan which triggers the need for NRC review. Additionally, the installation of the emergency gate in the sea wall for the wedge wire technology may require NRC review. These points will be addressed in Section 3 of the report. The permitting process prior to the insitu testing was considered but not displayed on the wedge wire schedule. The schedule will be updated to show the permitting process prior to the testing.
	The enormous excavation, and subsequent filling of 310 acres of canyon lands, for the closed-cycle options must be acknowledged as an incredibly difficult project to permit – and the timeframes and costs in the draft do not adequately reflect that fact. The same can be said for the wedgewire option, with the building of a large-scale undersea structure off the coast. These options would clearly take longer to permit than the fine mesh option and thus cost substantially more. Additionally, the draft has not been revised to include the time and cost of securing NRC approval. PG&E believes that NRC approval will be required – at least for the closed-cycle and wedgewire options. Bechtel's response to comments indicated that this would be added, but the approval process and associated costs are not included in the draft text. Finally, a site-specific wedgewire technology pilot study would require permitting prior to implementation. It cannot be assumed that the pilot study infrastructure can be installed without any permitting.	
	<u>Fine Mesh</u> • Proposed approach significantly underestimates construction complexity. In order to maintain the seismic qualification of the intake structure, both units would likely need to be offline for as long as 12 months, increasing costs of construction and replacement power. • The ability of 1 mm fine mesh screens to reduce entrainment is highly uncertain. A careful reading of Tenera's July 2013 report indicates that the most reasonable estimate of entrainment reduction is 39.7%, and the percentage of actual larval survival following initial screen impingement is likely quite low. Additionally, the operational issues for the plant due to biofouling and clogging present significant concerns.	Bechtel has not completed formal calculations but we have reviewed the structure and believe that the seismic design of the structure could be maintained during the modification on a per bay bases. Obviously during the detailed design phase if this technology were selected this assumption would have to be confirmed. It was agreed at the November 4th RC meeting that Bechtel and PG&E will have a technical discussion on this topic and PG&E can present their reasoning on why they believe the bay by bay approach would not work. Entrainment reduction results for different slot sizes for individual taxa from the Tenera's July 2013 were used, which shows a 67.6% average reduction for a 1 mm slot size for all species (Table 4 of the Tenera reference). Tenera's July 2013 report did provide an estimated entrainment reduction effectiveness of 39.7% for an installed 1 mm slot size screen at DCPP. However, due to the limited samples, Bechtel is not endorsing the findings. However, we will revise the report to indicate this assessment made for DCPP by Tenera. Finally, bio-fouling and clogging potential are definitely issues of concern and one of two major parts of the in-situ pilot study is to address this concern. Tenera has completed their 2013 evaluations which comes to a vastly different conclusion than their earlier report on the same subject. The Review Committee is having a peer review completed on the Tenera report. Bechtel agrees that the efficacy of the technology should be considered when deciding if this technology should be adopted. At the November 4th Review Committee meeting the Review Committee provided an updated Tenera study dated October 29th that was being peer reviewed by the State Water Resources Control Board and directed that, subject to the agreement of Dr. Ramondi, this report be the bases for the Bechtel efficacy review. Bechtel agreed to review the report and use it subject to that review.
	<u>Wedgewire</u> • There are no existing open ocean installations of wedgewire screens and thus, there are serious concerns regarding operability and effectiveness. In particular,	It is recognized that there is no open sea installation of wedge wire screens at the proposed screen size, which is why a pilot testing program is proposed.

	significant questions remain regarding the grout/seal design of the proposed breakwater modifications, including both performance and safety concerns.	This topic has been discussed several times and Bechtel has clearly stated that insitu testing must be completed prior to moving forward with the design and installation of wedge wire screens at DCPP. In regard to the sealing of the break water Bechtel is not proposing grout injection to seal the breakwater. The approach would be to install a grout filled liner to the inner wall of the breakwater to provide the seal see Report section 5.2.13.
	• A dual-unit outage of approximately 8 months is likely and must be incorporated into the schedule.	Bechtel believes that the acceptable operation of the wedge wire screening installation can be demonstrated while the units are on line since the technology is totally passive.
	• The proposed pilot study will require its own permitting process, necessitating a significant change to the schedule and costs for permitting. Additionally, the pilot study timeframe should be expanded to 30-36 months to effectively evaluate screen performance and maintenance in terms of fouling, corrosion and other performance factors.	Bechtel agrees that permits will be required for the testing and they have been considered in the schedule. The commenter has provided no bases for the statement that 30-36 months would be required for the testing. The period defined in the schedule is based on discussions with testing laboratories contacted for this study. The confirmatory testing could be continued longer while the technology permitting process is being worked through if the Owner desires.
	<u>Closed-cycle</u> The closed-cycle options are prohibitively expensive and create short- and long-term adverse environmental impacts well in excess of any possible impacts associated with once-through cooling. • All closed-cycle options require essentially the removal of a mountain – with excavation of between 190 and 316 million cubic yards – in order to create a 62 or 109 acre level pad for placement of the towers. To put the size of the proposed excavation in perspective, the Panama Canal required an excavation of approximately 240 million cubic yards for the 48-mile-long passage. The excavation will in turn require approximately 310 acres of canyon area north of the plant to be filled to a height of between 320 and 500 feet. Thus, at a minimum 400 acres north of the existing plant site would be irreversibly impacted – the mountain can't be replaced or the fill undone when the plant is no longer operational. The draft does not include sufficient information regarding the approach and feasibility of the excavation and fill.	Bechtel agrees that there is a tremendous amount of excavation required for the technology. Bechtel has provided the detailed excavation drawings that were used to develop the excavation quantities in the report. It is unclear what additional information and data is being requested. At the Direction of the Review Committee and with the agreement of PG&E at the November 4th meeting a renderings will be developed for the fill in addition to the excavation.
	• Bechtel's single rendering provides a sense of the scale of the excavation and the height and diameter of the towers. Additional renderings providing a view of each closed-cycle option would assist decision-makers in evaluating these options. Further, it is critical that the final report include a rendering of the fill areas (before and after).	Only one rendering was provided because we believed that it provided the reader an idea of the visual impact of the change. At the direction of the Review Committee and with the agreement of PG&E at the November 4th meeting a rendering will be developed for all five of the CCW technologies.
	• The draft does not include sufficient information regarding the difficulties of permitting and constructing the reclaimed water piping system. This would be a considerable undertaking, particularly given that it would supply no more than 10% of the needed water.	Bechtel has clearly stated that we would be providing the cost of the reclaim water supply on a cost per mile bases. We have also noted the permits we believe will be necessary. This approach was perceived as agreeable to the Review Committee. We believe getting the permits will be possible but will be a significant effort.
	• Given Bechtel's estimated 14-year project duration, any of the closed-cycle options would likely not be operational until 2030.	Bechtel does not know the bases for this projection.
	Section 3 Licensing Nuclear-Specific Assessment (Criterion 10) The Bechtel draft final report continues to reflect the position that none of the proposed technologies would require a Plant Nuclear Operating License Amendment via the License Amendment Request (LAR) process with the Nuclear Regulatory Commission (NRC).	Bechtel's conclusion is based on the Criterion 10 evaluation as written. As noted above Bechtel believes that the Technical Specification requirement to submit changes to the Environmental Protection Plan to the NRC may require a LAR and we have included funds in the estimate for each technology to cover that effort. The Diablo Canyon Independent Safety Committee letter of September 5, 2013 pointed to the emergency gates being

	As stated in comments submitted on July 26, 2013, PG&E disagrees with this position. Our earlier comments are incorporated by reference. PG&E believes that a License Amendment would likely be required for at least the cooling tower and wedgewire options. Providing information regarding the potential impacts to permitting, schedules, and cost in the event NRC approval is required is a prudent approach that ensures committee members have a complete understanding of all possible permitting requirements. Further, Bechtel's response to PG&E's comments noted that, based upon on a review of section 3.1 of the Environmental Protection Plan, NRC approval was required. Thus, PG&E is unclear why the time/cost for NRC permitting is not included in the text of the report.	added to the break water as a potential trigger for a LAR which could be the case, but we believe it could be shown that the complete blockage of the intake tunnel or the complete blockage of all of the wedge wire screens is not credible and the stop log structure is installed as a defense in depth. If an LAR is required we believe that the effort could be completed in parallel with the permitting process and not extend the schedule Agreed Bechtel did include the PG&E recommended funding of $300,000 per technology in the cost.
	Section 4.2.2 Justification 1 mm In justification of selecting a 1 mm slot size, the report cites Table 4 of Tenera's July 2013 report (Length Specific Probabilities of Screen Entrainment of Larval Fish Based on Head Capsule Measurements), which indicates that entrainment reduction would average 67.6%. There are two issues with reliance on this table. First, the data in this table reflects a non-site-specific assessment that incorporates data from eight coastal power plants (including SONGS and Diablo Canyon), and assumes screen effectiveness across all larval length classes. Second, and more importantly, as noted on page 13 of the Tenera report, "the most reasonable approach is to adjust the effective population level reductions for the slot size based on the length range of the larvae." This approach is documented in Table 9, and estimates a reduction of 39.7% for a 1 mm slot size that is site specific, and reflects the smaller larvae generally entrained at the Diablo Canyon facility. Further, Table 8 reflects a direct estimate of entrainment reduction based solely on larval size, and assuming that all larvae contribute equally to the population. This estimate for Diablo Canyon for 1 mm slot size is 5.2%. Thus, the true efficacy of fine mesh screens is likely quite low – certainly no higher than 40%. This estimate also does not consider larval survival following intake screen impingement and return to the source water. Additionally, this measure of efficacy does not include further considerations of biofouling and clogging in a marine environment which are likely to impact actual screen operability and performance. Bechtel should revisit the Tenera July 2013 report and ensure that its findings are accurately included and addressed within the fine mesh screen assessment.	Tenera's July 2013 report estimates entrainment potential based solely on comparing the head capsule size versus the slot opening. This approach is very conservative since it does not account for impingement of larvae notochord length on to a given slot opening. However, recognizing this conservative assumption, entrainment reduction results for different slot sizes for individual taxa from the Tenera's July 2013 were used, which shows a 67.6% average reduction for a 1 mm slot size for all species (Table 4 of the Tenera reference), based on the analysis of measured notochord length and head capsule dimensions using nonlinear allometric regression analysis . Tenera's July 2013 report did provide an estimated entrainment reduction effectiveness of 39.7% for an installed 1 mm slot size screen at DCPP using site specific data and assuming the notochord dimension to the head capsule relationship follow the same as used in Table 4. The effective entrainment reduction is lower since the DCPP site specific data exhibit smaller notochord dimensions overall. Due to the limited samples, Bechtel is not endorsing the site specific findings. At the November 4th Review Committee meeting the Review Committee provided an updated Tenera study dated October 29th that was being peer reviewed by the State Water Resources Control Board and directed that, subject to the agreement of Dr. Ramondi, this report be the bases for the Bechtel efficacy review. Bechtel agreed to review the report and use it subject to that review.
	4.1.5 Civil Design 1) Onshore Fine Mesh Screen - modifications to the intake structure appear to entail more than just increasing existing openings in the slab deck at the 17.5' elevation. • The modifications proposed do not reconcile adverse impacts to the seismic qualification, or how the Intake Structure can maintain seismic qualification during the modifications. • The proposed modifications will require extensive reanalysis to address the reduced	Bechtel has not completed formal calculations but we have reviewed the structure and believe that the seismic design of the structure could be maintained during the modification on a per bay bases. Obviously during the detailed design phase if this technology were selected this assumption would have to be confirmed by reanalysis. At the November 4th Review Committee meeting Bechtel agreed to have a conference call with the PG&E engineering team so they could explain why they believe it is not possible to modify a bay with the plant operating at reduced power. Agreed and this would be completed during the detailed design review if this technology were selected.

