Staff Report 61 (Informational)

PARTY:

California State Lands Commission

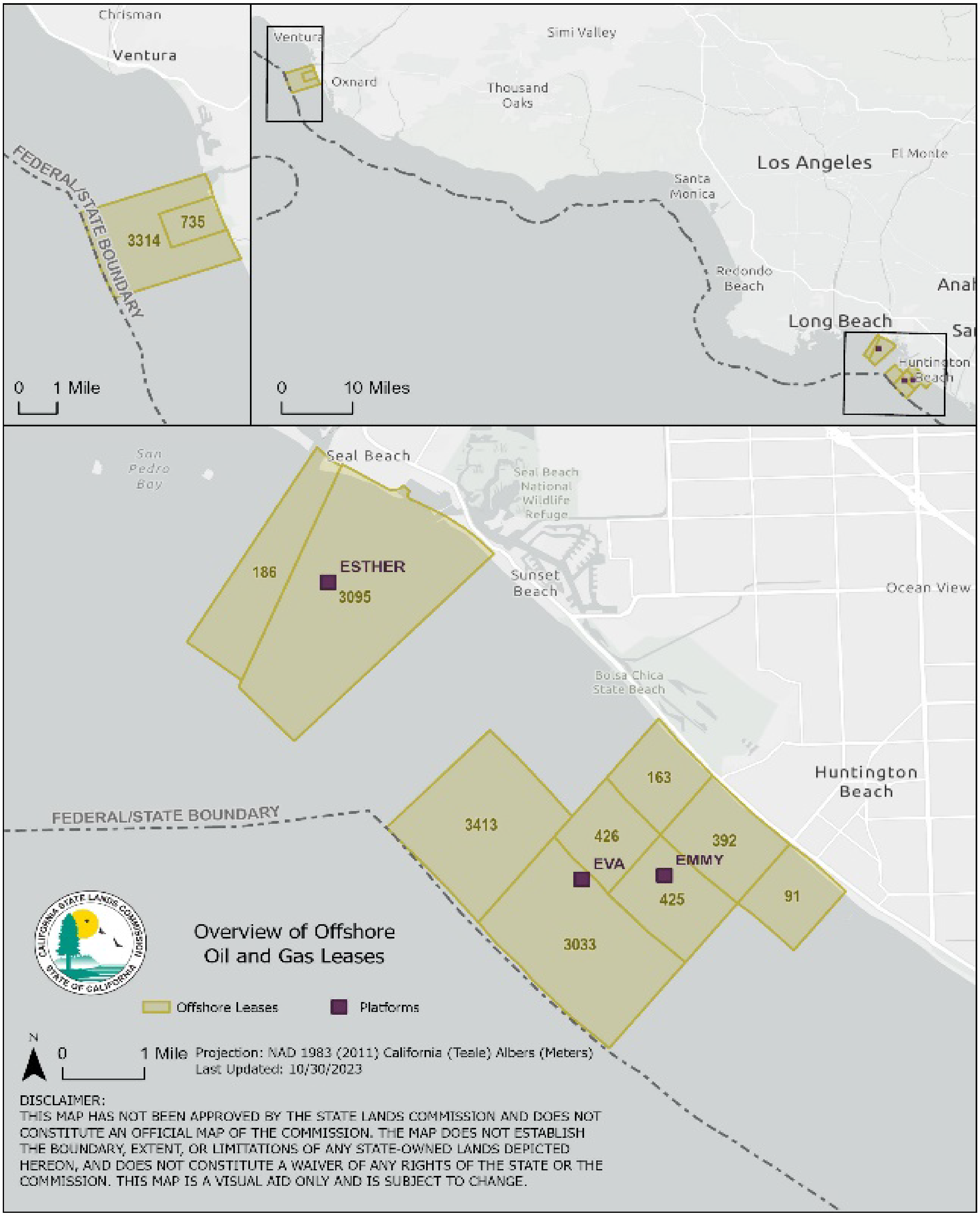
SUMMARY:

This item is a status update on developing a cost study that evaluates the fiscal impact of a voluntary relinquishment of any lease interests in actively producing state offshore oil and gas leases, as required by AB 2257 (Boerner Horvath, Chapter 692, Statutes of 2022).

AREA, LAND TYPE, AND LOCATION:

Statewide offshore oil and gas leases (as shown in Figure 1, below).

Figure 1. Location Map



BACKGROUND

The Commission manages offshore oil production facilities and leases within 3 miles of the coast, including oil-producing islands and offshore platforms. Currently, there are 11 producing oil and gas leases in state waters and three producing platforms, Esther, Eva, and Emmy. The three platforms produce oil and gas from eight leases, all of which are located in Orange County. The Commission also oversees three leases that produce offshore oil and gas resources from upland sites. Two of these leases are located in Ventura County and are produced from onshore sites. The third lease is located in Orange County and produces from Island Chafee in Long Beach.

While California banned new offshore oil and gas leases in state waters in 1994 through the California Coastal Sanctuary Act, the remaining offshore oil and gas leases may continue for as long as the leases are economically productive and produce oil in paying quantities. The Governor and Legislature have called for California to transition to a carbon neutral energy sector by 2045, and several major oil companies have committed to zero net carbon emissions by 2050.

In October 2021, an underwater pipeline operated by Amplify Energy Corp. ruptured, spilling nearly 25,000 gallons of oil into the Pacific Ocean, causing beach closures, damaging the environment, and harming the regional and state coastal economies. The Legislature held three hearings focused on the spill and state and federal offshore oil and gas development and decommissioning options. Since the spill, several state legislators introduced legislation to address existing oil and gas operations in state waters.

The 2022 Budget Act appropriated $1 million to the Commission to conduct an offshore oil and gas lease cost study to support AB 2257 (Boerner Horvath). AB 2257, signed by the Governor on September 28, 2022, requires the Commission to develop and submit to the Legislature and Governor, by December 31, 2024, a cost study that evaluates the fiscal impact of a voluntary relinquishment of any lease interests in the actively producing oil and gas leases in state waters. The cost study must consider: (1) Expected duration of oil production at the time of leasing; (2) State revenues received to date; (3) Expected remaining life of the reservoir based on proved reserves; (4) Reasonably anticipated unrealized lessee revenues and profits; (5) Reasonably anticipated unrealized state revenues; and (6) Lessees' decommissioning and restoration costs.

AB 2257 requires the Commission to submit a status update on the cost study to the Governor and Legislature by December 31, 2023. The status update must include a proposed outline of the cost study elements, identified data gaps, preliminary analysis, conclusions, and recommendations, and any public comments received by the Commission.

The cost study involves conducting a comprehensive engineering and economic analysis of unrealized state revenues, reasonably anticipated lost profits to operators, life of the reservoir based on proved reserves, well and facilities abandonment, lessee decommissioning costs, and potentially, the surface land value for facilities and wells located onshore on privately-owned lands. The cost study is intended to provide the knowledge necessary for informed decision making and practical solutions to responsibly end offshore oil and gas production. The cost study can also be a tool to assess ways the State can encourage oil and gas companies to voluntarily end offshore oil and gas production as a component of a credible strategy to reach zero net carbon emissions by 2050 or sooner. Staff would use all information yielded from the cost study as the foundation for a methodical and data driven negotiation strategy with each offshore operator to end offshore oil and gas production, provided funding is available.

In August 2022, the Commission authorized its Executive Officer to retain a consultant to conduct the cost study (Item 39, August 23, 2022). Staff retained Netherland, Sewell & Associates Inc. (NSAI) NSAI partnered with TSB offshore Inc. (TSB) to conduct the decommissioning cost estimate portion of the cost study. Staff formed a multi-divisional project team and have been working closely with both consultants to ensure that all project elements are on track. Exhibit A includes the 2023 Status Update Report to the Governor and Legislature

Staff will be compiling comments received before and during the December 5, 2023, Commission meeting to include in the status update submitted to the Governor and Legislature and will make them publicly available on the Commission's website.

Summary of Work Completed and Findings

Since January 2023, staff has collaborated with NSAI and TSB (Consultants). The Consultants have made substantial progress in estimating reserves, and an economic evaluation of the 11 producing offshore oil and gas leases, and on estimating the lessees' decommissioning and restoration costs. The values presented in this Staff Report and Exhibit A are preliminary assessments and may change as additional data and feedback are collected and as the final report is prepared in late 2024. The values in the tables below are general synopses of the broader data compilation completed thus far (for additional information see Exhibit A).

The 11 offshore leases (and associated surface leases) have been grouped into five lease areas for the purposes of this cost study. Each lease area represents a distinct area of operation that can be considered as a unit due to common infrastructure and ownership interests. The five lease areas are Belmont Offshore (186), Belmont Offshore (Esther), Huntington Beach (Eva), Huntington Beach (Near Shore - which includes Platform Emmy as well as wells drilled onshore that produce from offshore reservoirs), and West Montalvo.

Below are the activities the consultants performed and the preliminary results:

- Performed a well-by-well analysis to forecast future production on all producing wells based on well data and historical production data.
- Estimated future production from nonproducing zones and undeveloped wells based on the development plans presented by the lessees.
- Developed cash flow models to generate preliminary estimates of the proved oil and gas reserves, the expected remaining life, and the net present value for each of the actively producing leases.
- Reviewed data provided by staff, conducted site visits, and prepared preliminary estimates of decommissioning costs for each lease.

Section 8 of the 2023 Status Report (Exhibit A) describes the economic evaluation and proved reserves estimation methodology and the preliminary estimates and cash flows. Reasonably anticipated future state revenue, lessee revenues, and lessee profits are summarized in Table 1.

The preliminary estimates were made using oil, natural gas liquids (NGL), and gas prices set by Commission staff. Oil and NGL prices are calculated from a Europe Brent spot price of $77.00 per barrel, adjusted for quality, transportation costs, and market differences. Gas prices start with a NYMEX Henry Hub price of $3.60 per MMBTU, and are adjusted for energy content, transportation costs, and market differences. These prices remain constant throughout the estimates and are the basis for the operational valuations across all the properties (See Table 1). For more details on methodology and values, please refer to Exhibit A.

Table 1. Preliminary Estimates Of Reasonably Anticipated Future State Revenue, Lessee Revenues, And Lessee Profits

Lease Area	State Revenues (Million $)	Lessee Revenues (Million $)	Lessee Profit (Million $)
Belmont Offshore (186)	20.05	91.90	37.83
Belmont Offshore (Esther)	39.15	188.98	~~85.35~~72.96*

Lease Area	State Revenues (Million $)	Lessee Revenues (Million $)	Lessee Profit (Million $)
Huntington Beach (Eva)	72.19	327.19*~~3~~	165.32
Huntington Beach (Near Shore)	322.33	1,358.29	396.44
Onshore	244.08	1028.80	260.10
Platform Emmy	78.25	329.50	136.34
West Montalvo	4.55	22.23	7.86
Total	**458.27**	**1,988.5~~3~~9***	**~~692.80~~680.41***

* Revisions as of November 30, 2023, reflect the final refinements of values.

Section 7 of the 2023 Status Update Report includes the above estimates and costs to decommission wells, pipelines, platforms, and onshore facilities.

The Consultants reviewed data provided by staff, a variety of publicly available information datasets, internal proprietary datasets, visited the oil and gas lease sites, and prepared preliminary estimates of decommissioning costs for each of the 11 leases. These estimates include the costs to decommission the wells, pipelines, platforms, and onshore facilities. Table 2 presents TSB's preliminary decommissioning cost estimate for each lease area.

Table 2. Preliminary Decommissioning Cost Estimate For Each Lease Area

Lease Area	Lessee	Decommissioning Cost (Million $)
Belmont Offshore (186)	California Resources Corporation	~~12.70~~11.90*
Belmont Offshore (Esther)	Dos Cuadras Offshore Resources, LLC	80.00
Huntington Beach (Eva)	Dos Cuadras Offshore Resources, LLC	79.30
Huntington Beach (Near Shore)	California Resources Corporation	~~204.4~~197.60*
Onshore		~~131.10~~124.30*
Platform Emmy		73.30
West Montalvo	California Resources Corporation	7.00
Total		**~~383.4~~375.8***

* Revisions as of November 30, 2023, reflect the final refinements of values.

The Consultants estimated the expected remaining life of each lease area based on their preliminary estimates of proved reserves and revenue. The remaining life as of December 31, 2024, are shown in the following Table 3:

Table 3. Preliminary Expected Remaining Life Of Each Lease Area As Of December 31, 2024

Lease Area	Expected Remaining Life (Years)
Belmont Offshore (186)	13.20
Belmont Offshore (Esther)	11.90
Huntington Beach (Eva)	16.20
Huntington Beach (Near Shore)	18.80
West Montalvo	10.30

The main identified data gap is related to section 2 (b)(1) of AB 2257, which requires reporting the "Expected duration of oil production at the time of leasing." There are no public records or internal Commission documents from before the leases were signed that indicate how long production from the leases was expected to last. But there is data that provides reasonably accurate estimates of the economic life of the various operations at current commodity pricing.

Before the Commission considers the final cost study in 2024, the Consultants will update the preliminary proved reserves and cash flow estimates with the latest available data. They will also continue to refine their estimates with a probabilistic analysis and will add additional components to the estimates, including the costs for environmental assessments, material disposal, and potential savings from grouping decommissioning activities into multi-asset campaigns.

CLIMATE CHANGE:

The climate crisis is an existential threat and the need to reduce greenhouse gas emissions grows more urgent with each passing day because California is already feeling the impacts of climate change. According to a report by the Legislative Analyst's Office, the years from 2014 through 2020 (except for 2019) experienced the six highest annual average temperatures ever recorded in the State. The summer of 2021 set the State's record for hottest average summer temperatures, beating the previous record that was set only a few years prior in 2017. In addition to hotter temperatures, California is experiencing more frequent and intense droughts, setting numerous drought records over the past decade. The warming and drying climate has created conditions that lead to high-severity wildfires. Seven of the 20 most destructive wildfires in the State's history occurred in 2020 and 2021. The extreme temperatures, drought, wildfires, and other impacts of climate change will continue to worsen if greenhouse gases are not drastically reduced in the coming decades.

The most effective way to prevent the worst impacts of the climate crisis is to reduce greenhouse gas emissions by transitioning the State's energy portfolio from fossil fuels to clean energy. While advances in clean energy development are enabling California to decrease its reliance on fossil fuels and reduce greenhouse gas emissions, California will require much deeper greenhouse gas emissions reductions to reach its 2030 target of 40 percent below 1990 levels and its 2045 carbon neutrality goal. The growth in clean energy production must be paired with a deliberate phasedown of fossil fuel production and consumption to achieve California's emission reduction targets.

In 1994, California banned new leases for the extraction of offshore oil and gas in state waters; however, the remaining offshore oil and gas development in state waters continues to emit greenhouse gases. Methane leaks, venting, flaring, and gas and diesel power generation are the primary sources of emissions from offshore oil and gas production. Recent studies of offshore oil and gas infrastructure in the U.S. found they can leak methane at significantly higher rates than typical onshore production (Alana K. Ayasse et al., 2022, Alan M. Gorchoy Negron et al., 2023). Methane is a major driver of global warming – it is 80 times more potent at warming the planet than carbon dioxide. Oil spills can negatively impact marine and coastal ecosystems that provide important climate mitigation and resilience benefits. The risk of an oil spill, and the economic and environmental catastrophe that could follow, coupled with the fact that fossil fuels are the primary cause of climate change, call for California to seek out ways to quicken the end of offshore oil and gas development in state waters. The cost study is intended to provide the knowledge necessary for informed decision making and practical solutions to end offshore oil and gas development in state waters, which is important from a climate change, environmental, and public health perspective.

ENVIRONMENTAL JUSTICE:

Environmental justice is defined by California law as "the fair treatment and meaningful involvement of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies." (Gov. Code, § 65040.12.) This definition is consistent with the Public Trust Doctrine's principle that management of Public Trust lands is for the benefit of all people. Through its Environmental Justice Policy, the Commission reaffirmed its commitment to an informed and open process in which all people are treated equitably and with dignity, and in which its decisions are tempered by environmental justice considerations. A key goal in the policy is to support cleaner industry by transitioning California away from fossil fuels through the timely and responsible decommissioning of oil and gas facilities.

Oil and gas operations are a significant source of air pollution that affects the public health, safety, and environment of surrounding communities. These communities often lack access to resources to address the environmental and public health impacts that come with these activities. Not only are environmental justice communities burdened by pollution associated with oil and gas operations, but they often face cumulative pollution burdens from industrial activities and interstate traffic. These forms of pollution are known to cause significant human health effects, including cancer, cardiovascular diseases, low birth weights and premature birth and death. Many of these neighborhoods rank high on CalEnviroScreen 4.0 for health issues such as asthma and low birth weight, as well as many other population characteristics that increase vulnerabilities to pollution, including poverty, housing burdens, and unemployment. A deeper analysis of these environmental justice communities and the impacts they face is needed to fully understand the disparities associated with the continued operations of oil and gas on state land.

OTHER PERTINENT INFORMATION:

1. This report is consistent with the "Leading Climate Activism", "Meeting Evolving Public Trust Needs", "Prioritizing Social, Economic, and Environmental Justice," and "Committing to Collaborative Leadership" Strategic Focus Areas of the Commission's 2021-2025 Strategic Plan.

EXHIBIT

A. 2023 Status Update Report

NEXT STEPS:

In 2024, the Consultants will attempt to address and close the remaining technical and commercial data gaps described in the 2023 Status Update Report. The Consultants will update technical forecasts, economic parameters, and development plan assumptions based on the latest data available through the summer of 2024. They will incorporate any public comments that the Commission receives. Commission staff, with the assistance of the Consultants, will prepare a final report to satisfy the requirements of AB 2257.

With the finalized estimates of reserves and future net revenue to the lessees', the Commission will have the data necessary to inform potential negotiations for voluntary relinquishment of the offshore leases, provided funding is made available.

The Consultants intend to further develop decommissioning cost estimates and elaborate on options and their cost implications. This includes the following activities:

- Comparing the cost implications of mobilizing larger, more capable vessels from the Gulf of Mexico or the Far East against using smaller local counterparts.
- Further review of individual wellbore schematics of the 350+ onshore wells and providing costs on an individual, per-well basis. Currently, the onshore wells are estimated using a statistical approach in line with the approach of previous publicly available reports.
- Updating the Huntington Beach near Shore Highlands Facility estimate, after performing a third site visit. This last site visit will be solely focused on fully quantifying the equipment, piping, and acreage of the site. The Highlands Facility estimate provided in the 2023 Status Report is a high-level estimate given the Consultants' brief time spent in that area during a second site visit.
- Providing a cost comparison between lessee led versus state led decommissioning cost scenarios.
- Conducting a "probabilistic" analysis of the decommissioning estimates and providing proper reserves estimates.

Exhibit A

Assembly Bill 2257 Cost Study
Evaluating the Fiscal Impact of a Voluntary Relinquishment of Actively Producing State Offshore Oil and Gas Leases
on Behalf of the
California State Lands Commission

December 2023

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

December XX, 2023

Jennifer Lucchesi
California State Lands Commission
100 Howe Avenue, Suite 100 South
Sacramento, California 95825

Dear Jennifer Lucchesi:

In accordance with the request of the California State Lands Commission (Commission), we have undertaken a cost study, pursuant to Assembly Bill Number 2257 (AB 2257), to evaluate the fiscal impact of a voluntary relinquishment of lease interests in actively producing oil and gas leases located in state waters offshore California.

We will deliver our findings related to this cost study in two reports. This preliminary status update covers the work we have completed to date. The estimates contained in this report should be considered preliminary and are intended to facilitate interim review and feedback by stakeholders; we expect additional data to become available over the course of the next year, and this data may impact the technical and economic estimates contained herein. In the final report, scheduled for release in December 2024, we will present the full results of the cost study, including all of our findings and recommendations.

