COUNTY OF SAN LUIS OBISPO BOARD OF SUPERVISORS
AGENDA ITEM TRANSMITTAL

(1) DEPARTMENT Board of Supervisors	(2) MEETING DATE 8/7/2012	(3) CONTACT/PHONE Supervisor Bruce Gibson 781-5450

(4) SUBJECT
Submittal of a letter to California State Lands Commission concerning the permit for Central Coastal California Seismic Imaging Project (CCCSIP) near Diablo Canyon Power Plant/Hearing August 14, 2012.

(5) RECOMMENDED ACTION
It is recommended that the Board of Supervisors approved the attached letter to the California State Lands Commission concerning the permit for a high-energy offshore seismic reflection survey as part of the Central Coastal California Seismic Imaging Project (CCCSIP) near Diablo Canyon Power Plan (DCPP). Instruct the Chairperson to sign and instruct the Clerk to mail the letter to the California State Lands Commission.

(6) FUNDING SOURCE(S) N\A	(7) CURRENT YEAR FINANCIAL IMPACT $0.00	(8) ANNUAL FINANCIAL IMPACT $0.00	(9) BUDGETED? N\A

(10) AGENDA PLACEMENT
{ } Consent { } Presentation { } Hearing (Time Est. _______) { x } Board Business (Time Est.__1 hour)

(11) EXECUTED DOCUMENTS
{ } Resolutions { } Contracts { } Ordinances { x } N/A

(12) OUTLINE AGREEMENT REQUISITION NUMBER (OAR) N/A	(13) BUDGET ADJUSTMENT REQUIRED? BAR ID Number: N/A { } 4/5th's Vote Required { x } N/A

(14) LOCATION MAP N/A	(15) BUSINESS IMPACT STATEMENT? No	(16) AGENDA ITEM HISTORY { x } N/A Date ____________________

(17) ADMINISTRATIVE OFFICE REVIEW

(18) SUPERVISOR DISTRICT(S)
All Districts

County of San Luis Obispo

TO: Board of Supervisors

FROM: Board of Supervisors / Supervisor Bruce Gibson

DATE: 8/7/2012

SUBJECT: Submittal of a letter to California State Lands Commission concerning the permit for Central Coastal California Seismic Imaging Project (CCCSIP) near Diablo Canyon Power Plant/Hearing August 14, 2012

RECOMMENDATION

It is recommended that the Board of Supervisors approved the attached letter to the California State Lands Commission concerning the permit for a high-energy offshore seismic reflection survey as part of the Central Coastal California Seismic Imaging Project (CCCSIP) near Diablo Canyon Power Plan (DCPP). Instruct the Chairperson to sign and instruct the Clerk to mail the letter to the California State Lands Commission.

DISCUSSION

The seismic safety of DCPP has been a concern for a long as the plant has existed. The CCSIP is a comprehensive technical study being undertaken by PG&E to further refine the understanding of seismic hazards affecting DCPP. This is by far the most extensive high energy seismic reflection survey which requires a permit from the California State Lands Commission. The hearing for the permit will be held before the CSLC on August 14th, 2012 in Sacramento. It is important because it addresses fundamental issues of the seismic hazard (size, location and connectivity of offshore faults).

RESULTS

The safe operation of DCPP has a fundamental connection to the health, safety, prosperity & livability of SLO County.

FINANCIAL CONSIDERATIONS

None.

ATTACHMENTS

Letter to California State Lands Commission
Letter from Supervisor Gibson to PG&E
Letter from PG & E to Supervisor Gibson
Attachment 3 – Summary of Unresolved Technical Issues

BOARD OF SUPERVISORS

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FRANK R. MECHAM, Supervisor District One
BRUCE GIBSON, Supervisor District Two
ADAM HILL, Supervisor District Three
PAUL TEIXEIRA, Supervisor District Four
JAMES R. PATTERSON, Supervisor District Five

August 7, 2012

State Controller John Chiang, Chair
California State Lands Commission
100 Howe Ave. Sutie 100
South Sacramento, CA 95825-8202

RE: Permit for a 3-D high-energy offshore seismic reflection survey,
Central Coastal California Seismic Imaging Project (CCCSIP) near Diablo Canyon Power Plant, to be heard August 14, 2012

Dear Mr. Chiang:

The San Luis Obispo County Board of Supervisors appreciates the opportunity to comment on the high-energy offshore seismic survey referenced above, proposed by PG&E as part of a comprehensive evaluation of potential seismic hazards near the Diablo Canyon Power Plant.

In summary, our comments are these:

• Our Board endorses the execution a 3-D high-energy seismic survey (HESS) in the area generally outlined in PG&E's proposal, subject to conditions discussed below.

• We acknowledge that 3-D HESS at the scale necessary for this investigation will have significant environmental impacts that cannot be fully mitigated. We believe that, <u>if the survey is properly designed and executed</u>, the public benefit of enhanced knowledge of seismic hazards supports approval of such a survey, under the requirements of the California Environmental Quality Act (CEQA).

• We also acknowledge that the necessary survey will have significant economic impacts on ocean-dependent interests in this county, including commercial fishing, recreational fishing, other recreational activities (e.g., diving), and associated shore-based enterprises. The survey should be designed and executed to minimize these economic impacts, and the unavoidable economic impacts should be fully and fairly compensated.

• We are concerned that unresolved issues remain regarding the design of the proposed survey, specifically as to whether this proposal is consistent with industry state-of-the-art seismic reflection survey techniques (see discussion below and Attachments). The use of currently available industry technology could potentially reduce environmental impacts and improve the seismic image of important geologic targets.

Our Board believes that the State Lands Commission (CSLC) should only issue a permit for the Diablo Canyon HESS if the following conditions are met: 1) all environmental impacts are fully understood and mitigated to the maximum degree possible, understanding that mitigation to a level of insignificance may not be possible; 2) all unavoidable economic impacts are fully and fairly compensated; and 3) the technical details of the survey design have been subjected to independent third-party review by industry-qualified experts to confirm that the best available technology is applied to this crucial investigation.

DISCUSSION

Necessity of 3-D HESS. The threat of seismic hazards to the Diablo Canyon Power Plant (DCPP) has long concerned the County and its residents, other public agencies and PG&E. The most recent efforts to characterize seismic threats are driven by the requirements of Assembly Bill 1632 (Blakeslee, 2006), the discovery of the Shoreline fault immediately adjacent to DCPP (2008), and the tragic consequences of the Fukushima earthquake in 2011. The unexpectedly large earthquake at Fukushima, in particular, dictates that PG&E and all relevant public agencies meticulously re-examine every aspect of seismic hazard analysis and gather further information to expand and solidify our understanding of the seismic threat to DCPP.

High-resolution 3-D seismic reflection surveys are essential to reveal the details of geologic structures that relate directly to earthquake potential. Such surveys produce detailed images of fault location, size, connectivity and sense of movement; these are fundamental parameters in the analysis of potential earthquake magnitude. The importance of 3-D seismic reflection mapping was emphasized by the California Energy Commission in their 2008 assessment of seismic vulnerability at DCPP.

The geologic targets to be examined by the proposed survey have been reviewed by the Diablo Canyon Independent Peer Review Panel (IRPR, created by the California Public Utilities Commission). As stated in formal comments to CSLC, the IPRP found that "1) the proposed survey generally covers the appropriate geologic targets, although we believe one area of the survey can be eliminated without compromising the seismic hazard analysis, and 2) that minor adjustments to the survey track orientation and extent in certain areas would be prudent to assure the best coverage of certain targets."

Our Board concludes that the large scale of the proposed survey is necessary, acknowledging that some reduction may be possible, per the comment above.

Environmental impacts. CEQA obviously provides the appropriate framework for analysis of environmental impacts. We understand that CSLC staff has received numerous comments on the Draft Environmental Impact Report (DEIR) prepared for this project. In preparing the Final EIR (FEIR), and considering its certification, our Board urges the CSLC to be certain that, a) all relevant impacts have been identified, b) an appropriate range of alternative projects has been analyzed, and c) that the most extensive level of feasible mitigation has been applied, especially to impacts that are deemed significant and unavoidable (Class I).

As discussed below, issues of detailed survey design remain unresolved: the capability of the survey vessel directly relates to the time required for data acquisition and thus has bearing on the degree of impact to marine biological resources. Full examination of this issue may appropriately require the formal analysis of another alternative project.

Economic impacts. The FEIR identifies significant and unavoidable impacts to commercial fishing and recreational interests (Section 4.13) due to the preclusion of fishing during survey operations and damage to fish stocks. Environmental impact mitigations are centered on seasonal timing of the survey and communication with affected parties. While the FIER contains discussion of the value of fish landings, the unavoidable economic losses to these parties will also be significant and compensation for these impacts is not considered.

<u>Our Board believes that this survey should not be permitted until full and fair compensation for expected economic losses to fishing and recreational enterprises (including those based on shore, such as processors and distributors of local seafood) has been established</u>. Guidance for this effort might be provided by previous trans-oceanic cable laying projects, which had impacts due to the preclusion of fishing.

Seismic data acquisition, processing and interpretation specifications. In the IPRP's technical review of the proposed survey, SLO County's representative (Supervisor Bruce Gibson) has raised questions and requested public discussion regarding the specifics of data acquisition, processing and interpretation within the survey footprint. These issues are discussed at length in a letter from Sup. Gibson to PG&E (dated June 20, 2012, Attachment 1) and PG&E's response (dated July 13, 2012, Attachment 2).

While PG&E has provided considerable detail on a wide variety of issues, unresolved issues remain as to whether the proposed survey is consistent with the seismic exploration industry state of the art (see Attachment 3). As noted below, the appropriate resolution of these issues would be independent peer review by qualified industry experts, having expertise beyond that of the IPRP membership.

One of these issues is relatively easy to describe. The proposed survey vessel would tow 4 laterally-separated streamers of hydrophones, covering a swath of 300-400 m of ocean surface with each pass of the survey vessel. In contrast, industry vessels can tow 10 or more streamers similarly spaced, resulting in a swath about 1000 m wide. As noted in

PG&E's response (Attachment 2), the greater number of streamers "can reduce data collection time by a factor of 2 or 3."

PG&E contends, but has not demonstrated, that operation of a 10-streamer boat is not feasible in this survey area. The question should be settled by an industrial-level survey design review, which would model data acquisition geometry based on state-of-the-art streamer positioning technology. While the issue of data collection efficiency is certainly important because reduced survey time would reduce impacts to marine life, the larger streamer numbers and other industrial survey technologies could also improve the image quality of geologic targets.

CONCLUSION

Our Board believes that the high-energy 3-D offshore survey of geologic structures near Diablo Canyon Power Plant should be designed with the greatest care and conducted with industry state-of-the-art technology. The residents of San Luis Obispo County deserve to know that every effort has been made to design and execute a survey that provides the highest-quality image of the potential geologic hazards in this area. Given the significant environmental and economic impacts, we realistically have only one opportunity to do a survey of this magnitude – this survey must be done right.

In conclusion, we believe the information to be gained from this survey is crucial to public safety. We urge the State Lands Commission to issue permits for it only if the environmental and economic impacts have been properly addressed and the proposed survey design meets the highest scientific and technical standards.

Thank you for your consideration,

Sincerely,

JIM PATTERSON, Chair
San Luis Obispo, Board of Supervisors

Attachment 1 Letter from Supervisor Gibson to PG&E, June 20, 2012
Attachment 2 Letter from PG&E to Supervisor Gibson, July 13, 2012
Attachment 3 Summary of Unresolved Technical Issues

BOARD OF SUPERVISORS

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BRUCE GIBSON
SUPERVISOR DISTRICT TWO

June 20, 2012

Mr. L. Jearl Strickland
Director, Nuclear Projects
Diablo Canyon Power Plant
PO Box 56
Avila Beach, CA 93424

RE: Central Coastal California Seismic Imaging Project (CCCSIP) -- High-energy 3D seismic reflection survey near Diablo Canyon Power Plant (DCPP)

Dear Mr. Strickland:

The Independent Peer Review Panel (IPRP, convened by the California Public Utilities Commission under Decision 10-08-003, 2010) has met several times and has commented on the design of the 3-D seismic survey referenced above. The IPRP has commented that, with certain adjustments, the overall survey coverage of geologic targets relevant to the seismic hazard analysis appears adequate. The IPRP, however, has also suggested more detailed review of the seismic acquisition and processing techniques proposed to be used within the overall survey footprint.