	vertical and lateral resisting capacities. These items significantly impact the implementation difficulty, and thus the projected schedule and associated costs for completing the proposed intake modification are substantially underestimated. • The proposed schedule (Reference Figure 6.10-1) does not account for implementing the quality related materials and oversight activities as pertains to the requirements of the Plant Seismic Configuration Control Program CF3.ID11. • The proposed schedule does not account for the necessity of a dual unit outage as the structures seismic qualification cannot be maintained during implementation of the civil modifications to accommodate the dual-flow screen orientation. • It is estimated that a dual unit outage of as long as 12 months could be required to adequately implement the proposed design changes. This would include the extensive time periods required to accommodate all quality scope construction activity sub-tasks.	The provisions of this DCPP program were shared with Bechtel but the estimate does include provisions to analyze the structure and maintain the current seismic condition of the building based on the current design bases seismic criterion. As noted above Bechtel believes that this work can be accomplished on a per bay bases allowing for continuing operation of one unit at full power and one unit at reduced load with one circulating pump operating.
	4.1.7 Permitting A three-year timetable for permitting is likely underestimated. As noted above and in prior comments, the permitting schedule should include the likelihood that NRC approval is required.	The permitting schedule associated with the various cooling technologies options were generally based on an examination of the statutory and/or expected permit review periods and the schedule logic associated with each specific permit or approval. In the case of the schedule bounding CEQA review process, additional review steps were included based on specific information on the CEQA schedule process documentation. In addition, a specific final appeal period was selected which ranged from 3 months to a 1 year, depending on the cooling system technology and its attendant environmental impacts. These schedules did not address NRC licensing matters per the initial scope description for this effort. NRC licensing matters are addressed separately in the report (see Section 3.0 Licensing Nuclear-Specific Assessment). The schedule logic and associated assumptions for each cooling system technology assessment were clearly delineated in the report. Consequently, there is a credible basis for the permitting schedules. As with any environmental permitting process, there are uncertainties in the process that are difficult to forecast to every organizations' satisfaction. Most assuredly the time to prepare the permit applications and or comprehensive environmental assessment documentation, complexities associated with intervener actions and the length of the permit appeal process and associated legal processes can be the subject of much debate. The one-year period to develop the permit applications and CEQA-related EIR for the various options, which has been characterized as insufficient, was based in part are based on the assumption that that most of the conceptual engineering needed to support this permitting process has already been completed to support development of this report. Thus, the processes to prepare the EIR and associated permit applications have a significant head start, which would support immediate initiation of any appropriate related field investigation studies. In some cases, the significant amount of existing environmental information associated with this long-studied site will also serve to expedite this process. The two-year review period (CEQA review) has a specific basis that is aligned with the documented CEQA review process. Longer review periods can be predicted only with the foreknowledge that the initial EIR submittal and follow-up responses will be deemed incomplete. Finally, the length of the CEQA-related appeal periods do vary by cooling technology options, so the overall permitting periods are not the same for all of these technologies. The potentially more contentious wedge-wire and closed-cooling cycle options have the longer appeal periods. As noted earlier, the length of these appeal periods are subject to debate and there are no certain conclusions. While there are examples of projects (in California) which have boasted lengthier permitting schedules, there are also numerous complex power projects (on California-based "Greenfield" sites) with permitting schedules that are supportive of the permitting schedules listed in the report. Similarly, the costs estimates for the permitting process were also based on identification of statutory permit

		filing fees (if applicable), associated direct costs (e.g., emission offset fees) and specific assumptions regarding the number of job hours and cost per job hour associated with preparing the individual permit applications and the comprehensive environmental impact report. The assessment of permitting costs did not include legal costs and associated mitigation costs. The determination of these, not insignificant, cost considerations, were determined to be beyond the scope of this report - a point clearly delineated in the report. The rationale for this exclusion was specifically addressed with and approved by representatives of the PG&E and review board. Consequently, the report provided a specific, delineated and approved permit cost estimate methodology for the various cooling system technologies. The final permitting costs, inclusive of legal and mitigation costs, will, however, obviously be greater than the cost estimates reflected in the report. The permitting times displayed in the Draft Final report schedules were discussed at the November 4th Review Committee meeting and it was agreed that the proposed durations were acceptable and should not be changed.
	4.2.1 Existing Conditions The breakwaters design function will be adversely impacted by the proposed changes. The grouted/sealed modification (reference installation of seal liner 5.2.13) has several negative attributes: • Wave energy dissipation is partially negated • Increased forces will exceed the structures design capacity • Historically severe wave forces have demonstrated the existing systems limited design margin	The design approach being used by Bechtel is not to grout seal the break water. Bechtel will utilize a grout filled blanket on the inner surface of the break water. Refer to report section 5.2.13.
	4.2.2 Alternate Concept A New breakwater model (closed intake cove isolated from ultimate heat sink): The proposed alternatives could be considered adverse to safety due to the restricted inlets and potential events that would render the system ineffective. Alternatives do not address the possible consequences associated with a failure or loss of capability in a seismic event (Reference Comment Section 3 Licensing Nuclear-Specific Assessment). Therefore, the degree of quality related construction required to maintain a reliable heat sink should be accounted in the cost estimates associated with this alternative.	The design utilizes a 30 foot diameter seismically designed tunnel and screen arrays that include between 48 and 30 screening units depending on the final slot size. The ESW systems require a flow of 22,000 GPM to support the safety related applications. It is extremely unlikely that any event would cause blockage of the inlet system to the extent that less than 22,000GPM could flow through the inlet system. Additionally the cove would provide a reservoir to the system. The emergency cooling intake structure was provided as a defiance feature. The design, schedule, and cost do consider the seismic nature of the design.
	4.2.3 Alternate Concept B Comments relevant to quality related construction and subsequent cost impacts apply for similar reasons as stated regarding Alternate Concept A.	The design adopted the same quality philosophy as Concept A but during the pricing phase of the project it was evident that Concept B would be significantly more expensive than Concept A so efforts on Concept B were stopped.
	4.2.8 Permitting A three-year timetable for permitting is significantly underestimated. The schedule does not seem to include specific permitting for the pilot project. While some degree of coordination may be possible, the pilot project would require permitting prior to implementation. As with the other options, the possibility of NRC approval must be included in the permitting costs/schedule.	The permitting times displayed in the Draft Final report schedules were discussed at the November 4th Review Committee meeting and it was agreed that the proposed durations were acceptable and should not be changed.
	4.3.1.3 Civil Design Page 83 (2nd paragraph): "Existing plant buildings 102, 518, 519, 520, 521, 527, and 528	This comment will be incorporated.

	(refer to DCPP Drawing 512297, sheet 1)" - The text needs to be revised as follows: "Existing plant buildings 102, 518, 519, 520, 521, 527, and 528 (refer to Figure 4.3-6 Site Development Plan [Plant Site Area])."	
	4.3.1.3.1 230 kV Line Relocation Page 86: The following text requires revision (note: corrects an inadvertent error provided in an interim report revision request) - "Three two-circuit high-voltage transmission towers of the existing 230 kV line and one single-circuit high-voltage tower of the existing 500 kV line would have to be moved." The correct descriptive text is: "Three two-circuit high-voltage transmission towers of the existing 230 kV line and three single-phase high-voltage towers of the existing 500 kV line would have to be moved." This same revision is also required in draft report section 1.2.2.1 (Page 6) "230 kV Line Relocation."	Bechtel agrees with this comment and will change the wording in the report as follows: *Three ~~two~~ double circuit high-voltage transmission towers of the existing 230 kV line and three single-phase high-voltage towers of the existing 500 kV single circuit line would have to be moved. Only verbiage change no change to figures* If there is a significant cost impact the cost will be updated.
	4.3.8 Permitting Potential NRC approval of the closed-cycle options must be included in the permitting schedule/costs. Additionally, for the closed-cycle options, and likely the other options as well, an entry for a National Historic Preservation Act Section 106 consultation should be added, along with noting the need for tribal consultation. A three-year timetable for permitting is high unlikely. Providing only a year to develop an EIR/EIS for a project the magnitude of any of the cooling tower options is not reasonable. The project includes a massive excavation, fill of over 310 acres, and construction of a water pipeline to adjacent communities. Further, the two-year review process is underestimated – particularly given past experience with other significant projects on the plant site.	The permitting times presented in the Draft Final report schedules were discussed at the November 4th Review Committee meeting and it was agreed that the proposed durations were acceptable and should not be changed.
	5.1 Fine Mesh The construction approach should reflect the schedule changes associated with the adverse effect the modifications will have on the seismic qualification for the global Intake structure. The assumption that "the concrete deck and the Intake structure are adequate for openings" and "no other modifications are required [in the intake structure]" (Reference Section 4.1.5.3, Page32) is highly unlikely without significant added structural support. ▪ A dual-unit outage needs to be included in the construction approach for reasons stated in comments for the Civil Design, Section 4.1.5. Impact to schedule needs to reflect the QV/QA (Quality Verification and Quality Assurance) for the proposed modifications and reconstruction of the intake structure.	Bechtel has not completed formal calculations but we have reviewed the structure and believe that the seismic design of the structure could be maintained during the modification on a per bay bases. Obviously during the detailed design phase if this technology were selected this assumption would have to be confirmed by reanalysis. At the November 4th Review Committee meeting Bechtel agreed to have a conference call with the PG&E engineering team so they could explain why they believe it is not possible to modify a bay with the plant operating at reduced power.
	Section 6.2 CEQA is a review process, not a permit. The process is triggered by the need for a discretionary permit from an agency, unless the activity is categorically or statutorily exempt. This should be clarified throughout the document (e.g. subsection 6.3 below and other permitting sections). The "CEQA permit approval" row should be relabeled as project permitting. The proposed schedule duration for the offshore modular wedgewire concept does not	References to the CEQA permit will be revised to reflect its nature as a review process. This review process is appropriately referenced in reports Section 4.3.8 Permitting.