As shown in the Table of Contents, this status update includes an outline of the study; identified data gaps; our preliminary analysis, conclusions, and recommendations; and public comments received by the Commission.

This status update is intended solely for use by the Commission to satisfy its obligation to provide a status update to the Governor and Legislature of California pursuant to AB 2257. Netherland, Sewell & Associates, Inc. (NSAI) disclaims all responsibility for the use of or reliance on this report by any other parties or for any other purpose. This document is a preliminary status update, and all of the estimates contained herein are subject to change. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment. NSAI performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699.

Sincerely,

Joseph M. Mello, P.E. 125699
Vice President

JMM:NFH

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ABBREVIATIONS

$	United States dollars
%	percent
1P	proved
2P	proved plus probable
AB 2257	Assembly Bill 2257
BBL	barrels
CalNRG	California Natural Resources Group
CO_2	carbon dioxide
Commission	California State Lands Commission
CRC	California Resources Corporation
DCOR	Dos Cuadras Offshore Resources, LLC
ft	feet
M$	thousands of United States dollars
MBBL	thousands of barrels
MCF	thousands of cubic feet
MM$	millions of United States dollars
MMBTU	millions of British thermal units
MMCF	millions of cubic feet
NGL	natural gas liquids
NSAI	Netherland, Sewell & Associates, Inc.
PAES	Platform Abandonment Estimate System
PRMS	Petroleum Resources Management System
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
tCO_2e	equivalent global warming potential of a metric ton of CO_2
TSB	TSB Offshore Inc.

NETHERLAND, SEWELL & ASSOCIATES, INC.

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NETHERLAND, SEWELL & ASSOCIATES, INC.

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STATE WATERS OFFSHORE CALIFORNIA

1.0 EXECUTIVE SUMMARY

The California State Lands Commission (Commission) has contracted Netherland, Sewell & Associates, Inc. (NSAI) to perform a cost study on the voluntary relinquishment of lease interests in actively producing oil and gas leases located in state waters offshore California, as required by Assembly Bill 2257 (AB 2257).

This preliminary status update, presented at the end of the first year in this two-year study, includes an outline of the study as well as NSAI's preliminary analysis, conclusions, and recommendations.

1.1 SUMMARY OF PROGRESS ON MAJOR TASKS

We have made substantial progress on our estimates of reserves and on our economic evaluation of the properties. We have also estimated the reasonably anticipated unrealized state revenues using these preliminary reserves estimates. We have performed well-by-well analysis to forecast future production on all currently producing wells based on well data and historical production data. We have also estimated future production from non-producing zones and undeveloped wells based on the development plans presented to us by the lessees. We have built cash flow models to generate preliminary estimates of the proved and probable oil and gas reserves, the expected remaining life, and the future net revenue, exclusive of decommissioning costs, for each of the 11 actively producing leases included in this study. As detailed further in Section 2.2, these 11 offshore leases (and associated surface leases) have been grouped into five lease areas for the purposes of this cost study. Each lease area represents a distinct area of operation that should be considered as a unit because of common infrastructure and ownership interests. The five lease areas are Belmont Offshore (186), Belmont Offshore (Esther), Huntington Beach (Eva), Huntington Beach (Near Shore), and West Montalvo.

Section 7 includes a discussion of our economic evaluation and reserves estimation methodology along with our preliminary estimates of the reasonably anticipated unrealized state revenues and other related values. We will update these preliminary estimates with the latest available data in the summer of 2024 before issuing our final report in December 2024.

We have also made substantial progress toward estimating the lessees' decommissioning and restoration costs. NSAI subcontracted the aspects of the study related to the decommissioning cost estimates to TSB Offshore, Inc. (TSB). TSB has reviewed data provided by the Commission, conducted site visits, and prepared preliminary estimates of decommissioning costs for each of the actively producing leases included in this study. These estimates, which include the costs to decommission the wells, pipelines, platforms, and onshore facilities, are presented in Section 8. TSB will refine these estimates for the final report with a probabilistic analysis and will add additional components to their analysis, including the costs for environmental assessments, material disposal, and potential savings from grouping decommissioning activities into multi-asset campaigns.

1.2 PRELIMINARY RESULTS

1.2.1 Reasonably Anticipated Unrealized State Revenues

The preliminary estimates of reasonably anticipated unrealized state revenues shown herein are based on our preliminary estimates of proved plus probable (2P) reserves and revenue, as of December 31, 2024, to the State of California royalty interest in each lease area, plus rental fees associated with the mineral and surface leases. The following table presents our estimates of the reasonably anticipated unrealized state revenues by lease area:

Lease Area	Unrealized State Revenues (M$)
Belmont Offshore (186)	20,048.1
Belmont Offshore (Esther)	39,150.0
Huntington Beach (Eva)	72,192.1
Huntington Beach (Near Shore)	322,332.2
West Montalvo	4,545.2

1.2.2 Preliminary Decommissioning Cost Estimates

TSB's preliminary decommissioning cost estimates by lease area are as follows:

Lease Area	Decommissioning Cost (M$)
Belmont Offshore (186)	11,900.0
Belmont Offshore (Esther)	80,000.0
Huntington Beach (Eva)	79,300.0
Huntington Beach (Near Shore)	197,600.0
West Montalvo	7,000.0

2.0 INTRODUCTION

2.1 BACKGROUND AND PURPOSE OF THE STUDY

The Commission is responsible for managing approximately four million acres of tide and submerged lands and the beds of navigable rivers, streams, lakes, bays, estuaries, inlets, and straits. These lands, referred to as sovereign or Public Trust lands, stretch from the Klamath River and Goose Lake in the north to the Tijuana Estuary in the south, and from three miles offshore the Pacific Coast in the west to the Colorado River and Lake Tahoe in the east, and include California's two longest rivers, the Sacramento and San Joaquin. Prior to the passage of the California Coastal Sanctuary Act of 1994 (which prohibited new offshore oil and gas leases in California state waters), the Commission was the agency responsible for leasing properties in waters offshore California for oil and gas production; it remains the agency responsible for managing the remaining offshore oil and gas leases. As of October 2023, there are 11 actively producing offshore oil and gas leases in state waters. The active oil and gas leases are Lease Numbers 91, 163, 186, 392, 425, 426, 735, 3033, 3095, 3314, and 3413. Three surface leases, Lease Numbers 3116, 3394, and 5663, authorize the use of lands for pipelines and electrical conduits associated with the producing oil and gas leases.

AB 2257, which is part of the state's efforts to address climate change and protect its coastal economy, requires the Commission to develop a cost study that evaluates the fiscal impact of a voluntary relinquishment of lease interests in actively producing offshore oil and gas leases in state waters. The Commission has contracted NSAI to perform this cost study.

There are two primary objectives of the cost study:

1. To perform a comprehensive economic evaluation and develop estimates of reserves and future net revenue for the 11 producing leases.

2. To estimate the lessee's decommissioning and restoration costs for each lease, including the three surface leases.

NSAI subcontracted the aspects of the study related to the decommissioning cost estimates to TSB because of TSB's expertise in the subject matter and past work estimating decommissioning costs offshore California.

The findings of this cost study will be delivered in two reports. The first is this preliminary status update, which includes an outline of the study; identified data gaps; NSAI's preliminary analysis, conclusions, and recommendations; and public comments received by the Commission. The final report, scheduled for release in December 2024, will present the full results of the cost study, including all of NSAI's findings and recommendations.

2.2 DESCRIPTION OF THE LEASE AREAS

From a practical perspective, certain leases cannot be evaluated independently. For example, the lessee of Lease Number 3413 would not have a practical way to continue production without the platform, facilities, and economy of scale associated with Lease Numbers 3033 and 3116. Therefore, for the purposes of this cost study, the 11 offshore leases (and associated surface leases) have been grouped into five lease areas, each of which represents a distinct area of operation that should be considered as a unit because of common infrastructure and ownership interests.

2.2.1 Belmont Offshore (186) Lease Area

Belmont Offshore Field is an oil field located in the Pacific Ocean in state waters offshore California, approximately 1.5 miles southwest of Seal Beach, as shown on the location map in Figure 2.3.1. It was discovered in 1948 and is covered by Lease Numbers 186 and 3095. For the purposes of this cost study, the Belmont Offshore (186) Lease Area includes the portion of Belmont Offshore Field that underlies Lease Number 186. This lease produced from 1954 until 1994, when the wells and original artificial island (called Belmont Island) were decommissioned. Redevelopment of this lease area began in 2005 with production via directionally drilled wells based on Island Chaffee, which is located within the Long Beach Unit section of Wilmington Field. The lease area is currently leased to and operated by California Resources Corporation (CRC). The leasing and operation of Lease Number 186 only requires CRC to assume responsibility for decommissioning the wells on Island Chaffee that have produced from Lease Number 186. It is our understanding that CRC bears no responsibility for decommissioning the facilities located on Island Chaffee.

2.2.2 Belmont Offshore (Esther) Lease Area

Platform Esther is located in Belmont Offshore Field approximately 1.5 miles offshore in approximately 30 feet of water. For the purposes of this cost study, the Belmont Offshore (Esther) Lease Area includes the portion of Belmont Offshore Field covered by Lease Number 3095 as well as a surface lease (Lease Number 3394) that covers the right-of-way used by the pipelines and electrical conduit connecting Platform Esther to shore. The lease area is leased to and operated by Dos Cuadras Offshore Resources, LLC (DCOR).

2.2.3 Huntington Beach (Eva) Lease Area

Huntington Beach Field is an oil field located in Orange County, California, as shown on the location map in Figure 2.3.1. It extends from the coastal lands of the city of Huntington Beach out to nearly three miles offshore in California state waters. The onshore portion of the field was discovered in 1920, and production first extended offshore in 1942. Platform Eva is located in Huntington Beach Field approximately 2.25 miles offshore in approximately 58 feet of water. For the purposes of this cost study, the Huntington Beach (Eva) Lease Area includes two oil and gas leases (Lease Numbers 3033 and 3413) that are produced via wells drilled from Platform Eva as well as a surface lease (Lease Number 3116) that covers the right-of-way used by the pipelines and power cable connecting Platform Eva to shore. The lease area is currently leased to and operated by DCOR.

2.2.4 Huntington Beach (Near Shore) Lease Area

For the purposes of this cost study, the Huntington Beach (Near Shore) Lease Area includes five offshore oil and gas leases (Lease Numbers 91, 163, 392, 425, and 426) as well as Lease Number 5663, a pipeline right-of-way lease. The oil and gas leases are produced from onshore wells drilled directionally and offshore wells drilled from Platform Emmy, which is located approximately one mile offshore in approximately 45 feet of water. Since 1995, the royalties for these five leases have been aggregated in the Commission's internal accounting records onto a single entity, Lease Number 7820; therefore, we include the royalties reported for Lease Number 7820 in this cost study for the purposes of tabulating historical state revenues. The oil and gas leases in the Huntington Beach (Near Shore) Lease Area are currently leased to and operated by CRC. The surface lease is leased to and operated by SoCal Holding, LLC, a subsidiary of CRC.

It is our understanding that certain wells located onshore, producing from onshore oil and gas leases known as the Bolsa Leases, share common onshore infrastructure with the five offshore leases included in the Huntington Beach (Near Shore) Lease Area. According to CRC, decommissioning the onshore facilities associated with the offshore oil and gas leases would necessitate the cessation of production from the impacted onshore leases as well. Although these wells are not part of the leases specifically included in the study required by the AB 2257 legislation, we have evaluated the Bolsa Leases and have considered their future net revenue in our determination of the Huntington Beach (Near Shore) Lease Area's economic limit.

2.2.5 West Montalvo Lease Area

West Montalvo Field is an oil field located in Ventura County, California, as shown on the location map in Figure 2.3.2. It extends from an onshore portion into California state waters; all production comes from wells based onshore. For the purposes of this cost study, the West Montalvo Lease Area includes the offshore portion of the field on Lease Numbers 735 and 3314. West Montalvo Field is currently operated by California Natural Resources Group (CalNRG) on behalf of the lessee, CRC. It is our understanding that the Commission is currently reviewing an application from CRC to assign the leases to CalNRG. Details regarding the current arrangement between CalNRG and CRC are not available; therefore, for the purposes of this status update, we continue to refer to the lessee's interest as the CRC interest, notwithstanding any separate contractual arrangements that may exist that transfer some or all of the costs and revenues of the lease from CRC to CalNRG.

2.3 FIGURES

NETHERLAND
& ASSOCIATES, INC.
EWELL

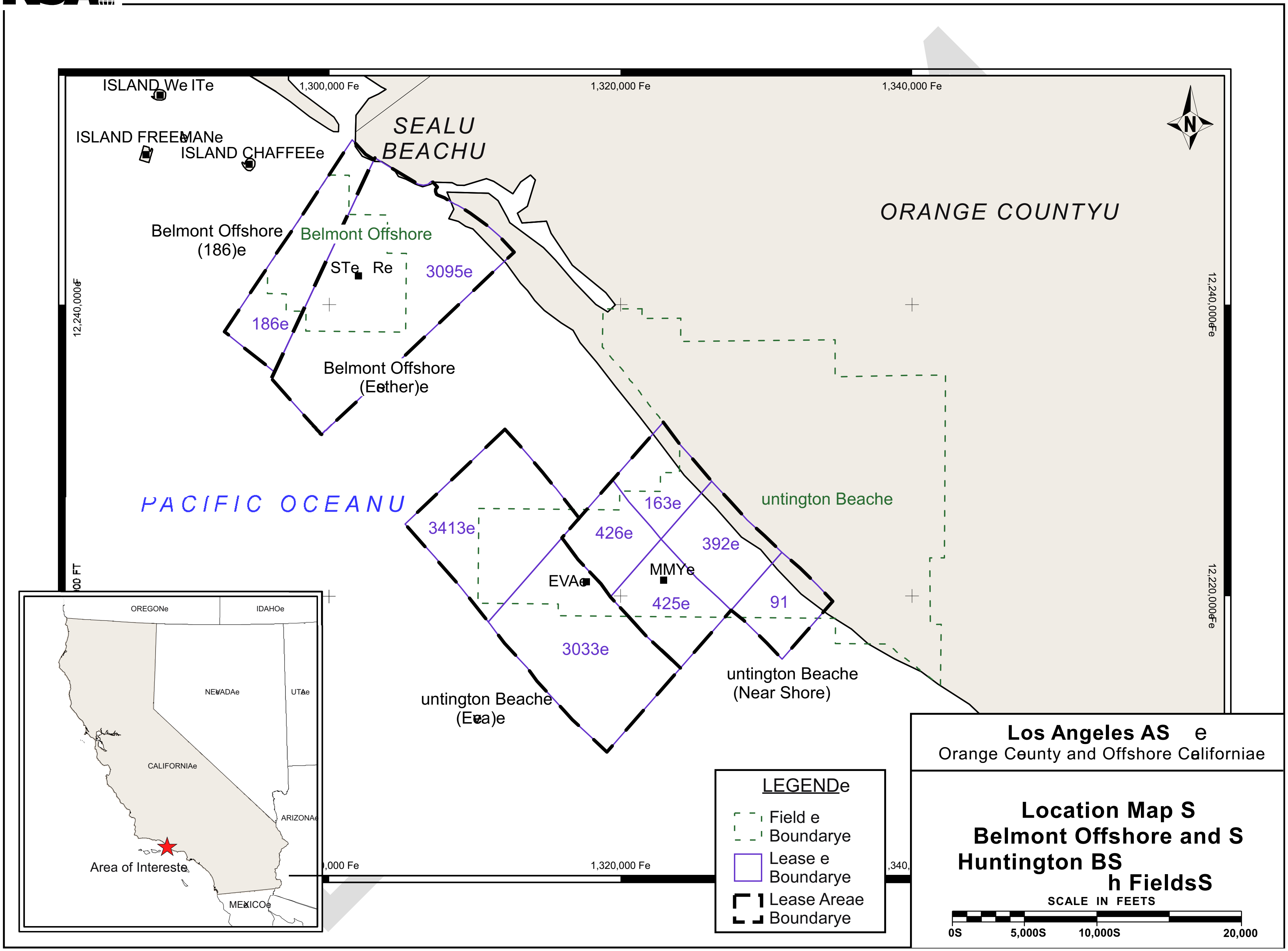

Figure 2.3.1e

All estimUtes and exhibits herein are pUrt of this NSAI report and are subject to its pHU eters and conditions.U

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NETHERLAND, SEWELL & ASSOCIATES, INC.

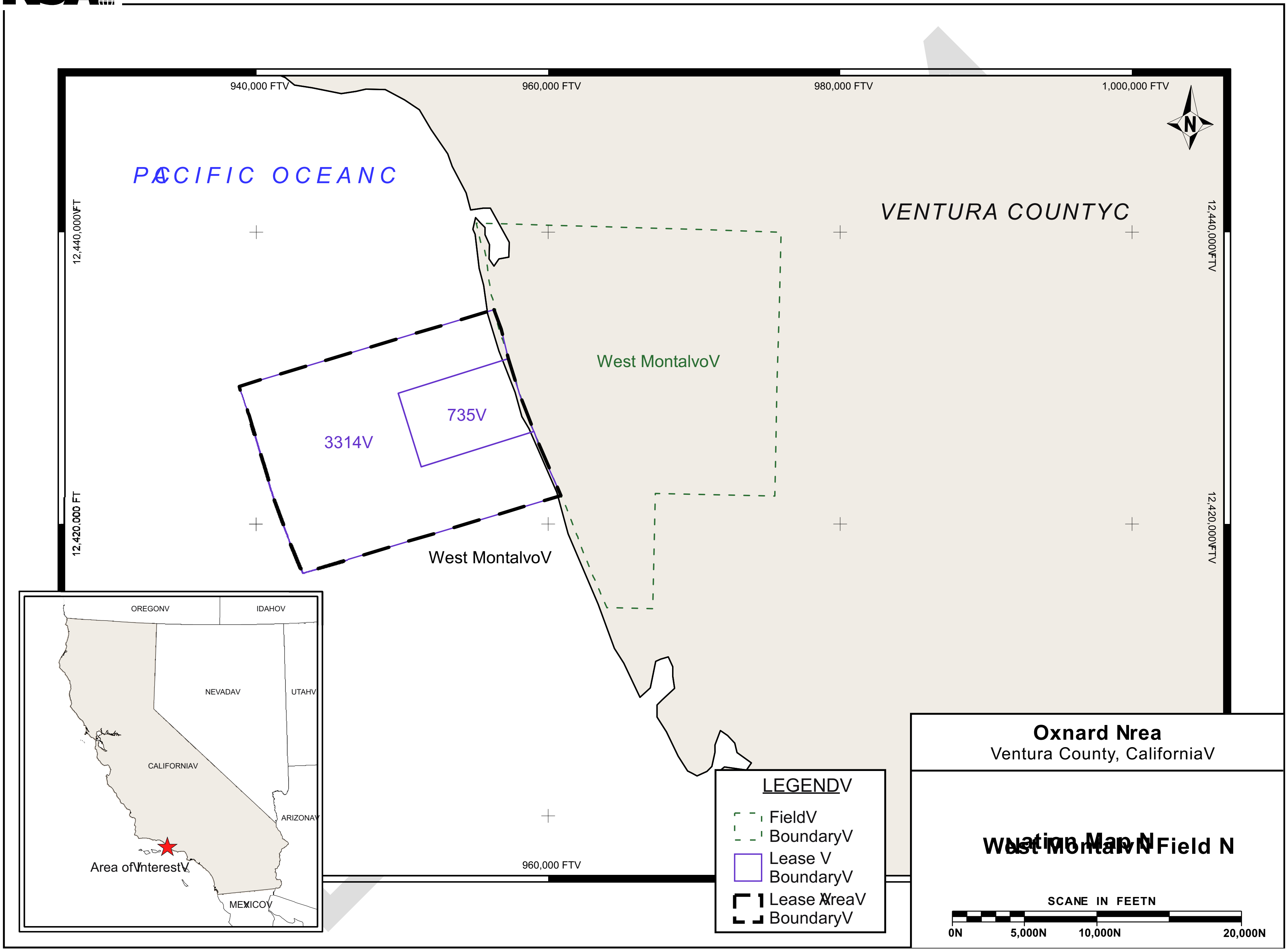

Figure 2.3

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

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3.0 PROPOSED OUTLINE OF THE COST STUDY ELEMENTS

The Commission has organized the cost study into a series of tasks in support of the primary objectives described in Section 2.1. For this preliminary status update, we present our findings from several of the tasks, based on the data available and analysis completed at the time of preparation. Our final report, scheduled for publication in December 2024, will present our complete findings on all of the cost study tasks and objectives, including updates to our preliminary findings based on data that becomes available in the interim.