With this letter, I am requesting that PG&E provide public responses regarding the data acquisition and processing issues described below. Please note that I am writing here as an elected official representing the residents of San Luis Obispo County (and not officially on behalf of the IPRP). The basis for these questions is my previous experience as a seismic exploration research geophysicist (CV attached) and consultation with current experts in seismic acquisition and data processing.

Discussion of these issues is warranted because PG&E has proposed to use a survey vessel owned by the National Science Foundation and operated by Lamont-Doherty Earth Observatory of Columbia University (LDEO). While LDEO is an outstanding research institution, the seismic imaging capabilities of the academic world have historically lagged those available from seismic exploration contractors ("the industry"). This difference is attributable to superior acquisition technology, enhanced data processing techniques, and a comprehensive integration of acquisition and processing decisions.

<u>The fundamental question then is whether PG&E's proposed survey is consistent with state-of-the-art seismic reflection imaging practice.</u> As noted below, the proposed survey vessel has less acquisition capability than most industrial vessels, and since no data processing approach has been specified, no acquisition/processing coordination has been detailed. Given the importance of the seismic hazard analysis of the area surrounding DCPP, PG&E should publically explain why industrial-level current technology has not been proposed for these studies.

Sections below include a summary comparison of PG&E's proposed survey with the current industrial state-of-the-art. Sections following that contain expanded discussions of the relevant technical issues of 3-D seismic reflection practice.

PG&E's proposed survey

The following summary specifications of PG&E's proposed survey are taken from the Project Description section of the Draft Environmental Impact Report prepared for the California State Lands Commission:

- One survey vessel towing 4 hydrophone streamers of 6 km length each, with a cross-line separation of 100 to 150 m.
- Two air-gun source sub-arrays towed by the survey vessel, fired alternately, cross-line separation 75 m.
- Offshore survey conducted over four defined areas. Within each area, air-gun shots taken along parallel track lines. Compass heading of track lines is constant in each area, resulting in a narrow range of source-receiver azimuths.
- Shallow water, near-shore (transition zone) data acquired by 5 lines of cabled geophones placed on the seafloor. Seismic sources located offshore (air-gun shots from the offshore survey) and onshore (vibrator trucks).

PG&E has indicated that design of the offshore and transition zone surveys was tested in an "illumination study" based on 2D and 3D ray-tracing calculations. No specific data processing for the acquired data or specific interpretation products have been specified.

Current industrial survey practice

The current industrial state-of-the-art for complex geologic areas with deep imaging targets is as follows:

- One survey vessel towing 10 or more streamers of 7 to 8 km in length, with cross-line separations of 75 to 125 m.
- One air-gun source array located on the streamer boat and at least one additional and identical source array on a source-only boat. The two or more sources fire alternately (or sequentially, if more than 2). The purpose of the additional source(s) is to provide a wider source-receiver azimuth range to the recorded wavefield.
- Adjacent traverses of the seismic vessel through the survey area are offset laterally such that there is a partial overlap of the streamer spreads. This provides a finer cross-line spatial sampling of the reflected wavefield.
- Major steps in current 2D and 3D data processing include: data conditioning (ambient noise attenuation, estimation and equalization of source wavelets from one shot to the next), 3D surface related multiple elimination (SRME), several passes of migration/tomography (velocity) analysis to determine subsurface velocities, 3D pre-stack reverse time migration (RTM) and post-image signal enhancements.
- Transition zone surveys include seafloor hydrophones, as well as geophones. Extensive data processing is especially directed at static timing corrections, source wavelet equalization and suppression of water column reverberations.
- In designing both offshore and transition zone surveys, iterative finite-difference wave equation modeling of expected targets is used to develop acquisition parameters (source-receiver type, spacing and location) and integrated data processing techniques.

- Required interpretation products are considered during survey design, and usually include time and depth maps of key reflectors, maps of faults with discernible travel time offset, horizon-based and volumetric attributes, several of which assist in small fault detection.
- Interpretation products also include interval velocity maps (including azimuthal variations) for the characterization of azimuthal velocity anisotropy and the horizontal stress field.

Attachment 1 includes an expanded discussion of these technical issues, beginning with a description of the process of modern survey design.

Summary request for response

Comparison of the information summarized above clearly shows areas where PG&E's proposed survey design and execution is not consistent with current industry standards. Assurance of the quality of seismic images produced by the offshore and transition zone surveys is foundational to understanding the seismo-tectonic setting and the quantitative analysis of seismic hazard.

<u>Given long-standing concerns regarding the seismic threat posed by the geologic setting near Diablo Canyon – concerns heightened by the Fukushima disaster – the public deserves to know that the best possible seismic survey technology is applied to the studies that PG&E is undertaking.</u> Taking care to document now that data are to be acquired and processed at the highest standards is fundamentally important to the future interpretation of the results.

<u>For these reasons, I request that PG&E provide justification for their proposed choice of survey parameters and approach, given the current industrial standards summarized above.</u> I ask that, at a minimum, PG&E provide a thorough discussion of the specific issues listed below:

- The overall design approach for both the offshore and transition zone surveys should be described. The survey design discussion should explain how survey acquisition parameters, data processing sequence, and interpretation products were chosen and how these three elements are integrated.
- The offshore and transition zone survey design process should analyze results of recently-conducted land surveys to confirm the adequacy of acquisition parameters and processing flow.
- The choice of basic parameters such as spatial sampling interval and maximum source-receiver offset should be discussed relative to the spatial resolution required to image expected target structures at depth. For instance, what spatial resolution is required to evaluate geologic markers that might provide a measure of fault slip rate?
- The choice of towing only 4 streamers in the offshore survey should be evaluated. Typical industrial surveys deploy 10 or more streamers to improve survey efficiency (i.e., reduced acquisition time). <u>This should be a significant issue for the proposed survey, which has been analyzed to have significant impacts to marine life, based on time exposure to the seismic source.</u>
- The potential benefit of data acquisition over a wide (in contrast to the proposed narrow) source-receiver azimuth range should be evaluated for both image quality improvement and the ability to evaluate the orientation of maximum horizontal stress.
- The proposed seismic data processing flow, data processing contractor and experience should be specified.
- The potential benefit of evaluating vertical fracture alignment, maximum horizontal stress, and directional stress inequality should be discussed. While this information is not typically used in traditional seismic hazard analysis, it does relate to the physical state of the overall seismo-tectonic setting.

- The specific acquisition parameters and processing sequence of the transition zone survey should be discussed. Of particular importance would be the processing proposed to assure a high-quality seismic image after merging the transition zone data with the onshore and offshore survey data.

Conclusion

I appreciate the effort required to design and execute a high-quality seismic survey of the geologic setting surrounding this important facility, and I thank you in advance for your responsiveness to this request. I believe it vitally important that the public is assured that we are all making best efforts to develop a more robust understanding of risks to the safety of the Diablo Canyon power plant, a critical feature of our county's environmental and economic landscape.

If I can answer any questions or provide any further information, please don't hesitate to contact me. Thank you.

Sincerely yours,

Bruce Gibson

Bruce Gibson, Ph.D.

Attachment 1. Discussion of survey design, acquisition, processing and interpretation
Attachment 2. B. Gibson's curriculum vitae

Distribution
Stuart Nishenko, PG&E
Tom Jones, PG&E
Eric Greene, CPUC
Sup. Adam Hill, SLO County
Jennifer DeLeon, State Lands Commission
Cy R. Oggins, State Lands Commission

ATTACHMENT 1
DISCUSSION OF SURVEY DESIGN, ACQUISITION, PROCESSING AND INTERPRETATION
June 20, 2012

Seismic survey design

The design of a modern industrial seismic survey begins with the question "What are the imaging goals of the survey?" The answer to that question involves specification of parameters such as imaging target depth and the desired vertical and horizontal resolution. The main objective of the seismic imaging project, as stated in IPRP Report No. 3 (dated April 6, 2012), is to "explore fault zones in the vicinity of the DCPP, especially the intersection between the Hosgri and Shoreline faults." Targets to be imaged might range in depth from the seafloor (top of the sedimentary section) to as deep as 15 km (maximum seismogenic depth). In general, a seismic survey of targets over this depth range will require long source-receiver offsets, densely spaced sources and receivers, and small common midpoint (CMP) bins.

Once these basic parameters are set, the next question is "Given the survey goals and desired parameters, our knowledge of the geology of the area, and all environmental issues, what data acquisition and processing specifications are sufficient to meet the goals in an environmentally sound and economical fashion?" Consideration of the geology is important because the complexity of an area has a large impact on the detailed design of the survey. Challenges such as those related to large subsurface dips, velocity-field complexity and high acoustic attenuation zones must be recognized and planned for. Environmental considerations encompass many aspects, including: weather, ocean currents, obstructions to navigation, shipping lanes, ambient noise, and the regional fauna and flora that could be affected by the survey activity.

As discussed below, the specifics of data acquisition parameters are typically determined by iterative modeling of the expected seismic response of the survey targets for a variety of source and receiver combinations. The modeled seismic response is then processed to confirm both the survey acquisition geometry and the necessary data processing flow. This integration of acquisition and processing, which has not been discussed by PG&E, is fundamental to modern reflection survey design to assure the expected effectiveness of the survey, as constrained by the environmental factors listed above.

The current industry state-of-the-art for survey design is to create synthetic acoustic seismic data using finite-difference wave-equation calculations for a specific geology and a range of acquisition parameters. Each model data set is then processed using appropriate techniques such as 3D surface related multiple elimination (SRME) and 3D reverse time migration (RTM). This allows the best of the acquisition designs to be selected based on the evaluation of the final image. If details of the geology are unknown, an informed guess can be used. For example, a survey designer can pose and answer a question such as "If a high-dip fault existed in this area, could it be imaged using this acquisition and processing scheme?"

In the complete design of a survey, the interpretation goals, methods, and products should be specified as well. At the minimum, the interpretation output would include: time and depth maps of all key reflectors, showing faults with discernible offset in time or depth; horizon-based and volumetric attributes for subtle fault detection, and interval velocity maps between key reflectors (including information on the azimuthal variation of interval velocity). The azimuthal interval velocity maps (co-rendering of the local fast, slow and azimuth of fast interval velocity) can be used to discern the azimuth of local maximum horizontal stress and the inequality of the horizontal stresses.

Marine acquisition parameters

Spatial sampling. In typical marine surveys, the spatial sampling is most dense along the streamer direction and thus most survey tracks are generally oriented in the targets' dip direction. In the CCCSIP, shooting tracks (which in some areas parallel the fault's strike) should be carefully assessed for the ability for direct fault imaging. However, shooting parallel to fault strike will enhance the spatial resolution of information that may be helpful in estimating past slip movement. The tradeoffs presented by shooting direction can be assessed with survey design modeling, described above.

Maximum source-receiver offset. From a pure imaging standpoint, longer offsets allow imaging of deeper structure. A 6-km maximum offset provides acceptable imaging down to a depth below sea level (BSL) of about 6 km. From an interpretation standpoint, longer offsets provide valuable amplitude versus offset (AVO) information for inversion of rock properties.

Number of towed streamers. Typical industrial survey vessels tow 10 or more streamers with nominal cross-line separations of 100 m. In general, a greater number of streamers towed reduces the number of required shooting passes. This improved data acquisition efficiency results in economic -- and potentially environmental -- benefits. An additional important advantage is that a wider streamer spread samples more of the reflected wavefield, which can enhance image quality relative to narrow-spread streamers.

While more streamers are potentially better, survey design decisions involving the number of streamers must consider both the capability of the survey vessel (streamer storage and handling capacity, towing horsepower) and environmental constraints (ocean currents and obstructions).

