

Staff Summary for April 15-16, 2026

3. General Public Comments for Items Not on the Agenda**Today's Item**Information Action

Receive public comment regarding the topics within the Commission's authority that are not included in either day of the April 15-16, 2026 meeting agenda.

Summary of Previous/Future Actions (N/A)**Background**

This item is to provide members of the public an opportunity to address the Commission on topics not on the agenda. Staff may include written materials and comments received prior to the meeting as exhibits in the meeting binder (if received by the written comment deadline), or as supplemental materials and comments at the meeting (if received by the supplemental comment deadline).

General public comments are categorized as either: (1) requests for non-regulatory action or (2) informational-only. Under the Bagley-Keene Open Meeting Act, the Commission cannot discuss or take action on any matter not included on the agenda, other than to schedule issues raised by the public for consideration at future meetings. Thus, non-regulatory requests generally follow a two-meeting cycle (receipt and direction). Any non-regulatory request received at today's meeting will be evaluated by staff and considered by the Commission at its next regularly scheduled meeting (currently June 17-18, 2026) under "Non-regulatory requests from previous meetings."

Significant Public Comments

1. New, non-regulatory requests are summarized in Exhibit 1; the original written requests are provided as exhibits 2 through 5
2. Informational comments are provided as exhibits 6 through 24

Recommendation

Commission staff: Consider whether to add any future agenda items to address issues that are raised during public comment.

Exhibits

1. [Summary of new, non-regulatory requests received by April 2, 2026](#)
2. [Eric Kayser](#), supports increased funding to protect pumas in California, citing habitat loss and frequent sightings in San Bernardino County. They also suggest constructing a land bridge near I-5 and Rancho Road overpass for wildlife, and request more Department wildlife officers in Hesperia and Oak Hills area to address illegal dumping and rising criminal activity, received March 13, 2026
3. [San Francisco Baykeeper et al.](#), requests the Commission place the white sturgeon status review report on the April 15-16, 2026 Commission meeting agenda, noting the Department's deadline to complete the report was in January, received March 23, 2026

Staff Summary for April 15-16, 2026

4. [James Jensvold, President, Democrats for the Protection of Animals](#), expresses concern over the euthanasia of a mother black bear in Monrovia, California and questions whether non-lethal options, full incident review, and community input were adequately considered before the decision was made. Democrats for the Protection of Animals requests policy reforms to increase transparency, require documented evaluation of alternative methods, involve local stakeholders, add independent review for lethal action determinations, strengthen prevention efforts, and establish safeguards for cases involving mothers with dependent young, received April 1, 2026
5. [Erin Sawicki, Experimental Fishing Permit holder](#), expresses thanks to the Commission and provides an update on recent results from the California brown box crab and king crab experimental fishery which required the use of “pop-up” fishing gear for commercial harvest, received January 29, 2026
6. [Three emails from Tom Hafer, Secretary, Morro Bay Commercial Fisherman's Organization](#), provides updates and supporting documents that outline current offshore wind projects in California and abroad, received between February 9 and March 29, 2026
7. [Shari Dalal](#), advocates for moving toward coexistence with keystone predators through an approach grounded in science, ethics, and a respect for wildlife, received February 12, 2026
8. [A representative sample of five form letter emails](#), opposing the eradication of Catalina Island's mule deer population, received between February 12, 2026
9. [Two public comments](#) suggesting alternative approaches for mountain lion protections in California, received February 12 and March 13, 2026
10. [Peter Drekmeier, Policy Director, Yosemite Rivers Alliance](#), provides a backgrounder on the Scientific Basis Report for Tuolumne River Voluntary Agreement, received February 13, 2026
11. [Two representative samples of 12 emails](#), addressing current coyote regulations and the impacts the species has in urban communities, received between February 14 and March 12, 2026
12. [Lorna Moffet](#), asks the Commission to review the information surrounding mute swans and the policy permitting lethal control, received February 26, 2026
13. [A representative sample of two form letter emails](#), opposing the eradication of Catalina Island's mule deer population, received between February 26 and February 27, 2026
14. [Whitt Strain, Vice President, Bodega Bay Oyster Company and Point Reyes Oyster Company \(PROC\)](#), outlines PROC's long-standing cleanup initiatives along Tomales Bay and its commitment to maintaining a clean and healthy shoreline through community collaboration, including regular patrols, post storm inspections, and organized public cleanup events, received March 2, 2026
15. [The Office of Assemblymember Chris Rogers](#), circulates a letter addressed to Governor Gavin Newsom in support of strengthening and expanding California's marine protected areas, received March 3, 2026

Staff Summary for April 15-16, 2026

16. [Tony Cohen](#), reports frequently finding plastic shotgun wads along the Sonoma Coast beaches during volunteer work for California State Parks and urges the Commission to ban these components to help reduce plastic pollution entering the ocean, received March 10, 2026
17. [Andrew Marshall](#), encourages reconsideration of lethal management practices of mute swans, citing extensive firsthand observations showing that the species often coexists with native waterfowl, and recommends adopting more balanced, humane, and evidence-based management strategies, received March 11, 2026
18. [Acadia Engelman](#), advocates for stronger protections through expanded marine protected areas, stricter commercial fishing regulations, and enhanced safeguards for vulnerable habitats, received March 12, 2026
19. [James Treat](#), believes striped bass predation is a major factor in low juvenile salmon survival and urges reconsidering current regulations with a recommendation to expanded harvest of striped bass as a strategy to better protect salmon populations, received March 15, 2026
20. [Two representative samples of nine emails](#), opposing the euthanasia of a mother black bear in Monrovia, California, received between March 17 and April 2, 2026
21. [Two emails from Mike Boehlert](#), objecting any study or consideration of grizzly bear reintroduction, expressing concerns about costs, public safety, and potential impacts on local communities, received March 26, 2026
22. [A representative sample of 42 form letter emails](#), opposing the euthanasia of a mother black bear in Monrovia, California, received March 27, 2026
23. [James Jensvold, President, Democrats for the Protection of Animals](#), representative of 12 substantially similar emails opposing the eradication of Catalina Island's mule deer population, received April 1, 2026
24. [Laura Deehan, Director, Environment California et al.](#), shares a letter on behalf of several organizations urging stronger protections within the state's marine protected area network and expresses disappointment in the Department's recommendations to deny a majority of proposed conservation actions, received April 2, 2026

Motion (N/A)

California Fish and Game Commission
Receipt List for Non-Regulatory Requests Received by 5:00 PM on April 2, 2026

Date Received	Name/Organization of Requestor	Subject of Request	Short Description	FGC Receipt Scheduled	FGC Action Scheduled
2/13/2026	Eric Kayser	LED	Requests CDFW Officers in Hesperia and Oak Hills area to address illegal dumping and criminal activity.	4/15-16/2026	6/17-18/2026
3/25/2026	San Francisco Baykeeper et al.	CFGC Meetings	Requests CFGC to agendaize the White Sturgeon status review report at the April 15-16, 2026 Commission meeting, noting the Department's deadline to complete the report was January 12, 2026.	4/15-16/2026	6/17-18/2026
4/1/2026	James Jensvold, Democrats for the Protection of Animals	Black Bear	Requests policy reforms to increase transparency, require documented evaluation of alternative methods, involve local stakeholders, add independent review for lethal action determinations, strengthen prevention efforts, and establish safeguards for cases involving mothers with dependent young.	4/15-16/2026	6/17-18/2026

RE: Feb 11th & 12th meeting

CALIFORNIA FISH AND GAME COMMISSION
RECEIVED 2/13/2026

2-2-26

To whom it may concern,
Today's "Sun" News paper had a article - More aid for Pumas eyed. Please accept my yes in support of more funds to aid Pumas in California. I'm from San Bernardino County. Since 2002 these Big Cats have had much of their habitat taken over by home development. Most of my sightings were in the morning and dusk. These sightings were all in Hesperia, CA. Arrowhead lake rd. by Silverwood Lake and Hesperia Lakes. Another time while at work right by Hwy 15 North. May i suggest a small bridge by Rancho Road overpass to cross the busy I15 freeway. This will allow access to northern territory. Sightings on HWY 138 are also common. May i also request additional Fish & Game Officers in the Hesperia & Oak Hills areas. National Forrests have illegal dumping & increased criminal activity in them.

Respectfully, Eric H. Kayser



March 23, 2026

Transmitted via Electronic Mail

California Fish and Game Commission
Melissa Miller-Henson, Executive Director
P.O. Box 944209
Sacramento, California 94244-2090
Email: fgc@fgc.ca.gov

RE: Agendizing White Sturgeon Status Review Report for April 15-16, 2026 Commission Meeting

Dear Executive Director Miller-Henson:

We write to request the California Fish and Game Commission (FGC) include on its agenda for its April 15-16, 2026 meeting the status review report for the White Sturgeon (*Acipenser transmontanus*). The California Department of Fish and Wildlife’s (CDFW) deadline to produce the status review report pursuant to Fish and Game Code section 2074.6 was on January 12, 2026. On February 27, 2026, we sent a letter to you and CDFW’s Director requesting CDFW finalize the status review report immediately and produce it for public comment. Since then, our communications with CDFW staff indicate no additional progress has been made.

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The best information available when we submitted the listing petition to FGC in 2023 was sufficient to support listing the White Sturgeon as threatened under the California Endangered Species Act (CESA). Scientific information produced since the petition was filed reinforces the need to protect this population under CESA. We ask the Commission to help move this process forward by directing CDFW staff to prioritize and finalize the status review report as soon as possible. This starts with adding White Sturgeon to the April 15-16, 2026 meeting's agenda.

Sincerely,



Jonathan A. Rosenfield, Ph.D.
Science Director
San Francisco Baykeeper
jon@baykeeper.org



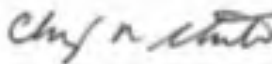
Nicole C. Sasaki
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Barbara Barrigan-Parrilla
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Chris Shutes
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Cc via Electronic Mail:

Eric Sklar, President
Darius W. Anderson, Vice President
Jacque Hostler-Carmesin, Member
Samantha Murray, Member
Erika Zavaleta, Member



March 28, 2026

Governor Gavin Newsom
California Department of Fish and Wildlife
California Fish and Game Commission
Secretary Wade Crowfoot, California Natural Resources Agency

RE: Recent killing of mother black bear in Monrovia

Dear Governor Newsom, Secretary Crowfoot, and Members of the Commission,

On behalf of Democrats for the Protection of Animals, we write in deep sadness, outrage, and frustration over the recent “euthanization” of “Blondie,” a mother black bear in Monrovia.

Blondie’s death has left behind two very young cubs, now orphaned and facing an uncertain path in captivity. Cubs at that age depend on their mother for survival, learning, and development. The loss of their mother is not an abstract consequence. It is a direct harm.

Blondie was killed despite significant public outcry, advocacy from local leaders, and calls for alternative solutions, including relocation. Thousands of residents signed petitions, and community members mobilized in real time to try to save her life. Yet the decision proceeded without meaningful transparency, without community inclusion, and without exhausting humane alternatives. It raises serious questions about how this decision was made.

If euthanasia is truly a last resort, it should only happen after all other options have been fully explored.

According to reporting, Blondie was euthanized after being designated a “Public Safety Bear” following two incidents involving minor injuries. However, local officials have stated they were not included in the decision-making process, and community members have raised concerns about whether the full context of those incidents was evaluated before such an irreversible action was taken.

We understand that human life must be protected. But that responsibility does not excuse a lack of transparency, failure to fully consider non-lethal alternatives, or the exclusion of local communities from decisions with irreversible consequences.

While this case involves a black bear, the concerns it raises extend far beyond a single incident or species. These standards should apply to all wildlife, and especially in cases involving mothers with dependent young.

LOS ANGELES COUNTY DEMOCRATS FOR THE PROTECTION OF ANIMALS

PO Box 445, Santa Monica, CA 90406

We are asking for immediate policy reform to ensure that future decisions reflect both public safety and humane, science-based wildlife management. Specifically, we call for:

1. Mandatory transparency and reporting prior to euthanasia decisions (all wildlife)
Clear documentation of incidents, including full context, witness accounts, and behavioral analysis, should be required and made publicly available, to the extent permitted by law, before a final determination is made.
2. Required exploration and documentation of non-lethal alternatives (all wildlife)
Relocation, aversive conditioning, monitoring, and other interventions must be meaningfully evaluated and documented, not dismissed without public explanation.
3. Formal inclusion of local stakeholders
Local governments, wildlife experts, and impacted communities must have a seat at the table before irreversible decisions are made.
4. Independent review for lethal action designations, including “Public Safety Bear” determinations
A second-level review process should be required before euthanasia is authorized, particularly in cases involving animals with dependent young, except in immediate threats to human life.
5. Expanded investment in prevention
Funding for education, attractant management, and tools such as GPS tracking can reduce human-wildlife conflict before it escalates to lethal outcomes.
6. Protocols specific to mothers with dependent young
Additional safeguards must be in place when euthanasia would result in orphaned wildlife, recognizing the heightened ethical and ecological consequences.

California should be a national leader in humane wildlife policy. We respectfully request a formal review of this case and a commitment to implementing the policy changes necessary to protect wildlife, including mothers and their dependent young.

Respectfully yours,



James Jensvold
President, Democrats for the Protection of Animals

Democrats for Protection of Animals endeavors to stimulate Democrats to be active in promoting the humane treatment of animals by promoting humane legislation and governmental policy and by increasing public awareness of animal protection issues at city, county, state, and federal levels.

LOS ANGELES COUNTY DEMOCRATS FOR THE PROTECTION OF ANIMALS

PO Box 445, Santa Monica, CA 90406

Dear Chair and Commissioners,

On behalf of participating and waitlisted fishermen and project partners, I would like to thank the California Fish and Game Commission and the California Department of Fish and Wildlife for their continued engagement and oversight of the California Brown Box crab and king crab experimental fishery. In particular, we are grateful for the recently updated Terms and Conditions associated with the approved Major Amendment, which expanded participation under EFP No. EFPT4-001. The revised framework reflects thoughtful consideration of both conservation objectives and operational realities, and it has materially strengthened the structure under which this work is being conducted.

I am writing to provide a brief update on the most recent results from the experimental fishery, which requires 100 percent use of on-demand (“pop-up”) fishing gear for the commercial harvest of California brown box crab (*Lopholithodes foraminatus*) and California king crab (*Paralithodes californiensis*).

From May 2024–Sept 2025, participating vessels completed 57 fishing trips and conducted 360 on-demand gear deployments in depths ranging from 60 to 200 fathoms. This effort represents the first structured, commercial-scale evaluation of on-demand gear in a **deep-water** trap fishery on the West Coast. Gear configurations were intentionally fished under true commercial conditions, including mixed substrates, variable currents, and a wide range of sea states, and were iteratively refined in collaboration with fishermen and technology developers.

Results to date demonstrate strong performance and continued improvement. Across the initial testing period, acoustic retrieval success averaged **98 percent**, with a gear loss rate of approximately 1.5 percent. In the current season, retrieval success has **exceeded 99 percent**, with overall trap recovery remaining above 99 percent. Early failures were largely attributable to preventable human-factors issues and declined substantially following standardized training, pre-deployment checks, and clearer deck workflows. These outcomes exceed previously identified reliability thresholds necessary for consideration of broader authorization and expansion.

The fishery has also demonstrated effective compliance visibility through a layered electronic monitoring and virtual gear-marking system that provides verifiable deployment, recovery, and location data without the use of persistent vertical lines. This approach has supported enforcement needs while reducing entanglement risk in whale-rich habitats.

Finally, participating and waitlisted fishermen (included below) respectfully request that the Commission and Department consider making additional spaces available under the EFP as requested in the application. Expanding participation from 10 to 20 would allow for increased high-quality data collection across a broader range of vessels, conditions, and operators, strengthening the scientific foundation needed for future management decisions. At the same time, market demand for box crab has expanded significantly, and

Commission Tracking Number# 2023-01

additional participation would help responsibly meet that demand while maintaining the strict conservation, monitoring, and reporting standards established under the permit. Lastly, it would reduce Department Administrative strain by reducing the number of minor amendments required to move fishers on and off the permit during seasonal breaks and shifts to other fisheries.

Thank you for your leadership and for supporting a collaborative process with the Department and participating fishermen. I am available to provide any additional information the Commission may find helpful.

Respectfully submitted,

Kim Sawicki

EFP Holder, EFPT4-001
Sustainable Seas Technology
Marine Innovations Gear Alliance
admin@sustainableseastechnology.org

Stephen Melz- F/V Jaqueline L

Louisa Siracusa-F/V Crazy Aussie

Hunter Nguyen- F/V Sunrise

Richard Axelson-F/V Lady Renee

Jonathan Tin- F/V Sunrise

Brand Little-F/V Pale Horse

Tylor Rechany-Aida Phyllis

Justin Middleton-F/V Pale Horse

Michael Volaski-F/V Coastal Reign

Michael Phillips-F/V Miss Alison

Austin Ashe-F/V Tipper

Bradford Sawicki- F/V To Be Determined

Mario Souza-Extremis

Jordan Souza-Extremis

Scott Jarvis-F/V Trapped

Parker Harris-F/V Trapped

Leo Patricelli-F/V St Gino

Drew Lewis-F/V Jaqueline L

Marco Voyatzis-F/V Dimi

Shell pulls out of 2 major Floating OSW projects off Scotland due to costs and technical challenges

From mbcfo member <mbcfo1972@gmail.com>

Date Mon 02/09/2026 07:23 AM

To Doug Boren <douglas.boren@boem.gov>; CentralCoast@Coastal <CentralCoast@coastal.ca.gov>; Andrea Chmelik <Andrea.Chmelik@asm.ca.gov>; Dobroski, Nicole@SLC <Nicole.Dobroski@slc.ca.gov>; Eckerle, Jenn@CNRA <Jenn.Eckerle@resources.ca.gov>; Executive Officer of SLC <ExecutiveOfficer.Public@slc.ca.gov>; ExecutiveStaff@Coastal <ExecutiveStaff@coastal.ca.gov>; FGC <FGC@fgc.ca.gov>; Flint, Scott@Energy <Scott.Flint@energy.ca.gov>; bgibson@co.slo.ca.us <bgibson@co.slo.ca.us>; Greg Haas <greg.haas@mail.house.gov>; Nancy Hann <nancy.hann@noaa.gov>; Harland, Eli@Energy <Eli.Harland@energy.ca.gov>; Dr. Caryl Hart <CommissionerCHart@coastal.ca.gov>; Gonzalez, Kathleen@Waterboards <Kathleen.Gonzalez@Waterboards.ca.gov>; Huckelbridge, Kate@Coastal <Kate.Huckelbridge@coastal.ca.gov>; Kalua, Kaitlyn@CNRA <Kaitlyn.Kalua@resources.ca.gov>; Kato, Grace@SLC <Grace.Kato@slc.ca.gov>; Zara Landrum <zlandrum@morrobayca.gov>; Liu, Serena@Waterboards <Serena.Liu@waterboards.ca.gov>

Shell is walking away from two major floating offshore wind projects off the north-east coast of Scotland in a blow to the nascent industry that forms a key part of the move towards decarbonization. The FTSE 100 company has swapped its stake in the MarramWind farm with joint venture partner Scottish Power in exchange for full control of the smaller ChampionWind project and handed back the latter's lease to Crown Estate Scotland. Under chief executive Wael Sawan, Shell is retreating from major investments in big power generation projects to focus on potentially more lucrative activities such as power trading. Floating offshore wind involves installing turbines on platforms far out to sea where there is more space and they can harness higher wind speeds. But **the technology is expensive and technically challenging and has yet to be developed at commercial scale in the UK.** "After a comprehensive review and in line with Shell's previously announced refocusing of its power strategy on leveraging Shell's strengths in trading and retailing, the conclusion was to not take the ChampionWind project forward," Shell said this morning. The ChampionWind site is around 100km off the east coast of Scotland in 77-metre deep waters. With a planned capacity of two gigawatts, it could supply electricity for the equivalent of more than 2mn homes. MarramWind is in 111-metre deep waters about 75km off the Scottish coast, with planned installed capacity of up to three gigawatts. Both projects were not due to come online until the 2030s. They are among several sites that secured seabed leases from Crown Estate Scotland in 2022 in a highly competitive bidding round in which companies such as BP and Vattenfall, as well as Shell and Scottish Power, paid huge sums for the rights. MarramWind and ChampionWind were Shell's only floating offshore wind projects in the UK. The so-called ScotWind auction marked a high point in the UK for **the offshore wind industry, which is now struggling with high costs and supply chain strains as well as long lead times for getting connections to electricity grids.** Scottish Power said it would "continue the development" of MarramWind and "maintain our positive

engagement with local people and businesses". Crown Estate Scotland said it "will assess options for the site, in line with market demand and best value for Scotland". Separately today, a government-backed innovation centre said it would start testing offshore wind turbines made by China-based manufacturer Ming Yang. The UK's Offshore Renewable Energy Catapult said it was the first testing agreement it had signed with Ming Yang, as part of its work to help the "sector make informed choices". Ming Yang said the agreement to test its 18.5 megawatt models was "a major milestone in our strategic push into the UK market". The privately owned company wants to build a £1.5bn factory in Scotland but is waiting for approval from the UK government, in a test of the UK government's appetite for investment from China. Ming Yang is not state-owned but critics have raised concerns about the risk of interference from Beijing in private companies, as well as the risks of relying too heavily on one country for critical equipment. But the UK government also wants to boost supply chains to meet clean energy goals, including its target to decarbonize the power sector by 2030.

Tom Hafer
Secretary MBCFO
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CPUC Portfolio Shows Offshore Wind Delayed up to 6 Years

From mbcfo member <mbcfo1972@gmail.com>

Date Mon 03/02/2026 08:23 AM

To Doug Boren <douglas.boren@boem.gov>; CentralCoast@Coastal <CentralCoast@coastal.ca.gov>; Andrea Chmelik <Andrea.Chmelik@asm.ca.gov>; Dobroski, Nicole@SLC <Nicole.Dobroski@slc.ca.gov>; Eckerle, Jenn@CNRA <Jenn.Eckerle@resources.ca.gov>; Executive Officer of SLC <ExecutiveOfficer.Public@slc.ca.gov>; ExecutiveStaff@Coastal <ExecutiveStaff@coastal.ca.gov>; FGC <FGC@fgc.ca.gov>; Flint, Scott@Energy <Scott.Flint@energy.ca.gov>; bgibson@co.slo.ca.us <bgibson@co.slo.ca.us>; Greg Haas <greg.haas@mail.house.gov>; Nancy Hann <nancy.hann@noaa.gov>; Harland, Eli@Energy <Eli.Harland@energy.ca.gov>; Dr. Caryl Hart <CommissionerCHart@coastal.ca.gov>; Gonzalez, Kathleen@Waterboards <Kathleen.Gonzalez@Waterboards.ca.gov>; Huckelbridge, Kate@Coastal <Kate.Huckelbridge@coastal.ca.gov>; Kalua, Kaitlyn@CNRA <Kaitlyn.Kalua@resources.ca.gov>; Kato, Grace@SLC <Grace.Kato@slc.ca.gov>; Zara Landrum <zlandrum@morrobayca.gov>; Liu, Serena@Waterboards <Serena.Liu@waterboards.ca.gov>

"The recommended base case portfolio differs from the 2025-2026 TPP base case by **extending the online dates for some offshore wind resources by up to six years, and recommending up to a two-year extension to the in-service dates for the transmission to support North Coast offshore wind.** The recommended sensitivity portfolio tests a **low-wind development scenario**, and represents an opportunity to identify other transmission development that could be needed under a worst-case scenario slowdown in wind development; it does not represent a policy recommendation away from a diverse resource mix. This information may be used to inform future TPP base case portfolios."

The CPUC is realizing the issues with offshore wind may be insurmountable and require development of scenarios without reliance on offshore wind to ensure stability of the grid.

Tom Hafer
Secretary MBCFO
(805) 610-2072
mbcfo1972@gmail.com

ALJ/JF2/nd3

PROPOSED DECISION Agenda ID #23963 (Rev.1)
Ratesetting
2/26/2026 Item #40

Decision PROPOSED DECISION OF ALJ FITCH (Mailed 1/14/2026)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to
Continue Oversight of Electric
Integrated Resource Planning and
Procurement Processes.

Rulemaking 25-06-019

**DECISION REQUIRING 2029-2032 ELECTRIC RESOURCE
PROCUREMENT AND TRANSMITTING PORTFOLIOS
FOR 2026-2027 TRANSMISSION PLANNING PROCESS**

TABLE OF CONTENTS

Title	Page
DECISION REQUIRING 2029-2032 ELECTRIC RESOURCE PROCUREMENT AND TRANSMITTING PORTFOLIOS FOR 2026-2027 TRANSMISSION PLANNING PROCESS	1
Summary	2
1. Background	3
1.1. Factual Background	3
1.2. Procedural Background.....	6
1.3. Submission Date	8
2. Procurement Issues	9
2.1. 2029-2032 Procurement Need.....	19
2.1.1. Comments of Parties.....	20
2.1.2. Discussion	23
2.2. Resource Eligibility	25
2.2.1. Comments of Parties.....	25
2.2.2. Discussion	27
2.3. Energy Procurement (instead of, or in addition to, Capacity)	29
2.3.1. Comments of Parties.....	29
2.3.2. Discussion	33
2.4. Local Procurement	36
2.4.1. Comments of Parties.....	36
2.4.2. Discussion	37
2.5. Need Allocation.....	37
2.5.1. Comments of Parties.....	38
2.5.2. Discussion	39
2.6. Compliance and Enforcement	41
2.6.1. Comments of Parties.....	42
2.6.2. Discussion	43
3. California Independent System Operator Transmission Planning Process Recommendations.....	46
3.1. Modeling Assumptions	46
3.1.1. Comments of Parties.....	49
3.1.2. Discussion	53
3.2. Base Case Portfolio.....	54
3.2.1. Comments of Parties.....	56
3.2.2. Discussion	62
3.3. Sensitivity Portfolio.....	67

3.3.1.	Comments of Parties.....	68
3.3.2.	Discussion	71
3.4.	Addressing High Solar and Storage Build Rates Implied in Base Case and Sensitivity Portfolios.....	73
3.4.1.	Comments of Parties.....	74
3.4.2.	Discussion	78
3.5.	Busbar Mapping Methodology	79
3.5.1.	Comments of Parties.....	81
3.5.2.	Discussion	88
3.6.	Busbar Mapping Results	90
3.6.1.	Mapping Criteria Issues	90
3.6.2.	Transmission-Related Issues	91
3.6.3.	Volume of Resources Mapped	93
3.6.4.	Offshore-Wind-Specific Issues	96
3.6.5.	Import Issues	96
3.6.6.	Issues Related to Gas Capacity Not Retained.....	97
3.6.7.	Specific Remapping Requests	99
3.7.	Production Cost Modeling Analysis of Base Case Portfolio as Mapped.....	100
4.	Summary of Public Comment	105
5.	Comments on Proposed Decision.....	106
6.	Assignment of Proceeding	122
	Findings of Fact.....	122
	Conclusions of Law	126
	ORDER	133

Attachment A: Procurement Obligations by Load Serving Entity

**DECISION REQUIRING 2029-2032 ELECTRIC RESOURCE
PROCUREMENT AND TRANSMITTING PORTFOLIOS
FOR 2026-2027 TRANSMISSION PLANNING PROCESS**

Summary

This decision requires load-serving entities under the California Public Utilities Commission's (Commission) integrated resource planning purview to undertake additional reliability procurement between 2029 and 2032, to pursue any viable projects that can still qualify for Federal tax credits or other incentives, as well as to continue the momentum of annual procurement activity that began under the Mid-Term Reliability (MTR) and supplemental MTR requirements in Decision (D.) 21-06-035 and D.23-02-040, respectively. The new procurement required is 2,000 megawatts (MW) of net qualifying capacity (NQC) by 2030, another 2,000 MW NQC, by 2031, and an additional 2,000 MW NQC by 2032. This procurement will be generally subject to the same eligibility, compliance and enforcement requirements as the prior MTR orders, including D.25-09-007 provisions and consideration of "good faith efforts" to procure, as described in D.21-06-035. In addition, at least one-quarter of the procurement by no later than June 1, 2032 is required to come from resources that have attributes that align with clean firm resources (with capacity factors of at least 80 percent and not use-limited) and/or long-duration storage resources (able to discharge for at least eight hours or more).

This decision also transmits a reliability and policy-driven base case electricity portfolio and a sensitivity portfolio to the California Independent System Operator (CAISO) for analysis in its 2026-2027 Transmission Planning Process (TPP). The recommended base case portfolio is consistent with the 2025-2026 TPP base case portfolio, which was designed to meet a 25 million metric ton greenhouse gas emissions target for the electric sector by 2035. This

target is consistent with both the statewide electricity sector emissions trajectory set by the California Air Resources Board in its 2022 Scoping Plan for Achieving Carbon Neutrality, as well as the requirements set by Senate Bill 1020 (Stats. 2022, Ch. 361). The recommended base case portfolio differs from the 2025-2026 TPP base case by extending the online dates for some offshore wind resources by up to six years, and recommending up to a two-year extension to the in-service dates for the transmission to support North Coast offshore wind. The recommended sensitivity portfolio tests a low-wind development scenario, and represents an opportunity to identify other transmission development that could be needed under a worst-case scenario slowdown in wind development; it does not represent a policy recommendation away from a diverse resource mix. This information may be used to inform future TPP base case portfolios.

This proceeding remains open.

1. Background

This section presents both a brief factual background on the issues covered in this decision, as well as a summary of the procedural steps that have led to this decision.

1.1. Factual Background

As part of the longstanding coordination formalized through the Memorandum of Understanding (MOU) between the California Energy Commission (CEC), California Independent System Operator (CAISO), and the California Public Utilities Commission (Commission) to collaborate on electricity resource and transmission planning, every year Commission staff develops a recommended set of portfolios for the CAISO to use in its annual Transmission Planning Process (TPP).

Generally, in each TPP cycle, the CAISO evaluates a reliability and/or policy-driven base case portfolio. Under the CAISO tariff adopted by the Federal Energy Regulatory Commission (FERC), if the results of the base case analysis show the need for additional transmission development, the transmission projects are brought to the CAISO Board for approval in the spring of the second year of the TPP. If approved by the CAISO Board, under the FERC tariff, the project would receive cost recovery through the transmission access charge.

Along with the base case analysis that generally leads directly to transmission project approval, in each TPP cycle the CAISO typically analyzes a sensitivity portfolio. The purpose of the sensitivity portfolio analysis is to assist in future planning by identifying relevant transmission needs and potential costs.

Decision (D.) 25-02-026 included both a base case and a sensitivity portfolio that the CAISO is in the process of analyzing for the 2025-2026 TPP cycle; the CAISO's 2025-2026 TPP analysis is not yet final. The base case portfolio was based on the scenario that achieves at 25 million metric ton (MMT) statewide greenhouse gas (GHG) emission target in 2035, and includes the resources online, under contract, or planned in the individual load-serving entity (LSE) integrated resource plans (IRPs) submitted in November 2022, including 4.5 gigawatts (GW) of offshore wind that is currently included in the 2025-2026 TPP base case.

The 2025-2026 TPP sensitivity portfolio currently being studied by the CAISO is a long lead-time (LLT) resource sensitivity. This sensitivity is based on the upper bounds of the need determination analysis of LLT resource volumes that the Department of Water Resources (DWR), as a central procurement entity (CPE), could potentially procure, as reflected in the Commission's adopted

decision (D.24-08-064), pursuant to Assembly Bill (AB) 1373 (Stats. 2023, Ch. 367). The need determination in D.24-08-064 included geothermal, long-duration energy storage (LDES) with specified durations, and offshore wind resources.

In D.21-06-035, also known as the Mid-Term Reliability (MTR) decision, the Commission required LSEs to procure 11,500 megawatts (MW) of net qualifying capacity (NQC) between 2023 and 2026.¹ As a part of that procurement decision, LSEs were required to procure resources with specific attributes encompassed in the decision's LLT and Diablo Canyon Power Plant (DCPP) replacement procurement requirements. Subsequently, in D.23-02-040 (also known as the Supplemental MTR decision), the Commission required LSEs to procure an additional 4,000 MW of NQC by 2028, using the same basic framework for generic resource procurement established in D.21-06-035. In addition, D.23-02-040 postponed the requirements for LSEs to procure 2,000 MW NQC of LLT resources, as defined in the MTR decision, until 2028, with the potential for a further extension to 2031, while allowing LSEs to cover any delays with generic capacity resources to cover the delayed NQC from MTR's LLT resources.

In Rulemaking (R.) 20-05-003, the prior IRP proceeding, a Staff Proposal for the Reliable and Clean Power Procurement Program (RCPPP) is under consideration. Parties have filed opening comments and reply comments on the content of the RCPPP Staff Proposal in R.20-05-003 and the details of RCPPP will

¹ NQC for each tranche of procurement required from LSEs is based on vintaged marginal effective load carrying capability (ELCC) values available on the IRP Procurement Track website at: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track>.

continue to be addressed in that rulemaking. However, some parties, in commenting on the timing of the potential for an RCPPP to be adopted, have commented that the Commission should consider another interim procurement order, to maintain electric system reliability during the time period while the RCPPP framework is considered. In response to the RCPPP Staff Proposal, approximately twenty parties commented on near-term reliability needs, generally for the period 2028-2032. Numerous parties generally recommended that the Commission conduct a near-term reliability need determination and issue an interim procurement order if a system reliability need was found.

Separately, also in R.20-05-003, American Clean Power – California (ACP-CA) filed the *Motion to Amend the Amended Scoping Memo to Include an Additional Track for Expedited Procurement*. Parties filed responses to the ACP-CA Motion on August 5, 2025 in R.20-05-003. Similar to the RCPPP Staff Proposal, the ACP-CA motion will be addressed in R.20-05-003. However, elements of the ACP-CA motion and its rationale are relevant to the near-term need determination considerations in this decision.

1.2. Procedural Background

An Administrative Law Judge (ALJ) Ruling (Ruling) was issued in this proceeding on September 30, 2025 seeking comments on the recommended electricity portfolios to be transmitted to the CAISO to use in its 2026-2027 TPP, as well as on whether there is a need for additional reliability procurement during the period 2029-2032.

Opening comments in response to the ALJ Ruling were filed by the following parties: Alliance for Retail Energy Markets (AReM); ACP-CA; Bioenergy Association of California (BAC); California Coalition of Large Energy Users (CLEU); California Community Choice Association (CalCCA); California

Energy Storage Alliance (CESA); California Environmental Justice Alliance (CEJA) and Sierra Club, jointly; California Grid Holdings, LLC (CalGrid); CAISO; California Resources Corporation (CRC); California Wind Energy Association (CalWEA); Calpine, LLC (Calpine); Clean Power Alliance (CPA); Coalition for Community Solar Access (CCSA), Coalition of California Union Employees (CUE), and California Unions for Renewable Energy (CURE), collectively; Defenders of Wildlife (DOW); EDF Power Solutions, North America (EDF-NA); ENGIE North America, Inc. (ENGIE); Environmental Defense Fund (EDF); Environmental Protection Information Center (EPIC); esVolta, Inc. (esVolta); Fervo Energy Company (Fervo); Form Energy, Inc. (Form); Golden State Clean Energy (GSCE); Golden State Renewable Energy, LLC; GreenGen Storage, LLC (GreenGen); GridLiance West, LLC (GridLiance); Hydrostor, Inc.; Independent Energy Producers Association (IEP); Invenergy California Offshore, LLC (Invenergy), Invenergy Geothermal, LLC, and Maravillosa Solar Energy, LLC, collectively; L. Jan Reid (Reid); Long Duration Energy Storage Council (LDES Council); Mainspring Energy, Inc. (Mainspring); Middle River Power, LLC (MRP); Mussey Grade Road Alliance (MGRA); Natural Resources Defense Council (NRDC); NextEra Energy Resources, LLC (NextEra); Oceantic Network, Inc. (Oceantic); Offshore Wind California (OWC); Pacific Gas and Electric Company (PG&E); Peninsula Clean Energy (PCE); Pioneer Community Energy; PivotGen; the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); Redwood Coast Energy Authority (RCEA) and Humboldt County, jointly; REV Renewables, LLC (REV); rPlus Hydro, LLC; San Diego Gas & Electric Company (SDG&E); Shell Energy North America (Shell); Solar Energy Industries Association (SEIA) and Large-Scale Solar Association (LSA), jointly; Sonoma Clean Power Authority (SCPA) and PCE,

jointly; Southern California Edison Company (SCE); Southern California Gas Company (SoCalGas); Terra-Gen, LLC (Terra-Gen); The Nature Conservancy (TNC); The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); Vineyard Offshore, LLC (Vineyard); Vote Solar; Western Power Trading Forum (WPTF); and XGS Energy, Inc. (XGS).

Reply comments in response to the ALJ Ruling were filed by the following parties: ACP-CA; AReM; CAISO; CalCCA; CalGrid; Calpine; CalWEA; Center for Biological Diversity (CBD); CEJA and Sierra Club, jointly; CESA; DOW; EDF; EPIC; Fervo; GreenGen; GridLiance; Hydrostor; Invenergy; LDES Council; LSA and SEIA, jointly; Marin Clean Energy (MCE); Mainspring; MRP; RCEA and Humboldt County, jointly; Reid; Small Business Utility Advocates (SBUA); SCE; SCPA; SDG&E; Shell; San Jose Clean Energy (SJCE); SoCalGas; UCS; Vineyard; Vote Solar; WPTF; and XGS.

On November 3, 2025, an ALJ Ruling was issued seeking comments on the preliminary mapping of energy and storage resources to transmission busbars for purposes of the TPP portfolios (Busbar Ruling). Comments in response to the Busbar Ruling were filed on November 21, 2025 by the following parties: ACP-CA; Bay Area Transmission Group (BAMx); Cal Advocates; Calpine; CalWEA; CEJA and Sierra Club, jointly; CRC; DOW; EDF; Fervo; GreenGen; GridLiance; GSCE; Invenergy; LSA; LS Power; MGRA; NextEra; Ormat Technologies, Inc. (Ormat); Pattern Energy Group, LP (Pattern); PG&E; SBUA; SCPA; TNC; and Vineyard.

1.3. Submission Date

This portion of the proceeding was submitted on November 21, 2025 upon filing of parties' comments on the Busbar Ruling.

2. Procurement Issues

The ALJ Ruling included staff analysis of reliability needs on the electric system between 2028 and 2032. The analysis was conducted in response to the increase in the load forecast in the 2024 Integrated Energy Policy Report (IEPR) of the CEC, comments on the RCPMP from parties in the previous IRP rulemaking (R.20-05-003), as well as the ACP-CA Motion to Amend the Scoping Memo in R.20-05-003.

The analysis noted that several critical things have changed since the Commission last issued an LSE procurement order in D.23-02-040 (as modified by D.24-02-047). First, relative to prior forecasts, significant load growth is now being forecasted in 2028-2032 in the CEC's 2024 IEPR demand forecast, much of it related to data centers, continuing vehicle and building electrification, and lower adoption of and lower capacity factors for behind-the-meter (BTM) solar and storage. In addition, Federal tax credit benefits are being rapidly phased out over the next few years. Other federal actions include executive orders imposing tariffs and limiting or delaying siting on federal lands for some types of renewable resources.

Second, as noted in the ALJ Ruling, as part of the CAISO interconnection queue in Cluster 14 and 15, many more projects are available than have been procured by LSEs. While LSEs will not need all of these projects to cover their load and contribute to their share of GHG reduction need, some of these projects, in addition to being able to meet any identified need, may also be at a point in their development timelines where they could still take advantage of Federal tax benefits, potentially saving California ratepayers money.

In addition, the resource adequacy program routinely studies reliability needs, and recently increased the planning reserve margin (PRM) in light of

loss-of-load-expectation (LOLE) studies in R.23-10-011. The Commission recently adopted an 18 percent PRM in the resource adequacy program for years 2026 and 2027, while also extending the effective PRM of 3-5.5 percent, in addition to the binding PRM, for those same years.

To assess whether these changes resulted in the need for another Commission order for capacity procurement in advance of consideration of the adoption of a programmatic framework for the RCPPP, Commission staff undertook a reliability analysis that was presented in the ALJ Ruling.

The analysis began with the following basic assumptions:

- The load forecast was updated based on the 2024 IEPR assumptions.
- A number of key supply assumptions were reviewed, including assumptions related to the realization of LLT resources and DCP status.
- The 2,000 MW NQC of LLT resources, as defined specifically and required by D.21-06-035 and D.23-02-040 (and further defined by D.25-06-005) to be online in 2028, but with the potential for an extension to 2031, are modeled as online in either 2028 or 2031, according to projected online data in the June 2025 IRP compliance filings of LSEs. In addition, based on the proposed decision in R.20-05-003 in response to the SCE Petition for Modification (PFM) of D.23-02-040 and D.24-02-047 dated August 13, 2025,² generic capacity was assumed to have been procured to replace any LLT capacity delayed to 2031 and is still online in 2032. This is likely an optimistic assumption, as further described below.
- Compliance with MTR obligations, across all LSEs collectively, was assumed. Staff analyzed the Commission's existing modeling baseline plus the LSEs'

² Available at the following link:

<https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=575603716>.

- June 2025 compliance filings and removed solar and storage contracts in excess of minimum MTR requirements.
- No additional resources, beyond those included in LSE June 2025 IRP compliance filings, were added to meet long-term GHG goals, even though some LSEs are likely planning to procure additional resources to meet these goals.
 - DCPD was modeled as offline in all years.³
 - Electricity demand was updated to reflect the 2024 IEPR “Planning” demand forecast, including the amount of BTM rooftop photovoltaics assumed.
 - Combined heat and power (CHP) plants were not assumed to be phased out.
 - Path 26 transmission was not assumed to be expanded.
 - Natural gas units were not assumed to retire on any set timetable.
 - No resources from the Strategic Reliability Reserve were included in the analysis.

Using this updated baseline and set of assumptions, Commission staff conducted modeling runs for the years 2028 through 2032 using the Strategic Energy and Risk Valuation Model (SERVM), which is the Loss-of-Load-Probability (LOLP) production cost modeling software regularly used in resource adequacy and IRP reliability analyses. Commission staff performed iterative model runs to try to achieve the reliability planning standard

³ Public Utilities Code Section 454.52(f)(1) states: “The commission shall not include the energy, capacity, or any attribute from Diablo Canyon Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025, in the adopted integrated resource plan portfolios, resource stacks, or preferred system plans.” See also Senate Bill (SB) 846 (Stats. 2022, Ch. 239), which added Public Utilities Code Section 712.8(q), which states: “the continued operation of Diablo Canyon Units 1 and 2 beyond their current expiration dates shall not be factored into the analyses used by the commission or by load-serving entities not subject to the commission’s jurisdiction when determining future generation and transmission needs to ensure electrical grid reliability and to meet the state’s greenhouse gas emissions reduction goals.”

of 0.1 LOLE, which means an expectation of one day with loss of load in ten years.⁴ Except for study years in which the base portfolio was modeled to be already over-reliable, Commission staff added perfect capacity⁵ (PCAP) MWs, which are equivalent to effective load carrying capability (ELCC) MW), to the model until the LOLE result was sufficiently close to 0.1 LOLE.⁶

Commission staff followed these basic steps to complete the analysis:

- Step 1: Create a 2025 Need Determination Analysis baseline, which assumes full compliance with the IRP procurement orders.⁷
 - Calculate the capacity of LSE contracts as of the June 2025 IRP procurement compliance filings (no incremental RESOLVE-selected resources to meet reliability or GHG-reduction targets were included, only existing resources plus LSE-reported contracted resources);
 - Evaluate the total MTR procurement claimed by LSEs as incremental contracts beyond the MTR baseline; and
 - Calibrate to the exact minimum compliance MTR NQC MW ordered by adding or subtracting capacity to establish the 2025 Need Determination Analysis baseline.
- Step 2: Analyze the 2025 Need Determination Analysis baseline with an LOLP model (SERVM) to determine incremental need.

⁴ D.24-02-047 adopted the 0.1 LOLE standard as the key input for determining reliability need and this is consistent with previous modeling efforts in IRP.

⁵ Within SERVM, “perfect capacity” is a modeling construct to represent a perfect resource with no operating constraints, no outages, and priced to dispatch only as a last resort, to avoid unserved energy.

⁶ Commission staff conducted iterative SERVM modeling runs to get to within 0.02 of the 0.1 LOLE target.

⁷ D.21-06-035 and D.23-02-040, as modified by D.24-02-047. This assumption includes 100 percent compliance with those orders, which may or may not actually occur.

- Enter the portfolio determined in the step above into SERVVM;
- For each study year, iteratively add increasing amounts of PCAP until the resulting LOLE is approximately 0.1 (equating to one day in ten years); and
- The PCAP added in each study year is equivalent to the ELCC MW need.
- Step 3: Analyze the impact of changes in supply or load through post-processing sensitivities.
 - Sensitivities were created after SERVVM modeling by changing the PCAP MW need by the change in firm capacity or by the change in managed peak (plus a 6 percent operating reserve margin).

Unlike for the development of the TPP portfolios described in Section 2 above, the need determination analysis did not involve running RESOLVE to generate an incremental build of resources to meet reliability and emissions targets at lowest cost. The study simply gathered data on the capacity associated with existing contracts as of the June 2025 IRP procurement compliance filings, adjusted for minimum compliance with MTR requirements, and analyzed the reliability of that portfolio in SERVVM, relative to a 0.1 LOLE planning standard.

Of note during the analysis of the MTR baseline used in this analysis is the fact that LSEs have reported 16.3 GW NQC (ELCC) of signed contracts, as of June 2025, to meet MTR requirements by 2028, which exceeds the 15.5 GW NQC requirement in aggregate. This quantity may not represent all LSEs being in full compliance with their IRP procurement obligations, because some LSEs have procured more than their minimum MTR requirements. LSEs may be procuring (*i.e.*, signing contracts) with resources in excess of current compliance requirements for a variety of reasons, including anticipation of resource development delays or failures, anticipation of resource adequacy requirements,

assessment of resource value, anticipation of renewables portfolio standard (RPS) requirements, LSE-specific portfolio objectives, or anticipation of future needs. The Commission has several times indicated that LSEs that procure in excess of their MTR requirements should expect to be able to count incremental additional resources towards any future needs without regards to a baseline update,⁸ and the ALJ Ruling proposed to continue that principle. In the staff analysis, no explicit failure rate for contracts and no assumptions for delays were used, aside from not counting contracts above the minimum level of required MTR procurement, which effectively means that resources above the minimum MTR requirements were assumed not to exist (which is the functional equivalent of assuming failure).

Subsequent to the modeling analysis, the proposed decision in response to the SCE PFM of D.23-02-040 and D.24-02-047 was revised and finalized, removing the proposed requirement in the original proposed decision for LSEs to be required to replace the delayed LLT resources with generic resources between 2028 and 2031.⁹ Due to this change, the model's assumption that capacity from delayed LLT resources will be replaced with generic capacity is no longer correct. Thus, the analysis overstates resources by the amount of replacement capacity added, or approximately 367 MW, for all years in the analysis. In addition, if LLT resources currently expected to come online in 2028 are delayed until 2031, the analysis also overstates available resources (up to 1,633 MW) for the 2028-2030 period. As described further below, Commission

⁸ See, for example, D.23-02-040, Conclusion of Law 7, and D.25-09-007 at 35.

⁹ The final version of the decision adopted by the Commission is D.25-09-007.

staff developed a “Delayed LLT” sensitivity scenario to account for these estimated deviations.

Table 1 below shows the results of the Commission staff analysis in SERVM for the original set of assumptions, referred to as the “Base Portfolio.” Table 2 then displays the modeling results, adjusted by staff to reflect a minimum compliance scenario under the terms of D.25-09-007, in which all LSEs have signed contracts to satisfy their LLT resource obligations, LLT resource online dates are delayed from 2028 to 2031, and all LSEs are compliant with their system resource adequacy month-ahead requirements. Under these assumptions, 13,500 MW NQC would be assumed to come online through 2027, in accordance with D.21-06-035 and D.23-02-040 (as modified by D.24-02-047). Then, all 2,000 MW NQC of LLT resources would be assumed to come online in 2031, leading to a modeled resource build of 15,500 MW NQC. Because many LSEs have requested LLT resource extensions, the ALJ Ruling proposed requiring procurement based on Table 2 below, rather than based on the originally-modeled Base Portfolio in Table 1.

Table 1. Cumulative SERVM PCAP Need Results for 2028-2032, Base Portfolio

Study Year	LOLE	Expected Unserved Energy (EUE)	Cumulative Added PCAP
Year	Days/Year	MWh¹⁰	ELCC MW
2028	0.043	254	NA
2029	0.115	850	1,200
2030	0.117	755	2,300
2031	0.111	619	4,000
2032	0.098	525	5,900

¹⁰ Megawatt-hour.

**Table 2. Cumulative SERVM PCAP
Need Results for 2028-2032, Delayed LLT Scenario**

Study Year	LOLE	Cumulative Added PCAP	Estimated Adjustment for Delayed LLTs	Cumulative Added PCAP, Adjusted
Year	Days/Year	ELCC MW	ELCC MW	ELCC MW
2028	0.043	NA	2,000	NA
2029	0.115	1,200	2,000	3,200
2030	0.117	2,300	2,000	4,300
2031	0.111	4,000	367	4,367
2032	0.098	5,900	367	6,267

Note that in years 2029-2031, as Commission staff only conducted SERVM modeling to get close to the 0.1 LOLE target but not achieve it precisely, a small amount of additional PCAP is likely needed in order to meet the standard. For 2028, staff originally found the existing resource build to be over-reliable compared to 0.1 LOLE. However, the surplus magnitude was not estimated as part of the staff analysis. Therefore, the estimate for the surplus or deficit in 2028 in the Delayed LLT Scenario adjustment is also undefined.

Commission staff also conducted post-processing sensitivity analysis by looking at three changes in assumptions and analyzing each using a heuristic approach, by manually adding or subtracting PCAP from the results, corresponding to the change in forecasted managed peak MW or firm MW available in each sensitivity. In assessing peak MW changes on PCAP need, an additional 6 percent operating reserves were assumed, instead of the load variability of the full PRM, since most of the load changes are not expected to have significant weather-driven variation. These scenarios were not analyzed in SERVM. Staff looked at the following sensitivity scenarios:

1. **Continued DCPD operations:** In this scenario, 2,200 MW was removed from the PCAP shortfall, using the assumption that DCPD would stay online through its current approved timeframe, which would retire Unit 1 on October 31, 2029 and Unit 2 on October 31, 2030.
 - It was assumed that both units would be available for the 2028 and 2029 peak periods;
 - Unit 2 (1,100 MW) would be available for the 2030 peak period; and
 - Neither unit would be available for 2031 or 2032.
2. **Increased data center load:** In this scenario, a managed peak change, plus 6 percent operating reserves, was added to the PCAP shortfall. The managed peak change was calculated by substituting in the data center load modifier from the 2024 IEPR “Local Reliability” scenario, instead of from the 2024 IEPR “Planning” scenario. No other changes from the 2024 IEPR “Local Reliability” scenario were used.
3. **Reduced load from electrification and data centers:** In this scenario, a managed peak change, plus 6 percent operating reserves, was removed from the PCAP shortfall. This sensitivity was designed to reflect potential impacts of recent policy changes, including the One Big Beautiful Bill Act (OBBBA), potential repeal of the Environmental Protection Agency Waiver from the Clean Air Act potentially influencing electric vehicle adoption, and uncertainty in building electrification and data center load. Potential impacts of federal import tariffs were not included. Details of how Commission staff adjusted load components to reflect the policy changes and uncertainty are described in the slide deck available at: https://www.cpuc.ca.gov/irp_procurement. Note that this heuristic method is less reflective of assumed load behavior, since the load components are more varied compared to the flat data center load changes in Sensitivity 2 above, which is more akin to a PCAP resource as modeled in SERVIM.

Sensitivities 1 and 3 above reduce the PCAP need, while Sensitivity 2 increases it.

Tables 3 and 4 below summarize the results of the sensitivity analyses for the Base Portfolio and the Delayed LLT Portfolio, respectively. In the Delayed LLT Scenario, upon which the ALJ Ruling proposed to base a need determination, the current DCPD continued operations schedule would substantially reduce the reliability need in 2029, but the statutory directives prohibiting consideration of DCPD extensions are important and likely render this scenario not actionable at this time. Increased data center load modestly increases the need. Reduced load may substantially reduce need in all years.

Table 3. PCAP Need Results for Sensitivities Compared to Base Portfolio (in MW)

Study Year	Base Scenario	Increased Data Center Load	Reduced Load	Continued DCPD Operations
2028	NA	0	0	NA
2029	1,200	1,301	0	0
2030	2,300	2,544	0	1,200
2031	4,000	4,306	301	4,000
2032	5,900	6,295	1,645	5,900

Table 4. PCAP Need Results for Sensitivities Compared to Delayed LLT Portfolio (in MW)

Study Year	Delayed LLT Scenario	Increased Data Center Load	Reduced Load	Continued DCPD Operations
2028	NA	0	0	NA
2029	3,200	3,301	1,014	1,000
2030	4,300	4,544	1,347	3,200
2031	4,367	4,673	668	4,367
2032	6,267	6,662	2,012	6,267

2.1. 2029-2032 Procurement Need

Based on the Commission staff analysis presented in the ALJ Ruling and summarized above, the ALJ Ruling proposed that the Commission order additional procurement during the years 2029-2032 in the amounts shown in Table 5 below.

Table 5. Proposed Procurement to be Required from LSEs Collectively (in ELCC MW)

Year	Cumulative Procurement Required in Model (rounded to nearest 500 MW)	Incremental Procurement Recommended
2029	3,000	1,500
2030	4,500	1,500
2031	4,500	1,500
2032	6,000	1,500

The ALJ Ruling also proposed that the compliance baseline for these procurement amounts would continue to be the one utilized in D.21-06-035. In D.21-06-035, the Commission required that any procurement that was intended to count towards the required amounts needed to be incremental relative to the existing resources and/or the resources already under contract at that time. To extend that concept to this new potential requirement would mean that any procurement already undertaken by an LSE that exceeds its obligations from D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) would be applied to the LSE's supplemental obligation, derived from the amounts in the final column of Table 5 above.¹¹ Likewise, any procurement undertaken in response to this

¹¹ This is consistent with D.23-02-040, Conclusion of Law 7, which states: "If an LSE already has procured its share of capacity for one compliance period, it may count any excess procurement from that compliance period in future compliance periods."

order would also be counted toward RCPPP requirements, if a program is ultimately adopted by the Commission.

2.1.1. Comments of Parties

The majority of parties commenting on the analysis of procurement need supported the Commission ordering some procurement as a result. A total of 26 parties supported the proposed order in the ALJ Ruling in some form, with some parties preferring a slightly reduced magnitude or duration of procurement requirements, and others preferring a longer or larger order. ACP-CA argues that the need determination analysis may understate the need due to anticipated future import constraints, and would prefer an order requiring 2,500 MW of procurement per year. GreenGen argues that a longer order would be better for more diverse resource development beyond solar and storage.

Meanwhile, SDG&E and Cal Advocates supported an order covering only 2029 and 2030, for a total of 3,000 MW of procurement. They both cite to high forecast uncertainty and the potential for RCPPP to be implemented beginning in 2031. CalCCA and SCPA/PCE recommended a two-tranche order of 2,000 MW for the 2029-2030 period and another 2,000 MW for the 2031-2032 period, with a reassessment in 2027 for the later period.

Approximately ten parties indicated neutrality toward the proposed procurement or did not express an opinion about it in comments. Nine additional parties were opposed to the Commission ordering procurement at this time, including AReM, Calpine, CLEU, Reid, MRP, Shell, WPTF, SJCE, and MCE. Generally, the arguments against an order were that a procurement need does not imply that a procurement order is necessary, the 2024 IEPR load forecast is highly uncertain, these types of procurement orders erode LSE negotiating leverage with developers in a market with fixed supply, different compliance

rules create administrative complexity, such an order would unnecessarily burden ratepayers, and an order spanning to 2032 would interfere with RCPPP implementation.

CLEU argued that the staff need determination analysis was by itself an insufficient factual record to justify a procurement order and requested workshops on the assumptions to build a more robust record. AReM expressed some support for a shorter procurement order that is based on the reduced load sensitivity, and Calpine and MRP also supported other parties' comments in their replies that argued for a shorter order.

PG&E, SDG&E, and CCSA suggested mechanisms to effectively reduce an order's size, given certain conditions are met. PG&E and SDG&E suggest amending the Public Utilities Code to clearly allow the Commission to account for DCCP's attributes. Then they argue that the procurement need would clearly be reduced. PG&E also argues that any incremental procurement conducted by PG&E and SCE in their roles as the local CPE for resource adequacy should be eligible to reduce procurement obligations. CCSA argues that in the event that front-of-the-meter (FTM) distributed energy resources (DERs) are modeled as load modifiers by CEC in a future IEPR, the LSEs should be able to count load-modifying FTM DERs in their compliance filings as reductions to their need allocations.

Several parties recommended alternative analyses for determining a procurement need. Calpine recommends basing an order on a combination of the reduced load sensitivity and the DCCP operations sensitivity. CLEU also suggests that the Commission is obligated by law (specifically, Public Utilities Code 454.52(a)(1)(E)) to consider DCCP capacity through 2030, as the need determination is a "midterm" analysis. CalCCA reports that its results were

similar to the Commission's when using the same assumptions, but cautions that the assumptions may not actually occur, and therefore recommends a set of "lighter" assumptions. ACP-CA and Hydrostor, on the other hand, recommend more generous assumptions about need, with Hydrostor suggesting that data center load may be higher than anticipated. CCSA and CBD recommend supplementing the staff analysis with the Aurora study, which supports a greater role for FTM solar development. MGRA cited a Form study on 100-hour batteries. Finally, Shell recommends that the Commission undertake a joint analysis with the CAISO to determine reliability needs, rather than relying on the analysis presented in the ALJ Ruling.

Parties' comments were also concerned with the potential impacts of a procurement order from the Commission on the market for clean energy and capacity. Several parties argue that an order would likely lead to more adverse conditions for LSEs in the market, including price increases. AReM argues that after D.21-06-035 there was so much procurement activity by LSEs attempting to meet those requirements that the LSEs scrambled to secure contracts, which drove up prices due to the scarcity of compliant resources. SCE and MCE argue this was particular true for battery storage projects. SDG&E and MCE also argue this caused resource adequacy price volatility as well.

ACP-CA and REV, on the other hand, argue that a procurement order on the order contemplated in the ALJ Ruling would not likely increase prices in the market. ACP-CA states that the quantity of uncontracted projects in the current interconnection queue suggests that LSEs maintain a strong position in negotiations. REV argues that the longer timeframe, with the first need being four years out, aligns very well with development timelines and should make the market competitive.

2.1.2. Discussion

As a starting point, we are always concerned about the impact that our procurement decisions have on the market. As we have since our first IRP procurement order in 2019,¹² we expect the LSEs generally to be in the market with solicitations regularly, as they should be planning for load growth and future resource needs in advance. Therefore, we expect that the Commission's consideration of requiring additional procurement after the expiration of the current MTR requirements should not come as a complete surprise to the LSEs or other market actors. LSEs have also been on notice that the Commission is considering approaching ongoing procurement needs with a programmatic approach, in the form of the RCPPP proposal under development in R.20-05-003. The adoption of some form of programmatic requirement will also impose ongoing procurement requirements on LSEs. In general, the proposed new resource requirement of 1,500 MW NQC annually in the ALJ Ruling does not seem unreasonable or particularly burdensome in light of the size of the resource need when considering the magnitude of California's GHG goals out through 2045.

We are also persuaded that there may still be some projects without contracts that can take advantage of remaining Federal tax credits, and if those are available, it would be to the benefit of ratepayers for the projects to be contracted, assuming other reasonable terms.

In addition, we note that the timing of this order allows for more procurement lead time than has often been the case with past IRP procurement

¹² D.19-11-016.

orders. On this, we agree with the argument made by REV that the longer lead time we are planning for here is likely to dampen negative market effects.

At the same time, we are concerned about impacts on ratepayer costs. While it is likely that DCPD will be online through 2030 in reality, the Commission models its impact pursuant to SB 846 requirements.

In light of all of the above factors, and in response to comments on the proposed decision from the CAISO, stating concerns with reliability in 2031, this order modifies the proposal in the ALJ Ruling to require the same total amount of procurement, but in three years instead of four. We adopt a requirement for 2,000 MW NQC total procurement online by June 1, 2030, with an additional 2,000 MW NQC online by June 1, 2031, and a third set of additional 2,000 MW NQC online by June 1, 2032. All resources are required to be online and delivering to the grid to be counted toward compliance on or before those deadlines. We also note that LSEs are encouraged to conduct procurement and bring resources online sooner than the compliance dates in this decision.

The baseline remains set in 2020 as in the D.21-06-035 baseline, so any resources procured since that date that otherwise qualify for the requirements, will be counted, with the exception of the provisions in this decision (*see* Section 2.2.2) related to new energy-only generation resources that are co-located with fully deliverable storage.

This timing will allow for a smooth transition to the potential adoption of an RCPD framework, along with implementation details, in a timeframe that is realistic and should not cause market disruption regardless of the form the RCPD may ultimately take.

2.2. Resource Eligibility

The ALJ Ruling proposed that qualifying resources to meet the procurement requirements would be the same as under D.21-06-035 and D.23-02-040. Namely, the resources would be required to be non-GHG-emitting and/or eligible for the RPS program. Only new resources (online after January 1, 2020¹³) would qualify. The rules around baseline swaps,¹⁴ baseline waivers,¹⁵ and obligations swaps¹⁶ would also be extended. Resources fueled by natural gas or any other fossil fuel would not qualify to meet the procurement requirements.

Most prior decisions did not allow the repowering of existing clean energy or natural gas resources to qualify to meet the procurement requirements. Given that there are resources that will enter retirement age in the late 2020s and early 2030s, parties were also asked to comment specifically on whether repowering should be eligible to count toward “new” resources requirements, including recommendations for how such resources should be verified (given that the CAISO rarely reissues new resource identifications or updates commercial online dates for repowering, which could make compliance verification challenging).

2.2.1. Comments of Parties

In general, most of the CCAs advocate for a technology-agnostic order, as does Calpine, esVolta, EDF, CESA, AReM, ACP-CA, CalWEA, and SCE. Parties also argue that the resource adequacy slice-of-day (SOD) requirements will drive procurement that is aligned with load.

¹³ See D.23-02-040 at 21.

¹⁴ See D.23-02-040, Ordering Paragraph 13.

¹⁵ See D.23-02-040 at 19.

¹⁶ See D.23-02-040, Ordering Paragraph 10.

EDF argues that the Commission should specify the need for clean firm resource procurement, particularly those resources which provide consistent output, including geothermal. Fervo agrees. BAC argues that the Commission should order firm and dispatchable procurement. CLEU argues for at least ten percent DERs, whereas GreenGen argues for resources that can provide output over many hours/days.

Ultimately, CAISO, NextEra, IEP, CEJA/Sierra Club, REV, GreenGen, and PG&E all advocate that this procurement order should have the same resource requirements as the MTR requirements.

Several parties also commented on whether resources with energy-only deliverability status should be eligible to count toward any requirements. SCE, AReM, SCPA, TNC, and CEJA/Sierra Club advocate for allowing energy-only resources to count if they are co-located with storage.

LSA/SEIA and SCPA advocate for broader eligibility of energy-only resources in the resource adequacy SOD framework to more realistically represent their ability to meet charging sufficiency requirements across the system. LSA/SEIA and SDG&E also advocate that the Commission work with CAISO to study the resource adequacy program's charging sufficiency requirement, with the goal of allowing energy-only solar to count towards charging sufficiency for storage within the local capacity or transmission zone where the solar is located, and not just for a co-located storage facility.

REV advocates that energy and storage that are contractually paired should be allowed to count towards the requirements in this order. SCPA/PCE and ACP-CA advocate for general eligibility of energy-only resources in the order, without requirements for co-location. CalWEA and LSA/SEIA suggest allowing interconnection customers that fail to obtain deliverability to convert to

energy-only status, rather than being eliminated from the queue. CalWEA and NextEra note that there is currently not much demand for energy-only resources because of program and eligibility rules. UCS argues that resources with deliverability status should continue to be required to meet any capacity component of a procurement order, but energy-only resources could help meet any energy component. CAISO and Fervo emphasize a general need for an order to ensure charging sufficiency.

On eligibility of repowering, AReM and ACP-CA advocate for incremental repowers to count. SDG&E also advocates for repowering, and SoCalGas advocates for the eligibility of gas repowers and gas resources overall.

2.2.2. Discussion

In general, we do not find justification to deviate from the previous MTR procurement resource eligibility requirements, which include that the resources must be zero-emitting and/or RPS-eligible. Only new resources (online after January 1, 2020¹⁷) will qualify to meet the procurement requirements in this order. The rules around baseline swaps,¹⁸ baseline waivers,¹⁹ and obligation swaps²⁰ will also be extended. Baseline swaps continue to follow the provisions outlined in D.23-02-040, including prohibition on swapping resources with contracts termination after January 13, 2023, and eligibility for swapping of 2030, 2031, or 2032 obligations. Resources fueled by natural gas or any other fossil fuel will not qualify for the procurement required in this decision. To qualify, all resources must be eligible to be counted for resource adequacy purposes,

¹⁷ See D.23-02-040 at 21.

¹⁸ See D.23-02-040, Ordering Paragraph 13.

¹⁹ See D.23-02-040 at 19.

²⁰ See D.23-02-040, Ordering Paragraph 10.

according to the rules in place for resource adequacy at the time the resources are required to be online.

For repowering, we will also leave the rules in place that govern MTR procurement, because no party provided a compelling justification to change the rules. Thus, a resource may be repowered, but only the incremental capacity that is added over and above the original resource capacity will count towards the procurement requirements herein. This also applies to modifications or upgrades to baseline resources, where only capacity added over and above the original baseline value will be eligible to be counted toward procurement required in this decision. We note that repowered resources will likely be an important part of future resource portfolios to help LSEs achieve their procurement obligations at lowest overall costs, but they also may satisfy other program requirements through the RPS or resource adequacy programs.

As to energy-only contracts, we find justification to allow hybrid projects and limited additional eligibility for projects where the generation and the storage are co-located and the storage is fully deliverable. This means that multiple separate resources with distinct CAISO identification numbers may qualify as long as they have the same point of interconnection on the CAISO system. This definition also aligns with the resource adequacy program eligibility under SOD charging sufficiency requirements. The individual storage and generation components of a co-located project should each count toward the procurement required in this decision based on their individual ELCC value. Their resource adequacy program eligibility is governed by the resource adequacy eligibility requirements. Other arrangements that are otherwise contractually paired will not be eligible, largely due to the difficulty involved in

verifying deliverability and charging sufficiency, for purposes of attributing increased reliability benefits.

These provisions for energy-only resources co-located with fully-deliverable storage are new and only apply to resources that come online after the effective date of this decision. These provisions may not be applied to existing energy-only resources already online; however, new energy-only resources are eligible even if their co-located, fully-deliverable storage resource was already online prior to the effective date of this decision.

2.3. Energy Procurement (instead of, or in addition to, Capacity)

In the ALJ Ruling, the required procurement amounts were also proposed as effective capacity amounts, in units of NQC-ELCC, consistent with past orders. Also in past orders, the Commission required staff to post the MTR-ELCC valuations for each technology type. Similarly for this decision, Commission staff proposed in the ALJ Ruling to determine the ELCC valuation for each technology and each tranche of procurement. It is important to note, for example, that as additional storage is added to the system, there may be a question about the need for energy resources to generate sufficient additional electricity to charge the storage. Parties were thus specifically requested to comment on whether generic capacity requirements would be sufficient or whether there should be a required energy component of the procurement. Further, parties were asked to weigh in on whether energy procurement, if required, would be best accomplished through the RPS program or a separate IRP requirement.

2.3.1. Comments of Parties

More than twenty parties commented on this issue in their response to the ALJ Ruling. About half of the parties support focusing on capacity procurement

requirements only and not requiring an energy component. Many of those parties suggest that a capacity framework provides LSEs with necessary flexibility to procure the least-cost, best-fit resources tailored to their specific resource needs. CalCCA, SDG&E, and SCE add that the RPS and resource adequacy programs already drive procurement of clean energy generation. CalCCA explains that the SOD framework requires LSEs to meet a charging sufficiency requirement to demonstrate that energy storage resources can be fully charged and discharged to meet the resource adequacy program's planning standards.

CESA argues that a separate energy-based requirement would be redundant because the marginal ELCC values inherently capture both capacity and energy constraints. REV argues that there is insufficient evidence of a system-wide shortfall of energy. Thus, a capacity-only target maps cleanly to reliability modeling and avoids pre-selecting technologies. CAISO, IEP, and SDG&E all argue that it is important to stay consistent with prior MTR orders.

These parties who are against requiring a separate energy procurement requirement also largely argue that the SOD framework better captures both capacity and energy needs, ensures alignment between IRP and resource adequacy programs, and provides more accurate, long-term planning signals than marginal ELCCs, which are very volatile. These arguments were made by, among others, CalCCA, AReM, Calpine, and LSA/SEIA.

Roughly the other half of parties commenting on this issue support including an energy component to the requirements for various reasons and to varying degrees. Most of these parties are concerned about the decline in ELCC values of stand-alone storage. PG&E, ENGIE, and CalWEA argue that heavy reliance on storage without sufficient renewable generation threatens energy

availability during critical hours. ACP-CA, Vote Solar, and LSA/SEIA argue that including an energy component would ensure that storage has adequate charging energy, especially from zero-carbon sources. ACP-CA concurs in reply comments, explaining that the entire rationale for a procurement order is to address the risk that there may not be sufficient signals to LSEs to procure necessary resources.

Further, ENGIE, CEJA/Sierra Club, and UCS argue that without explicit energy targets, LSEs may under-procure renewables because the RPS requirements have largely already been met. CEJA/Sierra Club and MGRA argue that an energy component connects procurement directly to GHG reduction goals and reliability needs, which is important.

Parties in support of including an energy procurement requirement generally argue that the SOD framework is incomplete, untested, and costly. These parties generally prefer the ELCC framework or a traditional resource adequacy approach, which provides clearer market signals and better manages existing resources. SDG&E also argues that updated incremental ELCCs will reflect reliability contributions accurately, whereas SOD is duplicative of resource adequacy functions and unnecessary in the IRP context.

PG&E argues that any procurement requirements should have an energy component and suggests that the procurement order should include a requirement for at least 50 percent of the capacity come from generating resources, to mitigate energy insufficiency risks and stabilize ELCCs.

Parties also commented on the idea of ordering energy procurement through the RPS program, instead of in this proceeding. Supporters of this idea believe that adjusting RPS program requirements would be the simplest and fairest way to spur an accelerated buildout of clean energy, but close

coordination with IRP would be required. UCS emphasizes that the LSEs are collectively behind on clean energy procurement and that accelerating RPS requirements would be simple and fair, recommending increasing RPS targets to 60 percent by 2028, 70 percent by 2029, and 80 percent by 2030, to allow LSEs to adjust, while bridging gaps until other programs, including RCPMP, are fully implemented. Reid also supports using the RPS mechanism.