	adequately reflect the need for extensive permitting to implement the pilot study. Additionally, as noted in comments on Attachment 2 – Offshore Modular Wedgewire Screen Pilot Testing Plan, the pilot period should be expanded to adequately evaluate screen module corrosion/fouling performance and deployment survivability during a site-specific pilot study. The reference to a five-year permit schedule does not align with the three-year estimates included in section 4 – Preliminary Design Development.	References to the five-year permit schedule reflect the inclusion of the supplemental permitting process associated with initial pre-development site investigations and the follow-on appeal period associated with the end of the CEQA review process.
	Section 6.10 If the construction approach cannot maintain the seismic qualification of the intake structure, both units need to be offline (dual-unit outage). Added quality scope to the construction approach will significantly impact the Bechtel proposed schedule (Figure 6.10-1) which incorrectly assumes the modifications can adequately be accomplished during individual circulation water pump (CWP) clearances; in conjunction with curtailment-only of the impacted unit. The proposed schedule identifies a 12-month period to implement the structural modifications, and install the new fine-mesh screen unit equipment, fish return system components, and additional screen wash pumps and piping for both units within the intake structure boundary; assuming that individual CWPs will be cleared sequentially to accommodate a staggered project implementation approach. Evaluation by PG&E plant project and construction experts determined the overall scope could only realistically be completed, at best, within the projected 12-month period if the civil structural modifications for both units (all circulators) were conducted in parallel, followed in sequence by the screening equipment conversions and new piping and pump installations; effectively eliminating a staggered approach. A dual-unit outage approach is also effectively a necessity due to the intake structure seismic qualification restraints. In addition, it is incorrect to assume that long-term individual CWP clearances would be an acceptable plant configuration in any scenario to facilitate significant structural or equipment modifications at the intake. This would create an extended adverse operational condition, placing a unit in an elevated trip risk in the event the single remaining operable circulator became unavailable on an emergent basis (equipment failure, excessive traveling screen debris loading, etc.). Curtailment of a unit and clearance of an individual main circulating water pump does occur for planned short-duration maintenance or testing activities. However, this configuration is not intended for long durations because of the inherent elevated operational risks. Significant traveling screen and screen wash equipment maintenance or upgrade activities, which generally do not incorporate structural modifications, are currently implemented only during unit outages for this same reason.	As noted above, based on preliminary structural investigations to be confirmed by detailed analysis during the detailed design phase Bechtel believes that it is possible to modify the structure on a bay by bay bases It is true that if a unit is operated for a period of time with one circulator out of service there is an elevated unit trip risk but it is believed that maintaining partial output is an important option to be considered due to the reduced cost and we believe it is technically feasible.
	6.12 Inclusion of partial outages (unit curtailments) as critical path activities is problematic. Reference comments regarding necessity for a dual-unit outage due to global intake structure seismic qualification restraints.	The reasoning for this approach is discussed in the report and above
	6.13 It is unrealistic to assume that an offshore wedgewire screen array could be placed in	During the build out of the breakwater prior to installing the Emergency Cooling Water Intake structure it will

	service, and the existing plant intake cove closed off, without significant operational testing to verify that the overall installation would perform as designed during full power operations. During final build of the breakwater modifications - which would effectively isolate the plant intake structure from direct connection to the ultimate heat sink (i.e. current configuration) - unit curtailments or outages would be required. It is unrealistic to assume that an offshore wedgewire screen array could be placed in service, and the existing plant intake cove closed off, without significant operational testing to verify that the overall installation would perform as designed during full power operations. During final build of the breakwater modifications - which would effectively isolate the plant intake structure from direct connection to the ultimate heat sink (i.e. current configuration) - unit curtailments or outages would be required. A minimum period of 6-8 weeks start-up testing would be required following final close-off of the existing breakwater opening. Unit outages would also be necessary during most, if not all, of the install of the breakwater closure infrastructure. This would incorporate functional testing of the as-installed emergency stop-log gate concept. Plant cooling source water draw would effectively be limited to the auxiliary salt water system, avoiding the potential for unit reactor trips due to a loss of main condenser cooling water flow (due to any unforeseen circumstances or possible scenarios) during this portion of project implementation. The timing for construction of the breakwater closure and incorporated stop-log infrastructure is approximately 6 months in the proposed implementation schedule (Reference Figure 6.13-1). A dual-unit outage of up to 8 months (6 months breakwater closure and 2 months subsequent start-up testing) is projected; and should be factored into both the schedule and cost estimates.	be very evident that the wedge wire screens are operating as intended. As the intake basin opening area is close the flow through the wedge wire system will increase and the basin level will remain constant. Additionally the water flow velocity through the opening will not increase substantially. This will be evidence that the wedge wire screens are working as designed and this coupled with the insitu testing that would be completed prior to completing the design with provide assurance that the technology will functionally as designed. Bechtel does not agree that a duel outage would be required to install this technology.
	6.14 The assumption that “an in-situ testing program for the wedgewire screens will take place during the permitting process in advance of the CEQA permit approval” is incorrect. Reference comments below related to Attachment 2 - Offshore Modular Wedgewire Screen Pilot Testing Plan. The significant infrastructure deployment and offshore lands-use aspects of the proposed pilot testing could not occur prior to securing permitting from the California Coastal Commission and State Lands Commission, as well as other state and federal agencies.	Bechtel agrees that a permitting process will be required for the testing program. The schedule improperly does not show this permitting process. The schedule will be revised to properly show the permitting process prior to testing. The permitting for the testing would be completed in parallel with the permitting approach necessary to implement the technology
	6.15 The assumption that “in situ testing for biological and debris effects will be accomplished during the permitting process” is incorrect. Reference comments below related to Attachment 2 - Offshore Modular Wedgewire Screen Pilot Testing Plan, and comments for subsection 6.14.	The permitting process prior to the insitu testing was considered but not displayed on the wedge wire schedule. The schedule will be updated to show the permitting process prior to the testing. The permitting for the testing would be completed in parallel with the permitting necessary to implement the technology
	7.1 Bechtel estimates are based on “overnight pricing” and exclude escalation. Presenting cost estimates for these long duration projects in present day 2013 dollars understates the true cost and expected financial obligation required to fund the projects. Bechtel estimates exclude owner’s costs such as engineering and project oversight, security and other support costs, simulator upgrades, plant shutdown and startup costs, as well as future increases in plant maintenance costs, and future costs associated with losses due to station derates for the various closed cooling options.	The Bechtel approach was discussed in detail at the August 12th Review Committee meeting and it was agreed that Bechtel was to provide overnight pricing with no escalation. Bechtel has a request in to PG&E to supply these costs. When they are supplied they will be applied as owner cost to each technology.

	7.3.2 to 7.3.6 Cooling Tower Options The average total project price (excluding replacement power costs) for the five closed-cycle cooling retrofit options provided by Bechtel is $7.7 billion (in present day 2013 dollars) with an average project duration of about 13 years. After spreading the Bechtel estimate over an assumed cash flow for the project duration and adding in necessary owner's costs, PG&E estimates that the average cost of the cooling tower options will increase by $3.2 billion, to $10.9 billion. This increase reflects the addition of the items noted in section 7.1 of this report. The major components of these added owner's costs are the inclusion of estimates for: 1) Burdens and Allowance for Funds Used During Construction (AFUDC or cost of capital) – 45% of added owners costs; 2) Escalation – 43% of added owners costs; and 3) PG&E project oversight and support costs, and simulator, facility and infrastructure modifications, and plant start-up costs after extended shutdowns –12% of added owner's costs. Projected costs for transportation of reclaimed water from offsite resources to the remote plant site were requested by the Review Committee (costs of piping and pumping infrastructure). This was intended to provide insight into the specific costs for this component of the wet variant technologies. This cost has not been itemized in the estimate, or otherwise provided in the report text.	Bechtel agrees that the cost will increase when the Owner costs are added to the price presented by Bechtel in the Draft report. Bechtel has a request in to PG&E to supply these costs. When they are supplied they will be applied as owner cost to each technology.
	7.3.7 Onshore Mechanical Fine Mesh Screening Bechtel's Total Project Price (excluding replacement power costs) for the Onshore Fine Mesh Screen implementation is $197 million with schedule duration of about 7.5 years. After spreading the Bechtel estimate over the project schedule with an assumed cash flow and adding in the necessary owner's costs, PG&E estimates the total Project cost for the Fine Mesh Screening Option to be $434 million (excluding replacement power costs). This represents an increase of $237 million. The major drivers for these added owners costs are the inclusion of estimates for: 1) Burdens and AFUDC – 32% of the added owners costs; 2) Escalation – 24% of the added owners costs; 3) PG&E project oversight and support costs and plant start-up costs after extended shutdowns – 44% of the added owners' costs, and 4) additions to the Bechtel estimate to allow for quality related concrete work, Security compensatory measures, and protection of the intake Auxiliary Salt Water trains during project implementation – $30 million of added costs, are included in the item 3 percentage. Bechtel's replacement power estimate for the fine-mesh screen concept is based on staggered unit curtailment(s) to 50% power for 183 days; effectively 91.5 days of lost station generating capacity. This assumes that individual circulating water pumps can be cleared and the impacted unit remains in operation at reduced capacity during the screen retrofit modifications. This assumption is incorrect due to the inability to maintain seismic qualification of the global intake structure during implementation of the civil structural modifications required. A dual-unit outage of at least 12 months duration would be required to adequately complete the proposed modifications due to the seismic restraints. Actual replacement power costs therefore would reach as high as $852 million.	Bechtel agrees that the cost will increase when the Owner costs are added to the price presented by Bechtel in the Draft report. Bechtel has a request in to PG&E to supply these costs. When they are supplied they will be applied as owner cost to each technology. Note that Bechtel understands that the construction work on the intake structure would be quality related and has factored this fact into our construction and material costs. As has been previously noted Bechtel believes that the modifications can be accomplished on a bay by bay bases and our schedule assumptions are correct.