Position accuracy. Position accuracy of the source and receivers directly affects the overall fidelity of the seismic image. For example, in marine surveys, accurate source and receiver depths lead to consistent and better deghosting from one trace to the next. In the land case, vertical accuracy is required for application of elevation statics. Lateral accuracy is related to the fidelity of both data conditioning (interpolation and 3D SRME in particular) and imaging processing steps. These algorithms depend on knowledge of the locations of the source and receivers; if those data are poor quality, then the algorithm results will be likewise. The end result of poor positioning accuracy is a decrease in the resolution of the final image. Typical vertical and lateral accuracy are about ± 0.5 m and ± 3 m or better, respectively. For wide-azimuth surveys the cable steering is generally used to keep the streamers parallel to one another. Active steering fins on streamer cables can change the cable feathering by as much as ± 4°. Knowledge of expected ocean currents is important to assessing streamer positioning accuracy.

Wide-azimuth seismic reflection surveys – acquisition and processing

For areas with complex geology, wide-azimuth data can contribute significantly to better quality of the subsurface image[1]. Additionally, wide-azimuth data analysis has become commonplace in mapping the in-situ horizontal stress field (azimuth of local maximum horizontal stress, and inequality of the horizontal stresses), and the dominant vertical aligned fracture set (its azimuth and relative fracture density)[2]. Differences in the horizontal stress field in and around the known (and unknown) faults may prove valuable to the tectono-physicists in understanding potential fault ruptures.

Marine wide-azimuth seismic acquisition was originally developed to improve the imaging of reflecting horizons lying below complex structures such as salt domes. The method is also valuable, however, for any regime that includes high dips and significant structure in the cross-line direction. For the geologic situations just mentioned, a narrow-azimuth seismic survey can produce sub-optimal imaging results. The basic problem is that with complex geology the subsurface can scatter the incident wavefield in all directions. If the orientation of an acquisition program favors only a specific source-receiver orientation (narrow-azimuth), then it is likely that portions of the scattered wavefield are not recorded. As a result, those portions of the scattered wavefield cannot contribute their information to the final seismic image, thereby creating zones in which the image is misleading or even entirely missing[3].

The acquisition of wide-azimuth marine data generally requires more than one shooting boat, although creative vessel navigation has been used to accomplish similar results[4]. The lateral offset of a second source boat (offset typically 1 – 2 km cross-line to the receiver array) is the most efficient means of widening the range of source-receiver azimuth. Since image quality is sensitive to source timing and location, sophisticated control systems are required to coordinate shot initiation and positioning of multiple vessels.

Among the first data processing issues of marine surveys, suppression of multiple reflections is particularly important. State-of-the-art processing includes a 3D SRME algorithm that is capable of predicting multiples for data that are irregularly sampled (because of cable feathering, for example). Failure to suppress multiples causes artifacts to appear in migrated images. Such artifacts can obscure primary reflections or might even be misinterpreted as primary reflections. Successful multiple suppression requires significant computing resources and experienced technical staff.

Processing software must also account for and estimate the azimuthal variation in travel times (velocity). Not only can this information be used in interpretation, it is essential to include the azimuthal variations in velocity to obtain the best image possible. Otherwise, the stacked image after pre-stack migration will lose bandwidth due to improper event alignment.

Data processing that reveals the azimuthal variation in the AVO (amplitude variation with offset) is the state-of-the-art for vertical aligned fracture detection and characterization. Azimuthal variations in interval velocities, after pre-stack time migration that preserves azimuth and offset, are used to characterize the in-situ horizontal stress field.

Transition zone surveys – acquisition and processing

Seismic surveys in areas covered by shallow water (transition zones) are particularly challenging because the physical characteristics of each transition zone are unique. Transition zone survey design must consider water depth, wave action, tides, water bottom characteristics, type of onshore terrain, and other factors. In general, the survey designer tries to create a well-sampled distribution of receivers and shots that will provide a data set that can be processed successfully using standard algorithms.

Most transition zone surveys include deployment of water-bottom and onshore recording sensors with air-gun arrays for offshore shots and vibrators for onshore shots. A dual-sensor (hydrophone/vertical component geophone) is the minimum industry standard for ocean-bottom recording in transition zones. Vertical geophones are particularly valuable for helping to eliminate water-column reverberations during processing. Four-component (3 components of geophone and one hydrophone) sensors are used when shear-wave information is acquired.[2] Four-component recording is indicated when knowledge of the in-situ stress field and vertical aligned fractures is desired. The P-S (mode-converted shear wave reflections) data are sensitive to the presence of unequal horizontal stresses and vertical aligned fractures; these P-S data can be compared to the azimuthal P-P reflections to learn of lithology, porosity, pore fill, stress state, and fractures.

A key challenge in processing transition zone data is that the individual portions of the survey have to be matched for the various combinations of sources and receivers. For a standard dual sensor, there are four data subsets: air gun/hydrophone, air gun/geophone, vibrator/hydrophone, and vibrator/geophone. Each source/receiver combination has a unique "wavelet" response to the initiation of a shot. Extensive data processing by experienced personnel is required to covert the individual wavelets to a common form. This conversion is necessary before the entire volume of recorded data can be merged to produce a unified image.

Other data processing challenges within the transition zone survey include 1) static time corrections that must be applied to the data subsets (each subset requiring a different set of statics, 2) water-column reverberations which can be extreme and might require specialized processing in order to reveal the subsurface reflections of interest, and 3) estimation and correction of the variability of geophone-seafloor coupling.

If the transition zone data are to be merged with the deep-water 3-D survey, additional data processing, including wavelet correction and ghost reflection corrections, must be applied. In any case, transition zone imaging requires extraordinary documentation (e.g., water depths, tidal variations) and seamless coordination of acquisition and processing.

General data processing issues

Major steps in current 2D and 3D data processing include: data conditioning (ambient noise attenuation, estimation and equalization of source wavelets from one shot to the next), 3D surface related multiple elimination (SRME), several passes of migration/tomography (velocity) analysis to determine subsurface velocities, 3D pre-stack reverse time migration (RTM) and post-image signal enhancements.

In marine surveys, successful data processing depends on good onboard quality control during acquisition. The survey vessel should have adequate computing capability to assure that noise and other possible processing issues can be successfully dealt with in the final processing flow.

While the data processing sequence will be evaluated in the survey design phase described above, it is also important to review the processing flow and image results of previously recorded data. For instance, in the CCCSIP, the images produced from the land-based data recorded in 2011 (vibrator and accelerated weight drop sources with nodal recording) should be reviewed to inform future processing decisions.

References

1. **Wide-azimuth streamer acquisition for Gulf of Mexico subsalt imaging**
Chris Corcoran, Colin Perkins, David Lee, Paul Cattermole, Richard Cook, and Nick Moldoveanu
SEG Expanded Abstracts **25**, 2910-2914 (2006)

2. **The Winds of Change,** *Heloise Lynn,* The Leading Edge, v. 23, 1156-1162.

3. **Breakthrough acquisition and technologies for subsalt imaging** (see Figure 1)
Denis Vigh, Jerry Kapoor, Nick Moldoveanu, and Hongyan Li
Geophysics **76**, p. WB41–WB51 (2011)

4. **A single-vessel method for wide-azimuth towed-streamer acquisition**
Nick Moldoveanu, Jerry Kapoor, and Mark Egan
SEG Expanded Abstracts **27**, 65-69 (2008)

Attachment 2

CURRICULUM VITAE

BRUCE GIBSON
San Luis Obispo County, California

CURRENT POSITION:
San Luis Obispo County Supervisor (District 2); reelected in June, 2010 to second term through 2014. As Supervisor, I also serve on the following local Boards and Commissions, and am active in the California State Association of Counties.

LOCAL BOARDS:
Local Agency Formation Commission (LAFCO)
San Luis Obispo Council of Governments (SLOCOG) (Chair)
San Luis Obispo Regional Transit Authority (SLORTA)
Air Pollution Control District (APCD) (Chair)
Integrated Waste Management Authority (IWMA)
San Luis Obispo First 5 Commission

CALIFORNIA STATE ASSOCIATION OF COUNTIES (CSAC):
Member, Board of Directors
Chairman, Government Finance and Operations Committee
Member, Coastal Counties Regional Association

PREVIOUS GOVERNMENTAL SERVICE:

2005 - 2006	Commissioner, San Luis Obispo County Planning Commission;
2000 - 2003	Member, Ag Preserve Review Committee, San Luis Obispo County Advisory Committee for Williamson Act contract applications;
1998 - 1999	Member, Facilities Advisory/Oversight Committee, Coast Union School District, Cambria, CA;

PREVIOUS CONSERVATION/ENVIRONMENTAL ACTIVITIES:

2001- 2006	Member, Board of Directors, Cayucos Land Conservancy (a private non-profit land trust);
1998 - 2006	Member, Board of Trustees, The Land Conservancy of San Luis Obispo County, (a private, non-profit land trust). President, 1999-2001 and 2002-2004.

PREVIOUS EMPLOYMENT:

1990 - present	Self-employed rancher/farmer, Cayucos
1984 - 1989	Research Scientist, Rice University, Houston, TX, Director of Data Processing for the Department of Geology and Geophysics. Responsible for data processing of crustal-scale seismic reflection data and teaching of seismic reflection data processing techniques. Conducted research on seismic reflection response and imaging issues of randomly heterogeneous crustal materials.
1976 - 1984	Senior Research Geophysicist, Western Geophysical Co., Houston, TX. Conducted research and development of seismic reflection imaging techniques. Published research on signal processing (deconvolution), and 2-D and 3-D time and depth migration imaging techniques.
1973 - 1976	Research Assistant, University of Hawaii, Honolulu, HI

EDUCATION:

B.A., Physics, 1973	Pomona College, Claremont, CA
M.S., Geophysics, 1975	University of Hawaii, Honolulu, HI
Ph.D., Geophysics, 1989	Rice University, Houston, TX

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SCIENTIFIC ORGANIZATION MEMBERSHIPS

American Geophysical Union
Society of Exploration Geophysicists

Pacific Gas and Electric Company®

Diablo Canyon Power Plant P. O. Box 56
Avila Beach, CA 93424

July 13, 2012

PG&E Letter DCL-2012-637

Dr. Bruce Gibson
Supervisor, District 2
San Luis Obispo County
San Luis Opispo, CA 93401

Response to June 20, 2012, Request for Information

Dear Dr. Gibson:

Please find attached a response to the questions that you presented in your June 20, 2012 letter associated with the Central Coastal California Seismic Imaging Project (CCCSIP).

After you have had time to review the responses, we are interested in bringing in our science team leads to expand upon the answers and address any other questions that may be generated from this response.

We look forward to further discussions on these important studies.

Sincerely,

L. Jearl Strickland
Director, Nuclear Projects
805-781-9785 (office)
805-441-4208 (cell)
LJS2@pge.com (email)

Enclosure

Pacific Gas and Electric Company's Response to Bruce Gibson June 20, 2012, Request for Information

Introduction

In 2008, the California Energy Commission (CEC) completed an assessment of the vulnerability of Diablo Canyon Power Plant (DCPP) to a major disruption due to a seismic event or plant aging, as required by CA Assembly Bill (AB)1632 (Blakeslee, Chapter 722, Statutes of 2006). As a result of that assessment, the CEC recommended that Pacific Gas and Electric Company (PG&E) complete additional seismic studies using three-dimensional (3D) seismic reflection mapping and other advanced geophysical techniques to explore fault zones near DCPP. In addition, PG&E funded U.S. Geological Survey research that reevaluated more than 20 years of earthquake data that lead to the discovery of the Shoreline fault zone in 2008. In 2009 and 2010, both the California Public Utilities Commission (CPUC) and the California Coastal Commission (CCC) directed PG&E to complete the advanced studies recommended in AB1632 as part of their license renewal feasibility studies and reviews. The CPUC established an Independent Peer Review Panel (IPRP) in 2010 to provide an independent peer review and comment on these proposed seismic studies.

The PG&E High Energy Seismic Survey (HESS) program is one task in a series of comprehensive geologic/ geophysical investigations that PG&E has been conducting as part of the Central Coastal California Seismic Imaging Project (CCCSIP). The CCCSIP represents the continuation of earlier studies initiated in 2008 and 2009 that specifically addressed the Shoreline fault zone. The CCCSIP involves government, academic and industry partners including the National Science Foundation, Columbia University/ Lamont-Doherty Earth Observatory, the Scripps Institute of Oceanography, the University of Nevada/Reno, the CSU Monterey Bay Sea Floor Mapping Lab, Fugro Consultants Inc., Nodal Seismic, Bird Seismic Services, Fairfield Nodal, NCS SubSea, and others in order to collect the highest quality seismic and geophysical data using state-of-the-art technologies. In recognition of the substantial costs involved to perform these types of studies, PG&E has adopted a systematic, nested approach to conduct the CCCSIP. Regional scale surveys are used to identify areas for more comprehensive, high-resolution site-specific investigations.