Most other parties opposed ordering additional energy procurement through the RPS program. PG&E argues that relying on the RPS program does not necessarily incentivize projects to achieve CAISO deliverability status, and thus could negatively impact reliability. Calpine, CEJA/Sierra Club, GreenGen, ICP, and AREM variously argue that the RPS framework is too narrowly focused and cannot adequately capture the capacity, duration, and flexibility contributions from non-RPS resources such as pumped storage hydro (PSH), compressed air energy storage, and other clean-firm technologies.

GreenGen further argues that the IRP is the only proceeding capable of addressing system reliability, resource adequacy, and portfolio diversity on a technology-neutral basis, while specifying the deliverability requirements of new resources. CalCCA, ACP-CA, Vote Solar, PG&E, and SDG&E concur. CalCCA also argues that to the extent that an LSE needs to procure additional clean energy to achieve RPS compliance, the Commission can presume that the LSEs will seek to satisfy its RPS needs and IRP procurement order needs by procuring a new clean energy resource that satisfies both requirements. CalCCA states that there is no need to place an entity under “double jeopardy” by issuing multiple penalties for the same deficiency.

TURN argues that the RPS program should not be relied on for near-term incremental energy needs because there is no guarantee that such an approach

would yield additional resources, meaning that increased RPS obligations could be met by banked or existing procurement rather than through the addition of new generation. MRP agrees, as do LSA/SEIA, ACP-CA, and PG&E in reply comments. ACP-CA also mentions the risk of multi-year delays, due to the RPS program timeline. SCE, SDG&E, CalCCA, and CalWEA also argue that expanding RPS at this time could also conflict with ongoing RCPMP development, or lead to potential duplication or misaligned incentives, procurement inefficiencies, or unintended market consequences.

Finally, CalCCA, MRP, and AReM argue that an RPS-based allocation approach may not align with individual LSE portfolio needs, whereas the IRP framework allows for tailored, system-aligned procurement.

2.3.2. Discussion

On the question of whether to require energy procurement along with capacity procurement, the Commission encourages LSEs to procure a balanced portfolio of resources that have the attributes needed to reliably meet state climate targets and avoid an over-reliance on any one technology. In recent procurement, we observe that LSEs found lithium-ion battery storage to be a very attractive resource, both because of its declining costs, as well as its modular nature and ability to be developed and brought online quickly. However, we caution against overreliance on short-duration battery storage or any other particular technology. Federal tariff policy may be having a negative impact on the battery storage market, due to the rising cost of components. In addition, the resource adequacy SOD requirements and the other RPS requirements would tend to encourage LSEs to procure more energy-generating resources naturally instead of more battery storage. LSEs should also have an interest in hedging energy market price volatility. Because all of these changes are occurring

relatively recently, it is not entirely clear how solicitations and procurement will play out in light of new market trends.

In response to comments of parties on the proposed decision, which overwhelmingly opposed the idea of imposing a cap on the amount of storage that could be procured to count towards the procurement requirements in this order, we have removed that concept from the final decision. There will be no overall cap on the amount of storage that may be counted for the procurement required herein. However, in meeting their procurement requirements, we encourage LSEs to include resources that have attributes found in longer-duration storage and/or diverse resources, rather than solely relying on attributes found in short-duration batteries.

We also will not require a specific amount of energy generation to comply with this order. Thus, at this time, we do not need to conclude whether to use an RPS mechanism or a regular IRP procurement order to require energy generation. Parties' comments remain instructive for our deliberations on the nature of the long-term procurement obligations as we move forward.

Having made the above determinations, we remain concerned about developing resources with a diverse set of attributes identified in the portfolio described in Section 3.2 of this decision for transmission planning. Removing the cap on storage could still result in overreliance by LSEs on short-term battery storage in the portfolio. In comments on the proposed decision, Hydrostor recommends requiring that at least 1,500 MW NQC or 25 percent of the procurement required herein be designated to come from long-duration storage resources of at least eight hours in duration. LDES Council also recommends that the Commission require that 25 percent of the capacity procurement be required to come from storage resources with eight or more hours of duration and with

efficiencies of 60 percent or more. Form raises concerns with the Commission not having specific ELCCs for LDES resources and suggests that the Commission take measures to ensure procurement of LDES resources. CUE and CURE further note that LSEs are unlikely to procure the LDES resources that the portfolio in Section 3.2 identifies as needed without a specific procurement requirement.

Also in comments on the proposed decision, EDF recommends that at least 500 MW in each tranche of procurement be required to come from clean, firm resources, which were first defined in D.21-06-035 as having capacity factors of at least 80 percent and not being use-limited. Not coincidentally, these are the same LLT resource types that we required to be procured in D.21-06-035, for many of the same reasons. CAISO, in replies, notes that, if there is a risk that LSE procurement will deviate significantly from the planned base case for the TPP, it supports the Commission adopted the LDES Council and Hydrostor's recommendations.

Based on LSEs' submitted compliance data, used in the need determination analysis discussed in Section 2.1, we are seeing LSEs procuring resources that have attributes associated with LLT resources as defined by D.21-06-035, as modified by D.25-06-005, in volumes up to, but not generally beyond, what D.21-06-035 required.

Therefore, instead of a cap on storage resources, we will instead make a requirement that at least one-quarter of each LSE's procurement used to satisfy the requirements of this decision come from either long-duration storage resources (eight hours or more in curation) or clean firm resources (with a capacity factor of at least 80 percent and not use-limited), as defined in Ordering Paragraph 2 of D.21-06-035, and further modified in D.25-06-005. For this decision's required procurement, an LSE may choose the amounts of each type of

resource, as long as the two types of LLTs total at least one-quarter of its total allocation, as given in Attachment A. This means that collectively a total of 1,500 MW NQC of the 6,000 MW NQC required to be procured by this decision must come from either LDES or clean firm resources, as defined in D.21-06-035 and modified by D.25-06-005. LSEs will have flexibility on when they procure the LDES or clean firm resources, but must have these resources procured by no later than the June 1, 2032 compliance deadline.

2.4. Local Procurement

The ALJ Ruling did not propose any requirements for local reliability procurement, but some parties requested this in their comments.

2.4.1. Comments of Parties

CCSA, CEJA/Sierra Club, REV, Vote Solar, EDF, and LSA/SEIA, argue for local capacity area procurement requirements to be included in any procurement order. Specifically, CEJA/Sierra Club suggest prioritizing areas with disadvantaged communities and where storage can replace the need for natural gas plants on a one-to-one basis. CEJA and Sierra Club suggest that at least 1,000 MW of energy storage and 1,000 MW of clean energy generation should be targeted to local areas.

CalCCA and SCE argue against a local capacity requirement, stating that it will drive up costs. Calpine also states that a local procurement requirement should not be assigned without a demonstration of need. AReM similarly argues that more study would be needed before requiring local procurement. Finally, ACP-CA argues that the resource adequacy central procurement entities should be the ones doing local procurement.

2.4.2. Discussion

On this issue, given the timeframe in which we are considering this procurement, we agree with CalCCA and SCE that it would be ill-advised to adopt a specific local procurement requirement in this context because it would likely increase costs and make procurement more difficult. However, we encourage LSEs to pursue procurement in local areas where it makes sense for their portfolios. We also intend to continue to evaluate the need for additional local solutions in IRP planning and procurement in general, as discussed in the Scoping Memo for this proceeding, as well as in the context of local capacity need evaluation in the resource adequacy proceeding.

2.5. Need Allocation

The ALJ Ruling proposed that the allocation of need to each LSE should be based on each LSE's share of the managed peak on the electric system as of the resource adequacy program year 2026 and the energy load forecasts for IOUs and CCAs, in the same basic manner as the procurement requirements were allocated under the MTR and Supplemental MTR orders. LSE requirements were proposed to be based on each LSE's year-ahead resource adequacy forecasts for 2026.

The ALJ Ruling also described other options that could be considered, including requiring procurement by the investor-owned utilities (IOUs) on behalf of all LSEs, with costs allocated via the Cost Allocation Mechanism (CAM). An argument for this approach could be to maximize the opportunities to take advantage of expiring tax credits. In addition, an argument could be made that having a smaller number of LSEs in the market to procure could simplify the task.

Parties were asked to comment on the centralized procurement approach in response to the ALJ Ruling.

2.5.1. Comments of Parties

Very few parties commented on the proposed primary allocation method in the ALJ Ruling, based on load forecasts and resource adequacy peak load. Shell specifically takes issue with allocating any procurement requirements to the ESPs until the cap on direct access load is lifted. AReM argues that allocation should be determined through a workshop followed by public comments. CESA argues for allocation based on a “contract baseline method” rather than using the MTR baseline, which would give credit for past procurement progress. CalCCA and MRP generally argue for share of peak load, which is an element of the ALJ Ruling proposal.

On the concept of having IOUs centrally procure on behalf of all LSEs, around twenty parties commented on this, with most parties opposing the idea. Most parties argue that LSEs should procure their own resources individually, for a variety of reasons. Calpine argues that most of the available resources are easy to contract in small increments, and therefore do not require centralized procurement. CPA and MGRA argue that central procurement could result in inconsistency with LSE portfolio needs, leading to market inefficiencies. MRP and MGRA argue that central procurement would hinder the ability of LSEs to tailor their portfolios to their customers’ needs. CalCCA similarly argues that central procurement would lead to non-optimization of LSE portfolios.

CalWEA and EDF both simply state that centralized procurement is not necessary to achieve the proposed resource procurement. PG&E fears that central procurement could hinder progress and undermine the reliability goal of the order in the first place. Shell argues that central procurement has not been shown

to reduce costs or improve reliability. REV also argues that individual LSE procurement creates more market competition, which can improve cost efficiency.

A few parties supported the idea of central procurement in their comments. LDES Council argues for central procurement for the technologies included under AB 1373. AReM argues that LSEs should be allowed to voluntarily opt in to centralized procurement by DWR as the backstop entity for LLT procurement. AReM also argues that central procurement is reasonable because it mitigates equity issues in spreading procurement responsibility for load growth, allows for allocation of procurement costs to new large loads via CAM, and avoids leaving out LSEs who may endeavor to procure as ordered but are unable to due to market unavailability. GreenGen suggests that any central procurement structure should be voluntary and transparent, functioning to facilitate options for resources that cannot otherwise aggregate sufficient offtake through bilateral or joint solicitations. Vote Solar argues that there should be backstop procurement authorized if it becomes apparent that some LSEs cannot meet their obligations. Reid suggests that LSEs should be allowed to opt out of central procurement, if it is ordered. SCE argues that for MTR procurement, the Commission required all LSEs to procure their proportional share and did not allow opting out. SCE supports this logic for any additional procurement.

2.5.2. Discussion

We generally support the principle that each LSE should be responsible for procuring electricity resources to serve its own load, unless there is a compelling reason to order centralized procurement for logistical or cost reasons. In the case of the need found for LLT resources in D.24-08-064, there was a compelling rationale for LSEs taking a collective risk on new resources that may be more

costly or difficult to develop than standard already-commercialized resources. In the case of the procurement required by this decision, we are expecting generally available and commercialized technologies to be procured. LSEs always have the option to jointly procure, if the amounts necessary for each individual LSE are small and easily aggregated. Thus, we do not see the need for the Commission to require centralized procurement for the capacity need identified in this decision. Instead, we will allocate this procurement responsibility to each LSE.

We understand the point made by Shell and others that the direct access load is capped. However, we decline to exempt ESPs from the need to procure their proportional share of the additional capacity found to be needed in this order. We note that all customers contribute to the overall need to add resources to meet reliability standards and we agree with reply comments on the proposed decision from SCE that all customers and providers benefit from a reliable electric system. Therefore, all LSEs should be required to procure for the reliability needs.

As proposed in the ALJ Ruling, we will allocate LSE procurement responsibility for the 6,000 MW NQC on the basis of each LSE's share of the managed peak on the electric system as of the resource adequacy program year 2026, and taking into account the energy load forecasts for the IOUs and CCAs, in the same basic manner as the procurement requirements were allocated under the MTR and Supplemental MTR orders. The proportional allocations will be rounded to the nearest whole MW amount.

In reply comments, Ava noted that the CEC released updated 2024 IEPR LSE energy demand forecast tables on February 6, 2026, and again on February 10, 2026, reflecting updated historical and near-term data and service territory expansions, among other changes. While Ava did not recommend

updating LSE allocations based on the new tables, we find it important to do so, while still relying on the 2024 IEPR demand forecast for the reasons previously discussed. CEC provided finalized energy demand forecast tables for the 2024 IEPR on February 20, 2026, and we employ data from that update in calculating LSE procurement responsibility allocations. Many parties noted uncertainty in the IEPR forecast, including on how that impacts procurement allocations required herein. Commission staff will continue to work with the CEC on the forecast, including for how the IEPR assigns load share responsibility to specific LSEs.

Attachment A to this decision contains the allocation (rounded to the nearest whole MW) of procurement responsibility to each LSE for each year (2030, 2031, and 2032), except that the ESPs are shown collectively. Individual ESP assignments are to be kept confidential and will be transmitted individually by Commission staff to each ESP within two weeks of the effective date of this decision and within two weeks of the posted reallocations for 2032 procurement, due to be posted no later than June 1, 2027, based on the adopted 2026 IEPR forecast.

The ESP allocations are calculated by dividing the individual ESP's year-ahead adjusted peak resource adequacy forecast for 2026 (for month 9) by the total/aggregate year-ahead adjusted peak resource adequacy forecasts for 2026 (for month 9) for all Commission-jurisdictional LSEs.

2.6. Compliance and Enforcement

The ALJ Ruling proposed that compliance and enforcement processes mirror those under the MTR and Supplemental MTR orders. First, new resources to meet the compliance requirements would be required to be online by June 1 of each year where procurement is required, via an annual tranche, and under

long-term contracts of at least ten years in length. Second, the baseline would be identical to the original baseline for D.21-06-035, which builds upon the baseline originally set in D.19-11-016. Third, resources would be counted based on a set of incremental ELCC values to be published by Commission staff. Alternatively, the ALJ Ruling noted that the Commission could extend the existing ELCC values from 2028-2032, though they may overstate the value of four-hour storage, but compliance obligation simplicity could offset the lost precision in ELCC valuation. Next, the ALJ Ruling proposed that any excess procurement in response to the MTR and Supplemental MTR requirements would count toward any additional procurement required by this decision. Finally, the ALJ Ruling proposed that non-compliance would be penalized at the net cost of new entry (CONE) for any amount of ELCC MW that an LSE is short in a given year. Compliance was proposed to be assessed on an annual basis.

The ALJ Ruling noted that even if the Commission orders procurement with a certain compliance regimen, other programs, including resource adequacy, RPS, and a potential RCPMP, could end up being more binding constraints on LSE procurement.

2.6.1. Comments of Parties

Every party making comments agreed that any excess MTR or Supplemental MTR procurement by an LSE should count toward the LSE's requirements from this decision requiring new procurement. Most parties did not comment on the ten-year contracting proposal. REV and Hydrostor do request that the Commission make it clear that this requirement is still in place, to give developers confidence and the ability to bring the resources online by the deadlines.

A number of parties were concerned with the way capacity accreditation would work under a procurement requirement. Generally, MRP, SoCalGas, Calpine, CAISO, PG&E, SCE ACP-CA, EDF-NA, CESA, REV, and GreenGen were in favor of using ELCCs to accredit resources for compliance purposes. ACP-CA specifically argues for “firm” ELCCs that the market can plan around. CAISO supports using marginal ELCCs and states that an effective PRM does not incentivize LSEs to acquire new capacity. SCE supports using the 2028 ELCCs already produced; REV prefers an updated ELCC analysis. PG&E supports using marginal ELCCs only for this order, and thereafter using the SOD framework as part of an adopted RCPPP framework.

CalCCA, AReM, and the Joint Solar Parties (in reply comments) prefer using the SOD framework to count for compliance with the procurement in this decision. CalCCA states that if the decision adopts an ELCC framework instead, it should account for charging sufficiency for storage and fix ELCCs in advance, to optimize procurement.

Separately, CalCCA specifically requests that the compliance flexibility rules in D.25-09-007 apply to any procurement ordered in response to the ALJ Ruling. This effectively would mean LSEs would have up to three years of flexibility to bring resources online after the due date, if LSEs have signed contracts and are otherwise compliant with their resource adequacy obligations.

2.6.2. Discussion

In this decision in general, we intend to keep compliance as simple as possible by remaining consistent, wherever possible, with MTR and Supplemental MTR requirements already in place and familiar to LSEs and stakeholders. Thus, we will continue to require that the new resources come online by June 1 in the year in which they are required (this means contracted to

begin deliveries and actually delivering energy to the grid) and that they be under a contract that is a minimum of ten years in length. Any LSEs with excess resources procured to meet MTR or Supplemental MTR requirements may use them to satisfy the requirements of this decision, as long as they otherwise meet the criteria specified herein.

On the issue of resource accreditation, we will use a marginal ELCC approach for accreditation of resources for compliance with the procurement required herein. This should not be read as any indication of the direction the Commission may take with the design of the RCPPP, if adopted in R.20-05-003. That consideration is independent of the requirements of this order, and the Commission will fully weigh the pros and cons of a marginal ELCC approach compared to using the resource adequacy SOD framework for resource accreditation under RCPPP. However, for purposes of the procurement required by this order, resources will be counted using marginal ELCCs, in the same manner as for the MTR and Supplemental MTR procurement.

We are not convinced that the 2028 marginal ELCCs already published will be appropriate to use for procurement due in 2030 and 2032, however. It seems likely that the values will be outdated, particularly so with respect to 4-hour lithium-ion battery storage, but without conducting a new study, we will not know by how much. Therefore, we will ask Commission staff to complete a new ELCC study to develop values for the 4,000 MW of NQC required to be procured by 2030 and 2031, and publish it in final form by no later than July 31, 2026. By July 31, 2026, Commission staff will also publish indicative values for 2032, but those will not yet be suitable to use for compliance purposes. Then, for the 2,000 MW NQC of procurement required to be online by June 1, 2032, Commission staff will complete and publish a new ELCC study for the year 2032

by no later than December 31, 2027 that fixes compliance ELCCs for the 2032 required procurement. The timing of these two ELCC studies should give LSEs sufficient time to procure and develop resources before the deadlines for the resource procurement required under this decision.

In response to comments from numerous LSEs on the proposed decision, we will also extend the compliance flexibility offered in D.25-09-007 to the procurement required herein, because the same conditions that led to the adoption of D.25-09-007 persist today. That is, there will be three-year flexibility for bringing resources online by showing resource adequacy compliance and executed contracts, in order to be deemed compliant with the 2030, 2031, and 2032 procurement requirements. Allowing flexibility, as long as near-term resource adequacy needs are met and long-term contracts are executed, should help mitigate costs and address delays that are outside the control of LSEs. LSEs may also use the baseline swap, baseline waiver, and/or obligation swap processes laid out in D.23-02-040, if applicable to their particular circumstance and approved by the Commission in the required advice letters applicable to the processes.

Any LSE that fails to deliver the requisite new capacity by June 1, 2030, June 1, 2031, and June 1, 2032, and/or does not have signed contracts and is not resource-adequacy compliant throughout the time in which their procurement is deficient, will be found non-compliant and subject to a financial penalty of the net CONE value. Compliance will be assessed separately for each year's procurement requirements.

We will also maintain the backstop procurement mechanism option associated with D.21-06-035 and D.23-02-040. The Commission will assess the

need for backstop procurement based on the compliance filings on June 1, 2030, June 1, 2031, and June 1, 2032.

Finally, we will maintain the semi-annual procurement compliance filing deadlines articulated in D.23-02-040. The compliance filings will continue to be due on June 1 and December 1 of each year between now and June 1, 2032, unless otherwise modified by the Commission.

3. California Independent System Operator Transmission Planning Process Recommendations

This section discusses the staff recommendations for electricity resource portfolios to be transmitted to the CAISO for their annual TPP that were contained in the ALJ Ruling, parties' comments on those recommendations, and the final recommendations to be transmitted to the CAISO for the 2026-2027 TPP.

3.1. Modeling Assumptions

Prior to recommending a base case portfolio, as well as any sensitivity portfolios, every year Commission staff update numerous assumptions on which the analysis of the portfolios is based. Since releasing the Draft 2025 Inputs and Assumptions document,²¹ there were several high-level policy changes, in addition to various changes to resource-specific assumptions.

First, the modeling takes into account the impacts of recent Federal action, including:

- The FY 2025 Congressional Reconciliation Bill (also referred to as the One Big Beautiful Bill Act (or OBBBA) that has impacted tax credit assumptions for impacted

²¹ The Draft 2025 Inputs and Assumptions document is available at the following link: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_doc_20250220.pdf.

technologies, including wind, solar, and other resources;
and

- The introduction of wide-ranging tariffs, applying across numerous trading partners, impacting every technology, with special impact on technologies dependent on imports from China and Southeast Asia.

Not included in the changed assumptions used for the analysis presented in this ruling, but on the horizon and being monitored are impacts related to:

- Anti-Dumping and Countervailing Duties (AD/CVD); and
- Foreign Entities of Concern (FEOC).

Guidance from the Treasury Department and Department of Energy, respectively, were not published in time to ensure sufficient review and incorporation of these issues into the updated modeling inputs.

For the updates to the tax credit assumptions, the model assumptions include ending tax credits for wind and solar projects that fail to commence construction by July 4, 2026. Energy storage and clean-firm technologies retain tax credit eligibility through 2032, as well as safe-harboring provisions and the three-year phase-out previously established in the Inflation Reduction Act of 2022.

For the tariff assumption changes, current tariff policy is assumed to last through 2029, reflecting historical precedent and maintaining consistency with how IRP modeling has treated similar assumptions in previous modeling efforts. U.S. trade policy impacts by technology were estimated by assessing the supply chains of imported components by country and applying the latest tariff rates (as of July 2025) to the proportions of projects' capital expenditures attributed to those imports, with the awareness that many of the assumptions are likely fluid. The analysis concludes that tariff impacts are largest for solar and lithium-ion battery storage, which source most of their components from China and

Southeast Asia. The analysis also assumes that solar developers will be able to adapt their supply chains to avoid AD/CVD penalties. The staff analysis also notes that the battery energy storage supply chain is uniquely dependent on imports from China, which is subject to some of the highest tariffs overall under current policy.

The resulting weighted average tariff for onshore wind is 29 percent, utility-scale solar photovoltaics is 70 percent, and battery storage (lithium-ion) is 122 percent. As noted earlier, this impact on battery storage costs does not consider the fact that China has been flagged as a FEOC. Under preliminary guidance, battery storage developers will need to demonstrate that the majority of their capital expenditures are not sourced from Chinese suppliers, or else risk forfeiture of federal tax credits. These impacts were not yet captured in the analysis presented in the ALJ Ruling.

In addition, wind resources are also affected by recent federal policies delaying or cancelling projects sited on federal land or seeking federal permits. The near-term onshore wind pressures are factored into the base case onshore wind development, but some consideration of impacts on extended offshore wind development timelines are also included in the recommendations for the base case portfolio. The recommended 2026-2027 TPP sensitivity portfolio considers the impact that federal policy could have on both onshore and offshore wind development. Regardless of federal policy changes, it is important to note that offshore wind is not optimally selected in least-cost modeling and its inclusion in recent TPP portfolios relies on previously-planned LSE resources included in their individual IRPs filed in 2022. In addition, the supply chain for wind turbines is assumed to be relatively insulated from many of the recent federal policy measures.

Other updates to the RESOLVE inputs for the 2026-2027 TPP include:

- Updates to the solar, wind, and near-field enhanced geothermal systems (EGS) resource potential;
- New transmission cost adders for out-of-CAISO wind and geothermal resources in Northeast California and the Imperial Valley;
- Full representation of Deep EGS on CAISO transmission deliverability constraints; changes to the retention costs of existing thermal units; and
- Corrections to the offshore wind hourly generation profiles.

3.1.1. Comments of Parties

Numerous parties made specific comments about the modeling assumptions, including about the RESOLVE model itself, transmission constraints, load forecasts, build limits, cost assumptions, and resource-specific assumptions.

Concerns about the RESOLVE model include AReM advocating to use the SERVIM model to investigate whether RESOLVE's low marginal ELCCs are accurate. EDF-NA suggests constraining RESOLVE and SERVIM assumptions to align with current resource adequacy rules. NextEra supports the RESOLVE model updates to disaggregate zonal topology and match RESOLVE zones to CAISO study areas.

On the topic of transmission constraint assumptions, AReM comments that the level of new-resource build within the base case is infeasible due to transmission constraints and would strain ratepayer affordability. AReM also argues that imports during peak demand hours should be based on an analysis of available imports, not an arbitrary 4,000 MW cap.

NextEra is particularly concerned with the East of Pisgah area, arguing that transmission constraints there are unreasonable and inconsistent with busbar mapping principles. They recommend forcing in a new 500 kilovolt (kV) line to be built in the 2036 timeframe, along with assuming that the new 500 kV Lugo-Victorville line is built by 2036. NextEra urges the Commission to work closely with the CAISO to accelerate the transmission solutions for Path 15 and Path 26 and to incorporate advanced grid technologies as part of the optimal long-term strategy.

SCE supports the addition of Path 26 upgrades as candidate resources in RESOLVE. SCE also recommends additional potential transmission corridor upgrades, expansions, and new build be included in future iterations of RESOLVE. PG&E agrees and specifically requests that Path 15 upgrades be considered for future iterations. Vineyard agrees, and is specifically concerned that Central Coast wind is being overvalued compared to North Coast offshore wind, because of the lack of modeling of the Path 15 South-to-North constraints. Invenergy disagrees with this, however, arguing that any potential limitations imposed on Central Coast resources by the Path 15 constraint will also limit North Coast transmissibility to any load centers below the constraint.

Several other parties had specific comments on load forecasts and the availability of imports. ACP-CA argues that maximum import capability requests from LSEs should be incorporated into modeling earlier. ACP-CA also argues that the availability of uncontracted/unspecified imports should be reduced or eliminated. VoteSolar further explains that data centers could locate in lower-cost states such as Oregon and Arizona, plus hydroelectric availability is impacted by drought conditions; both situations would reduce the availability of surplus generation to export to California from those states.

AReM states that the demand forecast reflects too high an estimate of data center load growth. Shell also suggests that the load forecast is uncertain and reliance on it is flawed.

Other parties comment on build rate assumptions. Fervo states that geothermal build limits should align with commercial development and build limits on out-of-state Deep EGS should be removed. NextEra comments that annual build limits on in-state wind through 2030 are a reasonable proxy, but post-2030 build limits are still too high and unsupported. NextEra includes discussion of local moratoria, California condor protections, fire threats, and military training routes. CalWEA disagrees, focusing on the fact that several wind developments are currently in progress, including fully contracted projects, demonstrating market viability. CalWEA also specifically refutes NextEra's comments point by point, arguing that NextEra's conflict maps are overly broad. CalWEA also notes that out-of-state wind projects face similar hurdles in terms of Federal policy changes compared to California wind projects. PG&E, SCE, and GreenGen all state that build rates in general are overstated and should be better grounded in historical performance and market data.

On the topic of portfolio cost assumptions, several parties had specific comments. EDF suggests that the forthcoming Western regional electricity market is likely to result in a reduction in the cost of out-of-state generation. GreenGen suggests that certain key assumptions are optimistic and risk overstating the near-term build feasibility and understating the costs of the portfolios. OWC suggests that the offshore wind cost assumptions should include a greater anticipated reduction as deployment increases globally. Fervo points to the NREL ATB binary advanced case as the correct source for EGS cost assumptions.

Several parties also commented on assumptions related to solar and storage resources. Form requests that we more specifically analyze the transmission-related benefits of LDES and multi-day storage, guided by updated marginal ELCCs. LDES Council also states that the modeling did not include the full benefits of multi-day LDES. NextEra recommends that resource selection be geographically diverse and robust to changes in solar cost and resource performance assumptions, noting potential changes in cost assumptions that could drive major portfolio differences.

Some parties also expressed concerns about the wind resource assumptions. CalWEA states that the complex approach used by staff underestimates capacity factors of wind in at least some areas. CalWEA argues that the net capacity factor for Northern California wind resources should be 30-35 percent, instead of the staff-calculated 26 percent. Invenergy suggests using the existing offshore wind leases in the planning assumptions. Vineyard is also concerned about the reduction in capacity factors for offshore wind on the North Coast. SCE agrees with extending the online date assumptions for offshore wind, but urges annual reexamination of these assumptions.

Other parties commented on the assumptions related to natural gas capacity retention. CRC suggests adding 1-2.5 GW of carbon capture and storage (CCS) projects to the portfolio, given that retrofits are easy, quick, affordable, mature, and scalable to meet GHG goals. Calpine and PG&E also suggest modeling CCS projects as candidate resources. IEP agrees, and comments that the Commission should not assume that all MTR procurement is achieved. CEJA and Sierra Club argue that natural gas cost assumptions should be updated to reflect the increased costs of contracting seen in the resource adequacy benchmark data, reliability must-run contract expenses, increasing methane fuel

costs, and non-energy costs. CRC disagrees with CEJA and Sierra Club, arguing that the resource adequacy prices do not reflect underlying cost increases, but rather market supply and demand.

Numerous parties also commented on the impact of Federal policy on the assumptions. CalWEA suggest that we should assume that wind and solar tax credits will be restored by 2029, noting that Congress has retroactively restored tax credits many times in the past. Invenergy agrees and would prefer that assumptions about federal tax policy not be embedded in modeling beyond 2028. DOW recommends planning for low-conflict siting of renewables to avoid potential federal conflicts. MGRA recommends frequent re-assessment of assumptions based on changing Federal policy.

3.1.2. Discussion

As is typical in each annual TPP cycle, parties have suggested numerous changes and improvements that are not feasible to be implemented in the timeframe available to us before transmitting the TPP portfolios to the CAISO for analysis, based on their tariff deadlines. However, also as in previous years, we intend to take into account parties' constructive suggestions for use in future TPP cycles and other analyses.

The particular suggestions we are interested in exploring for next year's TPP include the addition of Path 15 upgrades to be considered in future iterations of RESOLVE, similar to the addition of Path 26 upgrades this year. This is a critical transmission corridor that has large impacts on the ability to transfer electricity between the Northern and Southern parts of the state. Thus, we will ask staff to work on this improvement.

We also continuously evaluate our import assumptions to take into account changing conditions relative to historical patterns. We generally agree

with AREM that the import assumptions should be based on recent patterns in imports, but would not go so far as ACP-CA suggests to eliminate availability of imports for modeling purposes. Similarly, we will continuously update our assumptions relative to load growth projections, particularly as they relate to data center development and electrification. In addition, we also agree with PG&E, SCE, and GreenGen who suggest historical analysis of build rates for various types of resources, to inform those limits in the modeling. We will reevaluate those assumptions for next year's TPP as well. Also in the category of ongoing evaluation will be assessment of Federal policy impacts on the portfolio in general.

With respect to specific resource assumptions, there are two in particular to which we will pay close attention. The first is the capacity factor for onshore wind. In addition, we will ask staff to prioritize modeling CCS projects as candidate resources for the next TPP cycle, as this technology appears to be becoming a more viable option that should be modeled and evaluated.

Finally, we will continue monitoring progress toward MTR requirements, so that future TPP portfolios continue to reflect the reality of LSE procurement as much as possible.

3.2. Base Case Portfolio

The ALJ Ruling presented a proposed base case portfolio for the 2026-2027 TPP that includes approximately half of the upper bound of the LLT resources considered for central procurement by DWR in the need determination adopted in D.24-08-064, per AB 1373 (Stats. 2023, Ch. 367). The proposed base case in the ALJ Ruling included the new resource amounts shown below in Table 6. Table 6 includes values for model years 2031 and 2045, even though those results are not required for CAISO TPP analysis. The proposed base case also retains the

amount of offshore wind that LSEs reported in their November 2022 individual IRPs and as was included in the 2025-2026 TPP base case portfolio. However, the proposed 2026-2027 TPP base case assumes that the 2.9 GW of offshore wind in Morro Bay would come online by no later than 2036 rather than 2032, and that the 1.6 GW in Humboldt would come online by no later than 2041, rather than by 2035.

The recommended base case portfolio intends to provide the CAISO information it needs to study the transmission needed for the other non-offshore-wind resources that are needed in the nearer term in California.

Table 6. New Resources Included in 2026-272 TPP Proposed Base Case (in GW)

Resource Type	2031	2036	2041	2045
Natural Gas	-	-	-	-
Geothermal	1.2	3.4	3.4	3.4
Enhanced Geothermal	-	1.7	1.7	1.7
Biomass	-	-	-	-
In-State Wind	2.0	2.6	4.8	7.7
Out-of-State Wind	5.5	7.0	17.0	19.0
Offshore Wind	-	2.9	4.5	4.5
Solar	35.9	47.5	53.7	68.5
Li-ion Battery (4-hr)	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	10.0	13.2	13.2	18.6
Location-Constrained Storage (12-hr)	1.6	5.4	5.4	5.4
Generic LDES (12-hr)	-	-	-	-
Generic LDES (24-hr)	-	0.5	0.5	0.5
Generic LDES (100-hr)	-	-	-	-
Shed Demand Response	-	-	-	-

Resource Type	2031	2036	2041	2045
Gas Capacity Not Retained	(1.7)	(1.7)	(1.7)	(1.7)
Total	61.3	89.3	109.3	134.4

3.2.1. Comments of Parties

In comments in response to the base case portfolio recommendation, numerous parties showed general support in their comments, including CAISO, GSCE, EDF-NA, CEJA/Sierra Club, REV, GreenGen, SCE, SDG&E, GridLiance, and LSA/SEIA. CEJA and Sierra Club generally support the base case recommendation, particularly the decision to model the possibility that half of the LLT capacity is delayed to 2031. GridLiance agrees with the Commission's assessment of the limited in-state wind buildout in the base case portfolio. GreenGen supports the adoption of the recommended base case, but recommends incorporating into the base case transmission deliverability for LLT resources that is freed up from the delay of offshore wind development. SCE agrees with extending the online date assumptions, but urges Commission staff to update the assumptions annually. CalWEA, in reply comments, agrees with CEJA and Sierra Club support of the base case, but points out that onshore wind energy, even without tax credits, has been and continues to be one of the most affordable clean energy resources.

Numerous parties disagree with the idea of delaying transmission planning to support offshore wind on the North Coast beyond 2036. CalCCA suggests maintaining the amount of in-state and offshore wind in previous TPP portfolios to maintain consistency and limiting out-of-state wind in the base case to the amounts supported by the SWIP-North, TransWest Express, and Sunzia

transmission lines. EPIC suggests that North Coast and Central Coast offshore wind should be projected to come online at the same time.

OWC states that delaying online dates for transmission planning could jeopardize timeline-specific offshore wind goals; OWC suggests that federal permits could be delayed for several years but the online dates in 2035 could still be achievable. Vineyard is concerned that pushing back the offshore wind online dates sends mixed signals to the market about the Commission's commitment to clean energy and incorporating offshore wind in the portfolio. EDF is also concerned that the offshore wind industry is at an inflection point, and the change in assumptions for online dates could cause a significant chilling effect that would not be in the interest of ratepayers. CalGrid also argues against pushing back the online dates for offshore wind, in part due to the need for other resources, including geothermal and in-state wind, to utilize the transmission being developed to serve the offshore wind projects. Vineyard argues that the shift in the online date for North Coast wind fails to capture the Humboldt (transmission) Projects' timeline, which are on track to begin delivering power in the mid-2030s.

CalGrid also argues that the CAISO agreements for the Humboldt Projects include provisions not to incur any major costs in connection with the transmission development without the express written approval of the CAISO, which CalGrid states will ensure that the transmission facilities can continue to move forward, with protections in place for ratepayers before major expenditures are made.

ACP-CA and Oceantic also want to keep the North Coast wind assumption to being online by 2036, while Invenergy, in reply comments, argues that North Coast wind cannot feasibly come online in the mid-2030s. RCEA and

Humboldt County question why North Coast offshore wind development is delayed by six years, while Central Coast is delayed only by four years.

CalWEA states that planning for only 4.5 GW of offshore wind by 2041 leaves no room for additional development by 2045 in order to achieve economies of scale on cost. NRDC is concerned that changing the assumptions is premature and unsupported.

Several parties argue for alternative treatment of offshore wind in the 2026-2027 base case portfolio. CUE and CURE suggest retaining the online dates used in the 2025-2026 base, but planning for various resource options to ensure that California has the necessary resources and transmission infrastructure to get the resources online no matter the uncertainty, including development of the Valley Clean Infrastructure Plan.

Several parties argue that the base case should include even higher penetrations of various LLT resources, including offshore wind and multi-day storage, including NRDC, Oceantic, EDF, LDES Council, Invenergy, Mainspring, and SBUA. NRDC would include the full amount of LLT resources in the D.24-08-064 need determination, because the first tranche of procurement will be more expensive on a per-unit basis than subsequent tranches, and the full amount is needed to bring about economies of scale and cost reductions. EDF agrees in reply comments. Also in reply comments, SBUA suggests that this is important also for purposes of making optimal use of transmission and port investments.

Oceantic also suggests that including the full amount of the D.24-08-064 need determination in the base case is important to maintain a signal of continuity. Invenergy suggests that the Commission retain the full need

determination of 7.6 GW of LLT resources in D.24-08-064 in the base case, or the potential for up to 10 GW of offshore wind.

On the opposite end of the spectrum, some parties argue that there should not be any resources forced into the RESOLVE model. WPTF recommends excluding any planned DWR procurement, as no such procurement has yet taken place. CESA suggests that the base case should align with the least-cost comparison portfolio or, at a minimum, one that avoids forcing in the offshore wind volumes. PG&E prefers that the base case be based on the least-cost portfolio. In reply comments, CalWEA agrees with PG&E and CESA about the realistic ability of offshore wind to come online in the previous timeframes, and recommends that the Commission postpone the decision for at least a year on this question.

A number of parties proposed alternative portfolios to use as the base case portfolio. CalCCA recommends modifying the base case portfolio to use a more conservative forecast of data center load, to minimize the risk of building transmission for load that may not materialize. Vote Solar disagrees in reply comments, noting that there are countervailing trends that suggest that the proposed base case portfolio may actually underestimate the need for new reliability resources.

CalCCA also suggests maintaining the amount of in-state and offshore wind included in the previous TPP base case, but limiting out-of-state wind due to the CAISO's stated challenges with out-of-state wind integration. CalWEA would replace the offshore wind capacity with in-state, onshore wind capacity, to maintain the resource diversity provided by wind energy without excessive reliance on out-of-state wind.

CalGrid recommends distributing the offshore wind resources more evenly across the North Coast and Central Coast areas in 2036, given that the Humboldt Projects have already been approved in the CAISO's previous TPP. They argue this would also provide optionality in the event that DCPD remains operational, thereby reducing transmission capacity available for Morro Bay offshore wind.

SCPA and PCE suggest adopting the Limited-Wind Sensitivity portfolio as the base case, because the proposed base case relies too heavily on both out-of-state and offshore wind resources that are highly speculative. Reid agrees, and both EPIC and ACP-CA disagree, in reply comments.

CEJA and Sierra Club argue that the base case portfolio should include significant reductions in natural gas generation to comply with SB 887 (Stats. 2022, Ch. 358). CalWEA agrees in reply comments.

AREM generally argues that the Commission should model and adopt portfolios with reasonable levels of resource build to reduce the cost of the portfolios for consumers.

Several parties also argue that the GHG emissions targets should be altered in the base case. Cal Advocates argues that the Commission should model a new portfolio with a GHG emissions target of 30 MMT by 2035 en route to an 8 MMT target by 2045. Further, Cal Advocates would test the reliability of that portfolio in SERVIM and add resources, if necessary, to meet the 0.1 LOLE target.

AREM suggests that the base case should not have more aggressive GHG emissions reduction targets than current legislative requirements. PG&E suggests that the Commission reconsider whether the rationales underlying the 30 MMT target in 2030 continue to hold. SCE supports this view in reply

comments. SDG&E also states, in reply comments, that the Commission should adjust the GHG target to 38 MMT in 2035 to mitigate the need for an improbably high solar buildout.

Parties also raised various resource-specific concerns. Calpine argues generally that the base case portfolio should include a more diverse set of resources.

CalWEA argues that the 2.6 GW of in-state wind in 2036, down from 7.9 GW in 2035 in the 2025-2026 TPP base case is too low. Meanwhile, CalWEA suggests that the Humboldt Projects for transmission should be put on hold because the likelihood of achieving even 2.9 GW of offshore wind by 2036 is low.

BAC points out that there is no biomass capacity included in any of the portfolios, even though biomass is required by multiple state laws. RCEA and Humboldt County point out that biomass capacity should be included to help mitigate wildfire risk, especially in Humboldt County, where biomass is abundant. CalGrid, in reply comments, further argues that biomass facilities could use the transmission that will be made available by the Humboldt Projects.

In reply comments, Mainspring argues that the base case should include “firm zero-emitting ready” generation like green hydrogen resources.

Several parties also express concern about assumptions including high penetrations of solar resources in Arizona. DOW argues that the base case is overly-reliant on Arizona solar and there should be greater emphasis on in-state solar in the San Joaquin Valley. TNC and Cal Advocates make similar arguments, and CBD agrees, in reply comments. Also in reply comments, DOW argues that heavy reliance on out-of-state resources defers approval of needed in-state infrastructure that will be critically needed should out-of-state resources fail to materialize and meet expectations.

GridLiance also questions an “unreasonably” high concentration of solar in Arizona. PG&E recommends that the Commission cap the amount of Arizona solar at an amount that can be feasibly imported into the CAISO system, given that new out-of-state transmission is considerably more challenging to plan for than in-state transmission. CalWEA agrees in reply comments and notes that in-state wind is an important resource to meet GHG targets.

3.2.2. Discussion

To begin our consideration of the appropriate base case portfolio, we emphasize that the purpose of this scenario is for prudent transmission planning. Each year, the Commission studies a portfolio of resource attributes that the state could develop to cost-effectively and reliably serve load and meet state GHG emissions reduction goals, which the CAISO studies in its annual TPP cycle for least-cost system planning for incremental transmission needs. For this cycle, we choose this base case portfolio as a realistic portfolio for purposes of transmission studies.

In light of recent changes in Federal policy, the Commission’s TPP portfolio will reflect some extensions to resources, including for offshore wind, compared to our expectations last year. The assumptions proposed in the ALJ Ruling included Central Coast offshore wind coming online by no later than 2036, and North Coast offshore wind by 2041. It is important to note that this does not mean the entire volumes in each location would be delayed completely until those dates. Rather, the projects, or a portion of them, may come online on the Central Coast during the period 2032 through 2036, with North Coast projects taking slightly longer and coming online between 2036 and 2041. We note that CAISO’s latest analysis states that, even with DCPD online, approximately 3,000 MW of Central Coast offshore wind could be

accommodated using current transmission capacity.²² The longer timeline for the North Coast is due primarily to the transmission upgrades needed to deliver those projects to load.

We note that parties provided a number of generally conflicting comments about the proposed base case. There are inherent tradeoffs no matter which base case we choose. In general, we do not wish to make changes to the load forecast assumptions for the base case, because it is important to maintain continuity and the principle that we base our load assumptions on the most recent IEPR load forecast, consistent with the MOU between the CEC, CAISO, and the Commission, which commits these entities to relying on a single forecast set. Since the load forecast is updated every year, this is an assumption that is under constant reevaluation, but we will not further deviate from it in choosing a base case. Consistent with SB 350 (Stats. 2015, Ch. 547), the Commission uses the GHG reduction targets established by the California Air Resources Board (CARB) and previously adopted by the Commission in our IRP processes. Thus, we will stay the course with the 25 MMT target in 2035 and adopt an 8 MMT by 2045 target, as the emissions reduction trajectory.

Thus, we find that the proposed base case in the ALJ Ruling that includes approximately half of the AB 1373 LLT resources for which need was found in D.24-08-064, achieves a reasonable balance among the various options recommended by parties, and will result in usable transmission planning information, which is the ultimate purpose of the base case.

This leaves the situation where offshore wind on the Central Coast is assumed to come online between 2032 and 2036, with North Coast offshore wind

²² CAISO 2024-2025 Transmission Plan at 19.

expected to arrive between 2036 and 2041. The Humboldt transmission projects currently have in-service dates of June 1, 2034, and some parties have suggested that if the offshore wind generation projects come online later, the transmission potentially could or should also be delayed. After consideration of the generation timelines in the base case, we agree that extending the in-service date for the Humboldt transmission projects is reasonable and would still have transmission available for when offshore wind generation is anticipated to begin to become available. Thus, we recommend to the CAISO that they allow the potential in-service dates for the Humboldt transmission projects to extend out to June 1, 2036.

There are several types of ratepayer protections proposed for the Humboldt transmission projects, as explained in the CAISO's public selection reports identifying CalGrid, a wholly-owned subsidiary of Viridon Holdings, LLC, as the approved project sponsor for both projects. We also expect there will be additional opportunities to reevaluate the transmission projects before construction commences, after at least one solicitation has been held for offshore wind generation projects, as called for in D.24-08-064.

In addition, in D.25-02-026, our decision recommending the 2025-2026 TPP portfolios, for the first time we recommended that the CAISO reserve transmission deliverability for several types of LLT resources, including geothermal, biomass, offshore wind, out-of-state wind, in-state wind and locationally-constrained non-battery LDES. The CAISO largely implemented these recommendations, with two exceptions. First, biomass was assessed to be too locationally diffuse for deliverability to be specifically reserved. Second, in-state wind was not deemed to have a long lead time by the CAISO, because its development timeline is similar to other resources and there are already

numerous projects in the interconnection queue. We recognize this is a change in the recommendations from the previous TPP which asked for deliverability reservations for a larger range of diverse resources. With this decision, we are focusing on LLT resources, in part due to the lead-time associated with the development of additional transmission, rather than just the time to develop the resource itself.

In comments, stakeholders have expressed difficulty in bringing locationally-sensitive technologies online and argue that many LLT resources benefit from deliverability reservations. The CAISO has also demonstrated willingness to include technologies for deliverability due to the lack of presence in the queue and their importance to meet reliability and resource diversity needs. Thus, for the most part, we will continue our recommendations for LLT transmission deliverability to be reserved in this year's TPP. Specifically, we recommend that deliverability be reserved for all of the geothermal reservations made in the 2025-2026 TPP, as well as the in-state geothermal resources selected in this year's base case, as well as all of the non-lithium-ion-battery LDES selected in this year's base case.

In response to comments on the proposed decision, we are requesting that the CAISO allow in-CAISO transmission upgrades to be triggered by additional mapped out-of-state wind (1.5 GW of New Mexico wind and 1.5 GW of Wyoming wind) and the additional mapped out-of-state geothermal above the levels in the 2025-2026 TPP. In addition, we request that the CAISO reserve deliverability for out-of-state wind above the reservations made in the 2025-2026 TPP. The new deliverability reservations will continue to be reassessed in each subsequent TPP cycle to allow for prudent planning and transmission development.

Overall, the requested levels of deliverability to be reserved, compared to previous recommendations, are shown in Table 7 below. Deliverability reservations requested by substation are available in the busbar mapping dashboard displayed on the Commission’s web site.²³

**Table 7. Transmission
Deliverability Reservations by Year (in MW)**

Resource Type	2024-2025 TPP (2034) Reserved	2025-2026 TPP (2035) Requested	2025-2026 (2035) Draft TPP Reserved	2026-2027 (2036) TPP Mapped	2026-2027 TPP (2036) Requested Reservation
Biomass	-	171	-	-	-
Geothermal	950	1,639	1,639	5,105	3,177
LDES	-	1,264	1,264	5,948	2,642
In-state wind	-	5,589	-	1,743	-
Out-of-state wind	5,699	5,699	5,699	7,036	7,036
Offshore wind	3,855	4,531	4,531	2,924	4,531

Finally, returning to the selection of the base case, we note some parties’ concerns about specific resource issues and assumptions. The issue we are most concerned about is the assumed solar build rate to achieve the base case. We also understand the concerns about the concentration of resources, particularly solar, outside of California and agree with parties who point out that those resources may be more difficult to develop, particularly because they require additional transmission development. Planning for those transmission resources is already

²³ See the detailed TPP portfolio busbar mapping dashboards available at the following link: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2024-26-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp>.

underway with the results of past TPP analyses, and adopting this base case for 2026-2027 will maintain continuity and hopefully continue to move those transmission planning efforts forward.

3.3. Sensitivity Portfolio

The ALJ Ruling recommended that the Commission transmit one sensitivity portfolio to the CAISO for study in the 2026-2027 TPP. The recommended sensitivity portfolio is a Limited Wind Sensitivity, designed to reflect the recent increased difficulty of permitting wind projects in California and the recent changes in Federal policy toward wind projects. The sensitivity is intended to study how transmission needs would differ if recent PSP portfolios and prior TPP portfolios change over time to include fewer wind resources for reasons generally outside of California's control. Table 8 summarizes the new resource buildout results for the recommended sensitivity portfolio, including forced-in, LSE-planned, and RESOLVE-selected resources, above and beyond the RESOLVE modeling resource baseline.

In the recommended sensitivity portfolio, in-state wind development is limited to 2.5 GW, out-of-state wind is limited to the amount available on existing transmission where the CAISO has rights, and LSE-planned offshore wind from their November 2022 individual IRPs is excluded. These assumptions result in the portfolio selecting all of the conventional geothermal potential, as well as a significant amount of EGS. Solar and storage resources are also selected at very high levels, and the portfolio includes a smaller amount of natural gas retirement.

Also included in the ALJ Ruling were two other potential sensitivity portfolios that were evaluated but not recommended. The first was a DCP Extension Sensitivity, which modeled DCP as receiving a 20-year extension

through 2045. The second alternative sensitivity portfolio set GHG reductions to 25 MMT of emissions in 2035, and then held the target constant until 2045.

Table 8. New Resources Included in Proposed 2026-2027 TPP Sensitivity Case (in GW)

Resource Type	2031	2036	2041	2045
Natural Gas	-	-	-	-
Geothermal	1.2	3.4	4.7	5.6
Geothermal (enhanced)		3.6	3.6	3.6
Biomass	-	-	-	-
In-State Wind	0.9	0.9	2.5	2.5
Out-of-State Wind	4.0	4.0	5.1	5.1
Offshore Wind	-	-	-	-
Solar	37.5	48.6	67.6	83.2
Li-ion Battery (4-hr)	6.8	6.8	6.8	6.8
Li-ion Battery (8-hr)	12.1	17.7	17.7	26.9
Location-Constrained Storage (12-hr)	1.6	5.7	7.5	7.5
Generic LDES (12-hr)	-	-	-	-
Generic LDES (24-hr)	-	-	-	-
Generic LDES (100-hr)	-	-	-	-
Shed Demand Response	-	-	-	-
Gas Capacity Not Retained	(1.2)	(1.2)	(1.2)	(1.2)
Total	62.9	89.5	114.3	140.0

3.3.1. Comments of Parties

Many parties either support or do not object to the proposed Limited Wind Sensitivity portfolio. GreenGen, GSCE, SDG&E, and EDF-NA support the proposed sensitivity portfolio. CAISO also supports the recommendation, stating that it will ensure system reliability and alignment with state goals, if increased solar, storage, and geothermal development is required. MRP supports the intent

of the sensitivity portfolio, but notes the unrealistic build rates for other resources caused by the lack of wind development. AReM does not object, but is also concerned about the total resource build being potentially unreasonable.

TNC, VoteSolar, and DOW support the analysis of the Limited Wind Sensitivity, in light of recent Federal policy shifts.

SCE supports the development of the Limited Wind Sensitivity portfolio, but is concerned about the significant difference in the post-2035 out-of-state wind buildout between the proposed base case and sensitivity cases.

SCPA and PCE suggest that in addition to assessing the limited wind availability in the sensitivity portfolio, the portfolio should also be tested for increased load, limited geothermal and PSH availability, and higher resource costs.

GridLiance supports conveying a sensitivity portfolio to the CAISO with limited wind development, in part because it would substantiate what GridLiance characterizes as the critical need to address transmission constraints in the Victor-Lugo corridor.

LSA and SEIA endorse the characterization of the Limited Wind Sensitivity as a plausible alternative to the base case scenario and encourage the CAISO to approve no-regrets transmission upgrades that can serve both portfolios.

In contrast, several other parties do not support the Limited Wind Sensitivity. EPIC does not believe it is a realistic alternative portfolio and therefore does not support studying it. OWC states that the Limited Wind Sensitivity contradicts state policy, is not a “least regrets” strategy, and is flawed because RESOLVE has faulty cost assumptions for offshore wind, failing to

account for anticipated long-term cost reductions in the coming decade as more offshore wind is deployed.

Invenergy argues that the portfolio is not reasonable and the impacts to the portfolio due to Federal policy are not durable and planning for them to be so will prevent the selection of necessary transmission upgrades.

Calpine does not support the sensitivity recommendation, instead arguing that the Commission should study limited amounts of wind, solar, and storage to better understand how other resource types could meet clean energy goals. PG&E also does not support the sensitivity portfolio, because the increased solar build rates in it are even less feasible than the current base case.

ACP-CA states that it cannot support either a Limited Wind Sensitivity or the Diablo Canyon Sensitivity that was also considered but not recommended by Commission staff.

CalWEA strongly opposes the proposed Limited Wind Sensitivity, arguing that the analytical basis for it is entirely lacking and that it would add almost \$11 billion in costs by 2045 at a time when electricity affordability is already a major state concern.

CEJA and Sierra Club suggest that the Commission work to remove obstacles to wind development rather than plan for its failure. They argue that wind is still more affordable than other resources and the capacity is valuable. Rather than running the Limited Wind Sensitivity, CEJA and Sierra Club recommend studying another sensitivity with high natural gas retirements. EDF agrees in reply comments, though does not oppose the Limited Wind Sensitivity. They also suggest running such a scenario, with updated assumptions, every 2-3 years, incorporating results from previous "high gas retirement" portfolio analysis.

Several other parties suggested alternative lower-cost sensitivity portfolios to be studied instead of the recommended Limited Wind Sensitivity. MGRA suggests simply studying the least-cost portfolio. CalWEA recommends a sensitivity where Federal tax credits are restored in 2029, to inform whether to include higher levels of in-state wind in the 2036 portfolio.

TNC supports west-wide energy resource sharing and regionalization, and suggests studying a scenario where regional renewable investments are pursued.

CalCCA suggests studying a scenario that has a combination of high wind penetration and high data center load. PCE recommends studying a high distributed energy resource (DER) scenario, to determine how much it could lower portfolio and transmission costs. CCSA agrees in reply comments.

CRC recommends including carbon capture and sequestration in the portfolio instead of studying the scenario where GHG targets are relaxed after 2035, in order to lower costs while still achieving GHG goals.

PG&E disagrees with the assertion that the Diablo Canyon extension sensitivity portfolio would not be useful for the CAISO or the Commission. They argue that the results of modeling this scenario would be informative to understand the reduction in transmission upgrades required as compared to the base case portfolio. Calpine supports this viewpoint in reply comments. ACP-CA responds to these comments by suggesting that there be a sensitivity portfolio that examines the transmission upgrades necessary to accommodate both DCPD remaining online through 2045 and the addition of the clean energy resources included in the base case, particularly Central Coast offshore wind.

3.3.2. Discussion

One of the most important reasons to ask the CAISO to study a sensitivity portfolio is to learn information about the transmission needs of the portfolio

that would otherwise go unidentified in studying the base case portfolio. In the past few years, the Commission has asked the CAISO to study portfolios that explore transmission needs both in the absence of certain resources (*e.g.*, natural gas generation) as well as in the event of an abundance of certain resources (*e.g.*, offshore wind).

The staff-recommended Limited Wind Sensitivity under consideration for the 2026-2027 TPP is another portfolio that would study the absence of a certain resource (wind energy generally) with the purpose of understanding the transmission needs that would arise in that circumstance. This sensitivity is more expensive than the base case portfolio and would place a higher burden on California ratepayers compared to other options, but is selected for study to elicit critical transmission planning information. Of the potential sensitivity portfolios evaluated, the Limited Wind Sensitivity represents the portfolio that would provide the most information about transmission needs. The Diablo Canyon scenario is not as helpful for transmission planning as it is for creating an opportunity to compare the mix of resource attributes that would be selected with extended inclusion of an existing, clean, firm resource that utilizes existing transmission. In addition, the alternative sensitivity portfolio where the GHG target would be held steady after 2035 would also not tell us a great deal about transmission needs.

Thus, for this year, we find it reasonable to ask the CAISO to study the Limited Wind Sensitivity portfolio. This represents a portfolio that could result from recent Federal policy changes. We note that a better outcome would be continued robust development of all types of cost-effective wind resources that are needed to serve load and meet state goals, especially since wind can provide resource diversity and provide a higher capacity resource to meet increasing

winter loads in the outer years of the planning horizon. We also note CalWEA's comments that the Limited Wind Sensitivity portfolio is estimated to be a lot more expensive than the base case, but we are recommending it for study by the CAISO because it is a useful portfolio to analyze potential transmission planning needs.

It is important to understand how even near-term policy changes at the Federal level could slow wind deployment and result in the need for contingency planning. We agree with LSA and SEIA that it will be interesting to evaluate the transmission resources that are identified both for the base case and for the Limited Wind Sensitivity portfolios, and we encourage the CAISO to place increased emphasis on developing any transmission projects identified that are needed for both portfolios. We also encourage the CAISO to use the sensitivity portfolio analysis to identify cost-effective upgrades and enable right-sizing, including looking at any possible avoided upgrades, of the transmission portfolio overall, as requested by SCPA and SJCE in comments on the proposed decision.

For transmission planning beyond the 2026-2027 TPP, we will consider other parties' numerous recommendations for other sensitivity portfolios to be analyzed.

3.4. Addressing High Solar and Storage Build Rates Implied in Base Case and Sensitivity Portfolios

The ALJ Ruling noted that both the recommended Base Case and Sensitivity portfolios include a massive amount of solar, and to some degree storage, buildout between now and 2045. Given recent development pace, it could take extraordinary efforts to achieve the build rates implied in both

portfolios. Numerous parties addressed this challenge in their comments and had suggestions for how to approach it.

3.4.1. Comments of Parties

More than 25 parties addressed this issue in their comments and presented a diverse set of potential actions that could be taken. We have grouped the potential solutions into eleven different categories described below.

The first set of actions relates to reforming and expediting transmission, interconnection, and permitting processes. The majority of parties commenting in this category suggest simply approving more transmission development. SCPA and PCE request more expansive transmission investments from the CAISO through robust portfolios and “right-sizing” that allows more flexibility for resources to interconnect. GSCE recommends approving the solar capacity amounts identified in the ALJ Ruling and relaying to the CAISO the need to approve the associated transmission. LSA and SEIA recommend that the Commission and CAISO establish a process allowing CAISO to conditionally approve transmission upgrades based on the highest projected resource buildout levels, to the extent allowed by the CAISO tariff. Terra-Gen recommends increasing deliverability to the East of Pisgah area and promoting projects with shorter development timelines. CalWEA agrees in reply comments. TNC suggests evaluating expanding existing transmission capacity with advanced transmission technologies, in addition to building new lines, particularly when planning projects connecting Southern California solar to Northern California load. TNC focuses on studying where transmission can be upgraded to make use of existing and future solar resources. ACP-CA states that the high solar build rate is achievable and emphasizes that timely transmission development is key for achieving it.

For the second set of actions, many parties comment in favor of selecting more distributed solar rather than utility-scale solar. CCSA recommends studying a new sensitivity portfolio that includes dispatchable FTM load-modifying solar and storage projects connected to the distribution grid, to more fully examine the extent to which load-modifying DERs, inclusive of their avoided transmission and distribution benefits, can be part of a least-cost portfolio. CEJA and Sierra Club suggest a high DER sensitivity to identify potential tradeoffs between distributed solar deployment and associated demand-side tools compared to utility-scale resources, due to permitting uncertainty associated with utility-scale resources. DOW similarly urges the forced selection of distribution-connection solar, arguing that it would mitigate land-use limitations and avoid transmission and interconnection delays. VoteSolar brings up the role that virtual power plants and hybrid solar and storage projects interconnected to the distribution grid can play in meeting GHG emissions reduction targets. LSA and SEIA point out the additional benefits of reduced congestion, reduced curtailment, and resource adequacy, particularly with respect to hybrid projects with solar and storage on the same site. TNC generally supports continued study of how to accelerate and maximize deployment of solar on developed land, including distributed solar, in a cost-effective manner. GSCE specifically urges support for the Valley Clean Infrastructure Plan for 20 GW of solar, up to 20 GW of battery storage, and a new 500 kV transmission project in Fresno County.

The third set of actions generally involves selecting a more diverse portfolio. Form emphasizes that high solar build rates reflect the need for better modeling of long-duration and multi-day storage to turn intermittent solar into dispatchable energy and capacity. NextEra argues for greater portfolio diversity

across regions and resource types. Calpine argues that CCS retrofits and other clean firm resources should be incorporated into the portfolio. CalWEA seeks to ensure that the 1.6 GW of wind capacity planned for development in the Baja California area by 2032 is included in the base case analysis. Several parties also note concerns with relying so heavily on an out-of-state solar buildout when in-state resources, such as offshore wind, would be preferable.

For the next set of actions, some parties suggest relaxing the GHG targets, while other parties oppose this idea in reply comments. Cal Advocates suggests redesigning the base case portfolio to focus on a GHG emissions reduction to 30 MMT by 2035 rather than 25 MMT. PG&E suggests assuming a feasible build rate for solar (based on historic levels) and then relaxing the GHG constraint, to determine what emissions levels would result. In reply comments, SCE opposes these suggestions, because they would delay necessary infrastructure investments that are necessary for future reliability and climate goals. SCP also argues that backing off of GHG targets now will only make future portfolios even less achievable. SDG&E generally argues that the Commission has the discretion to select a higher GHG target that would result in a less costly buildout, but DOW opposes this and urges the Commission to stay the course, while utilizing more distributed generation and storage solutions.

A few parties suggest managing and/or reexamining load growth in order to reduce the need for so much resource procurement. AReM suggests using a reduced load scenario while also reassessing the availability of imports to meet needs. AReM would prefer that the GHG targets not go beyond statutory requirements. CEJA and Sierra Club suggest managing data center load growth through large load tariffs. Calpine recommends not relying on a potentially “inflated” load forecast and an “unlikely” DCPD retirement assumption.

Two parties suggest increasing the procurement of storage with energy-only deliverability status, as one potential solution. LSA and SEIA argue that energy-only solar is quicker to develop and less transmission-constrained. They suggest that the Commission work with the CAISO to allow interconnection projects that fail to achieve full deliverability to be converted to energy-only status, to avoid being eliminated from the interconnection queue. LSA and SEIA also suggest working with the CAISO to study the resource adequacy program's charge sufficiency requirement, with the goal of allowing energy-only solar to count towards charging sufficiency for storage within the local capacity area or transmission zone where the solar is located, not just for co-located facilities. GreenGen makes this same point in its comments. In addition, LSA and SEIA suggest bridging the gap between transmission development and offshore wind operations and avoiding stranded transmission assets by allocating energy-only resources to areas where transmission was approved for offshore wind, to address the uncertainty around solar build rates and advance transmission upgrades.

LSA and SEIA also support PG&E's observation that the Diablo Canyon Extension sensitivity is the only portfolio which includes a solar build rate from 2028-2031 that falls within the historic range, demonstrating that DCCP's extension to 2045 would not only solve high near-term solar build rates, but also reduce reliance on out-of-state wind and eight-hour storage, reduce emissions from natural gas, and potentially allow for retirement of additional natural gas units.

LSA and SEIA also suggest prioritizing projects for expedited development that can take advantage of expiring Federal tax credits.

IEP suggests that the Commission and other state agencies coordinate their efforts and increase staffing to meet statutory times for processing.

Finally, a number of parties suggest addressing the short-term build rates of solar by issuing a procurement order to procure more resources sooner. MGRA suggests that the staff analysis shows a need for a procurement order in the near term. EDF-NA suggests that the 6,000 MW need shown in the ALJ Ruling, if ordered for procurement, would be a step toward long-term confidence. SCPA and PCE recommend ordering procurement that allows energy-only projects to contribute to the need and to SOD resource adequacy requirements. UCS recommends raising the RPS requirement higher in the near term.

3.4.2. Discussion

The numerous suggestions of parties described above lead us to consider a number of potential portfolio configurations that could be evaluated in future TPP cycles.

With the exception of the Diablo Canyon extension and relaxed GHG emission targets scenarios, which we evaluated above and have decided not to recommend for the 2026-2027 TPP, many other scenarios are not feasible to create in the time left for this year's portfolio recommendations. However, we intend to consider many of the portfolios that parties recommended, and potentially other scenarios, for the 2027-2028 TPP and/or 2027 Preferred System Plan sensitivity analyses.

We also note that there is a lack of consensus among parties suggesting solutions this year, making it difficult to narrow the options further to one or two portfolios. Next year, we will make efforts to engage parties earlier in the portfolio development process, particularly for sensitivities, because parties

continue to raise helpful perspectives that may help inform future portfolio development.

Parties' comments also stressed the importance of several ongoing priorities. The first is continued efforts to reform the transmission, interconnection, and permitting processes, in concert with the CAISO. This includes efforts to expedite the interconnection of projects that qualify for expiring Federal tax credits. Second is reexamining the modeling assumptions that lead to high selection of solar resources (as we do every IRP cycle).

3.5. Busbar Mapping Methodology

Each year, Commission staff build on the methodology used in the previous year to map generation and storage resources to busbars on the transmission system. This locational analysis helps the CAISO, in its TPP analysis, understand the locations needed for potential expanded and/or upgraded transmission. This year, the following methodology updates were recommended in the ALJ Ruling:

Substation-level interconnection criteria

- Integrating Participating Transmission Owner (PTO) feedback and per-unit cost guide data to estimate the economic feasibility to interconnect at individual busbars. Commission staff coordinated with the PTOs to collect and synthesize interconnection data and feedback on:
 - Existing headroom (before transmission plan deliverability (TPD) allocation);
 - Number of available interconnection positions;
 - Upgrade condition; and
 - Available area within the fence line.
- New criteria are initially used for a subset of busbars that have high demonstrated commercial interest and/or have

- had large mapped total resources from previously-adopted TPPs.
- Data collected from the PTOs is used to estimate interconnection cost for each busbar as a function of PTO, tie-in voltage, and feasibility.
 - Substations with higher interconnection costs, including those that would require extensive upgrades or entire substations to facilitate new projects, will be de-prioritized over less expensive alternatives.
 - Cost estimates across all busbars are categorized to define thresholds for criteria alignments scores.

Land-use and environmental criteria

- Replacing the Commission's High Fire Threat Districts (HFTD) dataset which is no longer being updated, with the U.S. Department of Agriculture Forest Service (USFS) Wildfire Risk to Communities dataset. To assess the fire threat to resources and transmission:
 - The NFTD maps are outdated and will not be maintained going forward, which makes them poor candidates for use in future busbar mapping cycles.
 - Among the alternative data sources reviewed, the 2024 USFS Wildfire Risk maps are a newly-published dataset from a federal agency with nationwide coverage, making it a viable option to replace the current data source.
 - Commission staff classified USFS burn probability data to align with the busbar mapping criteria alignment levels of 1-5.

CEC land-use screens development and implementation

- Updated methodology and sources of land-use and environmental criteria that information environmental evaluation:
 - The CEC Protected Area Layer, one component of the Land-Use Screens, was expanded to include coverage

for CAISO-interconnecting regions of Southern Nevada and Western Arizona.

Commercial development interest

- No specific changes. Commission staff are adding clarification in the methodology document for how interconnection quantity data from neighboring balancing authority areas (BAAs) is used in the commercial interest criteria, due to confusion evidenced in stakeholder comments.

Gas capacity not retained

- Generators located within disadvantaged communities will no longer receive a blanket exemption from non-retention decisions for being among the youngest and/or most reliable units.
- Generators without any local effectiveness factor data from the CAISO Local Capacity Technical Report are now assigned the quartile scoring aligned with the lowest priority for non-retention.

3.5.1. Comments of Parties

Fourteen parties filed comments related to the recommended busbar mapping methodology updates. TNC generally recommends that the interagency busbar mapping working group maintain a public web viewer that displays draft busbar mapping results in their spatial form and allows for the downloading of the same spatial data.

GSCE recommends focusing on in-state transmission development and therefore consider shifting RESOLVE-selected solar from South of Path 26 to the Fresno area.

Several parties expressed specific concerns with the fire threat maps. CalWEA recommends not screening out high-quality wind resource areas based on the updated fire threat maps, because the maps cover too much area to serve as a meaningful screening tool and will de-prioritize most wind resource areas.

BAC suggests relying on Cal Fire's fire hazard maps in addition to, or instead of, the U.S. Forest Service maps. NextEra comments that the fire threat maps should be used to assess resource potential and select mapped resources for not only the project site, but also the necessary gen-tie and new transmission sites. TNC supports the use of the U.S. Department of Agriculture Wildfire Risk to Communities dataset to model fire threats, but notes its coarse resolution and suggests that Commission staff review the latest and best available data as part of the next planning cycle, to ensure that the most recent fires and disturbances are taken into account.

Several parties are also concerned about the land-use criteria. CalWEA recommends not screening out high-wind-speed areas where development is legally permissible based on discretionary GIS layers in the CEC's Core Land-Use Screen. CalWEA also provides statistics on how many existing projects would have been screened out by using these GIS layers.

GridLiance and NextEra comment that the effects of the U.S. Bureau of Land Management's (BLM's) Western Solar Plan in Southern Nevada should not be overstated in the land-use screens.

GridLiance generally states that despite recent news suggesting that solar projects on federal lands may face permitting challenges, GridLiance ultimately believes that a development path on federal lands will be found by the 2036 timeframe of this TPP. In the meantime, GridLiance recommends refining land-use screening to align with actual BLM implementation, recognizing partially exempt and variance-eligible projects, and integrating GridLiance's granular mapping into IRP modeling and busbar mapping.

TNC is generally in favor of extending the CEC's land-use screens to areas in Arizona and Nevada. TNC requests that staff include and publish latitude and

longitude values in the land-use evaluations spreadsheet provided by the CEC and make available environmental layers, specifically Areas of Conservation Emphasis layers, in the Data Viewer tool for the 2025 Draft Updates of Data for CEC Busbar Mapping Assessment. TNC would also like to reshare the geospatial tool that TNC created to better understand various potential resource and transmission scenarios from a land-use and environmental perspective.

Invenergy and SCE express differing views on the interconnection criteria included in the busbar mapping methodology. Invenergy does not support the change in the substation interconnection ease and feasibility analysis that ties the alignment levels to estimated cost ranges, as it may impose a one-size-fits-all process for evaluating substation interconnection viability, resulting in projects being mis-classified. SCE supports the updates, particularly the integration of PTO feedback and use of per-unit cost guide data. SCE also recommends evaluating new substations and demonstrating how consideration of both existing substation and new greenfield infrastructure upgrades, including assumptions and estimates, was incorporated, to ensure a comprehensive review and mapping process.