	This estimate assumes replacement of Unit-1 & Unit-2 base load generation of 2,310 MWe Net (Average 1,155 MWe per Unit) for 365 days (8,760 hours) with a 90% Capacity Factor; and using $46.76 per MWhr for the replacement power cost (E3; 2013). Reference comments regarding schedule development in subsection 6.10 (onshore mechanical fine mesh screening technology) describing projected requirement for a dual-unit outage of at least 12 months in duration.	Bechtel agrees and will apply the 90% capacity factor to the replacement costs.
	7.3.8 Offshore Modular Wedgewire Screening System Bechtel's Total Project Price (excluding replacement power costs) for the Offshore Modular Wedgewire Screening System implementation is $314 million with a project duration of about 9.5 years. After spreading the Bechtel estimate over the project schedule with an assumed cash flow and adding in the necessary owner's costs, PG&E estimates the total Project cost for the Offshore Modular Wedgewire Screening Option to be $621 million (excluding replacement power costs currently projected by Bechtel as $0). This represents an increase of $307 million. The major drivers for these added owners costs are the inclusion of estimates for: 1) Burdens and AFUDC – 35% of the added costs; 2) Escalation – 37% of the added costs; and 3) PG&E project oversight and support costs - 28% of the added owners' costs. A dual-unit outage of up to 8 months is projected to adequately complete installation (close-off the existing intake cove) and facilitate necessary start-up testing of the proposed offshore wedgewire screen concept. This would result in replacement power costs of approximately $560 million. The estimate assumes replacement of Unit-1 & Unit-2 base load generation of 2,310 MWe Net (Average 1,155 MWe per Unit) for 240 days (5,760 hours) with a 90% Capacity Factor; and using $46.76 per MWhr for the replacement power cost (E3; 2013). Reference comments regarding schedule development in subsection 6.13 (offshore modular wedgewire screens) describing projected necessity for a dual- unit outage of up to 8 months in duration. Projected cost for conducting a wedgewire screen pilot study was requested by the Review Committee. This was intended to provide insight into the costs for planning and implementing a site-specific test of the technology. This cost has not been itemized in the estimate, or otherwise provided in the report text.	Bechtel agrees that the cost will increase when the Owner costs are added to the price presented by Bechtel in the Draft report. Bechtel has a request in to PG&E to supply these costs. When they are supplied they will be applied as owner cost to each technology. As discussed above, Bechtel does not agree that an 8 month duel outage would be necessary to commission this technology. Bechtel agrees and will apply the 90% capacity factor to the replacement costs. The cost for the wedge wire insitu testing included in the cost presented in the report is $5,210,000. It will be itemized in the report.
	7.4.7 Page 188 Wedgewire The commodity quantity summary for the wedgewire screen concept identifies 10' diameter reinforced concrete headers and wedge wire screens, but no piping or connections that might be expected between the horizontal concrete headers and individual screen module outlet flanges (piping connections as depicted in the schematics for Concept A: Offshore Tunnel - Report Section 4.2.2). Additionally, the estimate developed for the wedgewire (7.3.8) shows 'piping' to be a total cost of $0. Is it correct that there are no separate itemizations for piping or other infrastructure connecting the screen module units to the concrete headers?	The pricing for the tunnel and risers was provided by a specialty contractor to Bechtel guidance. That pricing did not specifically call out quantities which will vary based on topography so the quantities were not specifically noted.

	7.10.5 Escalation Bechtel estimates exclude escalation. See estimate summary for Section 7.3 for PG&E estimate which includes owner's costs and escalation.	The Bechtel approach was discussed in detail at the August 12th Review Committee meeting and it was agreed that Bechtel was to provide overnight pricing with no escalation.
	7.10.7 Permits Page 193: References to multiple tables identify "DCCP" – these should be "DCPP"	This will be corrected in the final report.
	7.10.8 PG&E Costs Bechtel estimates exclude all PG&E costs with the exception of replacement power during plant shutdown for various proposed project installation periods. For estimates of PG&E costs reference the comments for Section 7.3 of the draft report. Bechtel does not include the going-forward costs of increased maintenance and power derates after the various projects have been implemented. Following are those site-estimated costs for the various options on an annual basis: Project — Incr. Annual Maintenance — Power Derate $* Avg. Cooling Tower Options — $6.3M/yr. — $44-80 M/yr. Onshore Fine Mesh Screens — $1.1M/yr. — 0 Offshore Wedge Wire Screens — $1.1M/yr. — 0 *Using E3 (2013) $46.76 per MWhr Replacement Power Cost Estimate. Bechtel's calculations for replacement power costs for long-duration dual-unit outages associated with the closed-cycle retrofit variants assumes a Capacity Factor (CF) of 1.0. Planned unit refueling outages and periodic maintenance or testing curtailments reduce actual power production over time to less than 100%. Unplanned forced unit outages or curtailments may also occur over time, and should be considered as well. A Capacity Factor of 0.9 is suggested for calculating long-duration replacement power costs; which assumes 90% unit/station availability and full-power production operations over time. This is a more conservative value in relation to actual averaged plant performance, and is also consistent with the Capacity Factor used in previous assessments of replacement power costs that would be realized to implement long-duration outages for closed-cycle cooling retrofit. Using a Capacity Factor of 0.9 reduces Bechtel's calculated estimate for replacement power cost for a 530-day dual-unit outage from $1.374 billion to $1.237 billion, and the estimate for a 576-day dual-unit outage from $1.493 billion to $1.344 billion.	Bechtel agrees that the cost will increase when the Owner costs are added to the price presented by Bechtel in the Draft report. Bechtel has a request in to PG&E to supply these costs. When they are supplied they will be applied as owner cost to each technology. Bechtel agrees and will apply the 90% capacity factor to the replacement costs.
	7.12 Exclusions In order to provide a more robust sense of the full costs of the various options, in Section 7.3 comments, PG&E provides estimates for the following excluded items: • 8. Engineering oversight by PG&E • 9. Security oversight by PG&E and security modifications • 11. Plant Shutdown and start-up costs • 12. Annual increase to operation and maintenance costs • 13. Annual cost of replacement power for lost MW (derates)	Bechtel agrees that the cost will increase when the Owner costs are added to the price presented by Bechtel in the Draft report. Bechtel has a request in to PG&E to supply these costs. When they are supplied they will be applied as owner cost to each technology.

	• 14. Simulator update modifications Additionally the following items are not listed as exclusions but have been included in PG&E's adders: • Owner's overheads • Cost of capital (AFUDC) • Other site infrastructure modifications and changes	
	Attachment 2 A.1 Introduction & Purpose An assessment of saltwater corrosive impacts should be a key objective of any pilot study for wedgewire deployment in a marine environment. The metal alloys that by necessity would be used in screen construction to retard encrusting bio-fouling would likely be prone to leaching. Specifically, copper, nickel, or other constituents of z-alloy or other similar materials. Potential adverse impacts to final plant wastewater discharge quality must be considered and adequately investigated as part of any proposed pilot study.	The pilot study focus on addressing the most important two questions facing the wedge wire screen deployments: (1) will a smaller screen slot size (between 2 mm slot and 6 mm slot) be sufficiently effective in reducing the entrainment and impingement, and (2) would there be bio-fouling and/or debris blockage issues to these screen slot sizes. The outcome desired for the pilot study would be to determine either 2 mm slot or 6 mm slot size be selected, or to conclude the wedge wire technology not effective (if both screen sizes fail the test) or if a slot size is effective but debris blockage would be an issue. Copper based screen material has been used for marine environments and its leaching rate is basically known and can be properly estimated. The leaching effect and its impact will be determined and is a permitting issue to be resolved during design and construction phase.
	A.2.2 Engineering Design and Testing Use of 24-inch diameter cylindrical screen modules to perform site-specific pilot testing would not adequately recreate the actual conditions that scaled operational modules (8-ft diameter, 35-ft length) would be subjected to in the open ocean environment. The impacts of long-period ocean swell energy in the near-shore zone and debris loading from disrupted understory algal debris and sediments on test modules would need to be adequately modeled. Larger test modules would likely be required to effectively determine performance and survivability of screens in turbulent ocean conditions accompanied by moderate to heavy debris loading suspended throughout the water column.	It is Bechtel's assessment after consulting with a world renowned testing laboratory that use of 24-in wedge wire screen will yield reasonable and sufficient data points for all involved to make a determination of its effectiveness. As it is noted, it is the thru slot velocity that matters, in terms whether screen clogging could occur or a reduction in entrainment be realized (assuming samples evenly distributed in the water column).
	The through-screen velocity proposed for the pilot study is 0.4 ft./sec. However, the proposed maximum through-screen operating velocity of the wedgewire array concepts is 0.5 ft./sec. Any pilot study should incorporate a flow-through velocity that is equivalent to the proposed scaled operation. Using a lower velocity could adversely skew screen debris loading performance data collected.	Thru screen velocity is not to exceed 0.5 fps so 0.4 fps is close to the value. Also there are margins in the proposed screen layout that the actual thru slot velocity is slightly less than 0.5 fps. Nonetheless, we can modify the report to indicate the nominal 0.5 fps thru slot velocity to be used in the pilot study.
	The proposed approach assumes that a pilot study would be conducted during the period when permitting was in-progress for the full-scale installation. The pilot study would include deployment of significant infrastructure; including 12- inch and 15-inch diameter HDPE piping (with concrete ballast weights) placed on the seafloor, rip-rap cover in the near-shore and intertidal zones, and camera equipment with battery packs. Authorization to install the significant pilot study infrastructure would be required from the California Coastal Commissions, the State lands Commission, as well as other state and federal agencies – it is not something that could be accomplished in parallel to obtaining permits for the full scale installation. The overall schedule and cost outlined for the wedgewire screen option must be revised to	The permitting process prior to the insitu testing was considered but not displayed on the wedge wire schedule. The schedule will be updated to show the permitting process prior to the testing. The permitting for the testing would be completed in parallel with the permitting necessary to implement the technology