In addition to the integration and interpretation of the diverse geologic and geophysical data sets collected as part of the CCCSIP, there are additional challenges and demands that are not usually encountered in industry work. These include the need for Nuclear Quality Assurance / Quality Control (QA/QC) oversight and documentation (including extensive software and hardware calibration and validation), participatory peer review requirements consistent with the needs of the informed technical community (including the CPUC IPRP, US Nuclear Regulatory Commission (NRC) and Senior Seismic Hazard Analysis Committee (SSHAC) processes), public transparency, and extraordinary environmental and permitting constraints.

The following comments are presented in response to the specific issues listed in Dr. Gibson's letter to PG&E dated June 20, 2012.

Request 1

The overall design approach for both the offshore and transition zone surveys should be described. The survey design discussion should explain how survey acquisition parameters, data processing sequence, and interpretation products were chosen and how these three elements are integrated.

Response 1

Initial IPRP review of PG&E'S plans focused on the geologic targets or fault segments to be surveyed and the potential impact of that information on the seismic hazard evaluation for DCPP. Those geologic targets and their potential impacts on the DCPP seismic hazard analysis were identified in PG&E's 2011 Shoreline Fault Zone report to the NRC. Updated ground motion models used in the NRC Report identified strike-slip earthquakes along the Shoreline and Hosgri fault zones as well as reverse-slip earthquakes on the Los Osos and San Luis Bay fault zones as the key contributors to seismic hazard at DCPP.

To better constrain the four main parameters needed for a seismic hazard assessment: geometry (fault length, fault dip, down-dip width), segmentation, distance offshore from DCPP, and slip-rate, PG&E conducted a series of sensitivity studies to document which of those four sets of parameters had the greatest impact on reducing the overall uncertainty for hazard estimates. The offshore target areas and the parameters to be addressed by the CCCSIP are listed in Table 1. These issues determined the design goals of both the Low and High Energy 2D and 3D Seismic Surveys.

Table 1 List of Targets for Offshore Geophysical Studies

Target Region	Technical Issue	Method
Hosgri-San Simeon step-over	Geometry of the step-over. Is it really a segmentation point?	Low Energy 2D / 3D High Energy 3D
Hosgri fault offshore DCPP	Slip Rate	Low Energy 2D / 3D
	Dip	High Energy 3D Regional geophysical studies
Shoreline fault zone	Geometry of northern segment	Low Energy 2D / 3D High Energy 3D

Target Region	Technical Issue	Method
	Southern extent	Low Energy 2D / 3D
	Slip Rate	Low Energy 2D / 3D
Hosgri-Shoreline Intersection	Structural relationship between the Hosgri and Shoreline fault	Low Energy 2D / 3D High Energy 3D
Los Osos fault	Structural relationship between the Hosgri and Los Osos fault	Low Energy 2D / 3D High Energy 3D
	Slip rate	Low Energy 2D / 3D
San Luis Bay fault	Dip	Low Energy 2D / 3D High Energy 3D

The overall design approach for both the LESS and HESS studies is dictated by the technical goals to be addressed as well geographic setting of the site (e.g., water depth, navigation obstacles), the capabilities of the survey vessel(s) and equipment, as well as environmental and permitting constraints

As shown in Table 1, the 2D and 3D LESS studies of the Shoreline fault conducted in 2010 and 2011 focused on the northern and southern ends, near Point Buchon and within San Luis Bay, respectively. These surveys addressed the shallow structure of the Shoreline fault as well as identified possible piercing points or areas where the Shoreline fault intersected recent geomorphic features in order to determine fault slip rates.

Both the LESS studies and the onshore 2D/ 3D seismic surveys in 2011 tested the feasibility of conducting further seismic profiling along the continental shelf offshore of DCPP. Much of the Tertiary rocks within the onshore Irish Hills and offshore continental shelf are underlain by the highly chaotic Mesozoic Franciscan Formation. As discussed in Request 2, results from onshore seismic surveys in 2011 provided an important pilot test or feasibility for conducting additional HESS surveys offshore. Could PG&E, in fact, use 3D seismic survey techniques to image structures within the Franciscan? Based on these initial results, the subsurface structures are truly complex and intrinsically 3D; 2D seismic reflection data acquisition is not a reliable or appropriate approach to accurately image crustal structure in this area. Systematic 3D data acquisition with rigorous population of common mid-point (CMP) bins over a wide range of offsets and azimuths is necessary to obtain spatially accurate images of crustal structure in CCCSIP study area.

Based on the lessons learned from the 2011 onshore survey and advice from PG&E's contractors concerning marine 3D multichannel data acquisition, PG&E's response to Request 3 discusses the basic seismic acquisition parameters, such as spatial sampling interval and maximum source-receiver offset, needed to image the target structures listed in Table 1 at depth. One of the major survey design issues is the close proximity of the geologic targets to shore. The central section of the Shoreline fault lies within the Transition or Intertidal Zone in water depths less than 25 m. As discussed in Request 4, safety concerns about operating large vessels in shallow water with rocks and kelp beds precluded conventional approaches to seismic imaging. As a result, other strategies, including high resolution helicopter aero magnetics and marine gravity surveys as well as the deployment of marine nodes were developed to image the Transition Zone.

In order to constrain the deeper geometry of fault zones and image to the depths at which earthquake are occurring, 3D HESS surveys require the use of 6 to 8 km long streamers. This influences the orientation of the survey racetrack design. While the ideal seismic survey orientation is generally perpendicular to structure (dip lines), the close proximity of both the Hosgri and Shoreline faults to shore in the region between Point Buchon and Point San Luis (less than 1 streamer length) requires orienting survey lines parallel to the strike of the fault (strike lines) instead of perpendicular to the fault (dip lines). The overall width or footprint of these strike line survey tracks, however, is still influenced by the closest approach to shore. As shown in Figure 1, HESS Survey Racetracks or Boxes 1, 2, and 3 were designed to account for these geometric constraints.

As shown in Figure 1, HESS Survey Box 4 in Estero Bay is oriented to be roughly perpendicular to the strikes of the Shoreline, Los Osos and Hosgri faults and provides an opportunity to conduct dip survey lines in this area. This would provide a broader azimuthal coverage of complex geologic structures in the area, consistent with PG&E's response to Request 5.

The data acquisition and processing is addressed in PG&E's response to Request 6. Initially, data from each of the offshore, transition zone and onshore 3D surveys will be collected and processed independently. Accordingly, the first phase of the survey data acquisition planning is focused on producing data sets in an industry standard SEG-Y data format that be integrated at a later date. Post-cruise, the latest industry processing toolkits will be used to produce both 3-D prestack time migration (PSTM) and prestack depth migration (PSDM) imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro Seismic Imaging and/or GeoTrace. Recent advances in 3D tomography and full waveform inversion (FWI) techniques will also be applied to these new data.

Once the seismic data are processed, interpretation teams consisting of geoscience professionals with expertise in specific areas (e.g., seismic interpretation, structural geology) will be assembled to integrate and interpret data following the delivery of final processed data. In addition to individual SEG-Y files, data will be merged in a Kingdom

Suite 3D volume or cube to facilitate analysis and visualization of data for interpretation and further analysis.

Request 2

The offshore and transition zone survey design process should analyze results of recently-conducted land surveys to confirm the adequacy of acquisition parameters and processing flow.

Response 2

The major findings from the 2011 onshore seismic reflection survey in the Irish Hills are:

(1) Successful imaging of the Franciscan basement can be accomplished, contrary to previous expectations

(2) The identification of swept frequency and geophone spacing parameters necessary to capture both shallow and deep imaging

(3) There is a higher expectation of success in imaging the Transition Zone through the use of onshore and offshore seismic sources

The following sections provide a more detailed discussion of these results.

Proprietary seismic reflection data within the greater Irish Hills owned by ConocoPhillips was licensed and reprocessed to determine the effectiveness of several types of seismic sources and recording configurations. The results of the ConocoPhillips data analyses were used to define the 2011 2D onshore testing and data acquisition program in the Irish Hills.

The primary findings from the analyses of the ConocoPhillips data are presented first, followed by a summary of the findings from the 2011 2D onshore testing and data acquisition program in the Irish Hills

1984 ConocoPhillips Data

ConocoPhillips acquired Dynamite data from one line in the central portion of the Irish Hills north of the DCPP property. Most of the ConocoPhillips line was located in Tertiary rocks, with the north end of the line extending about 1 km north of the southern Edna fault trace into Franciscan rocks. ConocoPhillips acquired data from six lines in the Irish Hills although five of the six lines were located east of the DCPP property. Three of the ConocoPhillips lines used Dynamite and three of the lines used Vibroseis™ sources (Table 2).

Table 2 1984 ConocoPhillips Reflection Line Acquisition Parameters

Line Number	Line Name	Datum (ft)	Fold	Source	Channels	Group Interval (ft)	Shot Interval (ft)	Length (s)
1	p6502-1	800	24	Vibroseis™	96	82.5	165	4
3	p6502-3	800	24	Vibroseis™	96	82.5	165	4
4	p6502-4	200	24	Vibroseis™	96	82.5	165	4
6	p6502-6	800	24	Dynamite	96	110	220	4
9	p6598-9	200	24	Dynamite	96	110	220	4
13	p6598-13	1600	24	Dynamite	96	110	220	4

The ratio of signal to noise in the data is a function of acquisition parameters (Table 2), as well as the source and receiver configurations (Table 3). The deep shot holes and large charge (10 lb) used for line 13 (Table 3) produces the best overall signal quality, but the resolution of deeper structure is compromised by the high frequency (28 Hz) geophones used to record the Dynamite source and the limits of the maximum offsets attained with the 96 channel recording systems (Table 3). Also, there were many dead channels and frequency strong coherent electrical noise in most of the Dynamite shot records that further decreased signal strength.

Table 3 1984 ConocoPhillips Reflection Line Source and Receiver Configurations

Line Number	Line Name	Source	Sweep (Hz) or charge (lb)	Source Configuration	Geophone	Offset range (ft)
1	p6502-1	Vibroseis™	18-80 (12 s)	4 Failing Y-900	10 Hz	330-4208
3	p6502-3	Vibroseis™	18-80 (12 s)	4 Failing Y-900	10 Hz	330-4208
4	p6502-4	Vibroseis™	18-80 (12 s)	4 Failing Y-900	10 Hz	330-4208
6	p6502-6	Dynamite	0.5 lb	9 5 ft holes	28 Hz	110-5280
9	p6598-9	Dynamite	0.5 lb	9 5 ft holes	28 Hz	110-5280
13	p6598-13	Dynamite	10 lb	1 25 ft hole	28 Hz	110-5280

The sequence of steps in processing the data (Table 4) was designed and adjusted to evaluate signal quality as a function of frequency. Several high-frequency upper limits were selected for band pass filtering and the data stacked to determine the maximum frequency that produced the best signal-to-noise ratio. Although the Dynamite source noise dominated at frequencies greater than 50-60 Hz and at frequencies greater than 40 Hz for times later than 2.3 to 2.5 seconds.