We propose that the 2024 final cost study include the following elements:

1. A table of contents, including a list of appendices.
2. An executive summary.
3. An introduction covering the cost study background and objectives.
4. Our analysis of the expected duration of oil production at the time of leasing.
5. A summary of the state revenues received to date.
6. Our estimates of the expected remaining life of each lease area based on proved reserves.
7. Our estimates of reasonably anticipated unrealized lessee revenues and profits.
8. Our estimates of reasonably anticipated unrealized state revenues.
9. A qualitative discussion of the potential impacts of Senate Bill 1137 (Gonzalez, Chapter 365, Statutes of 2022) on the estimates of reserves and future revenues.
10. Our estimates of lessees' decommissioning and restoration costs.

4.0 SUMMARY OF PUBLIC COMMENTS RECEIVED BY THE COMMISSION

The Commission held a public hearing regarding the AB 2257 cost study on December 5, 2023. The public comments received at this hearing are included as Appendix 1.

5.0 IDENTIFIED DATA GAPS

5.1 EXPECTED DURATION OF PRODUCTION AT TIME OF LEASING

Documents from the time of leasing indicating expectations of the duration of production from the leases are absent from public data sources and the internal records of the Commission that NSAI reviewed. If the Commission requires this information to be included in the final report, the Commission will need to provide data that would allow us to make this determination. However, we believe that expected production duration estimates from the time of leasing, more than fifty years out of date, would have very limited usefulness in achieving the core objectives of the cost study. Therefore, we recommend that the Commission limit discussion of this topic in the final report to a comment regarding the lack of available data.

5.2 OIL AND GAS LEASE RENT REVENUES

There are minor gaps in the historical rent revenue data in the Commission's dataset. Based on a discussion with Commission staff, we understand that these rental fees were likely to have been received, although confirmation would require a search for accounting records. The value of these rent payments is very small in comparison to the royalties, for which full records were available. Therefore, we conclude that a search for accounting records would not materially change the results of this cost study. We recommend proceeding under the assumption that historical rent has been paid as required under the lease agreements, with no further action needed.

5.3 BELMONT OFFSHORE (186) LEASE AREA FIRM DEVELOPMENT PLANS

We received various development scenario maps from CRC but could not clarify CRC's firm development plans in time to include all of the potential opportunities identified by CRC in this preliminary status update. If we can clarify the firm development plans for these properties, we may include additional non-producing or undeveloped reserves for the Belmont Offshore (186) Lease Area in our final report.

5.4 HUNTINGTON BEACH (NEAR SHORE) LEASE AREA FIRM DEVELOPMENT PLANS

We have not yet received firm development plans directly from CRC for the timing of future drilling. For the purposes of this preliminary status update, we have included undeveloped locations assuming a drilling pace of approximately five wells per year, similar to the average pace of the past nine years. We have assumed that lower water cut locations would be drilled first. If more data become available regarding CRC's near-term development plans, we may modify our classification of some or all of the undeveloped locations in our final report.

5.5 PLATFORM EVA RESTART

DCOR has indicated that they expect to achieve all regulatory approvals and restart Platform Eva in 2024 after rerouting production to Platform Edith, located in federal waters. We understand that the required infrastructure is already in place and startup is pending regulatory approvals. Because the restart date falls before the effective date of our report, our estimates in this preliminary status update reflect Platform Eva being online, and the existing well stock is subcategorized as developed producing. However, at the current time, not all regulatory approvals have been granted and the platform is idle. We will need to evaluate the actual situation closer to the effective date and make a final determination of reserves classification at that time.

5.6 WEST MONTALVO LEASE AREA LEASE OPERATING STATEMENTS

Because of the pending assignment of the West Montalvo Field state leases to CalNRG, CRC was not able to provide lease operating data beyond 2021. The data CRC did provide appeared to be a combination of costs for the state offshore leases and other onshore production. We used the data available, covering 2018 to 2021, and our knowledge of similar operations to estimate the operating expenses for the West Montalvo Lease Area. However, lease operating statements covering a more recent 12-month period and limited to the state leases in question would improve the accuracy of our operating expense estimates.

5.7 WEST MONTALVO LEASE AREA FIRM DEVELOPMENT PLANS

We have not received firm future development plans from CRC or CalNRG for the West Montalvo Lease Area. Therefore, we have not included any non-producing or undeveloped reserves in our estimates in this preliminary status update. Should sufficient data become available, we may include such subcategories in the final report.

6.0 STATE REVENUES RECEIVED TO DATE

As specified by the Commission, we have reviewed and tabulated the historical revenue data provided by the Commission. As discussed in Section 5.2, there are minor gaps in historical rent revenue data in the Commission's dataset. We have assumed that the rent fees during those gap periods were paid to the State of California as required under the leases.

Cumulative royalty and rent revenue received by the State of California through December 31, 2022, for each lease area is shown in the following table:

Lease Area	Lessee	Cumulative Revenue (M$)
Belmont Offshore (186)	CRC	137,267.1
Belmont Offshore (Esther)	DCOR	94,133.6
Huntington Beach (Eva)	DCOR	180,838.0
Huntington Beach (Near Shore)	CRC	827,237.3
West Montalvo	CRC	53,696.8

More detailed tables of annual historical revenue by lease area and by lease are shown in Figures 6.1.1 through 6.1.3.

6.1 FIGURES

ROYALTY AND RENT REVENUE BY LEASE AREA ($)
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Belmont Offshore (186) Lease Area	Belmont Offshore (Esther) Lease Area	Huntington Beach (Eva) Lease Area	Huntington Beach (Near Shore) Lease Area	West Montalvo Lease Area
1938	0.0	0.0	0.0	2,417.3	0.0
1939	0.0	0.0	0.0	245,042.0	0.0
1940	0.0	0.0	0.0	321,783.0	0.0
1941	0.0	0.0	0.0	440,695.0	0.0
1942	0.0	0.0	0.0	628,857.0	0.0
1943	0.0	0.0	0.0	905,292.8	0.0
1944	0.0	0.0	0.0	2,500,091.2	0.0
1945	1,342.5	0.0	0.0	2,818,656.0	0.0
1946	5,000.0	0.0	0.0	2,753,509.0	0.0
1947	8,828.0	0.0	0.0	3,932,566.0	0.0
1948	5,000.0	0.0	0.0	6,809,105.0	0.0
1949	13,216.0	0.0	0.0	6,600,192.0	0.0
1950	9,654.0	0.0	0.0	6,597,819.6	0.0
1951	9,618.0	0.0	0.0	8,087,826.0	0.0
1952	9,642.0	0.0	0.0	7,469,316.0	482.6
1953	10,084.0	0.0	0.0	7,602,562.0	104,338.0
1954	40,265.0	0.0	0.0	7,757,568.0	109,255.0
1955	346,195.0	0.0	0.0	7,440,166.0	185,531.0
1956	385,248.0	0.0	0.0	8,256,484.0	424,256.0
1957	578,017.0	0.0	0.0	8,620,160.0	511,265.0
1958	761,444.0	0.0	0.0	8,442,293.0	378,200.0
1959	709,731.0	0.0	0.0	5,325,831.0	168,074.0
1960	856,100.0	0.0	0.0	4,827,949.0	208,536.0
1961	922,914.0	0.0	0.0	4,611,021.0	234,032.0
1962	783,241.0	0.0	0.0	4,131,089.0	144,828.0
1963	699,574.0	0.0	920.6	3,922,135.0	81,381.0
1964	651,386.0	3,167.6	1,559,113.3	4,340,519.0	86,358.0
1965	623,587.0	847,330.7	3,530,070.1	4,099,148.0	87,404.6
1966	525,806.0	3,551,081.7	4,209,932.3	3,868,379.0	70,603.0
1967	596,249.0	3,856,610.7	3,331,571.3	3,537,154.0	49,653.0
1968	361,651.0	2,155,314.7	2,485,253.3	3,485,493.0	44,255.0
1969	325,034.0	1,572,867.7	1,873,123.3	3,518,079.0	43,715.0
1970	269,648.0	1,523,080.7	1,652,982.3	3,312,116.0	62,630.0
1971	236,652.0	1,114,605.7	1,280,879.3	4,585,002.0	43,470.0
1972	301,492.0	899,815.7	1,138,086.3	6,302,180.0	47,985.0
1973	263,904.0	682,434.7	689,027.3	4,943,801.0	31,700.0
1974	1,177,924.0	1,303,118.7	1,348,991.3	15,555,364.0	69,404.0
1975	1,454,789.0	1,479,719.7	1,198,384.3	13,210,776.0	61,024.0
1976	1,511,895.0	1,472,069.7	1,104,068.3	10,617,671.0	70,542.0
1977	1,309,619.0	1,250,472.7	1,039,693.3	9,278,229.0	43,680.0

ROYALTY AND RENT REVENUE BY LEASE AREA ($)
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Belmont Offshore (186) Lease Area	Belmont Offshore (Esther) Lease Area	Huntington Beach (Eva) Lease Area	Huntington Beach (Near Shore) Lease Area	West Montalvo Lease Area
1978	1,385,859.0	976,474.7	1,115,508.3	8,557,837.0	39,080.0
1979	1,778,916.0	1,056,919.0	1,476,916.3	12,217,116.0	42,640.0
1980	3,258,370.0	1,500,054.0	2,269,644.3	22,228,340.0	152,308.0
1981	3,860,888.0	3,215,547.0	6,249,232.3	32,545,535.0	112,599.0
1982	4,014,500.0	3,415,180.0	6,617,605.3	32,406,243.0	86,478.0
1983	2,445,174.0	224,179.0	5,727,205.3	24,555,672.0	66,444.0
1984	1,420,542.0	4,826.0	2,536,733.2	11,561,932.0	41,902.0
1985	2,533,831.4	5,310.0	4,282,316.4	17,379,766.2	79,305.3
1986	1,064,832.8	5,310.0	2,179,094.1	9,719,666.1	359,317.8
1987	804,718.1	5,310.0	2,229,708.5	8,109,363.1	232,218.0
1988	608,748.8	5,310.0	1,633,288.8	5,971,923.2	179,310.2
1989	1,025,314.1	5,310.0	1,873,485.0	5,915,306.7	138,815.5
1990	267,952.4	5,310.0	1,985,049.6	5,599,454.9	112,578.8
1991	569,086.9	26,913.1	1,439,692.9	5,644,676.0	256,236.3
1992	690,123.9	84,725.7	1,620,149.2	5,075,508.3	200,969.4
1993	323,489.3	434,343.2	1,214,235.9	4,515,476.5	142,231.0
1994	9,267.7	12,394.7	1,268,526.9	4,788,923.1	130,451.3
1995	5,000.0	439,945.6	565,244.2	4,792,463.8	170,568.7
1996	5,000.0	1,187,704.6	2,225,529.2	2,536,950.2	489,145.0
1997	5,000.0	2,509,692.9	3,378,631.7	457,983.5	389,836.8
1998	5,000.0	1,500,931.0	1,665,002.8	117,257.9	214,499.6
1999	5,000.0	1,917,705.2	2,138,555.2	389,886.3	281,942.6
2000	5,000.0	3,036,313.1	3,734,514.4	1,400,225.9	539,699.7
2001	5,000.0	2,005,559.7	2,631,074.0	1,922,863.3	448,003.0
2002	5,000.0	1,753,972.4	2,540,183.5	944,907.0	379,113.4
2003	5,000.0	1,576,286.7	3,009,871.2	12,510,803.9	535,525.2
2004	5,000.0	2,063,707.2	3,714,722.8	15,659,013.4	666,513.5
2005	1,355,960.9	2,390,200.3	4,306,904.3	19,167,819.5	741,104.1
2006	4,316,483.3	2,693,257.9	4,866,641.9	19,682,425.0	800,830.2
2007	6,414,888.8	2,847,815.0	4,619,873.3	20,203,882.5	867,568.7
2008	9,091,328.1	3,034,720.1	6,681,720.7	25,781,484.1	3,200,920.8
2009	5,753,104.8	1,246,289.5	3,959,119.4	15,199,378.2	1,527,460.9
2010	8,506,471.0	3,165,312.4	4,352,956.8	18,590,324.8	1,912,501.7
2011	11,064,718.4	4,005,595.9	5,317,632.5	22,166,495.8	2,554,454.6
2012	11,213,269.9	4,356,855.9	10,424,354.2	22,786,291.7	8,577,611.8
2013	8,823,640.9	4,468,619.0	10,223,244.4	26,091,018.8	7,325,547.3
2014	7,293,479.4	3,219,258.1	7,369,123.8	28,023,471.4	5,750,158.1
2015	3,031,154.5	1,343,944.5	2,805,996.4	17,655,504.0	1,930,655.4
2016	2,010,293.4	1,149,902.2	2,518,494.6	10,715,484.4	1,263,207.1
2017	2,735,480.8	1,431,176.5	2,995,611.7	14,751,150.9	1,596,056.4

ROYALTY AND RENT REVENUE BY LEASE AREA ($)
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Belmont Offshore (186) Lease Area	Belmont Offshore (Esther) Lease Area	Huntington Beach (Eva) Lease Area	Huntington Beach (Near Shore) Lease Area	West Montalvo Lease Area
2018	3,369,936.4	1,916,308.4	3,827,246.6	20,625,353.5	1,981,354.2
2019	2,735,695.9	1,657,202.0	3,496,970.9	21,021,393.3	1,692,603.4
2020	1,618,826.7	858,255.8	2,009,111.8	9,245,702.6	611,856.2
2021	2,525,162.1	1,472,128.6	3,152,839.5	20,632,406.2	572,574.5
2022	3,530,869.4	2,189,808.0	146,381.8	25,668,292.3	939,985.1
Total	137,267,128.3	94,133,575.9	180,838,041.8	827,237,310.1	53,696,784.6

Totals may not add because of rounding.