	accurately reflect the need to obtain permits for the pilot study. Water circulated through a pilot study apparatus would need to be discharged back to the source water body; the plan identifies this requirement. The projected volume for the proposed 2 mm and 6 mm wedgewire testing modules (using the small-scaled 2-ft diameter module concept) is approximately 6.5 million gallons per day. This volume does not include any contribution from study controls (open port) which is not described. Such a substantial water volume, which likely would likely be contaminated with metals, could not be discharged back to the ocean without agency authorization. Thus, in addition to ensuring that all permitting for the siting of pilot study infrastructure is accurately identified, the Plant's existing NPDES permit may need to be modified to address the discharge from the pilot study, or a separate permit may be required.	Testing permits would be completed as noted above.
	A.2.3 Biological Sampling The suggested study period is 12 months. This may be adequate for comparative screen slot entrainment exclusion and impingement avoidance efficacy assessment. However, this period would be inadequate to evaluate long-term fouling performance, screen corrosion and alloy degradation performance, or to profile metal alloy constituent leaching over time for wedgewire modules installed in the marine environment. A test period of 30-36 months is more realistic to evaluate these equipment performance factors on a site-specific basis; a necessity before any determination could be reached that a large offshore screen array could be installed and successfully operated.	It is recognized that, for a pilot study like this, the longer the testing period the better. It is Bechtel's assessment after consultation with two laboratories is that a 12-month of testing period will be minimum but adequate, in order to gather sufficient data points to make a determination.
	Seismic design should be conducted in accordance with current computation standards using the best available knowledge. This is an important concept because the information used to modify the plant's design in the 80s has been updated considerably since then and is currently in debate between PG&E and the IPRP. PG&E should use the best available knowledge and not rely solely on the ground motion values used in the 1984 Final Safety Analysis Report Updated (FSARU).	The bases of the Bechtel seismic evaluations are the licensing bases as documented in the UFSAR. Bechtel has not considered any new emerging industry approach.
	Permitting. Permitting ocean bottom excavations and shore line reconstruction will have significant opposition. This applies to all considered ocean bottom disturbing alternatives and to the enclosure of the intake basin.	Agreed but the regulatory agencies have not indicated that the required permits are not possible.
	Bechtel states that modification to the steam turbines would be necessary for the closed cooling system. In light of the problems experienced at San Onofre, it may not be prudent to "modify" operating/used steam turbines.	This is very different from the SONGS issue. The science involved with turbine modifications is well understood and the turbine does not directly interface with the reactor coolant system in any way.
	The excavation for the cooling towers is expected to generate 506 million cubic yards of spoils. There is no indication of where they intend to store that volume of soil.	Renderings are being developed at the request of the Review Committee and the Owner that will be added to the report.
	The water source for evaporative coolers is largely undetermined. Speculation for the use of industrial waste water is questionable as there is no local industrial area. As Bechtel pointed out in their report, there are new regulations being developed by State	

	Water Board that may add restrictions or additional regulations on the use of desalination on the site. The third possible source is potable water to be supplied from local resources, which is inherently scarce along the central coast.	The section 4.3.4.1 in the report discusses the use of reclaimed water for makeup as well as the use of the 1005 desalinization plant which would supply the makeup water to the wet tower technologies.
	The dry cooling alternatives would not require nearly as much land disturbance as the wet cooling option.	It is true that the dry cooling option s would not require the supply of reclaimed or desalinized water but the tower footprints require greater excavation of the mountain and actually would require more land disturbance for that reason
	Page 6 says, "Makeup water to replenish losses to the environment (i.e., through cooling tower evaporation) would be provided by a combination of freshwater from a new onsite desalination plant and industrial wastewater and potable water to be supplied from local resources." To reflect that getting industrial water due to the pipeline costs could be very expensive and that the makeup water may therefore only come from only desalination Page 6 needs to say, "Makeup water to replenish losses to the environment (i.e., through cooling tower evaporation) would be provided by freshwater from industrial wastewater and potable water to be supplied from local resources and/or a new onsite desalination plant." The distinction is important and I keep making this point that there needs to be an option that makeup water comes exclusively from a desalination plant without the extra costs incurred by piping in wastewater from faraway Waste Water Treatment Plants.	The desalinization system is sized to support the complete makeup requirement for the wet technologies. The recycled water would be used to supplement the desalinized water.
	Likewise page 152 states, "In addition to the desalination plant for the wet technologies, recycle water pump stations will be built at the San Luis Obispo Waste Water Treatment Facility (WWTF) located at 879 Morrow Street and the Morro Bay Waste Water Treatment Facility located at 955 Shasta Ave:" Again the additional pump stations and piping is not necessary as all issues related to having a desalination plant for makeup water should be on the DCPP property. No offsite makeup water is required and costs should be recalculated to reflect this.	Bechtel was directed by the Review Committee through PG&E to bring any reclaim water that is available within a 20 mile radius from DCPP to the plant for use as makeup for the Wet Technologies
	PG 4 Criterion 10, Licensing Nuclear-Specific Assessment **See also page 16-18 and DCISC discussion** "10 CFR 50.59 describes the review that is necessary to determine whether a change, test, or experiment in a licensed nuclear power plant must be approved by the USNRC before being implemented." **50.59 was the process used by the NRC to evaluate the steam generator replacement at SONGS, a process that is today, in retrospect, being reviewed for adequacy. When asked about the use of the 50.59 process at San Onofre, former NRC Commissioner Victor Gllinsky wrote in an email: "SCE and MHI screwed up, but so did NRC. It had a chance to review the changes, which SCE told them about in the Tech Spec change application, and flubbed it."** **After several hours of discussion on Sept 4, 2013 the Diablo Canyon Independent Safety Committee (DCISC) questions the adequacy of the 50.59 process:** **"**While we conclude that most of the proposed cooling system modifications would	Bechtel believes that since all of these technology would clearly be of interest to the NRC and would be watched closely by the NRC but Bechtel believes that the criterion 10 evaluation supports that these changes would be able to be installed without the specific need for an LAR except for the fact that the modifications would likely

	require a NRC license amendment request, Bechtel's conceptual design study has sufficient detail to allow a preliminary conclusion that NRC approval of the license amendment could likely be obtained.**"** **There seems to be a growing opinion that License Amendment Requests (LAR) would be needed for several, if not all, of the alternatives.** **The absence of a LAR was one of the driving components to the early shutdown of SONGS and the Alliance for Nuclear Responsibility believes Bechtel errs when it states,** **"Consequently, subject to the limitations of the Phase 2 assessment information, implementation of the closed-cycle cooling technology, the onshore dual-flow fine mesh screens, or the offshore modular wedge wire screening system design alternatives <u>is believed</u> to not require a License Amendment Request (LAR) in accordance with 10 CFR 50.59." [emphasis added]**	require a change to the Environmental Protection Plan which based on the plant Technical Specifications triggers the need for NRC review. Additionally, the installation of the emergency gate in the sea wall for the wedge wire technology may require NRC review. These points will be addressed in Section 3 of the report. As noted above Bechtel believes that the Technical Specification requirement to submit changes to the Environmental Protection Plan to the NRC may require a LAR and we have included money in the estimate for each technology to cover that effort. The Diablo Canyon Independent Safety Committee letter of September 5, 2013 also pointed to the emergency gates being added to the break water as a potential trigger for a LAR which could be the case, but we believe it could be shown that the complete blockage of the intake tunnel or the complete blockage of all of the wedge wire screens is not credible and the stop log structure is installed as a defense in depth. If an LAR is required we believe that the effort could be completed in parallel with the permitting process and not extend the schedule
	<u>Pg 5 Permitting</u> "Legal costs associated with managing appeal processes and related litigation were not included. Additionally, the bulk of the potential mitigation costs would be developed through negotiation and are consequently not included in the cost estimate. The permitting requirements, along with the associated cost and schedule requirements anticipated for each of the technologies, is summarized in Section 4 of the report. The cost and schedule are addressed in Sections 6 and 7, respectively. Depending of the technology option, the permitting durations range from 3 to 5 years." **It is clear that the Bechtel reviewers are not familiar with precedent and policy in California, as the above statement is overly optimistic. Unless California is willing to trample the rights of environmental and ratepayer organizations, litigation and mitigation will seriously hamper the permitting schedule.**	The costs estimates for the permitting process were also based on identification of statutory permit filing fees (if applicable), associated direct costs (e.g., emission offset fees) and specific assumptions regarding the number of job hours and cost per job hour associated with preparing the individual permit applications and the comprehensive environmental impact report. The assessment of permitting costs did not include legal costs and associated mitigation costs. The determination of these, not insignificant, cost considerations, were determined to be beyond the scope of this report - a point clearly delineated in the report. The rationale for this exclusion was specifically addressed with and approved by representatives of the Review Committee. Consequently, the report provided a specific, delineated and approved permit cost estimate methodology for the various cooling system technologies. The final permitting costs, inclusive of legal and mitigation costs, will, however, obviously be greater than the cost estimates reflected in the report. References to the five-year permit schedule reflect the inclusion of the supplemental permitting process associated with initial pre-development site investigations and the follow-on appeal period associated with the end of the CEQA review process.
	<u>Pg 6 Closed Cooling</u> "The average yearly lost generation (assuming 90% capacity factor) range from 53.6 to 97.3 MW." "The cost of the de-rated output resulting from the installation of these technologies has not been included as part of the installation cost estimate for the technologies." **Can PG&E provide this committee with a cost range for the de-rate?** "For the dry cooling options, modification of the steam turbines is considered necessary."	