Several parties express concerns about the busbar mapping criteria's impact on gas retirement and disadvantaged communities. Calpine supports not including the U.S. Energy Information Administration data major maintenance to prioritize gas retirement. CEJA and Sierra Club recommend eliminating the local effectiveness factors from the gas plant retirement criteria, and strongly agree with eliminating exemptions for gas plants in disadvantaged communities that are in the youngest quartile and the highest effectiveness quartile. In addition, CEJA and Sierra Club suggest including the gas retirements modeled in busbar mapping in the TPP base case or at least the sensitivity case transmitted

to the CAISO. CEJA and Sierra Club also support the busbar mapping guidance that biomass and biogas should avoid disadvantaged communities and air quality non-attainment areas. Finally, EDF supports the staff-proposed modifications and also recommends eliminating the blanket exemption for all gas plants, not just those in disadvantaged communities.

Several parties also expressly commented on how the busbar mapping methodology evaluates geothermal and PSH resources. Invenergy generally supports the new criteria. TNC also supports the criteria and encourages staff to resume this work in the next TPP cycle. GreenGen supports the new methodology, with the following recommendations: (1) adopting PSH-specific environmental and commercial-interest screens, (2) linking busbar mapping with deliverability pathways for LLT substitutions, and (3) enabling either-or mapping where PSH can compete directly with eight-hour batteries at specific nodes.

A number of parties also comment on the criteria to inform mapping of geothermal resources, and EGS in particular. SCPA and PCE argue that the RESOLVE model only selected near-field EGS and the Commission should honor that selection by mapping EGS only to nearby known geothermal resource areas. Conversely, XGS argues that the Commission should consider expanding the locations for EGS, as well as next-generation geothermal in general (a category which is broader than EGS), and use the Stanford Thermal Model to assess resource potential. SCPA and PCE also recommend that the Commission strive to maintain the total capacity of EGS on each side of Path 15 and Path 26.

SCE agrees with the mapping of EGS by Commission staff, but disagrees with the assumption that the EGS capacity potential at each site is the same as the conventional geothermal potential. XGS agrees in reply comments, stating

that EGS and next-generation geothermal potential should be higher than conventional geothermal potential.

ACP-CA supports greater inclusion of EGS in TPP modeling and recommends planning for it inside and outside of California. SCE recommends consideration of developing a more detailed sensitivity portfolio for use in a future TPP to explore in-state EGS potential, including potential CAISO transmission upgrades needed to ensure deliverability. XGS agrees in reply comments. Fervo also endorses planning for EGS within California and recommends new data sources.

PG&E also recommends conducting an annual survey among entities with commercial interest in geothermal development to present their new capacity projects for consideration in busbar mapping. Fervo also suggests utilizing the Nevada Power Company interconnection queue, while includes 3.3 GW of geothermal capacity. CEJA and Sierra Club recommend mapping geothermal with community impacts in mind, particularly with respect to earthquakes, water quality, and air quality.

Several parties are concerned with how busbar mapping methodology impacts reserving deliverability on the transmission system. CESA comments that only differentiating between distributed solar and non-distributed solar capacity values prevents distributed storage from receiving deliverability through the CAISO's Distributed Generation Deliverability process, putting it at a severe competitive disadvantage relative to distributed solar. In addition, CESA states that the lack of clarity regarding whether there is, in fact, distributed energy-only capacity at certain substations disqualifies those substations from being assessed in the CAISO's Distributed Generation Deliverability process.

RCEA and Humboldt County argue that North Coast transmission-constrained areas are failing to trigger upgrades necessary to meet local resource development needs. They recommend developing alternative trigger mechanisms to enable deliverability upgrades in underserved areas, especially those regions that are resource rich.

PG&E requests continuing to busbar map PG&E's Helms Uprate Project and continuing to reserve deliverability for the uprate in the 2026-2027 TPP. GreenGen agrees, in reply comments.

Some parties also note concerns with the commercial interest criteria. NextEra recommends commercial viability scores include projects that were withdrawn from the interconnection queue, as well as projects filed but not allowed to enter Cluster 15. PG&E is concerned that primarily using the CAISO transmission interconnection queue as the source of commercial interest relies on circular logic that is not supportable. CalCCA also makes this argument. PG&E suggests finding new ways to forecast commercial interest, particularly in the case of location-constrained generation resources. GreenGen agrees with this in reply comments. GridLiance also points out that reliance on the CAISO interconnection queue is no longer sufficient because of the CAISO's revised study selection criteria, which screen out projects at interconnection points with no deliverability. ACP-CA states that it agrees with parties who identify gaps in the interactions between the CAISO's new interconnection process, the development of TPP portfolios, and associated busbar mapping, which are likely devaluing the development potential and commercial interest in high-quality resource zones.

Several parties also suggest incorporating other data into the commercial interest assessment. NextEra recommends including IRP plan data from the

Western Transmission Expansion Coalition and other sources, as well as establishing an open process for developers to assist in addressing any gaps or inconsistencies in the data sets. REV suggests undertaking an annual developer survey to determine areas of interest. GridLiance suggests that site control and interconnection applications (including withdrawn or deferred projects), permitting milestones, offtake discussions or contracts, financing readiness, and development timelines should all be factored into the commercial interest criteria. Fervo also suggests integrating recent Federal permitting timelines, particularly for out-of-state resource assessment. SCE concurs, especially for projects sited partially or fully on BLM land.

GridLiance pushes for greater transparency, arguing that the Commission should work with CAISO to establish a joint process for reporting on constrained regions that reconciles “queue-visible” and “queue-filtered” development activity so that planning signals reflect actual market interest. In addition, GridLiance recommends creating a forward-looking forecast for merchant and zero-deliverability areas that weights documented pipelines and capacity expansions at existing facilities, not just queued projects able to clear the CAISO deliverability gate. GridLiance argues that IRP-mapped resources in areas with zero deliverability should be used as explicit triggers for evaluating cost-effective TPP upgrades.

Finally, MGRA argues that the Commission should evaluate commercial interest in PSH projects based on how far along they are in development. And CEJA and Sierra Club would prefer to prioritize environmental impact criteria over commercial interest.

3.5.2. Discussion

Many of the suggestions in party comments on the busbar mapping methodology represent ongoing areas for improvement and require discussion among the interagency busbar mapping working group. Many of the comments would also require more time to implement than we have available for the 2026-2027 TPP cycle. Several of the suggestions are already under discussion, including the following:

- Creating and maintaining a public viewer that displays draft busbar mapping results in their spatial form and allows for downloading of the data;
- Including the latitude and longitude values in the CEC's land-use evaluations spreadsheet;
- Reviewing and incorporating the most up-to-date, relevant fire threat data available;
- Gathering California and Federal permitting data, particularly in location-constrained areas, to augment the existing commercial interest criteria;
- Revising the geothermal mapping criteria, to implement better assumptions and data sources, plan for in-state EGS, improve commercial interest assessment, and improve community impact assessment; and
- Continuing improvements to the PSH mapping approach, including additional stakeholder engagement.

Although this work is beginning in the context of the interagency working group, most of these improvements could have impacts in the 2027-2028 TPP cycle and will not be able to be incorporated this year due to time constraints. Because the TPP process is annual and cyclical, we appreciate parties' ongoing attention to these methodological improvements so that we can continue to improve the process each and every year.

We also intend to ask Commission staff, along with the interagency busbar mapping working group, to devote particular attention to reviewing and refining the commercial interest criteria in time for the 2027-2028 TPP cycle. The Interconnection Process Enhancements that CAISO has made are reducing the number of projects in the interconnection queue, as expected. However, this limits CAISO queue data as a measure of commercial interest. Therefore, the busbar mapping working group is developing new measures of commercial interest, using California and Federal permitting data, to augment the existing commercial interest criterion. This process began in the 2026-2027 TPP cycle with the analysis of California Environmental Quality Act and National Environmental Policy Act permitting data, and will continue in the 2027-2028 TPP cycle with the implementation of new commercial interest criteria that consider both queue position and permitting data. This is also responsive to several parties' comments on the proposed decision, including ACP-CA and Fervo.

We also note that for this year, improvements to the RESOLVE model, in particular to its zonal topology, have lessened the influence of the commercial interest criteria on specific project mapping because resources are optimally selected in regions. Trends in the size of the mapped portfolio and the interconnection queue also mean that interagency staff have more ability to allocate capacity for existing commercial interest while also mapping a great deal of capacity to new areas. This year's base case portfolio maps around 50 percent more resources than the 2025-2026 base case. This also means that the amount of capacity informing the commercial interest criteria has fallen and many areas have more resources mapped than currently exist in the interconnection queue.

As a consequence, in the 2026-2027 base case, more capacity is being allocated to new areas without existing commercial interest.

3.6. Busbar Mapping Results

Based on the recommended base case portfolio included in the ALJ Ruling, Commission staff undertook a preliminary mapping of the identified generation and storage resources to busbars on the transmission system. This information was presented in a public webinar held on November 12, 2025. A November 3, 2025 ALJ Ruling allowed parties to make specific comments on the preliminary busbar mapping presented by Commission staff.

Parties' comments on the preliminary busbar mapping fell into several categories that are summarized in this section, including: mapping criteria issues; transmission-related issues; volume of resources mapped; offshore-wind-specific issues; import issues; issues related to gas capacity not retained; and specific remapping requests. This section summarizes only those comments where a change was made in response to the party's comment. Other comments will be taken under advisement for future TPP cycles.

3.6.1. Mapping Criteria Issues

Related to mapping criteria, Fervo comments that the commercial interest criteria and analysis should consider more EGS development in Utah and Nevada, because the Nevada Energy queue shows 3.3 GW and Cape Station reports 5 GW. In response, Commission staff initially remapped 290 MW of geothermal from Malin to an alternative tie-in location in Southern California. However, SERVVM analysis (discussed further in Section 3.7 below) showed reliability concerns with this remapping, so the resources were moved back to the original location at the Malin substation. Some geothermal was also initially remapped to the Geysers #17 substation due to stakeholder input and the

priority of continuing alignment with the 2025-2026 TPP portfolio. However, this created transmission exceedances; therefore, the original mapping was retained.

In response to comments on the proposed decision from ACP-CA regarding commercial interest in geothermal projects, Commission staff have moved 750 MW of geothermal from Malin to Hilltop, to facilitate the development of both in-state resources at Surprise Valley and imported resources from Northern Nevada. We ask the CAISO to study transmission solutions to increase import capacity between Hilltop and Malin, to facilitate delivery of geothermal across the CAISO system. Commission staff also intend to continue to refine the methodology for mapping geothermal projects in the next cycle, potentially taking into account the differences in various geothermal technologies.

3.6.2. Transmission-Related Issues

In comments, BAMx suggests providing additional guidance to avoid approving some major transmission upgrades in the 2025-2026 TPP that may not be required based on the proposed 2026-2027 TPP portfolios, specifically the Wilson-Storey-Borden Lines and the Delevan upgrades. In general, we are aiming to be as consistent as possible with prior years' portfolios, and therefore if resources mapped in the 2025-2026 TPP portfolio triggered a transmission upgrade, those resources will likely continue to be mapped this year for consistency. This could include resources that trigger the need for the lines mentioned by BAMx.

SCPA also suggests revisiting the analysis completed in the 2024-2025 TPP to assess the need for mapping additional "unaccounted-for" TPD in Northern California to address the discrepancy between the portfolio's inclusion of new Northern California resources and scarcity of TPD due to the Collinsville-Tesla

500 kV constraint. SCPA suggests not limiting the analysis to TPD related to offshore wind, but also including other resource types including geothermal. “Unaccounted-for TPD” generally refers to TPD that has been awarded by the CAISO to a specific project already in the interconnection queue, but for which there is no corresponding resource in the Commission’s portfolio at the same point of interconnection. The busbar mapping process does not include all interconnection requests in the CAISO queue as resources in the portfolio; the queue is used as an indication of commercial interest. TPD is awarded to projects prior to the execution of their generator interconnection agreements. Thus, the projects may not be included in the RESOLVE modeling baseline due to their uncertainty of being developed. This situation may arise when projects lose viability for a variety of reasons, such as inability to secure land.

In response to SCPA’s comments, Commission staff are using a new methodology of summing the non-operational prior commitment capacity and the TPD allocated capacity from the TPD report, and then subtracting the mapped FCDS capacities from this sum. Any non-negative deltas from these calculations were identified as unaccounted-for TPD, and this calculation was performed for each transmission constraint involving LLT resources.

Commission staff are working with the CAISO to better capture TPD in the busbar mapping dashboard by adding the unaccounted-for TPD across constraints, thus showing the additional transmission upgrades required.

In the 2025-2026 TPP, unaccounted-for TPD was an issue, and we added a certain amount of storage resources with TPD already allocated to the mapped

portfolio, to inform necessary transmission capacity to support deliverability of offshore wind resources.²⁴

For this year, with respect to transmission needed to ensure deliverability for LLT resources, if the CAISO takes into account all of the storage with TPD and adds LLT transmission needs, there is a risk of overbuilding the transmission system at considerable cost. To avoid this, Commission staff have worked with CAISO staff to identify a preliminary list of constraints where unaccounted-for TPD needs to be incorporated into the 2026-2027 TPP to allow for LLT deliverability reservations. The current analysis on the amount of unaccounted-for TPD needing transmittal to the CAISO is available in the Base Case portfolio tabs labeled “Unaccounted for TPD Calculator” and “Unaccounted for TPD Summary” and will be included, through further Commission and CAISO staff coordination, in addition to the mapped portfolio resources for study in the 2026-2027 TPP base case at the constraints identified.

Commission staff will continue to work with the CAISO to further refine a standardized policy and methodology for considering unaccounted-for TPD in busbar mapping, as feasible.

3.6.3. Volume of Resources Mapped

Multiple stakeholders, including DOW, GSCE, LSA, and NextEra, advocate for more solar resources to be mapped in the PG&E territory, particularly in the Central Valley. These parties generally assert that true commercial interest for solar is not captured by either the commercial interest or land-use metrics, especially for the PG&E Fresno and Kern study areas. GSCE

²⁴ See D.25-02-026 at 56.

argues that Fresno is suitable for additional resources due to the lower-implication lands there.

There are two main issues with increasing the amount of solar mapped to the PG&E area, and Fresno in particular. First, mapping more solar causes transmission exceedances due to overlapping constraints in the area. Second, the amount of solar selected by RESOLVE, even without additional remapping requested by stakeholders, already exceeds the amount of commercial interest shown in the dashboard, though in this TPP cycle there are significantly more resources in the base case portfolio than in past cycles, without a corresponding increase in commercial interest. There are several cases in the busbar mapping dashboard where mapping goes beyond identified commercial interest to reach the RESOLVE-selected amount of resources. Mapping at PG&E Fresno goes even further by remapping 2.5 GW of solar resources from SDG&E to PG&E Fresno. This was partially motivated by strong support from multiple stakeholder groups who indicated in their comments that there was solar development interest not captured by the busbar mapping methodology. As noted above, Commission staff are also actively working to improve the commercial interest criteria and hope to introduce these changes in the 2027-2028 TPP, which is intended to increase the amount of commercial interest captured in busbar mapping. Finally, there was stakeholder support for additional solar resources to be mapped to the Central Valley and because PG&E Fresno shows the most transmission upgrades triggered for study by the CAISO compared to the other CAISO study areas, there exists the potential for further solar resource mapping to PG&E Fresno in the future.

NextEra also suggests remapping some of the Arizona solar to East of Pisgah. Commission staff agree with this comment, due to the initial mapping of Arizona solar requiring potentially multi-billion-dollar transmission upgrades.

In response to all of these issues, Commission staff have engaged in strategic remapping of solar resources from the overloaded SDG&E Arizona study area to further optimize the mapping. Accordingly, a total of 8.3 GW of solar from Arizona originally mapped to SDG&E is being reallocated across several areas. Approximately 2.5 GW has been moved to the PG&E Fresno area, 0.5 GW has been moved to the PG&E Greater Bay Area, 3.2 GW has been moved to SCE's area, and 2.13 GW moved to SDG&E Imperial. As part of a transfer of 3.2 GW of SDG&E Arizona solar to the SCE area, 470 MW have been placed in the East of Pisgah area at the Lathrop substation.

This remapping results in ultimately mapping a total of 6.4 GW of solar to PG&E Fresno in 2036 and 7.5 GW in 2041, with 8.0 GW mapped to PG&E Kern in 2036 and 8.5 GW in 2041. In comments on the proposed decision, several parties point out that the amount of solar mapped to PG&E Fresno in 2041 is less than was mapped in 2040 in the previous TPP cycle. However, this year's portfolio enables the development of more solar in an earlier timeframe, aligned with busbar mapping criteria, including commercial interest, and the need to control costs by mapping resources to locations on the system that are best suited for resources development and where new infrastructure development is in the best interest of ratepayers.

Invenergy also questions the reduction in geothermal capacity mapped to the SCE Eastern study area. A small adjustment has been made in response to this comment by adding 70 MW back to Mirage substation. However, remapping 500 MW, consistent with the 2025-2026 TPP, would set off several transmission

exceedances in the area, necessitating further upgrades. Staff did not see those transmission upgrades as critical for investment, given the lack of commercial interest so far at the substation. Geothermal was instead moved to other locations showing more commercial interest and which did not require transmission upgrades. As discussed above, Commission staff will continue to evaluate and update the commercial interest criteria and we encourage stakeholders to submit comments in the next TPP cycle with additional insights. For this cycle, the geothermal resources in Imperial Valley are mapped either to SCE or SDG&E Imperial areas, and staff have verified that the geothermal totals across both areas are consistent with past TPP base cases.

It is also important to note that the size of this year's base case portfolio is larger than previous TPP cycles, due primarily to the increase in forecasted demand needs throughout the planning horizon. That increase in demand translates to a portfolio that has more of nearly every type of least-cost resource identified as needed to reliably meet state climate targets, including significant amounts of in-state solar, geothermal, and storage resources.

3.6.4. Offshore-Wind-Specific Issues

Vineyard suggests mapping Humboldt offshore wind only in 2036, or at least clearly directing CAISO to continue advancing the North Coast transmission lines without delay, so that the offshore wind can begin coming online as soon as 2036. This comment has been addressed earlier in this decision in Section 3.2.

3.6.5. Import Issues

LSA suggests remapping resources more evenly among the Arizona solar substations to avoid unintended consequences. As described above, approximately 8.3 GW of solar has been remapped from the Arizona area

importing into SDG&E, to avoid unstudied upgrades that are potentially multi-billion-dollar investments. Around 5.5 GW remains in the SDG&E Arizona import area, which is in line with CAISO estimates of current line carrying capabilities. The latest mapping reduces the solar initially mapped to the three Arizona substations by between 60-80 percent, leaving only 500 MW at North Gila. This addresses the point raised by LSA that the amount initially mapped to North Gila far exceeded the amount of available “low implication” land at that substation. The sensitivity portfolio, which contains more solar than the base case portfolio, will restore significant amounts of solar to SDG&E to encourage the CAISO to study the transmission constraints in the region for potential use in future TPP cycles.

3.6.6. Issues Related to Gas Capacity Not Retained

Related to the mapping of specific natural gas plants currently online, Calpine comments that the Delta Energy Center should not be assumed offline, because the initial busbar mapping did not consider the plant’s efficiency, functional age (based on major upgrades), and potential for CCS efforts. For this base case portfolio, Commission staff have made the change requested as part of addressing broader methodological issues related to the need to align with RESOLVE’s selection of gas technology type not retained. For the next TPP cycle, we will consider modifying the methodology overall for mapping of the natural gas plants not retained, with potential updates to include the unit efficiency, potential for decarbonization, local reliability factors, and repowering and/or upgrade potential.

There are two possible types of gas capacity not retained in the portfolio: capacity that is not retained because it is identified by policies that are forced into

the RESOLVE model and do not appear as RESOLVE-selected resources, and RESOLVE-selected generation not retained due to RESOLVE's economic cost optimization. The RESOLVE-selected generation not retained is only identified in aggregate amounts of gas capacity by technology type, but for the TPP studies, individual units need to be identified for non-retention. In identifying which units to model as offline, Commission staff implemented a scoring criteria to developed a prioritized ranking of plants to model as not retained. The scoring included environmental/community factors, performance-related factors, and the local reliability factor. The plants selected are intended to identify transmission needs and impacts, not select specific gas generators to retire, decisions over which the Commission does not have regulatory control.

For this year, RESOLVE identified gas capacity not retained totaling approximately 785 MW of combined cycle gas turbines and 890 MW of combustion turbines (peaking units). Commission staff implemented this non retention in busbar mapping by selecting units that scored the worst on the criteria up to the quantities identified within the zonal constraints required to avoid triggering reliability concerns, supported by the analysis in SERVIM discussed in Section 3.7 below. These capacities have been replaced in busbar mapping with generic battery storage up to the quantities identified in the CAISO's 2030 Local Capacity Technical Reports, released in April 2025.²⁵

EDF also recommends that the gas capacity workbooks and public materials be updated to more explicitly indicate scores and show the work

²⁵ The CAISO Local Capacity Technical Reports are available at the following links: <https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2026-Local-Capacity-Technical-Report.pdf> and <https://stakeholdercenter.caiso.com/InitiativeDocuments/Final-2030-Long-Term-Local-Capacity-Technical-Report.pdf>.

behind the non-retention decisions, especially for exempted plants. In response to this comment, Commission staff have updated the materials that are posted on our website.

Commission staff will also continue to refine the process for identifying natural gas units to be modeled as not retained in the next TPP cycle by incorporating additional stakeholder feedback on the methodology.

3.6.7. Specific Remapping Requests

A number of parties raised particular concerns with specific mapping decisions in the preliminary portfolio. LS Power states that corrections are required to accurately reflect the current status of the Manning 230 kV and 500 kV substations. Staff have made modifications in response to this comment, in order to increase alignment with the mapping criteria and provide consistency with the previous TPP base case portfolio.

PG&E requests that the 140 MW Helms PSH uprate project be mapped to the Gregg substation. PG&E also suggests revising the busbar mapping methodology to avoid the scenario in which commercial interest is not accurately reflected due to constraints on entering the CAISO queue and possible limitations on other proposed methodologies such as land-use permitting. Commission staff have discussed the Helms Uprate project with the CAISO and will remap the project as requested, which is consistent with the 2024-2025 and 2025-2026 TPP base cases. This should result in deliverability being reserved for the project, since it is a non-battery LDES project. Commission staff will also revise the treatment of unaccounted-for TPD, as discussed above, which is related to the Helms Uprate project.

In response to the GreenGen comments on the proposed decision, the amount of PSH mapped at Bellota substation has been increased, with

consideration of the commercial interest in the full design capacity of the Mokelumne pumped storage project in the area. In response to comments from SCVWA, the amount of PG&E Kern solar mapped at full capacity deliverability has been restored to reflect commercial interest. In response to comments from Viridon, the CAISO queue Cluster 15 projects in PG&E Fresno (solar and storage) have been remapped to this area. In response to SCP and SJCE comments, 100 MW of geothermal capacity has been mapped to Inyokern, which is consistent with the sensitivity portfolio, and also reflects commercial interest. Finally, in response to CalWEA comments, staff corrected an error that mischaracterized 700 MW of wind resources at the Madeline substation as energy only (when they should have full deliverability). However, no additional wind resources were mapped in this area; we ask the CAISO to continue to study the Northeastern California wind resources, as part of the final 2025-2026 TPP analysis. We also ask the CAISO to study transmission solutions for the delivery of these wind resources in the 2026-2027 TPP analysis, in conjunction with the request in Section 3.6.1 above to study transmission for the 750 MW of geothermal resources mapped to Hilltop.

3.7. Production Cost Modeling Analysis of Base Case Portfolio as Mapped

As with past TPP portfolios, Commission staff have conducted production cost modeling (PCM) of the recommended base case portfolio for the key years needed by the CAISO for its TPP, to ensure that it meets reliability standards and that the GHG emissions are within an acceptable range. For the 2026-2027 TPP base case portfolio, Commission staff conducted the PCM using SERVUM on the busbar-mapped version of the recommended portfolio.

Several modeling updates to SERVVM were made prior to conducting the analysis:

- The model was changed to reschedule up to 20 percent of generator maintenance around extreme weather events, to avoid unnecessarily causing reliability problems in winter months in future years.
- Import constraint assumptions were ramped during the hours ending 17 through 22 by adding three steps of 6,330 MW, 4,000 MW, and 8,660 MW, to avoid the sudden change from 11,040 MW down to 4,000 MW, which caused unrealistic dispatch patterns.
- GHG pricing assumptions were revised to be imposed only on in-state emitting units and unspecified imports to CAISO.
- SERVVM's storage dispatch logic was revised to operate storage more efficiently and better align with RESOLVE's storage dispatch.
- BTM photovoltaic hourly profiles were improved to better align with those used in the CEC's IEPR demand forecast process.
- Unit mappings were corrected for weather-driven thermal derating of gas and geothermal units.
- One-hour offset corrections to electric demand hourly profiles were implemented.
- Existing units with a monthly NQC were capped at that value.
- Other smaller corrections and debugging were performed to ensure accuracy of model results.

In addition, the model was calibrated to match the 2024 IEPR managed demand forecast from the CEC, including changes to the annual peak and energy forecasts, as well as penetration of demand-side resources.

SERVM modeling was conducted on the portfolio after the resources were mapped to transmission busbars. Busbar mapping considers transmission and interconnection constraints in more detail than the RESOLVE model and incorporates changes to siting of new resources between SERVVM regions compared to the raw RESOLVE results.

Table 9 presents the key metrics for the recommended base case portfolio, including LOLE and GHG emissions from various sources (in-CAISO generation, unspecified imports, and BTM CHP). The table includes comparisons of GHG emissions metrics from RESOLVE and SERVVM. Table 9 shows the SERVVM results for 2036 and 2041, which reflect the more optimal busbar-remapping of new resources mentioned above, that prioritizes placement in the PG&E sub-region. Table 10 shows the same metrics, but for the portfolio outputs taken directly from RESOLVE, prior to busbar mapping. Table 10 is provided for comparison purposes. In both tables, the RESOLVE results are identical and reflect the RESOLVE results of the portfolio before busbar mapping.

Table 9. Reliability and GHG Results in Key Planning Years for Proposed 2026-2027 TPP Base Case After Mapping to Busbars on the Transmission System

Metric	2036		2041		Units
	RESOLVE	SERVVM	RESOLVE	SERVVM	
Model	RESOLVE	SERVVM	RESOLVE	SERVVM	
<i>LOLE</i>	NA	0	NA	0.084	<i>days/year</i>
EUE	NA	0	NA	109.4	MWh
Loss of Load Hours (LOLH)	NA	0	NA	0.104	hours/year
LOLH/LOLE (average length of outage)	NA	0	NA	1.154	hours/day

Metric	2036		2041		Units
	RESOLVE	SERVM	RESOLVE	SERVM	
Model					
Normalized EUE (EUE divided by total electric demand)	NA	0	NA	0.00007	percent
CAISO emitting generation	24,873	34,156	16,130	30,110	GWh
CAISO generator emissions	10.23	14.17	6.50	11.75	MMT
Unspecified imports	13,091	9,162	14,114	8,943	GWh
Unspecified import emissions	5.60	3.92	6.04	3.83	MMT
CAISO BTM CHP emissions	3.16	3.16	-	-	MMT
Total CAISO emissions	18.99	21.25	12.54	15.58	MMT
GHG emissions difference		2.25		3.04	MMT

Table 10. Reliability and GHG Results in Key Planning Years for Proposed 2026-2027 TPP Base Case Before Mapping to Busbars

Metric	2036		2041		Units
	RESOLVE	SERVM	RESOLVE	SERVM	
Model					
LOLE	NA	0.003	NA	0.154	days/year
EUE	NA	1.8	NA	246.3	MWh
LOLH	NA	0.003	NA	0.193	hours/year
LOLH/LOLE (average length of outage)	NA	1.000	NA	1.231	hours/day
Normalized EUE	NA	0.00000	NA	0.00016	percent
CAISO emitting generation	24,873	34,179	16,130	30,149	GWh
CAISO generator emissions	10.23	14.14	6.50	11.74	MMT
Unspecified imports	13,091	9,168	14,114	9,219	GWh
Unspecified import emissions	5.60	3.92	6.04	3.95	MMT

Metric	2036		2041		Units
	RESOLVE	SERVM	RESOLVE	SERVM	
Model					
CAISO BTM CHP emissions	3.16	3.16	-	-	MMT
<i>Total CAISO emissions</i>	<i>18.99</i>	<i>21.22</i>	<i>12.54</i>	<i>15.69</i>	<i>MMT</i>
GHG emissions difference		2.22		3.15	MMT

As parties involved in the IRP process over the past several cycles are likely aware, there are differences between the RESOLVE and SERVM models in many aspects. Some differences, particularly in terms of GHG emissions estimates, are expected.

The 2026-2027 TPP recommended base case has a significantly smaller difference in modeled GHG emissions for 2036 and 2041 than the last TPP base case portfolio, due to Commission staff's continued calibration efforts across both models.

In general, we are most focused on the SERVM results for 2036, since this is the first critical planning year for purposes of CAISO TPP analysis and the key driver in identifying transmission needs and resulting recommendations for transmission investments to be sent to the CAISO Board. The Commission transmits both a ten-year and a 15-year portfolio, but consistent with its FERC tariff, the CAISO has discretion on a case-by-case basis about transmission projects identified in the 15-year timeframe and the 2041 TPP analysis does not require immediate commencement of recommendations for transmission investments to the CAISO Board for all projects identified.

The SERVM results show an acceptable level of reliability, with LOLE results below our planning standard of 0.1 days per year in both 2036 and 2041. In 2036, the LOLE is 0.00 days per year, which is due to the fact that meeting the

2031 GHG target requires additional renewable resource selection, as the GHG target is more binding than the reliability target in the early 2030s. The LOLE result for 2041 is 0.084, which Commission staff estimate to be within a few hundred PCAP MW of the 0.1 LOLE standard.

For GHG emissions in 2036, the estimate is 21.25 MMT of GHG emissions, which is consistent with the CAISO portion of the California electricity sector trajectory set by the CARB in the 2022 Scoping Plan for Achieving Carbon Neutrality (Scoping Plan Update).²⁶ For 2041, the SERVVM GHG emissions estimate is 15.58 MMT, which is also consistent with the electric sector trajectory set by CARB in the 2022 Scoping Plan Update.

These are still modeled estimates projecting out ten and 15 years into the future where many inputs have significant uncertainty and both models can continue to be improved and calibrated during that time.

For the 2026-2027 TPP, we are satisfied that these results are acceptable and sufficient to conclude that the base case portfolio is a reasonable one for the CAISO to analyze further for transmission needs. We will continue to closely monitor actual progress toward the new resource investment and GHG reduction results from these portfolios and will conduct similar analysis with our TPP portfolio recommendations next year and in subsequent years.

4. Summary of Public Comment

Rule 1.18 of the Commission's Rules of Practice and Procedure (Rules) allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant

²⁶ For more information, see more details on CARB's 2022 Scoping Plan Update, available at the following link: <https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf>.

written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

Two individuals submitted public comments related to this decision. The first comment is concerned with the busbar mapping of distributed storage and solar resources from the Wholesale Distributed Access Tariff queue. In particular, the commenter is advocating that energy-only solar and storage resources be mapped to busbars for the CAISO to analyze.

The second public comment comes from a representative of the Blue Lake Rancheria, a federally-recognized Native American Tribe. The Tribe comments in support of offshore wind development on the North Coast, not only for its environmental benefits, but also as a catalyst for workforce development and livable wage careers.

Commission staff have met with various stakeholders in response to requests to conduct busbar mapping of distributed storage resources, and continue to discuss the potential for implementing this recommendation with both stakeholders and the CAISO.

5. Comments on Proposed Decision

The proposed decision of ALJ Julie A. Fitch in this matter was mailed to the parties in accordance with Public Utilities Code Section 311 and comments were allowed under Rule 14.3. Comments were filed on February 6, 2026, by the following parties: ACP-CA; AReM; Bloom Energy Corporation (Bloom); CAISO; CalCCA; CalGrid; CFC; Calpine; CalWEA; CCSA; CEJA and Sierra Club, jointly; CESA; CLEU; CUE and CURE, jointly; Diamond Generating, LLC (Diamond); DOW; EDF; ENGIE; esVolta; Fervo; Form; GSCE; GreenGen; GridLiance; Hydrostor; IEP; Invenergy, Invenergy Geothermal, and Maravillosa, collectively; Reid; LDES Council; LSA and SEIA, jointly; MGRA; MRP; NextEra; Ormat;

OWC; PCE; Protect Our Communities Foundation (PCF); PG&E; Cal Advocates; RCEA and Humboldt County, jointly; REV; Santa Clara Valley Water Agency (SCVWA); SBUA; SCE; SCPA and SJCE, jointly; SDG&E; TNC; UCS; Vineyard; Viridon California LLC (Viridon); Vote Solar; WPTF; XGS; and Central Coast Community Energy (3CE).

Reply comments were filed on February 11, 2026, by the following parties: ACP-CA; Ava; AReM; Bloom; CAISO; CalCCA; CRC; CalWEA; CEJA and Sierra Club, jointly; CUE and CURE, jointly; Deploy Action; EDF; ENGIE; Fervo; GreenGen; Hydrostor; LDES Council; LSA and SEIA, jointly; Mainspring; MGRA; MRP; PG&E; SBUA; SCE; SCPA; SDG&E; SoCalGas; Vote Solar; and XGS.

This section summarizes the comments of parties thematically. Where relevant, changes have been made in the body of the decision to respond to the comments summarized below.

In general, the majority of parties support the procurement requirements in the proposed decision, with many suggesting some modifications, as described further below. PCF was the only party outrightly opposing the procurement order. Many other parties suggested more or less procurement. Parties suggesting a larger procurement amount and/or earlier requirements include ACP-CA, Hydrostor, CAISO, and MGRA, citing the likelihood of lower imports, the timing of the projected reliability need relative to the two tranches of procurement suggested in the proposed decision, reducing reliance on the Aliso Canyon natural gas storage facility, or other planning uncertainties. Parties recommending a lower amount and/or later timing of procurement include PG&E, SCE, SDG&E, AReM, CalCCA, Calpine, Ava, and CLEU. Many of these parties point to the 2025 IEPR demand forecast, where the base forecast adopted

by the CEC and published in early February 2026 has decreased from the 2024 IEPR adopted in February 2025. Some of these parties, including CalCCA, also request that the Commission conduct a reassessment of the need before ordering a second tranche of procurement.

On the issue of the amount of procurement, we are not persuaded to change the total away from 6,000 MW, as included in the proposed decision. The 2024 IEPR is the load forecast that formed the basis for the analysis presented in the ALJ Ruling, and as pointed out in the CAISO's comments, it is the only forecast consistent with the CEC-CAISO-Commission MOU agreement to use a single forecast set. It is the case every year that there is a new/updated IEPR forecast adopted right around the same time as we issue TPP recommendations, and it is not possible or necessarily prudent to make a load forecast substitution at this stage. Instead, we rely on the cyclical nature of the IRP analysis to continue to update our conclusions every year. There is also considerable uncertainty in the forecast, which is also normal. Finally, not all of the additional demand in the 2024 IEPR compared to the 2025 IEPR base forecast represents data center load. There is also electrification of buildings and vehicles driving the higher forecast, and these loads create additional uncertainty. Thus, we find it prudent to continue our deliberative approach and rely on the 2024 IEPR forecast for purposes of this decision.

As far as the timing of the procurement requirements, we are not persuaded to wait to order additional procurement beyond 2032 using a new forecast later. Instead, we agree with the CAISO's comments that having only 2,000 MW in 2030 and then not requiring additional procurement until 2032 could leave the electric system potentially vulnerable to reliability risks in 2031. In addition, as discussed further below, we intend to include additional

flexibility for LSEs to account for the potential of delays outside of their control, including the applicability of the provisions of D.25-09-007 that allow LSEs to be deemed compliant for a period of up to three years after the compliance deadline, by showing signed contracts and month-ahead resource adequacy compliance. In so doing, the importance of having two-year tranches for procurement is lessened. Therefore, we have modified the decision to require approximately 2,000 MW of procurement in each of the three years of 2030, 2031, and 2032 (with resources required to come online no later than June 1 of each year to show compliance with that year's requirements).

Several parties request that CCS projects be eligible to be procured in response to this decision, including CRC, PG&E and WPTF. WPTF also suggests that thermal power plant repowering and efficiency upgrades should be allowed to count fully, not just based on any incremental capacity added. MRP also requests that the proposed decision consider allowing short-duration battery storage that is co-located with thermal generation. Bloom requests that fuel cells be eligible. SCE, MRP, SDG&E, and Calpine also express support for greater CCS inclusion in IRP planning and procurement processes. EDF and CEJA/Sierra Club support a continued prohibition on counting fossil-fueled projects toward the procurement requirements. Generally, we are not persuaded to change our prior determination on any of these items, though we will continue to track CCS technology, including developments in other state processes, and may reevaluate the potential for such projects in our next IRP cycle and any subsequent procurement requirements after this decision.

A number of parties, including 3CE, SCPA, and SJCE, also suggest eligibility for standalone energy-only resources without full capacity transmission deliverability status, beyond those resources that are co-located

with storage projects. On this issue, we prefer to adhere to the resource adequacy eligibility requirements, which may change from time to time. Resources will be deemed eligible for the procurement requirements in this order if they are otherwise compliant with the resource adequacy eligibility rules in place at the time that they are used to show compliance with the procurement requirements.

SCE, Vote Solar, and LSA/SEIA also request clarifications to the manner in which energy-only resources co-located with storage will be counted, based on their marginal ELCC values. We have included these clarifications. SCE and CalCCA also go further, suggesting that “excess energy-only generation” from resources already in the baseline could be counted toward the procurement required in this decision, if they otherwise qualify. We disagree, and clarify that only resources that meet the qualifications described in this decision for energy-only resources co-located with storage may be counted for the procurement required herein if the energy-only generation resources come online after the effective date of this decision. In other words, the provision to allow these types of resources to count, if they otherwise meet all of the requirements, begins with the procurement required by this decision, and does not retroactively apply to existing resources already online and delivering to the grid.

The topic garnering the largest opposition in the proposed decision was the suggested 50 percent cap on the amount of storage procurement that could count toward each LSE’s obligation, with the intention of ensuring charging sufficiency for storage, given its recent prevalence in resource stacks of most LSEs. Many parties suggest that the Commission should remove the cap on the percentage of storage entirely from the provisions of the decision, including, IEP, esVolta, CESA, CLEU, 3CE, Hydrostor, LDES Council, AReM, Calpine, ENGIE,

REV, PCE, SDG&E, ACP-CA, NextEra, and WPTF. Arguments against including a cap on storage include that the CAISO interconnection queue may not contain enough non-storage resources to achieve the requirement, the cap is unnecessary because ELCC values will reflect the declining value of storage, it may limit least-cost best-fit contracting by LSEs seeking to manage their own resource portfolios, there hasn't been enough analysis to demonstrate the need for the cap, a cap is inefficient, and a cap may discourage procurement of longer-duration storage, which should be of high value to the electric system as a whole.

Some parties generally support the cap, some with reservations, including EDF and UCS. Other parties support a minimum energy requirement, assessed at the end of the compliance period, rather than the cap, including ACP-CA and CalWEA.

Some other parties support the cap with suggested amendments, including GreenGen, SCE, Form, CUE/CURE, PG&E, and Cal Advocates. Most of these parties suggest that LDES should be exempted from the cap. PG&E, SCE, Cal Advocates, and WPTF recommend that storage co-located or hybrid with energy resources should be exempt from the cap, if there is a cap. Cal Advocates would also exempt storage that is contractually-paired with other resources. PCE would prefer no cap, but if the Commission adopts one, suggests having the cap imposed on a nameplate basis (not NQC), using a slice-of-day methodology to measure compliance, and setting the cap higher and potentially lowering it after further analysis.

After consideration of the numerous party comments, we are persuaded that the imposition of a cap on the amount of storage to be procured would be unwise, including because we have no wish to discourage the development of longer-duration storage beyond four-hour lithium-ion batteries, which imposing

a cap could do. Therefore, we have removed the cap on storage resources that was in the proposed decision.

Having made the determination to remove the storage cap, we remain concerned about developing the attributes associated with the diverse portfolio identified in Section 3.2 of this decision for transmission planning also influences procurement of resources. Removing the cap on storage could still result in overreliance by LSEs on short-term battery storage in the portfolio. In comments on the proposed decision, Hydrostor recommends requiring that at least 1,500 MW NQC or 25 percent of the procurement required herein be designated to come from long-duration storage resources of at least eight hours in duration. The LDES Council also recommends that the Commission require that 25 percent of the capacity procurement be required to come from storage resources with eight or more hours of duration and with efficiencies of 60 percent or more. Form raises concerns with the Commission not having specific ELCCs for LDES resources and suggests that the Commission take measures to ensure procurement of LDES resources. CUE and CURE further note that LSEs are unlikely to procure the LDES resources that the portfolio in Section 3.2 identifies as needed without a specific procurement requirement.

Also in comments on the proposed decision, EDF recommends that at least 500 MW in each tranche of procurement be required to come from clean, firm resources. We note that these are the same LLT resource types that we required to be procured in D.21-06-035 (as modified by D.25-06-005), for many of the same reasons. CAISO, in reply comments, notes that, if there is a risk that LSE procurement will deviate significantly from the planned 2026-2027 TPP base case, it supports the Commission adopting the LDES Council and Hydrostor's recommendation.

Based on LSES's submitted compliance data, used in the mid-term need determination analysis discussed in Section 2.1, we are seeing LSEs procure resources that have attributes associated with LLT resources up to, but not generally beyond, the levels required in D.21-06-035.

Therefore, in lieu of a cap on short-term storage resources, we have instead made a requirement that at least one-quarter of each LSE's procurement used to satisfy the requirements of this decision come from either long-duration storage resources (eight hours or more in duration) or clean firm resources (with capacity factors of 80 percent or more and not use-limited), as defined in Ordering Paragraph 2 of D.21-06-035, as further modified in D.25-06-005. For this decision's procurement, an LSE may choose the amounts of each type of resource, as long as the two types of LLTs total at least one-quarter of its total allocation, as given in Attachment A. This means that collectively a total of 1,500 MW NQC of the 6,000 MW NQC required to be procured by this decision must come from either LDES or clean firm resources. This procurement will be required by the June 1, 2032 compliance deadline and may come from either type of LLT resource specified.

Several parties, including EDF, UCS, PCF, and CEJA/Sierra Club, in their comments continue to call for the procurement requirements to include a component that addresses local capacity area procurement, with the intent of supplanting fossil-fuel generation. As we have already stated in this decision, we are concerned that such requirements could raise costs and not provide commensurate benefits. However, we will continue to evaluate local capacity area needs, as discussed further in the Scoping Memo of this proceeding.

With respect to the allocation of procurement responsibility to individual LSEs, several parties commented on the method presented in the proposed

decision. CLEU argues the Commission should reconsider allowing optional central procurement for smaller LSEs to reduce the compliance burden. AReM and WPTF comment on the characterization of the cap on direct access load in the proposed decision, with AReM offering corrections to how the cap works. We have made these modifications to clarify the application of the cap. We have not allowed for central procurement herein, in part because non-IOU LSEs have generally suggested that they do not desire IOU procurement on their behalf, and because other mechanisms exist for LSEs to share procurement responsibilities.

In addition, both AReM and WPTF argue that ESPs should be exempted from requirements to procure to meet load growth, because ESP load cannot currently grow. In reply comments, SCE points out that all LSEs and their customers benefit from a reliable grid and therefore ESPs should be required to procure similarly to all other LSEs. On this issue, we agree with SCE, and also note that all LSEs must serve customers and contribute to the procurement needed to meet reliability standards.

AReM also argues that need allocation should be rounded to the nearest tenth of a MW rather than whole MW, to avoid over- or under-allocations for very small LSEs. On this issue, there is only one LSE that is significantly impacted by this rounding issue, and we have modified their allocation in Attachment A to make the requirements more practical, by requiring a total procurement amount only by the 2032 procurement deadline (or any time prior to it).

AReM also objects to being required to procure resources to meet data center load, because the Commission and/or the Legislature have not yet determined how cost allocation for serving data centers should be handled,

which risks unintended cost shifts onto other customers. At a minimum, AReM requests that the Commission clarify that it does not intend by this order to shift the costs of serving new large data center customers onto other ratepayers. On this issue we note, as stated earlier, that the load growth anticipated in the 2024 IEPR is caused by a combination of end uses and not only load centers. In addition, there is considerable uncertainty about the source of the load growth in general. We do not intend this decision to prejudge any issues that may be separately resolved in other venues with respect to data center growth projections, cost allocation, or any other related issues.

Several parties comment on the need for additional flexible compliance options for achieving the procurement required by this decision. 3CE, SDG&E, SCE, CalCCA, and PG&E all note that the proposed decision made no explicit reference to the “good faith efforts” outlined in D.21-06-035, and ask that this standard apply and be referenced. We agree that these provisions were intended to continue to apply, and have clarified this in various ways in the body and the findings of this decision. We also state that this decision is not intended to require LSEs to procure resources at any cost, and LSEs may show evidence of high, non-competitive, or unreasonable pricing received in their solicitations in their showings demonstrating good faith efforts.

SCE and SDG&E specifically request that we clarify that resources procured by IOUs are subject to Power Charge Indifference Adjustment treatment similar to the previous MTR procurement orders. They also suggest clarifying the requirement for IOUs to file Tier 3 advice letter for procurement that complies with this decision, except in the case of PSH or utility-owned resources, where an application is required. In addition, SCE suggests the option for Tier 1 advice letters for IOUs to use resources approved in other venues

toward the requirements of this decision. We agree with these clarifications and have made the required findings and orders to effectuate these recommendations.

Several parties, including NextEra, WPTF, 3CE, AReM, Calpine, Cal Advocates, SCE, and SDG&E, also suggest that the provisions of D.25-09-007 be applied to the procurement ordered in this decision. Those provisions would allow LSEs that have signed contracts to meet their obligations and are also compliant with the resource adequacy month-ahead requirements during any delay period to be deemed compliant with the procurement requirements. While the proposed decision declined to apply the D.25-09-007 compliance regime to the procurement ordered herein, that was in part due to the preliminary plan to move to two-year compliance tranches. Now that this decision is being revised to require procurement by three separate deadlines in three successive years (June 1 of each of the years 2030, 2031, and 2032), the provisions of D.25-09-007 are more applicable, particularly because the circumstances that led to that decision are still present in the market, including the potential for project delays outside of the control of the LSEs. Therefore, we have reinstated the applicability of D.25-09-007 provisions in the revisions to this decision. This will essentially leave the same compliance regime in place for all of the MTR-related procurement ordered (in D.21-06-035, D.23-02-040, and this decision).

In response to the comments of AReM, language has been added to clarify that any resource that meets the criteria outlined in this decision and is eligible to be counted under resource adequacy program rules, may also be counted toward the requirements herein.

A number of parties also comment on the timing of the ELCC studies required in the proposed decision. CLEU, CalCCA, SCE, SDG&E, NextEra, and

PG&E argue that procurement cannot proceed until ELCC values are released, and therefore the Commission should release the 2030 and 2032 studies concurrently, by July 2026. Alternatively, SCE and SDG&E suggest that if the studies cannot be accelerated, then the 2028 ELCCs should be used for the 2030 procurement, at a minimum. CalCCA suggests at least providing indicative values for the later procurement now.

This issue, particularly the idea of applying the 2028 ELCC values to later years, is interrelated with the question of how to ensure energy sufficiency in the procurement, primarily because we are fairly certain that the 2028 ELCC values for 4-hour lithium-ion battery storage are too high. Because we are removing the cap on the amount of energy storage that can be procured to meet the requirements in this decision, we find it would be unwise to continue to rely on the 2028 ELCC values for procurement in 2030 or later. At the same time, we understand the desire of LSEs to have certainty around the resource accreditation values sooner rather than later, to plan and execute their procurement accordingly.

To balance these considerations, we have revised the 2026 ELCC study plan to include finalizing ELCC compliance values for 2030 and 2031 procurement, with a second study to be finalized by the end of 2027 to determine marginal ELCC compliance values for procurement by 2032.

AReM comments that to avoid confusion, the Commission should clarify that the LSEs' individual IRP plans due to be filed later this year will not be required to quantify how each LSE will meet the procurement requirements of this decision. Contrary to AReM's suggestion, we strongly urge the LSEs to take this decision into account when preparing their individual IRPs.

CalCCA asks that the Commission clarify how the procurement required by this decision impacts the magnitude of the LLT resource requirements required in D.24-08-064. There is no impact. D.24-08-064 procurement may proceed as already adopted in D.24-08-064, and if procurement of LLTs proves successful, LSEs will be notified of allocations that may lessen their requirements going forward. As of today, LLT allocations from D.24-08-064 procurement are zero.

CalCCA also asks for clarification of the extension of the baseline swap rules adopted in D.23-02-040. In particular, CalCCA seeks confirmation that any contract terminated after January 13, 2023 is prohibited from being swapped, and that baseline swaps can be applied to the LSEs' procurement obligations for the new years required in this decision. We confirm these interpretations and have added additional language in the conclusions and order.

The rest of this section covers comments on the TPP portfolios recommended in the proposed decision.

CAISO comments requesting corrections to the resource amounts where transmission deliverability reservations are being requested or have been applied in the past. We have made the corrections consistent with those comments.

In response to comments from ACP-CA and CalWEA, the decision has been modified to state that the low-wind sensitivity is only intended to test the transmission needs of the more expensive portfolio for planning purposes. The Commission would prefer the state develop resources aligned with the base case, which includes more wind, as it would result in lower costs for ratepayers.

Next, there were numerous comments from parties about specific choices related to the mapping of resources to busbars on the transmission system, with particular emphasis on areas where parties feel that too many resources have

been mapped away from areas where transmission would be triggered, with some arguing that this is contrary to the purpose of transmission planning. In general, this process involves balancing a number of objectives. There are many potential allocations of resources that can work. The interagency busbar mapping team seeks to preserve the optimal transmission expenditures found during portfolio development, while taking into account the various busbar mapping criteria.

MGRA comments on some of the specific projects mapped to busbars that are no longer pursuing development, projects that DOW terms “zombie” projects. Commission staff are aware that there are some mapped projects that may no longer be in development, but there is always a lag between when the projects are abandoned and when assumptions can be updated to reflect changed conditions. We expect that some of the projects MGRA mentions will be removed from mapping by the next cycle, though we also note that some projects may simply be delayed and not abandoned permanently.

With respect to the treatment of offshore wind projects and the associated transmission on the North Coast of California, Vineyard and CalGrid support the proposed decision, stating that it provides assurance of the continued support for development of both the transmission and wind resources in the mid-2030s. CUE and CURE, as well as RCEA and Humboldt County, continue to argue that the Commission should not delay these projects at all and that the proposed decision is inconsistent with state policy. We believe that the decision achieves the right balance of acknowledging the potential for some delay, while still supporting the projects moving forward. We note that nothing in this decision prevents offshore wind or its associated transmission projects from coming online sooner than assumed in the modeling analysis reflected herein.

Several parties comment on the mapping of out-of-state resources for transmission planning. GridLiance seeks a finding to further support the mapping of out-of-state resources, stating that if the Commission waits until later TPP cycles to map the clean, firm, out-of-state resources that are now being sought for procurement, it may jeopardize their viability and delay the transmission expansions needed to deliver them. We generally agree with this point.

CUE/CURE comment that the proposed decision should be revised to relocate 16 GW of Arizona and Nevada solar to the Fresno area. GSCE specifically criticizes the mapping of approximately 17 GW of “mostly-generic” out-of-state wind because the resources are subject to permitting and development issues outside of California control. DOW also recommends reduced reliance on out-of-state solar and wind. However, approximately half of the out-of-state solar had already been remapped to California locations, as specified in the proposed decision. We decline to remap additional imported solar and wind resources at this time because they represent cost-effective resources to control costs for ratepayers and present the opportunity to decrease reliability risks because of increased resource diversity.

On issues related to the RESOLVE model’s non-retention of natural gas plants, EDF asserts that plants should not receive an exemption on the basis that there is insufficient data about the local effectiveness factors of the plants in the CAISO Local Capacity Technical Report. However, no blanket exemption was applied based on this situation. The shift in treatment of gas plants without effectiveness factors was a product of stakeholder input from the prior TPP cycle.

MRP also proposes that the decision consider hybrid facilities that include battery storage with existing gas plants, when modifying the methodology for

determining which gas units should be retained. Commission staff will continue to evolve the methodology for determining which natural gas plants are shown as not retained in the next TPP cycle.

RCEA and Humboldt County request clarification on how the busbar mapping changes include plans for resources that need to be sited for gas retirement. In response, we clarify that the assumptions for natural gas non-retention are for purposes of transmission planning, and do not directly relate to any procurement requirements.

In comments on the proposed decision, several parties point out that the amount of solar mapped to PG&E Fresno in 2041 is less than was mapped in 2040 in the previous TPP cycle. However, this year's portfolio enables the development of more solar in an earlier timeframe, signifying our continued prioritization of the PG&E Fresno area for solar development. We will continue to ask the CAISO to study this area in future TPP cycles.

In response to comments on the proposed decision from ACP-CA regarding commercial interest in geothermal projects, Commission staff have moved 750 MW of geothermal from Malin to Hilltop, to facilitate the development of both in-state resources at Surprise Valley and imported resources from Northern Nevada. We ask the CAISO to study transmission solutions to increase import capacity between Hilltop and Malin, to facilitate delivery of geothermal across the CAISO system. Commission staff also intend to continue to refine the methodology for mapping geothermal projects in the next cycle, taking into account the characteristics of various geothermal technologies.

In response to the GreenGen comments on the proposed decision, the Mokelumne pumped storage project has been mapped at its full design capacity. In response to comments from SCVWA, the amount of PG&E Kern solar mapped

at full capacity deliverability has been restored to reflect commercial interest. In response to comments from Viridon, the CAISO queue Cluster 15 projects in PG&E Fresno (solar and storage) have been remapped to this area. In response to SCP and SJCE comments, 100 MW of Malin geothermal capacity has been mapped to Inyokern, which is consistent with the sensitivity portfolio, and also reflects commercial interest. Finally, in response to CalWEA comments, staff corrected an error that mischaracterized 700 MW of wind resources at the Madeline substation as energy only (when they should have full deliverability). However, no additional resources were mapped in this area; we ask the CAISO to continue to study the Northeastern California wind resources, as part of the final 2025-2026 TPP analysis.

6. Assignment of Proceeding

Alice Reynolds is the assigned Commissioner and Julie A. Fitch and Colin Rizzo are the assigned ALJs in this proceeding.

Findings of Fact

1. Commission staff conducted an analysis of electric reliability needs between 2028 and 2032 with SERVM, using an updated 2024 IEPR load forecast, and updated list of resources procured to meet MTR and Supplemental MTR requirements, and in response to comments on the RCPPP proposal and the ACP-CA Motion to Amend the Scoping Memo in R.20-05-003.

2. Several things have changed since the Commission last ordered IRP procurement in D.23-02-040 (as modified by D.24-02-047): (1) the CEC's 2024 IEPR demand forecast projects significant load growth in 2028-2032; (2) Federal tax credit benefits are being rapidly phased out over the next few years; and (3) other Federal actions have been taken imposing tariffs and limiting or delaying renewables siting on Federal lands.

3. Commission staff SERVM analysis results in an estimated need for a cumulative total of 6,267 MW of perfect capacity to be online by June 1, 2032.
4. The proposed aggregate average of 1,500 MW of procurement per year in the ALJ Ruling is in line with prior procurement orders and LSEs have been on notice that in R.20-05-003 an ongoing procurement requirement as part of RCPPP may be imposed by the Commission.
5. D.21-06-035 required at least 2,000 MW NQC of LLT resources to be procured by 2026. D.23-02-040 extended the deadline to 2028 and allowed for extension requests for online dates out to 2031.
6. It is likely that there are still some renewables projects without contracts that can take advantage of expiring Federal tax credits, in order to provide cost savings to ratepayers.
7. Requiring procurement by 2030, 2031, and 2032 is far enough in the future that it should mitigate some potential negative market impacts. However, the market is still facing several challenges that are beyond the control of the LSEs, including expiring Federal tax credits, and other Federal actions including tariffs and changes to renewables siting requirements. There is therefore need for continued flexibility to allow LSEs to address procurement delays outside of their control.
8. DCPD is likely to remain online at least through 2030.
9. Based on the Commission staff analysis presented in the September 30, 2025 ALJ Ruling, there is likely to be a reliability shortfall of approximately 6,000 MW by 2032 based on 2024 IEPR load forecasts and expected resources online.
10. The MTR and Supplemental MTR orders specified that eligible new resources must be either zero-emitting or otherwise eligible under the RPS

program. Repowered resources were eligible on the basis of any incremental capacity added during repowering, but not for the full capacity of the resource. Incremental capacity from modifications or upgrades to resources on the baseline line is also eligible, but only for the capacity above and beyond the baseline amount.

11. D.23-02-040, Ordering Paragraph 13, allowed LSEs to undertake baseline swaps, for eligible resources under the MTR and Supplemental MTR orders.

12. Energy storage, especially battery storage, has made up a large proportion of the resources procured to meet MTR and Supplemental MTR requirements, both due to its declining costs, its modularity, and its fast average development timelines.

13. Individual ESP energy and peak load forecasts are maintained confidentially by the Commission due to the cap on direct access load and competitiveness implications.

14. LSEs are eligible to count excess procurement in response to D.21-06-035 toward D.23-02-040 requirements.

15. D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) required new resources used to satisfy their requirements be under contracts of at least ten years in length.

16. Resource accreditation under the MTR and Supplemental MTR decisions was on the basis of marginal ELCCs produced by Commission staff.

17. D.25-09-007 generally allowed LSEs a grace period of up to three years, if they can show long-term contracts to satisfy MTR and Supplemental MTR requirements, and are otherwise in compliance with resource adequacy requirements during the period of delay.

18. LSEs with procurement obligations under D.21-06-035 and D.23-02-040 (as modified by D.24-02-047) are subject to non-compliance penalties set as the net CONE level. The Commission and staff consider deficiencies and non-compliance on a case-by-case basis, taking into account the LSE's good faith efforts, as currently defined in D.21-06-035 Ordering Paragraph 5. Under D.21-06-035 and D.23-02-040, the Commission may also order backstop procurement to be conducted if LSEs are deficient in their obligations.

19. With each annual TPP cycle, Commission staff make updates to inputs and assumptions, which can include resource cost assumptions, import assumptions, transmission constraints, and/or other updates. This year's updates include changed assumptions related to Federal action on tax credits, tariffs, and renewables siting on Federal lands. Other updates include resource potential for solar, wind, and near-field EGS, transmission cost adders for out-of-CAISO wind and geothermal resources in Northeast California and Imperial Valley, full representation of deep EGS on CAISO transmission deliverability constraints, retention costs of existing thermal units, and corrections to offshore wind hourly generation profiles.

20. The base case portfolio being recommended in this decision builds upon and is a reasonable middle ground between the previous TPP base case portfolio and sensitivity portfolio included in D.25-02-026.

21. The base case portfolio recommended in this decision is consistent with the precedent of building on recently-adopted portfolios to move the base case incrementally toward the state's clean energy goals.

22. The base case portfolio recommended in this decision meets our adopted GHG and reliability targets.

23. The CAISO's selection reports for the two transmission projects needed to support offshore wind development on the North Coast (the Humboldt projects) contain several types of cost containment measures for ratepayer protection as proposed by CalGrid, the approved project sponsor for both projects.

24. If transmission deliverability is not reserved by the CAISO for the LLT and other diverse resources in the portfolio, it is possible that transmission may not be available by the time the diverse resources are developed and ready to come online.

25. Both the recommended base case and sensitivity portfolios for this year's TPP contain solar build rates that are several multiples of any recent year's accomplished development.

26. Consistent with prior experience, there is not sufficient time to adopt many busbar mapping methodology improvements proposed by parties in this year's TPP cycle, but much input from past years was included this year, and new comments this year will be carefully considered for next year's busbar mapping improvements.

27. Based on the results of SERVVM production cost modeling, the recommended base case portfolio for the 2026-2027 TPP meets the Commission's reliability standard of less than 0.1 LOLE in 2036 and 2041, and has GHG emissions results that are within the CARB Scoping Plan trajectory for the electricity sector.

Conclusions of Law

1. Based on the staff reliability analysis summarized in the September 30, 2025 ALJ Ruling, the Commission should require approximately 6,000 MW NQC of new resource procurement through 2032.

2. Requiring procurement by no later than 2030 should allow LSEs to take advantage of any remaining projects that are able to qualify for expiring Federal tax credits, if they provide cost savings to ratepayers.

3. Requiring more procurement at later dates, in 2031 and 2032, could mitigate some potential negative market effects and help secure reasonable costs to ratepayers.

4. The Commission should require LSEs to procure 2,000 MW NQC of total new procurement to be online by June 1, 2030.

5. The Commission should require LSEs to procure 2,000 MW NQC of total additional new procurement to be online by June 1, 2031.

6. The Commission should require LSEs to procure 2,000 MW NQC of total additional new procurement by June 1, 2032.

7. The Commission should maintain resource eligibility rules for the procurement ordered in this decision consistent with MTR and Supplemental MTR requirements, which means that resources must be zero-emitting or RPS-eligible, repowering or modifications/upgrades are eligible only for the incremental capacity (if any) that was added during repowering or modification/upgrade, and baseline swaps, baseline waivers, and obligation swaps should be allowed. Any resource with a contract terminated after January 13, 2023 should continue not to be eligible for a baseline swap.

8. In order for the attributes identified in the TPP base case portfolio recommended in this decision to be procured to support grid reliability, the Commission should require that each LSE procure at least one-quarter of its total procurement obligation given in Attachment A from clean firm and/or LDES resources, as defined in D.21-06-035 Ordering Paragraph 2, and further modified

by D.25-06-005. These resources should be required to meet the June 1, 2032 compliance deadline.

9. Resources counted toward the procurement ordered in this decision should be required to be compliant with resource adequacy eligibility rules in place at the time they are requested to be counted to show compliance with this decision.

10. Energy-only resources that come online after the effective date of this decision should be eligible to be counted toward the procurement required in this decision, in the limited situation where there are generation and storage projects that are co-located, the storage is fully deliverable, and the multiple resource IDs have the same point of interconnection on the CAISO system. The individual storage and generation components of a co-located project should each count toward the procurement required in this decision based on their individual ELCC value.

11. The Commission should encourage LSEs to procure resources with attributes identified as those that can enable the state to reliably meet 2045 GHG reduction goals at least cost.

12. Resources eligible for counting toward the procurement requirements in this decision must be otherwise consistent with the resource adequacy requirements in place at the time they are being requested to be counted for compliance with this decision.

13. Imposing a local procurement requirement for the capacity required by this decision is likely to increase costs and make procurement more difficult. Therefore, the Commission should not require a specific amount of local procurement, though LSEs are encouraged to pursue procurement in local areas where it makes sense for their portfolios.

14. The Commission should maintain the principle that each LSE is responsible for procuring electricity resources to serve its own load where possible, unless there is a compelling reason to order centralized procurement for logistical or cost reasons.

15. Responsibility for the 6,000 MW NQC of new resource procurement required in this decision should be allocated to LSEs on the basis of each LSE's share of the managed peak on the electric system as of resource adequacy program year 2026, and weighted by the 2026 energy load forecasts for IOUs and CCAs from the CEC's adopted 2024 IEPR.

16. Nothing in this decision should be read to prejudge any issues that may be separately resolved in other venues with respect to data center growth projections, cost allocation, or any other related issues.

17. Individual LSE allocation of procurement responsibility should be as given in Attachment A. The ESP allocations should be calculated by dividing the individual ESP's year-ahead adjusted peak resource adequacy forecast for 2026 (for month 9) by the total/aggregate year-ahead adjusted peak resource adequacy forecasts for 2026 (for month 9) for all Commission-jurisdictional LSEs.

18. Commission staff should transmit individual ESP allocations confidentially within two weeks after this decision is adopted.

19. This decision should keep compliance and enforcement as similar as possible to MTR and Supplemental MTR requirements, and also keep the requirements as simple as possible.

20. LSEs should be eligible to count any excess procurement undertaken to meet D.21-06-035 or D.23-02-040 requirements toward the requirements of this decision, or in the potential future RCPPP requirements, if the resources otherwise qualify under the terms of this decision.

21. LSEs should be required to bring online a total of 2,000 MW NQC by no later than June 1, 2030, an additional 2,000 MW NQC by no later than June 1, 2031, and a total of an additional 2,000 MW NQC total by June 1, 2032.

22. Contracts used to satisfy the capacity procurement requirements in this decision should be required to be at least ten years in length and must begin deliveries by the required online date for each tranche.

23. Resources used to satisfy the new resource procurement requirements in this decision should be accredited on the basis of ELCCs, to be calculated by Commission staff and published by no later than July 31, 2026 for the 2030 and 2031 requirements and by no later than December 31, 2027 for the 2032 requirements.

24. Because there continue to be significant market challenges to developing new resources that may lead to procurement delays outside of the control of the LSEs, the Commission should apply the three-year delay provisions of D.25-09-007 to the procurement required by this decision.

25. Each set of new resources for 2030, 2031, and 2032 should be assessed for compliance on the required online dates of June 1, 2030, June 1, 2031, and June 1, 2032.

26. LSEs who do not comply with the procurement required by this decision should be subject to the same compliance and enforcement provisions as D.21-06-035, including penalties, backstop procurement, and consideration of an LSE's good faith efforts defined in D.21-06-035, Ordering Paragraph 5. Penalties will be based on the net CONE for any resource amounts not online by the deadlines. LSEs should also be subject to the potential for backstop procurement, if ordered by the Commission, with cost responsibility allocated to the customers

of the non-compliant LSE whose procurement must be backstopped, in the same manner as for procurement required by D.21-06-035 and D.23-02-040.

27. LSEs should continue to be required to make semi-annual procurement compliance filings on June 1 and December 1 of each year through 2032, unless otherwise modified by the Commission in the future.

28. The Commission should update the TPP inputs and assumptions as recommended by Commission staff in the ALJ Ruling and as articulated in this decision.

29. The Commission should take parties' comments on the inputs and assumptions for this TPP into account when revising the inputs and assumptions for next year's TPP portfolios, to the extent feasible.

30. Commission staff should update the assumptions for next year's TPP based on the actual procurement accomplished by LSEs in response to MTR and Supplemental MTR requirements prior to the next TPP portfolios (for 2027-2028) being evaluated.

31. The base case portfolio described in this decision, which incorporates MTR resources and approximately half of the LLT resources found needed in D.24-08-064, with the offshore wind resources' online dates extended by four to six years, is reasonable and should be adopted as the recommendation for the CAISO 2026-2027 TPP.

32. The Commission should recommend that the CAISO allow the potential in-service dates for the Humboldt transmission projects to extend by two years to June 1, 2036, in order to have transmission available for when North Coast offshore wind generation projects are anticipated to begin coming online.

33. It is reasonable to ask the CAISO to continue to reserve deliverability for geothermal, LDES, out-of-state wind, and offshore wind resources in the

amounts summarized in Table 7 of this decision and detailed in the base case portfolio dashboards posted on the Commission's website.

34. It is reasonable to ask the CAISO to study a sensitivity portfolio in the 2026-2027 TPP that includes a worst-case scenario for all types of wind development, because the loss of critical wind resources could have a material impact on transmission needs for the resources that would be substituted for the wind.

35. The recommended sensitivity portfolio is more expensive than the base case, but we are recommending it for study by the CAISO because it is a useful portfolio to analyze for potential transmission planning needs. This sensitivity portfolio is more expensive than the base case portfolio and would place a higher burden on California ratepayers compared to other options, but it is selected for study to elicit critical transmission planning information.

36. To address the potential challenges associated with the high annual build rates for solar resources necessary to reach either the base case or the sensitivity portfolio amounts by 2041, the Commission should consider evaluating, for the 2027-2028 TPP sensitivity portfolio and/or a PSP sensitivity portfolio, a scenario that could impact solar build rates.

37. It is reasonable to update the busbar mapping methodology for next year's TPP cycle to incorporate the items further discussed in Section 3.5 of this decision, including but not limited to, updating of the commercial interest criteria.

38. It is reasonable to update the busbar mapping for this year's TPP to incorporate the items further discussed in Section 3.6 of this decision, including but not limited to accounting for otherwise unaccounted-for TPD and remapping solar resources from SDG&E Arizona to PG&E and SCE areas.

39. The PCM results for reliability and GHG emissions for the recommended base case portfolio presented in Tables 9 and 10 in this decision are in a reasonable range to request that the CAISO study the portfolio further.

O R D E R

IT IS ORDERED that:

1. All load serving entities (LSEs) subject to the California Public Utilities Commission's integrated resources planning purview shall procure new net qualifying capacity (NQC) from non-emitting, storage, and/or resources eligible under the renewables portfolio standard program, with 2,000 megawatts (MW) NQC total due online by no later than June 1, 2030, an additional 2,000 MW NQC online by no later than June 1, 2031, and an additional 2,000 MW NQC due online by no later than June 1, 2032. To be counted, resources must be delivering power to the grid and contracted to begin deliveries by the above dates.

2. Each load serving entity subject to the California Public Utilities Commission's integrated resources planning purview shall procure at least one-quarter of its total obligation as given in Attachment A of this decision from clean firm resources and/or long-duration storage resources, as defined in Decision (D.) 21-06-035 Ordering Paragraph 2, as modified by D.25-06-005, by no later than June 1, 2032.

3. Energy-only resources are eligible to be counted toward the procurement required in Ordering Paragraph 1, in the limited situation where there are energy-only generation and fully deliverable storage projects that are co-located, the multiple resource identification numbers have the same point of interconnection on the California Independent System Operator system, and the resources are eligible to be counted towards the resource adequacy slice-of-day requirements. The individual storage and generation components of a co-located

project will each count toward the procurement required in this decision based on their individual effective load carrying capability value. The energy-only resources must also come online after the effective date of this decision to be counted toward the procurement requirements in Ordering Paragraph 1.

4. Repowered resources and other baseline resources that have been modified or upgraded that otherwise qualify may also be used to satisfy the requirements of Ordering Paragraph 1, but only to the extent that the repowering or modification/upgrade results in incremental capacity, and only the incremental capacity may be counted toward the requirements.

5. All resources used to satisfy the procurement requirements of Ordering Paragraphs 1-3 must meet the resource adequacy eligibility requirements in place at the time they are being requested to be counted toward the procurement requirements of this decision.

6. The allocation of net qualifying capacity obligations in Ordering Paragraph 1 to individual load serving entities (LSEs) shall be done based on the individual LSE load forecasts from the 2024 California Energy Commission Integrated Energy Policy Report load forecast, weighted by contribution to the 2026 resource adequacy forecast managed peak, for community choice aggregators (CCAs) and investor-owned utilities (IOUs). Individual allocations for IOUs and CCAs individually, and electric service providers (ESPs) in aggregate, are given in Attachment A. The ESP allocations shall be calculated by dividing the individual ESP's year-ahead adjusted peak resource adequacy forecast for 2026 (for month 9) by the total/aggregate year-ahead adjusted peak resource adequacy forecasts for 2026 (for month 9) for all Commission-jurisdictional LSEs.

7. The allocations to individual electric service providers shall be maintained and transmitted confidentially by electronic mail addressed to the load serving entity's designated primary contact person from California Public Utilities Commission staff within two weeks of the effective date of this decision.