ROYALTY AND RENT REVENUE BY LEASE ($)
OIL AND GAS LEASES
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Lease No. 91	Lease No. 163	Lease No. 186	Lease No. 392	Lease No. 425	Lease No. 426	Lease No. 735	Lease No. 3033	Lease No. 3095	Lease No. 3314	Lease No. 3413	Lease No. 7820[1]	All Oil and Gas Leases
1938	0.0	0.0	0.0	2,417.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,417.3
1939	0.0	0.0	0.0	245,042.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	245,042.0
1940	0.0	0.0	0.0	321,783.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	321,783.0
1941	0.0	0.0	0.0	440,695.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	440,695.0
1942	0.0	0.0	0.0	628,857.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	628,857.0
1943	23,649.8	0.0	0.0	881,643.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	905,292.8
1944	454,567.0	402.2	0.0	2,045,122.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,500,091.2
1945	627,005.0	48,248.0	1,342.5	2,143,403.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,819,998.5
1946	520,920.0	116,832.0	5,000.0	2,115,757.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,758,509.0
1947	583,414.0	131,757.0	8,828.0	3,217,395.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,941,394.0
1948	834,897.0	222,605.0	5,000.0	5,751,603.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,814,105.0
1949	647,542.0	160,632.0	13,216.0	5,792,018.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,613,408.0
1950	568,137.0	139,010.0	9,654.0	5,388,566.0	358,672.0	143,434.5	0.0	0.0	0.0	0.0	0.0	0.0	6,607,473.6
1951	523,902.0	141,659.0	9,618.0	6,402,532.0	741,603.0	278,130.0	0.0	0.0	0.0	0.0	0.0	0.0	8,097,444.0
1952	466,770.0	113,445.0	9,642.0	5,152,263.0	1,340,595.0	396,243.0	482.6	0.0	0.0	0.0	0.0	0.0	7,479,440.6
1953	427,673.0	120,183.0	10,084.0	4,539,368.0	1,885,296.0	630,042.0	104,338.0	0.0	0.0	0.0	0.0	0.0	7,716,984.0
1954	356,195.0	102,104.0	40,265.0	4,102,567.0	2,164,153.0	1,032,549.0	109,255.0	0.0	0.0	0.0	0.0	0.0	7,907,088.0
1955	351,269.0	95,383.0	346,195.0	3,871,419.0	1,890,700.0	1,231,395.0	185,531.0	0.0	0.0	0.0	0.0	0.0	7,971,892.0
1956	328,889.0	98,715.0	385,248.0	4,118,030.0	2,043,487.0	1,667,363.0	424,256.0	0.0	0.0	0.0	0.0	0.0	9,065,988.0
1957	374,367.0	124,447.0	578,017.0	4,454,693.0	1,756,596.0	1,910,057.0	511,265.0	0.0	0.0	0.0	0.0	0.0	9,709,442.0
1958	358,214.0	133,709.0	761,444.0	4,911,809.0	1,417,190.0	1,621,371.0	378,200.0	0.0	0.0	0.0	0.0	0.0	9,581,937.0
1959	162,775.0	62,255.0	709,731.0	2,560,115.0	1,216,951.0	1,323,735.0	168,074.0	0.0	0.0	0.0	0.0	0.0	6,203,636.0
1960	138,281.0	59,224.0	856,100.0	2,380,453.0	1,017,167.0	1,232,824.0	208,536.0	0.0	0.0	0.0	0.0	0.0	5,892,585.0
1961	117,116.0	52,320.0	922,914.0	2,132,424.0	1,079,666.0	1,229,495.0	234,032.0	0.0	0.0	0.0	0.0	0.0	5,767,967.0
1962	102,661.0	42,128.0	783,241.0	1,765,488.0	1,023,417.0	1,197,395.0	144,828.0	0.0	0.0	0.0	0.0	0.0	5,059,158.0
1963	97,996.0	35,015.0	699,574.0	1,548,508.0	996,981.0	1,243,635.0	81,381.0	920.6	0.0	0.0	0.0	0.0	4,704,010.6
1964	87,855.0	35,284.0	651,386.0	1,803,167.0	1,201,330.0	1,212,883.0	86,358.0	1,559,113.3	3,167.6	0.0	0.0	0.0	6,640,543.8
1965	76,585.0	27,728.0	623,587.0	1,862,100.0	1,072,216.0	1,060,519.0	84,697.0	3,527,942.3	847,152.0	2,707.6	153.8	0.0	9,185,387.6
1966	68,903.0	22,766.0	525,806.0	1,800,647.0	928,452.0	1,047,611.0	65,173.0	3,713,609.3	3,550,903.0	5,430.0	495,571.0	0.0	12,224,871.3
1967	97,075.0	27,080.0	596,249.0	1,853,752.0	908,648.0	650,599.0	44,223.0	3,175,365.3	3,856,432.0	5,430.0	155,454.0	0.0	11,370,307.3
1968	97,305.0	28,491.0	361,651.0	1,835,482.0	1,079,922.0	444,293.0	38,825.0	2,384,738.3	2,155,136.0	5,430.0	99,763.0	0.0	8,531,036.3
1969	101,601.0	28,110.0	325,034.0	2,024,477.0	1,015,608.0	348,283.0	38,285.0	1,829,321.3	1,572,689.0	5,430.0	43,050.0	0.0	7,331,888.3
1970	128,036.0	19,939.0	269,648.0	1,912,312.0	914,054.0	337,775.0	57,200.0	1,612,748.3	1,522,902.0	5,430.0	39,482.0	0.0	6,819,526.3
1971	88,060.0	27,841.0	236,652.0	3,145,003.0	1,006,062.0	318,036.0	38,040.0	1,250,177.3	1,114,427.0	5,430.0	29,950.0	0.0	7,259,678.3
1972	275,831.0	32,745.0	301,492.0	4,105,191.0	1,573,756.0	314,657.0	42,555.0	1,102,729.3	899,637.0	5,430.0	34,605.0	0.0	8,688,628.3
1973	830,337.0	11,752.0	263,904.0	2,112,544.0	1,598,927.0	390,241.0	26,270.0	662,334.3	682,256.0	5,430.0	25,941.0	0.0	6,609,936.3
1974	3,406,294.0	12,148.0	1,177,924.0	4,214,424.0	6,762,414.0	1,160,084.0	63,974.0	1,269,955.3	1,302,940.0	5,430.0	78,284.0	0.0	19,453,871.3
1975	2,644,447.0	11,392.0	1,454,789.0	3,931,820.0	5,565,550.0	1,057,567.0	55,594.0	1,114,485.3	1,479,541.0	5,430.0	83,147.0	0.0	17,403,762.3
1976	1,651,615.0	8,469.0	1,511,895.0	4,111,069.0	3,973,575.0	872,943.0	65,112.0	1,031,571.3	1,471,891.0	5,430.0	71,745.0	0.0	14,775,315.3
1977	1,213,485.0	11,146.0	1,309,619.0	4,433,825.0	2,735,728.0	884,045.0	38,250.0	978,906.3	1,250,294.0	5,430.0	60,035.0	0.0	12,920,763.3
1978	1,097,576.0	13,144.0	1,385,859.0	4,674,201.0	1,850,685.0	922,231.0	33,650.0	1,068,985.3	976,296.0	5,430.0	45,771.0	0.0	12,073,828.3
1979	834,925.0	65,734.0	1,778,916.0	4,776,360.0	2,304,919.0	4,235,178.0	37,210.0	1,424,371.3	1,055,453.0	5,430.0	47,335.0	0.0	16,565,831.3
1980	1,088,047.0	177,845.0	3,258,370.0	10,121,891.0	4,103,670.0	6,736,887.0	146,878.0	2,209,727.3	1,498,588.0	5,430.0	54,707.0	0.0	29,402,040.3
1981	1,059,173.0	156,922.0	3,860,888.0	12,228,020.0	6,883,472.0	12,217,948.0	107,169.0	6,179,895.3	3,214,081.0	5,430.0	64,127.0	0.0	45,977,125.3
1982	1,288,101.0	106,017.0	4,014,500.0	11,888,093.0	7,330,462.0	11,793,570.0	81,048.0	6,557,520.3	3,413,714.0	5,430.0	54,875.0	0.0	46,533,330.3
1983	957,507.0	91,676.0	2,445,174.0	9,409,674.0	6,161,775.0	7,935,040.0	61,014.0	5,674,354.3	222,713.0	5,430.0	47,641.0	0.0	33,011,998.3
1984	428,297.0	19,932.0	1,420,542.0	4,615,821.0	3,073,083.0	3,424,799.0	36,472.0	2,500,026.3	3,360.0	5,430.0	25,644.0	0.0	15,553,406.3
1985	1,034,796.3	38,923.2	2,533,831.4	7,133,750.7	4,938,310.2	4,233,985.8	73,875.3	4,231,207.1	3,360.0	5,430.0	42,972.8	0.0	24,270,442.7
1986	639,781.6	21,425.4	1,064,832.8	3,684,535.5	2,637,245.5	2,736,678.0	30,695.7	2,160,717.5	3,360.0	328,622.2	2,075.6	0.0	13,309,969.8
1987	634,624.4	13,010.4	804,718.1	3,012,428.2	2,122,425.3	2,326,874.8	52,578.5	2,216,763.2	3,360.0	179,639.6	2,087.4	0.0	11,368,509.7
1988	310,673.6	16,846.3	608,748.8	2,285,213.8	1,556,421.4	1,802,768.1	38,421.8	1,620,447.5	3,360.0	140,888.4	1,983.2	0.0	8,385,773.0
1989	425,923.5	22,835.5	1,025,314.1	2,339,852.3	1,614,126.7	1,512,568.7	47,707.0	1,860,280.6	3,360.0	91,108.5	2,346.4	0.0	8,945,423.2
1990	504,206.5	16,579.6	267,952.4	2,305,378.2	1,367,228.4	1,406,062.2	47,560.2	1,972,021.0	3,360.0	65,018.6	2,170.6	0.0	7,957,537.7
1991	398,636.6	5,213.6	569,086.9	2,193,421.0	1,376,987.1	1,670,417.7	31,649.0	1,426,818.4	24,963.1	224,587.3	2,016.6	0.0	7,923,797.3
1992	513,025.0	24,199.5	690,123.9	1,976,191.7	1,288,022.2	1,274,069.9	29,714.1	1,355,011.7	82,775.7	171,255.3	1,988.8	0.0	7,406,377.9

Figure 6.1.2
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PRELIMINARY – FOR REVIEW ONLY

ROYALTY AND RENT REVENUE BY LEASE ($)
OIL AND GAS LEASES
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Lease No. 91	Lease No. 163	Lease No. 186	Lease No. 392	Lease No. 425	Lease No. 426	Lease No. 735	Lease No. 3033	Lease No. 3095	Lease No. 3314	Lease No. 3413	Lease No. 7820[1]	All Oil and Gas Leases
1993	352,328.2	36,120.2	323,489.3	1,621,902.2	1,456,075.1	1,049,050.7	57,362.2	1,198,829.8	432,393.2	84,868.8	4,548.1	0.0	6,616,967.9
1994	325,141.7	28,288.9	9,267.7	1,316,289.7	1,682,563.6	1,436,639.2	39,503.1	1,175,605.9	10,444.7	90,948.2	1,871.0	0.0	6,116,563.6
1995	305,044.9	18,067.3	5,000.0	1,197,178.2	860,866.1	1,293,315.3	54,094.7	508,821.2	437,995.6	116,474.0	1,871.0	1,117,992.1	5,916,720.3
1996	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	380,855.5	2,169,106.2	1,185,754.6	108,289.5	1,871.0	2,525,040.2	6,387,827.0
1997	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	311,626.5	3,322,208.7	2,507,742.9	78,210.3	1,871.0	446,073.5	6,684,642.8
1998	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	153,785.9	1,608,579.8	1,498,981.0	60,713.7	1,871.0	105,347.9	3,446,189.3
1999	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	220,662.8	2,082,132.2	1,915,755.2	61,279.8	1,871.0	377,976.3	4,676,587.3
2000	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	425,183.8	3,678,091.4	3,034,363.1	114,515.9	1,871.0	1,388,315.9	8,659,251.1
2001	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	334,347.6	2,574,651.0	1,973,331.7	113,655.4	1,871.0	1,910,953.3	6,925,719.9
2002	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	305,493.8	2,483,760.5	1,736,883.4	73,619.6	1,871.0	932,997.0	5,551,535.3
2003	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	382,791.5	2,953,448.2	1,559,197.7	152,733.7	1,871.0	12,498,893.9	17,565,846.0
2004	500.0	3,200.0	5,000.0	835.0	4,175.0	3,200.0	474,322.9	3,658,299.8	2,061,757.2	192,190.6	1,871.0	15,647,103.4	22,052,454.8
2005	500.0	3,200.0	1,355,960.9	835.0	4,175.0	3,200.0	536,858.1	4,250,481.3	2,373,111.3	204,246.0	1,871.0	19,155,909.5	27,890,348.1
2006	500.0	3,200.0	4,316,483.3	835.0	4,175.0	3,200.0	544,577.4	4,644,322.9	2,676,168.9	256,252.8	1,871.0	19,670,515.0	32,122,101.3
2007	500.0	3,200.0	6,414,888.8	835.0	4,175.0	3,200.0	493,225.5	4,480,502.3	2,830,726.0	374,343.2	1,871.0	20,191,972.5	34,799,439.2
2008	500.0	3,200.0	9,091,328.1	835.0	4,175.0	3,200.0	1,119,305.9	6,542,349.7	3,017,631.1	2,081,614.9	1,871.0	25,769,574.1	47,635,584.9
2009	500.0	3,200.0	5,753,104.8	835.0	4,175.0	3,200.0	647,971.1	3,819,748.4	1,229,200.5	879,489.8	1,871.0	15,187,468.2	27,530,763.7
2010	500.0	3,200.0	8,506,471.0	835.0	4,175.0	3,200.0	755,325.4	4,213,585.8	3,134,112.4	1,157,176.3	1,871.0	18,578,414.8	36,358,866.7
2011	500.0	3,200.0	11,064,718.4	835.0	4,175.0	3,200.0	1,046,993.7	5,169,961.5	3,974,395.9	1,507,460.9	1,871.0	22,154,585.8	44,931,897.1
2012	500.0	3,200.0	11,213,269.9	835.0	4,175.0	3,200.0	810,862.4	10,276,683.2	4,325,655.9	7,766,749.5	1,871.0	22,774,381.7	57,181,383.5
2013	500.0	3,200.0	8,823,640.9	835.0	4,175.0	3,200.0	774,423.9	10,075,573.4	4,437,419.0	6,551,123.4	1,871.0	26,079,108.8	56,755,070.3
2014	500.0	3,200.0	7,293,479.4	835.0	4,175.0	3,200.0	649,310.2	7,221,452.8	3,188,058.1	5,100,847.8	1,871.0	28,011,561.4	51,478,490.7
2015	500.0	3,200.0	3,031,154.5	835.0	4,175.0	3,200.0	301,560.5	2,658,325.4	1,294,264.5	1,629,094.9	1,871.0	17,643,594.0	26,571,774.8
2016	500.0	3,200.0	2,010,293.4	835.0	4,175.0	3,200.0	195,522.3	2,370,823.6	1,100,222.2	1,067,684.8	1,871.0	10,703,574.4	17,461,901.6
2017	500.0	3,200.0	2,735,480.8	835.0	4,175.0	3,200.0	274,598.6	2,833,166.7	1,381,496.5	1,321,457.8	1,871.0	14,739,240.9	23,299,222.4
2018	500.0	3,200.0	3,369,936.4	835.0	4,175.0	3,200.0	431,918.3	3,664,801.6	1,866,628.4	1,549,435.9	1,871.0	20,613,443.5	31,509,945.0
2019	500.0	3,200.0	2,735,695.9	835.0	4,175.0	3,200.0	455,990.2	3,334,525.9	1,607,522.0	1,236,613.2	1,871.0	21,009,483.3	30,393,611.5
2020	500.0	3,200.0	1,618,826.7	835.0	4,175.0	3,200.0	154,889.8	1,846,666.8	808,575.8	456,966.4	1,871.0	9,233,792.6	14,133,499.0
2021	500.0	3,200.0	2,525,162.1	835.0	4,175.0	3,200.0	125,331.3	2,990,394.5	1,422,448.6	447,243.2	1,871.0	20,620,496.2	28,144,857.0
2022	500.0	3,200.0	3,530,869.4	835.0	4,175.0	3,200.0	199,712.6	- 16,063.2	2,140,128.0	740,272.5	1,871.0	25,656,382.3	32,265,082.6
Total	31,044,977.1	3,264,144.1	137,267,128.3	202,862,530.0	101,989,778.4	93,331,688.0	16,808,784.4	175,462,901.0	93,383,836.5	36,888,000.2	1,673,729.2	394,744,192.5	1,288,721,689.6

Totals may not add because of rounding.

[1] It is our understanding that Lease Number 7820 is an aggregation of the other five Huntington Beach (Near Shore) leases, Lease Numbers 91, 163, 392, 425, and 426.

RENT REVENUE ($)
RIGHT-OF-WAY AND PIPELINE LEASES
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Lease No. 3116	Lease No. 3394	Lease No. 5663[1]	All Right-of-Way and Pipeline Leases
1965	1,974.1	178.7	0.0	2,152.8
1966	752.0	178.7	0.0	930.8
1967	752.0	178.7	0.0	930.8
1968	752.0	178.7	0.0	930.8
1969	752.0	178.7	0.0	930.8
1970	752.0	178.7	0.0	930.8
1971	752.0	178.7	0.0	930.8
1972	752.0	178.7	0.0	930.8
1973	752.0	178.7	0.0	930.8
1974	752.0	178.7	0.0	930.8
1975	752.0	178.7	0.0	930.8
1976	752.0	178.7	0.0	930.8
1977	752.0	178.7	0.0	930.8
1978	752.0	178.7	0.0	930.8
1979	5,210.0	1,466.0	0.0	6,676.0
1980	5,210.0	1,466.0	0.0	6,676.0
1981	5,210.0	1,466.0	0.0	6,676.0
1982	5,210.0	1,466.0	0.0	6,676.0
1983	5,210.0	1,466.0	0.0	6,676.0
1984	11,063.0	1,466.0	0.0	12,529.0
1985	8,136.5	1,950.0	0.0	10,086.5
1986	16,301.0	1,950.0	0.0	18,251.0
1987	10,858.0	1,950.0	0.0	12,808.0
1988	10,858.0	1,950.0	0.0	12,808.0
1989	10,858.0	1,950.0	0.0	12,808.0
1990	10,858.0	1,950.0	0.0	12,808.0
1991	10,858.0	1,950.0	0.0	12,808.0
1992	263,148.7	1,950.0	0.0	265,098.7
1993	10,858.0	1,950.0	0.0	12,808.0
1994	91,050.0	1,950.0	0.0	93,000.0
1995	54,552.0	1,950.0	0.0	56,502.0
1996	54,552.0	1,950.0	0.0	56,502.0
1997	54,552.0	1,950.0	0.0	56,502.0
1998	54,552.0	1,950.0	0.0	56,502.0
1999	54,552.0	1,950.0	0.0	56,502.0
2000	54,552.0	1,950.0	0.0	56,502.0
2001	54,552.0	32,228.0	0.0	86,780.0
2002	54,552.0	17,089.0	0.0	71,641.0
2003	54,552.0	17,089.0	0.0	71,641.0
2004	54,552.0	1,950.0	0.0	56,502.0
2005	54,552.0	17,089.0	0.0	71,641.0

RENT REVENUE ($)
RIGHT-OF-WAY AND PIPELINE LEASES
STATE WATERS OFFSHORE CALIFORNIA
STATE OF CALIFORNIA INTEREST
THROUGH DECEMBER 31, 2022

Year	Lease No. 3116	Lease No. 3394	Lease No. 5663[(1)]	All Right-of-Way and Pipeline Leases
2006	220,448.0	17,089.0	0.0	237,537.0
2007	137,500.0	17,089.0	0.0	154,589.0
2008	137,500.0	17,089.0	0.0	154,589.0
2009	137,500.0	17,089.0	0.0	154,589.0
2010	137,500.0	31,200.0	0.0	168,700.0
2011	145,800.0	31,200.0	0.0	177,000.0
2012	145,800.0	31,200.0	0.0	177,000.0
2013	145,800.0	31,200.0	0.0	177,000.0
2014	145,800.0	31,200.0	0.0	177,000.0
2015	145,800.0	49,680.0	0.0	195,480.0
2016	145,800.0	49,680.0	0.0	195,480.0
2017	160,574.0	49,680.0	0.0	210,254.0
2018	160,574.0	49,680.0	0.0	210,254.0
2019	160,574.0	49,680.0	0.0	210,254.0
2020	160,574.0	49,680.0	0.0	210,254.0
2021	160,574.0	49,680.0	0.0	210,254.0
2022	160,574.0	49,680.0	0.0	210,254.0
Total	3,701,411.6	749,739.4	0.0	4,451,151.0

Totals may not add because of rounding.

(1) It is our understanding that Lease Number 5663 does not pay rent to the State of California.

7.0 PRELIMINARY ESTIMATES OF RESERVES AND FUTURE REVENUE

The first objective of the cost study is to perform a comprehensive economic evaluation and estimate the total proved and 2P reserves for all 11 actively producing oil and gas leases in California state waters. We have estimated the proved and probable reserves and future revenue, as of December 31, 2024, to the State of California interest in the oil and gas properties located on these leases and the associated surface leases. From these reserves estimates, we derived estimates of the economic life, reasonably anticipated unrealized lessee revenues and profits, and reasonably anticipated unrealized state revenues for each lease area.

We completed our preliminary evaluation of reserves on October 16, 2023, based on data available through mid-2023. In 2024, after we receive additional data, we will update these preliminary estimates as well as our estimates of economic life, revenues, and profits, for our final report.

These preliminary estimates have been prepared using price and cost parameters specified by the Commission, as discussed later in Section 7.2. The reserves estimates in this report have been prepared in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE) except that, as specified by the Commission, decommissioning costs have not been included in our estimates of future net revenue. Definitions are presented in Appendix 2.

7.1 RESERVES OVERVIEW

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas that, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves that are sequentially less certain to be recovered than proved reserves.

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The reserves subcategorizations in this preliminary status update are based on the development plan timing provided to us by the operators of the properties and are relative to the effective date of the reserves estimates, which is more than one year from the date of this status update. If the development plans are not executed as presented by the lessees before the effective date, certain reserves tentatively classified herein as developed producing may be recategorized as non-producing or undeveloped in our final report, or they may be reclassified as contingent resources and removed from our final report altogether. The estimates of reserves and future revenue included herein have not been adjusted for risk. These estimates do not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

7.2 DATA AVAILABLE

For the purposes of this status update, we used technical and economic data including, but not limited to, well logs, geologic maps, production data, historical price and cost information, and property ownership interests.

The data used in our estimates were obtained from the Commission, CRC, DCOR, public data sources, and the nonconfidential files of NSAI and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned.

NSAI entered into certain confidentiality agreements with the lessees to protect their proprietary technical data while achieving the Commission's goal of using the best available information to conduct the cost study. The negotiation and execution of these agreements took substantially longer than anticipated. In some cases, the subsequent data collection and transfer processes were also delayed.

7.3 METHODOLOGY

For both reserves and decommissioning liability estimates, methodologies may be broadly categorized as deterministic or probabilistic. Deterministic assessment methods are based on discrete estimates made based on available geoscience, engineering, and economic data and correspond to a given level of certainty. In other words, specific values are selected for relevant input parameters to yield specific values of results. Probabilistic methods use probability distributions for relevant input parameters to generate a continuous range of estimates and their associated probabilities.

The reserves in this status update have been estimated using deterministic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the

Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to classify, categorize, and estimate reserves in accordance with the 2018 PRMS definitions and guidelines. A portion of these reserves are for behind-pipe zones and currently undeveloped locations; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment based on the data available to us at the time of our analysis.

Producing wells and idle wells with reactivation plans were generally evaluated based on performance analysis and consideration of historical oil, gas, and water rates versus time and versus cumulative oil production. Analogy to similar properties was also considered for these wells as needed to further guide the forecasts.