	COST of modification to steam turbines? "It will be necessary to excavate a portion of the mountains immediately north of the DCPP power block to an elevation of 115' to provide the space needed to build the new cooling towers. " **Is this parcel in the coastal zone?** 230 kV Line Relocation –**Proposed without an LAR (again from the DCISC) " "**While we conclude that most of the proposed cooling system modifications would require a NRC license amendment request, Bechtel's conceptual design study has sufficient detail to allow a preliminary conclusion that NRC approval of the license amendment could likely be obtained." "Makeup water to replenish losses to the environment (i.e., through cooling tower evaporation) would be provided by a combination of freshwater from a new onsite desalination plant and industrial wastewater and potable water to be supplied from local resources. " **Again Bechtel's lack of skepticism implies an unrealistic concept of CA law. The local communities cited in the report will be filing comments, as these were not contacted by Bechtel and their comments will reflect assumptions and inaccuracies about the availability and quantity of their water supplies.** "It should be noted that the State Water Board is currently developing amendments to the Water Quality Control Plan for Ocean Waters of California. The amended Plan, once adopted, may include requirements for intake and/or brine discharges that could result in restrictions or additional requirements on the use of desalination at the site. " **For those on this committee unfamiliar with proposed amendments a summary and likely prognosis would be valuable before final report.**	The cost of modifying the steam turbine is based on the actual cost experienced by PG&E escalated it from 2005 to present day dollars. The cost of the modification in the estimate is $148,131,000. This is part of the coastal zone Bechtel contacted the water treatment facilities and has realized that a permitting process would be required to be able to utilize the recycled water and that process has been reflected in the cost and schedules presented in the report. The use of this water was mandated by the Review Committee through PG&E. The Review Committee requested Bechtel add these specific words to the report at the August 13 meeting.
	Pg 7 Offshore wedge wire "The concept selected for installing the offshore modular wedge wire screening technology involves enclosing the existing intake cove to form a shoreline basin and extending a new circulating water (CW) conveyance system, either tunnel or buried piping, from the basin to the ocean. Wedge wire screen assemblies would be attached to the ocean end of this conveyance system to enable it to supply filtered seawater to the newly created intake basin, which would be sealed to prevent direct seawater inflow." **Again no NRC LAR – Bechtel is supposed to be world-renown for it's engineering expertise, but seems to be less than knowledgeable about when to use 50.59 or a LAR. However, the NRC has made the same mistake that has proven to be very costly and challenge the state's energy supplies. Ex. SONGS 50.59 approval versus requiring a LAR.** **DCISC The ultimate heat sink** The preceding discussion covered the normal non-safety-related plant cooling system, which discharges waste heat from the condenser to the Pacific	As previously noted, 10CFR 50.59 mandates the industry process to be used to determine if a LAR is required. Bechtel was not requested to do a 10CFR50.59 evaluation as part of this effort but the Criterion 10 evaluation that was required and closely parallels the 10CFR 50.59 process and was completed. Based on the design work completed to date, Bechtel believes the Criterion 10 evaluation supports that these technologies would not require a LAR. We have noted that the plant Technical Specifications do require a submittal to the NRC if the Environmental Protection Plan changes and we believe the plan will require revision which would trigger a submittal to the NRC of the revised plan and this has been included in our cost and schedule. If during the detail design process a LAR is determined to be required or if PG&E elected to submit a LAR the effort would be accomplished in parallel with the permitting process.

	Ocean via a Once-Through Cooling System. A totally separate system, the nuclear-safety-related Auxiliary Saltwater System, discharges plant decay heat to the Pacific Ocean in certain shutdown, off-normal, and emergency conditions. This arrangement is called the Ultimate Heat Sink (UHS) because it is the final or ultimate opportunity to keep the plant cool and safe if all other methods are unavailable or have failed. With two exceptions the seven cooling alternatives proposed by Bechtel would be independent and separate from the UHS, and thus should normally have no adverse impact on nuclear-reactor safety from the UHS standpoint. The two exceptions are the following options: ▪ Inshore mechanical (active) intake fine mesh screening systems ▪ Offshore modular wedge wire systems	
	Pg 7-8 Onshore "Even though this technology does not comply with the maximum 0.5 fps through-screen velocity for impingement mortality reduction described in the California Once-Through Cooling Policy rules, the inclusion of a fish recovery system provides the alternative mitigation measures that support compliance with the California Once-Through Cooling Policy requirements. In order for the plant to operate reliably, an automatic trash raking system is needed to remove large debris trapped on the trash racks located upstream of the plant traveling screens. The cost of designing and constructing an automatic trash removal system has not been estimated as part of this effort. [emphasis added]" **Can Bechtel or PG&E provide a rough estimate?**	If the current bar rack system remains in place and the utility maintains it clear then the Bechtel proposed system would work. Bechtel believes that without an automatic cleaning system this will require PG&E to devote a significant amount of labor to maintain the racks clean. Bechtel was advised that the current design provisions could not be used due to plant needs. Bechtel has not estimated the cost of a cleaning system and cannot offer a price due to the unique requirements the system would have to meet.
	Pg 8 Schedule and cost estimate Bechtel considered the concerns provided to the Nuclear Review Committee following Phase 1 on January 23, 2013, by Mr. Laurence G. Chaset for the Friends of the Earth and the January 23, 2013, letter from Mr. Noah Long and Mses. Angela Kelley, Sarah Sikich, and Sara Aminzadeh representing the Natural Resources Defense Council, Heal the Bay, and the California Coastkeeper Alliance. The concerns brought up in these letters were considered and addressed as appropriate as part of the Phase 2 effort. Has there been any feedback from the above groups? Other comments from outside committee? "The cost data is a Class 3 cost estimate as defined by the Association for the Advancement of Cost Engineering International (AACEI), the estimate includes 20% contingency and an expected accuracy range of -20% to +30%. Section 7 of the report includes a detailed discussion of the cost estimate development, including qualifications and assumptions, and exclusions."	The only other comments that have been received that Bechtel is aware of are the comments provided at the November 5th meeting from the Friends of the Earth, Crow White, the Northern Chumash Tribal Council, The City Of Morro Bay, and the City of San Luis Obispo. The Friends of the Earth comments will be address if directed to do so by PG&E when details are received. The comments from the cities of Morro Bay and San Luis Obispo will be addressed in the Final Report, and the comments from Mr. Crow White and the comments from the Northern Chumash Tribal Council will be addressed when details are provided and when directed by PG&E.

	Pg 8 Phase 2 Resutls Table 1-1. Technology Cost and Schedule Summary **Cost** **Schedule Duration in Years** **Technology** **in Millions** Closed-cycle cooling Mechanical (forced) draft dry/air cooling $8,519 – $12,453 13 years Passive draft dry/air cooling $8,412 – $12,353 13 years Wet mechanical (forced) draft cooling $6,875 – $9,955 14 years Wet natural draft cooling $8,504 – $12,431 14 years Hybrid wet/dry cooling $6,854 – $9,923 13 years Onshore mechanical fine mesh screening $371 - $493 8 years Offshore modular wedge wire screening $261 – $407 10 years **All timeframes (under optimal conditions) are longer that PG&E's current license for Diablo**	Bechtel did not consider the time remaining in the DCPP current license in our preliminary designs, schedule development, or the cost estimates..
	Pg 20 3.3.1 Seismic "The seismic requirements for a design change can be summarized as ensuring that seismically induced structural or functional failure of any new SSCs would not adversely affect safety- related SSCs. Direct effects, such as falling on a safety-related SSC, and indirect effects, such as functional failure affecting the ability of a safety-related SSC to perform its safety function, must be either demonstrated as acceptable or prevented from happening. The new cooling towers would be located remote from the power block and safety-related SSCs so that their partial or total structural failure would not adversely affect any safety-related functions. The new pumphouse(s) for the new CW pumps would be located within the existing power block area and would be sufficiently separated from safety-related SSCs as to pose no direct or indirect adverse effects. Functional failures of the closed-cycle cooling system would not be expected to adversely affect safety-related SSCs or functions since the safety-related cooling requirements of the ASW system would continue to be met since they would not be functionally modified by this change. The existing supports and piping associated with the component cooling water heat exchangers and interfacing ASW system components are seismically designed and would not be adversely affected by the proposed modifications." **Has PG&E made Bechtel or the Committee aware of the controversy surrounding the ability of Diablo Canyon to meet its current seismic design basis and the double**	Per the Contract, Bechtel considered the licensing bases presented in the UFSAR in our preliminary evaluations. Since no formal calculations were completed no specific damping values were used. During the detailed design

	design earthquake? It appears it would be a costly mistake to move towards permitting, much less implementation, until these issues are resolved.	phase the appropriate damping value for the structure being purchased or modified would be used.
	PG 22 3.4.1 Alternative 1–Onshore Mechanical (Active) Intake Fine Mesh Screening System **3.4.1.1 Seismic** "The seismic requirements for the new dual-flow fine mesh screening system, including the fish recovery system, would be same as the existing intake structure seismic design requirements. The safety-related SSCs associated with the ASW system would remain unchanged. The replacement of flow-through screens with dual-flow type screens would not pose an adverse impact from a seismic perspective. The intake and discharge structures do not perform an active safety-related function. They are seismically designed and indirectly support a safety-related function by structurally supporting the ASW pumps, associated once-though screens, and related piping located at the intake structure and the component cooling water system's heat exchangers located in the turbine building and related piping located at the discharge structure. The final design for the new intake and discharge structures for the closed-cycle cooling should ensure that seismically induced structural or functional failure of any new SSCs would not adversely affect safety-related SSCs" **Seismic is reviewed for each technology, but seismic vulnerability is yet to be resolved and will not likely be resolved by 2015. Therefore, with:** • **construction times from 8-14 years for the proposed technologies;** • **an end of operation date of 2024/25 in the current licenses;** • **the NRC's statement that only 1% of the OTC cooling capability would be necessary once plant is not operating** **the costs of phase out and replacement must be part of the SWQCB's decision-making, especially in light of 5 reactors closed in 2013 – what are we investing in and/or how much degradation to our marine life is California willing to allow for power that a CA-ISO study "…determined that there was no material mid-or long-term transmission system impacts associated with the absence of Diablo Canyon."**	As noted above, per the Contract, Bechtel considered the licensing bases presented in the UFSAR in our preliminary evaluations.
	PG 27 (ONSHORE MECHANICAL INTAKE) "Even though this technology does not comply with the maximum 0.5 fps through-screen velocity for impingement mortality reduction described in the California Once-Through Cooling Policy rules, the inclusion of a fish recovery system provides the alternative mitigation measures that support compliance with the California Once-Through Cooling Policy requirements. Similarly, implementation of onshore mechanical fine mesh screening technology substantially reduces entrainment loss and marks significant improvement over the current DCPP situation since it currently has a 100-percent administrative loss of fish, eggs, and larvae due to the very large mesh opening of 9.5 mm on the existing flow-through traveling water screens. In order for the plant to operate reliably, an automatic trash raking system is needed to remove large debris trapped on the trash racks located upstream of the plant traveling screens. Although the plant has a design for an automatic raking system, it cannot be installed on the existing structure due to the installation of the required plant security	