8. All resources used to satisfy the requirements of Ordering Paragraph 1 and Ordering Paragraph 2 shall be procured in contracts that are ten years or more in length and are required to be online, contracted to begin electricity deliveries, and actually delivering electricity to the grid, by June 1 in the year in which they are required in Ordering Paragraph 1 and Ordering Paragraph 2, to be counted toward the requirements.

9. Accreditation for resources used to satisfy the requirements of Ordering Paragraph 1 and Ordering Paragraph 2 shall be determined on the basis of two marginal effective load carrying capability (ELCC) studies conducted by California Public Utilities Commission staff. The marginal ELCC study for compliance values for resources due online by 2030 and 2031 shall be published by no later than July 31, 2026. The marginal ELCC study for compliance values for resources due online by 2032 shall be published by no later than December 31, 2027. The ELCC studies shall specify technology-specific and storage-duration-specific values to reflect expected ELCCs based on future resource portfolio composition.

10. Any penalties associated with failure to comply with the requirements of Ordering Paragraph 1 and Ordering Paragraph 2 shall be assessed on a case-by-case basis taking into account good faith efforts as currently defined in Decision 21-06-035 Ordering Paragraph 5 and based on a calculation of the net cost of new entry and will be assessed separately for the 2030, 2031, and 2032 compliance requirements. The need for backstop procurement shall be evaluated

in 2030, 2031, and 2032 after receipt and analysis of the procurement data filed on June 1 in each year.

11. The three-year flexible compliance provisions in Decision 25-09-007 that allow load serving entities to be deemed compliant if they have the required resources under contract and are otherwise compliant with resource adequacy requirements shall apply to the requirements of Ordering Paragraph 1 and Ordering Paragraph 2.

12. Load serving entities subject to the California Public Utilities Commission's (Commission) integrated resource planning purview shall continue to provide procurement compliance filings on June 1 and December 1 of each year through the end of 2032, unless otherwise modified by the Commission.

13. Load serving entities subject to the California Public Utilities Commission's integrated resource planning purview that have procured resources in excess of the requirements of Decision (D.) 21-06-035 and/or D.23-02-040 may use the excess procurement to satisfy the requirements of this decision, as long as they otherwise meet the criteria specified herein.

14. Any electric resources procured by an investor-owned utility in response to this decision shall be subject to Power Charge Indifference Adjustment (PCIA) vintage cost responsibility based on the effective date of this decision. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may each submit a Tier 2 advice letter within 60 days of the effective date of this decision to update their balancing accounts to address this PCIA treatment.

15. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall each file Tier 3 advice letters to

request cost recovery for any procurement conducted as a result of this order, except if the procurement is associated with a pumped storage resource or a utility-owned resource, a full application is required.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may file Tier 1 advice letters to claim compliance with the procurement requirements of Ordering Paragraph 1 and/or Ordering Paragraph 2 for any contract or resource that has already been approved by the California Public Utilities Commission for another purpose in another venue, except as limited by Ordering Paragraph 3.

17. The California Public Utilities Commission transfers to the California Independent System Operator (CAISO) for its annual Transmission Planning Process (TPP) a reliability and policy-driven base case portfolio that meets a 25 million metric ton greenhouse gas emissions level in 2035, incorporates the individual load serving entity resource plans from 2022, includes approximately half of the long lead-time resources found needed in Decision 24-08-064, as specified in Section 3.2 of this decision, includes delays to the expected online dates for offshore wind, and includes the results of the mapping of resources to busbars discussed in Section 3.6 of this decision. The base case portfolio includes modeled years of 2036 and 2041, and CAISO TPP analysis is requested for both years.

18. The California Public Utilities Commission recommends that the California Independent System Operator allow the potential in-service dates for the Humboldt transmission projects approved to support North Coast offshore wind resources in the 2024-2025 Transmission Planning Process to extend by two years, to June 1, 2036.

19. The California Public Utilities Commission requests that the California Independent System Operator reserve deliverability on the transmission system for the amount of geothermal, long-duration energy storage, out-of-state wind, and offshore wind resources summarized in Table 7 of this decision and detailed in the base case portfolio dashboard posted on the Commission’s website.

20. The California Public Utilities Commission transfers to the California Independent System Operator for its annual Transmission Planning Process a Limited Wind Sensitivity portfolio, as described in Section 3.3 of this decision, to facilitate contingency planning for transmission needed by other resources if the desired wind resources do not materialize. This sensitivity portfolio shall not be represented as a policy preference of the Commission.

21. Rulemaking 25-06-019 shall remain open.

This order is effective today.

Dated _____, at Santa Maria, California.

ATTACHMENT A

Attachment 1:

[R2506019 Fitch PD \(Redline Version\).pdf](#)

Attachment 2:

[R2506019 Attachment A \(Rev.1\).pdf](#)

Attachment 3:

[R2506019 Attachment A \(Redline Version\).pdf](#)

San Luis Obispo Measure A - ordinances for onshore facilities for offshore development

From mbcfo member <mbcfo1972@gmail.com>

Date Sun 03/29/2026 04:10 PM

To Doug Boren <douglas.boren@boem.gov>; CentralCoast@Coastal <CentralCoast@coastal.ca.gov>; Andrea Chmelik <Andrea.Chmelik@asm.ca.gov>; Dobroski, Nicole@SLC <Nicole.Dobroski@slc.ca.gov>; Eckerle, Jenn@CNRA <Jenn.Eckerle@resources.ca.gov>; Executive Officer of SLC <ExecutiveOfficer.Public@slc.ca.gov>; ExecutiveStaff@Coastal <ExecutiveStaff@coastal.ca.gov>; FGC <FGC@fgc.ca.gov>; Flint, Scott@Energy <Scott.Flint@energy.ca.gov>; bgibson@co.slo.ca.us <bgibson@co.slo.ca.us>; Greg Haas <greg.haas@mail.house.gov>; Nancy Hann <nancy.hann@noaa.gov>; Harland, Eli@Energy <Eli.Harland@energy.ca.gov>; Dr. Caryl Hart <CommissionerCHart@coastal.ca.gov>; Gonzalez, Kathleen@Waterboards <Kathleen.Gonzalez@Waterboards.ca.gov>; Huckelbridge, Kate@Coastal <Kate.Huckelbridge@coastal.ca.gov>; Kalua, Kaitlyn@CNRA <Kaitlyn.Kalua@resources.ca.gov>; Kato, Grace@SLC <Grace.Kato@slc.ca.gov>; Zara Landrum <zlandrum@morrobayca.gov>; JANO.DEKERMENJIAN@sen.ca.gov <JANO.DEKERMENJIAN@SEN.CA.GOV>

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Dear California politicians and other State agents,

It is important for all involved with permitting offshore wind energy to be aware of the many ordinances for onshore facilities for offshore development in 28 communities along California's coastline. It is called "The Blue Wall". It was designed to prevent offshore oil drilling but many of the ordinances apply to offshore wind onshore facilities. San Luis Obispo County, in 1986, passed Measure A. It has several ordinance requirements for onshore facilities, including a requirements for any oil storage facilities to be a long way from residential areas and for a majority vote of the people to approve. Here is a copy of SLO's Measure A for you to review:

Note on Page 48 of Measure A -

"Onshore facilities supporting offshore development must receive local government approval, including approval by the voters in accordance with measure A. Measure A, adopted by county voters in November 1986, provides an added requirement that any permit issued for onshore facilities related to offshore development must be approved by a majority of voters."

The onshore facilities required for Offshore Wind development are very similar to Offshore Oil development. Large storage tanks for oil and lubricants, transfer pumps, and pipelines of liquids to ships will be required.

Here is a list of the liquids required in each turbine that will need to be regularly changed out. It will need to be stored in large tanks at the Operations and Maintenance ports - San Luis Obispo and Morro Bay. This information was taken from BOEM Offshore Wind FEIS.

EACH TURBINE WILL USE:

THIS INFORMATION WAS TAKEN FROM (BOEM) BUREAU OF OCEAN ENERGY MANAGEMENT

187 GALLONS of GREASE

40 GALLONS of HYDRAULIC OIL

106 GALLONS of GEAR OIL

1,585 GALLONS of DIELECTRIC FLUID

793 GALLONS of DIESEL FUEL

243 LBS of SULPHUR HEXALFLOURIDE

357 GALLONS of PROPYLENE GLYCOL

48 GALLONS of ETYLENE GLYCOL

Please add this information to your records regarding Offshore Wind.

Thank you for your attention to this matter,

Tom Hafer
Secretary MBCFO
(805) 610-2072
mbcfo1972@gmail.com

COUNTY OF SAN LUIS OBISPO

OFFSHORE ENERGY ELEMENT

ADOPTED BY
THE SAN LUIS OBISPO COUNTY BOARD OF SUPERVISORS
DECEMBER 15, 1992 - RESOLUTION 92-543

COUNTY OF SAN LUIS OBISPO

Board of Supervisors

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Harry L. Ovitt, District 1
Evelyn Delany, District 3
Ruth Brackett, District 4
David Blakely, District 5

Planning Commission

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Anna Alexander, District 3
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Kenneth Schwartz, District 5
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Offshore Energy Task Force

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Avis Austin, League of Women Voters
Larry Allen, Air Pollution Control District
Sonya Bracken, League of Women Voters
Frank Bush, Sierra Club
M.K. Cannon, Chevron
Franklin Crane, Citizens for Adequate Energy
John Donovan, California Coastal Operators Group
Jay Elder, Port San Luis Harbor District
Travis Evans, Fishing Industry
Harry Hines, Citizen, San Luis Obispo County
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Carolyn Moffatt, Port San Luis Harbor District
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Beryl Reichenberg, Citizen, San Luis Obispo County
Darwin Sainz, Unocal

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TABLE OF CONTENTS

<u>Chapter</u>	<u>Page</u>
Preface	vii
User's Guide	viii
I. Introduction and Policies	
1.1 Authority and Purpose	I-1
1.2 Relationship to Other General Plan Elements	I-1
1.3 Methodology	I-1
1.4 Components of the Element	I-2
1.5 Policies	I-3
1.5.1 Chapter IV - Leasing	I-3
1.5.2 Chapter V - Biology	I-5
1.5.3 Chapter VI - Fisheries	I-6
1.5.4 Chapter VII - Air Quality	I-9
1.5.5 Chapter VIII - Onshore Facilities	I-13
1.5.6 Chapter IX - Supply and Crew Bases	I-14
1.5.7 Chapter X - Oil Spill Response	I-16
II. Offshore Oil Development	
2.1 Development and Production of Offshore Oil and Gas	II-1
2.2 Offshore Facilities	II-1
2.3 Offshore/Onshore Facilities	II-6
2.4 Onshore Support Facilities	II-8
2.5 Impacts	II-13
2.6 Regulatory Framework	II-14
2.7 Regulatory Phases of Development	II-16
2.8 State Waters	II-16
2.9 Onshore Facilities	II-17

<u>Chapter</u>	<u>Page</u>
III. Policy Base	
3.1 Introduction	III-1
3.2 Evolution of County Policies	III-1
3.3 Summary of Relationship to Local Coastal Plan	III-3
3.4 Summary of Relevant Coastal Act & LCP Policies	III-4
3.5 Policies Addressed by This Element	III-6
3.6 How to Locate Policies	III-6
IV. Leasing	
4.1 Outer Continental Shelf Leasing	IV-1
4.2 County Role in OCS Leasing	IV-3
4.3 Public Participation in Leasing Decisions	IV-3
4.4 Types of Leasing Issues	IV-4
4.5 Procedural Issues	IV-6
4.6 Other Issues	IV-7
4.7 San Luis Obispo County Position on Leasing	IV-7
4.8 Policies	IV-9
V. Biology	
5.1 Background	V-1
5.2 Description of Resources	V-3
5.3 Impacts	V-5
5.3.1 Offshore	V-5
5.3.2 Onshore/Nearshore	V-7
5.4 Regulatory Setting	V-8
5.4.1 Federal Role	V-9
5.4.2 State Role	V-10
5.4.3 County Role	V-11

<u>Chapter</u>	<u>Page</u>
5.5 Programs/Studies	V-11
5.6 Policies	V-12
VI. Fisheries	
6.1 Description of Resource	VI-1
6.2 Regulatory Setting	VI-3
6.3 Impacts to Fisheries	VI-5
6.4 Major Issues	VI-7
6.5 Policies	VI-9
VII. Air Quality	
7.1 Description of Resource	VII-1
7.2 Regulatory Setting	VII-7
7.3 Air Quality Impacts	VII-12
7.4 Offshore Emissions and Mitigation Measures	VII-15
7.4.1 Exploration	VII-16
7.4.2 Development	VII-17
7.4.3 Production	VII-19
7.4.4 Support Vessel Operations	VII-22
7.5 Onshore Emissions & Mitigation Measures	VII-24
7.6 Major Issues	VII-26
7.7 Policies	VII-30
VIII. Onshore Facilities	
8.1 Background	VIII-1
8.2 Description of Resource	VIII-1
8.3 Regulatory Setting	VIII-2
8.4 Operations	VIII-5

<i>Chapter</i>		<i>Page</i>
8.5	Impacts	VIII-8
8.6	Siting, Design, and Mitigation Considerations	VIII-11
8.7	Buffer Zones, Compliance, & Mitigation	VIII-19
8.8	Summary	VIII-23
8.9	General Policies	VIII-24
8.10	Specific Policies	VIII-26

IX. Supply and Crew Bases

9.1	Introduction	IX-1
9.2	Supply Base - General Characteristics	IX-3
9.3	Size/Land Requirements	IX-5
9.4	Waterfront/Harbor	IX-7
9.5	Materials to be Transported	IX-9
9.6	Crew Bases General Characteristics	IX-10
9.7	Westec Crew Base Siting Study	IX-10
9.8	Impacts from Supply and Crew Bases	IX-13
9.9	Policies	IX-15

X. Oil Spill Response

10.1	Introduction	X-1
10.2	Oil Spill Legislation	X-1
10.3	Industry Response Organization	X-3
10.4	Federal Response Organization	X-4
10.5	State Response Organization	X-7
10.6	Local Agency Role	X-9
10.7	Available Response Resources	X-10
10.8	Policies	X-12

<u>Table</u>	<u>Page</u>
Table II-1	Major Agencies, Laws & Permits II-15
Table VII-1	Maximum Pollutant Concentrations Measured in San Luis Obispo County from 1982-1989 VII-3
Table VII-2	1987 Annual Emissions Inventory - San Luis Obispo County (Tons per Year) VII-4-5
Table VII-3	Ambient Air Quality Standards VII-9
Table IX-1	Resource Estimates for a Supply Base IX-5
Table IX-2	Goods Transferred from a Supply Base per 10,000 Foot Well IX-11

<u>Figure</u>	<u>Page</u>
Figure II-1	Estimated Reserves in Santa Maria Basin and Santa Barbara Channel II-2
Figure II-2	Geophysical Operations II-4
Figure II-3	Offshore Drilling Rigs II-5
Figure II-4	Offshore & Onshore Pipeline Laying Methods II-7
Figure II-5	Oil & Gas Processing Facilities II-9
Figure II-6	Marine Terminal and Tank Farm II-11
Figure IV-1	Active Leases from Previous Lease Sales IV-2
Figure V-1	Some Threatened or Endangered Species in the County V-2
Figure V-2	Ecologically Significant Marine Areas V-4
Figure V-3	The Santa Lucia Bank V-14
Figure V-4	Nipomo Dunes and Northern San Luis Bay Intertidal V-15

<u>Figure</u>		<u>Page</u>
Figure V-5	North Estero Bay Rocky Intertidal Areas	V-16
Figure V-6	Cape San Martin-Pt. Piedras Blancas	V-17
Figure VI-1	Port San Luis & Morro Bay Fish Catch 1980-1989	VI-2
Figure VII-I	1987 Annual Emissions Inventory - San Luis Obispo County	VII-6
Figure VIII-1	Location of Oil & Gas Facilities in San Luis Obispo County	VIII-3
Figure VIII-2	Example of a Construction Schedule	VIII-9
Figure VIII-3	Oil Company Land Ownerships in the South County Planning Area	VIII-15
Figure VIII-4	Oil Company Land Ownership in the San Luis Bay Planning Area	VIII-16
Figure VIII-5	Oil Company Land Ownership in the Estero Planning Area	VIII-17
Figure IX-1	Supply and Crew Bases Serving the Santa Maria Basin	IX-2
Figure IX-2	Supply and Crew Boats	IX-4
Figure IX-3	Prototype Supply Base	IX-6
Figure X-1	Federal Response Organization	X-6

PREFACE

Oil development has always been a part of California's history. Native Americans gathered asphaltum from natural seeps, as did Spanish explorers and settlers. Lamp oil was being produced in a state refinery as early as 1850. The first exploratory well drilled for oil was in 1861 although the first producing well was not drilled in the state until 1865. Onshore development progressed rapidly the next 30 years, and the first offshore well was drilled in state tidelands (within 3 miles of shore) off Santa Barbara in 1896. The first lease sale on California's outer continental shelf (OCS) was in 1963. While these were unproductive, the first OCS production came from leases sold in 1965.

San Luis Obispo County has had onshore oil development for most of the last 100 years. Numerous wells have been drilled throughout the county. Although many wells were dry, there are eight producing oil fields in the county, some of which extend into Kern and Santa Barbara Counties. The county also has an existing oil refinery and a petroleum products factory on the Nipomo Mesa, and numerous crude and oil products pipelines and pump stations, natural gas pipelines, tank farms and marine terminals. Development continues on the OCS and an onshore oil processing facility and associated pipelines were applied for and conditionally approved by the county but was rejected by the voters. Accelerated OCS development pressures are expected. Recognizing this, the county is taking advantage of existing experience and knowledge available from other areas where development is occurring by creating a policy document to guide the county. The Offshore Energy Element will help the county assess offshore projects and lease sales, develop policies for future positions, and be prepared to address potential future OCS related projects.

The element will serve several functions and can be used by the public and the oil industry as well as decision makers. It is an educational document presenting many aspects of offshore oil development and associated necessary facilities, as well as the potential interactions and impacts of these developments on the county's marine and terrestrial resources. It can serve as a guide to potential developers, presenting some of the county's concerns and policies. The element also focuses on the planning of facilities related to OCS development, and will be the first place to turn for policy direction.

This Offshore Energy Element has been prepared by the Energy and Natural Resources Division of the Department of Planning and Building. Due to the wide interest in the topic and the need to address all of the varied perspectives, a task force with representatives of the general public, environmental organizations, and the oil and gas industry was formed. The role of the task force was to act as a liaison to the public and industry in reviewing and commenting on elements of the plan as they evolved. The task force reviewed each chapter and attended meetings at which comments were provided to county staff and a variety of issues were discussed. The task force is to be congratulated for their persistence, expertise and ability to debate difficult topics in a constructive manner.

User's Guide for the Offshore Energy Element

The following table should be used to identify county policies in the Offshore Energy Element that may apply to a particular offshore oil and gas activity. On the reverse side is a table showing the various federal, state and local regulations as well as agencies which have a role in the review process.

User Interest	Applicable Policies	Page	Chapter	□
Lease Sale	1.5.1 Leasing: All Policies	I-3	IV	
	1.5.2 Biological: #1 and 3.	I-5	V	
	1.5.3 Fisheries: #1, 3, 5, and 6.	I-5	VI	
	1.5.4 Air Quality: #1, 2, and 3.	I-9	VII	
Geophysical Surveys	1.5.1 Leasing: #1, 2, and 3.	I-3	IV	
	1.5.3 Fisheries: #2, 3, 4, and 5	I-7	VI	
Exploration	1.5.1 Leasing: #3	I-4	IV	
	1.5.2 Biological: #1, and 3.	I-6	V	
	1.5.3 Fisheries: All Policies	I-6	VI	
	1.5.4 Air Quality: #1, 2, 3, 4, and 7.	I-9	VII	
	1.5.6 Supp/Crew: All Policies	I-15	IX	
Construct/Operation	1.5.1 Leasing: #1, 2, and 3.	I-3	IV	
	1.5.2 Biological: All Policies.	I-5	V	
	1.5.3 Fisheries: All Policies	I-6	VI	
	1.5.4 Air Quality: All Policies	I-9	VII	
	1.5.5 Onshore Fac: All Policies	I-14	VIII	
	1.5.6 Supp/Crew: All Policies	I-15	IX	
	1.5.7 Oil Spill: All Policies	I-17	X	
The user should also consult the appropriate sections of the Local Coastal Plan, Land Use Ordinance, and other elements of the General Plan. These sections will provide specific information about the county's project review process.				

**Table II-1
MAJOR AGENCIES, LAWS AND PERMITS INVOLVING
OFFSHORE OIL AND GAS DEVELOPMENT**

FEDERAL AGENCIES	LAW	REGULATORY AUTHORITY
Minerals Management Service (MMS)	Outer Continental Shelf Lands Act	Permit to Drill
National Oceanic and Atmospheric Administration (NOAA)	Coastal Zone Management Act (CZMA)	Consistency Certification
Environmental Protection Agency (EPA)	Clean Water Act	National Pollution Discharge Elimination System (NPDES)
Army Corps of Engineers (COE)	River and Harbor of 1899	404 Permit, Section 10 Permit
U.S. Fish and Wildlife Service, National Marine Fisheries Service	Endangered Species Act	Section 7 Consultation
All agencies must comply with NEPA	National Environmental Policy Act (NEPA)	Environmental Impact Statement

CALIFORNIA AGENCIES	LAW	REGULATORY AUTHORITY
State Lands Commission	Submerged Lands Act; CPRC, Div 6, Sec 6001; & OSPRA	Right-of Way/State Waters Lease Management of State Lands Inspection of Marine Terminals
Regional Water Quality Control Board	Porter-Cologene Act Water Code	National Pollution Discharge Elimination System (NPDES)
Department of Fish and Game	California Fish and Game Code	Stream Alteration Permit/ Oil Spill Emergency Response
Department of Transportation (CALTRANS)	Streets and Highway Code	Encroachment Permit
Coastal Commission	California Coastal Act	Coastal Development Permit
Air Resources Board	Air Pollution Control Laws	

LOCAL AGENCIES	LAW	REGULATORY AUTHORITY
County/City Government (Planning Departments)	General Plans, Local Coastal Plans, Zoning Ordinances	Land Use Permit/Coastal Development Permit, Conditional Use Permit. Building Permits
Measure A	Local Coastal Plan	Voter Approval of Onshore Facilities
Air Pollution Control District (APCD)	Clean Air Plan	Authority to Construct, Permit to Operate

CHAPTER I: INTRODUCTION AND POLICIES

1.1 Authority and Purpose

The Offshore Energy Element of the San Luis Obispo County General Plan is a policy document developed to enhance public awareness and participation in decision-making regarding offshore and related onshore oil and gas activities. It is intended to be an educational document which also provides a summary of county policy, suggests new policies, and offers clear direction for implementation. The information presented in the element is crucial to the understanding of local and regional issues related to development of offshore petroleum resources. An understanding of the technical basis of impacts is necessary to recommend changes in county policy.

1.2 Relationship to Other General Plan Elements

Government code section 65300 et seq. requires the county to have a general plan that consists of seven mandatory elements. In addition to the required elements, the plan may include other optional elements, such as energy, which relate to the physical development of the county. Upon adoption, an optional element becomes an integral part of the general plan. It has the same force and effect as the mandatory elements.

The general plan is required by law to be an internally consistent statement of local government policy. Each element of the general plan must be integrated and consistent with all other elements. This element is related to the Land Use, Conservation, and Recreation Elements of the county general plan. The Local Coastal Plan Policies portion of the Land Use Element also has policies relating to energy and industrial development.

1.3 Methodology

This project was completed by county planning staff, with a great deal of assistance from the Offshore Energy Task Force. County funding came from grant monies received through the state Coastal Resource and Energy Assistance Program (SB 959). Since the primary purpose of the grant program was to allow local agencies to develop planning, monitoring, or mitigation projects related to offshore oil, this plan was an ideal candidate for grant funding.

This document is intended for use by the public, oil industry, and local decision makers to better understand the issues related to offshore oil development. In the past, there has been no one document that could be relied upon for such information. Onshore siting policies, formulated in the late 1970's as part of the Local Coastal Plan, were developed when there was not as great an interest in offshore oil development adjacent to our county. Similarly, policies have been

developed which address offshore oil leasing activities in response to specific leasing proposals. These policies needed to be refined, updated where necessary, and consolidated into one document. Though the state and federal governments have primary jurisdiction offshore, the county's policies nevertheless may influence the timing and location of offshore oil and gas development, as well as related onshore activities.

It is anticipated that the element will need periodic updating as new information becomes available. This could be as a result of increased offshore activity, subsequent environmental research, or simply changes in technology which could provide new opportunities for mitigation. Since the element is being developed in advance of any offshore production off the coast of our county, it is recommended that the plan be reviewed at least every two years for significant changes which need to be addressed.

1.4 Components of the Element

Chapter II is an informational section that provides an overview of offshore oil development. It describes the many agencies which become involved and their respective role in the process. Typical activities associated with offshore development are also outlined.

Chapter III describes the historic development of existing San Luis Obispo County energy policies. Background information is provided beginning with initial studies done in the preparation of the Local Coastal Plan and through the review of related land use permit applications.

Chapter IV presents issues related to leasing offshore areas, detailing the process as well as the impacts of leasing. Also included in this chapter a summary of recent county policies.

Chapters V, VI and VII are resource chapters covering biological, fisheries, and air quality issues related to offshore development. Each chapter presents a description of the resource, and details the major issues and impacts of concern for their respective topics. The regulatory setting, including the county's role, together with the coordination required with other agencies, is described in detail. Mitigation measures which potentially reduce or eliminate impacts to the resource are described. Specific policies are made at the end of each chapter.

Chapter VIII describes onshore facility siting and the issues the county will face when evaluating such a proposal. This chapter discusses the technological characteristics of each type of facility, the environmental, system safety, and land use considerations which must be addressed in the potential siting of a facility.

Chapter IX discusses various issues related to supply and crew bases. The chapter summarizes the issues associated with these types of facilities. Chapter X deals with oil spill prevention and response. It reviews existing studies and identifies the current response structure if a spill were to occur in the waters offshore our county.

1.5 Policies

This section contains a summary of the policies found at the end of chapters IV, V, VI, VII, VIII, IX, and X. Chapters I, II, and III provide background information related to offshore energy and do not include policies. The following policies will be implemented by the county to the full extent of the law when reviewing future offshore energy related proposals.

1.5.1 Chapter IV - Leasing

1. Lease sale stipulations, if responsibly drafted, can protect the natural resources of the county and promote county interests. In the lease sale process, the county will adopt positions requesting stipulations that require the following:
 - Lease sale stipulations prohibiting lessees from using an offshore storage & transfer vessel (OS&T) for the purposes of processing and transporting OCS production, and requiring instead that all offshore oil and gas production be piped onshore for processing and movement to market.
 - Agreements requiring that before further leasing, MMS conduct a baseline biological study which focuses on this county's offshore waters, or, if leasing occurs, a stipulation requiring the study prior to initiating development of any tracts leased.
 - Lease sale stipulations requiring site-specific biological surveys intended to define the presence of and provide protection for important biological resources. The survey shall define areas of special biological significance and higher productivity, diverse and/or complex ecosystems which include high-intensity fin-fish/shell fish areas, critical habitat and rare/threatened, endangered species, unusual, rare, uncommon ecosystems, areas having an abundance or high diversity of species, and areas critical to the life cycles of species (i.e. spawning, feeding, rearing or migratory areas).
 - Protection for biological resources identified in biological surveys shall include avoidance of areas, modification of operations, and provision for a regular monitoring program during operations with authority to require reasonable corrective measures to mitigate identifiable impacts.
 - Maintain the county's Offshore Energy Task Force during lease sale review and comment periods to enhance the flow of information to the public.
2. Controlling the overall pace of offshore development can reduce the level of peak cumulative impacts and increase opportunities for orderly change in the very limited

parts of the county which may prove suitable for onshore support facilities. To accomplish these purposes, the county will adopt a position which requires:

- Leasing agencies to comprehensively study the impacts of the development of already leased tracts offshore the county (most of which lie within the buffer zone defined by the county) before additional leasing occurs.
- Leasing agencies to recognize the difficulties in accommodating onshore facilities required for development of already leased tracts and to resolve such difficulties before any additional leasing occurs.
- Require that all future pipelines and processing facilities be consolidated to the maximum extent feasible.

3. San Luis Obispo County has consistently advocated policy positions which have not been adopted in federal lease sales. To provide further protection of biological and coastal resources, and to address the general unresponsiveness of the Minerals Management Service (MMS) to these county policies, the county will adopt a position which requires:

- Permanent protection and management of the county's coastal resources using the National Marine Sanctuary and the National Estuary Programs as vehicles for protection and management.
- Future lease sales and developments be consistent with the county position that no drilling be permitted north of Morro Bay, within 20 miles of Morro Bay, or within 12 miles of the southern boundary of the California sea otter range.
- That a 15 mile buffer zone of no offshore energy activities be established around the Santa Lucia Bank to protect the rich commercial fisheries and other natural resources.
- Opposition to future lease sales until concerns including leasing in sensitive areas, the county-proposed buffer zones, understatement of impacts, overly ambitious leasing schedules, failure to consider the need to plan for onshore support facilities, and the potential roles of conservation and alternative energy resources are adequately addressed by federal agencies.
- Pursuing maximum public awareness and participation in lease sales, as well as assuming an advocacy role in affecting policy, maintaining continued clear county policy direction, and coordinating efforts with other coastal counties.
- Actively supporting legislation consistent with the county's adopted leasing policies.

- Formal opposition to exploration and development plans submitted to MMS in the event these activities are inconsistent with the county's leasing policies (i.e. where such activities are proposed in locations where the county had previously objected to leasing).
- Disapproval of proposals for onshore support facilities that are incompatible with adopted leasing policies.
- Participation to advance county policies if either the current 5-Year OCS Leasing Plan or any lease sales are challenged in court on issues directly or indirectly affecting the county.
- Review and comment on proposed lease sales and leasing-related legislation affecting other areas in instances where we share common concerns and there may be potential impacts to our county.
- Continue the practice of providing for public discussion before the Board of Supervisors in all instances where the county has the opportunity to comment on lease sales or on leasing-related issues so that interested individuals and organizations are provided maximum opportunity for input.

1.5.2 Chapter V - Biology

1. The biological resources of the county have a long term value which is only partly economic. To protect this value should offshore oil development prove to be unavoidable, the county will adopt a position which requires:
 - All future pipelines and processing facilities be consolidated to the maximum extent feasible.
 - Adequately functional, sized, coordinated and staffed facilities for cleaning and rehabilitating seabirds and marine mammals be made available on the central coast prior to further leasing or development.
 - Biological surveys are conducted by lessees as part of the process of siting individual platforms.
2. General policies which reduce potential impacts of offshore oil and gas development on biological resources will be enacted. To implement such policies, the county will adopt a position which requires:
 - The lay barge method of laying pipelines be used offshore in coastal areas which have significant habitat values, unless the bottom pull, or another better method is found to be significantly less impacting to the environment.

- The environmental review be focused to determine in other coastal areas whether the lay barge, bottom pull or other methods of laying pipelines offshore adequately minimize impacts, and require the environmentally superior method.
 - Stipulations or conditions of approval which require that helicopters used to transport crew and/or materials to offshore platforms or other offshore oil-related projects avoid flying over areas significant to wildlife and also maintain a minimum 1000 foot altitude clearance.
3. Careful timing, location, and design and configuration decisions for specific offshore oil and gas exploration and development activities can lessen impacts on biological resources. To promote such decisions, the county will adopt a position which requires:
- Biological surveys be conducted by lessees as part of the preliminary work of siting individual platforms and pipelines.
 - Exploration and construction be conducted during times of the year likely to affect biological resources least, considering frequency of storms, breeding, migration, nesting seasons, seasonal upwellings and other factors.
 - Exploration and construction near sensitive species habitat (such as least tern nesting areas) be scheduled to avoid breeding and nesting seasons. Chart seasonal migrations, breeding, and nesting cycles to identify windows of exploration and construction.
 - Terrestrial surveys, including inventorying rare plants, be conducted as part of the preliminary work for any proposed onshore support facilities. This should take into consideration the various seasons migratory or transitory species may be in an area.
 - Pipeline routes avoid steep slopes and stream crossings and other fragile habitats where possible to minimize erosion.
 - A 15 mile buffer zone of no offshore energy activities be established around the Santa Lucia Bank to protect the rich commercial fisheries and other natural resources.
 - No drilling shall be permitted north of Morro Bay, 20 miles around Morro Bay, or 12 miles around the southern range of the California sea otter, to protect onshore, nearshore and offshore biological resources.

1.5.3 Chapter VI - Fisheries

1. The county shall participate in commercial fishing issues, providing rapid assistance to fishermen and oil industry personnel in dealing with each other and with different layers of government. The county should administrate and coordinate programs and conditions and resolve issues within its permitting framework and advocate policies and positions in lease sales, decisions by other agencies, and in legislation.
2. Commercial fisheries resources off the county need to be more accurately delineated as to the economic value of different fisheries and times of year and locations where commercially harvestable species may be found. An evaluation of existing fisheries and creation of new fisheries should be considered.
3. Fisheries have a long-term economic value as a renewable resource. To protect this value, the county will adopt a position which requires:
 - Evaluation of the long-term value of fisheries as a renewable resource in assessing the needs of the fishing and oil industries, in addition to acknowledging annual catch and landing values.
 - Use of the lease sale EIS and stipulation process to articulate and advocate the full range of fisheries concerns. Any concerns which are not addressed through stipulations, should become criteria for evaluating applications which result from the lease sales.
 - The impacts of discharging toxic muds at sea be considered sufficient grounds for denial of any proposal. Wastes and cuttings shall not be disposed of in environmentally sensitive areas.
 - Disposal of muds and cuttings from any exploratory or development activities in an environmentally safe manner.
 - Protection of rich fishing areas such as the Santa Lucia Bank. These areas shall be identified and precluded from offshore energy activities.
 - Participating actively in all NPDES permit matters where authority to discharge pollutants to waters off the county is sought. Request that the least environmentally impacting options be implemented.
 - Provisions in any project approval which promote prevention, detection, containment and cleanup of spills or releases.
 - Evaluation of projects from the perspective of cumulative impacts as well as from the standpoint of (artificially) isolated project impacts.
 - Denial of any project which the county may find poses unacceptable risks to county fisheries.

- Repair and/or restoration of anchor scarring caused by offshore oil and gas activities on soft bottom substrates be repaired and/or restored.
4. Insufficient knowledge exists as to the fisheries resource off the county's coast and as to the resource's susceptibility to damage from oil and gas development. To improve this knowledge and decision making, the county will adopt a position which requires:
- Analysis of direct and indirect effects of seismic testing on fishing and on all life stages (especially eggs and larvae) of commercially and recreationally important organisms. Indirect effects shall include impacts to the food web.
 - Analysis of direct and indirect impacts of oil industry operations, including drill muds and cuttings, on the fisheries resource. Indirect effects should include effects on the food web.
5. Careful timing, location, design and configuration decisions for specific oil and gas exploration and development activities can lessen impacts on fisheries. To promote such decisions, the county will adopt a position which requires:
- Stipulations or conditions which minimize or eliminate preclusions, obstructions, toxic discharges, and debris.
 - Minimizing potential interference with fisheries operations through careful evaluation of platform, pipeline and construction spread configurations, and other testing, construction, installation and operation activities.
 - Assurance that programs are implemented and maintained to mitigate the affects on fishermen for lost time/lost catch where projects and fishing seasons overlap. Consideration of the timing of testing, exploratory drilling, construction, and other temporary activities when affected regions are most intensely fished.
 - Stipulations that seismic testing not occur except after sixty days' notice to fishermen, and that such testing not be scheduled where it would conflict with significant fisheries and seasons.
 - That any pipeline exceeding 27 inches (including coating and insulation) in total diameter, be buried to lessen the likelihood of gear snagging on the pipeline.
 - Stipulations and conditions which eliminate depositing of debris and creation of anchor scars on the sea-bottom by operators, contractors, subcontractors, or vessel operators. In addition, insist that operators build enforcement powers into construction, service and supply contracts, and then use such powers, and provisions for post-construction bottom surveys and appropriate remedial actions.

- An enforcement and compliance program related to fisheries conditions be implemented by an agency not directly involved with offshore oil and gas.
6. Policies and programs which reduce potential conflicts between commercial fishing and offshore oil and gas development, and which provide opportunities for fishermen and the oil industry to identify additional problems for consideration shall be enacted. To implement such policies, the county will adopt a position which requires:
- Rapid assistance to fishermen and oil industry personnel in dealing with each other and with different layers of government.
 - Administration and coordination of programs which provide for conflict resolution within the county's permitting framework.
 - The protection of fisheries resources using lease sale stipulations, legislation, and regulation.
 - Dissemination of information concerning oil industry exploration, development, and operation to the entire fishing community, permitting the fishing industry to be aware of and plan for oil industry activities.
 - Stipulations and/or mandated conditions which insure continuation of commercial fishing activity through prompt oil and gas industry or federal funding for gear loss, associated loss of catch, and loss of opportunity to fish in state and federal waters.
 - That stipulations and conditions require 1) recognition that preclusion of areas to fishing impairs the local economy, 2) contribution for enhancements such as ice houses, landing equipment, and development of alternate fisheries or fishery locations, and 3) identification of appropriate proposals for funding.

1.5.4 Chapter VII - Air Quality

The following policies address issues that pertain to the general subject of offshore energy development and those which are specific to the individual phases of the process as presented in this chapter.

1. The development of offshore oil and gas resources is a lengthy and complex process requiring interaction and cooperation among many different agencies. To that end, the following policies shall be adopted:
 - A comprehensive scoping process at the start of each proposed project to receive input from all affected agencies prior to any regulatory approvals to proceed.

- A statewide Technical Advisory Committee (TAC) be established to provide preliminary review of proposed modeling protocols, feasibility studies for platform electrification, and general technical oversight for the air quality review process on each project. Participating members should include the EPA, MMS, ARB, the affected APCD's, industry, and an independent air quality consultant.
2. The performance and review of air quality analyses is also a complex and controversial process. Consistency in approach, methodology and interpretation of the analysis is necessary to provide an adequate basis for decision-making. As such, the following policies shall be adopted:
- Require the performance of a thorough, cumulative assessment of potential ozone impacts for each project, using an analysis approach approved by all affected agencies.
 - Development by the TAC of formal guidelines for the performance of a platform electrification feasibility analysis. The guidelines should include identification of the information and methodology to be used as well as the evaluation criteria by which to judge feasibility.
 - Further development of the regional air quality monitoring network is needed to enhance the air quality database for impact analysis and decision-making, and to track the future impacts of offshore development.
 - Request MMS to install meteorological buoys offshore Pismo Beach and Morro Bay to provide baseline offshore meteorological data for this region.
3. Establish firm policies to protect air quality in the county from the impacts of offshore energy development. Specifically, the following policies shall be adopted:
- Oppose all future lease sales along the central coast until the actual impacts from development of existing leases are determined and mitigated to levels which will not cause violations of state or national ambient air quality standards.
 - If future lease sales do occur, request lease sale stipulations be adopted which require a platform electrification feasibility analysis to be performed and submitted with each Development and Production Plan. Platform electrification from an onshore power source should be required to the maximum extent feasible, as identified in the analysis; other mitigation alternatives could also be considered, provided they achieve an equivalent level of emission reduction.
 - Require that significant consideration be given to potential cumulative impacts when making project-specific decisions.

- Require maximum feasible mitigation of ozone precursor emissions from offshore energy development projects.
4. Request Environmental Protection Agency and California Coastal Commission to place the following conditions on offshore exploration activities:
- Scheduling of exploration activities during the period between November and June to avoid impacts during the peak ozone season, provided that it does not conflict with seasonal limits for other sensitive resources and does not require operations during unsafe weather conditions.
 - Limit the number of drill rigs which can operate concurrently within a specified region.
 - Require the use of Caterpillar D-399 diesel electric generators on the drilling rigs, if feasible, or other prime movers with equivalent emissions. If not feasible or available, vessels with controlled emissions in the lower half of the exploratory vessel fleet (i.e. - the "cleanest" vessels) should be required.
 - Require helicopter transport of personnel, except during unfavorable weather conditions, to reduce the simultaneous occurrence of crew and supply boats at the drilling unit. If crew transport by boat is unavoidable, then careful scheduling of crew and supply boats should be required to reduce simultaneous occurrence at the platform.
 - Require maximum feasible mitigation of NOx and ROG emissions from the crew and supply boats which service the drilling unit (see support vessel recommendations below).
 - Require that crew and supply boats not be present together at the drilling unit during scheduled flaring for drill stem testing.
5. Require that the following mitigation measures be implemented for construction activities associated with offshore platform and pipeline installation:
- Require the use of Cat D-399 diesel electric generators on derrick and lay barges, if feasible, or the use of other prime movers with equivalent emissions. If direct injection diesels are used, injection timing retard of 4° and adjustments to the air-to-fuel ratio should be applied to reduce NOx emissions.
 - Require maximum feasible mitigation of NOx and ROG emissions from all support vessels involved in construction and installation activities, including crew and supply boats, light-duty tug boats and other applicable vessels (see support vessel recommendations below).

- Require the use of low-sulfur diesel fuels on all support and installation vessels operating within 3 miles of shore.
 - Require the development of a comprehensive activity management plan designed to reduce the simultaneous occurrence of large polluting activities where possible.
6. Require that the following emission control strategies be implemented for all offshore development and production operations:
- Platform electrification from an onshore power source, which currently represents the best available control technology (BACT), shall be implemented to the maximum extent feasible at the earliest stage of development; feasibility determinations should not include consideration of any construction of project components begun prior to completion of the regulatory review process. Other mitigation alternatives should also be considered if they can achieve equivalent emission reductions.
 - Use of natural gas for fuel and Best Available Control Technology (BACT) on all turbines permitted for use on platforms.
 - Use of ARB-certified automotive diesels on all independently-powered equipment for which electrification is demonstrated infeasible (e.g. - cement pumps, logging units, cranes, vessel generators, etc.).
 - Use of low-NOx natural gas-fired heaters for process heat needs, if applicable and feasible; applicability and feasibility should be determined during the platform electrification study.
 - Implementation of a rigorous inspection and maintenance program for detection and repair of process components and equipment which cause fugitive hydrocarbon emissions.
 - Use of state-of-the-art flare systems; restricting flaring events to documented emergencies, process upsets, well testing and scheduled maintenance.
 - Implementation of a comprehensive activity management plan to minimize the simultaneous occurrence of NOx generating activities.
 - Use of helicopters rather than crew boats for transport of personnel, except during unfavorable weather conditions.
 - Use of pipelines rather than tankers to transport produced crude to shore.

- Assure that platform design includes sufficient storage capacity to minimize the use of supply boats for added deck space.
7. Require maximum feasible mitigation of NO_x and ROG emissions from all support vessel operations associated with exploration, development and production activities. The following control strategies have been demonstrated, or have the potential, to achieve significant emission reductions:
- Use of injection timing retard of 4° combined with an enhanced intercooler on the turbocharger for all vessels under contract to a project. Limit the use of uncontrolled, spot-chartered vessels to scheduled downtime or emergencies requiring an extra vessel.
 - Reduction of vessel cruising speed to 15% below top speed.
 - Use of alternative fuels, such as propane or a dual-fuel mix, if feasible and able to comply with applicable regulatory restrictions.
 - Implementation of a comprehensive activity management plan designed to consolidate vessel use and reduce the number of trips required for each project.
8. Require the following measures to be implemented for the construction and operation of all onshore facilities associated with offshore energy development:
- Require each project to develop and implement a comprehensive Construction and Installation Emissions Mitigation Plan (CIEMP) covering all phases of onshore construction. Such a plan would specify the equipment, emission controls and activity management techniques to be employed to achieve compliance with local, state and federal ambient air quality standards.
 - Conduct onsite inspections of construction operations to assure compliance with the CIEMP.

The policies given above emphasize the need for stringent air quality protection while recognizing the unique and variable nature of the offshore development process. Adoption of these recommendations will provide guidance to future project applicants and regulatory direction for future development offshore San Luis Obispo County.

1.5.5 Chapter VIII - Onshore Facilities

Specific policies stated below are policy guidelines and are not intended as a comprehensive statement of conditions to be imposed on individual projects. The policies include:

1. Buffer zones shall be based on analysis recognizing maximum hazard footprints with a margin for safety, air pollutant and odor emissions, prevailing winds, noise, and viewsheds, incompatible uses, and long-term regional trends.
2. Facilities should be sited in swales or other natural depressions and should not be profiled against horizons.
3. Facilities shall be sited within five minutes response time of an adequately staffed and equipped fire/emergency response station.
4. Industry shall maximize employment opportunities for local residents to reduce impacts from the influx of out-of-area temporary employees.
5. Natural gas pipelines shall be sited away from population concentrations where possible.
6. Non-pipeline construction and development near residential areas shall be prohibited.
7. Facilities shall have state-of-the-art pressure relief, monitoring, and fire prevention, detection, and suppression devices.
8. Facilities shall be consolidated where possible unless cumulative impacts from consolidation produce an unacceptable "hot spot".
9. That conditions for specific onshore facilities be developed on a case by case basis, taking into consideration the type of facility proposed, proximity to population, environmental constraints of the site, the potential for upset, the facilities hazard footprint, and the cumulative impacts over the life of the facility.

1.5.6 Chapter IX - Supply and Crew Bases

Supply Base

1. A supply base proposal would require an amendment to and subsequent consistency with the county's existing Local Coastal Program and the Port San Luis Harbor Master Plan where applicable. A supply base is not consistent with the LCP as certified by the California Coastal Commission nor with the Port San Luis Master Plan and is not currently considered an allowable use. Projects shall be sited in such a manner that segregates the associated activities from other harbor users, thus reducing the potential for conflicts and accidents.
2. A proposal for an amendment to the LCP for a supply base shall clearly define the scope of the operation during the life of the project. The amount and type of supplies transported to and from should be identified, the number of personnel to be transported, the type and size of boats to be used, the number of daily trips, and other equipment that

would be operated. Also identified should be the types of drilling operations that will be supported and the time frame.

3. Air quality issues related to the operation of supply base will be evaluated and regulated by the county's Air Pollution Control District and shall utilize the best available control technology (BACT) to the maximum extent feasible.
4. A comprehensive analysis of the needs related to mooring, land, pier, water, roads and access, parking, and other harbor facilities required by a proposed supply base shall be completed. Current users, such as commercial fishermen and recreational boaters, shall be included in the analysis.
5. Designated vessel traffic lanes should be mutually agreed upon by all users and jurisdictions of a harbor where a supply base would be sited. The Fishermen/Oil Liaison office in Santa Barbara County should be used for coordinating these concerns.

Crew Base

6. A crew base proposed in San Luis Obispo County shall comply with the Local Coastal Program, Land Use Element policies and regulations and the Port San Luis Harbor Master Plan where applicable. It shall also be sited in such a manner that segregates the associated activities from other harbor users, thus reducing the potential for conflicts and accidents.
7. A proposal for a crew base shall clearly define the scope of the operation. The amount and type of supplies transported shall be identified, the number of personnel to be transported, the type and size of boats to be used, the number of daily trips and other equipment that would be operated. Also identified shall be the types of drilling operations that will be supported and the time frame.
8. Air quality issues related to the operations of crew base will be evaluated and regulated by the county's Air Pollution Control District when and if a proposal is submitted and shall utilize the best available control technology (BACT).
9. A comprehensive analysis of needs related to mooring, land, pier, water, roads and access, parking and other harbor facilities or resources required by a proposed crew base shall be completed. Current users such as commercial fishermen and recreational boaters shall be included in the analysis.
10. Designated vessel traffic lanes should be mutually agreed upon by all users and jurisdictions of a harbor where a crew base would be sited.

Specific Policies

1. That the county's Local Coastal Program, the industrial and energy policies in the Framework for Planning and the San Luis Bay planning area standards, shall be periodically reviewed for consistency and modified if appropriate. Specific consideration should be given to:
 - clarifying definitions of a crew, service and supply base;
 - updating the list of potential crew or supply sites based on new information;
 - clarifying the LCP to state that supply/service and crew base's are clearly different facilities;
 - updating the LCP to clearly indicate that a change in operational use by a base, such as from temporary to permanent status, will require a separate review and analysis; and
 - coordination with Port San Luis Harbor District for consistency with the Harbor Master Plan.
2. That any proposed crew base or proposed LCP amendment for a supply base provide a list of the types and quantities of supplies, materials and equipment to be transferred to and from the base.
3. Require crew boats to meet specific operational standards and have certain characteristics depending on the safety and environmental factors of the area they are proposed to operate in.
4. Require that all crew boats be manned or monitored 24 hours a day during storm season (October 15 through April 15) to assure they do not break off their moorage and damage other boats.
5. That the maximum number of crew boats docking per day per operator be limited depending on the carrying capacities of the area proposed for a site.
6. That a vehicle trip reduction program will be required to and from the a transfer site.
7. Local hiring of personnel shall be encouraged by companies participation in a local hire program.

1.5.7 Chapter X - Oil Spill Response

1. That San Luis Obispo County representatives participate in oil spill drills and activities implemented by the California Office of Oil Spill Prevention and Response.

2. That a county task force of local agencies and industry that may be involved in an oil spill response effort be formed to build an efficient and coordinated response organization that can support the state and the federal response structure. The task force shall consult with native american representatives regarding potential impacts to cultural resources during the formation and through implementation of the oil spill response effort.
3. That the county Office of Emergency Services work with the state Office of Oil Spill Prevention and Response to develop an oil spill contingency plan for the marine and coastal environments of the county.
4. That the county identify and obtain funding sources for contingency planning and related activities.
5. That training programs for county agencies related to oil spill prevention and response be developed.
6. That the county compile all industry contingency plans in a central and accessible location.
7. That the resources, equipment, and personnel who will respond to an oil spill are clearly known to all entities involved in an oil spill response. That identification badges be provided to those individuals who will be involved in spill response.
8. As part of land use permit applications related to new oil and gas facilities, the county should consider whether contingency funds are available that would be used to purchase response equipment, set up training programs, and provide funds for immediate response by pre-designated entities.
9. That the county coordinate with the state Office of Oil Spill Prevention and Response to insure that all facilities have adequate financial resources for reimbursing the county for any damages or costs incurred as a result of an oil spill.
10. That the county develop a program that provides citizens with the appropriate training and certification to be qualified volunteers in a clean up effort.
11. That industry oil spill contingency plans include immediate access to stockpiled equipment and materials which are appropriate for responding to spills in the nearshore, rocky intertidal areas of the county. A partial list of such equipment includes kelp cutters, small boats, sorbent materials, cranes and steam cleaners.

CHAPTER II: OFFSHORE OIL DEVELOPMENT

2.1 Development and Production of Offshore Oil and Gas

This chapter presents an overview of: 1) the ways in which offshore petroleum and gas reserves are found and developed, 2) facilities and equipment employed in locating, and producing petroleum resources, 3) a summary of expected impacts, and 4) a profile of the regulatory process.

Substantial petroleum and natural gas resources, recoverable in commercial quantities, are known to exist in the outer continental shelf off southern San Luis Obispo County. The exact potential for petroleum and natural gas reserves offshore the county's coastline is unknown, but future geophysical and exploration activities could reveal additional quantities of recoverable reserves. Figure II-1 on the following page shows the recognized discoveries and the estimated location of the reservoirs.

To date, regulatory agencies have received applications to produce, process and ship petroleum from one offshore lease. Over the next ten to twenty years, the county anticipates the possibility of development and production proposals for several additional leases and the attendant onshore processing, refining, storage and pipeline facilities. The county could also receive proposals for supply, crew or helicopter bases to transport workers and materials between shore and platforms. Further, the county may receive proposals for additional marine terminals to ship resources produced offshore or to expand existing terminals.

Petroleum development has the potential to adversely affect air, water, biological, cultural, and scenic resources of the county. Development may also add jobs and revenues to the local economy.

2.2 Offshore Facilities

Offshore facilities may either be mobile, including drilling vessels and drill rigs, or fixed, including production platforms. Production platforms are the focal point of offshore development because they accomplish the primary goal of production and because of the support platforms require. Platforms require immense quantities of energy, supplies and crew must be brought from shore, and petroleum and natural gas must be produced, treated, and shipped. A variety of offshore facilities are described in the next section.

Geophysical Survey Vessels: Geophysical survey vessels operated by petroleum companies or independent contractors perform offshore seismic and geological surveys to assess the potential for recoverable hydrocarbon resources. These vessels release large amounts of

sound energy into the water. The energy radiates through the water column and the sea floor.

Figure II-1
Estimated Reserves Santa Maria Basin and Santa Barbara Channel

Reflected energy received by the vessels helps to profile bottom and subbottom conditions, locate geologic anomalies, and highlight potential resource deposits. Survey vessels may tow cables up to two and half miles in length. Cable ends may be marked by buoys. Figure II-2 diagrams a geophysical vessel.

Exploration Rigs: A petroleum company which successfully leases (the lease sale process is discussed in chapter IV) an offshore tract from the state or federal government may choose to conduct exploratory drilling on the tract. The first exploratory step is using geophysical survey data to select likely drilling sites. Then the leaseholder brings in a drill ship or other mobile rig to drill test holes at the sites selected. After drilling, personnel analyze core samples and other data to locate and define hydrocarbon reserves. Finally, the leaseholder, taking economic and regulatory considerations into account, makes a decision on attempting to develop and produce petroleum resources from the lease.

Production Platforms: When a company decides to develop a lease, it uses data from geophysical surveys and exploratory drilling to choose optimal locations for permanent production platforms. Platforms are commonly built in separate components and assembled on the lease site.

The first and largest component is the *jacket*, a girdered structure set into the sea bottom and rising 100 feet or more above the sea surface. Modules containing drilling and production equipment, pumps, crew quarters, and any required processing equipment are set atop the jacket. A large number of transport, crane, and support vessels deliver and assemble the components.

Drill rigs operating through slots in the platform decks drill wells into the reservoir. Petroleum either rises to the platform as a result of reservoir pressure, or it is lifted by pumps. Natural gas normally rises by reservoir pressure. Natural reservoir pressures can be maintained or enhanced by injection of fluids.

Petroleum and natural gas may be partially or completely processed at a platform before shipment. Some leases may be developed by constructing and operating a multiple platform complex, with some platforms being devoted to drilling and production, while others serve as processing or storage points. Stationary vessels such as the offshore storage and treatment vessel, ("O.S.&T.") long associated with Exxon's Platform Hondo in the Santa Barbara Channel, may serve as offshore processing and storage facilities. Petroleum and natural gas can be shipped from the platform by pipeline or tanker.

Most of a platform's energy needs are for electricity. Electricity may be supplied by cable from shore or produced by burning fossil fuels in generators at the platform. The development and production plan may also include a provision for heat to process hydrocarbons, or, as in the case of the proposed San Miguel Project, to reduce the viscosity of the crude. Figure II-3 shows some of the different types of drilling rigs.

Figure II-2
Geophysical Operations

Figure II-3
Offshore Drilling Rigs

Subsea Completions: Subsea completions are wells, pumps and pipelines located entirely below the water's surface. Completions may be economical for small fields near shorelines or platforms. They do not cause a visual impact as platforms do, but are harder to manage and potentially more likely to produce spills or to snag fishing gear.

2.3 Offshore/Onshore Facilities

Pipelines transmitting fluids and cables transmitting electricity both support offshore development. Pipelines and cables run between onshore and offshore portions of projects, but may also be found entirely onshore or offshore.

Pipelines: Pipelines, metal or concrete tubes, transport fluids between production points and processing and refining facilities, and from the latter to market points. Pipeline diameters and wall thicknesses depend on expected shipment volumes and pressures, on external conditions in the pipeline corridor, and on economics. A pipeline may be double-walled to provide insulation or added insurance against rupture, may be wrapped in protective or insulating coatings, may be buried or laid on a surface, and may be designed to transport more than one fluid. Figure II-4 depicts onshore and offshore pipeline laying methods.

Pipelines serve offshore development by transporting a wide variety of fluids, including crude or processed petroleum, refined petroleum products for sale, processed or unprocessed natural gas, water, steam, brine, and process fluids such as diesel. Pipelines may move fluids between platforms, between platforms and onshore facilities, to or from a tanker, or between onshore points. The All-American Pipeline transports crude oil through San Luis Obispo County to major refineries on the Gulf Coast and then into the most extensive product distribution system in the United States. Unocal, Chevron, and the Gas Company also operate extensive pipeline systems in the county.

If properly sited, built and operated, pipelines are often the safest and cheapest means of moving fluids between points; they have few moving parts, low operating costs, and a low incidence of spills per volume of fluid transported. Major disadvantages include pipelines' high initial capital cost and their lack of flexibility in product destinations.

Pipeline routes are often conceived as straight lines between origin and destination points. Route adjustments are commonly made for engineering, environmental or political considerations. An offshore pipeline is built by designating a route, assembling pipe onshore or aboard a vessel, slowly pulling the pipe from shore or lowering it from the vessel, and, if needed, trenching on the bottom before or after the pipe is laid. An onshore pipeline is built by staking a route, clearing and grading a corridor, digging a trench, assembling pipe in the corridor, lowering pipe into the trench, filling the trench, and regrading and restoring the corridor. A pipeline uses pumps or gravity to move fluids.

Figure II-4
Offshore and Onshore Pipeline Laying Methods

Electric Cable: A platform may get some or all of its electric power from shore by way of a cable laid on the sea bottom or buried in a conduit. Onshore, electricity may be transmitted through buried cable or overhead lines. Route considerations are similar to those for pipelines.

2.4 Onshore Support Facilities

Offshore development and production facilities require onshore support. While most processing prior to refining could be performed offshore, processing is generally more economical and environmentally sound if conducted onshore. Similarly, pipeline shipment is generally preferable to transport by ocean vessels or by rail. Materials, supplies, and personnel must move to and from the platform; refining and marketing are typically onshore activities. Certain support facilities which may be proposed for construction in San Luis Obispo County are discussed below.

Oil Processing Facilities: Oil processing facilities remove water and impurities to prepare petroleum for shipping. Oil so processed is referred to as "pipeline quality" and is characterized by having less than one percent residual water content. Impurities may be disposed of by being hauled offsite to appropriate disposal sites or by being piped back to the platform for discharge into the ocean or reinjection. No facilities in the county currently process offshore oil. Figure II-5 shows oil and gas processing facilities.

A processing facility commonly includes heating units, pumps, flares and storage tanks. Its capacity to produce emissions and odors, as well as the possibility of fire and explosions, require that any such facility be sited an appropriate distance from residential areas. (Chapter VIII discusses buffer areas for these facilities.)

Grading for and construction of a processing facility should normally take less than one year. During operations, processing facilities normally require only a small number of workers.

Refineries: Refineries employ complex heating, cracking, (the break down of crude into different components) and compounding processes to turn crude oil into marketable petroleum products. Refineries normally require large quantities of power and water. Because of the special danger from fires, explosions, and air pollution and the presence of odors, refineries require large, isolated, industrial lands for siting. Upstream (near the point of production) partial refining of heavy crudes such as those found in the offshore Santa Maria Basin has been discussed as a means of upgrading the crudes before shipment to distant destinations such as Texas.

Grading for and construction of a refinery can be expected to take longer than similar activities for an oil processing facility, and refineries require more operation workers than do oil processing facilities. The Unocal Santa Maria refinery, located on the Nipomo Mesa in southern San Luis Obispo County, refines crude from various sources including Unocal's offshore Platform Irene, which is located offshore of Point Pedernales in Santa Barbara County. Unocal

Figure II-5
Oil and Gas Processing Plant

moves partially refined product by pipeline to its marine terminal at Port San Luis for tanker shipment to refineries in Los Angeles or San Francisco. This product could also be moved via pipeline to the San Joaquin Valley.

Oil Storage Tanks: Storage tanks are necessary for temporary storage of crude, processed, or refined oil prior to shipment. Numerous types of tanks with varying capacities may be built. Storage for several days of peak production may be required in a consolidated facility which serves several production sites. A typical storage tank is equipped with mixers, volume and temperature indicators, alarms, vapor recovery units, fire suppression equipment, and pressure protection devices. A storage tank is normally required to have berm around it which can contain its entire contents in the event of a spill. Figure II-6 shows a diagram of a tank farm.

Pump Stations: A pump station consists of machinery to push or pull fluids along a pipeline route. Gas transmission lines require periodic pump stations; liquid transmission lines also require periodic stations, but may get assistance from gravity on some parts of their routes. Pump stations do not require large amounts of land for siting, but do require road access for servicing and the availability of utility service for power. Most pump stations are electrically powered and unmanned.

A variation on the pump station which may become significant in this county is the "heater-treater" station, which combines pumping capability with equipment for reheating crude oil to reduce viscosity, thereby easing shipment. Onshore processing or refining facilities for heavy crude oil may require such facilities as may a pipeline transporting heavy crude. Impacts from any such facilities will depend on their size and location, and on specific heating and pumping requirements.

Gas Processing Facility: Gas processing plants are designed to remove impurities and recover liquid hydrocarbons such as methane, butane, and propane from produced gas. The plants vary in size depending upon the volume of incoming gas and processing required. The plants are especially susceptible to damaging fires and explosions and to emissions of air pollutants and odors. For siting, they require large isolated areas of land. Gas processing plants require immense quantities of water and produce significant quantities of hazardous and toxic materials.

As a result of projected gas production from the Northern and Central (predominantly Northern) Santa Maria Basin, Santa Barbara County has prepared a study to give direction for locating expected gas processing facilities. The study assumes a need for two 80 MMCFD (80 million cubic feet per day) gas processing plants. It was reviewed by a task force which included San Luis Obispo County staff, major oil companies, citizens' groups, and others.

A study prepared for the San Miguel Project EIS/R estimated a 125 MMCFD peak for Northern Santa Maria Basin gas production. In 1988, Minerals Management Service estimates anticipated a lower peak.

Figure II-6
Marine Terminal and Tank Farm

Marine Terminals: The purpose of a marine terminal is to load or offload tankers. The material shipped or received may be crude petroleum, petroleum products, or natural gas. A marine terminal is composed of a mooring system for the tanker, a hose or pipeline to transport the product, and storage facilities. Terminals may also contain ballast discharge systems and vapor balance and control systems. Ancillary equipment may include fixed or vessel-mounted fire-suppression equipment. Currently, terminals at Port San Luis and Estero Bay ship crude or partly refined petroleum and receive petroleum products. Figure II-6 shows a diagram of a marine terminal.

Siting a marine terminal is a sensitive issue because of the considerable potential for fire and explosions, air quality impacts, and oil spills. It is generally recognized that terminals engaged in shipment of liquid or pressurized natural gas must be located miles away from inhabited areas; in recent years, the same principal has been applied to the siting of crude petroleum and petroleum product terminals. More risk attaches to offloading than to loading petroleum products, but the risk is there for both. The loading port of Valdez, Alaska, for example, is located across several miles of water from the main community.

The size of a terminal will vary with the quantity and nature of materials shipped and received, and with the decision to provide a fixed-berth, multipoint or monobuoy loading or offloading facility. The total area required for a terminal, including storage facilities, is likely to be considerable.

Supply Bases: A supply base located in San Luis Obispo County would berth vessels for transporting crews and shipping materials such as drilling pipe, muds, cements, water, fuel, food and other supplies to platforms. It would require pier, roadway, parking and warehouse construction, construction of breakwaters, and possible recurrent dredging. A supply base brings frequent vessel movements, a great quantity of truck and/or rail traffic, industrialization, and attendant induced growth. Supply base construction in a beach area may cause beach erosion and harbor entrance clogging by disrupting littoral drift.

Currently, Port Hueneme in Ventura County is the only supply base serving the Santa Barbara Channel and areas to the north, including leases off San Luis Obispo County. Increasing oil development has caused some discussion of a possible need for an additional supply base nearer the Santa Maria Basin.

Crew Base: A crew base serves as a terminus for small vessels serving platform crew and minor supply needs. Crew base operations bring increased vessel and land traffic and an increase in storage facility needs, but on a smaller scale than supply bases. Currently, facilities physically adequate to serve as a crew base exist on the Unocal Oil Pier at Port San Luis. This use has been discussed in the county's local coastal program. No specific proposal for using the facilities has ever been submitted or approved.

Currently, the only large scale crew base is located at Port Hueneme. The Carpinteria and Ellwood piers in Santa Barbara County are currently operational but are used less frequently

than Port Hueneme. For reasons similar to those stated in the supply base discussion, there is some discussion of a need for a crew base nearer the Santa Maria Basin.

According to a 1984 siting study performed by Westec for San Luis Obispo County, a crew base facility for this area would need to accommodate 35% of the total trips generated in the Santa Barbara Channel and Santa Maria Basin, or 25 trips per day, based upon the projected activity north of Point Arguello. This is equivalent to 400 people per day, or 32 each trip. The study further noted that between 400-800 feet of pier berthing space would be required. Other requirements cited in the study include 200 parking spaces, shuttle bus parking, a warehouse (30' x 30' x 12' high), an office, and a helipad. The area between Point Arguello and Point Estero was evaluated in the study. Much more detailed and current information exists that could modify the needs evaluation used in preparing this study.

The study concluded that the Union Oil pier at Port San Luis was the most suitable site of those studied for such a facility. Nevertheless, no such facility has been proposed to date, and crew transport to platforms north of Point Conception is done largely by helicopter.

Helicopter Base: A helicopter base could be located at an airport, at a supply or crew base, or in an isolated area. Helicopters move crews and light supplies to and from platforms. A helicopter base requires landing pads, fuel facilities, parking and storage, and office space. Expected impacts would include noise, air pollutants, and vehicle traffic.

2.5 Impacts

While many impacts of offshore development may be partly mitigated on a project by project basis, the most important question for county residents may be the cumulative effect over time of many projects, instead of the incremental impacts of individual projects. Overall, the impacts of greatest concern are air pollutant emissions, spills, leaks, and chronic discharges, and the potential for fires and explosions.

Construction and operation of onshore facilities may also impact biological communities and adjacent land uses and may induce erosion, degrade water quality, increase noise, slow traffic, alter landforms and runoff patterns, increase sedimentation, and diminish cultural, recreational and aesthetic resources. Steadily increasing impacts on commercial fisheries and socioeconomic impacts from population increases and demands for services can be expected.

If development occurs, the energy industry's need for infrastructure would likely induce other growth. A trend toward petroleum-based land use in our county might also develop because of the need to consolidate facilities.

Chapters V, VI, and VII will discuss impacts anticipated on biology, commercial fishing, and air resources. Chapter VIII presents siting criteria and impacts for onshore facilities.

2.6 Regulatory Framework

Offshore oil activities in waters beyond 3 miles from shore are under the primary jurisdiction of the federal government.

Within the three mile limit the state government has primary jurisdiction. The State Lands Commission has jurisdiction between the mean high tide line and the three mile limit, while the California Coastal Commission exercises authority within the state's coastal zone.

Onshore support facilities are permitted by local government. County police powers extend at least to the three mile limit and CEQA duties obligate the county to consider the entirety of a project in making permit decisions. This section summarizes the regulatory framework and process governing OCS leasing and development in federal and state waters, as well as the associated onshore related facilities.

In 1977, Congress adopted a National Energy Policy Plan (NEPP). The plan, together with the Outer Continental Shelf Lands Act (OCSLA), gives the Secretary of Interior clear direction and broad authority to expedite leasing and development of the nation's offshore oil and gas resources. The plan and the act are intended to assure national security, maintain a favorable "balance of payments" through decreasing demand for imported oil, meet the country's energy needs as soon as possible, and balance implementation of the foregoing goals with protection of the environment. Summaries of the NEPP and OCSLA are provided below. Legislation and agencies which affect OCS development are summarized in Table II-1.

National Energy Policy Plan (NEPP): Objectives of the plan include reducing reliance on foreign oil, reducing exposure to supply interruptions, decreasing imports, and developing renewable and inexhaustible energy sources for sustained economic growth. The Department of Energy is required to update the plan every two years.

Outer Continental Shelf Lands Act (OCSLA): The Outer Continental Shelf Lands Act declares federal jurisdiction over submerged lands between three miles and two hundred miles offshore. It directs the Secretary of Interior to hold lease sales, and sets forth objectives including expedited expanding and developing resources, assuring national security, reducing dependence on foreign energy, maintaining a favorable balance of payments in world trade. The Act requires that energy needs be met as soon as possible, that fair market value be ensured, and that free enterprise be maintained, but that these needs be balanced against protection of the environment. The Act also mandates that technological improvements to reduce environmental impacts be encouraged. The OCSLA specifies a detailed review process for each 5-year leasing schedule. It provides for comment on lease sales by the public and by affected states, federal agencies, the President, and Congress.

**Table II-1
MAJOR AGENCIES, LAWS AND PERMITS INVOLVING
OFFSHORE OIL AND GAS DEVELOPMENT**

FEDERAL AGENCIES	LAW	REGULATORY AUTHORITY
Minerals Management Service (MMS)	Outer Continental Shelf Lands Act	Permit to Drill
National Oceanic and Atmospheric Administration (NOAA)	Coastal Zone Management Act (CZMA)	Consistency Certification
Environmental Protection Agency (EPA)	Clean Water Act	National Pollution Discharge Elimination System (NPDES)
Army Corps of Engineers (COE)	River and Harbor of 1899	404 Permit, Section 10 Permit
U.S. Fish and Wildlife Service, National Marine Fisheries Service	Endangered Species Act	Section 7 Consultation
All agencies must comply with NEPA	National Environmental Policy Act (NEPA)	Environmental Impact Statement

CALIFORNIA AGENCIES	LAW	REGULATORY AUTHORITY
State Lands Commission	Submerged Lands Act; CPRC, Div 6, Sec 6001; & OSPRA	Right-of Way/State Waters Lease Management of State Lands Inspection of Marine Terminals
Regional Water Quality Control Board	Porter-Cologene Act Water Code	National Pollution Discharge Elimination System (NPDES)
Department of Fish and Game	California Fish and Game Code	Stream Alteration Permit/Oil Spill Emergency Response
Department of Transportation (CALTRANS)	Streets and Highway Code	Encroachment Permit
Coastal Commission	California Coastal Act	Coastal Development Permit
Air Resources Board	Air Pollution Control Laws	

LOCAL AGENCIES	LAW	REGULATORY AUTHORITY
County/City Government (Planning Departments)	General Plans, Local Coastal Plans, Zoning Ordinances	Land Use Permit/Coastal Development Permit, Conditional Use Permit. Building Permits
Measure A	Local Coastal Plan	Voter Approval of Onshore Facilities
Air Pollution Control District (APCD)	Clean Air Plan	Authority to Construct, Permit to Operate

2.7 Regulatory Phases of OCS Development

Lease Sales: To fulfill the mandates of NEPP and OCSLA, the Department of the Interior's Minerals Management Service (MMS) conducts lease sales for designated tracts in OCS waters. Lease sales convey the right to develop and produce hydrocarbon resources from specific geographic areas of the OCS. Chapter IV provides a detailed description of the federal lease sale process.