Table 4 1984 ConocoPhillips Data Processing Sequence

Step	Description
1	Reformat field SEG-Ydata
2	Vibroseis cross-correlation Sample rate 2 ms
3	Geometry definition (Vibroseis™ and Dynamite data)
4	Pick first breaks; Calculate Refraction Statics; 1 Layer Model; VO is 3000 feet/sec Datum is 200/800/1600 feet, replacement velocity is 7500/8000 feet/second
5	Trace edits and reversals
6	Amplitude recovery $T^{1.2}$, Air blast attenuation
7A	Dynamite data only: Surface consistent deconvolution, operator 160ms, gap 18 ms, time variant spectral whitening, 6/12-57/65 Hz frequency limits determined from spectral analyses and stacking tests of the data, multiple gate equalization
7B	Vibroseis™ data only: Time variant spectral whitening, 8 - 80 Hz frequency limits, one gate equalization
8	Statics to floating datum
9	Interactive velocity analysis; Residual statics surface consistent; Interactive velocity analysis; Residual statics surface consistent; CDP trim statics
10	Final normal moveout; Initial mute; 500 ms agc
11	Flat datum statics, datum varies as per Table 1, VR is 7500/8000 fps
12	Create final unfilterd stack cdp stack 1/root(n) Time Variant Bandpass filter: For: Vibroseis™ data 10/18-55/65 hz. 0.0 - 1.7 sec. 8/18-35/45 hz. 2.3 - 4.0 sec. Fx predictive deconvolution, Trace balance For: Dynamite data 10/15-50/60 hz. 0.0 - 2.0 sec. 8/13-35/45 hz. 2.5 - 4.0 sec. Fx predictive deconvolution, Trace balance Output Final stack in SEG-Y format

The 28-Hz geophones used for acquisition of lines 6, 9, and 13 (Tables 2 and 3) reduce resolution at two-way travel times greater than 2.5 seconds because the stack tests revealed that there is little signal at times greater than 2.5 seconds in the Dynamite data at frequencies greater than 40 Hz (step 12 in Table 4). Because the frequency-dependent stacking tests showed that there is little signal in the Dynamite data at frequencies > 60 Hz, there is no need to use high-frequency geophones to acquire data in this area. Consequently, improved signal-to-noise would have been obtained for lines 6, 9, and 13 for depths > 8000 ft simply by using 10-14 Hz geophones, which have good response characteristics to > 60 Hz. In fact, the Vibroseis™ data generally produced better images of folded Tertiary structure using 10 Hz geophones in the first 1.7 seconds of the section than the Dynamite data using 28 Hz geophones (step 12 in Table 4) because the wider frequency bandwidth of significant signal-to-noise with the lower frequency geophones made it possible to consistently produce a more compact wavelet and obtain better overall resolution of even shallow reflectors than the Dynamite data acquired with high-frequency geophones. The Vibroseis™ data were also acquired with a shorter group and source spacing that also decreased aliasing in regions of steep dip relative to the Dynamite data.

Geologic mapping along the ConocoPhillips line showed little relationship between observed mapped dip directions and angles and shallow apparent dips in the ConocoPhillips seismic reflection data. Consequently, a key requirement in the specification of data acquisition parameters for the 2011 field program was to include sufficiently high-resolution data acquisition parameters to properly resolve shallow, often steep dips observed in many areas of the Irish Hills.

2011 Onshore 2D Seismic Reflection Field Program

Permitting inquiries revealed that the only permitted sources would be surface sources and that drilling and explosive sources could not be permitted. Consequently, the seismic sources available for the 2011 onshore seismic reflection field program were Vibroseis™ and impact surface sources. Permitting restrictions limited source positions to roads, precluding the types of regular source geometries required to properly populate CMP bins as a function of offset and azimuth and conduct rigorous 3D imaging tests. Permits for seismic operations on public areas restricted both sources and receivers to road right-of-ways. Consequently, limited 3D imaging testing was restricted to private properties where private landowners permitted deployment of regularly-spacing receiver 2D arrays away from roads.

As is typical in the oil and gas industry when both shallow high-resolution imaging of young faults and imaging deep structures and/or reservoirs are required, two data acquisition programs were designed to meet each of these objectives. Since permitting restricted data acquisition primarily to 2D imaging along roads, both data acquisition programs were run along the same routes when possible to provide resolution of both shallow and deep structure; the large Vibroseis™ trucks could not always access areas accessible to the AWD and the AWD did not operate on some of the roads used by the Vibroseis™ trucks, so there is not uniform overlap in all areas of the two data acquisition programs.

The shallow velocities in the Tertiary Pismo syncline along ConcoPhillips line 13 were used along with a maximum frequency of 50 Hz to determine that a 30-ft group spacing would avoid aliasing associated with steep dips and surface wave aliasing for a maximum surface wave frequency of 25 Hz (surface wave amplitudes decreased substantially above 25 Hz). A third-generation 450-lb accelerated weight drop (AWD) source was selected for shallow-high-resolution imaging tests and 2D production. This source could adjust its output force with adjustable nitrogen spring pressure so that it could operate on weak asphalt surfaces that had lost their bonding agents without producing any deflection of the road surface to ensure compliance with permits (permit compliance required no perceptible road deflection as measured with a 12-ft straight edge). The 450-lb AWD was also able to access narrower roads than large Vibroseis™ trucks to obtain shallow high-resolution data in these regions.

The 2011 field program began with a week of source testing on the DCPP facility to determine optimal production source parameters. Real-time field processing with a 2D 400-channel networked cable system was used to assess source and acquisition using 30-ft group intervals and 14 Hz geophones. AWD and Vibroseis source monitoring systems were used to measure near-source signatures and ensure precise synchronization of 4-5 Vibroseis™ trucks. Testing showed that four synchronized 64,000-lb Hemi-60 Vibroseis™ trucks provide excellent signal at offsets at least as far as 6 km. Specific Vibroseis™ testing systems were used to determine the sweep parameters that produced consistent phase lock between drive and output in a variety of surface conditions to ensure Vibroseis™ sweep stability and consistency across the entire project area. A long-duration linear sweep of 24 seconds from 5 to 60 Hz produced the best combination of good consistent long offset (> 6 km) signal-to-noise with a broad frequency bandwidth that was achievable across all the diverse geologic units in the Irish Hills necessary to achieve consistent source frequency bandwidth imaging of intermediate and deeper structure.

Initial testing within the DCPP property with the AWD showed that steep dips were generally confined to depths of < 2-3 km and that coherent 30 Hz signals from the DCPP turbines were very large within several km of the DCPP. A station spacing of 120-ft was used for the nodes that would record the large Vibroseis™ sources since it was apparent that deeper dips were generally not as steep as shallow thin-skinned structure and that deeper imaging might require restricting the data to the 5- < 30 Hz frequency bandwidth to achieve consistent signal to noise at depths of 8-18 km. A Vibroseis™ source spacing of 120 ft was used in most areas; this was decreased to 60 ft in areas where undershooting was required.

2011 Onshore Field Program Findings

Strikes and dips varying rapidly, both horizontally and in depth to 2 to 4 km throughout nearly all regions of the Irish Hills encompassed by the 2011 onshore seismic reflection program. The seismic imaging problem is truly complex and intrinsically 3D; 2D seismic reflection data acquisition is not a reliable or appropriate approach to accurately image crustal structure in this area. Systematic 3D data acquisition with rigorous population of CMP bins over a wide range of offsets and azimuths is necessary to obtain accurate images of crustal structure in the Irish Hills and adjacent areas. Multiple high-energy data acquisition geometries and source configurations are required to achieve image objectives for shallow and deep structure. The 30-ft group and source spacing used with the AWD source and > 300 channels effectively imaged shallow (0-2 km) steep dips at all locations, except where bedding was essentially vertical, to maximum frequencies of 50 Hz. This data acquisition configuration imaging faults from the surface to 1-2 km depth identified in previous paleoseismic investigations within the DCPP property. Consequently, a group interval on the order of 30 ft will be effective in 3D high-resolution imaging to depths of several km throughout the Irish Hills region when combined with systematic wider aperture recording at a wider group spacing. A 30-ft group interval will be effective near the DCPP where shallow velocities are generally among the highest shallow velocities found in the Irish Hills region, particularly compared to slower velocities found in Tertiary rocks in the Pismo Syncline located north of the DCPP property. However, near DCPP the AWD source became less effective because DCPP coherent noise was not effectively reduced by vertically stacking AWD impacts, resulting in low signal-to-noise at offsets > 1000 m using the AWD source near the DCPP. Consequently, for 3D high-energy high-resolution imaging of shallow structure proximal to DCPP in areas inaccessible to large Vibroseis™ trucks, mini-Vibroseis™ sources should be used to allow precise phase tuning to suppress 30 Hz coherent noise. The same approach can be used with the large Vibroseis trucks to suppress the 30 Hz coherent noise. Tuning of a mini-Vibroseis™ source should be performed to evaluate nonlinear sweeps and other sweep parameters and strategies such as slip-sweep recording. Mini- Vibroseis™ sweep tuning testing in necessary to find the optimal sweep program that provide the best-balanced resolution of structure from the near surface to several km depth within several km of the DCPP. While nonlinear sweeps and/or slip-sweep methods may be appropriate for shallow imaging with the mini- Vibroseis™ trucks, linear sweeps should be used with the large Vibroseis™ trucks to ensure good long-offset signal-to-noise to obtain good images in the 4-18 km depth range.

The large Vibroseis™ trucks operated in combination with 7220 discrete nodal receiver positions provided consistent observations of good first breaks to 8-12 km offsets in most locations, and clear first breaks to a maximum offset of 19 km. A total of > 5,800,000 good quality first-breaks were picked from a possible set of 16,700,000 first breaks from all recorded source-receiver pairs that spanned an approximately 20 km by 20 km region of the Irish Hills. Near the DCPP where plant noise was highest, the large Vibroseis™ trucks provided good first-breaks at the noisiest recording sites to at least 4 km offset. Tomographic inversion with the first-breaks was used to solve for 3D velocity structure to depths of 2 to 3 km and long-wavelength and residual source and receiver statics. The 3D tomographic approach was necessary to eliminate uncertainties in first-order statics associated with shallow steep dips and complex shallow velocity and geologic structure associated with extreme topography and thin-skinned deformation that produced irregular, and often steeply dipping reflectors.

A 2D seismic reflection profile was constructed from the Vibroseis™ -node data for a region spanning Point Buchon and Point San Luis. Consistent high-quality reflections were observed to at least 13 to 14 km depth and generally extended to 17 to 18 km depth using data in the 5-25 Hz frequency band below about 3-4 km depth. Between

Point Buchon and Point San Luis, maximum offsets of 4 to 6 km provide consistent high-quality imaging to depths of about 8 to 9 km depth. Incorporating data recorded to maximum offsets of 8 to 12 km produces consistent images to about 14 to 15 km depth. The Franciscan basement exhibited persistent reflectivity to depths of 14 to 18 km throughout most of the Irish Hills. This suggests that a good rule of thumb for this region is that the maximum image depth will be approximately 1.5 times the maximum offset in the recorded data for high-energy sources such as four synchronized 64,000 lb Vibroseis™ trucks or > 3000 in^3 air guns. Recording of longer-offset air gun data with onshore and offshore nodes in the region between Point Buchon and Point San Luis would improve aperture and azimuthal coverage and ensure good migration performance to depths of 8 to 14 km for the region bounded by Point Buchon and Point San Luis, the Hosgri fault to the south and the southern Irish Hills within the DCPP property to the north.

3D velocities from the tomography strongly correlate with surface geology and previously inferred shallow (1 to 3 km) geologic structure used to construct the 3D velocity model used in the 2011 illumination study. The continuously recording nodes produced clear recordings of at least 18 earthquakes at receivers located throughout the entire Irish Hills survey area, representing at least 30,000-40,000 arrival times that can be used in 3D velocity-hypocenter tomographic inversions to improve resolution of crustal velocity structure below the maximum 3D tomographic imaging depths of the active source data (2 to 3.5 km). These earthquake arrival time data will provide important tomographic constraints on deeper (> 3 km depth) crustal velocity structure than is provided by the active source data and will improve migration performance at depths > 3 km relative to industry-standard processing.

The 2011 onshore high-energy testing results indicate that in near-shore locations adjacent to the DCPP onshore large Vibroseis™ sourcing should provide good signal to noise at least 4 km offshore, which would be a sufficient aperture to record the steeper dips observed in the first several km in the onshore-near-shore region proximal to the DCPP. Offshore recording of onshore Vibroseis™ sources is essential to record sufficient aperture to migrate steeply-dipping structures that trend offshore from the onshore data within 8 km of DCPP.

<u>Request 3</u>

The choice of basic parameters such as spatial sampling interval and maximum source-receiver offset should be discussed relative to the spatial resolution required to image expected target structures at depth. For instance, what spatial resolution is required to evaluate geologic markers that might provide a measure of fault slip rate?