Behind-pipe reserves were estimated based on performance analysis of and analogy to recent results from similar activities. Undeveloped locations were evaluated based on volumetric analysis and analogy to similar properties. Some undeveloped wells are planned to target reservoirs and fault blocks with little or no production history. Recovery from such wells was estimated based primarily on volumetric analysis of the reservoirs. We mapped the reservoirs and evaluated well logs to estimate a range of potential oil-in-place estimates, and we applied recovery factors based on analogy to the performance of similar reservoirs in other fault blocks. Undeveloped wells targeting fault blocks with mature history for infilling or replacement of prior wells that have failed were more generally evaluated with performance analysis of the production from offset wells and other recent infill wells.

7.4 ECONOMIC PARAMETERS

The preliminary estimates have been prepared using oil, NGL, and gas price parameters specified by the Commission. The price parameters were selected by the Commission based on the Commission's review of the median historic Europe Brent spot and NYMEX Henry Hub prices for the past ten years. Oil and NGL prices are based on a Europe Brent spot price of $77.00 per barrel and are adjusted by lease for quality, transportation fees, and market differentials. Gas prices are based on a NYMEX Henry Hub price of $3.60 per MMBTU and are adjusted by lease for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties.

Operating costs used are based on operating expense records of CRC and DCOR and include only direct lease- and field-level costs. Operating costs have been divided into lease-level costs, per-well costs, and per-unit-of-production costs. As specified by the Commission, these costs do not include the per-well overhead expenses allowed under joint operating agreements, nor do they include the headquarters general and administrative overhead expenses of CRC or DCOR. Also as specified by the Commission, operating costs are not escalated for inflation.

For the purposes of these estimates, per-barrel and per-MCF fees assessed on oil and gas production in the State of California to fund the operation of the California Geologic Energy Management Division are shown as production taxes. For the State of California, statutory subvention payments that are made by the state to certain local municipalities are shown as ad valorem taxes. As specified by the Commission, production taxes and ad valorem taxes are not escalated for inflation.

Capital costs used were provided by CRC and DCOR and are based on authorizations for expenditure and internal planning budgets. Capital costs are included as required for workovers, new development wells, and production equipment. As specified by the Commission, capital costs are not escalated for inflation. Also as specified by the Commission, these preliminary estimates do not include any salvage value for the lease and well equipment or the cost of decommissioning the properties.

7.5 EXPECTED REMAINING LIFE OF LEASE AREAS

As specified by the Commission, we have included our estimates of the expected remaining life of each lease area based on our preliminary estimates of proved reserves and revenue. For the purposes of this status update, we expect the operator to end the life of each lease area on the date that would maximize the operator's cumulative future net revenue under the economic assumptions described in Section 7.4. Each lease area's expected remaining life, as of December 31, 2024, is shown in the following table:

Lease Area	Expected Remaining Life (Years)
Belmont Offshore (186)	13.2
Belmont Offshore (Esther)	11.9
Huntington Beach (Eva)	16.2
Huntington Beach (Near Shore)	18.8
West Montalvo	10.3

7.6 REASONABLY ANTICIPATED UNREALIZED REVENUES AND PROFITS

AB 2257 requires estimates of reasonably anticipated unrealized lessee revenues and profits and reasonably anticipated unrealized state revenues. The term "reasonably anticipated" is not defined in the PRMS; however, for the purposes of this status update, we have interpreted "reasonably anticipated" to be equivalent to a proved plus probable (2P) estimate. Under the PRMS definitions, the 2P estimate represents the best technical estimate based on available data and it is equally likely that the actual remaining quantities recovered will be greater than or less than this estimate. Therefore, we believe that it is reasonable to anticipate recovery of the 2P reserves and revenue.

For the purposes of this status update, we have also interpreted "revenues" to be equivalent to gross revenue at the lease area level. Gross revenue shown is the interest owner's share of the gross (100 percent) revenue from the properties prior to any deductions. For the State of California, gross revenue shown also includes rental fees associated with the mineral and surface leases, which are shown as other revenue. Additionally, we have interpreted "profits" to be equivalent to future net revenue at the lease area level. For each lessee, future net revenue is after deductions for the lessee's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. For the State of California, future net revenue is after deductions for subvention fees paid to certain local municipalities, shown herein as ad valorem taxes.

7.6.1 Lessee Revenues and Profits

Our preliminary estimates of reasonably anticipated unrealized lessee revenues and profits are based on our preliminary estimates of reserves and revenue, as of December 31, 2024, to each lessee's interest in each of the five lease areas. The following table presents our estimates of the reasonably anticipated unrealized lessee revenues and profits for each lease area:

Lease Area	Lessee	Unrealized Lessee Revenues (M$)	Unrealized Lessee Profits (M$)
Belmont Offshore (186)	CRC	91,895.7	37,825.0
Belmont Offshore (Esther)	DCOR	188,975.1	72,961.8
Huntington Beach (Eva)	DCOR	327,192.9	165,319.6
Huntington Beach (Near Shore)	CRC	1,358,294.6	396,444.5
West Montalvo	CRC	22,231.2	7,858.4

Summary projections of reserves and revenue to each lessee's interest at the lease area level are shown in Figures 7.9.1 through 7.9.5. The future net revenue shown in these summary projections has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

7.6.2 State Revenues

Our preliminary estimates of reasonably anticipated unrealized state revenues are based on our preliminary estimates of reserves and revenue, as of December 31, 2024, to the State of California royalty interest in each lease area, plus rental fees associated with the mineral and surface. The following table presents our estimate of the reasonably anticipated unrealized state revenues for each lease area:

Lease Area	Unrealized State Revenues (M$)
Belmont Offshore (186)	20,048.1
Belmont Offshore (Esther)	39,150.0
Huntington Beach (Eva)	72,192.1
Huntington Beach (Near Shore)	322,332.2
West Montalvo	4,545.2

Summary projections of reserves and revenue to the State of California royalty interest at the lease area level are shown in Figures 7.10.1 through 7.10.5. These estimates do not include other tax revenue sources of the state, such as payroll taxes and corporate income taxes, which may also be impacted by the premature decommissioning of the assets.

7.7 DISCLAIMERS AND OTHER INFORMATION

This status update is intended solely for use by the Commission to satisfy its obligation to provide a status update to the Governor and Legislature of California pursuant to AB 2257. NSAI disclaims all responsibility for the use of or reliance on this document by any other parties or for any other purpose. This document is a preliminary status update, and all of the estimates in this status update are subject to change.

NSAI did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. As described in Section 8.1.2, TSB performed site visits to certain facilities to evaluate the structures and equipment in support of their estimation of decommissioning liabilities. Neither NSAI nor TSB investigated possible environmental liability related to the properties due to unlawful pollution or other ecologic damage; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to each interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on each interest owner receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

The reserves shown are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed in this status update, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by CRC and DCOR, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing these estimates.

The technical persons primarily responsible for preparing the estimates presented in this status update meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

7.8 WORK OUTSTANDING

In 2024, NSAI will update technical forecasts, economic parameters, and development plan assumptions based on the latest data available. We will update the estimates contained in Section 7 accordingly.

7.9 FIGURES – SUMMARY PROJECTIONS OF RESERVES AND REVENUE TO THE LESSEE INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	142.1	50.9	116.7	26.0	0.0	69.24	3.087	0.00	8,081.9	80.2	0.0	0.0	8,162.0
12-31-2026	134.1	46.5	110.1	23.7	0.0	69.24	3.087	0.00	7,624.1	73.3	0.0	0.0	7,697.4
12-31-2027	131.3	44.1	107.8	22.5	0.0	69.24	3.087	0.00	7,467.4	69.4	0.0	0.0	7,536.8
12-31-2028	116.5	38.5	95.7	19.7	0.0	69.24	3.087	0.00	6,623.0	60.7	0.0	0.0	6,683.6
12-31-2029	102.8	33.4	84.4	17.1	0.0	69.24	3.087	0.00	5,842.7	52.6	0.0	0.0	5,895.4
12-31-2030	90.5	29.0	74.3	14.8	0.0	69.24	3.087	0.00	5,145.2	45.7	0.0	0.0	5,190.9
12-31-2031	80.8	25.8	66.4	13.2	0.0	69.24	3.087	0.00	4,596.7	40.6	0.0	0.0	4,637.3
12-31-2032	70.4	22.3	57.8	11.4	0.0	69.24	3.087	0.00	4,000.3	35.2	0.0	0.0	4,035.5
12-31-2033	63.5	20.2	52.2	10.3	0.0	69.24	3.087	0.00	3,612.6	31.8	0.0	0.0	3,644.4
12-31-2034	56.2	17.8	46.1	9.1	0.0	69.24	3.087	0.00	3,195.1	28.1	0.0	0.0	3,223.3
12-31-2035	51.0	16.2	41.9	8.3	0.0	69.24	3.087	0.00	2,902.0	25.6	0.0	0.0	2,927.6
12-31-2036	46.4	14.7	38.1	7.5	0.0	69.24	3.087	0.00	2,636.5	23.2	0.0	0.0	2,659.7
12-31-2037	42.1	13.4	34.6	6.8	0.0	69.24	3.087	0.00	2,396.0	21.1	0.0	0.0	2,417.1
02-28-2038	6.6	2.1	5.5	1.1	0.0	69.24	3.087	0.00	377.6	3.3	0.0	0.0	380.9
SUBTOTAL	1,134.4	374.8	931.6	191.4	0.0	69.24	3.087	0.00	64,501.1	590.9	0.0	0.0	65,092.0
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	1,134.4	374.8	931.6	191.4	0.0	69.24	3.087	0.00	64,501.1	590.9	0.0	0.0	65,092.0
CUM PROD	16,616.1	3,411.6											
ULTIMATE	17,750.5	3,786.4											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	20	20.0	120.5	233.2	0.0	0.0	3,559.5	4,248.9	4,248.9	4,058.6
12-31-2026	19	19.0	113.6	219.9	175.0	0.0	3,481.3	3,707.6	7,956.5	7,270.2
12-31-2027	19	19.0	111.2	215.3	0.0	0.0	3,511.5	3,698.8	11,655.3	10,190.0
12-31-2028	19	19.0	98.6	191.0	0.0	0.0	3,313.0	3,081.1	14,736.4	12,401.2
12-31-2029	17	17.0	87.0	168.4	0.0	0.0	3,086.4	2,553.6	17,290.0	14,067.3
12-31-2030	16	16.0	76.5	148.3	0.0	0.0	2,863.8	2,102.3	19,392.2	15,314.3
12-31-2031	15	15.0	68.4	132.5	0.0	0.0	2,728.5	1,707.9	21,100.2	16,235.5
12-31-2032	13	13.0	59.5	115.3	0.0	0.0	2,497.7	1,363.0	22,463.2	16,903.9
12-31-2033	13	13.0	53.7	104.1	0.0	0.0	2,429.2	1,057.3	23,520.6	17,375.4
12-31-2034	12	12.0	47.5	92.1	0.0	0.0	2,297.2	786.4	24,307.0	17,694.3
12-31-2035	12	12.0	43.2	83.6	0.0	0.0	2,256.6	544.1	24,851.1	17,895.1
12-31-2036	12	12.0	39.2	76.0	0.0	0.0	2,219.9	324.6	25,175.7	18,004.1
12-31-2037	12	12.0	35.6	69.1	0.0	0.0	2,186.6	125.8	25,301.5	18,042.8
02-28-2038	12	12.0	5.6	10.9	0.0	0.0	361.4	3.0	25,304.5	18,043.7
SUBTOTAL			960.2	1,859.8	175.0	0.0	36,792.5	25,304.5	25,304.5	18,043.7
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	25,304.5	18,043.7
TOTAL OF 13.2 YRS			960.2	1,859.8	175.0	0.0	36,792.5	25,304.5	25,304.5	18,043.7

PRESENT WORTH PROFILE	
DISC RATE %	CUM PW M$
8.000	19,157.5
12.000	17,050.3
15.000	15,749.6
20.000	13,980.2
25.000	12,582.6
30.000	11,456.0
35.000	10,531.4
40.000	9,760.7
45.000	9,109.5
50.000	8,552.7

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

Figure 7.9.1

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	142.1	50.9	116.7	26.0	0.0	69.24	3.087	0.00	8,081.9	80.2	0.0	0.0	8,162.0
12-31-2026	125.7	44.6	103.3	22.8	0.0	69.24	3.087	0.00	7,150.2	70.3	0.0	0.0	7,220.5
12-31-2027	112.6	39.8	92.5	20.3	0.0	69.24	3.087	0.00	6,403.1	62.8	0.0	0.0	6,465.9
12-31-2028	99.4	34.7	81.7	17.7	0.0	69.24	3.087	0.00	5,654.5	54.7	0.0	0.0	5,709.1
12-31-2029	87.3	29.9	71.7	15.3	0.0	69.24	3.087	0.00	4,961.4	47.2	0.0	0.0	5,008.6
12-31-2030	76.4	25.8	62.7	13.2	0.0	69.24	3.087	0.00	4,343.2	40.7	0.0	0.0	4,383.9
12-31-2031	68.0	22.9	55.8	11.7	0.0	69.24	3.087	0.00	3,866.9	36.1	0.0	0.0	3,903.0
12-31-2032	58.7	19.7	48.2	10.1	0.0	69.24	3.087	0.00	3,336.2	31.0	0.0	0.0	3,367.2
12-31-2033	52.9	17.8	43.4	9.1	0.0	69.24	3.087	0.00	3,008.2	28.0	0.0	0.0	3,036.2
12-31-2034	46.5	15.7	38.2	8.0	0.0	69.24	3.087	0.00	2,645.2	24.7	0.0	0.0	2,669.9
12-31-2035	42.2	14.2	34.7	7.3	0.0	69.24	3.087	0.00	2,401.5	22.5	0.0	0.0	2,424.0
12-31-2036	38.4	12.9	31.5	6.6	0.0	69.24	3.087	0.00	2,181.0	20.4	0.0	0.0	2,201.5
12-31-2037	34.8	11.8	28.6	6.0	0.0	69.24	3.087	0.00	1,981.5	18.6	0.0	0.0	2,000.1
02-28-2038	5.5	1.9	4.5	0.9	0.0	69.24	3.087	0.00	312.2	2.9	0.0	0.0	315.1
SUBTOTAL	990.6	342.4	813.5	174.9	0.0	69.24	3.087	0.00	56,326.9	540.0	0.0	0.0	56,866.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	990.6	342.4	813.5	174.9	0.0	69.24	3.087	0.00	56,326.9	540.0	0.0	0.0	56,866.9
CUM PROD	16,405.8	3,365.1											
ULTIMATE	17,396.4	3,707.6											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	20	20.0	120.5	233.2	0.0	0.0	3,559.5	4,248.9	4,248.9	4,058.6
12-31-2026	18	18.0	106.6	206.3	0.0	0.0	3,378.6	3,529.0	7,777.9	7,123.2
12-31-2027	18	18.0	95.5	184.7	0.0	0.0	3,275.2	2,910.5	10,688.4	9,421.1
12-31-2028	18	18.0	84.3	163.1	0.0	0.0	3,090.0	2,371.7	13,060.2	11,123.5
12-31-2029	16	16.0	73.9	143.1	0.0	0.0	2,875.4	1,916.1	14,976.3	12,374.0
12-31-2030	15	15.0	64.7	125.3	0.0	0.0	2,663.8	1,530.2	16,506.5	13,281.9
12-31-2031	14	14.0	57.6	111.5	0.0	0.0	2,538.5	1,195.3	17,701.8	13,926.8
12-31-2032	12	12.0	49.7	96.2	0.0	0.0	2,316.7	904.6	18,606.4	14,370.6
12-31-2033	12	12.0	44.8	86.8	0.0	0.0	2,256.5	648.2	19,254.6	14,659.9
12-31-2034	11	11.0	39.4	76.3	0.0	0.0	2,132.1	422.1	19,676.6	14,831.3
12-31-2035	11	11.0	35.8	69.3	0.0	0.0	2,098.4	220.6	19,897.2	14,912.9
12-31-2036	11	11.0	32.5	62.9	0.0	0.0	2,061.3	44.8	19,942.0	14,928.3
12-31-2037	11	11.0	29.5	57.1	0.0	0.0	1,913.4	0.0	19,942.0	14,928.3
02-28-2038	11	11.0	4.6	9.0	0.0	0.0	301.5	0.0	19,942.0	14,928.3
SUBTOTAL			839.3	1,624.8	0.0	0.0	34,460.9	19,942.0	19,942.0	14,928.3
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	19,942.0	14,928.3
TOTAL OF 13.2 YRS			839.3	1,624.8	0.0	0.0	34,460.9	19,942.0	19,942.0	14,928.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	15,718.3
12.000	14,216.2
15.000	13,272.5
20.000	11,966.1
25.000	10,913.9
30.000	10,051.1
35.000	9,332.4
40.000	8,725.4
45.000	8,206.5
50.000	7,758.2

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

CALIFORNIA RESOURCES CORPORATION INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED DEVELOPED NON-PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
12-31-2026	8.3	1.9	6.8	1.0	0.0	69.24	3.087	0.00	473.9	3.0	0.0	0.0	476.9
12-31-2027	18.7	4.2	15.4	2.1	0.0	69.24	3.087	0.00	1,064.3	6.6	0.0	0.0	1,070.9
12-31-2028	17.0	3.8	14.0	2.0	0.0	69.24	3.087	0.00	968.5	6.0	0.0	0.0	974.5
12-31-2029	15.5	3.5	12.7	1.8	0.0	69.24	3.087	0.00	881.3	5.5	0.0	0.0	886.8
12-31-2030	14.1	3.2	11.6	1.6	0.0	69.24	3.087	0.00	802.0	5.0	0.0	0.0	807.0
12-31-2031	12.8	2.9	10.5	1.5	0.0	69.24	3.087	0.00	729.8	4.5	0.0	0.0	734.4
12-31-2032	11.7	2.6	9.6	1.3	0.0	69.24	3.087	0.00	664.2	4.1	0.0	0.0	668.3
12-31-2033	10.6	2.4	8.7	1.2	0.0	69.24	3.087	0.00	604.4	3.8	0.0	0.0	608.1
12-31-2034	9.7	2.2	7.9	1.1	0.0	69.24	3.087	0.00	550.0	3.4	0.0	0.0	553.4
12-31-2035	8.8	2.0	7.2	1.0	0.0	69.24	3.087	0.00	500.5	3.1	0.0	0.0	503.6
12-31-2036	8.0	1.8	6.6	0.9	0.0	69.24	3.087	0.00	455.4	2.8	0.0	0.0	458.3
12-31-2037	7.3	1.6	6.0	0.8	0.0	69.24	3.087	0.00	414.5	2.6	0.0	0.0	417.0
02-28-2038	1.1	0.3	0.9	0.1	0.0	69.24	3.087	0.00	65.4	0.4	0.0	0.0	65.8
SUBTOTAL	143.8	32.3	118.1	16.5	0.0	69.24	3.087	0.00	8,174.2	50.9	0.0	0.0	8,225.1
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	143.8	32.3	118.1	16.5	0.0	69.24	3.087	0.00	8,174.2	50.9	0.0	0.0	8,225.1
CUM PROD	210.4	46.5											
ULTIMATE	354.1	78.8											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	1	1.0	7.0	13.6	175.0	0.0	102.7	178.6	178.6	147.1
12-31-2027	1	1.0	15.7	30.6	0.0	0.0	236.3	788.3	966.9	769.0
12-31-2028	1	1.0	14.3	27.8	0.0	0.0	223.0	709.3	1,676.2	1,277.7
12-31-2029	1	1.0	13.0	25.3	0.0	0.0	211.0	637.5	2,313.7	1,693.3
12-31-2030	1	1.0	11.9	23.1	0.0	0.0	200.0	572.1	2,885.8	2,032.5
12-31-2031	1	1.0	10.8	21.0	0.0	0.0	190.0	512.6	3,398.4	2,308.7
12-31-2032	1	1.0	9.8	19.1	0.0	0.0	180.9	458.5	3,856.8	2,533.3
12-31-2033	1	1.0	8.9	17.4	0.0	0.0	172.6	409.2	4,266.0	2,715.5
12-31-2034	1	1.0	8.1	15.8	0.0	0.0	165.1	364.3	4,630.3	2,863.0
12-31-2035	1	1.0	7.4	14.4	0.0	0.0	158.3	323.5	4,953.9	2,982.1
12-31-2036	1	1.0	6.7	13.1	0.0	0.0	158.6	279.9	5,233.7	3,075.9
12-31-2037	1	1.0	6.1	11.9	0.0	0.0	273.2	125.8	5,359.5	3,114.5
02-28-2038	1	1.0	1.0	1.9	0.0	0.0	59.9	3.0	5,362.5	3,115.4
SUBTOTAL			120.9	235.0	175.0	0.0	2,331.7	5,362.5	5,362.5	3,115.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	5,362.5	3,115.4
TOTAL OF 13.2 YRS			120.9	235.0	175.0	0.0	2,331.7	5,362.5	5,362.5	3,115.4