	system. Currently, plant personnel manually remove large debris. This inefficient method of trash removal at times causes the plant to reduce output until the cleaning can be completed. The cost of designing and constructing an automatic trash removal system has not been estimated as part of this effort but would have to be added if the onshore mechanical fine mesh screening technology is selected for implementation." **Is Bechtel assuming a new raking system would resolve the security concerns? Can an estimate (cost and time) for maintaining security while implement system be provided? If not, why not?**	A new raking system would be independent of the security system. If the current rack system remains in place and the utility maintains it clean then the Bechtel proposed system would work. Bechtel believes that without an automatic cleaning system this will require PG&E to devote a significant amount of labor to maintain the racks clean. Bechtel was advised that the current design provisions could not be used due to plant needs. Bechtel has not estimated the cost of a cleaning system and cannot offer a price due to the unique requirements the system would have to meet.
	Pg 27 -28 Hydraulic eval of Dual Flow "Due to the orientation of the dual-flow screen, the flow exiting the screen is through the middle section of the screen well. This results in a more concentrated flow pattern leaving each screen. Even though the exit velocity would be higher than that for the existing flow-through screen, hydraulic evaluation indicates that the current CW pump suction arrangement should tolerate this velocity increase, primarily due to the elaborate use of the formed suction inlet design, a smooth and accelerating turn toward the pump impeller, as shown in Section A of General Arrangement Drawing 25762-110-P1K-WL-00070. However, to confirm this hydraulic assessment, a physical CW pump intake model test should be conducted by a reputable hydraulic laboratory during the final design process if this technology is selected for implementation. Depending on the testing results, it may be necessary to add a surface beam/baffle downstream of the dual-flow screen exits." **Estimate of cost and time for hydraulic assessment?**	The estimated cost to perform a scale model test of the pump intake with consideration of dual flow screens to be installed would be about 6 months and $500,000. This cost will be added to the estimate.
	Pg 28 4.1.2 Justification of Selecting 1 mm Fine Mesh Opening "Fine mesh screens fitted to the traveling water screens belong to the active "collect and transfer" design with a mesh size sufficiently small to minimize entrainment loss of fish, eggs, and larvae. As background information, the existing DCPP traveling water screens have a mesh size of 9.5 mm, which essentially allows all fish, eggs, and larvae to pass through and suffer a 100-percent administrative entrainment loss during plant operation. Any reduction in the number of fish, eggs, and larvae entrained presents an improvement over the current situation of total entrainment loss." **A4NR is assuming this committee is not looking for "any reduction" in entrainment as meeting 316B criteria.** **Pg 34-36 permitting costs seem unrealistic and low**	As noted above, the cost estimates for the permitting process were also based on identification of statutory permit filing fees (if applicable), associated direct costs (e.g., emission offset fees) and specific assumptions regarding the number of job hours and cost per job hour associated with preparing the individual permit applications and the comprehensive environmental impact report. The assessment of permitting costs did not include legal costs and associated mitigation costs. The determination of these, not insignificant, cost considerations, were determined to be beyond the scope of this report - a point clearly delineated in the report. The rationale for this exclusion was specifically addressed with and approved by representatives of the PG&E and review board. Consequently, the report provided a specific, delineated and approved permit cost estimate methodology for the various cooling system technologies. The final permitting costs, inclusive of legal and mitigation costs will likely be greater than the cost estimates reflected in the report.
	PG 41 4.2.1.3 Site Geology and Geotechnical Engineering Data	

	"Geotechnical information is limited, and hydrographic/bathymetry, seismic, geophysical, and geotechnical subsurface investigations would be performed for final design." **As we are discussing Diablo Canyon, and this seismically vulnerable site has been the subject of major disagreement and cost overruns for decades, this issue must be resolved before any alternative is seriously considered.**	This point is outside the scope of the evaluation completed by Bechtel.
	PG 41-42 4.2.1.4 Site Seismicity "From the available information, there is indication for presence of the Shoreline fault located about 1,800 feet offshore of the DCPP. The fault is estimated to be 600 feet offshore of the DCPP inner breakwater, and for both concepts (tunnel and piping systems) the footprint of the wedge wire assembly area is very close to the Shoreline fault, if not overlapping. Based on several qualitative and indirect quantitative estimates of slip rate (the fault zone lies entirely offshore and there are no identified geomorphic features that can be reliably used as lateral offset markers), the interpreted slip rate on the Shoreline fault zone ranges from 0.02 inch/year (0.05 mm/yr) to possibly 0.04 inch/year (1 mm/yr), with a preferred range of 0.008 to 0.012 inch/year (0.2 to 0.3 mm/yr). The slip rate could also be zero (Reference 2). Thus, for both concepts (tunnel and piping), the systems/structures should be designed to withstand the ground motions from this fault and any impact of a potential slip. The extent of the fracture zone is not known at this time but can be estimated beforehand by drilling boreholes and performing geophysical tests during detail engineering studies." **Is Bechtel suggesting that this alternative be postponed until at least 2015 when PG&E's plans to provide the information necessary for any process at Diablo to continue in a seismically secure manner?**	No, Bechtel is indicating that as part of the detail design for the wedge wire design detailed geological surveys would be conducted in the area of the tunnel and wedge wire arrays.
	PG 52 Offshore tunnel "For the tunneling concept, depending on the site conditions evaluation, various remediation techniques can be considered to deal with fault zones involving soil/rock under water pressure. One solution may be to seal and strengthen the ground ahead of the working face. In deep tunnels, a permanent strengthening and sealing is often required and can be obtained by grouting. Injecting grout that subsequently hardens into the ground increases the ground's strength, stiffness, and imperviousness" **Are there any estimates (time and cost) of "remediation techniques" to "deal with fault zones?"**	Reasonable remediation efforts have been included in our estimate.
	PG 66 "The DCPP site has a fractured rocky shoreline with a bathymetry characterized by a sloping bedrock bottom with steep relief, rocky pinnacles, and prominent rocky ridges. These features may limit sea-bottom excavation for the pipe alternative. Similarly, the near-shore seismic fault zones would affect tunnel construction and, thus, the feasibility of the tunnel alternative. Detailed offshore geotechnical investigations and construction-method evaluations should be pursued to select the most viable alternative, considering the effect of a hypothetical offshore seismic event effect on either." **Again cost and time estimates are needed?**	These geological studies would be conducted early in the detailed design phase for the technology selected as

		noted on the schedule. These studies and reasonable mitigation has been considered in the provided schedule and estimate development.
	<u>Pg 71 4.2.8.2 Summary</u> "Revisions to the existing Fire Safety Plan are not expected to result in additional filing or direct regulatory fees. The initial filing fee of $408 would probably not apply. Labor costs for revising Fire Safety Plan = 20 hours @ $150/hr. **$1,110,999** **Undetermined $2,793,600** <u>The list of potentially applicable federal, state, and local permits for the offshore modular wedge wire screening system reflects the potentially significant impacts to the onshore and near-shore marine environment.</u> The efforts to conduct a successful CEQA review would be the primary critical path permitting process. The CEQA lead agency may be a shared responsibility among a number of key regulatory departments (e.g., SLO, CSLC). The requisite USACE Section 404 permit, CCC Coastal Development Permit, CSLC Lease, and NPDES permit modification would have potentially lengthy review processes but would all be essentially bounded by the critical path CEQA/EIR review process. The CEQA review process duration varies. The shortest path appears to be a nominal 210-day (7-month) period that would include the minimum 30-day period of review to determine that the initial CEQA application is complete. This process culminates in a Negative Declaration and does not involve developing a comprehensive EIR. The wedge wire screening system review process would likely demand preparation of an EIR, which would serve to significantly extend this review process. The process—inclusive of the initial 30-day completeness review, a 1-year EIR review, and a so-called 90-day "reasonable extension" triggered by compelling circumstances recognized by both the applicant and lead agency—would then extend out to 16 months. (CEQA Flowchart) The CEQA review process would be extended even further by conservatively adding an additional 8 months to cover "unreasonable delays" ostensibly associated with the applicant's difficulty in supplying requested information. Collectively, this longer and probably more" **A4NR would argue that Negative Declaration is a non-starter, and the most likely scenario is a lengthy CEQA process and years of litigation, none of which should start without the resolution of seismic vulnerabilities.**	The excerpted paragraph from the report clearly indicates that the wedge-wire screening system would likely demand the development of a comprehensive EIR, which is likely to include appropriate seismic analyses and assessments. The Negative Declaration process would not apply in this case. The seismic assessment and other specific features of the CEQA review process were not addressed in this summary discussion.
	<u>PG 75</u> "As previously stated, increased condenser pressure results in reduced turbine output. In addition, the additional auxiliary loads of some of the cooling system options (fans, additional pumping power, etc.) also lead to a reduction in plant net output. Figure 4.3-3 shows estimated loss of generation by month for the different cooling options compared to the current once- through system…" **At what point will PG&E declare many of the alternatives uncompetitive? At what point will the Water Board consider that California cannot meet 316B at its last remaining nuclear plant? How many years will ratepayers be required to pay to keep this reactor operating knowing that Diablo fails to meet its seismic design basis, cooling requirements, waste removal promises? How long do we pretend that the emperor is wearing clothes?**	Responses to these questions are outside of the Bechtel JUOTC scope.