<u>Response 3</u>

The NRC places a high emphasis/importance on mapping shallow, near surface geologic investigations in order to constrain the geomorphic expression of potentially significant and capable seismic sources. Low Energy Seismic Surveys (LESS) rather than High Energy Seismic Surveys (HESS) are the preferred tool to evaluate fault slip rate. Offsets of recent geomorphic features can be measured and dated to provide estimates for fault slip rates. These data serve as the control for estimating the rates and magnitudes for design earthquakes.

HESS surveys can provide information about the deeper geometry of seismogenic faults in the area and help constrain the source characterization of these structures. The basic acquisition parameters for the proposed 2012 HESS study are summarized in Table 5. Spatial resolution (as expressed by bin sizes) for the marine LESS studies that were conducted off of Point Buchon and in San Luis Bay were 1.56m x 3.125 m and 3.125 m x 3.125 m, respectively. Bin sizes for the HESS studies, dictated by streamer group intervals (12.5 m) and cross line spacing (100m to 150 m) are estimated to be 6.25 m x 25 – 37.5 m, respectively.

Table 5 Proposed HESS Acquisition Parameters

Survey Area	614 km^2
Source	Two (2) 3300 in^3 arrays, 9m tow depth
Recording	Syntrack
Streamer	4 x 6000m solid Sentry streamers, 100 - 150 m cross line spacing, 9 m tow depth
Channels per Streamer	468
Group Interval	12.5 m
Maximum Offset	6000 m
Shot Spacing	37.5 m flip flop (75m per source)
Shot Interval	37.5 m
Source / Streamer Location Accuracy	Source 1 -2 m / Tail buoy 7-12 m
Record Length	10 seconds
Bin Size	25 - 37.5m x 6.25m
Sample Rate	2msec
Fold	40

Request 4

The choice of towing only 4 streamers in the offshore survey should be evaluated. Typical industrial surveys deploy 10 or more streamers to improve survey efficiency (i.e., reduced acquisition time). This should be a significant issue for the proposed survey, which has been analyzed to have significant impacts to marine life, based on time exposure to the seismic source.

Response 4

Today's industry design and practice is heavily guided by the specifics of the intended target. During the past decade, the energy sector has experienced a significant move towards subsalt imaging in deep water (water depths in excess of 5000 ft, target depths in the 20,000 ft range and beyond); this operational mode is especially true for the Gulf of Mexico, offshore Brazil, and West Africa. For efficiency in regions with little or no operational hazards (such a shallow seafloor outcrops), combined with significant target depths, the industry developed a new breed of vessels, including "ramform" designs, that can tow up to 10-14 streamers with dual flip-flopping sources. In an appropriate environment, this strategy can reduce data collection time by a factor of 2 or 3—although a significant increase in the day-rate cost is realized for such vessels. Nevertheless, there are downsides to this approach. First, with respect to water depth, operations of "ramform" and similar boats are limited to water depths greater than 75 m. For comparison purposes, vessels towing 4 to 6 streamers with dual source arrays can survey into water depths of 25 m or greater. Offshore Diablo Canyon, this operational limitation would force a vessel towing 10 to 14 streamers to move offshore by an additional 2 to 4 km (from northwest to southeast). This attempt at efficiency would not only significantly increase the width of the transition zone between marine and land surveys, but would also compromise imaging quality along the Hosgri Fault (due to a migration aperture width that would overlap the intended target, creating an imaging problem at depth). Second, increasing the width of the array would also introduce unintended imaging problems, especially for shallowest sections of the crust as a wide variety of azimuths at a given location are needed to construct an image, which can be problematic (e.g., such as back tracking anisotropic effects). Third, for shallow targets, the lack of near offsets within certain bins can obscure shallow imaging of important targets such as faults. A better strategy would encompass two overlapping 3D surveys, with a narrower array (4 to 6 streamers), but shot along sail-lines from different azimuths, as is proposed for Boxes 2 and 4 in Figure 1. Ultimately, it is unsafe to use vessels towing 10 to 14 streamers given seafloor depths offshore Diablo Canyon, and the need to image structures from the Hosgri Fault toward the shoreline. Finally, the importance of both shallow and deep target imagings requires an approach that is not solely focused on the deeper subset.

PG&E's Request for Proposals (RFP) for the HESS project initially specified 6 to 12 streamers of 4 to 8 km length or offset for the HESS. The original racetrack design for the HESS was based on a minimum operating water depth of 50 m, which acknowledged safety concerns about operating in shallow water (presence of nearshore shallow rock outcrops, kelp beds, and other navigation obstacles). Input from the IPRP suggested extending the survey closer to shore, in shallower waters. Consultation with Columbia University Lamont-Doherty Earth Observatory, operators of the *R/V Langseth*, indicated that a safe operating depth could be extended to the 25 m contour for a closer approach to shore.

The minimum operational water depth for 10 or more streamer vessels is 75 m (3x deeper than identified for the *R/V Langseth*, 25 m) due to the depths of the lead-ins both online and in the turns. Operating at these depths would preclude imaging many of the near shore targets identified in the CCCSIP. The turning radius for a ten streamer vessel is 4 to 5 km vs. 2.5 km for a four streamer vessel. With the exception of Box 2, the 10 streamer line changes for Boxes 1 and 4 could be as long as the lines themselves and would impede navigation in tight areas such as Estero Bay. Shorter turns will allow more online or production time.

Ten streamer vessels are larger, require more deck space for equipment, tend to burn more fuel due to increased resistance (introducing additional air quality issues) and require a larger turning radius. Simply stating that 10-streamer multi-channel seismic (MCS) vessels are more efficient is not applicable to all environments, especially shallow-near shore environments. In fact, there might be no efficiency in survey time realized given the above considerations. The additional risk involved in using larger vessels in shallow coastal waters would also result in additional charges and risk premiums, as well as significant expense (i.e., millions of dollars) to mobilize/demobilize these vessels and equipment to the central coastal California area.

As noted above, the original RFP specified consideration of vessels capable of towing 6 to 10 streamers. Feedback from bidding and non-bidding firms concluded that the smaller vessels with less streamers were appropriate for the constraints of this location and this survey

Request 5

The potential benefit of data acquisition over a wide (in contrast to the proposed narrow) source-receiver azimuth range should be evaluated for both image quality improvement and the ability to evaluate the orientation of maximum horizontal stress.

Response 5

Collecting 3-D using a wide-swath geometry (e.g., 10 to 14 streamer configurations) is typically seen as a negative as anisotropic effects may need to be accounted for to produce a clean, crisp image. Nevertheless, constraining crustal anisotropy can help better understand the pattern of strain (not stress) in the crust, and hence, the history of deformation. The measurement of stress in the crust is elusive and certainly not the purview of the reflection seismology technique. See response to Request 7 below. A better acquisition strategy would consist of overlapping 3-D survey boxes (e.g., Boxes 2 and 4 in Figure 1), shot from different azimuths, using a narrow footprint of towed streamers to ensure both safety, the ability to image the shallow most sections of the crust, and estimate crustal anisotropy.

Request 6

The proposed seismic data processing flow, data processing contractor and experience should be specified.

Response 6

A number of industry contractors have been identified to conduct both the onshore and offshore seismic data acquisition and processing for the CCCSIP. All of the work performed will be in compliance with Nuclear Quality Assurance (NQA-1) requirements as stated in 10 CFR 50, Appendix B and10 CFR 21. The proposed processing flow for the 3D Diablo Canyon project will embody the latest, cutting-edge seafloor multiple removal and seismic imaging techniques (among a myriad of recent advancements) that are currently available within industry processing shops.

Marine Navigation Processing: NCS SubSea (Houston, TX; http://www.ncs-subsea.com/) will be responsible for the 3-D streamer navigation using Concept Systems' Spectra, Sprint and Reflex modules to provide the highest standard of streamer navigation. The flow chart in Figure 1 illustrates the software used, QC steps, and the outputs generated in industry data exchange formats for raw (P2/94) and processed (P1/90) navigation and positioning data

NCS Subsea has worked with Fugro and PG&E on the 3D Low Energy Seismic Survey (LESS) work offshore DCPP in 2010, 2011 and the upcoming 2012 PCable survey in August 2012.

Marine Seismic Data Acquisition and Processing: Contractors from well-established firms such as Fugro Geoteam (Houston, TX; http://www.fugro-geoteam.com/) and/or GeoTrace (Houston, TX; http://www.geotrace.com/) will be onboard the *R/V Langseth* during acquisition and will be responsible for all data QC and QA. This oversight will include careful inspection of trace amplitudes for all shots, potential effects of swell noise, dynamic 3D binning of data volume, etc. Table 6 and Figure 2 show an example of the data processing flow that will be used for the marine HESS. Post-cruise, the latest industry processing toolkits will be used to produce both 3D prestack time migration (PSTM) and prestack depth migration (PSDM) imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro Seismic Imaging and/or GeoTrace. Recent advances in full 3D tomography and waveform inversion (FWI) techniques will also be applied to these new data.

Table 6 Typical 3D Marine Processing Flow

Reformat
De-signature to zero phase using filter designed from supplied far field signature
Bandpass filter
Resample Gun and cable static correction
Velocity analysis @ 4x4 km
Gain recovery
Targeted FK filter (shallow water only)
Time-frequency denoise (shot and receiver station domains)
K dealias
Tau-p mute direct arrival attenuation
3-D SRME
Velocity analysis @ 4x4 km
Time-frequency denoise (shot and CDP domains)
Shot domain tau-p deconvolution and tau-p mute (shallow water only)
Receiver domain tau-p deconvolution and tau-p mute (shallow water only)
Sort to CDP
Velocity analysis @ 2km x 2km
Targeted FK filter (shallow water only)
Hi-resolution radon de-multiple
Q compensation (phase only)
Time-frequency denoise
Sort to offset domain
Predictive deconvolution (shallow water only)
Bin
Tidal correction
Residual water column statics
Pre-stack time migration
Target migration lines 1 x1 km
Build migration velocity model
Interpolate to 12.5 x 12.5 m
Pre-stack time migration (curved ray)
Residual parabolic radon de-multiple
Automatic residual velocity determination (every CDP)
Normal moveout correction
Mute
Stack
Low frequency boost
Post stack filtering
Bandpass filter
Scaling

Onshore Seismic Data Acquisition and Processing: Onshore, Nodal Seismic (Signal Hill, CA; http://www.nodalseismic.com/) and Bird Seismic Services (Globe, AZ; http://www.birdseismic.com/) will be conducting the onshore data collection in 2012, as a continuation of onshore studies conducted in and around the Irish Hills in 2011 and as part of the Transition Zone imaging. Nodal Seismic will be responsible for operation of Vibroseis and Zland nodal data collection, and Bird Seismic will be responsible for high-resolution shallow data collection. Instrument specifications fro the Zland nodals can be found at http://www.fairfieldnodal.com/Products/ZLand/specs.html. Onshore data processing will be overseen by Fugro Consultants, Inc. (Denver, CO; http://www.fugroconsultants.com). Table 7 shows an example of the onshore data processing flow. As in the case of the marine multi-channel 3D data collection, post-survey analysis will use the latest industry processing toolkits to produce both 3D prestack time migration and prestack depth migration imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro Seismic imaging and/or GeoTrace. Recent advances in full 3D tomography and waveform inversion (FWI) techniques will also be applied to these new data.

Table 7 Typical processing flow for land data including a mix of source types

Reformat
Geometry build and apply
Recording delay correction (separate correction for each source type)
Refraction static calculation
Gain Recovery
Linear noise suppression
Random noise suppression
Surface Consistent Deconvolution (with minimum phase conversion for Vibroseis™ data)
First-break picking
3D tomography
Full-waveform inversion (FWI)
3D solution for long wavelength and residual statics
Refraction static application
Velocity Analysis – one-mile grid
NMO application / Mute first breaks
Residual statics
Velocity Analysis – 2nd pass
Residual statics (2nd pass)
Surface consistent scaling (shot and receiver)
Linear noise suppression
Random noise suppression
Migration velocity analysis – half-mile grid(inline and cross line)
Pre-stack Kirchhoff time migration
Post-migration velocity analysis
NMO – Mute – CMP stack
Post-stack filtering, noise suppression
Pre-stack depth migration

Transition Zone Data Collection and Processing: FairfieldNodal (Sugar Land, TX; http://www.fairfieldnodal.com/) will be responsible for the Transition Zone data collection using up to 600 Z700 marine nodes. Instrument specification for the Z700 Nodals can be found at http://www.fairfieldnodal.com/Products/Z700/specs.html Figure 3 shows an example of the Transition Zone 3D data processing flow. As in the case for both the onshore and marine multi-channel data, post-survey analysis will use the latest industry processing toolkits to produce both 3-D prestack time migration (PSTM) and prestack depth migration (PSDM) imagery. This processing will take place in Houston, Texas and will be contracted through an industry processing shop such as Fugro and/or GeoTrace. Recent advances in full waveform inversion (FWI) techniques will also be applied to these new data.