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	3,439.2
12.000	2,834.1
15.000	2,477.1
20.000	2,014.1
25.000	1,668.8
30.000	1,404.9
35.000	1,199.0
40.000	1,035.2
45.000	902.9
50.000	794.5

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	18.9	7.7	15.5	4.0	0.0	69.24	3.087	0.00	1,074.1	12.2	0.0	0.0	1,086.3
12-31-2026	19.8	7.6	16.2	3.9	0.0	69.24	3.087	0.00	1,125.1	12.0	0.0	0.0	1,137.1
12-31-2027	20.4	7.4	16.8	3.8	0.0	69.24	3.087	0.00	1,160.8	11.6	0.0	0.0	1,172.4
12-31-2028	22.3	8.4	18.3	4.3	0.0	69.24	3.087	0.00	1,269.2	13.2	0.0	0.0	1,282.4
12-31-2029	24.4	9.4	20.0	4.8	0.0	69.24	3.087	0.00	1,387.8	14.9	0.0	0.0	1,402.6
12-31-2030	24.2	9.0	19.9	4.6	0.0	69.24	3.087	0.00	1,377.4	14.2	0.0	0.0	1,391.5
12-31-2031	23.0	8.1	18.9	4.2	0.0	69.24	3.087	0.00	1,308.5	12.8	0.0	0.0	1,321.3
12-31-2032	24.7	8.6	20.2	4.4	0.0	69.24	3.087	0.00	1,401.9	13.5	0.0	0.0	1,415.4
12-31-2033	19.3	6.1	15.8	3.1	0.0	69.24	3.087	0.00	1,096.7	9.7	0.0	0.0	1,106.4
12-31-2034	19.2	6.0	15.8	3.1	0.0	69.24	3.087	0.00	1,093.8	9.4	0.0	0.0	1,103.3
12-31-2035	17.3	5.3	14.2	2.7	0.0	69.24	3.087	0.00	985.2	8.4	0.0	0.0	993.6
12-31-2036	15.7	4.8	12.9	2.4	0.0	69.24	3.087	0.00	892.0	7.5	0.0	0.0	899.5
12-31-2037	15.3	4.6	12.6	2.4	0.0	69.24	3.087	0.00	870.3	7.3	0.0	0.0	877.6
12-31-2038	46.6	14.6	38.2	7.4	0.0	69.24	3.087	0.00	2,646.9	23.0	0.0	0.0	2,669.9
12-31-2039	49.0	15.3	40.2	7.8	0.0	69.24	3.087	0.00	2,783.7	24.2	0.0	0.0	2,807.9
SUBTOTAL	360.1	123.0	295.7	62.8	0.0	69.24	3.087	0.00	20,473.4	193.9	0.0	0.0	20,667.2
REMAINING	107.0	33.4	87.9	17.1	0.0	69.24	3.087	0.00	6,083.7	52.7	0.0	0.0	6,136.5
TOTAL	467.1	156.5	383.6	79.9	0.0	69.24	3.087	0.00	26,557.1	246.6	0.0	0.0	26,803.7
CUM PROD	26.4	10.7											
ULTIMATE	493.4	167.2											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	1	1.0	16.1	31.0	0.0	0.0	252.5	786.7	786.7	750.0
12-31-2026	1	1.0	16.8	32.5	0.0	0.0	215.1	872.8	1,659.5	1,505.5
12-31-2027	0	0.0	17.3	33.5	0.0	0.0	160.7	960.9	2,620.4	2,262.8
12-31-2028	0	0.0	18.9	36.6	0.0	0.0	257.2	969.6	3,590.0	2,957.7
12-31-2029	2	2.0	20.7	40.1	0.0	0.0	392.3	949.5	4,539.5	3,576.4
12-31-2030	3	3.0	20.6	39.8	0.0	0.0	420.5	910.7	5,450.2	4,116.0
12-31-2031	2	2.0	19.5	37.8	0.0	0.0	388.8	875.3	6,325.5	4,587.4
12-31-2032	4	4.0	20.9	40.4	0.0	0.0	520.3	833.7	7,159.2	4,995.6
12-31-2033	1	1.0	16.3	31.6	0.0	0.0	255.6	802.8	7,962.0	5,352.9
12-31-2034	2	2.0	16.3	31.5	0.0	0.0	277.5	778.0	8,740.1	5,667.7
12-31-2035	1	1.0	14.6	28.4	0.0	0.0	195.7	754.8	9,494.9	5,945.4
12-31-2036	0	0.0	13.3	25.7	0.0	0.0	123.5	737.1	10,232.0	6,191.8
12-31-2037	0	0.0	12.9	25.1	0.0	0.0	120.5	719.2	10,951.1	6,410.4
12-31-2038	0	0.0	39.4	76.3	0.0	0.0	1,912.2	642.1	11,593.2	6,588.2
12-31-2039	12	12.0	41.4	80.2	0.0	0.0	2,225.4	460.8	12,054.0	6,704.3
SUBTOTAL			305.0	590.5	0.0	0.0	7,717.7	12,054.0	12,054.0	6,704.3
REMAINING			90.5	175.3	0.0	0.0	5,404.2	466.5	12,520.5	6,807.5
TOTAL OF 17.6 YRS			395.5	765.8	0.0	0.0	13,121.9	12,520.5	12,520.5	6,807.5

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	7,560.3
12.000	6,173.9
15.000	5,397.6
20.000	4,437.2
25.000	3,754.6
30.000	3,251.2
35.000	2,868.1
40.000	2,568.6
45.000	2,328.9
50.000	2,133.3

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED + PROBABLE (2P) RESERVES

CALIFORNIA RESOURCES CORPORATION INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	161.0	58.6	132.2	29.9	0.0	69.24	3.087	0.00	9,156.0	92.4	0.0	0.0	9,248.3
12-31-2026	153.9	54.2	126.4	27.6	0.0	69.24	3.087	0.00	8,749.3	85.3	0.0	0.0	8,834.6
12-31-2027	151.7	51.4	124.6	26.2	0.0	69.24	3.087	0.00	8,628.2	81.0	0.0	0.0	8,709.2
12-31-2028	138.8	46.9	114.0	23.9	0.0	69.24	3.087	0.00	7,892.2	73.9	0.0	0.0	7,966.1
12-31-2029	127.2	42.8	104.4	21.9	0.0	69.24	3.087	0.00	7,230.5	67.5	0.0	0.0	7,298.0
12-31-2030	114.7	38.0	94.2	19.4	0.0	69.24	3.087	0.00	6,522.6	59.8	0.0	0.0	6,582.4
12-31-2031	103.9	33.9	85.3	17.3	0.0	69.24	3.087	0.00	5,905.2	53.5	0.0	0.0	5,958.7
12-31-2032	95.0	30.9	78.0	15.8	0.0	69.24	3.087	0.00	5,402.2	48.7	0.0	0.0	5,450.9
12-31-2033	82.8	26.3	68.0	13.4	0.0	69.24	3.087	0.00	4,709.3	41.5	0.0	0.0	4,750.7
12-31-2034	75.4	23.8	61.9	12.2	0.0	69.24	3.087	0.00	4,289.0	37.6	0.0	0.0	4,326.6
12-31-2035	68.4	21.5	56.1	11.0	0.0	69.24	3.087	0.00	3,887.2	33.9	0.0	0.0	3,921.1
12-31-2036	62.1	19.5	51.0	10.0	0.0	69.24	3.087	0.00	3,528.5	30.8	0.0	0.0	3,559.2
12-31-2037	57.4	18.0	47.2	9.2	0.0	69.24	3.087	0.00	3,266.3	28.5	0.0	0.0	3,294.7
12-31-2038	53.2	16.7	43.7	8.5	0.0	69.24	3.087	0.00	3,024.5	26.3	0.0	0.0	3,050.8
12-31-2039	49.0	15.3	40.2	7.8	0.0	69.24	3.087	0.00	2,783.7	24.2	0.0	0.0	2,807.9
SUBTOTAL	1,494.4	497.8	1,227.2	254.2	0.0	69.24	3.087	0.00	84,974.5	784.8	0.0	0.0	85,759.3
REMAINING	107.0	33.4	87.9	17.1	0.0	69.24	3.087	0.00	6,083.7	52.7	0.0	0.0	6,136.5
TOTAL	1,601.4	531.3	1,315.1	271.3	0.0	69.24	3.087	0.00	91,058.2	837.5	0.0	0.0	91,895.7
CUM PROD	16,642.5	3,422.3											
ULTIMATE	18,243.9	3,953.6											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	21	21.0	136.6	264.2	0.0	0.0	3,811.9	5,035.6	5,035.6	4,808.5
12-31-2026	20	20.0	130.4	252.4	175.0	0.0	3,696.3	4,580.4	9,616.0	8,775.7
12-31-2027	19	19.0	128.5	248.8	0.0	0.0	3,672.1	4,659.7	14,275.7	12,452.9
12-31-2028	19	19.0	117.5	227.6	0.0	0.0	3,570.3	4,050.6	18,326.3	15,358.9
12-31-2029	19	19.0	107.7	208.5	0.0	0.0	3,478.7	3,503.1	21,829.5	17,643.7
12-31-2030	19	19.0	97.1	188.1	0.0	0.0	3,284.3	3,012.9	24,842.4	19,430.3
12-31-2031	17	17.0	87.9	170.3	0.0	0.0	3,117.3	2,583.3	27,425.7	20,822.9
12-31-2032	17	17.0	80.4	155.7	0.0	0.0	3,018.0	2,196.8	29,622.4	21,899.5
12-31-2033	14	14.0	70.1	135.7	0.0	0.0	2,684.8	1,860.2	31,482.6	22,728.3
12-31-2034	14	14.0	63.8	123.6	0.0	0.0	2,574.7	1,564.5	33,047.0	23,362.0
12-31-2035	13	13.0	57.8	112.0	0.0	0.0	2,452.3	1,299.0	34,346.0	23,840.4
12-31-2036	12	12.0	52.5	101.7	0.0	0.0	2,343.4	1,061.7	35,407.7	24,196.0
12-31-2037	12	12.0	48.6	94.1	0.0	0.0	2,307.1	845.0	36,252.6	24,453.3
12-31-2038	12	12.0	45.0	87.2	0.0	0.0	2,273.6	645.1	36,897.7	24,631.9
12-31-2039	12	12.0	41.4	80.2	0.0	0.0	2,225.4	460.8	37,358.5	24,748.0
SUBTOTAL			1,265.2	2,450.3	175.0	0.0	44,510.2	37,358.5	37,358.5	24,748.0
REMAINING			90.5	175.3	0.0	0.0	5,404.2	466.5	37,825.0	24,851.2
TOTAL OF 17.6 YRS			1,355.7	2,625.7	175.0	0.0	49,914.4	37,825.0	37,825.0	24,851.2

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	26,717.7
12.000	23,224.2
15.000	21,147.3
20.000	18,417.4
25.000	16,337.3
30.000	14,707.2
35.000	13,399.5
40.000	12,329.2
45.000	11,438.4
50.000	10,686.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	174.0	119.2	144.7	55.3	0.0	72.13	4.843	0.00	10,434.4	268.1	0.0	0.0	10,702.4
12-31-2026	156.4	106.5	130.0	49.4	0.0	72.13	4.843	0.00	9,373.5	239.4	0.0	0.0	9,612.9
12-31-2027	273.0	126.4	226.9	58.7	0.0	72.13	4.843	0.00	16,366.6	284.2	0.0	0.0	16,650.8
12-31-2028	295.0	126.7	245.2	58.8	0.0	72.13	4.843	0.00	17,684.2	284.9	0.0	0.0	17,969.1
12-31-2029	243.0	107.9	202.0	50.1	0.0	72.13	4.843	0.00	14,570.3	242.6	0.0	0.0	14,812.9
12-31-2030	207.5	93.7	172.5	43.5	0.0	72.13	4.843	0.00	12,442.4	210.7	0.0	0.0	12,653.0
12-31-2031	182.2	83.6	151.5	38.8	0.0	72.13	4.843	0.00	10,925.8	187.8	0.0	0.0	11,113.6
12-31-2032	162.6	75.3	135.1	34.9	0.0	72.13	4.843	0.00	9,745.5	169.2	0.0	0.0	9,914.7
12-31-2033	145.8	68.0	121.2	31.6	0.0	72.13	4.843	0.00	8,738.9	153.0	0.0	0.0	8,891.8
12-31-2034	131.4	61.2	109.2	28.4	0.0	72.13	4.843	0.00	7,878.3	137.5	0.0	0.0	8,015.9
12-31-2035	117.9	54.3	98.0	25.2	0.0	72.13	4.843	0.00	7,070.1	122.1	0.0	0.0	7,192.2
11-30-2036	91.9	43.9	76.4	20.4	0.0	72.13	4.843	0.00	5,508.5	98.6	0.0	0.0	5,607.1
SUBTOTAL	2,180.7	1,066.8	1,812.5	495.2	0.0	72.13	4.843	0.00	130,738.4	2,398.1	0.0	0.0	133,136.5
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	2,180.7	1,066.8	1,812.5	495.2	0.0	72.13	4.843	0.00	130,738.4	2,398.1	0.0	0.0	133,136.5
CUM PROD	14,675.0	5,878.7											
ULTIMATE	16,855.8	6,945.5											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	18	18.0	151.7	487.4	0.0	0.0	5,443.5	4,619.8	4,619.8	4,414.5
12-31-2026	18	18.0	136.2	437.8	0.0	0.0	5,380.3	3,658.5	8,278.3	7,592.8
12-31-2027	24	24.0	235.1	758.4	19,000.0	0.0	6,055.9	-9,398.6	-1,120.3	-226.0
12-31-2028	24	24.0	253.6	818.5	0.0	0.0	6,289.9	10,607.3	9,487.0	7,395.0
12-31-2029	24	24.0	209.1	674.7	0.0	0.0	6,104.4	7,824.7	17,311.7	12,504.3
12-31-2030	24	24.0	178.6	576.3	0.0	0.0	5,977.7	5,920.4	23,232.1	16,017.9
12-31-2031	24	24.0	156.9	506.2	0.0	0.0	5,887.4	4,563.1	27,795.2	18,479.7
12-31-2032	24	24.0	140.0	451.6	0.0	0.0	5,817.1	3,506.0	31,301.2	20,199.4
12-31-2033	24	24.0	125.6	405.0	0.0	0.0	5,711.1	2,650.2	33,951.3	21,381.3
12-31-2034	23	23.0	113.2	365.1	0.0	0.0	5,596.5	1,941.1	35,892.4	22,168.6
12-31-2035	22	22.0	101.5	327.6	0.0	0.0	5,458.5	1,304.6	37,197.0	22,650.2
11-30-2036	20	20.0	79.2	255.4	0.0	0.0	4,841.8	430.7	37,627.7	22,797.7
SUBTOTAL			1,880.7	6,064.0	19,000.0	0.0	68,564.1	37,627.7	37,627.7	22,797.7
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	37,627.7	22,797.7
TOTAL OF 11.9 YRS			1,880.7	6,064.0	19,000.0	0.0	68,564.1	37,627.7	37,627.7	22,797.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	24,994.8
12.000	20,872.2
15.000	18,408.5
20.000	15,185.3
25.000	12,772.1
30.000	10,934.0
35.000	9,512.3
40.000	8,397.4
45.000	7,512.2
50.000	6,801.3

Figure 7.9.2

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	174.0	119.2	144.7	55.3	0.0	72.13	4.843	0.00	10,434.4	268.1	0.0	0.0	10,702.4
12-31-2026	156.4	106.5	130.0	49.4	0.0	72.13	4.843	0.00	9,373.5	239.4	0.0	0.0	9,612.9
12-31-2027	141.5	96.1	117.6	44.6	0.0	72.13	4.843	0.00	8,484.5	216.0	0.0	0.0	8,700.5
12-31-2028	128.7	87.1	107.0	40.4	0.0	72.13	4.843	0.00	7,714.4	195.9	0.0	0.0	7,910.2
12-31-2029	117.0	78.9	97.3	36.6	0.0	72.13	4.843	0.00	7,016.5	177.5	0.0	0.0	7,194.0
12-31-2030	106.0	71.0	88.1	33.0	0.0	72.13	4.843	0.00	6,357.8	159.7	0.0	0.0	6,517.5
12-31-2031	97.0	64.9	80.7	30.1	0.0	72.13	4.843	0.00	5,817.9	145.9	0.0	0.0	5,963.8
12-31-2032	88.9	59.4	73.9	27.6	0.0	72.13	4.843	0.00	5,330.3	133.5	0.0	0.0	5,463.8
12-31-2033	81.5	54.4	67.8	25.3	0.0	72.13	4.843	0.00	4,888.6	122.3	0.0	0.0	5,010.9
12-31-2034	74.1	49.1	61.6	22.8	0.0	72.13	4.843	0.00	4,444.7	110.4	0.0	0.0	4,555.1
12-31-2035	66.3	43.4	55.1	20.2	0.0	72.13	4.843	0.00	3,972.7	97.6	0.0	0.0	4,070.3
11-30-2036	54.5	35.5	45.3	16.5	0.0	72.13	4.843	0.00	3,270.0	79.8	0.0	0.0	3,349.8
SUBTOTAL	1,286.1	865.7	1,069.0	401.8	0.0	72.13	4.843	0.00	77,105.1	1,946.0	0.0	0.0	79,051.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	1,286.1	865.7	1,069.0	401.8	0.0	72.13	4.843	0.00	77,105.1	1,946.0	0.0	0.0	79,051.2
CUM PROD	8,425.5	3,505.9											
ULTIMATE	9,711.6	4,371.6											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	18	18.0	151.7	487.4	0.0	0.0	5,443.5	4,619.8	4,619.8	4,414.5
12-31-2026	18	18.0	136.2	437.8	0.0	0.0	5,380.3	3,658.5	8,278.3	7,592.8
12-31-2027	18	18.0	123.3	396.3	0.0	0.0	5,327.4	2,853.5	11,131.8	9,846.8
12-31-2028	18	18.0	112.1	360.3	0.0	0.0	5,281.5	2,156.3	13,288.2	11,395.7
12-31-2029	18	18.0	101.9	327.7	0.0	0.0	5,240.0	1,524.4	14,812.6	12,392.2
12-31-2030	18	18.0	92.4	296.8	0.0	0.0	5,200.7	927.5	15,740.1	12,943.9
12-31-2031	18	18.0	84.5	271.6	0.0	0.0	5,168.6	439.1	16,179.2	13,182.3
12-31-2032	18	18.0	77.4	248.9	0.0	0.0	5,086.1	51.4	16,230.6	13,208.3
12-31-2033	18	18.0	71.0	228.2	0.0	0.0	4,711.7	0.0	16,230.6	13,208.3
12-31-2034	18	18.0	64.5	207.5	0.0	0.0	4,283.1	0.0	16,230.6	13,208.3
12-31-2035	17	17.0	57.7	185.4	0.0	0.0	3,827.3	0.0	16,230.6	13,208.3
11-30-2036	15	15.0	47.5	152.6	0.0	0.0	3,149.8	0.0	16,230.6	13,208.3
SUBTOTAL			1,120.2	3,600.4	0.0	0.0	58,099.9	16,230.6	16,230.6	13,208.3
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	16,230.6	13,208.3
TOTAL OF 11.9 YRS			1,120.2	3,600.4	0.0	0.0	58,099.9	16,230.6	16,230.6	13,208.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	13,716.6
12.000	12,738.2
15.000	12,096.5
20.000	11,169.7
25.000	10,387.6
30.000	9,720.2
35.000	9,145.0
40.000	8,644.9
45.000	8,206.5
50.000	7,819.3