	PG 76 "The cost of the derated output resulting from the installation of these technologies has not been included as part of the installation cost estimate for the technologies." **Best guess? A million, a hundred million, a billion???**	The report provides an estimate of the yearly lost generation in MW but the costs associated with that lost generation capacity would have to be provided by PG&E
	PG 79 "However, based on site weather data, it is estimated that backpressures for the dry cooling options will exceed the alarm level almost 300 hours per year. Restricting plant load during these hours would result in significant lost generation (during periods of high ambient temperatures when this generation is typically needed the most). The other option would be to modify the LP section of the turbine to allow higher backpressure operation. the turbine supplier has indicated that removal of the last (L-0) stage of the turbine could be a solution; however, further work would be required to assess the feasibility of this option. For the dry cooling options, modification of the steam turbines is considered necessary." **All unconsidered costs.**	The lost generation data that is provided in the report considered that the turbines are modified and the estimate for that technology includes the cost of modifying the turbine, so we believe the costs are captured.
	Pg 80 "Access/maintenance roads would be provided. The existing fire loop would be extended to the cooling tower area. It has been assumed that the existing fire system can provide the required fire water flows and pressures required at the cooling tower area." **The Committee should be aware that PG&E does not meet its NFPA 805 fire protection standards, so there may be questions about "existing fire system."** "The existing CW pump motors and pump internals (two per unit) would be decommissioned and removed as necessary." **The term "decommissioning" in the above sentence elicits the question as to whether PG&E would use their decommissioning funds for this project or would they try and charge ratepayers under the OTC alternative project?**	The fire water supply system would not be changed if the utility modified their fire protection criterion from Appendix R based to the NFPA 805 bases. The use of the word decommissioned is intended to mean removed from service. The funding source for that work is outside the scope of the JUOTC program.
	Pg 82 "It would be necessary to excavate the mountain to an elevation of 115 feet to provide the space needed to build the new cooling towers and, for the wet technologies, the makeup water storage pond. The number of cooling towers needed is technology specific. The location of the new cooling towers has been chosen carefully to provide the most economical solution and to preclude impact to the nearby archeological site." **We understand the notion of sensitivity to the archeological site, but please explain why the site is more "economical". Also the "sensitivity" may not be adequate in the**	The 115' elevation was selected since it is the existing site elevation where the piping passes over the Diablo Creek east of the SLO-2 archeological site. The crossing point was selected based on drawings supplied by

	eyes of the Chumash Nation.	PG&E delineating the SLO-2 boundaries. The preliminary designs are all clearly outside of the SLO-2 area as shown on the various General arrangement drawings. The duct design within the turbine buildings that convey the circulating water to and from the condenser was evaluated and the pressure required based on the elevation of the cooling towers and it was determined that if the tower elevation was raised above 115 foot elevation modifications to those ducts would likely be necessary. Since the ducts are an integral part of the turbine building structure it was considered not advisable to modify them to increase their design pressure by increasing the tower elevation. During the detailed design phase of the project if a CCW technology were selected a cost study could be completed to determine the cost of modifying the ducts to accept a higher pressure to the excavation cost and determine if a ground elevation above 115' could be determined but that study is outside the scope of the JUOTC program.
	Pg 83 "Existing plant buildings 102, 518, 519, 520, 521, 527, and 528 (refer to DCPP Drawing 512297, sheet 1) would need to be demolished to provide space for the new pumphouses, CW pipes, and conduits. The estimate considers replacement costs for buildings 102, 519, and 527. The existing plant north perimeter security infrastructure, including several substantial structures, would have to be removed during the course of the project and either replaced in the same location or relocated with a similar configuration to an alternative location in the immediate vicinity. The integrity of the plant protected area boundary would need to be reestablished by project completion. The exact orientation and nature of this infrastructure cannot be incorporated in this report; therefore, a more detailed description of the equipment and structures involved is not provided or otherwise depicted on the provided drawings and site layouts." **Is the reason the above infrastructure cannot be incorporated due to security? Can the cost and time estimate for this relocation be assigned a ball-park figure? Would PG&E attempt to use decommissioning funds for this removal?**	The cost of removal and replacement of the buildings is included in the estimate but the location where they would be put has not been determined by PG&E.
	Pg 84 "Based on the tower evaluations, it was concluded that the existing conduits outside the turbine building would not be adequate for the new design pressure; therefore, they would be demolished and replaced with new concrete conduits to meet the new design pressure requirements." **"new conduits" to meet "new design pressure requirements" should not fall under 50.59 review, but require an LAR**	The new conduits are non safety related and would not fall under 10CFR 50.59 and not reqire a LAR.
	Pg 86 "The existing two-circuit 230 kV line that provides the main source of offsite power for DCPP and the northernmost 500 kV circuit that transmits DCPP Units 1 and 2 electrical output offsite via the Gates transmission intertie would need to be rerouted. Three two-circuit high voltage transmission towers of the existing 230 kV line and one single-circuit high voltage tower of the existing 500 kV line would have to be moved. In accordance with DCPP Operating License Specifications, **the maximum allowable outage time for the 230 kV offsite power source to accommodate the relocation work is 72 hours** if either site reactor is operating in modes 1–4." **What could go wrong in just 3 days?**	The 72 hour limit is based on the current plant technical specifications approved by the NRC not on a specific event.

	PG 97 "Therefore, water required for the towers would be obtained from a new onsite desalination plant and from processed reclaimed water obtained from the surrounding communities." **Desal? Processed water? Local decision-makers where "reclaimed water is being considered were completely "surprised" that there had been claims that water would be available.**	As noted above, Bechtel contacted the water treatment plants directly. We understand that a permitting process would be required and that process was considered in the schedules for the wet technologies.
	PG 99-100 "The drift droplets would be of the same water quality as the CW and would contain any water treatment chemicals being used at the site. Based on the estimated CW quality for DCPP, the 0.0005-percent drift rate would result in the emission of approximately 30 tons of solids per year from the towers. After drift droplets leave a tower and land on surrounding areas and structures, the contaminants in the droplets are deposited when the droplets evaporate. Different tower design considerations, including tower discharge height and air exit velocity, affect how far the drift droplets travel and thus the area on which the drift can land, as well as the concentration of contaminants deposited on the affected surfaces. One concern is that the presence of salts and chemicals in the drift droplets could result in a conductive film being left on insulators if the droplets land on the switchyard. This film could cause electrical arcing and other safety and operational issues. Based on the conceptual plot plans, the wet cooling technologies would be located approximately 1,300–1,700 feet from the nearest boundary of the 500 kV switchyard. The predominant wind direction for the site is from the NW about 30–40 percent of the time. This wind direction results in tower discharge air being blown toward the switchyard. Wind directions of NNW and WNW would also drive tower discharge air in the general direction of the switchyard. A review of site wind roses indicates that consideration of all three of these directions accounts for approximately 60 percent of the year. Thus, this is considered as the length of time that tower air and drift discharges would be directed toward the switchyard This does not necessarily mean that all of the drift would deposit on the switchyard area and contaminate the insulators and other equipment; the actual volume of solids deposition on the switchyard area (in acres per month) can be quantified by using the Electric Power Research Institute's Seasonal/Annual Cooling Tower Impact (SACTI) model or a similar program. During the detailed design and execution of the project, this type of analysis would be completed for the selected cooling tower design. Quantifying the deposition on the switchyard would help to determine appropriate equipment and maintenance requirements to minimize the potential for arcing. This includes correct selection of insulator type and planning for site personnel to wash the insulators frequently enough to avoid significant solids buildup" **Again what could go wrong and what will be the cost to fix "drift" issues?**	The "fix" if required is more frequent cleaning of the insulators. The SACTI model is used to more accurately predict the influence of the drift in the4 area of the towers.
	PG 108 "The desalination and water reclaim vendors have provided estimates for the electrical equipment required for power distribution for their supplied equipment. The desalination vendor provided a typical single-line diagram showing the electrical equipment configuration. The desalination/reclaim area electrical building size, tray quantity, and	

	duct bank quantity were estimated from the desalination vendor typical single-line diagram, mechanical equipment lists, and vendor-supplied conceptual plant general arrangement drawings." **How does a "single line diagram" compare with the actual desal needs for Diablo?**	The single line diagram provides an idea of the size of the various components necessary for the operation of the desalinization system. The cooling tower and water treatment equipment would be powered from a new circuit off the 500KV switchyard.
	PG 118-131 "Discussion of permits (income) to responsible agencies" What permits will be needed (are being considered for SONGS) to transition from a nuclear facility to decommissioned reactor status and possible re-use of the land as a repurposed site?	This question is outside of the Bechtel JUOTC effort
	Pg 131 "The efforts to conduct a successful CEQA review would be the primary critical path permitting process. The CEQA review process duration varies. The shortest path appears to be a nominal 210-day (7-month) period that would include the minimum 30-day review period to determine that the initial CEQA application is complete. This process culminates in a Negative Declaration and does not involve developing a comprehensive EIR. However, all of the closed-cycle cooling processes under consideration would likely demand preparation of an EIR, which would further extend this review process. The process—inclusive of the initial 30-day completeness review, a 1-year EIR review, and a so-called 90-day "reasonable extension" triggered by compelling circumstances recognized by both the applicant and lead agency—would then extend out to 16 months. (CEQA Flowchart) The CEQA review process would be extended even further by conservatively adding an additional 8 months to cover "unreasonable delays" ostensibly associated with the applicant's difficulty in supplying requested information. Collectively, this longer and probably more applicable 2-year CEQA review process would likely follow a 1-year period of permit application development. The other permitting processes are assumed to proceed in parallel to the critical path CEQA review process. While there could be some variation on the permitting timeline for the various closed-cycle cooling systems under consideration, such variation would be effectively enveloped by the lengthened CEQA review process. The total permit filing and permitting service costs associated with the various closed-cycle cooling system options does vary. The permitting costs for the dry cooling options total about $3.0 million. The permitting costs for the wet cooling options increase to $4.3 million in response to the additional costs associated with the offsite reclaimed water pipelines. As noted earlier, the overall 3-year permitting process and associated costs do not reflect the impact of permit appeals, litigation, or potentially negotiated CEQA-related mitigation fees. In recognition that such complications may occur, the project execution schedule includes a 1-year appeal period following the CEQA final decision." This assumes that there will not be LAR's vs 50.59 required by NRC	This section of the report offers no conclusions regarding NRC licensing matters. Per the original scope of work for this effort, the NRC licensing and other non-nuclear Federal, state, and local permitting matters were addressed separately. Any conclusions regarding NRC licensing can be found in the section of report devoted to

		that subject matter (Section 3.0 Licensing Nuclear-Specific Assessment).
	Pg 155 "Timeframe from 8-14 years to complete (chart)." Again the optimistic assumption of minimum 8 years is only three years before license expiration. Nowhere in this document is license renewal considered and with costs to continue safe operation mounting it is unclear to many whether Diablo Canyon will seek, much less obtain approval for operation beyond 2024-2025, thus rendering the propsed alternative construction projects moot.	Bechtel did not consider the time remaining in the DCPP current license in our preliminary designs, schedule development or the cost estimates..