Exploration Plan (POE): Oil companies may conduct exploratory drilling on tracts which they secure through the lease sale process. A leaseholder must submit a plan of exploration along with an oil spill contingency plan and an environmental report to the MMS prior to commencing drilling. The environmental report should describe project effects on the environment. It is not an Environmental Impact Statement (EIS). An EIS would address a wider range of topics and would be subject to a more extensive public review process. Plans of exploration are subject to the Coastal Commissions consistency review process.

Development and Production Plan (DPP): A leaseholder must submit a Development and Production Plan (DPP) to MMS before constructing a platform on a lease. The DPP must include a description of the drilling platform, pipelines, and other facilities to be used, wells, geologic data, applicable safety standards, and a time schedule. MMS may specify additional requirements to reflect local conditions. Like the POE, the DPP is accompanied by an oil spill contingency plan and an environmental report. The environmental report describes the extent and timing of proposed offshore and related onshore operations, requirements for land, labor, material, and energy, proposed means of oil transportation (pipeline and tanker), waste disposal, cultural concerns, oceanographic, meteorological, and geological conditions, and the significance of potential impacts.

Once it deems an application complete, MMS has 120 days to approve or disapprove the DPP, or, if approval might significantly affect the quality of the environment, to determine that an Environmental Impact Statement should be prepared. DPPs are also subject to Coastal Commission consistency review. In recent years in Central California, some impact statements have been jointly prepared with affected state and local agencies to satisfy federal (NEPA) and state (CEQA) environmental requirements. Preparation of joint statements has been managed by joint review panels composed of representatives of local, state, and federal agencies with jurisdiction over the project.

2.8 State Waters

The State Lands Commission (SLC) has jurisdiction over leasing and development such as geophysical testing and exploratory drilling within three miles of shore. This includes pipelines and other facilities placed within three miles of shore to service facilities located in federal waters. The SLC first studies an area, then holds a lease sale. A leaseholder seeking development must obtain development plan approval from the SLC, coastal approval from the Coastal Commission, and an NPDES (National Pollution Discharge Elimination System) permit from the Regional Water Quality Control Board (RWQCB). The county and the Department of Fish and Game also have regulatory authority.

There has been no leasing in state waters offshore San Luis Obispo County. The state legislature has exempted these waters from drilling by designating them a sanctuary. Sanctuary status could be eliminated either by a legislative act or by findings by the State Lands Commission that petroleum resources underlie

the sanctuary and that the resources are in danger of being drained by production occurring on nearby lands.

2.9 Onshore Facilities

Onshore facilities supporting offshore development must receive local government approval, including approval by the voters in accordance with measure A. Measure A, adopted by county voters in November 1986, provides an added requirement that any permit issued for onshore facilities related to offshore development must be approved by a majority of voters.

A development plan application containing detailed project information must be submitted for most major projects. For projects in the coastal zone, the development plan application is also the coastal development permit application.

After accepting the application, the county determines whether an environmental impact report should be prepared. The application is reviewed by the Planning Commission and afterward by the Board of Supervisors for consistency with county plans and ordinances and with provisions of the California Environmental Quality Act.

For most new petroleum facilities, the county also requires that a specific plan be prepared by the applicant and approved by the county Board of Supervisors before a development plan application is filed. The specific plan process is used to evaluate a project in a more comprehensive manner. This process allows the county to better assess the offsite and long-term impacts of a particular project. A specific plan will enable the county to more accurately evaluate the compatibility of large industrial projects with the characteristics of the region and will provide for long term assurances for both the county and industry.

Applicants or other affected parties may appeal local development permit decisions on to the Coastal Commission. After the administrative review of local decisions is exhausted, court review may be sought.

CHAPTER III: POLICY BASE

3.1 Introduction

The county has adopted policies which address energy facilities in the coastal zone. These are primarily contained in the county's Local Coastal Plan (LCP). In addition, the county has adopted positions on offshore leasing and development activities. These positions have taken the form of recommendations to appropriate state and federal agencies. Together, these coastal policies and recommendations comprise the county's existing policy base with regard to offshore oil and gas development. The Offshore Energy Element is a policy document that addresses many issues associated with offshore oil and gas development. The element outlines these policies and positions and suggests how they may be revised or expanded through this plan.

3.2 Evolution of County Policies

The majority of county policies related to offshore energy and related onshore activities are contained in the Local Coastal Plan (LCP). The LCP was certified in 1988 by the California Coastal Commission. Some of the energy policies it contains were first developed in the late 1970's. This was before there was significant public interest in development of oil and gas resources offshore our county. Consequently, the policies are limited in scope and do not necessarily reflect knowledge gained from subsequent oil development activities.

In addition to LCP policies, the county has formally adopted positions at public meetings on federal offshore oil and gas leasing proposals. These positions have been transmitted as recommendations to the California Coastal Commission for their consideration in making consistency findings, to the Governor for consideration when developing the state's comments, or directly to the Minerals Management Service.

The County has developed a series of statements passed by resolutions of the Board of Supervisors on the Five-Year Programs and individual lease sales including, #53, 73, and 95. In 1990, the county presented written and oral testimony to the Presidents Outer Continental Shelf Task Force at a hearing in Santa Barbara.

The development of the Offshore Energy Element provides an opportunity to study and consider amendments of related policies contained in the LCP in the future. The policies and recommendations found at the conclusion of later chapters may in some instances be appropriate for inclusion into the LCP. This can be done through an implementation program.

In addition, the information, policies and recommendations approved by the Board of Supervisors, are reflected in comments to state, federal, and other local agencies involved in review of offshore energy projects and programs proposed in the state and federal waters.

Specific leasing actions the county has commented on include: the Federal 5-year OCS Leasing Schedules, Lease Sale 53, Lease Sale 73, and the Lease Sale 95 Call for Information. In 1991, the county responded to the 1992-97 five year leasing program proposed by the Minerals Management Service. It is the position of the county that the MMS require the following:

1. The proposed leasing within the Santa Maria Basin does not meet the "critical balance" criteria (the environmental and economic costs and benefits of development) as set forth in Outer Continental Shelf Lands Act (OCSLA), and shall not be offered separately from the balance of the west coast. This is consistent with H.R. 2295 currently being considered by the United States Congress.
2. All blocks (3 x 3 mile lease tracts) north of Morro Bay, 20 miles around Morro Bay, and 12 miles around the southern range of the California sea otter (the Santa Maria River) shall be deleted from consideration due to environmental sensitivity. Leasing of these areas shall not occur until the proposed program considers the type of alternatives, similar to those being considered elsewhere in the country.
3. Further pre-leasing and development activities shall be stopped until MMS complies with all the recommendations of the National Academy of Sciences and a detailed program schedule has been established outlining the timing of studies completion.
4. The Santa Maria Basin shall be precluded from leasing consideration based on the inadequate onshore infrastructure to support oil and gas development and being inconsistent with the President's OCS Task Force recommendation to target areas "in close proximity to existing onshore infrastructure."
5. The Santa Maria Basin shall be precluded from consideration of leasing until NOAA's Marine Sanctuary Site Evaluation List process is revised and H.R. 3099 has been given adequate consideration by the United States Congress.
6. Offshore oil and gas lease sales shall not occur until the federal government adopts and implements a national energy policy. The program should incorporate a "least-cost" national energy policy which places the highest priority on federal actions that reduce demand for oil and gas consumption through efficiency and conservation, and which removes subsidies for non-renewable resource depletion and creates incentives for renewable energy sources.
7. MMS shall defer the 87 blocks proposed in the southern California planning area due to the substantially underestimated and deficient impact analysis of marine productivity and environmental sensitivity.

8. New pre-leasing activities shall not be considered until the cumulative impacts from previously leased and undeveloped blocks in the Santa Maria Basin have been defined and more thoroughly analyzed and a mitigation program developed. Appropriate stipulations should be incorporated directly into all existing leased blocks, all lease sales, and subsequent post-lease plans and permits to insure that the cumulative impacts from OCS activity, and onshore processing, refining, and transport operations are fully mitigated.
9. The Southern California Planning area is too diverse and shall be further divided into a Santa Barbara Channel and Santa Maria Basin planning areas subject to their own environmental impact statements for the proposed program Draft Environmental Impact Statement (DEIS).
10. The program for the Pacific Region shall not go forward because the environmental costs are clearly in excess of the assumed benefits as presented in the Proposed Program.

In 1988, the county conditionally approved a development plan for the Shell San Miguel Project. The county's approval encompassed the onshore portion (processing facility and associated pipelines) whereas, the offshore platform and pipelines were approved by the federal Department of Interior, Minerals Management Service. The offshore platform (Julius) would have been the first platform off the county's coastline and the northern-most platform offshore California. The onshore processing facility and pipelines were designed to accommodate production from as many as six additional platforms. The county's action approving these onshore support facilities is therefore significant and further contributes to the county's policy base.

Very few policies were available in the LCP to guide the county's review of the Shell application. Thus, the county's decision to approve the project, as well as the conditions imposed, were a result of analysis performed by county staff in consultation with other agencies during review of the application. The county's action on the Shell permit has been taken into consideration in developing policies as part of this plan.

3.3 Summary of Relationship to the Local Coastal Plan

The San Luis Obispo County LCP was prepared in the period from 1978 to 1980. The LCP contains policies related to energy and industrial development in the coastal zone. Its policies reflect mandates of the California Coastal Act (Coastal Act).

While emphasizing protection, enhancement, and restoration of coastal resources, the coastal act plan recognizes that energy-related development on or adjacent to the ocean is necessary for the social and economic well-being of the state and the nation and to insure preservation of inland and coastal resources. The Coastal Act specifically provides that coastal-dependent industrial activity be encouraged to locate or expand within existing sites. The policy document

of the Local Coastal Plan reflects this direction. The policy document also provides direction related to:

- *Petroleum Extraction Operations and Processing Facilities*
- *Marine Terminals*
- *Pipelines*
- *Power Plants and Electrical Transmission Lines*
- *Liquefied Natural Gas (LNG)*
- *Aquaculture*
- *Offshore Oil and Gas Development including:*
 - *Service and Supply Base*
 - *Partial Oil and Gas Processing Facilities*
- *Guadalupe Dunes Energy Management*

While many LCP policies relate to possible offshore energy development, the section entitled Offshore Oil and Gas Development is the present adopted policy direction for San Luis Obispo County. These policies were developed to reflect the requirements of the California Coastal Act; however, the county was generally unfamiliar with offshore leasing procedures and potential issues related to offshore energy development. Since the development of these policies, the county has participated in a number of OCS Lease Sales, development of three Five-Year OCS Oil and Gas Leasing Programs, review of projects occurring in Santa Barbara County, and its first application for onshore facilities related to an offshore oil project. These have all provided valuable information concerning issues and impacts that have or could occur from development of offshore energy.

3.4 Summary of Relevant Coastal Act and Local Coastal Plan Policies

The policies contained in the LCP and in lease sale position statements are summarized below:

Coastal Dependent Criterion: An underlying Coastal Act policy incorporated into the county's LCP is that development must be "coastal dependent" to be sited on or adjacent to the sea. Coastal dependent refers to those uses which could not function at all if not located there. Recognized coastal dependent uses include: ports and commercial fishing and aquacultural facilities. Coastal dependent uses have priority over other uses, however such uses are required to be consolidated within or adjacent to existing sites. Further, no siting is permitted within a wetland.

Coastal Dependent versus Coastal Related Industry: The Coastal Act distinguishes between coastal dependent and coastal related development and uses. Section 30101 of the Coastal Act defines a coastal dependent development or use as:

"...any development or use which requires a site on or adjacent to the sea to be able to function at all."

In 1979, the state legislators amended the Coastal Act by adding Section 30101.3, which defines a coastal related development as:

"...any use that is dependent on a coastal dependent development or use."

The distinction which the 1979 amendment established is quite important when addressing industrial land uses in the coastal zone. Onshore support facilities for offshore oil development can potentially be either coastal dependent or coastal related. Most onshore facilities which support offshore petroleum development do not require a site on, or adjacent to the sea to be able to function. While both coastal dependent and coastal related development are listed among priority uses in the Coastal Act, a coastal dependent industry is further eligible for consideration under Section 30260 of the Coastal Act. Section 30260 provides that a coastal dependent industry which cannot be feasibly accommodated consistently with other requirements of the Coastal Act may nonetheless be permitted if:

1. **alternative locations are infeasible or more environmentally damaging;**
2. **to do otherwise would adversely affect the public welfare;**
3. **adverse environmental effects are mitigated to the maximum extent feasible.**

Marine Terminals: The LCP states that no new marine terminals shall be permitted north of Shell Beach. Expansion of existing marine terminals or construction of additional onshore pipelines are preferred over construction of new marine terminals. Further, if a marine terminal does not require an ocean site to function, then it must be setback from the ocean.

Pipelines: Biological field surveys are required to be conducted for sensitive resource areas to minimize impacts of pipeline placement. In addition, pipeline segments are required by the federal Department of Transportation to be isolated by automatic shut-off valves. The county has the option to impose additional standards where appropriate. Consolidation of pipelines is also required.

Crew Boats - Port San Luis: In October 1984, a Crew Boat Siting Study was initiated by the county in order to determine whether a suitable location for a crew base existed in our county. A task force, similar in composition to the one created for this Plan, was formed. Of the various sites evaluated, the Union Oil Pier at Port San Luis was identified as the site which would cause the least amount of impacts.

In September 1987, the county's LCP was tentatively approved for the Port San Luis area. The current LCP stipulates that oil-related uses, including crew boats associated with exploratory drilling activities, are permitted "conditional" uses subject to the following findings:

- *alternative locations are infeasible or more environmentally damaging*
- *to do otherwise would adversely affect public welfare.*
- *existing and projected services would not be significantly impacted.*

- *impacts would be mitigated to the maximum extent feasible.*
- *ordinances are enacted requiring permits, conditions, hearings, etc.*

Other oil-related uses associated with development drilling, as well as new or expanded facilities (applicable to any development requiring a coastal permit), require an LCP amendment, and an approved specific plan, as well as submittal of a development plan.

3.5 Policies Addressed By This Element

The county has developed relatively well defined and consistent policies addressing offshore leasing. Possible revisions to these policies will be considered in the "Leasing Issues" chapter. Alternative implementation strategies, in addition to commenting on leasing programs, will also be evaluated in the leasing chapter. Few policies exist to guide the county in evaluating the types of onshore facilities which are appropriate and, if so, under what conditions.

This plan will address some of the major issues with regard to siting an onshore processing facility and propose general siting criteria. Issues associated with other types of onshore support facilities will be only briefly addressed. These may relate to: siting of a supply base or multi-use harbor, expanding an existing marine terminal or siting of a new terminal, refinery siting, crew boat operations at Port San Luis, in addition to other activities. Thus, this document is not intended to address the full range of issues associated with offshore oil and related onshore activities.

3.6 How to Locate Policies

At the end of each issue chapter policies and recommendations are presented. These involve either revisions to existing policies or formulation of new policies. Chapter one, Introduction and Policies, summarizes the chapter policies and recommendations.

The county's existing energy-related Local Coastal Plan policies are available at the Department of Planning and Building. In addition, the county's comments regarding previous lease sales, five year programs, and other OCS related activities, can be found at the Department of Planning and Building.

CHAPTER IV: LEASING

4.1 Outer Continental Shelf Leasing

Offshore oil leasing occurs prior to exploration and development. The federal government through the Department of Interior, Minerals Management Service (MMS) controls the mineral rights to the waters of the Outer Continental Shelf (OCS), lying between 3 and 200 miles offshore. The waters within 3 miles of the coastline are controlled by the State, through the State Lands Commission (SLC).

These state and federal waters are divided up into 9 square mile tracts. The MMS and SLC periodically conduct lease sales in which oil companies can bid on these tracts. The Secretary of the Interior develops a 5-Year Leasing Plan/Schedule which specifies when and where lease sales are to be held during the forthcoming 5-year period.

The federal sales generally encompass large numbers of tracts. Two major lease sales have occurred in federal waters offshore San Luis Obispo County, Lease Sale 53 in 1980 and 73 in 1984. (Figure IV-1). However, many of these leases have since expired as have five tracts that were leased off Morro Bay. Five active leases are located directly off the southern county line, and numerous others to the south offshore Santa Barbara County (Figure IV-1). The proposed five year plan for 1992-1997 included 87 tracts located in the Santa Maria Basin and the Santa Barbara Channel. All 87 tracts were deleted from this program because of the lack of scientific information and intense opposition from state agencies and local communities.

Leasing and development have occurred in state waters offshore portions of southern California. However, no leasing in state waters has yet occurred offshore this county. The California state legislature has excluded certain state owned tide and submerged lands from oil and gas extraction activities. The state waters offshore San Luis Obispo County are among those areas which are called oil and gas sanctuaries.

As part of the process, the California Coastal Commission reviews the proposed notice of sale for consistency with the California Coastal Management Plan. If the Coastal Commission determines that the sale is inconsistent with the Plan, MMS may not proceed directly with the sale. The Commission's determination may, however, be overridden by the U.S. Secretary of Commerce. If the Secretary finds either that the Coastal Commission's decision would result in a significant impairment of national security or national defense, or that an override of the Commission's decision would be consistent with the objectives of the Coastal Zone Management Act (CZMA), would not cause unacceptably adverse environmental damage, would not violate provisions of the Clean Air Act or Clean Water Act, and could not be replaced by an alternative action consistent with the CZMA. If a sale proceeds, the Secretary of Interior must consider

Figure IV-1
Active leases from previous lease sales

the Governor's comments on the "size, timing, and location" of the sale prior to issuing the final notice of sale.

4.2 County Role in OCS Leasing

The county's role in OCS leasing is advisory. The county can submit comments on the Department of Interior's 5-Year Leasing Plan and on the individual lease sale they propose. Because the Secretary of the Interior is required by the Outer Continental Shelf Lands Act Amendments (OCSLAA) to consider comments of the Governor of the affected state, the county provides comments via the Governor's office. The Governor consolidates local government comments together with those received from state agencies, and transmits them along with recommendations he/she formulates to MMS. The county also provides comments to the California Coastal Commission, who is responsible for reviewing impacts of the lease sale, on the States Coastal Zone Management Program. The Coastal Commission, in turn, provides comments to the Department of the Interior.

The lease sale process involves a number of steps occurring over a two year time period. The county normally provides comments three times during this process: At the scoping meetings conducted by MMS, following release of the Draft Environmental Impact Statement (DEIS), and following release of the Final EIS and Final Notice of Sale.

4.3 Public Participation in Leasing Decisions

Participation in county and MMS hearings on lease sales is the primary means by which interested individuals and organizations influence leasing decisions. The County Board of Supervisors has held public hearings to consider public comments on the Draft and Final EIS and on the Notice of Sale. At the Board of Supervisor's hearing, county staff analysis and public comments are considered by the Board as part of adopting a county position on the sale.

Members of the public may further affect leasing decisions through the electoral process (i.e. local, State, Congressional, and Presidential elections). The president has the most influence over leasing through the selection of a Secretary of Interior. For example, the next president may determine whether to carry out the California lease sales, the processes for which are currently underway.

Another avenue open to the public is through contacts with Congressional representatives concerning pending leasing-related legislation.

Interested persons may keep apprised of leasing as well as other offshore energy related activities through a variety of means including:

- *Contacting the county's Energy and Natural Resources division for the current status of leasing activities;*

- *Contacting the California Coastal Operators Group (CCOG) which acts as representatives to oil companies and associated businesses operating in the Ventura, Santa Barbara, and San Luis Obispo County area.*
- *Contacting members of the county's Offshore Energy Task Force, which is comprised of oil industry and environmental, as well as other interests.*

4.4 Types of Leasing Issues

A number of issues have been raised concerning the Federal Five Year Leasing Schedule and individual lease sales. Generally, these issues concern the size, timing and location of lease sales, the regulatory framework under which such sales occur and the environmental assessment process used in arriving at lease sale decisions. This chapter is to discuss these leasing issues in more detail.

There is a distinction between leasing and development issues. Leasing issues deal with questions of "if" and "where", as opposed to "how", development occurs. Lease sale stipulations, where they are applied, provide general direction on "how" development may occur. Questions pertaining to areawide, cumulative and long-term impacts of offshore oil activities are most important to consider at the lease sale stage. Once a lease sale takes place and resources are discovered, development usually follows. Thus, involvement at all stages of the lease sale process is crucial.

Leasing issues can be divided into specific concerns about: 1) the environmental, economic and physical impacts of leasing; 2) the procedures used in the lease sale process; 3) concerns about national security and energy supplies; and 4) the potential for increased conservation and development of renewable energy resources. There is disagreement over the degree to which these impacts may occur, where and how they occur, and their effect on the county's economy. Though many of the impacts described above do not directly result from leasing, lease sales set the stage for subsequent development. These issues are directly related to overall questions concerning the pace and extent of leasing, and are discussed below.

Air Quality: Emissions from offshore platforms are transported onshore where they combine with other emission sources to increase air pollution. In some cases this will contribute to exceeding some of the state and federal air quality standards. Disagreement exists over the degree to which offshore sources contribute to onshore air quality impacts. Since federal standards are less stringent than state standards, the state, along with California coastal counties, have argued for implementation of stronger air quality standards for OCS projects. Recent amendments to the Clean Air Act may provide those types of standards. The air quality chapter provides a more detailed discussion.

Water Quality and Marine Life: Impacts result primarily from oil spills and other discharges into the environment. Tanker accidents are the main cause of oil spills. Thus, coastal counties, as well as state agencies, have proposed that oil be transported via pipeline

wherever feasible. While spills from platforms are less likely, they can also occur. To avoid potential impacts to water quality and marine life, the county has recommended against leasing in sensitive areas and for providing buffers around resource areas.

Another water quality concern involves the discharge of drilling muds and cuttings. These materials are used in conjunction with drilling operations and may contain constituents harmful to marine life. Such discharges are primarily governed through Environmental Protection Agency permits in the OCS, and Regional Water Quality Control Board permits in state waters. Disagreement over the fate and effects of the muds and cuttings materials continues to exist within the scientific community.

Land Use: At the lease sale stage, concerns are raised regarding availability of appropriate areas to accommodate onshore support facilities, as well as the pace at which these facilities are constructed. In addition, the effect of such development on future land use patterns, and on county plans and policies are important considerations.

Significant land use conflicts may arise due to the siting of onshore facilities in areas with limited public services to support industrial development or in areas which have surrounding incompatible uses. Some of these issues may be easily resolved, while others, due to the nature of a particular location, may not be. The siting evaluation in Chapter VIII evaluates land use impacts related to processing and treatment facilities siting.

Socioeconomic: Since the early 1980's, oil and gas development in the Santa Barbara Channel and in the Santa Maria Basin north of Point Conception has increased. This new development has heightened the demand for onshore oil and gas treatment, storage, and transportation facilities in the tri-county area (Ventura, Santa Barbara, and San Luis Obispo Counties). Because this development may also result in large numbers of people moving into the region, these counties have required that the companies involved in offshore oil and gas projects participate in the Tri-county Socioeconomic Monitoring and Mitigation Program (SEMP). The purpose of this program is to document the ongoing socioeconomic impacts of each project, and to provide an equitable means for mitigating impacts. Development of onshore related oil facilities may also have benefits in the form of additional tax revenues and, in some instances, job opportunities.

Commercial Fishing: At the lease sale stage, the primary impact on commercial fishing resources and the fishing industry is "area preclusion." This results when the use of historical or potential future fishing grounds may be precluded because of placement of oil platforms and subsea structures, or through reductions in fishing yield as a result of oil spills and discharge of drilling muds. Impacts from geophysical survey impacts are also of concern at the pre-lease stage. Other issues may arise over the potential displacement of fishing vessels by oil crew and support vessels because of limited harbor space. The issues raised in connection with these impacts concerns their significance upon commercial fishermen, the local economy, the availability and price of food resources, and to what extent mitigation of these impacts is possible.

Tourism: The offshore oil impacts to tourism commonly identified with the lease sale stage include impacts of a possible major oil spill and impacts from conflicts arising from nearshore and onshore oil-related activities. For example, the Unocal oil storage tanks at Avila Beach preclude direct lateral coastal access to Pirates Cove from Avila Beach as well as impacting coastal views. Likewise, the Unocal pier and marine terminal and associated oil tanker onloading operations conflict with recreation and tourism uses in the harbor.

Cultural: The county has many archeological sites located onshore and some that are submerged in the offshore areas. Many of the sites are from the Chumash and are easily disturbed or destroyed by development. Some sites are over 9,500 years old.

4.5 Procedural Issues

The OCSLAA gives the Secretary of the Interior broad, discretionary power to conduct lease sales. However, the Secretary is required to adhere to additional provisions of the OCSLAA which provide for participation of affected states, and further, to ensure compliance with the National Environmental Policy Act (NEPA). A number of procedural concerns have been raised concerning how the lease sale process is administered. These are summarized below:

Inadequate Environmental Analysis: All the lease sale documents, including the various 5-year leasing schedules prepared by the Department of Interior, Minerals Management Service have been judged by most coastal counties and states to be inadequate because of the limited environmental analysis they contain.

Objectivity: In addition, the environmental documents are prepared by MMS and are for the purpose of justifying lease sales which they have proposed. The conclusions reached in these documents relating to impacts have appeared to be somewhat limited in scope.

Areawide Leasing Too Broad: The areawide approach to leasing does not provide for a meaningful assessment of impacts. Moreover, this approach, because of its lack of focus, makes reviewing and preparing for possible impacts very difficult. The Lease Sale 95 EIS, for example, would have covered the area between the Monterey-San Luis Obispo County line and the Mexican border, from 3 to 200 miles offshore. Proposed lease sale 163 (scheduled for 1996), is smaller but failed to adequately consider the cumulative impacts of existing and proposed leases.

Opportunities for Meaningful Participation: Public and local government opportunities for participation in the lease sale process have been extremely limited, including the location of Draft EIS hearings, and the limited comment period. In addition, past EISs have failed to adequately incorporate or respond to the comments of state and local governments.

Fair Market Value: The OCSLAA, Section 18(a)(4), requires that leasing activities be conducted to assure that the federal government receives fair market value. In the absence of

the OCSLAA defining fair market value, the Secretary of Interior has defined it as the amount a willing owner would sell such property to a willing buyer. Concern has been expressed over the fact that accelerated leasing, as provided by the 5-Year OCS Leasing Schedule, may result in less intense competition and lower bids for some tracts.

4.6 Other Issues

Need for Additional Oil: An important issue concerns whether the need for leasing has been adequately demonstrated by the Department of Interior. The EIS's prepared for Lease Sales 53 and 73, and the 5-year Leasing Schedule, only summarily discussed this issue. These documents, for the most part, rely on the National Energy Policy adopted by Congress in 1977 and the OCSLAA of 1978, both of which are intended to expedite leasing and development of the nation's offshore energy resources. Several national energy policy bills are currently being considered by congress. However, projections contained in Department of Interior's 5-Year Leasing Program (Mid-1987 to Mid-1992) cite doubling of U.S. oil imports over the next decade, despite the contributions from proposed OCS leasing. The report further advocates increased energy efficiency and utilization of alternative energy. Thus, an integral part of the "need/benefits" question is renewable energy and conservation potential. Many argue that such relatively benign alternatives afford greater net environmental and economic benefits in the long-term than expanded offshore oil development as proposed in the current 5-year OCS Leasing Program. Development of a "comprehensive" national energy plan which would consider these alternatives is recommended.

Timing of Lease Sales and Phasing: Phasing is an alternative which local government has requested the Department of Interior consider as one means to minimize effects of lease sales. Once a lease sale takes place, phasing would control the timing of development of leased tracts. From the standpoint of local government, impacts could be predicted more easily and planning to accommodate these activities would be more effective.

Coastal Commission Consistency Review: The California Coastal Commission had in the past reviewed leasing actions for consistency with the California Coastal Management Plan. However a federal court in reviewing Lease Sale 53 ruled that the Commission did not have the authority to review consistency at the lease sale stage. Legislation may be proposed in the future to further clarify the Commission's role with regard to reviewing federal offshore oil leasing decisions.

4.7 San Luis Obispo County Position on Leasing

San Luis Obispo County has historically adopted a position opposing leasing 20 miles around Morro Bay and 12 miles around the southern range (the Santa Maria River) of the California sea otter. This position has evolved from previous comments submitted by the County Board of Supervisors and Area Council of Governments in response to the Federal Five-Year OCS

leasing plans, Lease Sale 53, Lease Sale 73 and Lease Sale 95. The 12-mile buffer is proposed to ensure protection of the California sea otter range and other resources.

Examples of resources which could be impacted from leasing include: the Morro Bay estuary and watershed, the sea lion haul out areas along the Montana De Oro coastline, the southern sea otter, whose recognized range extends to the Santa Maria River and the Nipomo Dunes complex. The proposed buffer areas would provide additional oil spill response time, without which containment and recovery of a spill are extremely difficult in the typical sea conditions of the area above Point Conception. A number of federal and state agencies have also supported establishing these buffer areas, citing the need to protect specific marine mammals and fishery habitats.

The county submitted extensive comments on the 1992-1997 five year leasing program. The major points are included in Chapter III, Policy Base.

The county also submitted comments on the Draft Environmental Impact Statement for the 1992-1997 five year leasing program. The following are the major recommendations adopted by the Board of Supervisors:

1. That the DEIS be found incomplete because of inaccurate assumptions relative to existing infrastructure described in the base and high case scenarios and lack of mitigation for major impacts identified in the cumulative case. A review of the process by which these assumptions are developed should be completed.
2. That the final EIS focus on the specific resources and ecosystems of the Santa Maria Basin and Santa Barbara Channel since these areas will incur the impacts of the proposed lease sale. If leasing does occur, EIS's specific to the Santa Barbara Channel and the Santa Maria Basin should be completed before the lease sale. Prior to preparation of the EIS's the studies previously recommended by the County of San Luis Obispo and the National Academy of Sciences should be completed.
3. Tracts within the Santa Maria Basin be deleted from consideration in this 5 year program and DEIS because the scientific information about the area is currently inadequate. To date, a comprehensive, up-to-date and scientific information base for objective and reasonable leasing decisions regarding the Santa Maria Basin and San Luis Obispo County does not exist. This data base should be fully developed before a decision to lease is made.
4. The final EIS should include the Pacific Region in a similar analysis as that of Alternative III., Slowing the Pace Alternative V., Establishing Coastal Buffers and Alternative VI., Exclude Certain Seafloor Features.

5. That the DEIS be found to be inadequate since information is portrayed in such a manner as to justify the leasing program and does not provide an objective and systematic analysis of the affected environments and the impacts to those environments.

Additional considerations in developing the county's policies have included: recommend for deletion where the presence of severe geohazards occurs on certain tracts; unresolved concerns regarding air quality; protection proposed for high yield fishing areas; avoidance of vessel traffic; and projected socioeconomic effects.

4.8 Policies

1. Lease sale stipulations, if responsibly drafted, can protect the natural resources of the county and promote county interests. In the lease sale process, the county will adopt positions requesting stipulations that require the following:
 - Lease sale stipulations prohibiting lessees from using an offshore storage & transfer vessel (OS&T) for the purposes of processing and transporting OCS production, and requiring instead that all offshore oil and gas production be piped onshore for processing and movement to market.
 - Agreements requiring that before further leasing, MMS conduct a baseline biological study which focuses on this county's offshore waters, or, if leasing occurs, a stipulation requiring the study prior to initiating development of any tracts leased.
 - Lease sale stipulations requiring site-specific biological surveys intended to define the presence of and provide protection for important biological resources. The survey shall define areas of special biological significance and higher productivity, diverse and/or complex ecosystems which include high-intensity fin-fish/shell fish areas, critical habitat and rare/threatened, endangered species, unusual, rare, uncommon ecosystems, areas having an abundance or high diversity of species, and areas critical to the life cycles of species (i.e. spawning, feeding, rearing or migratory areas).
 - Protection for biological resources identified in biological surveys shall include avoidance of areas, modification of operations, and provision for a regular monitoring program during operations with authority to require reasonable corrective measures to mitigate identifiable impacts.
 - Maintain the county's Offshore Energy Task Force during lease sale review and comment periods to enhance the flow of information to the public.

2. Controlling the overall pace of offshore development can reduce the level of peak cumulative impacts and increase opportunities for orderly change in the very limited parts of the county which may prove suitable for onshore support facilities. To accomplish these purposes, the county will adopt a position which requires:
 - Leasing agencies to comprehensively study the impacts of the development of already leased tracts offshore the county (most of which lie within the buffer zone defined by the county) before additional leasing occurs.
 - Leasing agencies to recognize the difficulties in accommodating onshore facilities required for development of already leased tracts and to resolve such difficulties before any additional leasing occurs.
 - Require that all future pipelines and processing facilities be consolidated to the maximum extent feasible.

3. San Luis Obispo County has consistently advocated policy positions which have not been adopted in federal lease sales. To provide further protection of biological and coastal resources, and to address the general unresponsiveness of the Minerals Management Service (MMS) to these county policies, the county will adopt a position which requires:
 - Permanent protection and management of the county's coastal resources using the National Marine Sanctuary and the National Estuary Programs as vehicles for protection and management.
 - Future lease sales and developments be consistent with the county position that no drilling be permitted north of Morro Bay, within 20 miles of Morro Bay, or within 12 miles of the southern boundary of the California sea otter range.
 - That a 15 mile buffer zone of no offshore energy activities be established around the Santa Lucia Bank to protect the rich commercial fisheries and other natural resources.
 - Opposition to future lease sales until concerns including leasing in sensitive areas, the county-proposed buffer zones, understatement of impacts, overly ambitious leasing schedules, failure to consider the need to plan for onshore support facilities, and the potential roles of conservation and alternative energy resources are adequately addressed by federal agencies.
 - Pursuing maximum public awareness and participation in lease sales, as well as assuming an advocacy role in affecting policy, maintaining continued clear county policy direction, and coordinating efforts with other coastal counties.

- Actively supporting legislation consistent with the county's adopted leasing policies.
- Formal opposition to exploration and development plans submitted to MMS in the event these activities are inconsistent with the county's leasing policies (i.e. where such activities are proposed in locations where the county had previously objected to leasing).
- Disapproval of proposals for onshore support facilities that are incompatible with adopted leasing policies.
- Participation to advance county policies if either the current 5-Year OCS Leasing Plan or any lease sales are challenged in court on issues directly or indirectly affecting the county.
- Review and comment on proposed lease sales and leasing-related legislation affecting other areas in instances where we share common concerns and there may be potential impacts to our county.
- Continue the practice of providing for public discussion before the Board of Supervisors in all instances where the county has the opportunity to comment on lease sales or on leasing-related issues so that interested individuals and organizations are provided maximum opportunity for input.

CHAPTER V: BIOLOGY

5.1 Background

The county's biological resources, both onshore and offshore, would be affected through offshore oil and gas exploration, construction, and production activities. This chapter will review some of the county's important coastal resources, significant biological issues, and ongoing or planned biological studies. The chapter will also present policies and recommendations to protect these resources.

San Luis Obispo County spans 96 miles of coastline and has many areas with important habitat, recreational, and agricultural resources. Those areas include the lands surrounding Nipomo Dunes, the north coast areas and the Morro Bay watershed. The county's coast contains spectacular scenery and pristine waters. Rocky shores alternate with unspoiled sandy beaches. Other characteristics of the coastal land mass include low volcanic and tectonic mountains, fertile plains, and extensive dunes. Millions of tourist visits are recorded each year because of the scenic, aesthetic and recreational values of the coast and the coastal waters.

The north coast is characterized by the rugged headlands to Big Sur. The rocky shoreline along Hearst Ranch is highly valued for the offshore views of scenic cliffs and rocky points. The beach, sandspit, and extensive wetlands of Morro Bay have been nominated by Governor Wilson for inclusion into the National Estuary Program administered by the Environmental Protection Agency. The sheltered coves and beaches of Avila and Pismo Beach state parks provide a contrast to the marine terrace and offshore rocks of the north county coastline. The Monterey Bay National Marine Sanctuary extends south to Santa Rosa creek near the town of Cambria.

The region contains a rich variety of sensitive coastal habitats. It includes wetlands and estuaries, rocky intertidal zones, long stretches of open sandy beach, coral communities, numerous offshore rocks used by birds and marine mammals, and hard-bottom substrate. Large environmentally sensitive kelp forests stretch along the coast. Major feeding and resting areas exist for migratory birds.

The offshore waters provide for a rich biotic diversity resulting from factors such as the location in a transition zone of meteorological and oceanographic provinces, a year round upwelling extending from Point Sal to Point Conception which is one of the most significant nutrient sources in the entire North Pacific Basin. There are strong seasonal upwellings at Point Piedras Blancas and Point Buchon and productive wetlands such as the Santa Maria river mouth and the Morro Bay estuary. Some of the most intense biologic research on the California coast has been done at Diablo Cove, while significant benthic communities at the Santa Lucia Bank and Arguello Canyon remain understudied. Archaeological sites of the Chumash people exist in dunes and coastal terraces along the coast.

Figure V-1
Some Threatened or Endangered Species in the County

Threatened and endangered species in the region include the California least tern, the California brown pelican, the southern sea otter, the clapper rail, and four species of sea turtle. Seven endangered species of whale, the gray whale, the humpback whale, the blue whale, the fin whale, the right whale, the sei whale, and the sperm whale may be found in the area. The entire population of gray whales in the eastern Pacific migrates through the area twice each year, as does half the northern Pacific population of humpback whales.

5.2 Description of Resources

Marine: In general, site specific biological resources offshore San Luis Obispo County are not well known. Other resources have been well defined through studies and different environmental impact reports. The marine environment of San Luis Obispo County is characterized by intertidal regions of sandy beach, rocky shoreline, an estuary, and offshore regions ranging from sand and mud flats to rocky reefs with kelp beds. The area also has many small to medium size rocky outcrops. These physical features attract marine mammals, provide a number of areas for roosting and nesting land for seabirds, and support an abundance of fish. Many of these are listed as endangered, such as the least tern and brown pelican, or threatened, such as the southern California sea otter, whose range extends along the entire length of our county's coastline. The county's proposal to create a Central Coast Marine Sanctuary contains more details on the biological significance of the area. Native and migratory endangered and threatened species are shown in figure V-I. Hundreds of fish species also inhabit the varied the varied marine settings, many of them are important to sport and commercial fisheries.

The county's north coast region, which extends into Big Sur, is characterized by steep cliffs descending to the rocky, sometimes inaccessible, shoreline below. The area is known for remote coves and is inhabited by seals, otters, and many other types of marine life. Off Cape San Martin, elephant seals breed and have pups. Similarly, Point Piedras Blancas to Point Estero are important seabird and marine mammal areas. The kelp beds lying off crescent-shaped San Simeon Cove provide a haven for a number of fish species, as kelp beds do everywhere.

Morro Bay is an important resting, feeding and breeding area for migratory waterfowl and Morro Rock is one of four breeding sites within the county for the endangered Peregrine Falcon. The nomination package for the National Estuary Program and prepared by the Morro Bay Task Force provides a detailed description of the biologically significant areas.

The rugged coastline stretching from the Morro Bay sandspit, south to Hazard Canyon, Spooners Cove, Point Buchon, and Lion Rock and beyond to the Point San Luis Lighthouse and breakwater, contains diverse physical features which contribute to its biological significance. Above this coast lies the marine terrace and coastal mountain range, a portion of which is occupied by the 7000-acre Montana de Oro State Park. The chaparral, Bishop pine and coastal live oak provide important wildlife habitat. Ranch land also occupies a portion of this area, as does the Diablo Canyon Nuclear Power Plant. The Montana de Oro Pecho coast is one of the

largest seal and sea lion haul-out areas for pupping, resting and molting. Harbor seals also breed here. The Pecho coast also includes a mainland haul-out for California sea otters.

Figure V-2
Ecologically Significant Marine Areas

Below Point San Luis, the coastline turns east and south forming Avila Bay. Though adjacent to developed communities, a variety of marine life is found in the bay, including many seabirds, sea otters, seals and sea lions, and fish. A marine terminal is located at Avila Beach. Tankers load crude and partially refined product for shipment to other destinations. The tankers unload gasoline for onshore distribution.

South of Pismo Beach lies the Nipomo Dunes which have been recommended for nomination to a National Seashore status and is currently considered a National Natural Landmark by the Bureau of Land Management. The dunes contain Oso Flaco Lake and the Dune Lakes and a unique variety of native plants, some them protected species. A large portion has been designated a preserve and is being managed by the Nature Conservancy. While other portions of the dunes have been impacted by the Unocal Refinery and the Guadalupe oil field, the dunes remain a vital ecological resource. Further south lies the Santa Maria River mouth wetlands, approximately along the county line. Figure V-2 is a map that summarizes some of the ecologically significant marine areas. The maps in figures V-3 through V-6, found at the end of the chapter, show some of the important resources that are offshore and along the coast of the county.

5.3 Impacts

Development of offshore oil and gas has the potential to impact biological systems at all stages, starting with seismic surveys through exploration and continuing through construction, operation and abandonment. Nearshore or onshore support facilities may impact biological systems, as discussed below.

5.3.1 Offshore

Seismic Survey: Seismic survey activities are known to cause behavioral changes in fish. Further, it has been suggested, based on information available for anchovy larvae, that some larval forms might be harmed by seismic survey activities. While it has been suggested that gray whale migration patterns may be affected by seismic testing, limited studies conducted thus far by MMS do not identify any evidence of interference. The State Lands Commission has determined that for future seismic surveys proposed for state waters, an Environmental Impact Report shall be required. The effects of seismic testing are further discussed in Chapter VI, "Fisheries Issues".

Platform and Pipeline Placement: Bottom dwelling organisms may be impacted through burial, sedimentation or increased turbidity during placement of platforms, pipelines, cables or other subsea structures. With pipelines, the major impacts occur nearshore in the intertidal and shallow subtidal zones of the landfall. Other impacts occur through laying of the pipeline. The lay barge technique usually results in less impact than the bottom-pull method.

Impacts from platform and pipeline placement may be reduced through avoiding ecologically productive or sensitive habitats, although as indicated, site specific biological information is

very sparse. San Luis Obispo County has requested that MMS include a lease sale stipulation mandating site-specific offshore biological surveys prior to: a) any drilling activity; and b) the placement of any structure for exploration or development.

Oil Spills: A major oil spill remains the single most dramatic threat to biological resources off the coastline although chronic impacts from exploration and operation may be more damaging over time. Spills may result from a variety of events: well fire or blowout, pipeline rupture, vessel collision or grounding while enroute through the area or during on-loading or off-loading crude oil at a marine terminal. While major spills are uncommon events, they continue to occur on a worldwide basis. The extremely limited effectiveness and lack of response equipment in the conditions common off our coast has caused considerable concern over continued leasing and development. Additionally, adequate facilities to care for injured seabirds and marine mammals have not yet been provided, although such facilities are required by stipulations included on development occurring on Lease Sale 73 tracts. The California sea otter is particularly vulnerable to spill impacts because of the otter's dependence on its fur for insulation. In reviewing proposed development, the Fish & Wildlife Service is required to conduct a consultation assessing the extent to which impacts from a proposed project could threaten the viability of the sea otter population. The subject of oil spill prevention and response will be further addressed as part of a separate study being undertaken by the county.

Drilling Muds and Cuttings Discharges: Within the Outer Continental Shelf (OCS), discharges of drilling fluids are regulated by the Environmental Protection Agency (EPA). In the past, a single permit was issued for all operations occurring in the Pacific OCS. This general National Pollution Discharge Elimination System (NPDES) permit allowed discharges of muds and cuttings containing specified concentrations of various chemical constituents. This process was intended only as a temporary mechanism to permit discharges until the effects of these discharges could be further assessed and new regulations adopted. The NPDES permit has since expired. EPA is now issuing permits on a case-by-case basis until a new General Permit can be developed. The only individual permit issued (as of March 1988) has been for Platform Gail offshore Ventura County.

The State Water Resources Control Board, through the Regional Water Quality Control Boards (RWQCB), issues discharge (NPDES) permits in state waters. The Coastal Commission is also responsible for water quality issues to the extent they are related to impacts on coastal resources. Thus, the Commission has considered the effects of these discharges in their review of Coastal Development Permits for drilling in state waters. Environmental Impact Reports prepared for leasing and development projects in state waters in more recent years have recommended onshore disposal of drilling muds rather than discharge at the platform. Moreover, the State Lands Commission has supported onshore disposal over ocean discharge.

Disagreement continues within the scientific community over the fate and effects of drilling muds and cuttings. This is due to the difficulty involved in measuring effects, particularly over large areas and over the long-term, and because only limited field studies have been conducted on the West Coast. However, studies which have been conducted note that the major effects

have been due to burial of benthic (bottom-dwelling) organisms in the immediate area of the platform. A radius of 656 feet around a platform and 320 feet around an exploratory rig, were found to have been affected in the Mid-Atlantic Study referenced in the Coal Oil Point EIR. Other changes may arise from topographic alteration, toxic effects, turbidity, and decreased oxygen. Cumulative regional impacts have been postulated, but are difficult to substantiate.

The chief concern with the issuance of a General NPDES Permit has been that such a generic approach fails to reflect site specific biological and physical diversity and related sensitivity.

5.3.2 Onshore/Nearshore

A wide range of potential biological impacts are associated with development of near and onshore support facilities. The nature of these facilities and associated impact areas are discussed in Chapter VIII. In general, the following types of potential impacts can be expected:

Onshore Pipelines, Processing and Treatment Facility: Numerous potential biological impacts were identified in the San Miguel EIS for the proposed onshore pipelines and an oil processing facility in the South County. The majority of biological impacts could be reduced to insignificant levels through physical mitigation measures, timing of construction to minimize unavoidable impacts, and, to the extent possible, modifying the facility location and associated pipeline corridors.

Many biological impacts from the San Miguel Project would result from construction of the pipeline through the dunes which are a prime example of sensitive habitat in the county. Pre-siting habitat and biological community surveys, route selection, corridor narrowing, restrictions on construction techniques, and re-vegetating the disturbed area were intended to mitigate these impacts over time. Nevertheless, future offshore development may require cutting through this corridor again or establishing additional corridors, thus defeating initial mitigation efforts. Therefore, a major question to be dealt with concerns the sizing of the first corridor and number of pipelines initially placed within it as well as the number of pipelines which may be required to accommodate possible future offshore platform development. Similar concerns exist in regard to processing sites, where the geographic area affected is more limited, but construction activity is more prolonged and intense, and where permanent habitat displacement can occur.

Fires and oil and/or hazardous materials spills at a refinery, processing facility, or along a pipeline, as well as offsite flow of oily water after a rain, may also affect biological resources. Onshore pipelines can be ruptured, resulting in oil spilling and reaching sensitive resources. Measures available to reduce these impacts include: emergency shut-off valves at stream crossings and other sensitive locations, fire prevention/response plans, oil spill contingency plans and equipment positioning, berming, continuous leak detection monitoring, facility siting near fire stations, double walling of pipe at and near stream crossings, and capture of oily runoff at the processing site.

The first step towards reducing the potential for biological impacts related to offshore oil and gas development and their associated onshore facilities is a thorough environmental review process. This will identify all potential impacts and establish mitigation where possible. These factors also need to be taken into account during the decision-making process. Avoidance of a potential impact area or situation is generally preferable to an engineering solution. To this end, it is important to have reliable information with which to make siting decisions.

Marine Terminals: Millions of barrels of petroleum materials are transferred each year through the Avila Beach and Estero Bay marine terminals. When oil tankers enter Port San Luis, Avila, Estero Bay or other existing or potential sites for on and off-loading petroleum products or crude oil, there is an increased risk of collision or grounding, particularly during bad weather conditions. This increases the risk of an oil spill. In addition, a spill risk is present during crude and product transfer operations when fires or other accidents may occur. Should existing marine terminals be expanded or new terminals sited, these risks would increase.

Crew Boat Operations: The operation of crew boats, could result in biological effects through discharges of oil and exhaust into the water during normal operations and collisions with marine mammals.

Helicopters: Helicopter traffic (used to transport crew and supplies) has the potential to disturb roosting and nesting birds, and hauled-out marine mammals, both of which are vulnerable to disturbance.

Supply Base: Significant onshore and offshore impacts, would be expected to result from a major supply base, if one is to be located along the county's south coast. These impacts would arise from pier and breakwater construction, dredging, degradation of water quality, disruption of wetlands, and alteration of significant landforms. These impacts, in turn, could substantially affect marine and terrestrial plant and animal life. The type and severity of impacts would depend upon the specific proposal.

5.4 Regulatory Setting

Over 60 plant and animal species in San Luis Obispo County have been identified as being of special concern. Some of these require special protection or consideration as a matter of law and others are generally recognized because of their complex contribution to the local and regional environment (e.g. Morro Bay estuary, Santa Maria River wetlands, Oso Flaco and the Dune Lakes).

Marine mammals receive special legal protection through the Marine Mammal Protection Act (MMPA). Whale, dolphin and porpoise are present in the marine waters of the county; some only pass through during migration while others may be found year round. The California sea otter receives special legal protection through the Endangered Species Act.

Seabirds are another group to receive special consideration. Their requirements for roosting and nesting areas along the coast often conflict with human uses and they are particularly vulnerable on land.

5.4.1 Federal Role

A number of federal, state, and county agencies are involved in the review of offshore oil activities. These agencies are charged with the statutory responsibility to enforce various regulations, many of which affect biological resources. For federal tract development the primary responsibility lies with the Minerals Management Service (MMS) of the Department of Interior. They are charged with administering lease sales as well as preparing the Environmental Impact Statements (EIS) for those sales. Various agencies submit comments to MMS during the Draft EIS review period. During this process, the U.S. Fish and Wildlife Service (USFW), the Department of Fish and Game and California Coastal Commission are primarily concerned with biological issues.

To respond to the responsibilities to protect biological resources, MMS has established special requirements. As part of Lease Sale 53, MMS Biological Stipulations 1 and 8 requires that lessees satisfactorily show that no special biological resources would be adversely affected by their actions. Oil and gas vessel operators and facility supervisors are required to participate in a training program that emphasizes the sensitivity of marine mammal and seabird sites that could be affected by their operations.

For Lease Sale 73 tracts, stipulation (Number 9) requires the Oil Spill Contingency Plan adopted for a project to ensure the availability of a care facility for mammals and seabirds and ensure that the best available cleaning and rehabilitation methods are provided.

During the development stage, the MMS is generally responsible for preparing an EIS. A recent trend, particularly where several agencies are involved, has been to establish a panel of affected agencies to manage the preparation and coordinate review of the environmental document. In the course of reviewing a development plan, USFW issues a "biological" opinion to MMS, outlining their recommendations concerning endangered species. This requirement for special consultation and impact assessment is required by the Endangered Species Act of 1973 (P.L. 93-209). The opinion must determine whether the project will cause "jeopardy" to population of threatened or endangered species.

The agencies involved in affecting biological resources and their respective statutory responsibility to enforce various regulations are outlined below:

The U.S. Fish and Wildlife Service (USFW) is the primary federal agency responsible for implementing regulations related to biological resources. This includes the Endangered Species Act of 1973 which provides protection for species listed under the Act and for their critical habitat. USFW also enforces the Migratory Bird Treaty Act of 1972, which seeks to protect birds, including seabirds. USFW and the National Oceanic and Atmospheric Association

(NOAA) share responsibility in implementing the Marine Mammals Protection Act, which limits the incidental taking of marine mammals.

The Environmental Protection Agency (EPA) enforces Section 404 of the Clean Water Act, which regulates development in Streams and Wetlands. The Army Corps of Engineers is responsible for Section 10 of the Rivers and Harbors Act, which regulates development in navigable waters, onshore and offshore.

5.4.2 State Role

Primary state regulations and agency roles concerning biological resources include the following:

The State Lands Commission is the trustee and steward of tidal and submerged lands. They are responsible for ensuring that lessees act in a manner which protects the offshore area's water and biological resources according to all applicable laws and regulations.

The California Water Resources Control Board provides protection for areas of special concern through designation of marine life refuges, reserves, ecological reserves, and Areas of Special Biological Significance (ASBS).

California Department of Fish and Game (DFG), preserves, protects and manages marine and terrestrial resources and regulates sport and commercial fishing. The California Endangered Species Act of 1970 (Sections 2050-2098, California Fish and Game Code; amended September 1984) and the California Native Plant Protection Act of 1977 (Sections 1900-1913, California Fish and Game Code) provide protection at the state level for species designated as threatened or endangered and requires consultation between the lead California Environmental Quality Act agency and the Department of Fish and Game for projects that may affect state-listed species. Sections 1601 and 1603 of the California Fish and Game Code regulate developments in onshore waters including intermittent streams.

The California Environmental Quality Act (CEQA) provides additional protection for animal or plant species which are not state or federally listed, but which meet criteria of "rare" or "endangered" as defined in Section 15380 of the act.

Under California's federally approved Coastal Management Program, the Coastal Commission must determine whether offshore oil and gas projects in the outer continental shelf can be sited consistently with the biological provisions (among others) of that program.

The California Coastal Act of 1976 regulates development and provides protection for biological resources in the coastal zone, which includes state tidelands and submerged lands. Provisions of the act related to onshore biological resources are administered by San Luis Obispo County.

5.4.3 County Role

The county's role includes providing recommendations to state and federal agencies and counties regarding projects beyond our jurisdiction. In cases where a project or portion thereof lies within its jurisdiction, the county has an active role which may involve processing land use permits, including coastal development permits and assuming a "lead agency" role for purposes of preparing the project's environmental assessment.

San Luis Obispo County has a comprehensive general plan that addresses resources in the county. The Land Use Element portion contains pertinent environmental and land use regulation policies. In order to implement the plan, the county has been divided into 13 planning areas, 4 of which are in the coastal zone. The Land Use Element designates "sensitive resource areas" (SRA) as a combining designation added to the land use category (zoning) that provides specific protection for significant resources.

San Luis Obispo County has an approved Local Coastal Program (LCP) and Coastal Zone Land Use Ordinance; permit authority was transferred to the county in March, 1988. The existing coastal policy is to protect sensitive habitats, wetlands, streams, terrestrial environments, including native vegetation, rare and endangered species, and dune vegetation; and marine habitats. The LCP designates "sensitive resource areas" and "environmentally sensitive habitat areas" as described in the preceding paragraph. In addition, the LCP includes specific policies pertaining to oil and gas projects with respect to biological resources.

5.5 Programs/Studies

A number of programs and studies address biological issues raised by offshore oil and gas development. A partial bibliography is available at the energy and natural resource division of the county. Certain important studies and programs are discussed below:

Marine Wildlife Contingency Plan: This plan is required to be developed by offshore operators to establish procedures to be followed in the event of an oil spill. The plan also includes an inventory of resources/animals that would be at risk in such a situation as well as the location of rehabilitation centers.

U.S. Fish and Wildlife Consultation: Federal law requires MMS to consult with USFW concerning marine life impacts on the OCS from proposed leasing or development activities. Under this provision, USFW issues a "biological opinion" regarding the particular project which MMS must either adopt or defend an action to the contrary.

San Luis Obispo County Emergency Response Study: The county Office of Emergency Services is conducting an analysis of current and potential offshore oil activities which may result in oil spills, as well as available methods to minimize these risks. Oil spill response procedures will also be evaluated. In addition, studies being conducted by other

jurisdictions (e.g. Santa Barbara County, Laguna Beach, Joint Central-Northern Counties Project) will be monitored.

Environmental Studies Programs: A number of biological studies have implications for coastal counties. These programs and studies are implemented by various organizations including the Minerals Management Service, the Seagrass program, NOAA, and universities. The purpose of MMS's Environmental Studies Program is to provide scientific information about the environment of a proposed lease sale. Many studies have been completed and much information gathered. However, the program has focused a good deal of these efforts on the areas to the north and south of the Santa Maria Basin, leaving the basin and its coastline without needed decision-making information. The Seagrass program or other organizations could be vehicles for future studies related to the Santa Maria Basin.

State Lands Commission: State Lands has recently completed a study of cumulative impacts from State Lands and OCS development. The county has provided comments and information to the Commission regarding this study.

5.6 Policies

1. The biological resources of the county have a long term value which is only partly economic. To protect this value should offshore oil development prove to be unavoidable, the county will adopt a position which requires:
 - All future pipelines and processing facilities be consolidated to the maximum extent feasible.
 - Adequately functional, sized, coordinated and staffed facilities for cleaning and rehabilitating seabirds and marine mammals be made available on the central coast prior to further leasing or development.
 - Biological surveys are conducted by lessees as part of the process of siting individual platforms.
2. General policies which reduce potential impacts of offshore oil and gas development on biological resources will be enacted. To implement such policies, the county will adopt a position which requires:
 - The lay barge method of laying pipelines be used offshore in coastal areas which have significant habitat values, unless the bottom pull, or another better method is found to be significantly less impacting to the environment.
 - The environmental review be focused to determine in other coastal areas whether the lay barge, bottom pull or other methods of laying pipelines offshore adequately minimize impacts, and require the environmentally superior method.

- Stipulations or conditions of approval which require that helicopters used to transport crew and/or materials to offshore platforms or other offshore oil-related projects avoid flying over areas significant to wildlife and also maintain a minimum 1000 foot altitude clearance.
3. Careful timing, location, and design and configuration decisions for specific offshore oil and gas exploration and development activities can lessen impacts on biological resources. To promote such decisions, the county will adopt a position which requires:
- Biological surveys be conducted by lessees as part of the preliminary work of siting individual platforms and pipelines.
 - Exploration and construction be conducted during times of the year likely to affect biological resources least, considering frequency of storms, breeding, migration, nesting seasons, seasonal upwellings and other factors.
 - Exploration and construction near sensitive species habitat (such as least tern nesting areas) be scheduled to avoid breeding and nesting seasons. Chart seasonal migrations, breeding, and nesting cycles to identify windows of exploration and construction.
 - Terrestrial surveys, including inventorying rare plants, be conducted as part of the preliminary work for any proposed onshore support facilities. This should take into consideration the various seasons migratory or transitory species may be in an area.
 - Pipeline routes avoid steep slopes and stream crossings and other fragile habitats where possible to minimize erosion.
 - A 15 mile buffer zone of no offshore energy activities be established around the Santa Lucia Bank to protect the rich commercial fisheries and other natural resources.
 - No drilling shall be permitted north of Morro Bay, 20 miles around Morro Bay, or 12 miles around the southern range of the California sea otter, to protect onshore, nearshore and offshore biological resources.

Figure V-3
The Santa Lucia Bank

Figure V-4
Nipomo Dunes & Northern San Luis Bay Intertidal

Figure V-5
North Estero Bay Rocky Intertidal Areas

Figure V-6
Cape San Martin - Pt. Piedras Blancas

CHAPTER VI: FISHERIES

6.1 Description of Resource

Fish have been harvested from marine waters off the county for as long as people have been present. This renewable resource will remain if harvested judiciously and not subjected to pollution or other stress.

The resource is used in a variety of ways. Commercial fishing includes the commercial harvest of fin fish and invertebrates by a variety of methods, and also includes kelp harvest and mariculture. Central Coast Salmon Enhancement has a successful program to raise and release salmon into the San Luis Bay. Sport fishing includes party-boat fishing in commercial passenger fishing vessels, recreational fishing from small private and commercial vessels, and surf and pier fishing. Subsistence fishing (licensed as sport fishing) from small vessels, surf zones or piers also occurs in the county. To aid in the goal of continuity for the fishing resource, energy management practices addressing fishing needs should be developed and adhered to.

Commercial Fishing: The commercial fishing industry includes many locally based, relatively small vessels (less than 85 feet in length) operating in coastal waters within 20 miles of shore and close to port. Larger vessels also come to fish the waters. A wide variety of fishing gear is used: Drift gill nets, set nets, trawl gear, hook and line gear, seines, and various traps and diving gear.

The two major fishing ports in the county are Port San Luis/Avila and Morro Bay. Ports outside the county, including Ventura, Santa Barbara, Port Hueneme, San Pedro and Moss Landing, may receive fish harvested in the region. Most vessels in the Morro Bay and Avila fleets fish by trolling hook and line, trawling, trapping, and gill nets. Dive vessels make up the balance. Most of the catch brought into the two ports is produced by trawling (the northern Santa Maria Basin is an especially productive trawling ground). When albacore and salmon are present, trollers come from the north (as far as Oregon) and south. Other vessels regularly come in search of groundfish. Figure VI-1 shows the pounds and value of the fish landed over the last ten years at Morro Bay and Port San Luis.

Commercial fishing's importance to the county economy includes the diversity it adds to the economic base, the income it provides to fishermen and the indirect support it gives to a variety of onshore jobs. Economically significant species harvested include dover sole, swordfish, halibut, salmon, shrimp, and albacore.

Commercial fishing attracts tourists and vitalizes harbor operations. Much of the catch is shipped to non-county markets. Fishing sales and purchases are integrated into the county's

Figure VI-1
Port San Luis and Morro Bay Fish Catch 1980-1989

economy. Most dollars received from catches sold at local ports are re-spent within the county economy.

Kelp is harvested in the county in the region north of Cayucos and occasionally near Avila. Several mariculture operations exist for species such as abalone, coho salmon, and oysters. Concern for impacts of oil development on the fishing industry extend from the pre-lease stage, in which seismic and similar testing may occur, through the lease sale, post-lease exploration, development, construction and operation phases, to abandonment.

Sport and Subsistence Fishing: Commercial passenger fishing vessels take people for offshore fishing from Avila and Morro Bay. Fishing occurs generally in nearshore waters, within 12 miles. Private recreational vessels for personal fishing may be launched from Port San Luis, San Simeon, or Morro Bay. Fishing for sport and for subsistence occurs from small vessels and from beaches and piers. One potential enhancement offered by offshore oil development is concentration of sport fish around structures (to the extent that sport fishers can gain access to the vicinity of such structures; see "U.S. Coast Guard" discussion below).

6.2 Regulatory Setting

The roles of local, state and federal agencies and other organizations and programs which affect the mix of interests between the fishing industry and the oil and gas industry are summarized below:

U.S. Coast Guard: The Coast Guard polices the safety zone extending 500 meters from the outer projections of platforms and excludes vessels over 100 feet from safety zones. It also establishes vessel traffic corridors.

Minerals Management Service (MMS): MMS Pacific OCS orders, lease sale stipulations, approvals, and notices to lessees may be used to reduce potential impacts to commercial fishing in OCS waters. Orders, stipulations, approvals and notices may address a wide variety of commercial fishing interests, such as criteria for locating platforms, approved times for exploratory drilling, requiring smooth surfaces on exposed pipelines, disposal of waste materials, and appropriate training.

MMS issues orders to all operators within an area or region. MMS issues stipulations when it leases the right to explore particular tracts and develop any oil and gas reserves discovered after input from other public agencies and private sources. Approvals issued for proposed projects may contain conditions which recognize commercial fishing concerns. Notices are issued to reflect changes in circumstances which may affect operations.

Federal Fisherman's Contingency Fund and Related Funds: The federal contingency fund and two related funds, one for oil spill loss and the other for gear damage. They are programs which compensate fishermen for loss and damage to equipment occurring

in OCS waters from petroleum industry activities in instances where no particular operator has the responsibility for providing compensation.

State Lands Commission: The California State Lands Commission fulfills a function in state waters similar to the MMS role in the OCS. The Commission also has a bonding program similar to the federal compensation programs, but it does not reimburse fishermen for gear loss or damage due to normal offshore oil construction or operation activities.

California Coastal Commission: The Coastal Commission reviews OCS plans of exploration and development and production plans for consistency with the California Coastal Management Plan. This review normally includes consideration of the adequacy of mitigations proposed to reduce impacts to fishermen. The Coastal Commission may condition a consistency finding on an applicant's agreeing to new mitigations. The MMS Pacific OCS Office's present policy, however, is not to honor such agreements pertaining to fisheries or other topics in subsequent MMS approvals.

NPDES Permits: The Federal Water Pollution Control Act of 1972 and the Clean Water Act of 1977 require that an operator proposing to discharge pollutants to water obtain a National Pollutant Discharge Elimination System (NPDES) permit, setting limits on type, quantity, and location of pollutants discharged. The Environmental Protection Agency and the Regional Water Quality Control Board (the latter by delegated authority) issue such permits.

California Department of Fish & Game: Fish and Game imposes various regulations on commercial fishing to protect the fisheries resource. Regulations include gear specifications, season closings, and open area restrictions. A Fish and Game office in Morro Bay provides assistance to local fishermen.

Marine Advisor: The University of California Sea Grant Marine Advisory Program provides current information and training to fishermen, and publishes a monthly oil and gas project newsletter for fishermen and offshore operators which presents information on proposed oil company developments and summaries of fishing activities.

Liaison Office: The California Coastal Operators' Group, representing offshore oil and gas developers and associated businesses, and the commercial fishing industry have jointly funded a Fisheries Liaison Office. This office distributes information on oil-related research and development projects, facilitates communication between the industries on such items as seismic testing and prime fishing seasons, aids fishermen in filing oil-related damage claims, and keeps records. The liaison office has also fostered cooperation between fishermen and crew and supply boat operators in establishing vessel traffic lanes.

San Luis Obispo County: The county's regulatory authority stems from discretionary authority and from the California Environmental Quality Act (CEQA). As a precondition of approving development, the county may impose conditions which protect and enhance portions

of its existing economy which would be impacted by physical effects on the environment. In addition to decision-making duties, the county may present fisheries concerns in lease sales, consistency determinations, and permitting actions taken by other agencies.

6.3 Impacts to Fisheries

Oil and gas activities in waters off the county, including seismic testing, exploration, drilling and production, and support vessel traffic, directly overlap fishing industry interests. The present need for energy must be balanced against preserving the fisheries resource, effective fish harvesting and marketing, and the significance of sport fishing to the local economy. Some impacts are easily identified, others are subject to more study and debate. The following summarizes major concerns.

Seismic Testing: Wherever it occurs, seismic testing reduces the viability of fisheries for a time. Noise impacts of testing render areas unfishable by driving fish away or by stunning them. Seismic boat movements may interfere with or damage fishing gear.

Preclusion: Short- or long-term presence of oil industry construction or supply vessels, platforms, pipelines and related equipment precludes offshore areas from commercial and sport fishing. Effects are not equally spread, due to different gear types, seasons, and locations. Oil industry exploration and development will occur gradually, but seismic testing and movement and placement of specific exploration, construction and production equipment will cause sudden, periodic disruption of fishing.

Offshore construction activities such as platform placement and assembly and pipeline and cable laying effectively preclude fishing in defined areas for months, in some cases for more than a year. The radius of exclusion around an existing platform may extend for one mile. An offshore pipeline construction flotilla may occupy a mile's width for part or all of an offshore construction corridor. Support vessel traffic may make vessel traffic lanes, if designated, especially unadvisable for fishing. The effective exclusion area for forms of fishing such as trawling, which depend on the ability of a boat to make long passes through productive grounds, may be much greater than the area formally excluded. Since trawlers tend to follow bottom contours, construction of north-south pipelines will generally impair trawling less than east-west pipelines.

Using onshore electrical power at any platform would require laying a power cable from shore. Cable laying may slightly extend any construction period, incrementally increasing preclusion of fishing. All types of nearshore construction will temporarily preclude surf fishing.

A platform's presence precludes fishing in its vicinity. The area of preclusion depends on the size of the platform and the type of fishery. During operations, pipelines to shore should not affect many types of commercial fishing. Nevertheless, if projecting objects are left on pipelines, if pipeline diameters are too large for trawls to cross (about 69 centimeters or 27 inches outside diameter, including coating and insulation), if large anchor scars or any debris

are left on the sea-bottom from construction, bottom-fishing gear may snag and fishing grounds may be temporarily or permanently lost. (See section 6.2 for discussion of funds which may provide compensation for gear loss.) A potentially beneficial impact is that platforms may be used for mariculture operations.

Discharge of Drill Muds and Cuttings: Drill muds, which are used to decrease the friction between the drilling bit and the earth formation, and cuttings, which are the portions of the earth drilled out by the bit, may be discharged during drilling operations. Muds and cuttings alter seafloor topography near platforms. To varying degrees, they may introduce toxins to the water column and seafloor. Cuttings normally settle quite close to platforms, while muds may be deposited over a radius of several kilometers around a platform. The deposits may interfere with trawl fishing by fouling gear or by altering the distribution of fish. These discharges may be made only upon issuance of an NPDES permit, and only in accordance with permit terms.

NPDES permits typically define the three dimensional boundaries of mixing zones in the water column. Within mixing zones, pollutants introduced in high concentrations are allowed to dissolve or be diluted. An applicant may discharge only in ways and quantities which result in pollutant concentrations below allowable limits at the edges of the zone. Permits specify allowable pollutant concentrations at the edges of mixing zones.

Certain drill mud and cutting discharges are known to affect eggs and larvae of pelagic (free-swimming) and benthic (bottom) species. Whether such discharges have direct toxic or other effects on organisms of commercial value is unresolved. Indirect effects could result from changes in water quality or impacts to bottom dwelling organisms which are passed on to commercial species through their food chain. Non-commercial species and water quality may also be directly affected. Also, the nature of the food web and the mobility of many species mean that any effects on eggs and larvae or benthic organisms may result in loss of prey species or bio-accumulation of toxins, thereby lessening fishing opportunities even in areas not subjected to direct oil industry presence.

Debris: Oil industry debris left on the seafloor is a continuing problem. Fishing nets and gear can snag debris and be destroyed or damaged. The results are gear loss, loss of catch, and loss of opportunity to fish during downtime. Also, lost gear may continue to kill fish. In federal waters, MMS OCS Order # One has reduced the problem by establishing an extensive inventory control and transfer procedure and prohibiting oil industry dumping. A State Lands Commission study is using a remote controlled vehicle to identify seafloor debris in certain areas of the Santa Barbara Channel.

Anchor Scars: In the course of constructing platforms and laying offshore pipe, vessels must change position, repeatedly raising and lowering anchors and sometimes pulling against anchors to provide slow, steady motion. The anchors employed are large; at best, they may leave indentations of several feet in soft substrates. This occurs most often in the fine silts and clays which characterize much of the seafloor off the county. When anchors are dragged in high sea

conditions or during exaggerated vessel movements, the indentations may be magnified. The indentations do not readily disappear; they may foul or hang up trawling gear for years.

Spills: Unpredictable events which may impact fisheries include spills of oil, diesel or other petroleum products. Major consequences of spills include fouling fish gear and vessels, precluding fishing in contaminated grounds, tainting otherwise saleable catch with oil and oil aromas, and damaging eggs and larvae. An oil slick could preclude surf fishing and prevent kelp cutters from functioning. A slick reaching Avila or Morro Bay might seriously affect existing mariculture operations. Slicks may foul gear for relatively short periods of time. Weathered oil floating in the water column or laying on the bottom can foul set nets, trawls, crab traps and similar gear for many months or even years. Oil sinking to the bottom can alter the benthic habitat and directly or indirectly expose organisms to hydrocarbons. The effects of such exposure may be subtle and long term. The direct toxic effect of spills on commercial species has been clearly demonstrated in spills which have reached bays. Conclusive demonstrations in open-water spills have not yet been made. The probability of a large spill occurring off the county will increase in proportion to the volume of oil produced offshore, amounts transported along the coast by tanker, amounts transferred at county marine terminals, and miles of pipeline laid.

Cumulative Impacts: Cumulative impacts on fisheries are important considerations at the lease sale stage as well as when specific developments are proposed. Preclusion of areas from fishing will increase as more platforms are installed and more large diameter pipelines are laid. Constructing two facilities near each other can preclude an area greater than either facility would preclude in isolation.