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED UNDEVELOPED RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
12-31-2027	131.5	30.4	109.3	14.1	0.0	72.13	4.843	0.00	7,882.1	68.2	0.0	0.0	7,950.3
12-31-2028	166.3	39.6	138.2	18.4	0.0	72.13	4.843	0.00	9,969.9	89.1	0.0	0.0	10,058.9
12-31-2029	126.0	29.0	104.7	13.4	0.0	72.13	4.843	0.00	7,553.8	65.1	0.0	0.0	7,618.9
12-31-2030	101.5	22.7	84.4	10.5	0.0	72.13	4.843	0.00	6,084.6	51.0	0.0	0.0	6,135.6
12-31-2031	85.2	18.7	70.8	8.7	0.0	72.13	4.843	0.00	5,107.9	41.9	0.0	0.0	5,149.8
12-31-2032	73.6	15.9	61.2	7.4	0.0	72.13	4.843	0.00	4,415.2	35.7	0.0	0.0	4,450.8
12-31-2033	64.2	13.6	53.4	6.3	0.0	72.13	4.843	0.00	3,850.3	30.7	0.0	0.0	3,880.9
12-31-2034	57.3	12.1	47.6	5.6	0.0	72.13	4.843	0.00	3,433.6	27.1	0.0	0.0	3,460.8
12-31-2035	51.7	10.9	42.9	5.0	0.0	72.13	4.843	0.00	3,097.4	24.4	0.0	0.0	3,121.9
11-30-2036	37.3	8.3	31.0	3.9	0.0	72.13	4.843	0.00	2,238.5	18.8	0.0	0.0	2,257.2
SUBTOTAL	894.6	201.1	743.6	93.3	0.0	72.13	4.843	0.00	53,633.3	452.0	0.0	0.0	54,085.3
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	894.6	201.1	743.6	93.3	0.0	72.13	4.843	0.00	53,633.3	452.0	0.0	0.0	54,085.3
CUM PROD	0.0	0.0											
ULTIMATE	894.6	201.1											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	6	6.0	111.8	362.1	19,000.0	0.0	728.5	-12,252.1	-12,252.1	-10,072.7
12-31-2028	6	6.0	141.5	458.2	0.0	0.0	1,008.3	8,450.9	-3,801.2	-4,000.8
12-31-2029	6	6.0	107.1	347.0	0.0	0.0	864.5	6,300.3	2,499.1	112.1
12-31-2030	6	6.0	86.3	279.5	0.0	0.0	777.0	4,992.9	7,492.0	3,073.9
12-31-2031	6	6.0	72.4	234.6	0.0	0.0	718.8	4,124.0	11,616.0	5,297.4
12-31-2032	6	6.0	62.6	202.7	0.0	0.0	731.0	3,454.6	15,070.6	6,991.1
12-31-2033	6	6.0	54.6	176.8	0.0	0.0	999.4	2,650.2	17,720.8	8,173.0
12-31-2034	5	5.0	48.6	157.6	0.0	0.0	1,313.4	1,941.1	19,661.9	8,960.4
12-31-2035	5	5.0	43.9	142.2	0.0	0.0	1,631.2	1,304.6	20,966.5	9,441.9
11-30-2036	5	5.0	31.7	102.8	0.0	0.0	1,692.0	430.7	21,397.2	9,589.4
SUBTOTAL			760.4	2,463.6	19,000.0	0.0	10,464.1	21,397.2	21,397.2	9,589.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	21,397.2	9,589.4
TOTAL OF 11.9 YRS			760.4	2,463.6	19,000.0	0.0	10,464.1	21,397.2	21,397.2	9,589.4

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	11,278.2
12.000	8,134.0
15.000	6,312.0
20.000	4,015.6
25.000	2,384.5
30.000	1,213.8
35.000	367.3
40.000	-247.5
45.000	-694.3
50.000	-1,018.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	32.4	24.6	26.9	11.4	0.0	72.13	4.843	0.00	1,941.2	55.3	0.0	0.0	1,996.5
12-31-2026	30.8	22.9	25.6	10.6	0.0	72.13	4.843	0.00	1,845.6	51.5	0.0	0.0	1,897.1
12-31-2027	69.1	46.7	57.4	21.7	0.0	72.13	4.843	0.00	4,142.9	105.0	0.0	0.0	4,247.9
12-31-2028	76.7	54.4	63.7	25.3	0.0	72.13	4.843	0.00	4,597.4	122.4	0.0	0.0	4,719.8
12-31-2029	63.6	43.5	52.9	20.2	0.0	72.13	4.843	0.00	3,814.8	97.8	0.0	0.0	3,912.6
12-31-2030	56.3	37.8	46.8	17.6	0.0	72.13	4.843	0.00	3,373.0	85.1	0.0	0.0	3,458.1
12-31-2031	50.5	33.4	42.0	15.5	0.0	72.13	4.843	0.00	3,027.7	75.1	0.0	0.0	3,102.9
12-31-2032	45.0	28.9	37.4	13.4	0.0	72.13	4.843	0.00	2,695.5	65.0	0.0	0.0	2,760.5
12-31-2033	42.0	26.6	34.9	12.3	0.0	72.13	4.843	0.00	2,516.4	59.7	0.0	0.0	2,576.1
12-31-2034	39.7	25.3	33.0	11.7	0.0	72.13	4.843	0.00	2,378.4	56.8	0.0	0.0	2,435.2
12-31-2035	39.5	25.4	32.8	11.8	0.0	72.13	4.843	0.00	2,366.0	57.1	0.0	0.0	2,423.0
12-31-2036	53.2	29.7	44.3	13.8	0.0	72.13	4.843	0.00	3,192.0	66.7	0.0	0.0	3,258.7
12-31-2037	133.2	67.6	110.7	31.4	0.0	72.13	4.843	0.00	7,986.7	152.0	0.0	0.0	8,138.7
12-31-2038	121.6	61.8	101.0	28.7	0.0	72.13	4.843	0.00	7,287.7	138.9	0.0	0.0	7,426.6
07-31-2039	56.9	32.2	47.3	15.0	0.0	72.13	4.843	0.00	3,412.4	72.5	0.0	0.0	3,484.9
SUBTOTAL	910.4	560.8	756.7	260.3	0.0	72.13	4.843	0.00	54,577.9	1,260.7	0.0	0.0	55,838.6
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	910.4	560.8	756.7	260.3	0.0	72.13	4.843	0.00	54,577.9	1,260.7	0.0	0.0	55,838.6
CUM PROD	39.8	28.7											
ULTIMATE	950.2	589.5											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	0	0.0	28.3	90.9	0.0	0.0	115.6	1,761.6	1,761.6	1,681.1
12-31-2026	0	0.0	26.9	86.4	0.0	0.0	109.9	1,673.9	3,435.5	3,133.0
12-31-2027	0	0.0	60.2	193.5	0.0	0.0	246.7	3,747.5	7,183.0	6,060.2
12-31-2028	0	0.0	66.9	215.0	0.0	0.0	273.8	4,164.1	11,347.2	9,049.7
12-31-2029	0	0.0	55.5	178.2	0.0	0.0	227.2	3,451.8	14,799.0	11,300.9
12-31-2030	0	0.0	49.0	157.5	0.0	0.0	200.9	3,050.7	17,849.7	13,109.4
12-31-2031	0	0.0	44.0	141.3	0.0	0.0	180.3	2,737.3	20,587.0	14,584.3
12-31-2032	0	0.0	39.1	125.7	0.0	0.0	160.5	2,435.1	23,022.1	15,777.0
12-31-2033	0	0.0	36.5	117.3	0.0	0.0	172.9	2,249.4	25,271.6	16,778.5
12-31-2034	0	0.0	34.5	110.9	0.0	0.0	181.9	2,107.9	27,379.4	17,631.6
12-31-2035	1	1.0	34.3	110.4	0.0	0.0	271.1	2,007.2	29,386.7	18,369.9
12-31-2036	3	3.0	46.1	148.4	0.0	0.0	844.0	2,220.2	31,606.9	19,110.3
12-31-2037	23	23.0	115.0	370.7	0.0	0.0	5,603.0	2,050.1	33,656.9	19,734.8
12-31-2038	22	22.0	104.9	338.3	0.0	0.0	5,506.2	1,477.2	35,134.2	20,144.3
07-31-2039	20	20.0	49.3	158.7	0.0	0.0	3,077.0	199.9	35,334.0	20,196.2
SUBTOTAL			790.5	2,543.2	0.0	0.0	17,170.8	35,334.0	35,334.0	20,196.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	35,334.0	20,196.2
TOTAL OF 14.6 YRS			790.5	2,543.2	0.0	0.0	17,170.8	35,334.0	35,334.0	20,196.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	22,289.6
12.000	18,403.2
15.000	16,163.6
20.000	13,318.7
25.000	11,240.0
30.000	9,674.7
35.000	8,464.6
40.000	7,508.0
45.000	6,736.9
50.000	6,105.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	206.4	143.8	171.6	66.8	0.0	72.13	4.843	0.00	12,375.6	323.3	0.0	0.0	12,698.9
12-31-2026	187.1	129.4	155.5	60.1	0.0	72.13	4.843	0.00	11,219.1	290.9	0.0	0.0	11,510.0
12-31-2027	342.1	173.1	284.3	80.4	0.0	72.13	4.843	0.00	20,509.5	389.2	0.0	0.0	20,898.7
12-31-2028	371.7	181.2	308.9	84.1	0.0	72.13	4.843	0.00	22,281.7	407.3	0.0	0.0	22,689.0
12-31-2029	306.7	151.4	254.9	70.3	0.0	72.13	4.843	0.00	18,385.2	340.4	0.0	0.0	18,725.6
12-31-2030	263.8	131.6	219.3	61.1	0.0	72.13	4.843	0.00	15,815.4	295.8	0.0	0.0	16,111.1
12-31-2031	232.7	117.0	193.4	54.3	0.0	72.13	4.843	0.00	13,953.5	263.0	0.0	0.0	14,216.5
12-31-2032	207.5	104.2	172.5	48.4	0.0	72.13	4.843	0.00	12,440.9	234.2	0.0	0.0	12,675.1
12-31-2033	187.7	94.6	156.0	43.9	0.0	72.13	4.843	0.00	11,255.2	212.7	0.0	0.0	11,467.9
12-31-2034	171.1	86.5	142.2	40.1	0.0	72.13	4.843	0.00	10,256.7	194.4	0.0	0.0	10,451.1
12-31-2035	157.4	79.7	130.8	37.0	0.0	72.13	4.843	0.00	9,436.1	179.1	0.0	0.0	9,615.2
12-31-2036	145.1	73.5	120.6	34.1	0.0	72.13	4.843	0.00	8,700.5	165.3	0.0	0.0	8,865.8
12-31-2037	133.2	67.6	110.7	31.4	0.0	72.13	4.843	0.00	7,986.7	152.0	0.0	0.0	8,138.7
12-31-2038	121.6	61.8	101.0	28.7	0.0	72.13	4.843	0.00	7,287.7	138.9	0.0	0.0	7,426.6
07-31-2039	56.9	32.2	47.3	15.0	0.0	72.13	4.843	0.00	3,412.4	72.5	0.0	0.0	3,484.9
SUBTOTAL	3,091.1	1,627.6	2,569.2	755.5	0.0	72.13	4.843	0.00	185,316.3	3,658.8	0.0	0.0	188,975.1
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	3,091.1	1,627.6	2,569.2	755.5	0.0	72.13	4.843	0.00	185,316.3	3,658.8	0.0	0.0	188,975.1
CUM PROD	14,714.9	5,907.4											
ULTIMATE	17,806.0	7,535.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	18	18.0	180.0	578.4	0.0	0.0	5,559.1	6,381.4	6,381.4	6,095.6
12-31-2026	18	18.0	163.2	524.2	0.0	0.0	5,490.2	5,332.4	11,713.8	10,725.8
12-31-2027	24	24.0	295.3	951.9	19,000.0	0.0	6,302.6	-5,651.1	6,062.7	5,834.3
12-31-2028	24	24.0	320.5	1,033.4	0.0	0.0	6,563.6	14,771.4	20,834.2	16,444.7
12-31-2029	24	24.0	264.5	852.9	0.0	0.0	6,331.6	11,276.5	32,110.7	23,805.2
12-31-2030	24	24.0	227.6	733.8	0.0	0.0	6,178.6	8,971.1	41,081.8	29,127.3
12-31-2031	24	24.0	200.9	647.5	0.0	0.0	6,067.7	7,300.4	48,382.2	33,064.0
12-31-2032	24	24.0	179.1	577.3	0.0	0.0	5,977.6	5,941.1	54,323.3	35,976.4
12-31-2033	24	24.0	162.0	522.3	0.0	0.0	5,884.0	4,899.6	59,222.9	38,159.8
12-31-2034	23	23.0	147.7	476.0	0.0	0.0	5,778.4	4,049.0	63,271.9	39,800.2
12-31-2035	23	23.0	135.9	437.9	0.0	0.0	5,729.6	3,311.8	66,583.7	41,020.1
12-31-2036	23	23.0	125.3	403.8	0.0	0.0	5,685.8	2,650.9	69,234.6	41,908.0
12-31-2037	23	23.0	115.0	370.7	0.0	0.0	5,603.0	2,050.1	71,284.7	42,532.4
12-31-2038	22	22.0	104.9	338.3	0.0	0.0	5,506.2	1,477.2	72,761.9	42,942.0
07-31-2039	20	20.0	49.3	158.7	0.0	0.0	3,077.0	199.9	72,961.8	42,993.8
SUBTOTAL			2,671.2	8,607.2	19,000.0	0.0	85,734.9	72,961.8	72,961.8	42,993.8
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	72,961.8	42,993.8
TOTAL OF 14.6 YRS			2,671.2	8,607.2	19,000.0	0.0	85,734.9	72,961.8	72,961.8	42,993.8

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	47,284.4
12.000	39,275.5
15.000	34,572.1
20.000	28,503.9
25.000	24,012.1
30.000	20,608.6
35.000	17,976.9
40.000	15,905.4
45.000	14,249.1
50.000	12,906.3

Figure 7.9.2
Page 5 of 5

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	319.2	60.8	264.1	50.6	0.0	72.15	5.288	0.00	19,053.3	267.7	0.0	0.0	19,321.0
12-31-2026	311.8	59.6	258.0	49.7	0.0	72.15	5.288	0.00	18,616.1	262.7	0.0	0.0	18,878.8
12-31-2027	286.1	54.7	236.8	45.6	0.0	72.15	5.288	0.00	17,082.1	241.2	0.0	0.0	17,323.3
12-31-2028	263.0	50.3	217.6	41.9	0.0	72.15	5.288	0.00	15,697.5	221.7	0.0	0.0	15,919.2
12-31-2029	241.9	46.3	200.1	38.6	0.0	72.15	5.288	0.00	14,440.2	204.1	0.0	0.0	14,644.2
12-31-2030	222.7	42.6	184.2	35.5	0.0	72.15	5.288	0.00	13,293.1	187.9	0.0	0.0	13,481.0
12-31-2031	205.1	39.3	169.7	32.7	0.0	72.15	5.288	0.00	12,243.7	173.2	0.0	0.0	12,416.9
12-31-2032	189.0	36.2	156.4	30.2	0.0	72.15	5.288	0.00	11,282.7	159.6	0.0	0.0	11,442.3
12-31-2033	174.2	33.4	144.2	27.8	0.0	72.15	5.288	0.00	10,401.7	147.2	0.0	0.0	10,549.0
12-31-2034	160.7	30.8	133.0	25.7	0.0	72.15	5.288	0.00	9,593.5	135.9	0.0	0.0	9,729.4
12-31-2035	148.1	28.4	122.5	23.7	0.0	72.15	5.288	0.00	8,839.8	125.3	0.0	0.0	8,965.1
12-31-2036	135.8	26.1	112.4	21.8	0.0	72.15	5.288	0.00	8,106.5	115.2	0.0	0.0	8,221.7
12-31-2037	125.4	24.2	103.8	20.1	0.0	72.15	5.288	0.00	7,488.0	106.5	0.0	0.0	7,594.4
12-31-2038	115.6	22.3	95.7	18.6	0.0	72.15	5.288	0.00	6,901.5	98.2	0.0	0.0	6,999.7
12-31-2039	106.0	20.5	87.7	17.1	0.0	72.15	5.288	0.00	6,330.2	90.4	0.0	0.0	6,420.6
SUBTOTAL	3,004.7	575.7	2,486.1	479.7	0.0	72.15	5.288	0.00	179,369.8	2,536.8	0.0	0.0	181,906.5
REMAINING	112.6	21.8	93.2	18.2	0.0	72.15	5.288	0.00	6,724.4	96.0	0.0	0.0	6,820.4
TOTAL	3,117.3	597.5	2,579.3	497.9	0.0	72.15	5.288	0.00	186,094.2	2,632.8	0.0	0.0	188,727.0
CUM PROD	27,102.2	4,214.3											
ULTIMATE	30,219.5	4,811.8											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	21	21.0	271.8	255.3	5,800.0	0.0	6,273.4	6,720.5	6,720.5	6,212.4
12-31-2026	21	21.0	265.6	249.4	0.0	0.0	6,259.8	12,103.9	18,824.4	16,718.2
12-31-2027	21	21.0	243.7	228.9	0.0	0.0	6,174.8	10,675.9	29,500.4	25,142.2
12-31-2028	21	21.0	224.0	210.3	0.0	0.0	6,098.0	9,386.9	38,887.3	31,876.0
12-31-2029	21	21.0	206.0	193.5	0.0	0.0	6,028.3	8,216.5	47,103.7	37,234.5
12-31-2030	21	21.0	189.7	178.1	0.0	0.0	5,964.7	7,148.6	54,252.3	41,473.0
12-31-2031	21	21.0	174.7	164.0	0.0	0.0	5,906.5	6,171.6	60,423.9	44,799.8
12-31-2032	21	21.0	161.0	151.2	0.0	0.0	5,853.2	5,277.0	65,700.9	47,386.0
12-31-2033	21	21.0	148.4	139.4	0.0	0.0	5,804.4	4,456.8	70,157.7	49,371.9
12-31-2034	21	21.0	136.9	128.5	0.0	0.0	5,759.5	3,704.4	73,862.1	50,872.7
12-31-2035	21	21.0	126.1	118.4	0.0	0.0	5,707.1	3,013.5	76,875.6	51,982.8
12-31-2036	20	20.0	115.7	108.6	0.0	0.0	5,613.0	2,384.4	79,260.0	52,781.5
12-31-2037	20	20.0	106.9	100.3	0.0	0.0	5,578.7	1,808.6	81,068.6	53,332.5
12-31-2038	20	20.0	98.5	92.5	0.0	0.0	5,530.1	1,278.7	82,347.3	53,686.9
12-31-2039	19	19.0	90.3	84.8	0.0	0.0	5,450.3	795.1	83,142.4	53,887.5
SUBTOTAL			2,559.4	2,403.3	5,800.0	0.0	88,001.5	83,142.4	83,142.4	53,887.5
REMAINING			96.0	90.1	0.0	0.0	6,311.4	323.0	83,465.3	53,962.1
TOTAL OF 16.2 YRS			2,655.3	2,493.4	5,800.0	0.0	94,312.9	83,465.3	83,465.3	53,962.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	58,259.8
12.000	50,200.9
15.000	45,379.3
20.000	39,008.3
25.000	34,129.4
30.000	30,292.9
35.000	27,207.4
40.000	24,677.9
45.000	22,569.6
50.000	20,787.4