Request 7

The potential benefit of evaluating vertical fracture alignment, maximum horizontal stress, and directional stress inequality should be discussed. While this information is not typically used in traditional seismic hazard analysis, it does relate to the physical state of the overall seismo-tectonic setting.

Response 7

The evaluation of tectonic stress and strain are components of the seismic hazard analysis that is currently being conducted as part of the Senior Seismic Hazards Advisory Committee (SSHAC) process.

Principal stress directions can be determined from the evaluation of earthquake focal mechanisms and borehole hydro fracture data. Analysis of seismicity and earthquake focal mechanisms in the central coastal area indicates that the principal compressive stress direction, σ_1 is N15°E ± 4° north of latitude 35°N and N47°E ± 15° south of latitude 35°N. As seen in Figure 4, this direction is consistent with a uniform NE-SW maximum horizontal stress orientation from borehole break out data in the area and the overall pattern of recent transpressional tectonic deformation (*McLaren and Savage, 2001, Seismicity of South Central Coastal California: October 1987 through January 1997, Bull. Seismological Society of America,* ***91****, 1629-1658*)

Request 8

The specific acquisition parameters and processing sequence of the transition zone survey should be discussed. Of particular importance would be the processing proposed to assure a high-quality seismic image after merging the transition zone data with the onshore and offshore survey data.

Response 8

The central segment of the Shoreline fault zone, between DCPP and Point San Luis, lies with the Transition or Intertidal Zone, where water depths are less than 25 m. As shown in Figure 1, the Transition Zone widens south of DCPP towards Point San Luis and the HESS Box 1 racetrack is oriented at angle to the coastline. PG&E has proposed to undershoot this gap in coverage by placing a series of marine nodes on the seafloor and using both marine airguns and onshore Vibroseis™ sources. The Draft EIR specified a deployment of 600 Z700 marine nodes placed in a series of five transects perpendicular to the coast with 50 m spacing between nodes. See Figure 1 for node transect locations. Instrument specification for the Fairfield Nodal Z700 Nodes can be found at http://www.fairfieldnodal.com/Products/Z700/specs.html

PG&E is currently working with industry seismic processing companies to update the 2011 Illumination study, based on improved velocity models from 2011 onshore survey, to optimize marine node placement as well as onshore and offshore imaging capabilities. Recognition of environmental restrictions, including placement of nodes on hard (rocky) bottom, avoidance of protected species, etc. need to be addressed before the final node configuration is established.

A processing flow of these Transition nodal data is shown in Figure 4. Once these data are processed they will be integrated with the onshore and offshore data to develop a comprehensive 3D volume of the study area for interpretation.

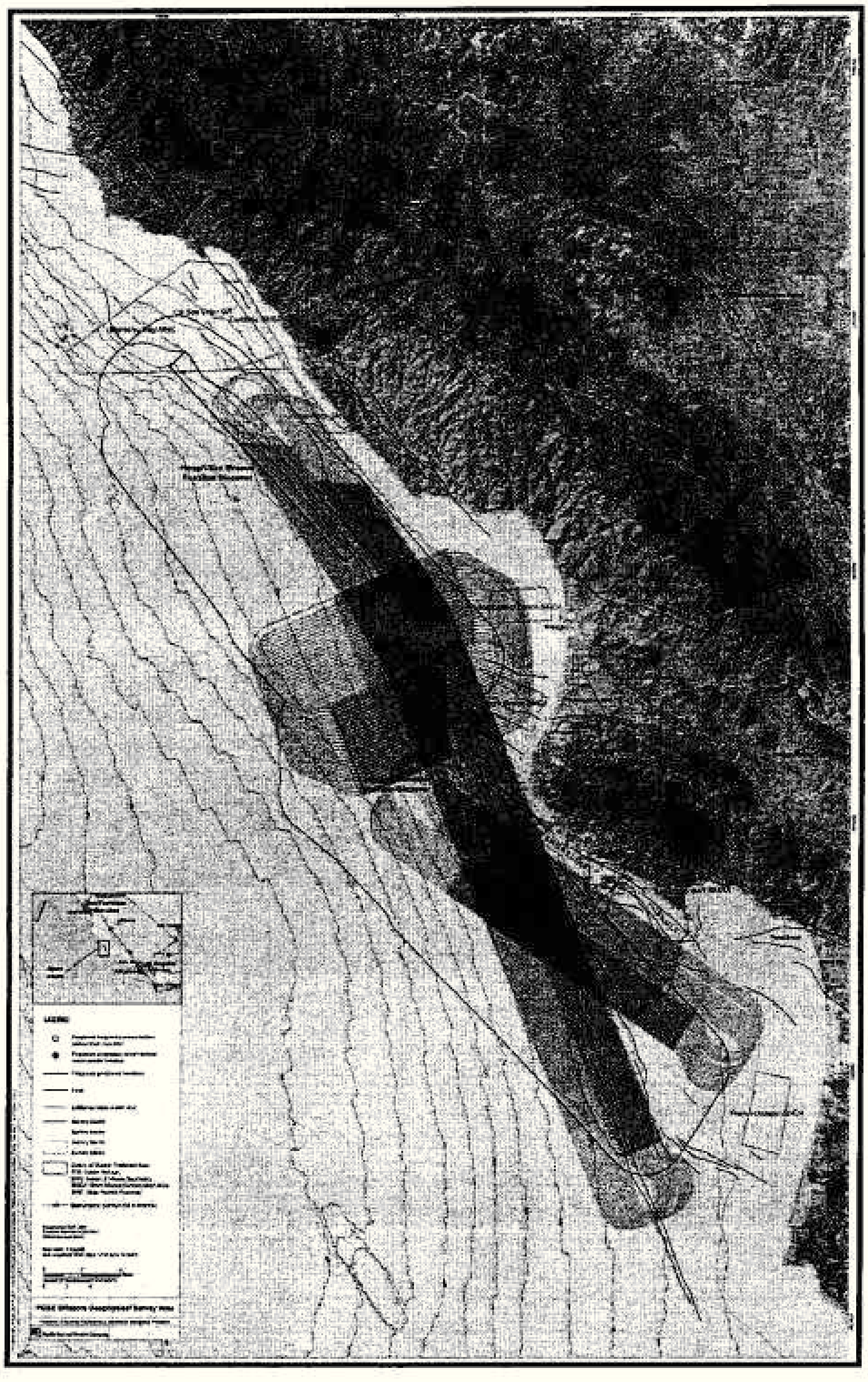

Figure 1. HESS Racetrack Diagram

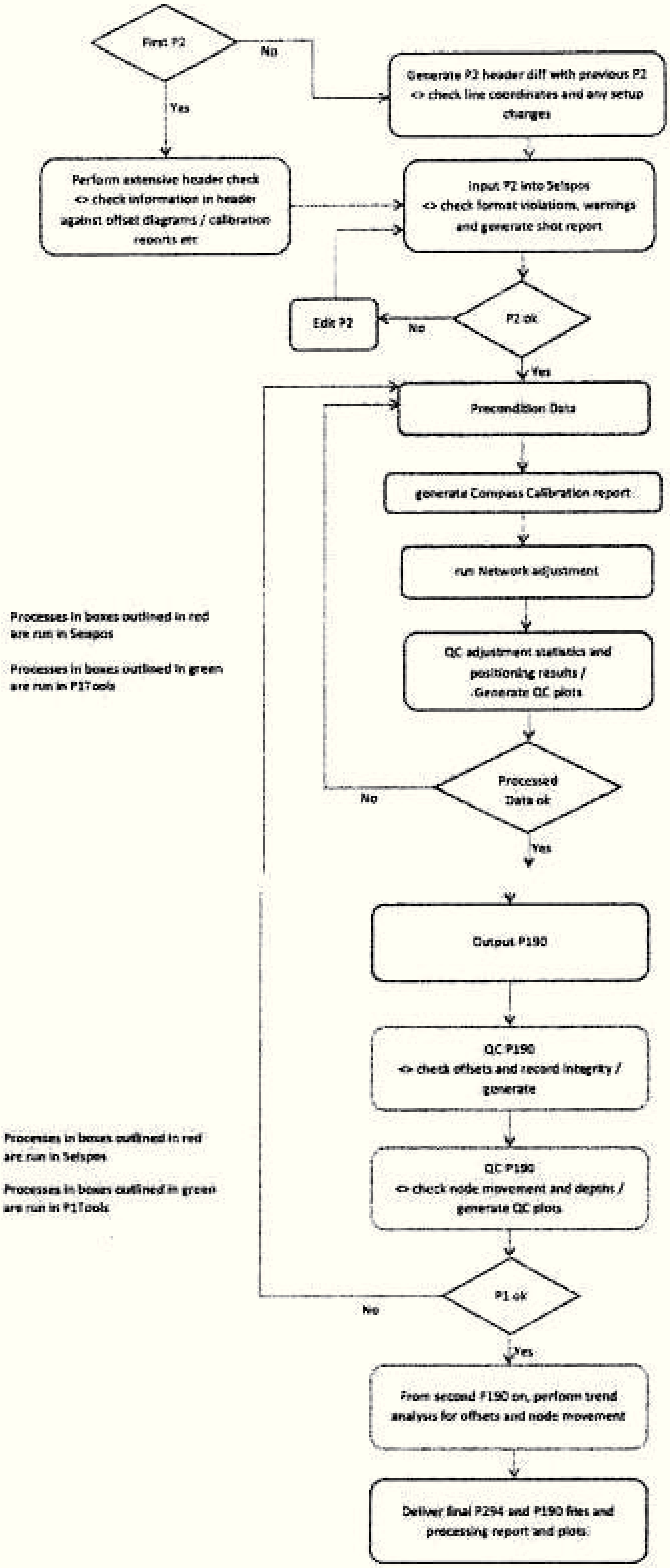

Figure 2 Typical Marine Seismic Navigation Data Processing Flow
P2/94: Industry data exchange format for raw navigation and positioning data for seismic surveying
P1/90: Industry data exchange format for processed navigation and positioning data for seismic surveying. The P190 provides the processed position for each channel/group. SeisPos: Commercial software package for QC and processing of navigation and positioning data for seismic surveying.
P1Tools: The QC component of the SeisPos software package.