Offshore oil development and production activities are but one of several significant sources of oil pollution in the oceans. Offshore development increases the potential for chronic or massive pollution and toxin accumulation over that from tanker, industrial and municipal discharges.

Abandonment: An offshore energy project can normally be expected to be shut down and abandoned at the end of the project's economic life. Fishing industry interests can be promoted at this point if platforms, pipelines, and any ancillary equipment are disposed of in a way which ends any physical preclusion, thereby restoring fishing opportunity, and, where appropriate locations can be found, by depositing oil production structures on the sea bottom to create artificial reefs. The concentration of sea life at such reefs can be of special benefit to both commercial and sport fisheries.

6.4 Major Issues

Measures to reduce oil development impacts on fisheries include providing funds to compensate for loss of equipment, catch, and fishing opportunity, studies to address areas of uncertainty, coordination between the industries to promote awareness of activities and interests, and restrictions on activities at significant times or locations. Although not a mitigation measure,

rejection should also be a legitimate option if a project is found to pose unacceptable risks to fisheries.

Muds and Cuttings: Not all drill muds are equally harmful. The use of chrome-free lignosulfates, (non-toxic) for example, substantially reduces the potential for toxic effects. Non-toxic muds may not be usable in all drilling scenarios.

Alternatives exist to discharging drill muds and cuttings near platforms. Muds and cuttings can be disposed of onshore or could be discharged in areas not regularly fished, for example, off the edge of the continental shelf. Secondary impacts of alternatives would have to be evaluated and found acceptable in particular instances before any could be approved.

Anchor Scarring: In waters off the coast, the period from May through October generally brings calmer weather, lower sea states and less potential for severe anchor scarring than does the period from November through April. Careful anchor settings and removals by anchor handling vessels reduces the occurrence of dragging and scarring. Accurate logging of anchor movements and post-construction bottom surveys can identify scarred and scar-free areas. Post-construction dragging of large bars across soft bottom substrate is a partial mitigation for anchor scarring.

Construction Practices: It is essential that the oil industry give effective notice to fishermen of impending construction, testing, or exploration which may affect fishing or gear. Any pipeline suspended in the water column during laying should be clearly marked by buoys. As soon as any line segment is in place, buoys should be removed to restore access for fishing gear.

Industry employees, contractors, subcontractors, and support vessel operators need to be clearly instructed that tossing debris or equipment overboard or handling anchors improperly violates terms of employment. An applicant should have a means, such as substantial penalty clauses in contracts, for enforcement against contractors and subcontractors.

Partial or complete pipeline burial by jetting or excavation is a possible means of lowering a pipeline profile high enough to impair trawling. Burial, however, increases the risk of rupture if a seismic event occurs. Post-construction surveys using means such as side scan sonar and bottom photography followed by debris removal and reduction of anchor scarring can restore an area's fishability. Phasing development may reduce impacts on trawling and drift gill netting by reducing vessel traffic and cumulative preclusions.

Fishing Enhancement and Compensation Programs: Because some impacts on commercial fishing, including destruction of habitat and preclusion from fishing grounds, do not lend themselves to direct mitigation, alternate strategies such as establishment of fisheries enhancement funds may be considered. Contributions to such a fund could be used in programs designed to offset project and cumulative impacts, including pier or harbor improvements,

contributions to a commercial fishing insurance pool, or commercial fishing research and development.

Offshore construction and deposit of debris on the seafloor during construction and operation may result in damage to and/or loss of fishing gear and lost fishing opportunity. If shown that their own activities have caused the damage in question, most offshore operators will directly compensate fishermen for loss. Fishermen sometimes lose gear and fishing opportunity in instances where clear responsibility of a particular operator cannot be established. If the loss occurs in OCS waters, the federal funds described above in the "Regulatory Setting" section may produce compensation, but the federal claim process involves considerable paperwork, a lengthy review (8 to 9 months is not uncommon), and applying for a claim does not guarantee payment. Further, there is no parallel to the federal claims process in state waters.

To alleviate such impacts, offshore developers can be required to contribute money to a local fishermen's contingency fund. A local contingency fund can establish a quick and effective way of aiding commercial fishermen who have suffered gear loss or damage apparently related to oil and gas exploration, development, or production. Such a fund can loan money on a valid application within a very small (e.g. 5) number of days. The loan must be repaid upon receipt of money from a federal or other fund. If the loss occurs in state waters, money provided by the local fund may amount to a payment instead of a loan.

Research: Various activities including drill mud and cutting discharges and oil spills affect eggs and larvae of pelagic and benthic species to an unknown extent. Studies of these effects on eggs and larvae have been conducted in other parts of the world. Work on these topics in this part of California is just beginning.

Opportunities for research to assist fishermen also exist. Examples include the need for marketing research, gear improvement, and alternate gear types.

Lease Sale Provisions: The lease sale process offers an opportunity to state concerns and seek solutions to impacts of offshore development on fisheries. Most or all of the concerns identified in this chapter, including exploration timing and criteria for locating equipment, may be raised. Exclusion of significant fisheries areas from leasing and other means of reducing impacts must be sought during these sales.

6.5 Policies

1. The county shall participate in commercial fishing issues, providing rapid assistance to fishermen and oil industry personnel in dealing with each other and with different layers of government. The county should administrate and coordinate programs and conditions and resolve issues within its permitting framework and advocate policies and positions in lease sales, decisions by other agencies, and in legislation.

2. Commercial fisheries resources off the county need to be more accurately delineated as to the economic value of different fisheries and times of year and locations where commercially harvestable species may be found. An evaluation of existing fisheries and creation of new fisheries should be considered.
3. Fisheries have a long-term economic value as a renewable resource. To protect this value, the county will adopt a position which requires:
 - Evaluation of the long-term value of fisheries as a renewable resource in assessing the needs of the fishing and oil industries, in addition to acknowledging annual catch and landing values.
 - Use of the lease sale EIS and stipulation process to articulate and advocate the full range of fisheries concerns. Any concerns which are not addressed through stipulations, should become criteria for evaluating applications which result from the lease sales.
 - The impacts of discharging toxic muds at sea be considered sufficient grounds for denial of any proposal. Wastes and cuttings shall not be disposed of in environmentally sensitive areas.
 - Disposal of muds and cuttings from any exploratory or development activities in an environmentally safe manner.
 - Protection of rich fishing areas such as the Santa Lucia Bank. These areas shall be identified and precluded from offshore energy activities.
 - Participating actively in all NPDES permit matters where authority to discharge pollutants to waters off the county is sought. Request that the least environmentally impacting options be implemented.
 - Provisions in any project approval which promote prevention, detection, containment and cleanup of spills or releases.
 - Evaluation of projects from the perspective of cumulative impacts as well as from the standpoint of (artificially) isolated project impacts.
 - Denial of any project which the county may find poses unacceptable risks to county fisheries.
 - Repair and/or restoration of anchor scarring caused by offshore oil and gas activities on soft bottom substrates be repaired and/or restored.

4. Insufficient knowledge exists as to the fisheries resource off the county's coast and as to the resource's susceptibility to damage from oil and gas development. To improve this knowledge and decision making, the county will adopt a position which requires:
 - Analysis of direct and indirect effects of seismic testing on fishing and on all life stages (especially eggs and larvae) of commercially and recreationally important organisms. Indirect effects shall include impacts to the food web.
 - Analysis of direct and indirect impacts of oil industry operations, including drill muds and cuttings, on the fisheries resource. Indirect effects should include effects on the food web.

5. Careful timing, location, design and configuration decisions for specific oil and gas exploration and development activities can lessen impacts on fisheries. To promote such decisions, the county will adopt a position which requires:
 - Stipulations or conditions which minimize or eliminate preclusions, obstructions, toxic discharges, and debris.
 - Minimizing potential interference with fisheries operations through careful evaluation of platform, pipeline and construction spread configurations, and other testing, construction, installation and operation activities.
 - Assurance that programs are implemented and maintained to mitigate the affects on fishermen for lost time/lost catch where projects and fishing seasons overlap. Consideration of the timing of testing, exploratory drilling, construction, and other temporary activities when affected regions are most intensely fished.
 - Stipulations that seismic testing not occur except after sixty days' notice to fishermen, and that such testing not be scheduled where it would conflict with significant fisheries and seasons.
 - That any pipeline exceeding 27 inches (including coating and insulation) in total diameter, be buried to lessen the likelihood of gear snagging on the pipeline.
 - Stipulations and conditions which eliminate depositing of debris and creation of anchor scars on the sea-bottom by operators, contractors, subcontractors, or vessel operators. In addition, insist that operators build enforcement powers into construction, service and supply contracts, and then use such powers, and provisions for post-construction bottom surveys and appropriate remedial actions.
 - An enforcement and compliance program related to fisheries conditions be implemented by an agency not directly involved with offshore oil and gas.

6. Policies and programs which reduce potential conflicts between commercial fishing and offshore oil and gas development, and which provide opportunities for fishermen and the oil industry to identify additional problems for consideration shall be enacted. To implement such policies, the county will adopt a position which requires:
- Rapid assistance to fishermen and oil industry personnel in dealing with each other and with different layers of government.
 - Administration and coordination of programs which provide for conflict resolution within the county's permitting framework.
 - The protection of fisheries resources using lease sale stipulations, legislation, and regulation.
 - Dissemination of information concerning oil industry exploration, development, and operation to the entire fishing community, permitting the fishing industry to be aware of and plan for oil industry activities.
 - Stipulations and/or mandated conditions which insure continuation of commercial fishing activity through prompt oil and gas industry or federal funding for gear loss, associated loss of catch, and loss of opportunity to fish in state and federal waters.
 - That stipulations and conditions require 1) recognition that preclusion of areas to fishing impairs the local economy, 2) contribution for enhancements such as ice houses, landing equipment, and development of alternate fisheries or fishery locations, and 3) identification of appropriate proposals for funding.

CHAPTER VII: AIR QUALITY

7.1 Description of Resource

San Luis Obispo County can be divided into three general air quality regions: the Coastal Plateau, the Upper Salinas River Valley and the East County Plain. Air quality in each of these regions is characteristically different, although the geographical features which divide them provide only limited barriers to transport of pollutants between regions. The coastal plateau will be the area most affected by air emissions from offshore energy development. This region of the county is five to ten miles wide and varies in elevation from sea level to about five-hundred feet. It is bounded on the northeast by the Santa Lucia Mountain Range, which rises abruptly to approximately three-thousand feet. Seventy-five percent of the county population and a corresponding portion of the commercial and industrial facilities are located within this coastal zone.

The air quality in a given location is described by the concentration of various pollutants in the atmosphere. The significance of a given pollutant level can be evaluated in several different ways: by comparing its atmospheric concentration to state and national air quality standards; by comparison to levels known to cause vegetation or property damage; or by analyzing historical data to determine how much deterioration has occurred or will occur over time.

The primary factors affecting air quality in a given area are the rate, type and location of pollutant emissions, the topographic and geographic features of the region, and the local and regional meteorological conditions. An emission rate represents the amount of pollutant released into the atmosphere by a given source over a specified time period; it is generally expressed in units such as pounds per hour (lb/hr) and tons per year (ton/yr). Local and regional meteorological conditions govern the transport and diffusion of emissions in the atmosphere. Wind speed, wind direction, atmospheric stability, temperature, and the presence or absence of inversions are some of the key parameters which affect pollutant dispersion.

Local and Regional Meteorology

The regional meteorology in coastal San Luis Obispo County is strongly influenced by the Pacific Ocean. This effect is reduced inland in proportion to distance from the coast or by major intervening terrain features, such as the coastal mountain ranges. Seasonal temperature extremes experienced inland are moderated near the coast due to the relatively constant temperature of the ocean. A broad cell of high pressure commonly resides over the ocean, centered several hundred miles offshore. Seasonal variations in the position and strength of this cell cause seasonal changes in the weather patterns of the area.

Temperature differences between air masses over land and water drive both the strong, prevailing northwest (onshore) daytime winds and the weak, nighttime drainage winds

(offshore) on the coastal plateau. The presence of the Pacific high pressure system to the west tends to enhance afternoon and evening onshore winds. However, these conditions of strong northwesterly flow are generally not those associated with maximum air pollution impact from present or future offshore and coastal emission sources.

Maximum impact conditions generally occur when the Pacific high pressure cell has weakened or moves inland to the east; this can produce a "Santa Ana" condition which transports air (usually pollutant-laden) from the southeast. The breakup of a Santa Ana condition often leads to relatively stagnant air and a buildup of pollutants, which can be transported over the ocean during the nighttime land breeze. The occurrence of the typical daytime sea breeze can bring these pollutants back onshore, where they combine with local emissions to cause high pollutant levels. This situation is probably the most important for producing high ozone concentrations in San Luis Obispo County.

Air Quality in San Luis Obispo County

San Luis Obispo County is currently designated as attainment or unclassified for all pollutants regulated under the national air quality standards. This essentially means that air quality within the county meets the requirements of the federal Clean Air Act. However, San Luis Obispo County has been designated a nonattainment area for the state air quality standards for ozone and PM10. As shown in Table 7-1, violations of the state standards for ozone and PM10 (fine particulate matter 10 microns or less in diameter) are recorded several times each year at various monitoring locations in the county; ozone concentrations exceeding the federal standard are also occasionally measured (see Table 7-3 for listing of applicable standards). In addition, sulfur dioxide (SO₂) levels on the Nipomo Mesa have violated the state SO₂ standards in the past.

Ambient measurements of pollutants such as SO₂, carbon monoxide (CO), and particulate matter (PM), are primarily influenced by nearby sources of emissions. Thus, concentrations of these pollutants are usually localized and can vary considerably between monitoring stations. On a regional basis, ozone is the pollutant of greatest concern in the county, particularly within the coastal plateau. Ozone is a secondary pollutant, formed in the atmosphere by complex photochemical reactions involving precursor pollutants and sunlight. The amount of ozone formed is dependent upon both the ambient concentration of chemical precursors and the intensity and duration of sunlight. Consequently, ambient ozone levels tend to vary seasonally with the weather.

Nitrogen oxides (NO_x) and reactive organic gases (ROG) (also called reactive hydrocarbons, RHC, or volatile organic compounds, VOC) are the primary precursors to ozone formation. NO_x emissions result primarily from the combustion of fossil fuels; ROG emissions occur through combustion processes and through evaporation of petroleum and solvent-based products. NO_x and ROG constitute a major portion of the emissions resulting from offshore energy development and from stationary and mobile sources onshore. Table 7-2 presents the 1987 emissions inventory for San Luis Obispo County; Figure 7-1 graphically depicts the

proportional distribution of ROG and NOx emissions among the major source categories in this county.

Table VII-1
Maximum Pollutant Concentrations Measured
in San Luis Obispo County from 1982-1989

Table VII-2
1987 Annual Emissions Inventory - San Luis Obispo County
(Tons per Year)

Table VII-2 (continued)

Figure VII-1
1987 Annual Emissions Inventory - San Luis Obispo County

Further information regarding existing emissions and air quality in the county can be found in the 1991 Clean Air Plan for San Luis Obispo County.

7.2 Regulatory Setting

Offshore energy development and associated onshore activities are subject to air quality regulations and standards that have been promulgated by federal, state, and county regulatory agencies. Jurisdictional authority tends to overlap among the various permitting agencies due to the regional scope of potential impacts and the relationship between interconnected project facilities located both onshore and offshore. Coordination between the various regulatory agencies is thus essential to the permitting process.

Federal Clean Air Act Amendments

Prior to 1977, the federal Clean Air Act required that all areas of the country attain the National Ambient Air Quality Standards by 1975; this deadline was later extended to 1977. The 1977 Amendments to the Act further delayed the attainment deadlines to 1982, with an additional extension for ozone and carbon monoxide to 1987.

The Amendments also established local air quality planning processes, requiring separate plans for each local area that had not attained the standards. These plans, called nonattainment plans, were to be prepared by local agencies designated by the governor of each state and incorporated into a State Implementation Plan (SIP). The federal Environmental Protection Agency (EPA) was given power to impose sanctions for failure to submit a plan or carry out commitments in a plan. Sanctions could be a ban on construction of major new facilities and the withholding of federal highway, sewage treatment, and air planning funds.

Numerous areas throughout the United States failed to meet the December 1987 deadline for attainment of the federal ozone and carbon monoxide standards. As a result, on November 15, 1990, new federal Clean Air Act Amendments (CAA) were signed into law by President Bush. These amendments represent the fifth major effort by the U.S. Congress to improve air quality. The new CAA is generally less stringent than the California Clean Air Act. However, unlike the California law, the CAA sets statutory deadlines for attaining federal standards.

San Luis Obispo County has been designated as attainment or unclassified for the federal air quality standards and is not mandated to develop a federal nonattainment plan. However, rules and regulations adopted by the District are submitted to the California Air Resources Board (ARB) for inclusion in the SIP.

Several new sections have been added to the CAA, including requirements for the control of toxic air contaminants; reductions in pollutants responsible for acid deposition; development of a national strategy for stratospheric ozone and global climate protection; and requirements for a national permitting system for major sources. A significant change in federal agency jurisdiction also occurs. The new CAA transfers authority for regulation of air quality on the

Outer Continental Shelf from the Minerals Management Service to the EPA. The law allows local APCDs to apply to EPA for delegation of that authority. EPA regulations regarding offshore energy development are described under a separate heading in this section.

California Clean Air Act

The California Clean Air Act (CCAA), signed into law in September of 1988, requires all areas of the state to achieve and maintain the California ambient air quality standards by the earliest practicable date. These standards are generally more stringent than the federal standards; for example, the state ozone standard is 0.09 ppm compared to the 0.12 ppm federal ozone standard. Thus, emission controls to comply with the state law are more stringent than necessary for attainment of the federal standard. State and federal standards for ozone and other pollutants are presented in Table 7-3.

San Luis Obispo County has been designated a nonattainment area for the state air quality standards for ozone and PM10. Nonattainment designations are further categorized into 3 levels of severity: "moderate" (can demonstrate attainment by 1994); "serious" (can demonstrate attainment by 1997); and "severe" (cannot demonstrate attainment until sometime after 1997). This county is considered a "serious" ozone nonattainment area and must implement an attainment plan with sufficient control strategies to achieve at least a 5% per year reduction in ROG and NOx emissions countywide, using 1987 emissions as the baseline level.

The 1991 Clean Air Plan for San Luis Obispo County, adopted by the San Luis Obispo County Air Pollution Control Board on January 21, 1992, is designed to meet these requirements.

Environmental Protection Agency Regulations

The 1990 Amendments to the federal Clean Air Act added section 328 to the Act, which transfers air quality regulatory authority on the OCS to the EPA. Congress further specified that EPA's initial rulemaking must require OCS sources within 25 miles of states' seaward boundaries to comply with the same requirements that would be applicable if the OCS source were located in the Corresponding Onshore Area (COA). This shall include, but not be limited to, state and local requirements for emission controls, emission limitations, offsets, permitting, monitoring, testing and reporting. New OCS sources must comply with such requirements on the date of promulgation; existing OCS sources must comply 24 months after the rules are promulgated.

Each state adjacent to an OCS source may promulgate and submit to the Administrator its own regulations for implementing and enforcing the Section 328 requirements. The EPA may delegate implementation and enforcement authority to state or local agencies if their regulations are adequate to meet the requirements of the Act. If the EPA finds that compliance with a specific pollution control technology requirement is "technically infeasible or will cause an unreasonable threat to health and safety", the OCS source may be exempted from the

Table VII-3
Ambient Air Quality Standards

requirement. Written findings must document the basis for the exemption, and the EPA must impose "another requirement equal to or as close in stringency to the original requirement as possible."

EPA regulations implementing this section of the Clean Air Act are currently under development.

County Air Pollution Control District (APCD) Regulations

The San Luis Obispo County APCD has primary responsibility for assuring that the state and national air quality standards are achieved and maintained within the jurisdictional boundaries of the District. State law delegates regulatory authority to the APCD over all non-vehicular sources of air pollution within the District. The County Board of Supervisors acts as the District Air Pollution Control Board in all decision-making concerning the policies, rules and regulations of the APCD.

The District rules and regulations limit the emissions of specific contaminants and require permits specifying equipment and operating procedures for all emission sources subject to the rules. New and modified stationary sources must comply with the District's New Source Review (NSR) rule. This rule identifies the control requirements for new or modified emission sources and the thresholds of applicability for sources subject to the rule.

Regulation II, which contains the NSR rule, was revised and adopted by the District Board on November 5, 1991 to meet the no net increase provisions of the California Clean Air Act. Best Available Control Technology (BACT) is required for new, modified, or relocated equipment that emit criteria pollutants or their precursors. All new or modified sources of NO_x, ROG, PM₁₀, and SO_x which result in an increase in emissions are also required to offset those emissions through the use of Emission Reduction Credits or Community Bank Credits. There are no exemptions from the mitigation requirements. Either the District or the applicant must provide offsets for all emission increases.

The District's NSR rule has been included in the proposed EPA air quality regulation for OCS sources. It is expected that the District will be delegated authority to enforce the rule on future OCS development activities offshore San Luis Obispo County.

Department of the Interior (DOI) Regulations

The 1990 Clean Air Act Amendments transferred air quality regulatory authority on the OCS from DOI to EPA. However, previous lease-sales offshore California have contained stipulations requiring the DOI Administrator to impose specific air quality requirements for development of tracts within the sale area; these stipulations are still in effect. Of particular interest is the stipulation for lease sale 73 tracts. Any LS 73 tract within ten miles of shore must, if technically feasible, minimize emissions of NO_x by using electric power supplied from shore rather than generating their own power at the platform; four of the 5 existing LS 73 tracts

fit this category. Three of these leases are less than 10 miles offshore Point Sal, while the other 2 are located west of Point Arguello. It is unclear at this time whether the lease sale stipulations or the OCS air quality regulations will prevail in the event of a regulatory conflict during development of one of these tracts.

The Minerals Management Service (MMS) is also responsible for implementing the National Environmental Policy Act (NEPA), which requires the evaluation and mitigation of any project under federal jurisdiction that may have a significant effect on the environment. This typically requires the preparation of an Environmental Impact Statement (EIS) to identify potential significant impacts and appropriate mitigations. The EIS is often prepared in conjunction with the state-mandated Environmental Impact Report, described below.

California Environmental Quality Act (CEQA)

Offshore energy development and associated onshore activities generally involve large emission sources with the potential to cause significant air quality impacts. A significant air quality impact is typically defined as the potential to cause or contribute to a violation of any state or federal ambient air quality standard; the potential to interfere with the attainment and maintenance of those standards; or the potential to cause significant deterioration of the existing air quality. CEQA establishes a duty for public agencies to avoid or minimize environmental damage where feasible in regulating public or private activities.

The Act requires the preparation of an Environmental Impact Report (EIR) for any project under state or local jurisdiction which may have a significant effect on the environment. This is usually triggered by an application to construct a project requiring an approved land use permit. The EIR must identify and describe the direct and indirect significant impacts of all parts of a project, and any mitigation measures or project alternatives which could minimize those impacts. The EIR must also evaluate the potential for a project to contribute to significant cumulative impacts when analyzed in conjunction with impacts due to related past, present and foreseeable future projects. The County then uses this information in its decision to approve, modify or deny a land use permit. CEQA requires that public agencies not approve projects as proposed if there are feasible alternatives or feasible mitigation measures available which would substantially lessen the significant environmental effects of such projects.

California Coastal Commission Consistency Certification

The California Coastal Commission has the authority to review Exploration Plans and Development and Production Plans (DPP) in federal waters for consistency with the California Coastal Management Program (CCMP) under the Coastal Zone Management Act. Coastal Act policies are enforceable policies of the CCMP which require that new development be consistent with the requirements imposed by an Air Pollution Control District or the California Air Resources Board.

Additionally, the CCMP requires that adverse impacts, including air impacts, be mitigated to the maximum extent feasible. All air quality impacts from offshore energy development, including those from associated onshore facilities to be constructed, increased use of existing facilities, and impacts from all marine vessels, must be considered in the determination of consistency with the CCMP. The Coastal Commission has permit jurisdiction, in addition to that of the counties and the APCD's, over projects within state waters and in certain other areas of the Coastal Zone. These developments are subject to the requirements and standards of the Coastal Act, including the requirement that adverse impacts be mitigated to the maximum extent feasible.

To be found consistent with the California Coastal Management Program (CCMP), the air pollution emissions from a project must meet all applicable standards and conform to federal, state and local air quality regulations. In addition, Section 307(f) of the Coastal Zone Management Act specifically requires that the provisions of the federal Clean Air Act (CAA), and state standards adopted to implement the CAA, be incorporated into state coastal programs. A proposed activity cannot be found consistent with the CCMP if it would individually, or in combination with other existing or proposed activities, result in violations of these provisions or otherwise impede the State's ability to meet the requirements of the Clean Air Act. Any consistency determination by the CCC can be appealed to the Secretary of Commerce, however, with whom rests final authority on the decision.

Jurisdiction and Interagency Coordination

The development of offshore energy resources is a complex process requiring substantial support facilities both offshore and onshore. Production platforms, marine supply vessels, helicopter transport, marine tankers and terminals, oil and gas pipelines and onshore processing facilities are some of the common components of offshore development projects. The diversity and scope of such projects results in lengthy and complicated regulatory review involving many agencies and overlapping jurisdictions. Interagency coordination and cooperation is essential to the review process. In particular, consultation and coordination between the MMS, the EPA and local Districts, and the United States Coast Guard is necessary to ensure that air quality requirements do not result in unsafe or hazardous operating conditions for regulated vessels and stationary offshore facilities.

7.3 Air Quality Impacts

The effects of air pollution on health and public welfare has been the subject of intense study and concern over the past four decades. The following discussion presents a brief summary of the adverse impacts from the individual pollutants of concern associated with offshore energy development. For ease of reference, a list of the applicable state and federal health standards is provided as Table A-1 in Appendix A.

Ozone

Ozone is a secondary pollutant, formed in the atmosphere by complex photochemical reactions involving precursor pollutants and sunlight. It has a pungent odor and indiscriminately oxidizes a broad spectrum of substances, ranging from rubber and fabrics to vegetation and sensitive human respiratory tissues. Breathing impairment is the primary and most noticeable health effect of ozone exposure. Symptoms of sore throat, chest pain, coughing and headaches can occur in healthy individuals at ozone levels of 0.20 to 0.30 ppm. Children, the elderly, and those with diminished respiratory function (asthmatics and those with chronic bronchitis or emphysema) are known to be affected at much lower levels and can suffer severe health problems from prolonged or acute exposure to ozone. A variety of other health effects have also been found, including cell and chromosome damage and increased susceptibility to disease.

Ozone is also the most serious pollutant threat to California agriculture and native vegetation due to its pervasive nature. Many sensitive plant species are known to suffer damage at concentrations below the state and federal health standards. Ozone attacks leaves, causing them to yellow, develop dead areas and drop early. Continued exposure of plants to low levels of ozone can reduce growth and yield and increase susceptibility to disease and insect attack. The pine forests above Los Angeles in particular have suffered severe damage. Trees and other plant life in the Sierra Nevadas statewide are also increasingly impacted by ozone formed in the inland valleys. Crop damage from ozone exposure is also extensive and has caused changes in land use in several areas in California, with formerly productive orchards and fields no longer suitable for agriculture. Many of the major crops grown within this county are particularly sensitive to ozone injury, including orchard crops, lettuce and several grape varieties. The California Air Resources Board (ARB) estimates statewide agricultural losses due to ozone damage from all sources at over \$500 million annually. A portion of those losses could be incurred by crop growers within this county.

The effects of ozone on public health, vegetation and materials in San Luis Obispo County are not well documented. We do, however, approach and exceed ambient ozone standards more frequently than for any other pollutant, and our terrain and meteorology are conducive to future deterioration in ozone air quality. Thus ozone remains the pollutant of greatest concern countywide.

Sulfur Dioxide

Sulfur dioxide (SO₂) is a colorless, corrosive gas with an acrid odor. It occurs in the atmosphere chiefly as a by-product of sulfur-containing fossil fuel combustion. The health and physical effects of SO₂ relate directly to its propensity to form sulfuric acid in the presence of moisture. Its primary health effect is on the upper respiratory tract, where the inhaled gas is rapidly adsorbed and converted to acid, causing inflammation of sensitive mucous linings. Adsorbed on fine particulate matter, or oxidized to suspended sulfate, SO₂ can also cause enduring damage deep in the lungs.

Impacts to vegetation from sulfur dioxide are well known and can occur at levels below the health standards. Damage to the outer surfaces of plant leaves occurs from adsorption of wet SO₂ gas or dry sulfate particle deposition. Gaseous SO₂ absorbed through leaf stomata causes injury to internal leaf tissues. Short-term, high-concentration exposures create dead spots on leaves and reduce photosynthesis. Long-term exposure to low levels of SO₂ can reduce root and stem weight, decrease protein and carbohydrate content and ultimately result in plant death.

Sulfur dioxide has similarly pronounced corrosive effects on a wide spectrum of materials including metals, stone, fabrics and leather, and is a primary contributor to the global acid precipitation problem.

Oxides of Nitrogen

Oxides of nitrogen are produced by a variety of natural and man-made processes but, like SO₂, they primarily result from the combustion of fossil fuels. The principal gaseous oxides of nitrogen in the atmosphere are nitric oxide (NO) and nitrogen dioxide (NO₂). Of these, only NO₂ has significant health effects at ambient concentrations. Like sulfur dioxide, these effects stem from its ability to oxidize other compounds. Moist respiratory tissues are inflamed both by single, short-term exposure to dilute NO₂ and by repeated exposure to even lower concentrations. Chronic exposure to NO₂ concentrations between 0.08 and 0.15 ppm has been associated with increased incidence of respiratory illness.

Low levels of NO₂ can cause a decline in the growth and yield of sensitive crop plants and other vegetation, while acute doses may result in direct foliar injury. When NO₂ and SO₂ occur together they may act synergistically to inflict more plant damage than would occur from the additive effects of each pollutant individually.

Oxides of nitrogen are a significant contributor to acid precipitation nationwide and are its primary precursor in California. NO₂ is also a major culprit in visibility degradation, imparting a reddish-brown color to plumes and to widely dispersed, hazy air masses.

Carbon Monoxide

Carbon monoxide (CO) is an odorless, colorless gas produced by the incomplete combustion of fossil fuels. This pollutant tightly binds to blood hemoglobin, reducing the amount of oxygen which reaches the heart, brain, and other body tissues. Exposure to CO particularly endangers people with coronary artery disease. Even healthy individuals can experience headaches, fatigue and slow reflexes at relatively low concentrations. Carbon monoxide impacts to vegetation have been shown only at concentrations substantially above those known to cause health effects.

Particulate Matter

Airborne particulate matter (PM) includes dust and smoke and may contain sulfur, nitrogen, carbon and various metals. Inhaled particles can directly irritate the respiratory tract, constrict airways and interfere with the mucous lining of the airways. Although the nose and throat are able to stop most large particles, very small ones may penetrate deep into the lungs. Particulate matter may also be a carrier for toxic materials, allowing them to enter the lungs where they can be absorbed into the blood and circulated to other parts of the body.

Heavy particulate deposition on vegetation can reduce photosynthesis and clog stomata, preventing the free exchange of gases between a plant and the surrounding air. In contrast, absorption of small particles into the stomata can keep them from closing and thus allow excessive water loss and increased penetration of gaseous pollutants into the leaf.

Hydrogen Sulfide

Hydrogen sulfide (H₂S) is a colorless gas with an offensive odor suggesting rotten eggs. It is used in a variety of chemical manufacturing and agricultural applications and occurs as a by-product in many industrial processes. It is a common component of natural gas and is frequently encountered during drilling and production of oil and gas wells.

Hydrogen sulfide odors are extremely pungent and are detectable at very low concentrations (1 part per billion). At sufficiently high concentrations H₂S is very toxic to humans. It is usually absorbed through the respiratory tract and carried by the blood stream to various body organs. H₂S generally acts as a cell and enzyme poison, and its presence in the blood can lead to blocking of oxygen transfer, especially at high concentrations. Ambient levels above 500 ppm can cause paralysis of the respiratory center, which can lead quickly to unconsciousness and death. At lower levels (20 - 350 ppm) hydrogen sulfide may cause conjunctivitis, respiratory tract irritation, damage to the heart muscle, nerve paralysis and several other disorders. Common symptoms of exposure include metallic taste, fatigue, diarrhea, blurred vision and intense aching of the eyes.

Hydrogen sulfide impacts to vegetation and various man-made materials are similar to those caused by sulfur dioxide, which were discussed previously.

7.4 Offshore Emissions and Mitigation Measures

Development of offshore energy resources is a lengthy process which can be grouped into three major phases: exploration, development and production. Although the activities and operations which characterize each phase are distinctly different, timing of phases may overlap, particularly during development and production. For instance, if a large number of wells are planned for a given platform the development phase may involve a 4 year drilling program; production activities, however, usually begin upon completion of the first well. Thus, the highest emissions are typically generated during the first few years of a project, when development and production activities are occurring simultaneously.

The following discussion describes the major emission sources associated with each phase and the mitigation strategies available to reduce their impact. Support vessel activities are a major emission source common to all phases and are discussed separately in Section 7.4.4.

7.4.1 Exploration

Once the potential for oil and/or gas has been established in an area and the tracts are leased, exploratory drilling is undertaken to determine if sufficient resources exist to merit a development effort. The number of wells drilled depends, to some degree, upon the expected level of resources and their geographical extent. Each well typically requires 40 to 60 days to drill and abandon. If hydrocarbons are found, an additional 30 days may be needed to test the well.

Emissions: Offshore exploratory drilling is performed using large mobile drilling platforms or vessels. Personnel and supplies are transported to and from the drill sites by helicopters, crew boats and supply boats. The large diesel engines used to power the drilling units, and the support vessels which service the units, are the main sources of air emissions. Emissions may also occur as a result of natural gas flaring if well testing is conducted. The pollutants emitted primarily consist of NO_x, with smaller amounts of ROG, CO, SO₂ and particulate matter. On a short-term basis (hourly or daily) NO_x emissions can be substantial; typical estimates may exceed 100 lbs/hr for each well. Annual NO_x emissions can also be significant if a large number of wells are drilled. On average, 2 to 5 wells are drilled during the exploration period, generating 175 to 250 tons of NO_x.

Mitigations: A typical drilling unit has between three and six large diesel engines used as "prime movers" to generate electricity. These diesel-electric generators drive the locomotive, positioning, pumping, compressing and drilling equipment on the unit. The amount of emissions per engine and the effectiveness of available control measures is very dependent on the type of engine and the operating conditions. For direct injection diesels, retarding the injection timing by 4° can reduce NO_x by 15-20 percent. Exhaust gas recirculation may also be effective on engines operated at less than 50% load.

In contrast, indirect injection diesels (such as the Caterpillar D-399 engines) are available which employ staged combustion and prechamber mixing techniques. These engines generate less than one-fourth of the NO_x emissions from any other engine commonly used on exploratory drilling vessels. Use of these engines on the drilling units is currently the most effective emission control measure available.

Upon completion of an exploratory well it may be flow-tested for up to 48 hours, resulting in the flaring of natural gas. The amount of emissions produced depend on the length of the test and the chemical properties of the gas. Hydrogen sulfide content is the largest variable and determines the amount of sulfur dioxide produced during flaring. Placing limits on the duration of testing is the most effective control measure available. Restrictions on well testing, however, may make it difficult to acquire certain production information necessary for future

development of the resource. The applicability of this control measure should thus be evaluated on a case-by- case basis.

To mitigate the impact of these emissions, stipulations may be placed on the timing and duration of the drilling period so as not to coincide with the peak ozone season, typically defined as the period between June and November. Care must be taken however, to avoid conflict with other timing restrictions designed to protect sensitive biological resources.

7.4.2 Development

Development occurs after exploration confirms the presence of sufficient quantities of oil and/or gas to justify production. The major activities during this phase include platform installation, pipeline installation and drilling. The number of production wells drilled, the type and number of platforms installed, and the miles of pipeline laid depend upon the amount of recoverable resources in a zone and, to some extent, on the transportation and processing plans for the produced oil and/or gas. In addition, a variety of technical factors also play a large part in determining the ultimate configuration of the development and production effort. These include the gravity of the oil, porosity and permeability of the formation, water depth and distance from shore, fracture extent of the reservoir and other variables.

Platform Installation

For platform installation, the jacket and deck modules are fabricated onshore (at a specialized manufacturing facility outside the county) and towed to the offshore site. Once offshore, the jacket is sunk by one or more derrick barges and secured to the sea floor by pilings driven through the jacket legs. The platform decks are then lifted onto the jacket and secured in place. A heavy transport vessel (HTV) and several tug boats are required to maneuver the derrick and material barges used to lift and secure the platform components. Once the decks are complete and major pieces of equipment have been installed, the generators and cranes on the platform can supply power and move the remaining pieces of equipment into place. Thus, the tugs and derrick barge are not required during the later stages of installation. Platform installation and hookup generally takes 3 to 6 months to complete.

Emissions: The equipment on the barges, and the vessels used to maneuver them, are the major emission sources associated with this activity. Emissions primarily consist of NO_x, with considerably smaller amounts of CO, ROG, SO₂ and PM. Large diesel engines are used to power the major pieces of equipment on the derrick barge while small diesels are used for the welding machines, compressors and other miscellaneous equipment. Large diesel prime-movers are also used to power the HTV and the 7 to 10 tugs used in the installation. In addition, the use of support vessels to transport crew and supplies can be particularly intense during this period. Total NO_x emissions range from 190 to 240 tons during installation, depending on the size and layout of the platform.

Mitigations: The diesel-electric generators on the derrick barge are similar to those found on exploratory drill rigs and are subject to the same emission control strategies. Similarly, diesel engines on the light-duty tugboats are similar to those used on the support vessels (see section 7.4.4 for applicable control measures). Use of low-sulfur diesel fuels can substantially reduce the SO₂ emissions from these sources. Activity management techniques can provide additional impact mitigation by reducing the simultaneous occurrence of large polluting activities where possible (e.g. - scheduling crew and supply vessel trips so that both vessels are not at the platform at once). Such techniques reduce the frequency and impact of peak pollutant concentrations by spreading the emissions over time.

Pipeline Installation

There are at least two different methods for constructing submerged pipelines: the single-pipe, lay-barge method and the multiple-pipe, pull barge (bottom pull) method. The choice of method depends on factors such as the length and diameter of the pipe, water depth, and sea bottom conditions. The lay barge technique is most commonly used and involves heavy-duty machinery for welding and moving pipe, tugboats to assist in movement of the barge, supply boats to deliver pipe and crew boats to transport workers. The time period involved in pipeline construction depends on the number of pipelines required and the distance from platform to landfall; a 6-month construction period is often assumed for impact analyses.

Emissions: As with platform installation, the major emission sources are the handling tugs, support vessels and equipment operations on the lay barge, with NO_x being the primary pollutant. The diesel-electric generator on the lay barge produces the majority of the emissions from this activity. The total emissions generated are directly related to the length and number of pipelines. Emission estimates typically range between 5 and 15 tons of NO_x per mile of pipeline installed. On an hourly basis NO_x emissions can be substantial and represent a significant potential for short-term air quality impacts onshore.

Mitigations: The mitigation measures applicable to platform installation apply also to offshore pipeline installation.

Development Drilling

Platform operations essentially begin with the start of development drilling, at which time the platform is fully functional with all operating systems in place. The development drilling phase lasts from the start of drilling on the first production well until all planned wells have been completed. The drilling is done using 1 to 2 large drill rigs mounted on the platform; the number of wells drilled depends on the amount and types of recoverable resources expected. Power for drilling is provided either by diesel engines, turbine generators (natural gas or diesel-fired), or subsea electric cable. Production is also occurring from the time the first well is flowing oil and/or gas; thus, production related activities and emissions also occur throughout most of the development drilling phase.

Emissions: With a few exceptions, the emission sources associated with both development drilling and production operations are the same (unless self-powered drill rigs are used). Compared to production, however, development drilling places additional power demands for the operation of the drill rigs, increases crane use, requires substantially more support vessel activity, and requires intermittent operation of some additional equipment such as cement pumps and logging units. Platform emissions generally reach a peak near the end of the development drilling period when production is high and drilling activities are still occurring. The major emission sources during this period are the turbines (if present); the stand-alone diesel engines which power the cranes, cement pumps, logging unit and various types of emergency and standby equipment; support vessel operations; fugitive hydrocarbons from leaks in valves, seals, compressors and other petroleum handling and storage equipment; and natural gas flaring or venting. NO_x is emitted in the highest quantity, followed by ROG, CO, SO₂ and PM. Peak annual NO_x emissions can range from 100 to 500 tons/year, or higher, with power production and support vessel activities being the largest variables. Hourly emissions can also be substantial due to the amount of large equipment operating simultaneously under high load conditions during this time period. Thus, this stage of the development/production cycle has the highest potential for causing or contributing to elevated ozone levels onshore.

Mitigations: Emission control strategies for sources also associated with production operations, including generation of power and process heat, fugitive emissions, routine flaring and various other sources are outlined in the next section. Emissions from self-powered drill rigs can be reduced by about 25% through a combination of injection timing retard and air-to-fuel ratio adjustment on the large diesels. Substitution of electric motors powered by gas-fired turbines or subsea cable, however, will provide a much greater reduction. Emissions from the industrial diesels typically used to power the cranes, cement pump and logging unit can be substantially reduced by replacing them with California-certified automotive diesels. Direct emission control of emergency and standby equipment is generally not cost-effective due to their low frequency of use. However, the timing and duration of intermittent activities, such as testing and maintenance, can be restricted to ensure they don't occur simultaneously with other significant emission generating activities.

7.4.3 Production

The production phase occurs over a much longer period than either the exploration or development phases. Depending on the extent of the resource, production may continue for 20 to 30 years. For purposes of this discussion, production activities have been separated into platform operations and transportation of the resource.

Platform Operations

Once all planned production wells have been drilled many of the major emission generating activities at the platform decrease substantially. Much of the drilling equipment is removed from the platform, support vessel and associated platform activities are reduced, and overall power demand declines to a relatively stable lower level.

Emissions: As noted in the previous discussion, the potentially significant emission generating activities during the production phase include power and process heat production, fugitive hydrocarbons, routine flaring, various intermittent sources such as cranes and emergency or standby equipment, and support vessel operations.

The demand for power on a production platform usually involves a relatively stable base-load and a fluctuating, variable-demand load. Base-load power is used for lighting, machine shops, instrumentation, control systems and other basic utility functions. The variable-demand load consists of the power requirements of the mechanical equipment needed during production, such as pumps and compressors for oil and gas sendout, submersible pumps, and gas lift. This load fluctuates with the number and type of active wells and the level of production, but typically exceeds the base load demand.

Power for offshore platforms is usually supplied by onboard turbine generators or submarine electric cables from shore. Onboard turbines are major emission sources and often account for over 80% of all NO_x emissions from a platform. They typically burn diesel fuel during the first six months of drilling until gas production (if available) is established. If cable electric power from shore is used, the turbine emissions at the platform can be eliminated (see pages 28-30 for a detailed discussion of platform electrification issues).

Heating of produced crude for initial water separation or to maintain critical flow characteristics can be accomplished through natural gas fired heaters, electric heaters, or turbine waste-heat recovery. Electric heaters themselves do not generate emissions. Similarly, turbine waste-heat recovery does not cause any additional emissions if the turbines are already being used for power on the platform. Gas heaters produce low levels of NO_x and ROG through the combustion process.

Evaporative losses, or fugitive emissions, result from leaks in valves, seals, compressors, and other petroleum handling and storage equipment. Fugitive emissions are primarily hydrocarbons, but can also include impurities in the product such as hydrogen sulfide (H₂S). The average reactive fraction of fugitive hydrocarbon emissions is about 34 percent. The total evaporative losses from a given platform depends on the number of components with the potential to leak hydrocarbons, the production throughput, and the effectiveness of the maintenance program undertaken by the operator.

Emissions associated with venting and flaring of natural gas depend primarily on the frequency and duration of their occurrence and on the composition of the raw gas. Though not a part of what would be termed "normal operations", short-term flaring events occur rather routinely in the course of producing natural gas and crude oil on an offshore platform. Flaring may occur when an unexpected high pressure pocket of natural gas is encountered during drilling; during process upsets such as compressor failures; or during maintenance and repair of equipment, instrumentation, and controls. MMS estimates an average of three 10-minute flaring events occur each day on a typical OCS platform. Flaring emissions consist primarily of NO_x,

although SO₂ emissions can also be substantial depending on whether the flared gas is sour (high in H₂S) or sweet (low H₂S content).

Emissions also result from the small diesel engines used on various types of intermittently operated equipment, including emergency generators, firewater pumps and cranes. The annual emissions contribution from these sources is small; however, short-term (hourly) NO_x emissions can be significant, particularly if operations occur simultaneously with other emission generating activities.

Mitigations: Gas turbines, for power generation or cogeneration, are the major source of NO_x on a platform. Water or steam injection is a standard control technology on offshore turbines and can reduce uncontrolled NO_x emissions by 50 to 70 percent. Selective catalytic reduction (SCR) has shown up to 90% NO_x control for onshore turbines but poses currently unresolved safety issues for offshore application. Recent experimental efforts using premixed combustors and catalytic combustors on gas turbines also offer considerable promise for significant NO_x reductions. As is the case with other emerging techniques, the duty cycles of offshore equipment pose a particular challenge to these technologies. Provision of power through subsea cable remains the single most effective method for reducing emissions of all pollutants at the platform. A more detailed discussion of this measure is presented in section 7.6.

Uncontrolled evaporative and fugitive emissions can be reduced more than 50% through an effective inspection and maintenance program for valves, pumps, compressors and pressure relief valves. Further reductions can be achieved through the use of more efficient process components (e.g.- metal bellows valves, packless valves, dual mechanical and tandem seals, etc.) and an effective vapor recovery system. Thorough consideration of component efficiency at the design stage will minimize the overall level of fugitive emissions from the process.

Flaring emissions can be reduced through the use of smokeless flares and by implementing an inspection and maintenance program to increase their combustion efficiency. SO₂ emissions from sour gas can be controlled, if necessary, by routing the gas through a caustic pollutant scrubber prior to flaring.

Emissions from the diesel engines used to power intermittently operated equipment, such as the cranes and firewater pump, can be reduced by the use of California-certified automotive diesels. Alternatively, crane emissions can be further reduced using electric motors powered by subsea cable, if available; large electric cranes are commonly used on derrick barges and exploratory drill rigs. Safety concerns do exist, however, and the applicability of this measure should be studied on a case-by-case basis. Potential impacts from these activities can be lowered by effective activity management to ensure that testing and maintenance operations for emergency and standby equipment do not coincide.

Resource Transportation

Oil and gas produced offshore must be transported onshore for final treatment and eventual distribution to the marketplace. Produced gas is typically moved to shore by pipeline; produced oil can be either piped to shore or transported from the offshore site by tankers. Offshore storage facilities would be required in cases where oil was tankered directly from the offshore site.

Emissions: For pipeline transport, emissions result from the generation of the necessary electric power to pump the oil and gas to shore, as previously discussed. If tankers are used to transport crude oil to shore, emissions result from fuel combustion in the large diesel engines used to power the ship, and evaporative losses due to product loading and taking on ballast. Combustion emissions occur at the offshore production site, during vessel transit, and in port. Evaporative hydrocarbon losses occur primarily at the offshore loading location and in port; vapors saturating the airspace in the storage tanks at the offshore facility and on the tanker are displaced by the oil loaded into them. The amount of emissions produced are very dependent on the size of the tanker and the quantity of product being loaded or unloaded. ROG is the primary pollutant emitted, followed by SO₂ and NO_x. For a 40,000 barrel of oil/day (BOD) production scenario, ROG emissions can exceed 250 tons/yr.

Mitigations: Pipeline transport produces substantially less emissions than tankering and is the preferred method of resource transportation. If tanker transport is unavoidable, however, the use of steamships can achieve up to 60% reduction in the amount of NO_x typically emitted by diesel-fueled motorships; use of low-sulfur fuels can also provide significant reductions in SO₂ emissions. Evaporative losses can be reduced by requiring ships to use segregated ballast, and through effective vapor recovery systems on the ships, on the offshore storage facility, and at the marine terminal.

7.4.4 Support Vessel Operations

Varying levels of support, involving the use of supply boats, crew boats and helicopter transport, are required for each phase of offshore activity. Supply boats transport all of the food, materials, and equipment required at the offshore sites. When serving construction sites, such as platform and pipeline installation operations, they may also be used as additional deck space for staging of materials during the construction process. Many of the larger supply boats are also used as ocean-going tugboats. Most of the service boats rated for towing are in the 3000 horsepower to 7500 hp range, while ordinary supply boats are somewhat smaller.

Crew boats ferry the work crews back and forth from the sites to shore and range in size from about 680 hp to 1530 hp; most of the newer boats are about 100 ft in length and rated at about 1500 hp. Large helicopters are also used for crew transport when necessary; smaller helicopters are used primarily to transport VIP's and supervising personnel, and for medical emergencies.

Emissions: Emissions from crew and supply boats result from fuel combustion in the large diesel engines and from the small auxiliary generators which power the bow thrusters and provide electricity when moored or in port. The quantity of emissions produced is

project-specific and depends on the length and frequency of trips required and the type and size of engines used on the vessels. In addition, different activities produce different levels of emissions: idling and queuing in port and at the offshore site, maneuvering during crew or supply loading and unloading, towing during construction or installation, and cruising to destination. Depending on the project, emissions from support vessel operations can easily equal or exceed those caused by activities at the platform. NO_x is the primary pollutant emitted, followed by CO and ROG; SO₂ emissions depend on the sulfur content of the diesel fuel.

Helicopter emissions also depend on length and frequency of trips, type of engines, and amount of time spent idling and cruising. NO_x is the primary pollutant emitted during cruising, while CO and ROG are the largest emissions produced at idle.

Mitigations: Control of NO_x emissions from crew and supply boats can be accomplished through several different strategies used alone or in combination. Recent testing has shown that injection timing retard combined with an intercooled turbocharger can reduce NO_x emissions by at least 30%; enhancement of the intercooler configuration provides another 9% to 17% of additional control. Furthermore, a 15% decrease in vessel cruising speed has been shown to cause a substantial drop in fuel consumption; this can result in a further 45% reduction in NO_x emissions per nautical mile traveled.

The use of alternative fuels could reduce emissions by varying amounts depending on the type of fuel used. A combination of diesel and natural gas may provide up to 25% reduction in NO_x emissions, while substitution of propane for diesel fuel could realize a 90% NO_x reduction. Fuel switching is subject to the approval and code requirements of the U.S. Coast Guard and the U.S. Bureau of Shipping. Existing Coast Guard regulations prohibit the use of propane fuels on supply vessels.

Provisions for additional platform storage could reduce the time that a supply boat must queue at a platform when used to provide storage space for equipment and expendables. In addition, careful planning to consolidate vessel use can reduce the number of trips required for each project. For instance, the use of fewer, larger vessels for the transport of crew and supplies will result in reduced vessel trips. The coordination of shift changes between proximate platforms may further allow a single vessel to transport the crew or supplies for several platforms.

The use of helicopters for crew transport can also provide a significant reduction in NO_x emissions, depending on the percentage of trips committed to versus those actually achieved in practice. Helicopter use is restricted by weather conditions which affect visibility.

Finally, emission reductions may be achieved by locating a supply base in closer proximity to the Northern Santa Maria Basin, thereby significantly reducing travel distance to platforms in this region. Such a facility, however, would create a number of additional onshore emission sources: the idling and queuing of vessels in port; the associated operation of heavy-duty equipment onshore; and a substantial increase in heavy-duty truck traffic transporting supplies and equipment to the base. In addition, significant impacts to other sensitive resources need to be considered. Thus, the net potential benefit of this strategy cannot be determined until a

specific supply base proposal is analyzed. This subject is discussed in further detail elsewhere in this document.

7.5 Onshore Emissions and Mitigation Measures

The development of offshore energy resources requires an extensive network of onshore support facilities, including storage yards, pipelines, pump stations, marine terminals, supply bases, processing plants, etc. The construction and operation of these facilities can result in substantial air pollutant emissions with the potential for significant onshore air quality impacts. For purposes of this discussion, onshore support activities have been separated into construction activities and facility operations.

Construction

The nature and scope of project-specific onshore construction depends on the type and scope of the proposed offshore development and the adequacy of existing onshore support facilities. For most projects, however, the construction and installation activities and equipment used are similar.

Emissions: Construction activities generally involve digging, scraping, grading, lifting, trenching, hauling and other activities using large pieces of mobile construction equipment. Examples of such equipment include tractors, dozers, graders, cranes, trenchers, backhoes, dredges and various types of heavy-duty and light-duty trucks. Substantial quantities of PM are emitted as fugitive dust from these operations. In addition, the large diesel engines which power this equipment, and the diesel generators used to power the compressors, welding machines and other smaller equipment onsite, can be substantial emission sources when operating concurrently. NO_x is the primary pollutant emitted, followed by CO and PM. The quantity of emissions produced depends on the particular construction activity and the time period over which it occurs.

Mitigations: Although construction activities are temporary in nature they can cause significant short-term impacts which require mitigation, particularly on projects with several different construction phases. Reducing potential impacts is generally accomplished through the joint application of both direct control strategies and activity management techniques. Retarded injection timing can reduce NO_x emissions from the diesels by 15 to 20%; a simultaneous increase in the air-to-fuel ratio can achieve an additional 15% reduction. SO₂ emission impacts can be reduced through the use of low-sulfur fuels. Water sprays can be used to reduce fugitive dust emissions in areas under active construction; chemical soil binders or permanent dust control measures may be applied in areas no longer subject to construction activity.

Activity management can also provide effective mitigation of construction impacts. Careful planning can minimize the overlap periods between concurrent construction operations by extending or phasing certain activities. In addition, the equipment spread can be monitored and

adjusted to ensure that emissions from large equipment do not accumulate in localized areas due to unnecessarily bunched activity. Although no direct emission reductions are achieved by these techniques, effective activity management can reduce the significance of potential impacts through minimizing the simultaneous occurrence of emission generating activities.

Facility Operations

Resources produced offshore must usually be processed, refined and stored at onshore installations prior to marketing. Additional support facilities covering a broad range of coastal-based activities are also required to provide service, supplies, and port capabilities for the day-to-day and long-term operational needs of the offshore oil and gas industry. Thus service and supply bases, storage yards, marine terminals, pump stations, processing plants and refineries are all part of a complex onshore infrastructure required to support offshore development. Existing oil and gas production facilities within the county include a refinery on the Nipomo Mesa, marine terminals in Morro Bay and Port San Luis, and several tank farms. In addition, a large gas processing plant and a small oil refinery are located nearby in Santa Maria, and an oil processing and treatment plant is proposed for the Nipomo Mesa as part of the San Miguel Project.

Emissions: Onshore resource processing can range from a simple oil dehydration facility to a complex gas processing plant or oil refinery, depending on the type and intended use of the product. Emissions from an oil dehydration facility are usually much smaller than those produced at an oil refinery or gas processing plant. NO_x is the primary pollutant emitted in all cases due to natural gas combustion in the processing equipment. Flaring events may create substantial emissions of SO₂ depending on the sulfur content of the flare gas. Fugitive hydrocarbon emissions also result from leaking process components and storage tanks. The quantity of emissions produced by each device depends on the type, configuration and throughput of the facility.

Emissions from a service and supply base generally result from the queuing and idling of crew and supply boats which operate from there. Emissions from marine terminals result from tanker loading and ballast operations. Both topics are discussed individually in previous sections.

Mitigations: Processing and refining facilities are subject to the rules and regulations of the APCD, which typically require implementation of Best Available Control Technology (BACT) for each pollutant-emitting device at the facility. This may include Selective Catalytic Reduction (SCR) and water injection for gas turbines; low-NO_x burners and flue gas recirculation for boilers and heaters; vapor recovery and gas blanketing for storage tanks; a stringent inspection and maintenance program to minimize leaks from valves, flanges, seals and other process components; smokeless flares; and retarded ignition timing on standby and emergency equipment. New or emerging control technologies could also be required. The type and extent of emission control required is very dependent on the type and nature of the facility equipment and operations under consideration.

7.6 Major Issues

Several important issues exist which bear directly on the offshore development process as a whole and require separate consideration. The following discussion deals with the most pertinent air quality aspects of those issues.

Permit Actions By Other Agencies

As noted previously, the complexity and scope of the offshore development process precipitates the need for regulatory review by many different agencies. Permit issuance for the various facets of a project proceeds along a schedule which, for certain phases, is predetermined by statutory deadlines. However, in many cases the regulatory schedule is set by the timing of the application for a required permit. Regulatory review and decision-making for the different permits may occur concurrently or sequentially depending on the goals and strategy of the applicant. Decisions made early on can affect the options available in the later stages of the regulatory process. For instance, design decisions and regulatory requirements made in the issuance of initial permits may limit the type of mitigation strategies to be considered during the environmental review process. This is particularly true for air quality mitigation, which often requires equipment or process modifications or the installation of additional control equipment.

The determination of appropriate emission controls should be driven by technical and economic feasibility considerations, not by consequential decision-making. A comprehensive scoping process should be implemented for each project to allow critical input by all affected agencies prior to the granting of any regulatory approvals to proceed. The new EPA air quality regulation for OCS sources, when adopted, will facilitate this goal.

Project vs. Cumulative Development

Several separate air quality analyses performed in the recent past have predicted exceedances of state and federal ozone standards to occur in San Luis Obispo County with even limited OCS development in this region. The MMS air quality analysis for LS 73, the Northern Santa Maria Basin (NSMB) Area Study, and analyses done for the 1987-1992 MMS 5-Year Leasing Program all predicted significant impacts to result from emissions generated by 1-3 production platforms offshore the Central Coast. In addition, air quality modeling for the NSMB area study also predicts significant air quality impacts from the onshore oil and gas processing necessary to accommodate the projected area buildout.

The rapid expansion of offshore energy development in the Santa Barbara Channel during the 1980's has contributed to the substantial air quality problems faced by Santa Barbara County. As identified in the above-mentioned MMS 5-year leasing plan, a severe shortage of available emission offsets has become a limiting factor in planning for additional development south of Pt. Arguello. Industry attention is thus expected to be increasingly focused on the Northern Santa Maria Basin. Exploratory drilling has already been completed on many NSMB tracts with promising hydrocarbon potential. As the price of oil rises, development pressures on these

tracts will increase. As indicated in the referenced studies, the attendant air quality impacts of offshore development may be substantial and could contribute to or increase existing ozone levels in the region.

San Luis Obispo County is a nonattainment area for the state ozone and PM10 air quality standards. Implementation of the 1991 Clean Air Plan (CAP) for this county requires an aggressive rulemaking schedule that will reduce ozone precursor emissions from existing sources by 40% between 1992 and 1998. No net emissions increase is allowed from any modification of an existing source or location of a new source in this county. Thus, emissions from future offshore exploration and development must be controlled to the maximum extent feasible and residual emissions fully offset.

Consideration of this information is crucial to the regulatory process that accompanies each individual project. Decisions made on one project may ultimately affect the manner in which future projects can and will be configured. This is of particular concern with respect to the long-term availability of offsets for both onshore and offshore development. Cumulative impacts must therefore be given significant weight, as required by CEQA, when determining the mitigation appropriate to each project. Failure to do so could limit the regulatory options available for other projects and may ultimately preclude future development both onshore and offshore.

Mitigation Feasibility

Evaluating the feasibility of a potential mitigation measure is necessary to the determination of its applicability to a given project. In making this determination several parameters must be considered: the effect of the measure on process operations; the technical difficulties involved in its implementation; and the economic impact it places on the project. The determination of operational feasibility focuses primarily on ensuring that the required mitigation will not result in unsafe project operations. Technical feasibility involves analyzing whether the measure is currently available and has been proven in similar operations; or alternatively, whether sufficient test data and other information exist to warrant the application of a control strategy not yet proven in the field. In either case, both operational and technical feasibility determinations are fairly straightforward and are based on sound engineering analysis. The determination of economic feasibility is a much more difficult task, requiring the use of complex financial analysis techniques. The capital and operational costs, and their projected change over time, must be determined to evaluate the impact of the measure on the financial viability of the project. An overall feasibility determination can then be made based on the comprehensive information developed in the analysis.

The feasibility analysis should not be influenced by any construction or other substantial project commitments begun prior to completion of the County's regulatory review process. This includes preconstruction of platform components, purchase of equipment, scheduling commitments and so forth. Consideration of these factors is inappropriate from a procedural and regulatory standpoint and would set undesirable precedents. In choosing to proceed prior

to regulatory approval, an applicant accepts the risk that later decisions may require project modifications.

Determination of feasibility is a complex process. Much of the information required is proprietary, and the ultimate conclusions reached are often open to subjective interpretation. Formal guidelines should be developed to identify the information required in the analysis and to establish evaluation criteria by which to judge feasibility.

Platform Electrification

Offshore platforms have typically met their power requirements by using on-board turbine generators, as well as separate diesel prime movers (engines) to operate various other equipment. These combustion sources are usually responsible for over 90% of all emissions produced at the platform, with the turbines representing the major emission source. Electrification of platforms and facilities (except for emergency and standby equipment) can reduce the need for onsite combustion sources and is the most effective method currently available to substantially reduce emissions of all pollutants. For the purposes of this discussion, platform electrification refers to the provision of power to the platform through a subsea electric cable from an onshore power source.

Various degrees of platform electrification are possible, each involving different technical and economic considerations. Full electrification typically involves the use of onshore power for most of the non-heat power demands of the platform; it also includes replacement of prime movers, such as those for drilling rigs or platform cranes, with electric motor drives if feasible. Partial electrification can have many configurations, including the combined use of both subsea cable and on-board turbines to provide platform power; it may or may not include substitution of electric motors for the prime movers.

The feasibility of platform electrification, and the degree to which it can be accomplished, is dependant on many variables. Factors to be considered include project electrical needs, process heat requirements, project design, safety concerns, available electric power sources, and cost of electrification. Technical difficulties associated with platform electrification are more easily resolved if addressed early in the design phase of the project. Economic concerns are more often the determining factor in how a project is ultimately configured.

The cost of purchased power from the onshore utility grid can be substantial over the life of a project and may result in a shorter economic life. This concern must be weighed against the air quality benefits of electrification and its effect on future development in the area. Modifications to utility rate structures or the use of onshore cogeneration may help reduce the financial burden of this emission reduction measure. Onshore cogeneration in particular may offer economic incentives for platform electrification, considering the cost of offsets and the need for additional power and heat for the onshore processing.

The use of utility grid power or onshore cogeneration for any platform configuration would create additional emissions onshore to some degree, but at a much lower level than those resulting from offshore power production. Emissions generated by the utility grid to meet the power demands of an offshore project would likely originate at several different power plants within the grid system. In addition, a large portion of that power demand would be met using nuclear and hydropower, which do not cause NOx or ROG emissions; fossil fuel-fired plants would contribute only during the hours and seasons of peak load demand. Thus, additional emissions from the utility grid would not occur on a continuous basis and would likely be widely dispersed. Emissions from onshore cogeneration, in contrast, would originate at a single stationary source and typically result from the use of turbines similar to those used offshore. However, onshore control technology is significantly better, with up to 90% reduction in uncontrolled NOx emissions possible through the use of selective catalytic reduction. Emerging control techniques for onshore equipment promise even greater NOx reductions in the near future.

Platform electrification is currently the most effective means available for reducing emissions, at the source, of all pollutants from offshore development and production operations. An electrification feasibility analysis should be performed for each proposed platform prior to submission of a Notice of Intent (NOI) to the EPA by the project applicant. The feasibility analysis should undergo review by all affected air quality agencies prior to a consistency determination by the California Coastal Commission.

Offsets

Emissions from offshore energy development, even after application of maximum feasible mitigation, will cause a long-term increase in the overall pollutant burden of the region. NOx and ROG emissions, in particular, pose a threat to the air quality attainment status of the county due to their contribution to elevated ozone levels during periods of adverse meteorology. This potential impact can be offset by requiring project applicants to achieve emission reductions at non-project sources in an amount necessary to compensate for permitted project emissions. Specifically, all emissions of NOx and ROG, after implementation of all required onshore and offshore air quality mitigations, should be fully offset by emission reductions from existing sources within the project impact area. These offsets should be acquired according to the requirements and guidelines of the District's New Source Review Rule.

It is important to note that offsets are not a substitute for feasible emission controls at the source. They are not as effective as source controls in mitigating air quality impacts, and the supply of available offsets is limited. Unnecessary use of offsets by offshore projects could reduce their availability to onshore projects, thereby limiting the potential for future expansion of onshore industry in the county. Thus, offset usage should be managed wisely to preserve them as a necessary resource for future growth.

7.7 Policies

The following policies address issues that pertain to the general subject of offshore energy development and those which are specific to the individual phases of the process as presented in this chapter.

1. The development of offshore oil and gas resources is a lengthy and complex process requiring interaction and cooperation among many different agencies. To that end, the following policies shall be adopted:
 - A comprehensive scoping process at the start of each proposed project to receive input from all affected agencies prior to any regulatory approvals to proceed.
 - A statewide Technical Advisory Committee (TAC) be established to provide preliminary review of proposed modeling protocols, feasibility studies for platform electrification, and general technical oversight for the air quality review process on each project. Participating members should include the EPA, MMS, ARB, the affected APCD's, industry, and an independent air quality consultant.

2. The performance and review of air quality analyses is also a complex and controversial process. Consistency in approach, methodology and interpretation of the analysis is necessary to provide an adequate basis for decision-making. As such, the following policies shall be adopted:
 - Require the performance of a thorough, cumulative assessment of potential ozone impacts for each project, using an analysis approach approved by all affected agencies.
 - Development by the TAC of formal guidelines for the performance of a platform electrification feasibility analysis. The guidelines should include identification of the information and methodology to be used as well as the evaluation criteria by which to judge feasibility.
 - Further development of the regional air quality monitoring network is needed to enhance the air quality database for impact analysis and decision-making, and to track the future impacts of offshore development.
 - Request MMS to install meteorological buoys offshore Pismo Beach and Morro Bay to provide baseline offshore meteorological data for this region.

3. Establish firm policies to protect air quality in the county from the impacts of offshore energy development. Specifically, the following policies shall be adopted:
 - Oppose all future lease sales along the central coast until the actual impacts from development of existing leases are determined and mitigated to levels which will not cause violations of state or national ambient air quality standards.

- If future lease sales do occur, request lease sale stipulations be adopted which require a platform electrification feasibility analysis to be performed and submitted with each Development and Production Plan. Platform electrification from an onshore power source should be required to the maximum extent feasible, as identified in the analysis; other mitigation alternatives could also be considered, provided they achieve an equivalent level of emission reduction.
 - Require that significant consideration be given to potential cumulative impacts when making project-specific decisions.
 - Require maximum feasible mitigation of ozone precursor emissions from offshore energy development projects.
4. Request Environmental Protection Agency and California Coastal Commission to place the following conditions on offshore exploration activities:
- Scheduling of exploration activities during the period between November and June to avoid impacts during the peak ozone season, provided that it does not conflict with seasonal limits for other sensitive resources and does not require operations during unsafe weather conditions.
 - Limit the number of drill rigs which can operate concurrently within a specified region.
 - Require the use of Caterpillar D-399 diesel electric generators on the drilling rigs, if feasible, or other prime movers with equivalent emissions. If not feasible or available, vessels with controlled emissions in the lower half of the exploratory vessel fleet (i.e. - the "cleanest" vessels) should be required.
 - Require helicopter transport of personnel, except during unfavorable weather conditions, to reduce the simultaneous occurrence of crew and supply boats at the drilling unit. If crew transport by boat is unavoidable, then careful scheduling of crew and supply boats should be required to reduce simultaneous occurrence at the platform.
 - Require maximum feasible mitigation of NO_x and ROG emissions from the crew and supply boats which service the drilling unit (see support vessel recommendations below).
 - Require that crew and supply boats not be present together at the drilling unit during scheduled flaring for drill stem testing.
5. Require that the following mitigation measures be implemented for construction activities associated with offshore platform and pipeline installation:

- Require the use of Cat D-399 diesel electric generators on derrick and lay barges, if feasible, or the use of other prime movers with equivalent emissions. If direct injection diesels are used, injection timing retard of 4° and adjustments to the air-to-fuel ratio should be applied to reduce NO_x emissions.
 - Require maximum feasible mitigation of NO_x and ROG emissions from all support vessels involved in construction and installation activities, including crew and supply boats, light-duty tug boats and other applicable vessels (see support vessel recommendations below).
 - Require the use of low-sulfur diesel fuels on all support and installation vessels operating within 3 miles of shore.
 - Require the development of a comprehensive activity management plan designed to reduce the simultaneous occurrence of large polluting activities where possible.
6. Require that the following emission control strategies be implemented for all offshore development and production operations:
- Platform electrification from an onshore power source, which currently represents the best available control technology (BACT), shall be implemented to the maximum extent feasible at the earliest stage of development; feasibility determinations should not include consideration of any construction of project components begun prior to completion of the regulatory review process. Other mitigation alternatives should also be considered if they can achieve equivalent emission reductions.
 - Use of natural gas for fuel and Best Available Control Technology (BACT) on all turbines permitted for use on platforms.
 - Use of ARB-certified automotive diesels on all independently-powered equipment for which electrification is demonstrated infeasible (e.g. - cement pumps, logging units, cranes, vessel generators, etc.).
 - Use of low-NO_x natural gas-fired heaters for process heat needs, if applicable and feasible; applicability and feasibility should be determined during the platform electrification study.
 - Implementation of a rigorous inspection and maintenance program for detection and repair of process components and equipment which cause fugitive hydrocarbon emissions.
 - Use of state-of-the-art flare systems; restricting flaring events to documented emergencies, process upsets, well testing and scheduled maintenance.

- Implementation of a comprehensive activity management plan to minimize the simultaneous occurrence of NO_x generating activities.
 - Use of helicopters rather than crew boats for transport of personnel, except during unfavorable weather conditions.
 - Use of pipelines rather than tankers to transport produced crude to shore.
 - Assure that platform design includes sufficient storage capacity to minimize the use of supply boats for added deck space.
7. Require maximum feasible mitigation of NO_x and ROG emissions from all support vessel operations associated with exploration, development and production activities. The following control strategies have been demonstrated, or have the potential, to achieve significant emission reductions:
- Use of injection timing retard of 4° combined with an enhanced intercooler on the turbocharger for all vessels under contract to a project. Limit the use of uncontrolled, spot-chartered vessels to scheduled downtime or emergencies requiring an extra vessel.
 - Reduction of vessel cruising speed to 15% below top speed.
 - Use of alternative fuels, such as propane or a dual-fuel mix, if feasible and able to comply with applicable regulatory restrictions.
 - Implementation of a comprehensive activity management plan designed to consolidate vessel use and reduce the number of trips required for each project.
8. Require the following measures to be implemented for the construction and operation of all onshore facilities associated with offshore energy development:
- Require each project to develop and implement a comprehensive Construction and Installation Emissions Mitigation Plan (CIEMP) covering all phases of onshore construction. Such a plan would specify the equipment, emission controls and activity management techniques to be employed to achieve compliance with local, state and federal ambient air quality standards.
 - Conduct onsite inspections of construction operations to assure compliance with the CIEMP.