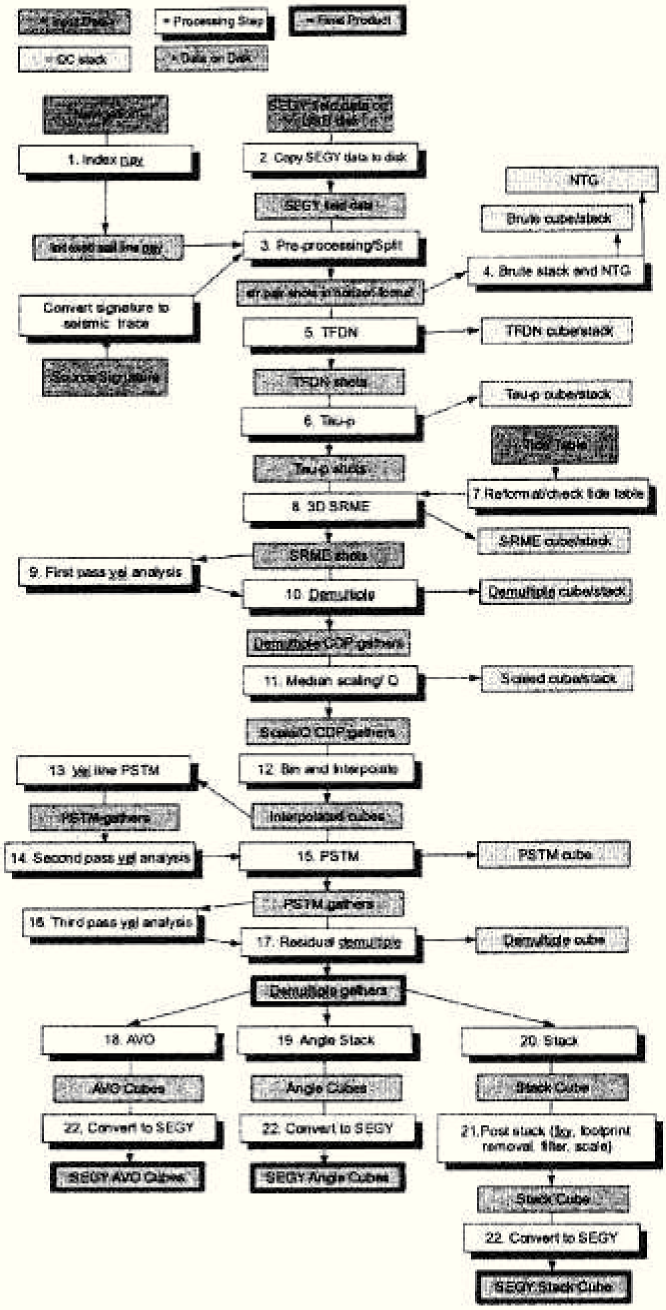

Figure 3 Typical 3D Marine Processing Flow

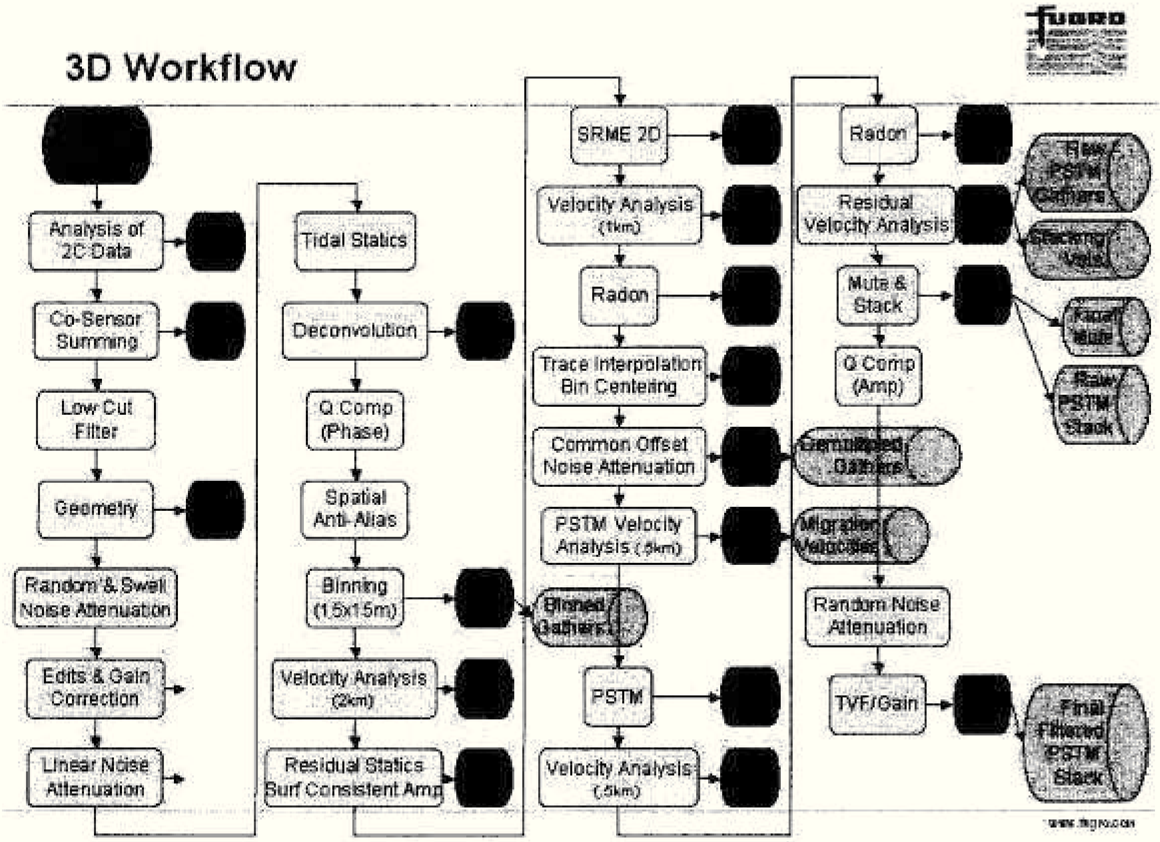

Figure 4 Typical Transition Zone Processing Flow.

Note the co-sensor summing - this is utilizing multiple components in an Ocean Bottom Node or Cable to remove receiver ghosts.

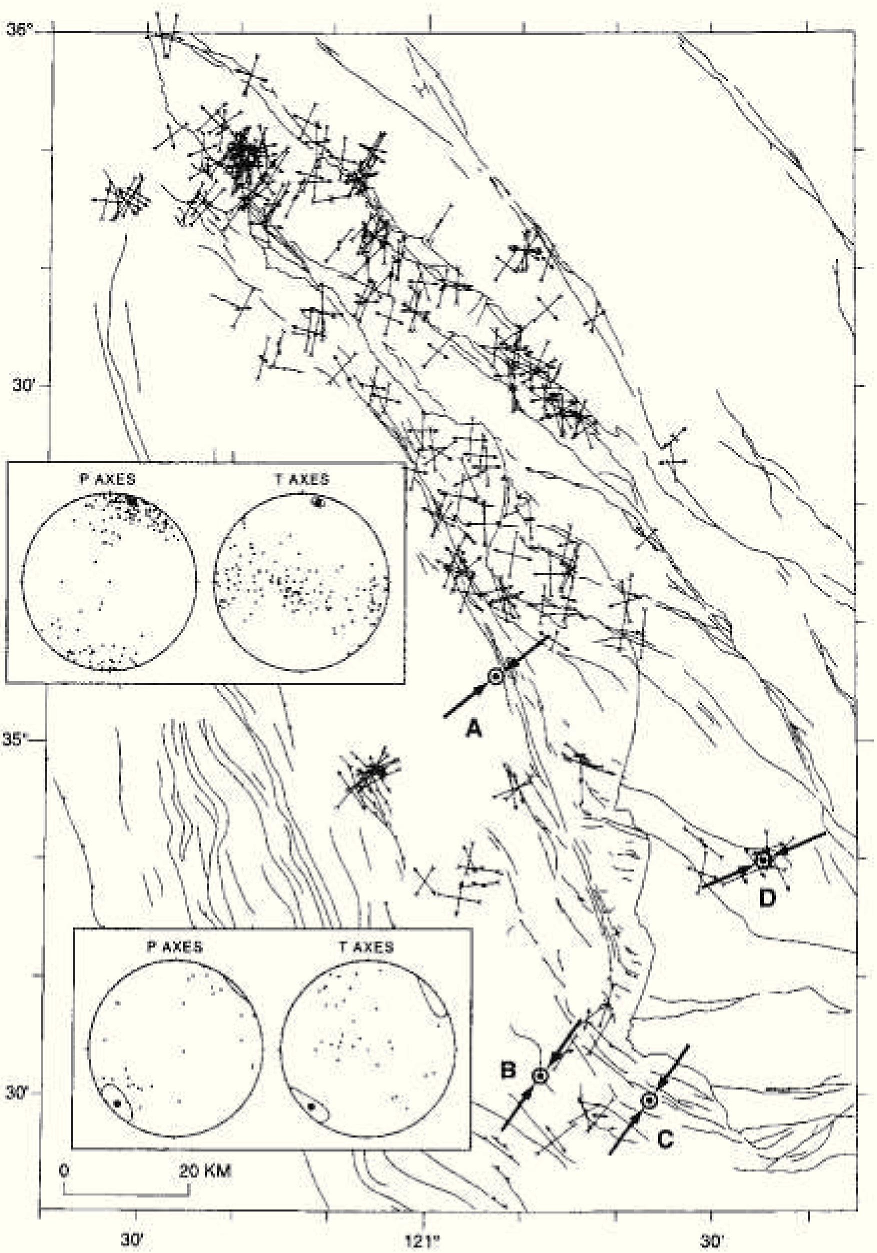

Figure 5 Horizontal surface projections of P and T axes from earthquake focal mechanisms. Encircled solid circles are locations of borehole breakout data. The two insets are stereo net plots of the distribution of P and T axes of the fault plane solutions for earthquakes in the northern and southern regions (i.e., north and south of 35°N). From McLaren and Savage, 2001.

ATTACHMENT 3

July 29, 2012

SUMMARY OF UNRESOLVED TECHNICAL ISSUES

The following sections include summary technical discussion of some issues remaining unresolved after discussions at the IPRP and the exchange of letters in Attachments 1 and 2.

Number of streamers

The proposed survey includes 4-streamer vessel operations in water as shallow as 25 m, in order to cover targets near shore. PG&E asserts (Attachment 2, pg 13) that boats capable of towing 10 or more streamers cannot operate in water depths shallower than 75 m. Recent communication from one industry seismic contractor indicates that a 10-streamer boat can operate in 25-m water depths under nominal conditions.

This project should be submitted for a complete survey design review that would include a navigational obstruction survey of the area and modeling of streamer tracking behavior (horizontal and vertical) based on modern streamer steering and control technology. The survey design review would assess data collection efficiency, including 1) the potential use of greater numbers of streamers, and 2) the application of a second shooting boat, which is a common industry practice that improves data collection efficiency and image quality as well.

As in other issues listed below, the survey design should aim to delineate the survey best suited to accurately image the expected targets. Only after that determination, should issues of feasibility, cost and schedule be considered in modifying survey design.

Transition zone data collection and processing

The Shoreline fault, a particularly important target of the survey, is overlain by shallow water and lies close to the shoreline (in the "transition zone"). PG&E's onshore surveys have identified steeply-dipping and complex structures of interest in this area. Gaining a high-quality image of these features in a transition zone environment will be challenging.

In this case shallow water receivers (nodes) are proposed along 5 irregularly spaced and oriented lines. While plots of common-midpoint coverage have been offered, there remain questions about whether this survey geometry can image the structures of interest.

Industry standard transition zone survey design would have modeled the seismic response of expected targets and adjusted survey geometry and data processing flow to assure image quality. The data processing flow is particularly important if data from the

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transition zone survey are to be merged with onshore and offshore data in a single data volume.

Spatial sampling and shooting along strike

The IPRP has suggested eliminating the northernmost part of the survey (Box 3) because little new seismic hazard information was expected to be obtained (IPRP Report #3). In their response to the IPRP, PG&E disagrees, arguing that further survey of the Hosgri-San Simeon fault intersection could reveal important geologic detail.

Note that the survey direction of Box 3 (Attachment 2, Figure 1) is along the strike of the Hosgri-San Simeon faults. PG&E argues that this shooting orientation is necessary because shallow water near the shoreline constrains boat maneuvering. Strike line shooting is less preferred because the important geologic changes occur in the perpendicular (dip) direction (Attachment 2, pg 4).

The cross-line bin size of the HESS is nominally 25-37m. PG&E discusses in Attachment 2 that the onshore data show optimal group interval is closer to 10 m. Thus, the adequacy of the cross-line (dip direction) sampling in Box 3 (and other areas shooting along strike) should be reviewed.

As with other issues above, a comprehensive survey design approach would model the expected reflection response for the proposed survey geometry and processing sequence to confirm that features could be adequately imaged. This should be especially important in the northernmost area of the survey, where geologic details are to be asssessed. A second shooting boat and streamer track overlap could also benefit cross-line resolution and should be studied.

Data processing coordination

Industry standard survey design integrates data acquisition, processing and interpretation. PG&E has helpfully listed numerous potential processing contractors and steps that appear to be state of the art (Attachment 2).

Given that, 1) data processing flows are listed as "typical" (not currently determined), 2) the expected data processing flow is complex, and 3) multiple surveys comprise the overall CCCSIP, a clear sense of how different data processing steps are coordinated is important. In particular, PG&E should identify who has the responsibility and authority to evaluate processing quality and make processing flow decisions.