The policies given above emphasize the need for stringent air quality protection while recognizing the unique and variable nature of the offshore development process. Adoption of these recommendations will provide guidance to future project applicants and regulatory direction for future development offshore San Luis Obispo County.

CHAPTER VIII: ONSHORE FACILITIES

8.1 Background

Commercially viable petroleum and natural gas reserves have been identified offshore the county. A proposal to produce and transport these reserves would normally include onshore facilities. Often, much concern given such a project goes to the potential of offshore portions to cause air pollution, oil spills, habitat disruption, and aesthetic degradation. Though county decisions can be expected to have effects beyond county borders, the county's ability to affect placement and mitigation of platforms and pipelines off its coast is unsettled. County authority to approve or disapprove pipelines, processing facilities, refineries, marine terminals, storage tanks and related facilities proposed within its borders is unchallenged. The county's most direct concern lies with location, characteristics, and impacts of onshore facilities.

Decisions on approval, location, and mitigation of onshore facilities supporting offshore development may affect the county's rural residential and agricultural character, its quality of life, and its rate and type of growth. Onshore facilities can be heavy industry. They bring potential hazards which require sensitive siting and sufficient buffering from other land uses. Environmental, political and economic concerns are inevitable and sensitive.

This chapter addresses the environmental review, siting, and permitting of petroleum and natural gas processing facilities. These can include: petroleum upgrading and refining facilities, heat and pump stations, storage tanks, and tank farms, pipelines, and other related facilities. The chapter discusses the qualities of these facilities as well as particular characteristics of different facility types. It contains specific recommendations on paths and criteria for siting decisions and for resolving major mitigation issues when facilities are sited.

8.2 Description of Resource

San Luis Obispo County is a rural coastal county located midway between San Francisco and Los Angeles. It is bounded on the north by Monterey County, on the east by Kern County, on the south by the Santa Maria River and Santa Barbara County and on the west by the Pacific Ocean. Its physical characteristics include low volcanic and tectonic mountains, high dunes, sandy beaches, fertile coastal and inland plains, and arid regions. Air quality has been generally good but is deteriorating. (See air quality discussion in Chapter VII.) Water is scarce.

The county has significant wetland and other sensitive habitat, and consequently, a rich biotic diversity. Several state and federal threatened or endangered species, and many candidate species are resident or transient. (Please see Chapter V.)

Significant numbers of people work in the tourist, service, energy, and agricultural industries. There are also a large number of people working in government, primarily at institutions such as Camp Roberts, California State Polytechnic University, California Men's Colony, and the Atascadero State Hospital. Many people of retirement age have moved to the county.

Present Petroleum Activity: Several onshore petroleum facilities exist in the county. There is a refinery on the Nipomo Mesa, marine terminals in Estero Bay and at Avila, a small number of producing fields, tank farms and pump stations, and associated equipment. Figure VIII-1 shows most of the locations of various facilities in the county.

Geophysical surveys, leasing, and exploratory drilling have occurred in federal waters offshore the county. Commercial reserves of oil and gas have been discovered in federal waters off the southern portion of the county. Platform Irene, located off Point Sal, is the closest offshore platform to San Luis Obispo County. Oil from a platform off Santa Barbara County is being partially refined at Unocal's Santa Maria Refinery in southern San Luis Obispo County. These products are then shipped from Avila by tanker or pipeline.

State waters off the county have been declared a sanctuary. As long as sanctuary status remains, no drilling or production can occur between the high tide line and three miles off the coast.

Trends: Over the past several years, cities and rural areas of the county have experienced rapid growth in population and in residential and commercial activity. Growth has been concentrated on relatively level land in the western half of the county. The issues of managing growth and limiting rates of increase are ongoing concerns. The low supply of water and the high price of land are significant issues in developing areas.

The existence of commercial reserves of oil and gas offshore has created pressure to site industrial development onshore. In the past, facility siting efforts have focussed on the rural coastal zone in the southern part of the county. As more offshore leasing and development is proposed, pressure for onshore support facilities can be expected to spread to other coastal portions of the county.

The trend toward residential expansion in rural areas may conflict with efforts to site onshore industrial facilities to support offshore production. There are incompatibilities between industrial and residential growth, and between petroleum industry needs and the expectations of many county residents. One purpose of this chapter is to identify and discuss these issues.

8.3 Regulatory Setting

Various federal, state and local provisions affect the siting and characteristics of onshore facilities. Following sections discuss those elements of the regulatory framework which most affect local government. In addition to provisions mentioned below, air quality regulations, detailed in chapter VII apply.

Figure VIII-1
Location of Oil and Gas Facilities in San Luis Obispo County

Local Coastal Plan - Coastal Zone Land Use Ordinance: Initial siting applications for onshore facilities will likely focus on the county's coastal zone. Even if facilities are proposed inland, pipelines and other transmission facilities will pass through the coastal zone. Consequently, the primary land use regulations affecting onshore facility development are likely to be the county's Local Coastal Program (LCP) and Coastal Zone Land Use Ordinances (CZLUO).

The LCP and CZLUO contain various provisions regulating energy facilities. Regulations include the plan's energy and Guadalupe Dunes policies, various area and community standards in the Framework for Planning, and ordinance provisions specifically addressing petroleum processing, pipeline, and related facilities. These documents now address onshore facilities in a general fashion, but with specific recognition for facilities within the Unocal refinery tract or the oil field in the Guadalupe Dunes. Certain types of facilities likely to be proposed, such as natural gas processing facilities, are not specifically addressed in these documents.

Land Use Element-Land Use Ordinance: Development outside the Coastal Zone is regulated by the County Land Use Element (LUE) and Land Use Ordinance (LUO). The LUE and the LUO address general issues and list certain requirements for onshore facility siting, focusing on petroleum processing and transmission. Area and community standards in the LUE also focus on these same issues.

Measure A: In 1986, San Luis Obispo County voters passed Measure A which has been incorporated into the LCP. Section 1 of Measure A provides:

No permit, entitlement, lease, or other authorization of any kind within the County of San Luis Obispo which would authorize or allow the development, construction, installation or expansion of any onshore support facility for offshore oil and gas activity shall be final unless such authorization is approved by a majority of the votes cast by a vote of the people of the County of San Luis Obispo in a general or special election. For the purpose of this ordinance, the term "onshore support facility" means any land use, installation, or activity required to support the exploration, development, production, storage, processing, transportation, or related activities of offshore energy resources.

Coastal Act: The state Coastal Act provides for review of local decisions on siting energy facilities in the coastal zone. A local decision to deny a project that the California Coastal Commission deems of regional or statewide interest can be reviewed and reversed on the Commission's own motion. The Coastal Act also provides that the Commission exercises original permit jurisdiction where a local coastal plan has not been approved. The Commission has permitting authority over projects proposed for state waters, and is empowered to determine whether a project proposed in federal waters is consistent with the California Coastal Management Plan. (See Chapter II) The consistency determination and the state waters permit can lead to mitigation of onshore impacts. There can be differences between Commission and local decisions regarding the permitting of a project.

California Environmental Quality Act (CEQA): The California Environmental Quality Act (CEQA) and its accompanying guidelines direct local agencies to analyze and evaluate the environmental consequences of siting or not siting projects when reviewing applications for onshore facilities. CEQA's broad scope and pervasive analytical requirements compel agencies to evaluate project impacts and the effectiveness of mitigations across a full range of affected local interests. If more than one agency makes permitting decisions on a project, CEQA obligates the lead agency to consider the entire project when making decisions. CEQA empowers an agency to deny a project found to have unavoidable significant negative impacts.

While fulfilling CEQA obligations and appending permit conditions to approvals, local governments have addressed impacts from the offshore portions of oil and gas projects. Federal, state, and local agencies disagree on the extent of local government's decision-making role offshore, especially in federal waters.

Interagency Coordination: Agency coordination in evaluating applications furthers both consistent decision-making and responsiveness to the public and to applicants. Agency coordination is essential in responding to emergency events. Interagency environmental reviews are usually conducted by joint review panel representatives from primary permitting agencies. Documents may be prepared to serve National Environmental Protection Act (NEPA) as well as CEQA purposes.

Pipeline routes spanning more than one county or crossing through incorporated communities require obvious coordination measures. Assuring the availability of a sufficient number of personnel and vehicles to respond to a major refinery, processing plant, or tank farm fire could require cooperative agreements among city and county fire fighting agencies of one or more counties. Existing agreements should be assessed and updated as new facilities are proposed and possibly approved.

8.4 Operations

A diversity of potential hazards are typically associated with onshore facilities. These hazards exist because crude petroleum, natural gas and associated fluids and solids are flammable, explosive, or toxic. These materials are both subjected to intense applications of energy in the form of heat, pressure, etc., and are moved or stored in large quantities.

Facilities: Treatment and storage facilities supporting offshore development have several common characteristics. They present potential flammable, explosive, odor, and air pollution hazards which require distancing from other uses. They are technologically sophisticated, requiring careful construction and subsequent detailed inspection. These facilities may be massive. They have the potential to significantly affect a full range of environmental interests.

A tank farm, which normally has a large number of large cylindrical hydrocarbon storage tanks, may be required at a treatment facility or at a point along a pipeline route for storage or for blending crude, processed, or refined petroleum. Storage tanks present the most siting

difficulties associated with treatment facilities. Tanks can be visually intrusive, a potential fire hazard, a source of spills, and a threat to ground water, if not properly designed, sited, and mitigated.

These types of facilities are not the only treatment/storage facilities which may be proposed for the county in support of offshore development. The Santa Maria refinery partially refines offshore oil taken from Unocal's platform Irene, located off Point Pedernales, in Santa Barbara County. The potential exists for full or partial upstream refining of other Santa Maria Basin crudes as a means of improving shipment and marketability characteristics. Various other processes intended to upgrade heavy, viscous Santa Maria basin crudes have also been suggested.

Offshore developers may propose onshore electric co-generation plants. Co-generation plants could supply electricity to platforms while minimizing emissions to the air. Sweet or sour gas from the offshore reservoir might be brought ashore to fuel turbines, or fuel could be bought from companies such as Southern California Gas. Co-generation facilities do not treat or store hydrocarbons, but should be included in this grouping.

A smaller hybrid facility, (sometimes called a heater-treater), may include a heat-and-pump station which could be necessary to serve heavy crudes. A heat-and-pump station consists of a pump and a reheating unit. It may include a stripper unit that separates out impurities from the crude oil. The application of heat and pumping force are necessary to keep heavier crudes fluid and moving in the pipelines.

Transmission facilities which may be required to develop offshore resources include pipelines and electric transmission lines. Pipelines move a variety of fluids such as crude, diesel, other petroleum products, sweet or sour natural gas, natural gas liquids, and water. Electric lines may move current from a distribution grid or co-generation plant to onshore or offshore facilities. Normal transmission facility routing is a straight line between points of service. Pipelines and electric lines are allowable, subject to CZLUO permitting requirements, in all land use classifications in the county.

Materials: Crude oil, natural gas and other reservoir fluids found on the central coast are normally extracted in conditions rendering them unsuitable for sale or long distance shipment. The industry need to promptly improve the crude would require onshore treatment and storage facilities near the southern San Luis Obispo County or northern Santa Barbara County coasts and near Morro Bay for crude and gas produced from offshore northern basin reservoirs. Complete processing of northern basin crudes in the confined area of a platform is unlikely.

Petroleum may emerge in an oil-water or water-oil emulsion containing various metals, soils and other impurities. The impurities increase viscosity, reduce capacity for laminar flow, and raise shipment expense. Crude may be improved onshore in a processing facility, which dehydrates and removes impurities, in a refinery, which "cracks" crude (breaks it into various

components), turning it partly or completely into a variety of petroleum products, or in an upgrading facility which produces high quality synthetic crude.

Onshore and offshore facilities are often mechanically interdependent. A project design may be integrated to a point where the offshore platform and the onshore processing facility function as a single unit. One northern Santa Maria basin project proposed partial offshore and partial onshore processing of its reservoir production.

Offshore northern Santa Maria basin crudes have exhibited unusually low API gravities (the lower the API gravity the thicker the crude) and high viscosities. These qualities multiply difficulties in shipping and end use. Significant quantities of diluent, refractants, and heat may be required to ship the crudes to shore.

Untreated natural gas from a reservoir may be impure, flammable, explosive, and toxic. At all points from production to sale, it has to be isolated from flame, spark, and non-process heat. Gas extracted from northern basin fields likely will contain significant concentrations of hydrogen sulfide (H₂S). H₂S is toxic on inhalation at concentrations of 600 parts per million or more, and must be reduced before gas is brought into the distribution and sales network. The removed sulfur is also classified as hazardous. Gas processing creates, as byproducts, liquid petroleum gas and natural gas liquids. The fluids are useful, but are also flammable and explosive.

Construction: Construction includes the movement of machinery, large prefabricated pieces of metal, quantities of smaller metallic and other construction materials, piping, electric wiring, construction machinery, foundation materials, and similar supplies. Thousands of gallons of water per day may be needed for drinking, construction use, and dust control. Fork lifts, cranes, dozers, compactors, trucks, vibrators, generators, welders and similar machinery are required. An example of a typical construction scenario for a processing plant is attached as Figure VIII-2.

The elapsed construction time for a treatment, storage, or co-generation facility will vary depending upon circumstances. A refinery or natural gas processing plant could take a longer time, while a co-generation facility or a storage facility alone might take somewhat less. In addition to primary facilities, construction might include roadways, building and parking areas, and containment berms.

For any large facility, peak construction work force will number in the hundreds. The skills and jobs required for the work force will change over the course of construction. Networker in-migration is an issue of concern not only to local government agencies dealing with the consequences of in-migration, but to the local work force. The Socioeconomic Monitoring Program (SEMP), administered by Santa Barbara County Council of Governments attempts to monitor and mitigate this impact.

Site preparation involves clearing and stripping vegetation. Stripped material is removed for disposal, and grading, contouring and compacting occurs. Hundreds of thousands of cubic yards of soil may be moved in such cut-and-fill operations, depending on site topography and the intended facility.

Fuel and electric power are required during construction, as are construction machinery, welding tools, and earth moving equipment. Companies often prefer to run construction sites on a continuous 24 hour basis, with bright lighting to allow site preparation, fabrication and assembly.

Operation: Crude oil and natural gas are normally extracted from reservoirs in emulsions, mixtures of several fluids. The primary purpose of processing is to separate and dispose of the other fluids and gases in the crude oil stream. Treatment facilities use chemicals, heat and other physical processes to dehydrate and to remove impurities from crude petroleum and natural gas. Storage facilities contain hydrocarbon-based fluids for batch shipment or blending.

Treatment facilities normally require large quantities of electricity, natural gas, waste heat, if available, and chemicals to conduct their operations. Facilities will normally require substations or co-generation plants for electric power. Natural gas for treatment and co-generation may be supplied from the reservoir or from local gas distribution companies.

Natural gas removed from the emulsion may be injected into a natural gas processing stream, used for fuel at a processing facility, or processed and sold. Produced water comes up with the crude oil and is treated to remove oil and other impurities before discharge at an offshore platform or injection into an underground reservoir. Sulfur removed from the hydrocarbon stream is normally transported by truck or rail. Any fluid stream containing natural gas, including crude petroleum with entrained gas, requires a flare system for maintenance and emergency purposes.

Process control and office functions at a site are carried on by a small number of people. An administration building and one or more buildings housing equipment and storing materials can be expected. Communication equipment, such as microwave equipment, would be installed to link onshore facilities with offshore platforms and other company operations.

8.5 Impacts

Petroleum and natural gas treatment and storage facilities and co-generation plants are large industrial operations which can emit pollutants to the air and water, require lengthy and intensive construction, and pose potential problems for the community in the event of upset or accident. The materials used in operations, the residues produced by different processes, and the hazardous nature of crude oil and natural gas and various products may cause adverse impacts.

Figure VIII-2
Example of a Construction Schedule

Treatment facilities can be significant consumers of electricity. Depending on processes used, natural gas processing typically consumes extremely large volumes of water, can be expected to emit pollutants and odors to the atmosphere, to continuously require and produce hazardous materials which have to be removed from the site, and to have potential to alter topographical and surface water flow patterns.

Construction Impacts: Major construction impacts include noise, especially from assembling large pieces of metal, the repetitive motions of machinery, traffic, and air quality degradation in the form of dust and engine emissions. Noise causes more severe impacts in evening hours, early morning hours and at night than during the normal working day and more impacts on weekends than week days. Housing, health and community services impacts may be caused by in-migration of construction workers. Habitat disturbance, loss of archaeological resources, alteration of surface water flow patterns, topographical alterations, and spills of fuels and lubricants may also occur. Construction impacts can be considered of relatively short duration in the sense that many construction events are transient, and overall construction stages will normally be measured in months rather than in years.

Construction may provide employment for hundreds of workers for several months, creating substantial temporary impacts in areas ranging from housing demand to transportation. During site preparation and construction, substantial traffic congestion in a site's vicinity caused by moving materials and workers is the norm. A variety of air emissions, fluid discharges, and refuse can be expected. Continuous construction is incompatible with residential neighborhoods.

Transmission Line Construction Impacts: Impacts from pipeline construction can be expected to be short term in any given area. On the other hand, pipeline construction impacts are ordinarily more severe than any normal operational impacts.

Pipeline ruptures are considered abnormal (unplanned) operational events. While this chapter does not deal with the consequences of spills or leaks, with environmental degradation from released oil, or with ignition or inhalation of released gas, it is clear that hydrocarbon releases result in the largest detrimental impacts. Improved long-term monitoring for hydrocarbon presence has the potential to reduce and better define impacts. Certain siting considerations which may reduce the likelihood of ruptures or the magnitude of their consequences are mentioned in the section that follows.

Impacts from electric transmission facilities may be greater during operation than construction. If a facility site is not near high voltage lines, the applicant or PG&E may have to construct or expand transmission corridors. Upgraded transmission lines, in turn, may impact the health or the aesthetics along the route.

Operational Impacts: Potentially significant long term impacts from operation of treatment, storage and co-generation facilities include pollutant and odor emissions to air and water, adverse effects on human health and natural habitat, groundwater consumption, contamination of surface water, noise from pumps and other equipment, visual impact from industrial

equipment and flares, and spills of hazardous materials. Potentially significant land use related impacts include induced industrial and commercial growth in surrounding areas, incompatibility with residential, recreation or other low intensity uses in rural regions, taking of land particularly suitable for other purposes such as agriculture, and the potential for subsequent expansion of heavily industrialized areas. When operating, a facility may provide a relatively small number of permanent jobs. Initial tax revenues to the county general fund might be substantial, but not likely significantly larger than the cost of demands on county services attributable to the facilities.

Applications regarding permits for an onshore facility should include material which addresses concerns such as; land slumping, surface water and ground water contamination, disturbance or loss of significant habitat including damage to threatened, endangered, or sensitive species, and loss of archaeological resources. Noise reaching nearby residents, workers or visitors, the incongruent siting of large industrial facilities in otherwise rural, residential, or commercial landscapes, demands on community services, and traffic congestion and damage to roadways should also be considered. Many of these concerns can be resolved or diminished by careful siting, design, and mitigation, and by confirming that measures either proposed by a proponent or imposed by a governmental agency are actually performed in the course of construction and operation.

8.6 Siting, Design, and Mitigation Considerations

The most significant mitigation in locating onshore facilities is selecting a site which minimizes the adverse consequences of interactions between the facility and the surrounding region's populace, habitat, and land uses. Affirmation of compliance with permit conditions is essential before facility start-up, and procedures should reflect this requirement.

Given the existing leases in federal waters and the continuation of federal lease sales, applications for onshore facilities can be expected over time along the length of the county's coast. In coastal areas, few industrially designated parcels could accommodate large onshore facilities. As residential and related development increases in coastal areas, difficulties associated with siting onshore facilities will grow.

Buffer Zones: Siting potentially hazardous operations requires a piece of land which (alone or with adjacent undeveloped parcels) provides an undeveloped or compatibly developed space between the facility and other uses. This space, a buffer zone, is one of the most important factors in siting onshore facilities. A buffer must be large enough to protect residents, workers, and transients from potential incidents created at the facility.

Although the resulting buffer zone is likely to be sized differently for different facilities, the process of determining an adequate minimum size for a buffer zone is similar whether the facility is a natural gas processing plant, an oil refinery, an oil processing facility, or a set of storage tanks at a pipeline junction.

A sufficient margin for error is an essential part of determining any buffer zone. For example, if a study calculates that the maximum potential radiant heat footprint for a particular facility is 900 feet, and the nearest homes are 1000 feet from the plant, the 100 foot difference is not likely to provide residents with a sufficient safety margin, or with a strong sense of safety.

Siting Considerations: Establishing as a primary criteria locating a facility away from residential, commercial, recreational, and unrelated industrial areas and from major public thoroughfares provides a basis for evaluating other issues such as habitat, cultural resource disturbance, and groundwater consumption. Facilities should be located near fire and emergency response stations having trained personnel and adequate equipment, or they should be located near the proposed site at the applicant's expense. Development of petroleum and natural gas resources must be balanced by the public's interest in not being unduly exposed to significant, avoidable dangers. County decisions should be based on assuring that the public's interest is protected.

Information disclosure followed by thorough review and sensitive decision-making can achieve a proper balance between an applicant's interest in development and the community's concern for compatible, proportional, and safe uses of the land. Careful evaluation of site selection, design, expansion potential, and impact mitigation can reduce or eliminate impacts. It can also produce the conclusion that a particular site is not acceptable for even a heavily mitigated facility.

A well designed, thoroughly mitigated project on a carefully selected site, assuming the project has acceptable parameters for future expansion and induced growth, could be acceptable to a community. On the other hand, not all projects are or ought to be approved. For example, facilities which emit significant amounts of pollutants to the air, even unavoidably, should not be sited. No facilities should be sited near to and upwind (prevailing direction) from nearby population centers.

Site selection must recognize both an applicant's technical concerns and a community's understandable reluctance to accept intrusive development. The applicant and the county should examine and maintain surrounding land for potentially inconsistent land uses over the life of a facility.

Complete mitigation is not always achievable. The likelihood of oil spills, fire and explosions can be reduced, exposure to risk can be minimized, and response capability can be maximized, but the possibility of these events cannot be eliminated. Nor can effects on tourism, recreation, or visual quality. The inability to completely mitigate should be a basic, acknowledged consideration in site selection.

Facility Consolidation: An important aspect of any onshore facilities proposal is the extent to which initial facilities may eventually be expanded or "built out". The number of platforms extracting fluids from an offshore field will often increase over time. Consequently, onshore facilities may be initially sized to handle smaller production than may ultimately be developed.

For example, an initial proposal for an oil processing facility with a 40,000 barrel a day capacity may be a precursor of expansion to 125,000 barrels per day. Similarly, a scenario for a gas processing plant with a 30 million cubic feet per day capacity may contemplate a second 30 million cubic foot increment and a third 65 million cubic foot increment later being added.

An oil processing plant and a gas processing plant located together may be designed differently than the two facilities if located apart. Common siting allows combining some waste treatment, product storage, generating, and other systems. County and state land use and coastal policies require an applicant to carefully consider consolidating existing and proposed facilities. Consolidation can minimize pipeline and traffic routes, less broadly affect overall area development, concentrate the need for response to emergency situations, and minimize regional exposure to actual and potential impacts associated with oil and gas development.

Reserves have been found on several leases off the county and are not always owned by the same operator. Given differences among hydrocarbon fluids and company processes, not all reserves may be easily served by common facilities. Consolidation allows concentrating impacts from several facilities, avoiding duplicate controls and minimizing regional disruption. On the other hand, consolidation may create a "hot spot" with unacceptable cumulative impacts.

Applicant and Governmental Considerations: Applicant's considerations in selecting sites for facilities will include, in addition to suitable physical characteristics, a determination that there are technically, legally and politically feasible means of accessing the site for pipeline, electric transmission and ground transportation. A piece of land on which a processing facility could be constructed to serve an offshore platform, but which is reachable by pipeline only over sheer cliffs, or which could be served by trucks only along mediocre roads passing through residential areas, is a less preferable site. An inappropriately designated site poses difficulty. Any site near a recreation area, a sensitive habitat, or a residential area can expect to encounter substantial political opposition.

A permitting body, in turn, will have a specific interest in proposals of any of the sorts described immediately above. The local governmental process involves political as well as legal considerations. The voices of constituents opposed to a project in a sensitive area may have their effect on the process. An application which proposes facilities in unlikely locations deserves special scrutiny in terms of site rationale, effects of construction, operational hazards, and alternatives.

Selection of Land: An applicant will likely seek land which is either appropriately designated or reasonably susceptible to an amendment. An applicant in this region can be expected to propose a processing facility site close to shore because the exceptionally heavy, viscous nature of northern Santa Maria basin crude makes it difficult to ship for any distance without removal of impurities. There is real potential that crudes may "set up," becoming more solid than fluid, if allowed to cool.

An applicant should seek sites with at least two overriding characteristics; sites which would not expose substantial numbers of residences, workers or transients to fire, explosion, or hydrogen sulfide (H₂S) in the event of accident, upset, or maintenance failure, and sites away and downwind from present and expected residential and commercial development. Locating a tank farm or co-generation facility would involve similar considerations.

Land Characteristics and Ownership: Another significant consideration for the applicant is land ownership or leaseholding. ("lease" here refers to surface rights rather than mineral rights.) Land already owned or leased by the applicant, by another oil company or partnership or land which can be readily purchased or leased for a long term is a necessity. The most likely course of action at present is for development to be proposed on land already owned by a petroleum company.

Staff has conducted a computer search of petroleum company ownership of lands in the coastal zone or in the valleys and mesas near the county's coast. Not all potential names under which the companies' land is held were available to staff. A more exhaustive search of ownership records in areas close to the county's coast was not feasible.

Figures VIII-3, 4, and 5 show the information obtained concerning petroleum company ownership as of fall, 1988, in lands reasonably close to the county's coast. With the exception of the Unocal Santa Maria Refinery tract, there is no indication that any of these parcels or any other parcels which may be held by petroleum companies have been specifically considered for siting onshore facilities.

The part of the county from Avila and Port San Luis south to the county line is the area most likely to be subject to offshore development under current lease sale conditions. Approximately six tracts are currently leased in nearby waters. Commercially viable finds have been made on nine tracts.

Physical and land use characteristics of particular parcels together with uses and characteristics of surrounding tracts are primary considerations in selecting sites. Currently, onshore support facilities can be sited only in industrially designated areas. The only industrially designated land in the coastal area south of Pismo Beach, Arroyo Grande, and Grover City lies on the Nipomo Mesa, either on or adjacent to the Unocal Santa Maria refinery tract. The refinery tract itself is dedicated exclusively to petroleum product and related uses. The adjacent industrial parcels are closer to residential development.

Careful site selection is imperative. Onshore facilities for one project were originally proposed for the Callender site, one of the tracts adjacent to the Santa Maria refinery. The proposal included a 40,000 barrel per day processing facility, a 280,000 barrel capacity tankfarm, and expansion to triple crude processing capacity, increase crude storage, and install a 125,000,000 cubic feet per day gas processing facility.

Figure VIII-3
Oil Company Land Ownership in the South County Planning Area

Figure VIII-4
Oil Company Land Ownership in the San Luis Bay Planning Area

Figure VIII-5
Oil Company Land Ownership in the Estero Planning Area

The site was proximate to a growing rural residential area and was located in a grove of flammable eucalyptus trees which reach nearby homes. The site was contiguous to a stretch of state highway characterized by sharp turns and limited visibility. There was no potential for a sufficient buffer zone. Nevertheless, the site was properly designated and the application was intensely pursued. Issues raised in the course of environmental review and sustained expressions of public concern persuaded the applicant to seek a different site.

The Santa Maria refinery is used for refining petroleum produced offshore. The only other areas identified in the South County sufficiently distant from residential development to permit contemplation of petroleum facilities are on prime agricultural land or are far from the coastal zone. Consequently, any major facility siting in this part of the county would most likely focus on the Santa Maria refinery.

South of Price Canyon and west of Highway 101, very little additional land could be considered for siting. East of Highway 101, east of Nipomo and the Five Cities area, there is land which, if rezoned, might not be attractive for oil processing because of distance from shore, but might be considered for gas processing, refining, or upgrading.

A producing onshore field sits in Price Canyon between Pismo Beach and the Edna Valley. From offshore, pipeline access to Price Canyon could prove difficult. Given Price Canyon's proximity to the increasingly residential/grape growing area of Edna Valley, air quality considerations would be problematic for onshore facilities. On the other hand, large relatively flat sites lie among the hills on the canyon's west side.

The large hills to the north and east of Pismo Beach are owned by oil companies. Pipelines currently run between the Unocal tank farm at Avila, the Price Canyon oil field, and the Unocal refinery. Expansion of these pipeline corridors may provide an applicant with a means of solving pipeline access problems to an otherwise desirable site.

Between Port San Luis and Montana de Oro State Park, the county's coast and upland topography become more rugged, while population concentrations decrease. Much of the coast could conceivably be reached by pipeline either from northerly tracts off San Luis Bay or from future lease sales in the northern Santa Maria Basin. Complications in this area include the proximity of the Diablo Canyon Nuclear Electric Generating Plant and PG&E's extensive land ownership. Transmission of airborne pollutants and the exposure of sensitive habitat to spill risks are also factors. The sensitive and increasingly recognized Morro Bay estuary, and the communities of Morro Bay, Los Osos and Baywood make onshore facility siting difficult north of Montana de Oro. The Montana de Oro and Atascadero State Beaches are held by State Parks. These prime recreation areas would be difficult to cross by pipeline. Significant habitat in this and other portions of the county's coastal regions are discussed in Chapter V, the biology chapter.

Between Morro Bay and Cayucos there is a strip of petroleum company land along Toro Creek. Chevron maintains pipelines and a tank farm serving multi-point mooring systems in Estero Bay. Vessels occasionally carry crude from the Chevron terminal around Point Buchon to the

Unocal pier at Port San Luis, as well as to other destinations. If offshore leasing and development occur near Toro Creek, the area may be considered for siting associated facilities.

North of Toro Creek, there are no active leases and no parcels designated as compatible with petroleum support facilities. Nevertheless, if offshore leasing followed by significant hydrocarbon finds occurs in this region, efforts to amend land use categories will likely follow. The land immediately north of Cayucos, between Cayucos and Point Estero is, because of present uses and land availability, perhaps as likely as any other to be considered for an onshore facility development.

8.7 Buffer Zones, Compliance, and Mitigation

A well-run, properly maintained facility should not expose the public to fires, explosions, toxic emissions, or persistent odors. Nevertheless, human error, unexpected events, and equipment wear do occur, and upsets sometimes result. Site selection which avoids exposing local residents and visitors to upsets is an important aspect of planning for onshore facilities supporting offshore development.

Buffer Zones: The size of a buffer zone should be central in influencing the choice and review of a site. A buffer zone sufficient to protect against fire, explosion, to lessen the effect of odors and emissions, to reduce visual and noise impacts to acceptable levels, and to ensure compatibility with surrounding land uses should be mandatory. Proximity to services such as electricity, fire and emergency services, and adequate, safe transportation routes are necessary. An adequate separation from incompatible land uses, such as residential areas, biologically sensitive areas, and prime agricultural lands should be required. Maintenance of the separation should continue over the life of the project. A proposal's potential to induce secondary growth should be considered. A tract large enough for anticipated expansion should be sought.

Defining a buffer zone should involve an interdisciplinary study. Acceptable separation from residential areas and maximum radius of exposure to radiant heat from a fire, to debris from an explosion, or to other hazards will vary with facility size and operations conducted. A buffer zone should include enough distance from other uses to allow dissipation of odors occurring under normal operation circumstances.

To determine a safe perimeter, footprints for different accident types should be calculated and overlaid. Typical hazard footprints include ignition of a large product spill and radiant heat and flying debris from a boiling liquid vapor explosion. Other events include H₂S releases and various fires and explosions. The various hazard and odor footprints and the proximity of residences or significant numbers of transients, especially those reasonably expecting a different viewscape than heavy industry, should be specific factors in determining buffer size.

A buffer of sufficient size can protect an ongoing petroleum use from a challenge that it has become a nuisance. Land uses change in type and intensity over time. An area sparsely

populated when a plant is sited may become gradually developed with residences as years pass. Though a plant may precede residential development, it may become an unacceptable irritant to residential or other uses. A buffer zone which ensures compatible nearby uses on a long-term basis can minimize the difficulty.

In summary, a site should be buffered to protect other uses, activities, resources, and aesthetic sensibilities, to keep people from being exposed to hazards, and to promote the long-term viability of any approved petroleum use. The size of a buffer will vary from project to project. A site which does not offer an adequate buffer for all identified hazards and compatibility of long-term uses should not be designated for the use.

Proximity to Public Fire Response: An applicant should be expected to install state-of-the-art pressure relief, monitoring, fire prevention, detection, and suppression equipment and to have thoroughly trained personnel at its facility to respond to fires, explosions or similar events. Nevertheless, because of the possibility of explosions, the size and intensity of blazes, the potential for off-site effects, and the difficulty of suppressing such fires, it is essential that quick response capability from the California Department of Forestry or other responding agency be available.

A facility should be located within a brief (the current standard is five minutes) response time from an adequately equipped and staffed CDF fire station. Alternately, the applicant should bear the cost of equipping and initially operating a new, nearby, adequately equipped CDF station. Also, well-drawn mutual aid pacts need to be in place for fires, explosions, and other events at facilities and along transportation routes.

Other Construction and Operation Mitigations: Possible mitigations for many potential impacts must be developed after review of specific proposals. This section does not present a comprehensive discussion of mitigations. Nevertheless, the following should be considered:

- Paying locally prevailing wages to construction workers can significantly reduce incentives for in-migration and can thereby lessen any adverse consequences of in-migration.
- Any storage tanks have to be bermed with impervious lining and with sufficient capacity to hold the contents of tanks in the berm with an allowance for rainfall. Berms should be graded to run to drain pumps.
- Sanitary wastes and runoff from process and storage areas would be generated. The former can be handled by either community sewer or septic tank and leach field systems. The latter requires installation of a system for separating rainfall from spilled hydrocarbons before discharge from the site.

- Heat-and-pump stations should not be located in residential, recreational, commercial, or other areas subject to large concentrations of people, and should not be sited in sensitive habitat. Appropriate buffer zones should be defined according to the methodology described above. Emissions to air and water from heat-and-pump stations should be analyzed. Stations should ordinarily be powered by electricity.

Transportation Routes: Access to services and transportation routes present problems for both applicant and county governments. Transportation routes are an essential siting issue. Gas processing plants produce large volumes of hazardous materials. Some cannot easily be shipped by pipeline. Refineries, upgraders, and other facilities also require movement of significant quantities of hazardous materials. Sites which induce transportation of these materials onto high risk (because of population exposure or roadway characteristics) roads or railroads should be avoided. Projects seeking rail shipment should be close enough to rail terminals to avoid intermediate truck movements. Any site which does not have adequate or cannot provide road or rail routes, especially a refinery, upgrader, or processing facility site, should be rejected.

Pipeline Routing: During normal operations, pipelines are arguably the safest, most innocuous and least costly means of transporting petroleum or natural gas. Greater hazards are posed by vessel, rail or tanker truck movement of various commodities produced by offshore development. County policy strongly favors transportation of crude and products by onshore pipeline. Many petroleum operators disagree with the county policy.

Many pipeline and transmission route mitigations are straightforward. Careful route selection, as opposed to straight lines between origins and destinations, can avoid or reduce impacts by increasing distance from sensitive receptors.

Pipelines can be laid in most terrestrial topography. Non-liquefiable soil is preferable either to rock or to soil subject to liquefaction. Gentle topography is better than sharp elevation changes; sensitive habitat and archaeological sites are to be avoided. Pipelines or electric cable running to a platform should be buried at the shoreline to a depth where erosion and wave action pose no threat to line integrity.

Pipelines should be sited to minimize the chance that spills will reach sensitive resources and the amount of construction disturbance in residential areas and near public facilities. Gas pipelines should avoid residential areas and, where possible, major transportation routes. Jacketed pipe where lines may be exposed to stress, cathodic protection, and frequent, regular visual inspections of a route are appropriate protective measures, as are operational techniques such as dehydration, inhibition, and pigging. Periodic barriers or baffles on sloped lines can slow or prevent the migration of fluids through filled soils in the pipeline trench. State-of-the-art leak detection systems, appropriately located valves and integrated, centralized operation can help limit the size and impact of spills and releases. Properly operated leak detection systems can quickly inform pipeline operators of large liquid spills. Small leaks may remain unnoticed for a considerable length of time, until there is an observable hydrocarbon

pool, detectable groundwater contamination, or ignition. Currently, leak detection technology for natural gas pipelines is primitive. A properly drawn and implemented containment and response plan can lessen impacts.

A potential operational impact from one type of pipeline presents a problem of a different order. Northern Santa Maria basin gas as produced from the reservoir can be expected to be "sour," that is to have a high hydrogen sulfide content. Hydrogen sulfide is odorless and extremely toxic at high concentrations and may not be removable offshore. Separation of large quantities of hydrogen sulfide in a confined area such as a platform and the problem of disposing of massive amounts of sulfur are extremely difficult propositions. Consequently, a company needing to process reservoir gas for sale, or use it for co-generation, will likely bring sour gas ashore. The characteristics of hydrogen sulfide at high concentrations make a release an extreme hazard for human health and safety.

In siting gas lines, it is essential that population and transportation centers be avoided where possible. It is desirable that sweetening and processing of natural gas be conducted in an isolated, unpopulated area. Bringing natural gas ashore also requires that regulatory bodies have a precise understanding of characteristics of the gas and of measures necessary to control toxicity, flammability, and explosiveness.

Electric Transmission Line Routing: Considerations in siting electric transmission lines are not substantially different for offshore oil projects than for other circumstances. Towers should be spaced to minimize visual impact. For the same reason, the least visually intrusive tower configurations should be selected. Routes should avoid profiling towers and transmission lines against the sky. Residential and other land use which concentrate populations should be avoided because of potential health concerns.

Pipeline and Electrical Transmission Line Construction Mitigations: Not all pipeline construction impacts can be completely mitigated except by avoidance of sensitive receptors, i.e., rerouting. Construction noise cannot be completely baffled, generated dust cannot all be subdued. Only avoidance of populated areas can minimize certain construction impacts. Similarly, the potential for impact to sensitive habitat or to an archaeological site can be completely resolved only by rerouting. Pipeline construction may alter landscapes and surface and near-surface flow patterns in land with undulating topography. Steep slopes, dunes, and land prone to sliding or slumping should be avoided where possible. Stream crossings should be avoided or selected to decrease proximity to nearby and downstream sensitive habitat. Fuel depots should be defined, bermed, removed from sensitive habitat, impermeable during construction, infrequent, and the only locations for normal refueling. This holds for all fuel depots associated with a project. Existing transmission corridors should be utilized wherever appropriate.

The effect of constructing transmission lines to serve a project must be evaluated along with other environmental considerations. Electric substations are normally a part of such a project.

Environmental considerations associated with transmission lines include visual impacts and the unresolved issues regarding health impacts.

Pipeline Operating Mitigations: Pipelines require pump stations to operate. Pumps normally operate continuously and oil line pumps may operate noisily. Noise impacts can be mitigated by buffering or by enclosure. Pump station noises may be the only significant impact from normal pipeline operations.

The possibility of operational upsets, such as spills, fires, explosions and toxic releases exists. These events can occur, sometimes with devastating impact, at pump stations, compressors, or points along a pipeline route. Spills and gas releases from pipelines can result from clean line breaks, major ruptures, or small cracks or holes.

8.8 Summary

Proposals for onshore facilities to support offshore development are likely to continue because commercially viable offshore oil and gas reserves exist on several offshore leases. Continued exploration may locate additional offshore reserves. Additional lease sales may occur offshore San Luis Obispo County.

The present county land use and coastal zone land use programs try to provide for all reasonably anticipated uses by including the uses in designated zoning classifications set forth in the county's ordinances and land use element ("Table O"). Onshore support facilities, classified as petroleum refining and related uses, can be generally permitted on industrially designated parcels after specific plan approval. The county will not likely be asked to site a great number of these facilities.

The heavy industry discussed in this chapter is not paralleled by any other business moving into the county. A company's decision to proceed with a particular project and to propose a specific facility will become a significant land use and planning issue for the county. A facility proposal will be driven to a great extent by factors outside the physical limits of the county, and outside the county's frame of reference. A partial list of such factors is:

- Reservoir location and size and quality of reserves.
- Gravity and viscosity of crude.
- Impurities in crude, natural gas and other recoverable fluids.
- Water depth.
- Ability to retain heat in emulsions moving to shore.
- Interest in nearby developable leases.
- Economics of processing, refining, and transportation alternatives.
- Refineries and markets available to the particular company.
- Leasing and development policies.
- Political climate.

What type of facility a particular company will need to develop offshore reserves, how large a facility may be required, and where a facility can feasibly be located, given problems with heavy crude, sour gas, and the sensitive nature of the rural environment, are factors which contain tremendous variables in terms of compatibility with other uses. Additionally, at the early stages of field development, an applicant's knowledge of reservoir characteristics and future needs may be too incomplete to provide more than a limited assessment of the onshore facilities required to effect full economic development of the field.

The county needs to understand and be able to deal effectively with an applicant's long term intentions for development before it can determine the appropriateness of a land use proposal. Given the variety in size and type of facilities, it cannot be said that any or all of the industrially zoned parcels in the county are suited for the range of petroleum development which may occur.

Refineries, crude oil and gas processing plants, upgrading facilities, and tank farms present a range of potential impacts to human health and safety, to habitat, and biological communities, and to a range of other resources including air and water quality, the serenity and visual character of the county, the transportation infrastructure and the course of growth. Many impacts or potential hazards can reach well beyond the boundaries of any individual parcel.

Studying the county's physical circumstances and regulatory structure, its population and growth patterns, and the nature of the pressure to pursue petroleum development results in general recommendations and a number of specific recommendations which would change county planning and permitting for onshore facilities supporting onshore and offshore oil and gas development.

8.9 General Policies

1. Redesignating Petroleum Refining, Marine Terminals, Piers and Related Uses

A specific plan is required prior to establishing these types of uses. This procedure should be established whereby a company which has ascertained a need for onshore facilities to support petroleum or natural gas development. The procedure should apply to all refining, processing, storage, or co-generation facilities processing hydrocarbons produced onshore or offshore, except for facilities limited to in-field processing of hydrocarbons produced from the field surrounding the facility.

The specific plan proposal would in effect be a statement of intent to use industrial land in the county for potentially hazardous, tightly integrated, physically complex heavy industry engaged in large-scale, energy-intensive handling of a range of hazardous materials. Hydrocarbons could come from producing fields inside or outside the county. The burden of establishing the plan should be on the applicant, because selection of a site and design of facilities can produce tremendous variance in the scope and type of impacts, and can have a pervasive effect on the character of a region. An applicant's existing right to seek redesignation of a parcel to industrial

would not be affected. An application should discuss general compatibility of the proposed use with characteristics of the parcel, with surrounding uses, and with regional considerations.

A specific plan application should reflect the overall plans of the proponent and any partners or other operators in fields expected to send production to the facility site. It should discuss long-term plans for using the site, including but not limited to:

- Characteristics, volumes, and sources of hydrocarbons
- Expected incoming and outgoing transmission routes
- Size, type and location on site of initial and subsequent refining, processing, co-generation, storage, transmission, and associated facilities
- Timing for initial and later phases of site development
- Volume and timing of required ancillary resources such as water and electricity
- Volume and nature of hazardous materials required or produced
- Transportation routes
- A discussion of the extent to which the characteristics and configuration of intended facilities and operations will be compatible over time with surrounding uses and regional characteristics.

This process should help to focus an applicant's planning efforts not only on maximizing facility efficiency, but on the long-term compatibility of interactions between the intended use and the surrounding region. A properly drawn plan would also focus the county on assessing the compatibility of a proposal with the intensity of surrounding uses and on the adequacy of separation of potential hazards from sensitive receptors. It would further encourage the county to make comprehensive land use decisions which minimize effects on the public and resources of a region from heavy industrial facilities, and also protect facilities from encroachment over time by incompatible surrounding uses. Encroachment might otherwise cause facilities to be regarded as nuisances in the future.

2. Pre-operational Compliance and Systems Review

The second general recommendation, based on the complexity of these projects and the need to insure that terms of their construction and operation are observed, is that, for petroleum refining and related uses, the county's condition compliance procedures be enhanced. Specifically, two procedures for newly constructed or modified facilities, a pre-operational compliance review and a systems safety review committee, should be studied, adapted to local circumstances, and put in place. Pre-operational compliance review addresses the reality that

approval of a plan for any of the facilities constructed in this chapter can be expected only if a large number of conditions intended to protect people, habitat, resources, and community are placed on the approval. The San Luis Obispo County Board of Supervisors placed well over 300 conditions on the San Miguel Project.

Certain conditions may prove complex in application; others may require the passage of time, expert opinion, or another agency's participation. Many conditions will be critical to the compatibility of a facility with its surroundings. County scrutiny of projects should include post-construction review, with approval by the Board of Supervisors of compliance with all pre-operational conditions and of readiness to comply with operational conditions. Permission to operate a facility should be given only when a satisfactory demonstration of compliance has been made.

Another consequence of the multiplicity and complexity of conditions is that many inspections, studies, decisions, and technical adjustments will need to be made by county staff. Consultants may be hired, and direction to the applicant may be needed. As part of compliance review, the county should publicly create a systems safety review committee composed of management-level representatives of agencies such as planning, engineering, environmental health, and the APCD to integrate and guide the day-to-day monitoring of condition and ordinance compliance. The committee should have power to make decisions and approvals and give guidance within the framework of approved conditions, subject to the Board's ultimate power to determine compliance. The committee should exercise the county's powers to initiate studies, hire consultants, and halt or modify work, subject to the Board's ultimate responsibility. Its operation should be funded by the project proponent.

8.10 Specific Policies

Specific policies stated below are policy guidelines and are not intended as a comprehensive statement of conditions to be imposed on individual projects. The policies include:

1. Buffer zones shall be based on analysis recognizing maximum hazard footprints with a margin for safety, air pollutant and odor emissions, prevailing winds, noise, and viewsheds, incompatible uses, and long-term regional trends.
2. Facilities should be sited in swales or other natural depressions and should not be profiled against horizons.
3. Facilities shall be sited within five minutes response time of an adequately staffed and equipped fire/emergency response station.
4. Industry shall maximize employment opportunities for local residents to reduce impacts from the influx of out-of-area temporary employees.
5. Natural gas pipelines shall be sited away from population concentrations where possible.

6. Non-pipeline construction and development near residential areas shall be prohibited.
7. Facilities shall have state-of-the-art pressure relief, monitoring, and fire prevention, detection, and suppression devices.
8. Facilities shall be consolidated where possible unless cumulative impacts from consolidation produce an unacceptable "hot spot".
9. That conditions for specific onshore facilities be developed on a case by case basis, taking into consideration the type of facility proposed, proximity to population, environmental constraints of the site, the potential for upset, the facilities hazard footprint, and the cumulative impacts over the life of the facility.

CHAPTER IX: SUPPLY AND CREW BASES

9.1 Introduction

A general description of supply and crew bases and marine terminals is provided in chapter II. This chapter will provide a more detailed look at these facilities, the general circumstances of siting such facilities on the central coast, a summary of impacts, and recommendations related to such facilities. Information related to the physical size, resource needs, and logistical characteristics will also be presented. Supply bases will be discussed in the first part of the chapter. Crew bases will be presented in the second half of the chapter.

Permit authority for a supply or crew base is held by several agencies. The Coastal Commission has approved the Local Coastal Programs prepared by the county, and the City's of Morro Bay, Pismo Beach, and Grover City. In areas above the high tide line the county's Local Coastal Plan has authority. The Port San Luis Harbor District and Coastal Commission have permit authority regarding portions of a supply or crew base below the high tide line. An applicant is encouraged to coordinate with all of the involved agencies to fully understand the permitting process.

The county's Local Coastal Program (LCP) describes a service and/or supply base (the terms service and supply are synonymous for this documents purposes) as logistical links that are used to transfer materials and workers between shore and offshore operations. A supply base generally includes berthage for supply and crew boats, dock space for loading and unloading, warehouses, open storage areas, and space to house supervisory and communication personnel. The LCP Framework for Planning policies further define these facilities into **major** and **minor**. A major base would transfer heavy equipment and large amounts of supplies using large supply boats that many times have a length of 180 feet or more. A minor base is defined as a small supply, crew ship base that uses crew boats up to 80 feet in length. Figure IX-2 shows typical supply and crew boats. The Land Use Element portion of the LCP provides further description of a minor crew base in the San Luis Bay Planning Area standards. In that section, it limits crew bases to handling only light supplies that are characterized as being incidental items, consisting only of small packages that can be carried on by hand. When applied to a project, planning area standards are given a higher priority than general policies in the LCP. The Local Coastal Plan contains other more detailed policies and standards that would apply to a supply base or crew base proposed in San Luis Obispo County.

The supply and crew bases currently serving the Santa Barbara Channel and the southern Santa Maria Basin are located in Ventura and Santa Barbara Counties. Figure IX-1 shows the locations of existing supply and crew bases. If oil and gas development in the northern Santa Maria Basin continues, a support facility may be proposed in the central coast area.

Figure IX-1
Supply and Crew Bases serving the Santa Maria Basin

9.2 Supply Base - General Characteristics

Offshore oil and gas development activities require onshore support from supply bases which serve as transfer points for construction materials, heavy equipment, supplies, and personnel. A supply base can function as a crew base as well. Personnel, materials and heavy equipment are transported to the platforms via supply and crew boats. Helicopters are sometimes used to transport light equipment and personnel. Helipads are sometimes proposed as part of a supply or crew base. The Lompoc and Santa Maria airports currently provide this type of support for offshore oil and gas activities in the southern Santa Maria Basin. Supply bases are normally operational 24 hours a day, 7 days a week.

A supply base would typically include berthage for supply and crew boats, dock space for loading and unloading of equipment and materials, warehousing and open storage areas, possibly a helipad, space for temporarily housing personnel, and parking. The physical size of a supply base depends on the scope of oil and gas activities in a particular area, land availability, infrastructure, and surrounding land uses. It should also be noted that a supply base can be configured using offsite storage, offices, and remote areas for staging (loading and unloading of materials), parking and other associated activities. Table IX-1 provides estimates of needed resources related to the different phases oil and gas activities. It should be noted that the existing ports in San Luis Obispo County do not have the physical attributes necessary for a supply base to operate. Also, the Energy and Industrial Development policy of the LCP Framework for Planning states that:

Policy 29 **SERVICE BASE LIMITATION.** Service bases shall be concentrated to a single facility and site and shall be further limited, where possible, to minor service bases. All heavy equipment and large quantities of bulky supplies should be transported from existing deep water ports or any proposed oil supply base in the northern Santa Barbara Channel. [This policy shall be implemented as a standard.]

Table IX-A provides estimates of needed resources related to the different phases of oil and gas activities. These are estimates only, the actual amount required may vary depending on the intensity of the activities and manner in which a particular company completes development. Development on the West Coast is completed in a different fashion when compared to other parts of the country. The reasons for the differences include:

- *The use of coastal resources for other activities;*
- *Oceanographic conditions are a factor in how base activities are done;*
- *Local land use policies may preclude development of supply and crew base facilities;*

Figure IX-2
Supply and Crew Boats

- *Industry ordering and delivery practices may reduce the size and amount of resources needed. Also, helicopters would be the preferred mode of transportation of personnel to platforms in the Santa Maria Basin.*

**Table IX-1
Resource Estimates for a Supply Base**

Facility Requirement	Exploratory Drilling	Development Drilling	Production
Land (On & off site)	5-10 acres *	25-50 acres ***	25-50 acres ***
Wharf Space	200-400 feet **	400-800 feet**	400-800 feet**
Water (potable)	.53 acre ft per * 10,000 ft oil well	.36 acre ft per * 10,000 ft oil well	38 gal per person per day *
Water (non-potable)	1.43 acre ft per * 10,000 ft oil well	1.45 acre ft per * 10,000 ft oil well	Not Avail.
Waste Disposal	110 lbs per day *	233 lbs per day *	112 lbs per day *
Sources: * MMS California Factbook, 1985. ** NERBC OCS Factbook, 1976. *** Both.			

9.3 Size/Land Requirements

During the different phases of offshore oil and gas activities, the supply base can be expected to vary in size. During exploration activities, a smaller scale base is needed than during the construction, development and production phases. The latter activities will require a larger scale supply base capable of transporting and storing increased amounts of equipment and supplies.

A typical supply base might require 25 to 50 acres of preferably flat, waterfront property for staging and storage. Figure IX-3 is an example of a well designed supply base. The acreage used for staging and storage purposes only could be proposed for a location at an inland site. The land would be used for loading and unloading of equipment, warehouses, silos, storage tanks and open storage. A long term base should be located in an all-weather harbor in order to avoid transportation delays due to bad weather. The amount of land necessary for a permanent supply base would depend on the number of platforms and rigs being serviced, and the variety of offshore oil and gas activities being supported. It should be noted that if large amounts of acreage are not available, the industry will try to coordinate deliveries so that the supply boat can load up and leave the same day. This would avoid having to store large quantities of materials.

Figure IX-3
Prototype Supply Base

The Petroleum Transportation Committee of Santa Barbara County's Resource Management Department stated that a minimum of 25 acres is necessary for a supply base. A supply base was proposed in Gaviota which included 27 acres of land. The proposed Cojo supply base was to utilize 24 acres. The MMS 1985 Factbook indicates that a supply base would require between 27 and 35 acres. At Port Manatee, Florida ten acres were used to support two exploratory drilling rigs operated by different oil companies. In another study completed by Alaska Consultants, Inc., it estimates that a minimum of 3.5 acres of waterfront property is required for one berth and related support facilities for a single exploration rig. The study indicates that five acres would be a more likely land requirement.

Exploratory: Supply bases used to support exploratory activities differ from bases that would service construction, development, or production phases of offshore activities. During this phase of development, the base would typically be smaller in scope. Drilling muds, cement, pipe, personnel, tools, small amounts of explosives and wellheads are some of the items that would be transported.

Construction: During the construction phase of development when fixed platforms and pipelines are installed, supply base activities would focus on storing and moving large equipment and bulky materials. These materials would be related to platform installation, pipe laying, storage of anchors, anchor chain or cable, buoys, and other similar marine construction equipment. Also stored would be food, fuel, pipe, and water for boats and barges.

During the construction phase of a typical project in the Santa Maria Basin various types of support vessels would be used. Seagoing tugs, barges, and heavy transport vessels would be used to transport the platform jacket piling, the production and drilling modules and drilling rigs. Several vessels could be expected to remain in the area on standby during construction.

Development: The development drilling phase requires land space similar in size to the construction phase. Development drilling does not require storage for mooring systems and other marine materials required during the first two phases. Materials needed to drill a development well include: pipes, tubular goods, muds, water, cement, bits, fuel, and wellheads (1 per well).

9.4 Waterfront/Harbor

A supply base should have berths in a protected harbor with adequate space for maneuvering. Supply boats typically have a draft of 13 to 18 feet. A minimum channel depth of 15 feet would be required at all tides. Approximately 225 to 250 feet of dockside space is generally required for each 200 foot supply boat. An efficient supply base should be able to load and unload numerous vessels at the same time. The use of supply boats may necessitate dredging the harbor because bow thrusters in the boats sometimes cause scouring and silting. This can lead to build up of sand and silt which creates shallow water in which the vessels cannot navigate.

In order to avoid conflicts with fishing and recreational users of a harbor, consideration must be given to the amount of space available within a harbor for a supply boat to maneuver and pass through the channels to dock. This is an important factor because supply and crew boats make frequent trips and are large vessels that require greater space to maneuver than smaller recreational and commercial fishing boats. Designating vessel traffic lanes, especially at the harbors entrance where fishing gear is sometimes placed, is one example of how conflicts can be reduced. In Santa Barbara County the Fisheries/Industry Liaison Office has been used to mediate conflicts.

A sheltered harbor that is near offshore leases is a major consideration in the selection of a supply base site. The harbor must permit the loading and sheltering of supply vessels even though there may be rough seas offshore. Neither Port San Luis or Morro Bay are considered to be fully protected harbors. Policy 32 of the LCP Framework for Planning states:

No service base shall be sited in areas north of Point San Luis due to distance from leasing areas and their high environmental sensitivity of the area unless substantial leasing has been permitted in the northern portion of the county and it is demonstrated that: 1) the alternative sites are infeasible or more environmentally damaging, and 2) adverse environmental impacts are mitigated to the maximum extent feasible.

The efficiency of a supply base is largely judged by the amount of turn-around time required for each trip. Ideally, a base would be located so that boats could move as freely as possible to and from their berthing and loading areas. It would be desirable that a supply base be segregated from other uses in order to avoid operations conflicts, congestion, and delays.

Staging Areas: The apron is the principal staging area for supply boats and is used for the loading and unloading of supplies and equipment. The apron extends from the supply boat berth, back to the warehouse and storage facilities. The staging area should be capable of supporting heavy loads which would be lifted by large cranes onto boats. A large apron allows for the assembly of pipes, containers and other items, before the supplies are lifted onto a supply vessel. An ideal apron would be 100 feet wide, but this is not always feasible.

Warehousing: A warehouse is necessary to store a variety of materials. Tools, powdered commodities such as dry drilling mud and cement, food, and other supplies need shelter from the weather. The size of the warehouse will depend generally on the intensity of offshore development and the amount of available waterfront space.

Open Storage: Land that is flat and can support heavy loads of casing, pipes and other heavy materials is needed for a supply base. The open area is used for storing pipe, equipment, drill rigs and other large scale supplies, materials and equipment. This open space area should be adjacent to the base. The open space storage area could be located elsewhere, but adequate transportation facilities must exist and traffic impacts must be mitigated.

Fueling Facilities: Most bases will have their own fuel storage tanks for serving the needs of supply boats and the offshore rigs. If fuel storage tanks are on the base, they should be in a remote area. The amount of fuel stored will depend on how many platforms are served, the availability of storage, what phase of development they are in, and the number of trips made by support vessels.

It is estimated during development drilling approximately half million gallons of fuel per year are needed for the transportation of materials and personnel to and from one offshore platform drilling four 15,000 foot wells. Fuel is used by supply and crew boats used to transport materials and personnel. These boats may have on-board generators that use fuel to produce electricity. The electricity is used to power pumps that transfer materials (muds, cement, water, etc.) from on-board tanks to the platform. If not fully electrified, a platform uses fossil fuels to generate electricity. It is likely, because of new air quality regulations, that platforms will be required to be fully electrified. A platform may use diesel powered turbines during start-up operations and switch to electrically powered turbines.

Mud and Cement Supplying Facilities: Bulk dry drilling mud and cement are stored in silos which are typically located just off the apron or staging area of the dock. These materials are blown into storage tanks on board the supply boats. This blowing process is done using compressors and has limitations as to how far away the silos can be positioned from the dockside. Typically 100 feet is the maximum distance a silo can be from dockside. Drilling mud, cement, and other fillers can also be transported in sacks.

Mobile Equipment: Cranes and forklifts are used to load and unload supplies. The cranes are used for loading and unloading activities and for moving materials in the open storage areas. Different sizes of moving equipment will be used depending on what stage of offshore activity is occurring.

Water Facilities: Large quantities of potable and non-potable water are transported from a supply base. It may be necessary, depending on water availability, to construct a desalinization plant or other means of providing the necessary amounts of potable water. Also, water storage and pumping facilities may be needed. Demands for potable and non-potable water can vary depending on the availability of desalinization units on a platform.

9.5 Materials to be Transported

A supply base would be used to transport a variety of goods to platforms. Table IX-2 summarizes some of the items and estimates the amounts that could be shipped. The largest demand for materials and equipment is during the exploratory and development drilling stages. It is estimated that one 10,000 foot deep exploratory oil well needs 2.7 million pounds (1,352 tons) of materials. Drilling a 10,000 foot development well needs slightly less material, 2.65 million pounds (1,328 tons). This is a representative sample, the actual number could be more or less. Items appearing more than once are used in different amounts during the various phases of development.

Materials from the Platform: Transportation of goods and services from the shore to the drill rigs or platforms is the major activity. Personnel are returned from the drill rig to the shore. Parts that needed onshore repair also come back to shore. Solid and hazardous wastes are returned to shore and are required to be disposed of in an appropriate manner. At Port Hueneme, solid waste is picked up by the City of Port Hueneme and taken to the local landfill. Hazardous materials are disposed of using private contractors. Future regulations may require operators to dispose of more wastes on shore. Industry is required by law to use an inventory monitoring system that tags and labels items transported to and from the platform.

9.6 Crew Bases - General Characteristics

A crew base is a shore based facility which supports the exploration, development and production activities related to offshore energy development. Crew bases are used to transport personnel, light equipment and supplies to and from offshore operations. As previously discussed, crew base activities can be a function of a supply base. This section of the chapter will focus on the functions, spatial requirements, and characteristics of the crew base.

Light supplies and equipment may also be transported from a crew base. Typically, crew bases do serve as light supply bases, which can provide for the transport of such limited commodities such as food, water, some dry mud and cement and light equipment. Such supplies would weigh less than 500 pounds individually and could weigh up to 1500-2000 pounds per trip. The county's Local Coastal Plan for the San Luis Bay planning area currently limits the supplies that can be transferred from a crew base to items that can be carried on by hand. In the Santa Maria Basin, the industry would prefer to use helicopters instead of crew boats to transport crew and light supplies because of the rough offshore sea conditions.

A base serving the Santa Maria Basin from San Luis Obispo County could be expected to operate 24 hours a day, 7 days a week. The base would probably consist of 2 to 6 crew boat berths. The crew boats could range from 65 feet in length to 115 feet long with an average draft of 6 to 10 feet. At a minimum, a crew base typically includes a pier with berthing spaces, mooring buoys, an office, a personnel waiting lounge, and parking lot.

These facilities are much smaller in scale when compared to a supply base. Currently, the Carpinteria and Ellwood piers along with Ventura harbor are used for transferring light supplies and crew. The Gaviota and Goleta piers are also used for light supplies and crew on a temporary emergency basis with prior approval from state and local agencies. A typical crew base is located in Santa Barbara County at Carpinteria. The facility consists of a pier and a 2.5 ton capacity hydraulic crane. A higher capacity crane (75 ton) is available on the pier to load heavier supplies on crew boats.

9.7 Westec Crew Base Siting Study

This study was completed in 1984 and focused on identifying and evaluating sites for locating a new, long-term crew base in Santa Barbara or San Luis Obispo County. The study area was from Point Estero south to 3 miles east of Point Arguello. The study included three major tasks:

Table IX-2

Examples of Goods Transferred from a Supply Base per 10,000 foot well

Item/Good	Unit	Exploration	Development	Production
Drill Bits	.466 bits/day	X	X	
Bleach	30 gal/well	X	X	X
Cement (1)	5,561 sacks/well	X		
Cement (2)	3,652 sacks/well		X	
Detergent	110 lbs/well	X	X	X
Diesel (1)	4,494 gal/drill day	X		
Diesel (2)	1,260 gal/drill day		X	
Diesel (3)	210 gal/well/per			X
Food	variable	X	X	X
Linen	variable	X	X	X
Lube Oil	42 gal/drill day	X	X	
Electrical	variable			X
Mud	216 sacks/drill day	X	X	
Paint	500 gal/well	X	X	X
Rope	variable	X	X	
Sand	20,000 lbs/well	X		
Tubular	7,800 lbs/drill day	X	X	
Wellheads	1/well	X	X	
Water-Drill	variable	X	X	
Potable Water	variable	X	X	X

Source: Facilities related to Offshore California: A Factbook. MMS study, 1985.

1. *Screening of the study region and candidate site identification;*
2. *Evaluation of the candidate sites;*
3. *Preparation of the final report on tasks 1 and 2.*

Of the study area, 90 percent of it was disqualified as a potential site because of physical oceanographic conditions, impacts on biological resources and restrictive land uses. Three final candidate sites were identified, all of them in San Luis Obispo County. They included:

1. *Morro Bay Harbor near Coleman Park;*
2. *Port San Luis Harbor South west of Harford Pier*
3. *Union Oil Pier in Port San Luis Harbor*

Even though these sites were selected as candidates none of the locations were acceptable when compared to the assumptions used to complete the study.

The results of the Westec study indicated that Morro Bay Harbor was not suitable. This was primarily because of the land use regulations in the City of Morro Bay's Coastal Land Use Plan.

The 1984 study also found that building a facility in Port San Luis Harbor southwest of Harford Pier posed serious conflicts with current land use designation and the Harbor Master Plan. The conclusion was that this site was "was not the most suitable location" for a crew base.

Although the study found that the Union oil pier at Port San Luis was "a suitable location" compared to the three other sites considered, the pier does not meet a number of the assumptions upon which the study was based. Those assumptions are listed below. Also, the study may or may not be true today because circumstances in the county and the industry have changed since 1984. However, the study does provide site specific information and characteristics of a crew base that are useful in considering them. In preparing the study, the base was assumed to have the following characteristics:

Westec Study - 1984
Assumptions for an Operational Crew Base

1. *base would be operational 92% of the time, closing 2 days in every 25;*
2. *maximum hours of continuous down time would be 48 hours;*
3. *the base would be operational 24 hours a day;*
4. *the maximum acceptable wave height is five feet; **
5. *crew boat berths would be a minimum of 2 and a maximum of 6;*
6. *water depth of 9 foot is the minimum required;*
7. *crew boat size: a maximum length of 115 feet, an average of 80 feet, a draft of 7 ft;*
8. *a pier length of 300-700 feet and 30 feet wide;*
9. *deck cargo of 2 tons maximum per boat trip: drilling equipment, valves, food, etc;*
10. *a pier crane; 2 ton jib crane;*
11. *potable water storage in boats. 600 gallons loaded by hose;*

12. *crew boat trip maximum of 25 trips per day and 3-4 trips per peak hour;*
13. *crew personnel passing through the base; 400 people per day - 32 people per trip;*
14. *parking spaces 200 auto, 2 bus loading areas;*
15. *remote parking and shuttle bus program;*
16. *a warehouse 30 x 30 x 12 feet high, with fork lifts;*
17. *an office 30 x 30 feet;*
18. *a 20 x 30 foot personnel waiting lounge;*
19. *helipad if land is available, 80 x 80 foot;*
20. *potable water needs for crew base estimated to be 5,000 gallons per day;*
21. *onshore base area, if land is available, .5 to 4 acres;*
22. *dredging of channel and berth area will be needed;*
23. *breakwater may be needed, 2,500 feet in 30 feet of water.*

In reviewing oceanographic data, the study also found that the central coast area had very high wave energy levels. In 1983 the Union Oil Pier was subjected to 25 foot high waves and was totally destroyed. In Morro Bay during the 1983 winter storms, the entrance was closed for 30 consecutive days.

9.8 Impacts from Supply and Crew Bases

The following is a summary of potential impacts that may be caused by supply and crew bases. It should be noted that the impacts of a crew base would generally be significantly less than a supply base. Several factors should be considered regarding the intensity of use that would result in impacts:

1. *other existing harbor uses;*
2. *the daily number of personnel passing through a base;*
3. *the daily and monthly tonnage of supplies and materials being transported;*
4. *the number of daily trips by vehicles and vessels;*
5. *the types of vessels used to transport supplies and materials; and*
6. *the environmental constraints of an area.*

These and other factors need to be carefully considered when identifying and analyzing the impacts of a proposed base.

Road Access and Traffic: Vehicle traffic could be significantly increased. Road access would be a serious consideration in the siting of any base because the traffic increase will have impacts related to air quality, congestion, increased risk of accidents, and the possible construction of new roads and parking areas. These impacts could be partially mitigated by using remote parking areas (offsite parking locations) and shuttle buses to transport personnel. In the case of a crew base, light and medium sized trucks would probably be used to deliver supplies and materials. Trips per day to and from a crew base would depend on the intensity and phase of development being supported. A supply base would utilize larger trucks to transport bulky materials. The trip frequency and road use would increase, as would the need

for a much larger loading and unloading area. A supply base would necessitate a significantly more intensive industrial use than would a crew base. It would require large trucks, cranes and mobile equipment. Roads could be significantly impacted.

Land Resources: The amount of land used, adjacent uses, current land use designations, and the impacts of a supply and crew base will be major siting considerations. The siting of a supply base at Port San Luis would subject the Avila Bay area to an intense use that would increase the industrialization of the area. A supply base proposed in Morro Bay Harbor would have similar implications. A supply base, unless carefully sited, could result in the degradation of sensitive habitats, agricultural land, or archaeological sites. Expansion of existing facilities for supply base purposes would raise issues related to cumulative impacts, the intensity of industrial activities, and conflicts with currently allowed harbor uses.

Water: Direct water impacts associated with a supply/crew base originate with both the project and the population directly related to the support base. Water use would be associated with onshore and offshore needs for potable and non-potable water. The amount of water used would vary depending on the phase and intensity of OCS development. Table IX-A on page IX-4 provides estimates of water usage during the different phases of drilling. Water demands are greatest during periods of drilling, whether exploratory or development. In 1985, Port Hueneme supplied an averaged of 37 acre feet (12 to 13 million gallons) per month for offshore drilling activities. It was estimated that water use would increase to approximately 61 acre feet (20 million gallons) per month in the near future. Port San Luis is currently allocated approximately 100 acre feet (32 million gallons) of water per year for all uses. It should be noted that Port Hueneme supports many platforms in the Santa Barbara Channel and the Santa Maria Basin. Typically, bases use the municipal water supply. Other sources such as groundwater wells and desalinization plants can be used. Given the current water situation in San Luis Obispo County, proposed water needs and consumption should be carefully studied and considered in siting a facility.

Air Quality: The effects on local air quality would be significant. It is unclear what the cumulative air quality impacts would be if future OCS activities in the Santa Maria Basin were continued to be supported from the existing network of supply/crew bases or if new facilities were developed in the northern Santa Maria Basin. Emissions would be generated by supply and crew boats while idling at the pier, cruising to their destinations, vehicle traffic to and from the site, loading equipment, and other small internal combustion engines.

Marine Traffic: Any supply/crew base would increase the number of vessels using a port. This increase in traffic would raise the risk of vessel collision and conflict. Increased congestion within a port or harbor waters can be expected. The competition between commercial and recreational fishing, recreational boats and support vessels for facilities would increase. In regard to other harbor users, the Local Coastal Plan states:

Service bases shall be sited in such a manner as to minimize conflicts with other harbor uses through the use of segregated wharfage, dock and fueling area,

careful site design in the location of wharfage and vessel approval lanes, and segregated vehicular traffic and parking facilities and areas.

Congestion at fueling areas could create long periods of idling and the potential for vessel conflicts.

Vessel Moorage Space: A base may need room within the harbor to safely moor vessels. Mooring space at existing county ports and harbors is becoming increasingly limited. In 1991, the Port San Luis Harbor had a waiting list of over 300 applicants for a mooring space. Morro Bay has a waiting list of 18-20 applicants for slips or moorings. Both facilities currently have a greater demand for moorings and slips than are currently available. The Local Coastal Plan also states that a proposed service base for an existing port shall study the feasibility of improving the present level of facilities and moorage for commercial fishing and recreational boating. A support base would create increased competition among users for mooring space. Port San Luis currently has no dockside berths available. Port San Luis is not a sheltered harbor. During storms and or southerly swells the waves have been as high as 25 feet within the harbor.

Noise: As support vessels approach the shore and leave from the base, noise from their engines will be noticeable. This issue could be significant especially if a crew base is to be operated 24 hours a day. This issue should be evaluated when a base is proposed. A base may have pumps, small machinery and other equipment that create noise. Also, if helicopters are used to transport personnel, the noise impacts could be significant. Helicopter noise can be mitigated to certain degree by using helicopters with certain specifications. These noise impacts to the community would need to be considered.

9.9 Policies

Supply Base

1. A supply base proposal would require an amendment to and subsequent consistency with the county's existing Local Coastal Program and the Port San Luis Harbor Master Plan where applicable. A supply base is not consistent with the LCP as certified by the California Coastal Commission nor with the Port San Luis Master Plan and is not currently considered an allowable use. Projects shall be sited in such a manner that segregates the associated activities from other harbor users, thus reducing the potential for conflicts and accidents.
2. A proposal for an amendment to the LCP for a supply base shall clearly define the scope of the operation during the life of the project. The amount and type of supplies transported to and from should be identified, the number of personnel to be transported, the type and size of boats to be used, the number of daily trips, and other equipment that would be operated. Also identified should be the types of drilling operations that will be supported and the time frame.

3. Air quality issues related to the operation of supply base will be evaluated and regulated by the county's Air Pollution Control District and shall utilize the best available control technology (BACT) to the maximum extent feasible.
4. A comprehensive analysis of the needs related to mooring, land, pier, water, roads and access, parking, and other harbor facilities required by a proposed supply base shall be completed. Current users, such as commercial fishermen and recreational boaters, shall be included in the analysis.
5. Designated vessel traffic lanes should be mutually agreed upon by all users and jurisdictions of a harbor where a supply base would be sited. The Fishermen/Oil Liaison office in Santa Barbara County should be used for coordinating these concerns.

Crew Base

6. A crew base proposed in San Luis Obispo County shall comply with the Local Coastal Program, Land Use Element policies and regulations and the Port San Luis Harbor Master Plan where applicable. It shall also be sited in such a manner that segregates the associated activities from other harbor users, thus reducing the potential for conflicts and accidents.
7. A proposal for a crew base shall clearly define the scope of the operation. The amount and type of supplies transported shall be identified, the number of personnel to be transported, the type and size of boats to be used, the number of daily trips and other equipment that would be operated. Also identified shall be the types of drilling operations that will be supported and the time frame.
8. Air quality issues related to the operations of crew base will be evaluated and regulated by the county's Air Pollution Control District when and if a proposal is submitted and shall utilize the best available control technology (BACT).
9. A comprehensive analysis of needs related to mooring, land, pier, water, roads and access, parking and other harbor facilities or resources required by a proposed crew base shall be completed. Current users such as commercial fishermen and recreational boaters shall be included in the analysis.
10. Designated vessel traffic lanes should be mutually agreed upon by all users and jurisdictions of a harbor where a crew base would be sited.

Specific Policies

1. That the county's Local Coastal Program, the industrial and energy policies in the Framework for Planning and the San Luis Bay planning area standards, shall be

periodically reviewed for consistency and modified if appropriate. Specific consideration should be given to:

- clarifying definitions of a crew, service and supply base;
 - updating the list of potential crew or supply sites based on new information;
 - clarifying the LCP to state that supply/service and crew base's are clearly different facilities;
 - updating the LCP to clearly indicate that a change in operational use by a base, such as from temporary to permanent status, will require a separate review and analysis; and
 - coordination with Port San Luis Harbor District for consistency with the Harbor Master Plan.
2. That any proposed crew base or proposed LCP amendment for a supply base provide a list of the types and quantities of supplies, materials and equipment to be transferred to and from the base.
 3. Require crew boats to meet specific operational standards and have certain characteristics depending on the safety and environmental factors of the area they are proposed to operate in.
 4. Require that all crew boats be manned or monitored 24 hours a day during storm season (October 15 through April 15) to assure they do not break off their moorage and damage other boats.
 5. That the maximum number of crew boats docking per day per operator be limited depending on the carrying capacities of the area proposed for a site.
 6. That a vehicle trip reduction program will be required to and from the transfer site.
 7. Local hiring of personnel shall be encouraged by companies participation in a local hire program.

CHAPTER X: OIL SPILL RESPONSE

10.1 Introduction

Responding to a large oil spill is a complex undertaking that involves many federal, state and local government agencies and private companies. Private companies involved include the owner of the oil spilled, the company transporting the oil, private contractors who are hired to clean up the spill, and response organizations designed specifically for oil spill response. This chapter will outline the current response structure if a large oil spill occurred offshore San Luis Obispo County, discuss the resources that are available for responding to an oil spill, and the present role of the county. The chapter will begin with a discussion of the most recent laws affecting oil spill response: the federal Oil Pollution Act of 1990 (OPA 1990) and California's Oil Spill Prevention and Response Act (Senate Bill 2040).

10.2 Oil Spill Legislation

The Oil Pollution Act of 1990 (OPA) is broad federal legislation that covers a variety of issues related to oil spill prevention and response. This legislation was enacted largely in response to the Valdez tanker incident. The following is a list of some of the components:

- The National Oceanic and Atmospheric Administration (NOAA) is developing natural resource damage assessment regulations (more precise ways of evaluating the environmental damage caused by an oil spill);
Studies related to liability limits and safe navigation;
- Report on maritime oil pollution prevention training program;
- Regulations on vessel communications equipment;
- Revisions to the National Contingency Plan;
- Report on and addition of equipment to vessel traffic systems in Port of Valdez;
- The Coast Guard has developed a report that studies vessel traffic systems;
- The establishment of a National Pollution Fund Center;
- The development of regional contingency plans and regulations for contingency plans;

- Initiates a study of safe navigation procedures and develops regulations for tanker escorts;
- Develop regulations on oil spill clean up equipment;
- A report on double hulled tanker alternatives.

OPA 1990 is multi-faceted legislation that is being implemented by a variety of federal agencies and will affect state and local governments, as well as industry. The act gives the Coast Guard more authority to direct a response effort without federalizing the clean-up. An oil spill response can still be federalized when the response effort is deemed inadequate.

California has passed Senate Bill 2040, the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act which amends several state codes with relation to oil spills. The bill requires several tasks be completed:

- The Governor will appoint an administrator for oil spill response;
- Establish the state oil spill contingency plan pursuant to the California Emergency Services Act. It also requires an amendment to this plan by adding a marine oil spill contingency planning section, which provides the best achievable protection of the coast and marine waters by January 1, 1993;
- The bill creates the State Interagency Oil Spill Committee which consists of state agencies who will be involved in an oil spill response;
- The bill also describes the powers and duties of the administrator concerning prevention, removal, response, and containment of spills in state marine waters;
- The bill specifies marine safety requirements for tankers, barges, and marine terminals operating in marine waters;
- The bill requires the notification of the state Office of Emergency Services regarding all oil spills;
- The bill requires preparation and implementation of oil spill contingency plans for petroleum facilities such as marine terminals, refineries, and separating plants; and
- As of January 1, 1992, the bill requires every operator of a vessel used to transport oil in state marine waters or the operator of a marine facility (such as terminal) to obtain a certificate of financial responsibility.

The bill also creates three funds, each with a different purpose. The Oil Spill Prevention and Administration Fund implements oil spill prevention programs, completes related studies, reimburses member agencies of the State Interagency Oil Spill Committee, and provides a funding mechanism to implement and maintain emergency programs. This fund is supported by a 4 cent per barrel fee on crude oil transported across, under or through marine waters. The Oil Spill Response Fund is created for use only in the event of an oil spill. It is funded by a 25 cent per barrel fee paid by the operators of marine terminals, pipelines, and refineries. The Environmental Enhancement Fund will be created by the penalties charged to the spiller. The funds will be used for environmental enhancement projects. It cannot be used for oil spill clean-up or restoration of an area damaged by a spill. The bill creates the Office of Oil Spill Prevention and Response under the Department of Fish and Game. This office is responsible for preventing, preparing for, and responding to an oil spill.

The state administrator for oil spill response has a variety of other duties related to training of personnel, equipment deployment, and the use of volunteers to help cleanup a spill. The administrator can also delegate some of the tasks to a deputy administrator and an assistant deputy administrator. The administrator is responsible for developing an interstate compact with the states of Alaska, Washington and Oregon, regarding the tankers and barges that transport oil.

The bill also creates the State Interagency Oil Spill Committee which consists of representatives from over 15 state agencies. The administrator is the chairperson of the committee. This committee will work together to coordinate an efficient response.

10.3 Industry Response Organization

In general, the spiller is responsible for all emergency response operations and long term clean up activities. The spiller is to hire contractors to clean up the spill, direct the clean up, and provide adequate resources in response to the spill. The spiller may request federal assistance from the federal On-Scene Coordinator (OSC) in responding to a spill. The OSC will monitor the response to make sure it is proceeding in an expeditious manner. The spiller will be held liable for all costs related to the response and clean-up. If the response is deemed inadequate by the federal on-scene coordinator (OSC) or the spiller is unknown or refuses to take responsibility, the OSC can take command of the response effort. This action means the spill has been "federalized" and that federal money and resources can be used to insure an adequate response effort.

As discussed earlier, industry would be responsible for the first line of response. During the response a number of organizations may be involved in responding to the spill. Typically, oil companies have a unified command system which provides a structure for coordination and communication between the various parties involved in the response.

Offshore oil operations are regulated by several different government agencies with regard to oil spill response. The Coastal Commission require platforms to comply with specific

preparedness, training, and prevention standards. The Minerals Management Service (MMS) also have regulations regarding preparedness and prevention. They perform regular inspections of blowout prevention equipment and require oil spill drills at the platform.

Each company typically has its own oil spill contingency plan that is designed specifically for their needs. The plan needs to comply with various government regulations. The new federal and state legislation has stricter criteria for contingency plans, thus many company plans are in the process of being revised. A companies internal contingency plan will include:

- a brief description of the facility, its purpose, and the physical layout;
- the response organization which describes the roles and responsibilities of various employees;
- a notification/activation system which provides a structure for contacting key people within the company and government agencies;
- response and training techniques are discussed;
- health and safety procedures for workers and local community;

The plan should include a description of the area that could be affected by a spill. This would include information about animal species that are present during certain times of the year, haul out ares for pennipeds, shoreline type and other data about the environment. Also included should be a list of resources to be called in to assist with the clean up.

10.4 The Federal Response Organization

This section will describe the responsibilities each organization has in the event of an oil spill. The party responsible for a spill is legally required to notify both the state Office of Emergency Services and the National Response Center. Generally, a spill has two phases of response; the initial emergency response in the first few hours of the spill, and the longer term clean up that may take months to complete. It should also be noted that with the new federal and state legislation that has recently been approved and is still being interpreted, the responsibilities of various governmental agencies may be revised. The end result of the legislation should be an overall strengthening of the response structure, along with an increase in the amount of equipment and other resources that can be used to clean up a spill. Figure X-1 shows the general structure of the federal response organization.

National Response Team (NRT): The National Response Team (NRT) is an interagency group with representatives from 14 federal agencies. Each agency has expertise or jurisdiction involving oil spills and their affect on public health and welfare and the environment. The framework for the federal national response system is the National Oil and Hazardous Substances Pollution Contingency Plan, referred to as the National Contingency Plan (NCP).

The NRT's primary responsibilities include setting and maintaining national response policy, evaluating the effectiveness of the national response system, and making recommendations to improve the system. The NRT is not a direct responder in the event of an oil spill.

Regional Response Team (RRT): The Regional Response Team (RRT) is made up of federal and state representatives. Local municipalities and counties are invited to participate through the state representatives. The RRT is co-chaired by the Environmental Protection Agency (EPA) and the Coast Guard when there is not a response situation. When responding to a spill, the Coast Guard or EPA representative will become the chairperson depending on where that spill occurs. If a spill occurs, the jurisdictional line is described in the Region IX contingency plan (plan for western part of the United States), and generally follows Highway 1. The area west of Highway 1 is the jurisdiction of the Coast Guard and the area east of the Highway the EPA's.

The RRT is first alerted and then activated if necessary. An alert means that members of the team are informed about the incident and the likelihood of activation. The chairperson is responsible for alerting team members. The Regional Response Team is activated by the federal on-scene coordinator. The RRT's major responsibility is to provide technical assistance and coordinate available resources to the OSC for decision making.

One of the RRT's primary responsibilities when not responding to a spill is to ensure that regional and local contingency plans provide adequate information about a region's resources, and response capabilities. The organization chart on the following page depicts the Regional Response Team. The RRT conducts regular meetings, which are open to the public, a minimum of two times per year.

Federal On-Scene Coordinator: The Region IX Oil and Hazardous Substance Pollution Contingency Plan describes the land and water west of the Coast Highway 1 as the coastal zone. A representative of the U.S. Coast Guard acts as the federal on-scene coordinator (OSC) for incidents originating in the state's coastline and navigable waterways or tributaries within the state. The OSC determines the status of the state and local response and monitors the situation to determine if increased federal involvement is necessary. The OSC may take command of the response if:

1. the spill is beyond the capacity of the company, industry, local, or state responders to manage; or
2. the scope or complexity of the response is beyond local responders capabilities; or
3. local responders lack or experience and/or equipment to manage the spill; or
4. the spiller is unknown.

Figure X-1
Federal Response Structure

The Coast Guard Captain of the Port of San Francisco Bay is the pre-designated federal OSC for oil discharges in the coastal zone (west of Highway 1) from the California/Oregon border south to the Santa Maria River. While the National and Regional Response Teams are essential elements of the federal program, the OSC is the actual decision-making official in any "federalized" response. In the area east of Highway 1 the Regional Administrator for EPA would be the federal on-scene coordinator (OSC).

Federal Classification of a Release: An oil release which causes a sheen on the navigable waters of the United States must, by law, be reported. A minor discharge is a spill to the inland waters of less than 1,000 gallons of oil, or a discharge to the coastal waters of less than 10,000 gallons of oil. The Coast Guard responds to most of these cases in the coastal zone without active participation by local or state agencies. The Coast Guard oversees the clean up. Where local or state agencies actively respond and/or express concern, the response is coordinated via informal communications. If disagreements arise that cannot be adequately resolved by on-scene personnel, the Coast Guard will seek further direction up the chain of command.

A Medium discharge is a release of 1,000 to 10,000 gallons of oil to the inland waters, or a discharge of 10,000 to 100,000 gallons of oil to the coastal waters. A more formal organization is necessary to ensure proper response coordination. The OSC will direct field personnel regarding response procedures, delegate authority, and coordinate with other regulatory agencies.

A major discharge is a discharge of more than 10,000 gallons of oil to inland waters, or more than 100,000 gallons of oil to the coastal waters.

10.5 State Response Organization

Although not required by law, many states have developed oil spill contingency plans. California's plan is consistent with the National and Regional plans. California is in the process of revising its contingency plan according to the new state oil spill legislation (Senate Bill 2040). In the event of an oil spill potential threatens state waters, the federal OSC and the administrator from California's Office of Oil Spill Prevention and Response would work closely with the responsible party to provide an adequate and coordinated response.

Administrator: The position of administrator is appointed by the Governor and was created by Senate Bill 2040. The administrator or his/her designee is the Incident Commander (IC) for California and is responsible for the management and coordination of all activities related to the incident. The administrator is to coordinate various aspects of oil spill response, including:

- ensuring support services, personnel trained in oil spill response, containment, and clean-up technologies, and emergency systems safety are available for emergency response;

- the primary authority to direct prevention, removal, abatement, response, containment and cleanup efforts with regard to all aspects of any oil spill in the marine waters of the state;
- cooperating with any federal on-scene coordinator as specified in the National Contingency Plan;
- be on the scene of any oil spill in excess of 100,000 gallons as soon as possible after notice of the discharge;
- appraise the State Interagency Oil Spill Committee, the local APCD and local government entities of the status of the spill and cleanup efforts;
- work with the State Fire Marshall, State Lands Commission, and the federal on-scene coordinator to determine the cause and the amount of the discharge;
- authority over use of dispersants consistent with water code regulations and with consultation of the federal OSC; and
- ensure that biologists and other personnel are onsite to complete natural resources assessments and collect data that documents the damage.

The state's incident commander (IC) is the counterpart of the federal on-scene coordinator. Conflicts between the federal and state contingency plans are being resolved. Oil spill drills are providing the federal and state agencies an opportunity to cooperate. Lines of communication and authority between the federal and state agencies are being defined. It should be noted that the use of dispersants is a multi-agency decision, made by the federal and state incident commanders with input from various agencies and local government. Specific federal regulations and state guidelines limit the use of dispersants to only prescribed meteorological and geographic circumstances.

State Interagency Oil Spill Committee: This committee is made up of a variety of state and local agencies which supports and advises the incident commander during an oil spill. The committee is much like the Federal Regional Response Team in that it provides technical support to the states incident commander.

State Classification of a Release: State officials define an oil spill as any unauthorized release of at least 42 gallons of oil into marine waters. A minor incident is categorized by the less than 10,000 gallons and can usually be handled by local resources. Significant human health and safety and/or environmental issues do not typically arise in a spill of this size. However, it should be noted that a spill of 10,000 gallons in a biologically sensitive area can be very damaging if the response effort is not well coordinated and vigorous.

A moderate incident involves a coastal release of 10,000 to 100,000 gallons and may require the use of mutual aid agreements or operational assistance or logistic support. This type of response usually requires that outside resources be contacted. Human health and safety and/or the environment are significantly affected.

A major incident involves coastal release of greater than 100,000 gallons and is beyond the capabilities of a local jurisdiction. Human health and safety and/or environment are severely affected. A declaration of local or Gubernatorial emergency may be issued and the Emergency Operations Center may be partially or fully activated.

A catastrophic incident significantly exceeds local capabilities. Considerable and substantial environment and/or public health impacts have occurred or are expected. A local emergency is usually declared, and a Governor's proclamation is issued along with a request for a Presidential Declaration.

10.6 Local Agency Role

The urgent nature of offshore oil spills necessitates a rapid and coordinated response. Most spills are responded to by local agencies (fire district, Health department, etc.) who assign an Incident Commander (IC) to ensure proper response. The federal OSC will be involved if the response is beyond local capabilities. The burden is on local responders to recognize when they require assistance. The Coast Guard may contact local agencies to determine if there is a need for federal assistance. If so, the Coast Guard will provide technical assistance to the incident commander, often times working directly with the county or city agencies. Although the Coast Guard takes on greater coordination role during spill incidents on waterfront facilities, a local agency should supply an IC. The Coast Guard will be the lead agency on shipboard hazardous material incidents when the vessel is away from the dock.

The Coast Guard does not have the authority to order an evacuation of local residents, but may make recommendations to the local IC after careful consideration. Initial response will be taken by the responsible company. That company will contact the cooperatives as needed. Local response to spiller companies and to the Coast Guard will generally be that of traditional police and fire field capabilities. Local agencies will be requested to support traffic control, communications, and equipment. The Coast Guard, the lead state agency, and local agencies are expected to maintain communication and closely work together in response to oil spills.

More detailed analysis of local issues related to emergency response will be described in the Oil and Gas Emergency Response Study being prepared by the Scientific Ecology Group under the direction of the San Luis Obispo County Office of Emergency Services.

Local government agencies that have a contingency plan would have a predesignated role in the response effort. Currently, San Luis Obispo County does not have a contingency plan dedicated strictly to marine and coastal oil spill. The county Office of Emergency Services is working with the state Office of Oil Spill Prevention and Response to develop a contingency plan. If a

spill were to occur, the county's role would be limited to supporting state and federal agencies. The county would appoint an incident commander (IC) to represent local concerns and help coordinate the response effort. Other local agencies that may be involved in the response include the Sheriff's Department, local fire agencies, County Health Department, County Engineering, Office of Emergency Services, and city officials. The Pacific Care Wildlife Group has set up an emergency oiled sea birds program that would be activated in the event a spill affects seabirds.

10.7 Available Response Resources

The response/cleanup process is a multi-level system. The concept is based upon on-site equipment suitable for first response and handling the majority of smaller spills. This is supported by large, more capable equipment stockpiled by industry-owned oil spill cooperatives and corporations as a second level of response.

The initial level of response is the onsite equipment or immediate response equipment. This equipment is usually owned or leased by the individual company operating the facility, whether it be an offshore platform, exploratory drilling vessel, or a marine terminal. In San Luis Obispo County several facilities have some on site equipment. Booms, skimmers, portable tanks, and sorbent pads are available at facilities in Estero Bay and Avila Beach. This response would be the activation of the companies internal contingency plans.

The secondary level of response may be the local oil spill cooperative. Each co-op has detailed contingency plans and a large inventory of equipment and trained personnel on standby. These are private companies funded by the companies involved in transporting, producing, and refining of petroleum.

The next level of response is the federal government and outside industry resources available on a 24 to 48 hour time frame. Examples are the National Strike Force, Navy owned equipment available from Stockton, California, and industry owned equipment available outside the local co-op. The co-ops have agreed to provide mutual aid to one another.

The following is a description of the various organizations and that are available to respond in the event of a large oil spill.

Clean Seas: The primary co-op for member company oil spills occurring along the coast line of San Luis Obispo County is Clean Seas. The Clean Seas organization is structured to respond to different levels of oil spills and to different levels of assistance requested by a member company. Clean Seas has two mobilization levels:

- Primary Response - Involves key staff members
- Secondary Response - Involves the mobilization of supervisors and operating personnel as needed to address the spill situation.

Upon notification of a spill and request for assistance by a member company, nonmember company, or a government agency, the Clean Seas manager will determine the level of activation necessary based on the type of assistance requested by the spiller. The primary response staff and their alternates are member company personnel who can be made available in the event of a mobilization request.

Upon determining the degree of response necessary to meet the spiller company's request for assistance and ascertaining which staff positions the spiller company will fill with its own personnel, the Clean Seas manager will instruct the mobilization coordinator to activate the response plan. Clean Seas conducts regular training and has an oil spill clean up vessel stationed at Avila Beach and also stores equipment near the marine terminal in Estero Bay.

Fishermen's Offshore Response Team (FORT): This is an organization made up of local fishermen who are being trained to use booms and other clean up equipment. They would be activated in the event of a large oil spill. The organization is sponsored by the oil industry. The training is conducted by Clean Seas.

Marine Spill Response Corporation (MSRC): This is a non-profit organization funded by industry. The purpose of the organization is to respond to large oil spills that are beyond local response capabilities. MSRC would be directed by the responsible party. The corporation is developing a comprehensive data base of equipment and personnel resources for oil spill response. They are doing research and development to improve oil spill information and clean up technology. They are setting up five regional response centers, each supported by equipment storage sites. Port Hueneme will be the site of the response center and equipment storage. Two new oil recovery vessels on the west coast will be added, one in Port Hueneme and one in San Francisco.

By February, 1993, the Oil Pollution Act of 1990 requires vessel owners and operators and other responsible for transportation or storage to show they have in place contracts to contain and clean up, to the maximum extent practical, a worst-case scenario oil spill. By becoming a member of MSRC an oil company stands a better chance of meeting this requirement. So far most of the major companies have joined the organization.

National Strike Force: Occasionally a situation may occur where there are no contractors available. In such cases the Coast Guard has a National Strike Force. This strike force consists of three regional teams located in New Jersey, Alabama, and Marin County, California at the former Hamilton Air Force Base. The strike force will provide technical advice on cleanup or containment procedures and will bring equipment to be used in the actual cleanup operation. A national inventory of pollution response and support equipment has been developed to assist the on-scene coordinator and the Regional Response Teams. The Coast Guard is presently stationing additional oil spill equipment in Long Beach port and in the Clean Seas yard in Carpinteria. The strike force has equipment in San Francisco. The federal OSC has the authority to request that the equipment be used.

Pacific Strike Team: The strike team is located at Hamilton Air Force Base in Marin County. The team was created as part of the Special Forces from the Federal Water Pollution Control Act of 1972, which was later amended to the Clean Water Act. It is a cadre of Coast Guard personnel trained in oil and chemical spill cleanup. It has twenty-eight personnel, four officers, twenty four enlisted. They provide support for the OSC. The OSC has the authority to call upon the strike team for assistance.

10.8 Policies

1. That San Luis Obispo County representatives participate in oil spill drills and activities implemented by the California Office of Oil Spill Prevention and Response.
2. That a county task force of local agencies and industry that may be involved in an oil spill response effort be formed to build an efficient and coordinated response organization that can support the state and the federal response structure. The task force shall consult with native american representatives regarding potential impacts to cultural resources during the formation and through implementation of the oil spill response effort.
3. That the county Office of Emergency Services work with the state Office of Oil Spill Prevention and Response to develop an oil spill contingency plan for the marine and coastal environments of the county.
4. That the county identify and obtain funding sources for contingency planning and related activities.
5. That training programs for county agencies related to oil spill prevention and response be developed.
6. That the county compile all industry contingency plans in a central and accessible location.
7. The resources, equipment, and personnel, who will respond to an oil spill are clearly known to all entities involved in an oil spill response. That identification badges be provided to those individuals who will be involved in spill response.
8. As part of land use permit applications related to new oil and gas facilities, the county should consider whether contingency funds are available that would be used to purchase response equipment, set up training programs, and provide funds for immediate response by pre-designated entities.
9. The county will coordinate with the state Office of Oil Spill Prevention and Response to insure that all facilities have adequate financial resources for reimbursing the county for any damages or costs incurred as a result of an oil spill.

10. That county develop a program which provides citizens with the appropriate training and certification to be qualified volunteers in a clean up effort.

Public comment 2/12/26 Wolves and keystone predators

From Shari Dalal [REDACTED]

Date Thu 02/12/2026 10:45 AM

To FGC <FGC@fgc.ca.gov>

Dear commission,

Coexistence with predators like wolves, bears, and mountain lions is essential to healthy ecosystems and biodiversity. These animals are not threats to be eliminated; they are keystone species that regulate prey populations, prevent overgrazing, support plant regeneration, and maintain ecological balance. When predators are removed, ecosystems unravel—leading to degraded habitat, increased human–wildlife conflict, and long-term harm to biodiversity.

California should be a leader in science-based, compassionate wildlife management. Yet recently, California Fish and Wildlife killed five wolves in Northern California. Lethal control undermines decades of conservation progress and ignores proven nonlethal solutions that protect both wildlife and rural communities. Coexistence tools—such as range riders, fladry, guard animals, improved husbandry, and community-based conflict prevention—work when they are properly supported and funded.

Mountain lions, wolves, and bears belong on this landscape. Habitat loss, road mortality, and human expansion already place immense pressure on these species. Killing predators only deepens ecological instability and erodes public trust. We must move away from fear-based management and toward coexistence rooted in science, ethics, and respect for wildlife.

I urge decision-makers to prioritize nonlethal management, protect predator populations, and commit to policies that recognize predators as vital to ecosystem health—not expendable obstacles. True conservation means learning to coexist.

Thank you.



Stop the Deer Slaughter

From Samantha Cano <scano3@dons.usfca.edu>

Date Thu 02/12/2026 03:03 PM

Hello,

I am writing to respectfully and strongly request that you use your position to stop the planned slaughter of the deer on Catalina Island.

I, along with my friends and family, vehemently oppose the planned killing of Catalina's deer because:

- Catalina's deer are part of the island's cultural and scenic heritage. They have lived on the island for nearly a century — part of the fabric of this special place, cherished by residents and millions of visitors.
- The Conservancy has once again failed to hold a genuine public process. Simply informing residents of a predetermined plan is not engagement.
- The proposed methods are cruel and unnecessary, inflicting immense suffering on these cherished animals.
- Alternatives exist. Hunting, sterilization, and relocation deserve real investment and public input.
- Science doesn't justify this slaughter. Independent ecologists reviewing the Conservancy's own data found no credible evidence that deer eradication is the only path to ecological recovery.
- Catalina Island's deer belong to all Californians. We will not stand by while this precious wildlife resource is destroyed behind closed doors.

As a resident of CA, this is an important issue that I feel passionately about. Furthermore, as a future lawyer interested in the area of animal law, I strongly oppose this cruel and inhumane treatment of Catalina's deer.

As a representative of the people of California, you have a duty to consider the requests of individuals you represent.

As a representative of the animals of California, you are acting in an irresponsible and outrageously cruel manner if you support the slaughter of Catalina's deer. Your duty, instead, is to protect the animals and wildlife of this beautiful state.

Do the right thing and cancel the slaughter of Catalina's deer.

Sincerely,

Samantha Cano

--

Samantha Cano (she/her)
President, USF Student Chapter Animal Legal Defense Fund
J.D. Candidate 2026
University of San Francisco, School of Law

To Whom it may concern;

I like mountain lions. Except for the ones killed by cars - I've seen them in person, Summer. Anyway, maybe if we could protect them they might start attacking ICE agents instead of hikers and such. So I'm for the proposal to list the Central Coast and Southern California mountain lion populations and their habitat as Threatened under California law.

Thank

Jim Jowet



Outlook

Question Feb 12 threatened list

From Philip Salgado [REDACTED]

Date Fri 03/13/2026 03:32 PM

To FGC <FGC@fgc.ca.gov>

Can we send our vet bills to the mountain lion foundation since their huge debt is now payed for by the grants triggered by the threatened listing? Thank you.

Tuolumne River Voluntary Agreement

From Peter Drekmeier <peter.drekmeier@yosemiterivers.org>

Date Fri 02/13/2026 12:30 PM

To FGC <FGC@fgc.ca.gov>

Dear Chair Sklar and Commissioners:

I appreciated the opportunity to comment (although briefly) on the Healthy Rivers and Landscapes program (Voluntary Agreements) at yesterday's Commission meeting. Yosemite Rivers Alliance supports the Bay Delta Water Quality Control Plan and is very opposed to the HRL. I do not know of any Tribe or conservation, fishing or EJ group that supports the Voluntary Agreements.

Attached, please find a very short backgrounder on the Scientific Basis Report for Tuolumne River Voluntary Agreement.

Thank you.

-Peter

Please note my new email address.

Peter Drekmeier
Policy Director
Yosemite Rivers Alliance
(Formerly Tuolumne River Trust)
peter.drekmeier@yosemiterivers.org



Tuolumne River Voluntary Agreement Scientific Basis Report

(Backgrounder prepared by Yosemite Rivers Alliance)

Background

In 2018, the State Water Board adopted Phase 1 of the Bay Delta Water Quality Control Plan, addressing the lower San Joaquin River and its three major tributaries (Stanislaus, Tuolumne and Merced). The Plan requires 30-50% of unimpaired flow (starting at 40%) to remain in the rivers between February and June. Despite being adopted, the Plan has yet to be implemented. Even worse, the Tuolumne River diverters have introduced a Tuolumne River Voluntary Agreement (TVA) to be considered as an alternative to the Bay Delta Plan. The TVA would produce much less flow than the adopted 30% minimum, so the Water Board would have to amend Phase 1 in order to consider it.

What Are the Issues?

The TVA Scientific Basis Report (SBR) is clear – the Tuolumne River desperately needs higher flows.

“Fish habitat quantity and quality on the Tuolumne River is primarily controlled by flows.” – SBR, p. 2-15.

The TVA would contribute very little new water to the Tuolumne.

“The TVA is expected to result in new flow contributions (change relative to Existing Conditions) downstream of La Grange Dam from January through June that range from 2 to 12 thousand-acre feet (TAF) per year on average...” – SBR, p. ES-6.

(Note: For comparison, the average annual yield of the Tuolumne River is 1,850 TAF.)

Proposed drought off-ramps (reductions in flow requirements in sequential dry years) would further limit flows.

“From 1970 to 2024, 17 out of the 55 years would have included sequential dry year off-ramps which is a frequency of 1 out of every 3 years.” – SBR, p. 5-65.

“...the TVA temperatures would exceed the Existing Conditions scenario from mid-April through mid-May when the off-ramps are being implemented.” – SBR, p. 5-69.

The TVA focuses on non-priority measures that require little new water, such as adding spawning gravel.

“These findings suggest that spawning habitat and instream rearing habitat are not as limiting to recruitment as temperature, flow, and floodplain habitat during the rearing period in the Tuolumne River (Table 2-6).” – SBR, p. 2-29.

Water temperature is a limiting factor, and it is flow-dependent.

“Providing suitable water temperatures is critical to the health of the lower Tuolumne River aquatic ecosystem. Water temperature influences every freshwater life stage of anadromous salmonids...” – SBR, p. 2-26.

Floodplain rearing habitat for juvenile fish is a limiting factor and should be prioritized over spawning habitat.

“Existing habitat availability on the lower Tuolumne River is far less than what is estimated to be required to recover listed salmonid species populations. For example, it is estimated that rearing habitat

in the Tuolumne River can only support the offspring from no more than 434 fall-run Chinook salmon adults during managed flow releases (Mesick 2009).” – SBR, p. 2-3.

Higher flows can reduce or eliminate predation of juvenile fish by non-native bass.

“In general, reduced spring flows, elevated water temperatures, and the presence of low-velocity habitats...favor fish communities dominated by non-native, warmwater species, such as largemouth bass and other potential predators on native salmonids (EA 1992; McBain & Trush 2000; Brown and Ford 2002).” – SBR, p. 2-5.

“Another predation study performed on the Tuolumne River at high flows found no salmonid predation occurred (Stillwater Sciences and McBain & Trush 2006).” – SBR, p. 2-5.

The TVA would contribute very little to restoration of the San Joaquin River and Bay-Delta, despite the fact that it is proposed as an alternative to the **Bay Delta** Water Quality Control Plan.

“These volumes, when provided, will not be subject to flow protection below La Grange Diversion Dam. It’s expected that these flows will be released when the State Water Project and the Central Valley Project (Projects) would be able to increase exports, which means these flows would not result in Delta outflow.” – SBR, p. 3-3.

“The TVA is expected to result in new contributions to Delta outflow that range from 7 to 17 TAF per year on average depending on the amount of TVA flow at Vernalis that is not diverted in the Delta.” – SBR, p. ES-6.

Simply put, the TVA would **not** meet the Water Board’s revised water quality objectives and would **not** provide reasonable protections for fish and wildlife. It would **not** enable the State to meet its co-equal goals of ensuring reliable water supplies AND restoring the Bay-Delta ecosystem.

For more information, contact Peter Drekmeier, Policy Director, Yosemite Rivers Alliance – peter.drekmeier@yosemiterivers.org.

Re: OC Title 14 and Experiences

From M P [REDACTED]
Date Sat 02/14/2026 11:02 AM
To FGC <FGC@fgc.ca.gov>

Fish and Game Commission,

Regulating the current habituated coyote situation is already a difficult task given the limited county assistance.

It should be easier to address coyotes habituated to residential areas, not harder.

Since the coyote information is outdated and we are currently using wild coyote information in an urban environment—both under different conditions—it does not make sense to loosen coyote regulation.

I oppose changing coyote regulations in a way that makes it harder for communities to already address habituated coyotes in residential areas.

Public safety must remain a priority.

Respectfully,
-Mark

On Fri, Jan 2, 2026 at 12:37 PM M P [REDACTED] wrote:

I support petition 2025-16.

Below are my experiences and public concerns within the last year in my residence, walking distance from downtown Disney.

Within **the last year alone**, my neighborhood has experienced repeated, escalating coyote incidents that demonstrate **severe habituation and loss of fear of humans**:

- **Spring 2025:** A neighbor's dog was **attacked in broad daylight** while being walked. The coyote showed **no fear of the owner**. Owner came directly to me later that day to warn me.
- **Spring 2025:** A coyote **chased a neighbor's cat into a tree at midnight**, actively hunting within our residential area.
- **Summer 2025:** A coyote was found **resting in broad daylight on a neighbor's footpath**, behaving as if the area were its home.

- **Fall 2025:** A coyote **stalked a parent walking with their child**, exhibiting clear predatory behavior. My immediate neighbor personally informed me.

Coyotes have **no natural predators in urban environments**. They are no longer passing through — **they have moved in**. They walk alongside pedestrians, remain active during the day as well as night, and show **no fear of people**.

The commonly promoted **long-term deterrence strategies** may have value in **rural or wildland settings**, where coyotes still associate humans with risk.

That is not the reality in urban neighborhoods. While updating Title 14 Section 472 is necessary, **this situation is already urgent**. I do support updating the **urban language in Title 14 Section 472**, But that update **must be recognized as only the first step**.

Regards,
Mark Prok



Public Comment: Petition 2025-16 (Urban Coyote Take)

From Lisa Halstead [REDACTED]
Date Wed 03/11/2026 10:22 AM
To FGC <FGC@fgc.ca.gov>

My name is Lisa Halstead and I am a resident of Southern California living in Ventura County near the base of the Santa Monica Mountains. I am writing to share my perspective regarding the presence of coyotes in our region and the importance of protecting these animals.

The Santa Monica Mountains are a remarkable and biologically rich environment that support a wide range of wildlife species. Among them are coyotes—animals that unfortunately carry a negative reputation in many communities. In my experience living and walking regularly in this area, I have observed that coyotes are generally cautious and avoidant of human interaction. They are intelligent, adaptive, and essential members of the natural ecosystem.

It is important to recognize that much of what is perceived as wildlife “encroaching” on human areas is actually the result of increasing human development within previously natural habitats.

Over time, construction, roadways, and recreational activities have gradually reduced and fragmented the land that these animals have historically occupied. In many ways, it is not that coyotes are invading human spaces—it is that human expansion has increasingly moved into theirs.

Because of this, I believe that wildlife management should focus on coexistence and thoughtful stewardship rather than lethal control.

One potential solution worth exploring could involve coordinated wildlife management strategies through Fish and Wildlife agencies. For example, designated habitat zones that ensure reliable access to natural food sources and year-round fresh water within mountain areas could help encourage wildlife to remain within their natural ranges.

I also feel strongly that coyotes should not be treated as animals that can simply be killed indiscriminately. They are highly intelligent creatures that play an important ecological role in controlling rodent populations and maintaining balance within the environment. From my firsthand observations, coyotes are typically skittish around humans and seek small natural prey such as rabbits and rodents. They are not aggressive animals looking to create conflict with people or livestock.

Living at the base of the mountains, I see these animals pass through the natural corridors from time to time. Each time I see them, I am reminded of how beautiful and remarkable they are.

They are cautious, perceptive, and part of the wild heritage of Southern California.

For these reasons, I respectfully encourage policymakers to consider wildlife protection and coexistence strategies that reflect compassion, ecological understanding, and responsible stewardship of our shared environment.

Coyotes are not simply nuisances—they are a vital part of the landscape we are fortunate to live alongside. They deserve thoughtful management, protection, and respect.

I love my coyotes....please protect them.

Thank you for considering my comments.

Sincerely,

Lisa Halstead
Ventura County Resident
Santa Monica Mountains Region

(No subject)

From annie griffin [REDACTED]
Date Thu 02/26/2026 08:50 AM
To FGC <FGC@fgc.ca.gov>

Hi Melissa my name is Lorna Moffett and I am appealing to your compassion and your scientific curiosity and righteous indignation of convoluted science to undo the lies that have occurred regarding mute swans. your commission is now mandated under a state law for the shooting of these sacred beautiful birds . there are species of migratory Birds that have to be considered Planet citizens their native to the planet and they travel everywhere so they're not just native to one place and as the changing climate unfolds we have to tolerate other species that now seek our climate as opposed to The Climate that they once had. The lies that are perpetuated by the hunters so they can take more than their fair share of quota that the swans are attacking mallards and other wildlife and is completely untrue. have a friend of mine who watches over the city Swans in Orlando Florida he's been doing it for years in a large pond like setting and never once has he seen any of the swans attacking other birds please make sure that this practice is stopped and please call me and let me know how best we can go about ending this vial horrible hunting practice thank you so much. Sincerely, Lorna Moffett

Stop the inhumane eradication of Catalina Island's mule deer

From Christina Lindeman [REDACTED]
Date Fri 02/27/2026 03:09 AM
To FGC <FGC@fgc.ca.gov>

To whom it may concern:

I'm writing to urge you to stop the plan to eradicate Catalina Island's mule deer through lethal methods. These deer were introduced by humans long ago and should not be made to suffer for our mistake.

Please pause lethal operations and require humane, publicly accountable alternatives — including expanded fertility control/sterilization and other nonlethal management — with full transparency and independent review.

California can protect ecosystems without resorting to cruelty.

Sincerely,

Christina Lindeman

Northridge, CA

Sent from my iPad

RE: PROC Cleanup Efforts

From: Whitt Strain [REDACTED]
To: jessica.girardot [REDACTED]; Randy Lovell

Sent: Monday, March 2, 2026 at 03:09:01 PM PST

Subject: PROC Cleanup Efforts

Hey folks,

Thanks for reaching out last week Jessica. I'd like to detail the scope of our company's cleanup efforts over the past decade here, though in truth, our history of cleaning up Tomales Bay began in the mid 1980's when my father acquired his first lease. I will be preparing some comments around this topic for the upcoming MRC meeting as well.

Our quarterly cleanups first began in earnest in August of 2016 after a grower's meeting in which we divvied up the shoreline of Tomales Bay equally between the growers and agreed to conduct quarterly shoreline patrols. These quarterly events were augmented by post-storm patrols which are an essential part of any aquaculture operation. The best time to see if your systems are working properly is during a post-storm patrol - giving you time to retrieve lost gear if necessary and assess the soundness of your farm structure.

In addition to these regular cleanups, for the past several years we have teamed up with the staff of Nick's Cove Restaurant (located adjacent to the Miller Boat Launch) to host an annual shoreline cleanup that is open to members of the public. This event takes place in the fall (on a good low tide) and is generally scheduled around California Coastal Cleanup Day. We start out in the morning from Miller Boat Launch and walk north along the shoreline to the mouth of Walker Creek. Afterwards, we all meet back at Nick's Cove for a tasty lunch and a few oysters.

Over the course of the past decade doing these cleanups, a few themes have emerged. Generally speaking, the vast majority of trash that we collect is of residential or recreational origin. There are hundreds of homes along the shores of Tomales Bay, as well as a major thoroughfare in Highway 1. Anyone who has walked along a highway before knows well the amount of trash that is inevitably generated by the vehicles traveling on it. Highway 1 runs the length of Tomales Bay on the eastern shore. As many of the members our cleanup crews have noted over the years, you can collect a lot more trash by walking along the side of Hwy 1 than you can on the shoreline of Tomales Bay.

Additionally, the Miller Boat Launch at Nick's Cove is a significant generator of marine debris. This is likely the single most highly trafficked spot on Tomales Bay and it is certainly the only public access point on the eastern shore of the bay. With so many people coming and going, it is only natural that trash is generated at this location.

Point Reyes Oyster Company has been farming on Tomales Bay for 41 years now and part of our core mission is to leave the bay cleaner than it was when we arrived. We are happy to dispose of the waste generated by others and will continue to do so without complaint in the years to come. We feel fortunate to make our living on the waters of Tomales Bay and we only ask that members of the community continue to assist us in our efforts to keep the bay clean and free of debris. Thank you for your concern in this matter.

Sincerely,

Whittaker Strain

Vice-President
Bodega Bay Oyster Co

Point Reyes Oyster Co

PO Box 16

Tomales, CA 94971 (mailing)



<http://www.bodegabayoyster.com>

Ocean MPA Letter

From Chavez, Katie <Katie.Chavez@asm.ca.gov>

Date Tue 03/03/2026 03:00 PM

To grant.mack@gov.ca.gov <grant.mack@gov.ca.gov>

Cc meghan.hertel@resources.ca.gov <meghan.hertel@resources.ca.gov>; Eckerle, Jenn@CNRA <Jenn.Eckerle@resources.ca.gov>; Crowfoot, Wade@CNRA <Wade.Crowfoot@resources.ca.gov>; FGC <FGC@fgc.ca.gov>; fgcericsklar [REDACTED]

Hello,

Thank you again for your consideration of California's marine protected area (MPA) letter. Considering some recent suggested changes by the supporting agency (NRDC) after a discussion with Catherine Baxter from the Governor's Office, I have reattached the newly formatted letter. Thank you again for your attention to this matter.

Best,
Katie Chavez
Legislative Aide
Office of Assemblymember Chris Rogers
1021 O Street, Room 5130
Sacramento, CA 95814
Katie.chavez@asm.ca.gov
(916)319-2002

STATE CAPITOL
P.O. BOX 942849
SACRAMENTO, CA 94249-0002
(916) 319-2002
FAX: (916) 319-2102

DISTRICT OFFICE
50 D STREET, SUITE 450
SANTA ROSA, CA 95404
(707) 576-2526
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E-MAIL
Assemblymember.Rogers@assembly.ca.gov



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UTILITIES AND ENERGY
WATER, PARKS, AND WILDLIFE

BUDGET SUBCOMMITTEE NO. 4 ON
CLIMATE CRISIS, RESOURCES,
ENERGY, AND TRANSPORTATION

March 3, 2026

Governor Gavin Newsom

1021 O Street, Suite 9000

Sacramento, CA 95814

Re: DMR Adaptive Management Process and Strengthening California's MPA Network

Dear Governor Newsom:

We write to urge you to strengthen and expand California's world- renowned marine protected area (MPA) network through the adaptive management process to ensure the long-term health of our ocean ecosystems. In 2020, you were the first U.S. Governor to commit to the global 30x30 initiative through EO N-82-20, which calls for California to conserve 30 percent of its ocean and lands by 2030. To reach the goal for the ocean, California will need to conserve an additional eight percent of its state waters in the next four years. We request that you provide clear direction to California Department of Fish and Wildlife (CDFW), the California Ocean Protection Council (OPC), and the California Fish and Game Commission (FGC) that the state's first-ever MPA adaptive management process should result new conservation areas what will constitute meaningful progress towards the 30x30 goal.

CDFW, in partnership with OPC and FGC, is currently evaluating proposals that would strengthen and expand California's MPA network – conserving healthy kelp forests, key habitat for endangered species, and providing safe havens for juvenile and big old fat fertile female fish (BOFFF) upon which California's commercial and recreational fisheries depend. Approving these conservation proposals through the state's first-ever MPA adaptive management process is the best opportunity to add protections that will effectively conserve the state's unparalleled marine biodiversity. They would expand Tribal co-stewardship, and improve outdoor access to a thriving ocean.

There are also proposals before CDFW that would weaken the MPA network. State Marine

Reserves (SMRs) form the backbone of the state’s world-class MPA network, and proposals to allow new extractive activities in the reserves, or more fishing in State Marine Conservation Areas, should be denied.

The California Legislature has long recognized the importance of protecting our marine environment. Through the passage of the Marine Life Protection Act (MLPA), we initiated California’s science-based, statewide network of MPAs, with the intent that it be adaptively managed over time to meet the goals of the MLPA. We further solidified California’s network, it also must also consider and address future challenges. California’s MPA network must be modernized to remain effective – designed not just to protect what we have now, but foster resilience to better withstand threats in an uncertain future.

Thank you for your dedication to protecting California’s ocean resources. We look forward to working together to uphold California’s environmental legacy, to ensure a clean, safe, and healthy future for all.

Sincerely,



Assemblymember, 2nd District

Cc: President Erik Sklar, Secretary Jenn Eckerle, Secretary Wade Crowfoot, Director Meghan Hertel



Jessica M. Caloza



Steve Bennett



Jesse Arreguin



Robert Garcia



Pilar Schiavo



Rick C. Zbur



Gregg Hart



Jacqui Irwin

Dawn Addis



Chris Ward

Ban plastic shotgun wads

From Tony Cohen [REDACTED]
Date Tue 03/10/2026 10:05 AM
To FGC <FGC@fgc.ca.gov>

Dear Commission -

I am a retired lawyer who regularly picks up trash from the Sonoma Coast beaches, in particular Bodega Head Beach, and I frequently find plastic shotgun wads washed up on shore. I've attached a picture of one of them.

I am doing that work as a volunteer for California State Parks and my main focus is preventing plastics from getting into the ocean, where they become microplastics that damage all living things in the ocean.

I urge the Commission to take all necessary steps to ban plastic shotgun wads and would be happy to support that effort in any way that is useful to the Commission.

I understand you have a meeting scheduled to discuss that subject in April and would appreciate being on your list to receive notices and information about that meeting.

Please feel free to reach out to me to discuss the subject if that could be of help.

Thank you.

Tony Cohen
[REDACTED]

Sent from my T-Mobile 5G Device
Get [Outlook for Android](#)



Consideration of Humane Management for Mute Swans

From andrew marshall [REDACTED]

Date Wed 03/11/2026 07:59 AM

To FGC <FGC@fgc.ca.gov>

Cc info@friendsofafaether.org <info@friendsofafaether.org>; Lisa Levinson <lisa@idausa.org>

Dear Melissa Miller-Henson,

I am writing to respectfully share my perspective regarding the current management approach toward mute swans in California and the policy that has resulted in their killing due to their designation as an invasive species.

While I understand that wildlife agencies must carefully consider ecological balance and the protection of native species, I hope to offer some firsthand observations that may contribute to a more nuanced discussion about these birds and their actual interactions with native waterfowl.

My wife and I care for two mute swans that live on a lake alongside a variety of native species, including mallards, moorhens, and other ducks. Over many seasons observing their behavior closely, we have never once witnessed our swans disturbing or displacing nesting native birds. In fact, these species routinely nest and raise young in close proximity to the swans without conflict.

Additionally, through my work with Friends of a Feather, a nonprofit organization dedicated to the welfare and stewardship of waterfowl, I have had the opportunity to observe numerous mute swan nesting sites throughout lakes in the downtown Central Florida area. In these environments, mute swans coexist alongside many native waterfowl species. In our repeated observations, we have not seen mute swans push other waterfowl species out of nesting territories or disrupt their breeding behavior.

Mute swans are territorial during nesting, as are many waterfowl species, but the blanket assumption that they broadly displace native birds does not reflect what we have consistently observed in real-world environments where multiple species share the same habitat. Because of this, I respectfully ask that wildlife agencies consider more balanced and humane management approaches, such as monitoring populations, habitat management, or relocation when necessary, rather than lethal removal as a primary strategy.

Mute swans are intelligent, long-lived birds that have become valued members of many local ecosystems and communities. Policies affecting them deserve careful consideration that includes both ecological science and direct field observation.

In addition to personal observation, I believe there are several broader considerations worth acknowledging when evaluating mute swans as a management concern.

- 1) Many wildlife management discussions focus on the territorial nature of mute swans during breeding season. However, territorial behavior is common across numerous waterfowl species, including native species that defend nesting areas in similar ways. In many multi-species wetlands and lakes, different waterfowl species establish territories that naturally space themselves without eliminating the presence of others.
- 2) habitat quality is often the primary driver of native waterfowl population changes. In many urban and suburban water bodies, factors such as shoreline development, pollution, loss of aquatic vegetation, and human disturbance have a far greater influence on native bird populations than the presence of a relatively small number of mute swans.
- 3) There are many documented examples of water bodies supporting both mute swans and native waterfowl simultaneously for long periods of time. In these environments, species often adapt to shared habitat use rather than being displaced outright. Observations from urban lakes, parks, and managed wetlands across the country frequently show mallards, coots, moorhens, geese, and other ducks nesting successfully in areas occupied by mute swans.

Additionally, some concerns raised about mute swans focus on their consumption of submerged aquatic vegetation (SAV) and the suggestion that their feeding significantly damages aquatic ecosystems. While it is true that swans feed on aquatic plants, grazing by waterfowl is a natural ecological process that occurs in

many healthy wetlands. In many cases, moderate grazing can actually stimulate plant regrowth, help maintain plant diversity, and prevent overgrowth that can lead to oxygen depletion or stagnation in shallow water systems.

In lakes and wetlands across the country where mute swans are present, submerged vegetation continues to support fish, amphibians, and invertebrates alongside waterfowl populations. Based on both observation and broader ecological understanding, the presence of mute swans does not automatically translate into the destruction of aquatic habitat, particularly when populations remain relatively small and habitat conditions are otherwise healthy.

Finally, I believe it is important to recognize that wildlife management classifications can sometimes evolve over time as more data becomes available. The designation of a species as “invasive” should ideally reflect demonstrated ecological harm that is consistent and measurable across habitats. When evidence is mixed or context-dependent, management strategies that prioritize humane, proportional, and site-specific approaches may better serve both ecological and ethical considerations.

For these reasons, I believe it is important that management strategies remain proportional and evidence-based, ensuring that lethal control is used only when clearly justified by demonstrated ecological harm rather than broad assumptions about species interactions.

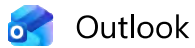
I appreciate the difficult responsibility your department carries in managing wildlife resources and thank you for taking the time to consider perspectives from those who spend significant time observing and caring for these animals.

Respectfully,

Andrew Marshall

Friends of a Feather





Position letter: Protecting marine ecosystems

From Acadia Engelman <aengelman1418@sdsu.edu>

Date Thu 03/12/2026 06:45 PM

To FGC <FGC@fgc.ca.gov>

Cc Commission@fgc.ca.gov <Commission@fgc.ca.gov>; MPA@wildlife.ca.gov <MPA@wildlife.ca.gov>

Dear California Fish and Game Commission,

Attached is my position letter advocating for stronger marine protection through expanded Marine Protected Areas, stricter commercial fishing limits, and enhanced protection for vulnerable habitats.

Sincerely,

Acadia Engelman

San Diego, CA

aengelman1418@sdsu.edu

March 12, 2026

President Eric Sklar
California Fish and Game Commission
715 P Street, 16th Floor
Sacramento, CA 95814

Dear President Sklar,

I am writing to urge the California Fish and Game Commission to strengthen marine ecosystems through the expansion of Marine Protected Areas (MPAs), the implementation of stricter commercial fishing limits, and the increased protection for threatened coastal habitats such as kelp forests and wetlands. California's coastal waters and intertidal zones are among the most biologically productive and diverse marine environments in the world, yet the habitats and species within are at increased risk of extinction and loss due to human activity.

The marine ecosystem in coastal California waters functions as a complex but balanced interconnected food web. Just a single disruption or removal of a species can cause a trophic cascade and destabilize entire ecosystems. Declines in predator or prey populations have been linked to food chain imbalances and overall decline in coastal wetland, rocky intertidal zones, kelp forests and other marine habitats.

Overfishing also disrupts ecosystem balance and ecological carrying capacity. Fish populations require sufficient time and habitat structure in order to maintain sustainable numbers. When extraction exceeds reproductive capacity, populations decline and recovery becomes increasingly difficult. Globally, a majority of commercial fishing stocks and estuaries are overexploited and even fully exploited due to overfishing and consumption and California is no exception to this threat. While important steps have been taken by placing MPAs along the coastline, this is not enough to restore and maintain balanced ecosystems that can sustain healthy fish and crustacean populations. Continued environmental stressors and fishing intensity serves as a warrant to strengthen already existing MPAs and implement more so that a majority of California's coast is preserved

Expanding Marine Protected Areas can provide refuge zones where species can reproduce and mature, allowing populations to recover. This benefits the commercial fishing industry by providing spillover zones in adjacent waters. On a larger scale, MPAs also strengthen and protect habitats, creating ecosystem resilience to climate change effects and natural disasters. In addition, implementing stricter catch limits for commercial fisheries can prevent population collapses and maintain long term productivity.

I respectfully encourage the California Fish and Game Commission to prioritize expanding Marine Protected Areas, regulating commercial fishing, and protecting threatened coastal habitats. California can continue to serve as a national leader in marine conservation while benefiting from increased ecosystem fitness.

Thank you for your leadership in protecting California's marine resources and for considering these recommendations. I appreciate the Commission's commitment to environmental stewardship and the opportunity to contribute to this important discussion.

Sincerely,

Acadia Engelman
San Diego, CA
aengelman1418@sdsu.edu

Oceanbound Salmon

From Not User friendly [REDACTED]
Date Sun 03/15/2026 06:46 PM
To FGC <FGC@fgc.ca.gov>

Understanding that Striped bass are ravenous eaters of pansized trout, so much that one invented the Castaic Trout Luer. Am I correct in assuming that seabound juvenile salmon are looking alot like a young trout? Uh duh... no \$#/+.

And knowing the Striped Bass is an invasive species, 19" legal kill size by law? Obviously , Those Bass can consume vast ammounts of small juvenile seabound salmon. The majority most likely never make it to the Golden Gate. Im no aquaculture know it all. But come on . Low counts are not climate related . Water released from dams comes from the bottom of lakes usually cooler than the un dammed portions of watershed upstream . Overfishing is another questionable statement.... Unless you call foraging schools of Striped Bass fishermen woman fisher its. Ooops i apologize . Didnt mean to offend anything. (its Califreakshow). So! Its so very California. Backwards . An invasion of a race called Striped Bass Sneak in and get sanctuary as the citizen Salmon have had to deal with it . Working , living to run the gauntlet as the protected invaders get priority. All under Californias Salmon endagerment hoax. Its Literal Liberal B.S.

One 15" Bass can vacume , digest and excrete at least one Young salmon a day. Comfortably. a 19" Bass? mayne 2 a day . A large sStriped Bass will , and does so much damage , you brurocrats must think everybody is stupid about those Salmon eating machines . In fact , all of Californias citizens are getting shafted under the lie spread by All entities involed . Especially farmers. Those founding families offspring sell out to real estate, cause of the blues Mom And Pop, Grampa and Grandma endured for decades because of the draconian , illogical mahem created by the State by people that have the concept that food comes from a grocery store... with that warped mindset dictate water policy.

As for the precious endangered Delta Smelt? If you drive 350 miles south and shine a flashlight in the Califreakshow aqueduct? You will observe in 14 seconds , 200 of 2 trillion smelt. Smelting . Doin what smelt Do . Our new Govenor will get this info , research , confirm and eliminate all involved. Thank God . We will make Calfreakshow California Again. (charging me \$90 to fish for a year. as the illegals have eaten every clam , mussel , crab , fish along this coast in several years . Shells littering beaches, and rocks stripped bare .) Game wardens gang up on me as whole muti generational groups of family, entered illegally, scour the wildlife just like the striped bass do. Striped bass regulation proposal: Limit 10 per day , any size .No catch and release. Permits available for Harvesting Striped bass for Fertilizer , Pet Food and other uses.

Sincerely a victim,
James D Treat

[REDACTED]
Littlerock California.

Outrage Over Euthanizing Monrovia Mother Bear

From Sai Annapureddy [REDACTED]
Date Tue 03/17/2026 08:54 PM
To Wildlife Ask R5 <AskR5@wildlife.ca.gov>; Boring, Misty [REDACTED]; Klopping, Cort [REDACTED]; Gonzalez, Stephen [REDACTED]; Kellum, Krysten [REDACTED]; Tira, Peter [REDACTED]; Kukulka, Katharine [REDACTED]
Cc college@peta.org <college@peta.org>; kathryn@bos.lacounty.gov <kathryn@bos.lacounty.gov>; Wildlife DIRECTOR <DIRECTOR@wildlife.ca.gov>; cityclerk@monroviaca.gov <cityclerk@monroviaca.gov>; FGC <FGC@fgc.ca.gov>; newstips@abc7.com <newstips@abc7.com>

Hello California Department of Fish and Wildlife,

I am writing with deep anger and heartbreak over the decision to euthanize the mother bear in Monrovia.

Let us be absolutely clear about the facts. A woman sustained non-life-threatening injuries after being swiped on the leg while walking her dog. This was not a fatal attack, not even a severe mauling yet it resulted in a death sentence for a wild animal that was, by all reasonable understanding, acting defensively in proximity to her cubs.

This bear was a mother. She had cubs, who were later captured separately and are now left without her. The image this leaves behind is deeply disturbing: a family broken apart because a wild animal behaved exactly as nature has programmed it to protecting its young.

What is even more troubling is that this was not a rogue animal terrorizing a community. Residents themselves described the encounter as unusual, with no history of frequent aggressive incidents in the area. In fact, many neighbors and even city officials pushed for relocation instead of euthanasia, yet their voices were ultimately ignored.

So the question must be asked:
When did coexistence stop being the goal?

California is home to tens of thousands of black bears, and human-bear encounters are known to be rare. If every defensive encounter, especially one resulting in minor injuries leads to euthanasia, what precedent are we setting? That wildlife must be perfect, or it pays with its life?

This decision does not reflect compassion, balance, or modern wildlife management. It reflects a system that defaults to lethal action even when alternatives such as relocation, monitoring, and aversive conditioning are clearly possible and publicly supported.

I urge you to:

- Publicly explain why relocation was not pursued despite requests from the community.
- Reevaluate policies that treat defensive wildlife behavior as justification for euthanasia.
- Commit to prioritizing non-lethal solutions in future human-wildlife conflicts.

This was not just the loss of a bear. It was the loss of public trust, the loss of compassion, and the loss of an opportunity to do better.

We can and must do better.

Regards,
Sai

Urgent: Public Concern Over Euthanization of Mother Bear in Monrovia Leaving Cubs Orphaned

From Nadia J [REDACTED]

Date Fri 03/20/2026 09:01 AM

To askcdfw@wildlife.ca.gov <askcdfw@wildlife.ca.gov>; FGC <FGC@fgc.ca.gov>;
publiccomments@bos.lacounty.gov <publiccomments@bos.lacounty.gov>

To Governor Newsom, the California Department of Fish and Wildlife, and relevant oversight authorities,

I am writing to formally demand an immediate investigation into the decision to euthanize a mother bear in Monrovia, an action that has now left two dependent cubs without their mother and has caused widespread public outrage.

This was not a rogue or predatory animal acting outside normal behavior. By all accounts, this bear was exhibiting instinctive maternal protection of her cubs. Killing her under these circumstances raises serious questions about judgment, proportionality, and adherence to non-lethal wildlife management protocols.

I am asking for clear and immediate answers:

- Who specifically authorized the euthanization, and under what written criteria?
- What non-lethal alternatives were attempted or considered prior to this decision?
- Why was relocation, hazing, or temporary containment not pursued?
- What is the current plan for the survival and care of the orphaned cubs?
- Will there be an internal or independent review of this decision, and will those findings be made public?

This incident reflects a broader and deeply concerning pattern: wildlife is being forced into closer proximity with humans due to habitat encroachment, yet the consequences are borne almost entirely by the animals. That is not responsible stewardship; it is reactive and avoidable.

There must be accountability where decisions fall short of ethical and professional standards. If protocols were not followed, or if better options were available and not used, then those responsible must be held accountable.

I am also calling for:

- A formal review and strengthening of CDFW's non-lethal response policies, particularly in cases involving mothers with dependent young
- Mandatory transparency in future lethal action decisions
- Greater investment in coexistence strategies and public education to prevent these outcomes

Californians expect humane, science-based wildlife management, not irreversible decisions that orphan young animals and erode public trust.

I request a formal response outlining both the justification for this action and the steps that will be taken to ensure this does not happen again.

Sincerely,

Nadia Jordan Hedkvist - Los Angeles resident

Grizzly bear reintroduction

From Mike boehlert [REDACTED]
Date Thu 02/26/2026 07:56 AM
To FGC <FGC@fgc.ca.gov>

To spend any money, employee time, or any other resources to support a study on Grizzly bear reintroduction is beyond being stupid.

The cuts that have already occurred to DFG over the years has left it short on Indians and heavy on Chiefs, we don't need to spend agency time on a useless study.

Whoever, outside of the agency is pushing for this should have to pay for any study that they want to see done as there is absolutely no way the public would allow reintroduction to happen.

What are the costs of our grey wolf introductions in time, money, and investigating and paying for predation on ranchers assets.

What are the possible dangers to backpackers, ranchers, bicyclists, fisherman, and people living in the margins of what would become their territories.

THIS PROPOSAL IS ABSURD.

You would promote and should expect otherwise reasonable people to shoot any that they see on sight, the same thing that has happened after disallowing Mountain Lion hunting, shoot it, shut up, and bury it. If I was backpacking , camping, biking, or fishing in the backcountry I would include bear spray and a 45, and would not hesitate to use it.

Michael Boehlert
[REDACTED]

Sent from my iPad

Grizzly bear reintroduction

From Deanne Boehlert [REDACTED]
Date Thu 02/26/2026 08:08 AM
To FGC <FGC@fgc.ca.gov>

If you are serious about this, how about we first introduce them in the mountains west of St. Helena, east of Kenwood, McKinleyville, and Santa Cruz, and in Torrey Pines State Park.
If you Commissioners want them reintroduced, do it in your backyard, not mine.
Michael Boehlert
Shingletown, Ca

Promote Peaceful Coexistence with California's Wildlife

From Nancy Bohan [REDACTED]

Date Fri 03/27/2026 06:09 AM

To Hertel, Meghan [REDACTED]; FGC <FGC@fgc.ca.gov>

Dear Director Hertel and California Fish & Game Commission,

I am reaching out with deep concern over the recent events involving the tragic loss of a mother bear in Monrovia, highlighting a critical need for change in wildlife management practices. It is imperative that we prioritize non-lethal methods to address conflicts between humans and wildlife.

California stands at the forefront of scientific innovation and community support for wildlife preservation. However, the absence of decisive political action is a significant barrier to progress.

Lethal measures are not a sustainable solution. They merely create temporary vacancies that soon attract other wildlife. Instead, we must invest in proven non-lethal strategies, such as bear-resistant containers, community education, and comprehensive wildlife corridors, which remain woefully underfunded.

I urge the California Department of Fish and Wildlife to:

1. Halt the issuance of lethal removal permits where non-lethal measures have not been fully explored.
2. Secure funding specifically for enhancing community coexistence initiatives in regions inhabited by bears and mountain lions.
3. Advocate for educational programs in schools that focus on wildlife coexistence.
4. Implement transparent public disclosure of all lethal removal activities, detailing species, locations, and reasons.

California's reputation as a conservation leader is at stake. The public demands a compassionate and forward-thinking approach to wildlife management.

Respectfully,

Nancy Bohan

Sent from my iPhone



March 18, 2026

RE: Proposed killing of deer on Catalina Island

Recently, the California Fish and Wildlife Department approved a permit that allows all of Catalina Island's mule deer to be shot and killed within five years. The Catalina Island Conservancy, that proposed this plan, claims getting rid of the deer is needed to restore and preserve the island's ecosystem, including rare plants.

Democrats for the Protection of Animals, a chartered club of the Los Angeles County Democratic Party, opposes this extreme plan and urges the adoption of one of the many reasonable and compassionate proposed alternatives of non-lethal means to control the deer population.

Respectfully yours,

James Jenvold

President, Democrats for the Protection of Animals

Democrats for Protection of Animals endeavors to stimulate Democrats to be active in promoting the humane treatment of animals by promoting humane legislation and governmental policy and by increasing public awareness of animal protection issues at city, county, state, and federal levels.

LOS ANGELES COUNTY DEMOCRATS FOR THE PROTECTION OF ANIMALS

PO Box 445, Santa Monica, CA 90406

Fw: MPA Petition FGC Hearing Requests

From: Laura Deehan <Ideehan@environmentcalifornia.org>

Sent: Thursday, April 2, 2026 04:12 PM

To: FGC <FGC@fgc.ca.gov>

Cc: Marce Graudiņš <mar@azul.org>; ashley@eacmarin.org <ashley@eacmarin.org>; Aylesworth, Sandy <saylesworth@nrdc.org>; Azsha Hudson <ahudson@environmentaldefensecenter.org>; ray@coastkeeper.org <ray@coastkeeper.org>

Subject: MPA Petition FGC Hearing Requests

Dear President Sklar and Commissioners,

Hope you are well.

I'm submitting the attached letter on behalf of several groups who proposed petitions to strengthen protections within the state's marine protected area network.

The letter expresses disappointment in the CDFW recommendation to deny the overwhelming majority of proposed conservation actions, and requests a fair, transparent public engagement process this spring as you make your decisions.

Thank you.

Laura

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Laura Deehan / State Director / Environment California

Environment California Research and Policy Center

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California Fish and Game Commission
Marine Resources Committee
P.O. Box 944209
Sacramento, CA 94244-2090

April 2, 2026

Submitted electronically to fgc@fgc.ca.gov

Dear President Sklar and Commissioners,

The undersigned organizations are advancing petitions to adaptively manage and strengthen the marine protected area (MPA) network so that it continues to provide important benefits for Californians, fish populations, and healthy ocean ecosystems.

We are disappointed that the California Department of Fish and Wildlife (CDFW) has recommended denying almost every proposed conservation change so far. We understand CDFW's recommendations are just one aspect in the evaluation of the petitions and trust that the Commission will incorporate the best available science, public input, and the responsibility to consider current and future ocean conditions as outlined in the [Marine Life Protection Act Master Plan](#) in its decisions on the various petitions.

As we approach the first public discussions of our petitions at the three regional meetings in April and May, we respectfully request that the Fish and Game Commission (Commission) establish and maintain a consistent and transparent process for discussing the MPA petitions that have been under consideration for more than two years.

Since petitions were submitted in November 2023, the Commission has asked that public comments focus on informing evaluation criteria and setting shared expectations for the evaluation process. We have therefore focused on providing comments to ensure that equity, climate resilience, and the best available science inform the state's adaptive management process. We have also advocated for a process that allows for meaningful public engagement that reflects the interests of non-consumptive ocean users, Tribes, and the broad and diverse array of

ocean users across many parts of the state. Many petitioners have had limited time at any one meeting to discuss the substance of their proposals over the last two years, and mostly only during open public time, if at all. We are eager for the opportunity to explain the scientific rationale behind our proposals, to describe the extensive multi-year outreach efforts we have undertaken, and to present information about amendments and new science that further inform our proposals.

Heading into these in-person meetings in April and May, we want to ensure that all petitioners have an equal opportunity to explain the rationale behind their petitions. **We request that each petitioner have at least 10 minutes to present their proposal.**

We appreciate and fully support that members of the public always retain the right to offer comment, cede time, and offer input on items not on the agenda. Our request is simply that the Commission ensure that petitioners have a clearly defined opportunity to present relevant information consistent with other petitioners.

We would appreciate guidance at the April 15 Fish and Game Commission meeting on:

- How the current suite of petitioners can share petition-specific information at the upcoming regional meetings in late April and May;
- The timeline for the Tribally-led petition evaluations and confirmation that those petitions will be heard at the regional meetings, regardless of the status of those evaluations; and
- What members of the public can expect as an outcome of the regional meetings. For example, will Commissioners indicate which way they intend to vote on each petition or what, if any, additional information is needed to inform their decision? Or, are the regional meetings intended to be an opportunity for Commissioners to ask questions of the petitions and CDFW, and for members of the public to register their support or opposition to specific petitions? If it is the latter, when will Commission votes on each proposal occur?

Our organizations have done extensive community outreach for each petition, and we consider it necessary and respectful to be able to relay the key process details to members of the public, and Tribal community members who wish to engage in this process.

Thank you for your continued commitment to a transparent adaptive process.

Sincerely,

Laura Deehan, State Director
Environment California

Ashley Eagle-Gibbs, Executive Director
Environmental Action Committee of West Marin

Ray Hiemstra, Associate Director
Orange County Coastkeeper

Sandy Aylesworth, Director, Pacific Initiative, Oceans
NRDC

Marcela Gutierrez-Graudins, Founder and Executive Director
Azul

Azsha Hudson, Marine Conservation Analyst & Program Manager
Environmental Defense Center