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	247.9	48.3	205.1	40.3	0.0	72.15	5.288	0.00	14,796.8	213.1	0.0	0.0	15,009.9
12-31-2026	225.2	44.0	186.3	36.6	0.0	72.15	5.288	0.00	13,443.0	193.7	0.0	0.0	13,636.7
12-31-2027	205.3	40.1	169.9	33.4	0.0	72.15	5.288	0.00	12,256.5	176.7	0.0	0.0	12,433.2
12-31-2028	187.5	36.7	155.2	30.5	0.0	72.15	5.288	0.00	11,194.6	161.5	0.0	0.0	11,356.2
12-31-2029	171.5	33.5	141.9	27.9	0.0	72.15	5.288	0.00	10,237.4	147.8	0.0	0.0	10,385.2
12-31-2030	156.9	30.7	129.9	25.6	0.0	72.15	5.288	0.00	9,369.2	135.3	0.0	0.0	9,504.5
12-31-2031	143.7	28.1	118.9	23.4	0.0	72.15	5.288	0.00	8,579.2	123.9	0.0	0.0	8,703.2
12-31-2032	131.7	25.8	108.9	21.5	0.0	72.15	5.288	0.00	7,859.4	113.6	0.0	0.0	7,973.0
12-31-2033	120.7	23.6	99.8	19.7	0.0	72.15	5.288	0.00	7,202.9	104.1	0.0	0.0	7,307.0
12-31-2034	110.6	21.7	91.5	18.1	0.0	72.15	5.288	0.00	6,603.5	95.5	0.0	0.0	6,699.0
12-31-2035	101.2	19.9	83.8	16.5	0.0	72.15	5.288	0.00	6,044.2	87.5	0.0	0.0	6,131.7
12-31-2036	92.0	18.1	76.1	15.1	0.0	72.15	5.288	0.00	5,491.8	79.8	0.0	0.0	5,571.6
12-31-2037	84.5	16.6	69.9	13.9	0.0	72.15	5.288	0.00	5,041.8	73.3	0.0	0.0	5,115.1
12-31-2038	77.3	15.2	63.9	12.7	0.0	72.15	5.288	0.00	4,612.3	67.1	0.0	0.0	4,679.5
12-31-2039	70.1	13.9	58.0	11.6	0.0	72.15	5.288	0.00	4,187.3	61.2	0.0	0.0	4,248.5
SUBTOTAL	2,126.1	416.3	1,759.1	346.9	0.0	72.15	5.288	0.00	126,919.9	1,834.4	0.0	0.0	128,754.3
REMAINING	73.6	14.6	60.9	12.2	0.0	72.15	5.288	0.00	4,396.0	64.3	0.0	0.0	4,460.3
TOTAL	2,199.7	430.9	1,820.0	359.0	0.0	72.15	5.288	0.00	131,316.0	1,898.6	0.0	0.0	133,214.6
CUM PROD	24,596.9	3,885.0											
ULTIMATE	26,796.6	4,315.9											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	19	19.0	211.2	198.3	0.0	0.0	5,919.8	8,680.6	8,680.6	8,289.9
12-31-2026	19	19.0	191.9	180.2	0.0	0.0	5,844.7	7,419.9	16,100.5	14,731.9
12-31-2027	19	19.0	174.9	164.3	0.0	0.0	5,778.9	6,315.1	22,415.6	19,716.4
12-31-2028	19	19.0	159.8	150.0	0.0	0.0	5,720.1	5,326.3	27,741.9	23,538.6
12-31-2029	19	19.0	146.1	137.2	0.0	0.0	5,667.0	4,434.9	32,176.7	26,432.2
12-31-2030	19	19.0	133.7	125.6	0.0	0.0	5,618.8	3,626.4	35,803.1	28,583.5
12-31-2031	19	19.0	122.5	115.0	0.0	0.0	5,575.0	2,890.7	38,693.8	30,142.8
12-31-2032	19	19.0	112.2	105.3	0.0	0.0	5,535.1	2,220.3	40,914.2	31,232.1
12-31-2033	19	19.0	102.8	96.5	0.0	0.0	5,498.7	1,608.9	42,523.1	31,950.1
12-31-2034	19	19.0	94.3	88.5	0.0	0.0	5,465.5	1,050.8	43,573.9	32,376.8
12-31-2035	19	19.0	86.3	81.0	0.0	0.0	5,423.8	540.6	44,114.5	32,577.0
12-31-2036	18	18.0	78.4	73.6	0.0	0.0	5,318.0	101.6	44,216.1	32,611.9
12-31-2037	18	18.0	72.0	67.6	0.0	0.0	4,975.5	0.0	44,216.1	32,611.9
12-31-2038	18	18.0	65.8	61.8	0.0	0.0	4,551.8	0.0	44,216.1	32,611.9
12-31-2039	17	17.0	59.8	56.1	0.0	0.0	4,132.6	0.0	44,216.1	32,611.9
SUBTOTAL			1,811.7	1,701.0	0.0	0.0	81,025.4	44,216.1	44,216.1	32,611.9
REMAINING			62.8	58.9	0.0	0.0	4,338.6	0.0	44,216.1	32,611.9
TOTAL OF 16.2 YRS			1,874.5	1,760.0	0.0	0.0	85,364.0	44,216.1	44,216.1	32,611.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	34,429.7
12.000	30,977.7
15.000	28,818.4
20.000	25,843.5
25.000	23,461.1
30.000	21,518.0
35.000	19,907.4
40.000	18,553.4
45.000	17,400.8
50.000	16,408.8

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	42.3	6.6	35.0	5.5	0.0	72.15	5.288	0.00	2,526.3	29.1	0.0	0.0	2,555.5
12-31-2026	54.4	9.2	45.0	7.7	0.0	72.15	5.288	0.00	3,249.6	40.5	0.0	0.0	3,290.1
12-31-2027	51.2	8.7	42.4	7.2	0.0	72.15	5.288	0.00	3,056.0	38.3	0.0	0.0	3,094.3
12-31-2028	48.2	8.2	39.8	6.8	0.0	72.15	5.288	0.00	2,874.7	36.2	0.0	0.0	2,910.9
12-31-2029	45.3	7.8	37.5	6.5	0.0	72.15	5.288	0.00	2,704.9	34.2	0.0	0.0	2,739.1
12-31-2030	42.6	7.3	35.3	6.1	0.0	72.15	5.288	0.00	2,545.8	32.3	0.0	0.0	2,578.1
12-31-2031	40.1	6.9	33.2	5.8	0.0	72.15	5.288	0.00	2,396.7	30.5	0.0	0.0	2,427.2
12-31-2032	37.8	6.5	31.3	5.5	0.0	72.15	5.288	0.00	2,256.9	28.8	0.0	0.0	2,285.8
12-31-2033	35.6	6.2	29.5	5.2	0.0	72.15	5.288	0.00	2,125.8	27.3	0.0	0.0	2,153.1
12-31-2034	33.6	5.8	27.8	4.9	0.0	72.15	5.288	0.00	2,002.8	25.8	0.0	0.0	2,028.6
12-31-2035	31.6	5.5	26.2	4.6	0.0	72.15	5.288	0.00	1,887.4	24.4	0.0	0.0	1,911.8
12-31-2036	29.8	5.2	24.7	4.4	0.0	72.15	5.288	0.00	1,779.1	23.1	0.0	0.0	1,802.2
12-31-2037	28.1	5.0	23.2	4.1	0.0	72.15	5.288	0.00	1,677.5	21.8	0.0	0.0	1,699.3
12-31-2038	26.5	4.7	21.9	3.9	0.0	72.15	5.288	0.00	1,582.0	20.6	0.0	0.0	1,602.6
12-31-2039	25.0	4.4	20.7	3.7	0.0	72.15	5.288	0.00	1,492.3	19.5	0.0	0.0	1,511.8
SUBTOTAL	572.2	98.1	473.4	81.8	0.0	72.15	5.288	0.00	34,158.0	432.4	0.0	0.0	34,590.4
REMAINING	27.4	4.9	22.7	4.1	0.0	72.15	5.288	0.00	1,634.8	21.5	0.0	0.0	1,656.3
TOTAL	599.6	103.0	496.1	85.8	0.0	72.15	5.288	0.00	35,792.8	453.9	0.0	0.0	36,246.7
CUM PROD	2,505.3	329.3											
ULTIMATE	3,104.9	432.3											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	1	1.0	35.9	33.8	2,000.0	0.0	204.2	281.6	281.6	226.0
12-31-2026	1	1.0	46.3	43.5	0.0	0.0	244.3	2,956.1	3,237.7	2,790.5
12-31-2027	1	1.0	43.5	40.9	0.0	0.0	233.6	2,776.3	6,014.0	4,980.1
12-31-2028	1	1.0	40.9	38.5	0.0	0.0	223.5	2,608.0	8,622.0	6,850.0
12-31-2029	1	1.0	38.5	36.2	0.0	0.0	214.1	2,450.3	11,072.3	8,447.0
12-31-2030	1	1.0	36.3	34.1	0.0	0.0	205.3	2,302.5	13,374.8	9,811.4
12-31-2031	1	1.0	34.1	32.1	0.0	0.0	197.0	2,164.0	15,538.8	10,977.0
12-31-2032	1	1.0	32.1	30.2	0.0	0.0	189.3	2,034.1	17,572.9	11,973.2
12-31-2033	1	1.0	30.3	28.4	0.0	0.0	182.0	1,912.4	19,485.3	12,824.5
12-31-2034	1	1.0	28.5	26.8	0.0	0.0	175.2	1,798.1	21,283.4	13,552.2
12-31-2035	1	1.0	26.9	25.3	0.0	0.0	168.8	1,690.9	22,974.3	14,174.3
12-31-2036	1	1.0	25.3	23.8	0.0	0.0	184.5	1,568.5	24,542.8	14,699.2
12-31-2037	1	1.0	23.9	22.5	0.0	0.0	496.4	1,156.6	25,699.3	15,051.9
12-31-2038	1	1.0	22.5	21.2	0.0	0.0	875.0	683.9	26,383.3	15,241.8
12-31-2039	1	1.0	21.3	20.0	0.0	0.0	1,217.5	253.0	26,636.3	15,306.2
SUBTOTAL			486.4	457.0	2,000.0	0.0	5,010.7	26,636.3	26,636.3	15,306.2
REMAINING			23.3	21.9	0.0	0.0	1,608.2	2.9	26,639.2	15,306.9
TOTAL OF 16.2 YRS			509.7	478.9	2,000.0	0.0	6,618.9	26,639.2	26,639.2	15,306.9

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	16,890.0
12.000	13,945.9
15.000	12,238.5
20.000	10,055.5
25.000	8,448.5
30.000	7,230.0
35.000	6,281.8
40.000	5,527.4
45.000	4,915.4
50.000	4,410.6

Figure 7.9.3
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED UNDEVELOPED RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	29.0	5.8	24.0	4.8	0.0	72.15	5.288	0.00	1,730.1	25.5	0.0	0.0	1,755.6
12-31-2026	32.2	6.4	26.7	5.4	0.0	72.15	5.288	0.00	1,923.5	28.4	0.0	0.0	1,951.9
12-31-2027	29.6	5.9	24.5	4.9	0.0	72.15	5.288	0.00	1,769.6	26.1	0.0	0.0	1,795.8
12-31-2028	27.3	5.5	22.6	4.5	0.0	72.15	5.288	0.00	1,628.1	24.0	0.0	0.0	1,652.1
12-31-2029	25.1	5.0	20.8	4.2	0.0	72.15	5.288	0.00	1,497.8	22.1	0.0	0.0	1,519.9
12-31-2030	23.1	4.6	19.1	3.8	0.0	72.15	5.288	0.00	1,378.0	20.3	0.0	0.0	1,398.3
12-31-2031	21.2	4.2	17.6	3.5	0.0	72.15	5.288	0.00	1,267.8	18.7	0.0	0.0	1,286.5
12-31-2032	19.5	3.9	16.2	3.3	0.0	72.15	5.288	0.00	1,166.3	17.2	0.0	0.0	1,183.6
12-31-2033	18.0	3.6	14.9	3.0	0.0	72.15	5.288	0.00	1,073.0	15.8	0.0	0.0	1,088.9
12-31-2034	16.5	3.3	13.7	2.8	0.0	72.15	5.288	0.00	987.2	14.6	0.0	0.0	1,001.8
12-31-2035	15.2	3.0	12.6	2.5	0.0	72.15	5.288	0.00	908.2	13.4	0.0	0.0	921.6
12-31-2036	14.0	2.8	11.6	2.3	0.0	72.15	5.288	0.00	835.6	12.3	0.0	0.0	847.9
12-31-2037	12.9	2.6	10.7	2.1	0.0	72.15	5.288	0.00	768.7	11.3	0.0	0.0	780.1
12-31-2038	11.8	2.4	9.8	2.0	0.0	72.15	5.288	0.00	707.2	10.4	0.0	0.0	717.7
12-31-2039	10.9	2.2	9.0	1.8	0.0	72.15	5.288	0.00	650.6	9.6	0.0	0.0	660.2
SUBTOTAL	306.4	61.3	253.5	51.1	0.0	72.15	5.288	0.00	18,291.8	270.0	0.0	0.0	18,561.9
REMAINING	11.6	2.3	9.6	1.9	0.0	72.15	5.288	0.00	693.6	10.2	0.0	0.0	703.8
TOTAL	318.0	63.6	263.1	53.0	0.0	72.15	5.288	0.00	18,985.4	280.3	0.0	0.0	19,265.7
CUM PROD	0.0	0.0											
ULTIMATE	318.0	63.6											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	1	1.0	24.7	23.2	3,800.0	0.0	149.4	-2,241.6	-2,241.6	-2,303.5
12-31-2026	1	1.0	27.5	25.8	0.0	0.0	170.8	1,727.9	-513.7	-804.2
12-31-2027	1	1.0	25.3	23.7	0.0	0.0	162.2	1,584.5	1,070.8	445.7
12-31-2028	1	1.0	23.2	21.8	0.0	0.0	154.4	1,452.6	2,523.4	1,487.4
12-31-2029	1	1.0	21.4	20.1	0.0	0.0	147.2	1,331.3	3,854.7	2,355.3
12-31-2030	1	1.0	19.7	18.5	0.0	0.0	140.5	1,219.7	5,074.4	3,078.2
12-31-2031	1	1.0	18.1	17.0	0.0	0.0	134.4	1,117.0	6,191.3	3,680.0
12-31-2032	1	1.0	16.7	15.6	0.0	0.0	128.8	1,022.5	7,213.8	4,180.8
12-31-2033	1	1.0	15.3	14.4	0.0	0.0	123.6	935.5	8,149.3	4,597.3
12-31-2034	1	1.0	14.1	13.2	0.0	0.0	118.9	855.6	9,004.9	4,943.7
12-31-2035	1	1.0	13.0	12.2	0.0	0.0	114.5	782.0	9,786.9	5,231.4
12-31-2036	1	1.0	11.9	11.2	0.0	0.0	110.5	714.3	10,501.2	5,470.4
12-31-2037	1	1.0	11.0	10.3	0.0	0.0	106.8	652.0	11,153.2	5,668.7
12-31-2038	1	1.0	10.1	9.5	0.0	0.0	103.3	594.7	11,747.9	5,833.2
12-31-2039	1	1.0	9.3	8.7	0.0	0.0	100.2	542.0	12,290.0	5,969.4
SUBTOTAL			261.2	245.2	3,800.0	0.0	1,965.5	12,290.0	12,290.0	5,969.4
REMAINING			9.9	9.3	0.0	0.0	364.6	320.1	12,610.0	6,043.3
TOTAL OF 16.2 YRS			271.1	254.5	3,800.0	0.0	2,330.0	12,610.0	12,610.0	6,043.3

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	6,940.1
12.000	5,277.3
15.000	4,322.4
20.000	3,109.4
25.000	2,219.8
30.000	1,545.0
35.000	1,018.2
40.000	597.1
45.000	253.4
50.000	-32.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROBABLE RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	88.0	13.8	72.8	11.5	0.0	72.15	5.288	0.00	5,251.6	60.8	0.0	0.0	5,312.5
12-31-2026	98.6	15.7	81.6	13.1	0.0	72.15	5.288	0.00	5,887.5	69.3	0.0	0.0	5,956.8
12-31-2027	96.9	15.6	80.2	13.0	0.0	72.15	5.288	0.00	5,786.6	68.6	0.0	0.0	5,855.2
12-31-2028	95.0	15.3	78.6	12.8	0.0	72.15	5.288	0.00	5,669.8	67.6	0.0	0.0	5,737.4
12-31-2029	92.9	15.1	76.8	12.6	0.0	72.15	5.288	0.00	5,543.9	66.5	0.0	0.0	5,610.5
12-31-2030	90.6	14.8	75.0	12.3	0.0	72.15	5.288	0.00	5,408.9	65.3	0.0	0.0	5,474.2
12-31-2031	88.2	14.5	73.0	12.1	0.0	72.15	5.288	0.00	5,264.1	63.9	0.0	0.0	5,328.0
12-31-2032	85.6	14.1	70.9	11.8	0.0	72.15	5.288	0.00	5,112.0	62.4	0.0	0.0	5,174.3
12-31-2033	83.0	13.8	68.7	11.5	0.0	72.15	5.288	0.00	4,953.8	60.7	0.0	0.0	5,014.5
12-31-2034	80.3	13.4	66.4	11.1	0.0	72.15	5.288	0.00	4,791.0	58.9	0.0	0.0	4,849.9
12-31-2035	77.7	13.0	64.3	10.8	0.0	72.15	5.288	0.00	4,637.2	57.2	0.0	0.0	4,694.4
12-31-2036	75.8	12.7	62.7	10.6	0.0	72.15	5.288	0.00	4,522.1	55.8	0.0	0.0	4,578.0
12-31-2037	72.8	12.2	60.3	10.2	0.0	72.15	5.288	0.00	4,347.4	53.8	0.0	0.0	4,401.2
12-31-2038	70.2	11.8	58.1	9.8	0.0	72.15	5.288	0.00	4,192.1	52.0	0.0	0.0	4,244.1
12-31-2039	68.2	11.5	56.4	9.5	0.0	72.15	5.288	0.00	4,069.6	50.5	0.0	0.0	4,120.1
SUBTOTAL	1,263.7	207.3	1,045.6	172.7	0.0	72.15	5.288	0.00	75,437.6	913.4	0.0	0.0	76,351.0
REMAINING	1,026.7	187.2	849.5	156.0	0.0	72.15	5.288	0.00	61,290.2	824.8	0.0	0.0	62,115.0
TOTAL	2,290.4	394.4	1,895.0	328.7	0.0	72.15	5.288	0.00	136,727.8	1,738.2	0.0	0.0	138,466.0
CUM PROD	20.7	4.1											
ULTIMATE	2,311.1	398.5											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	2	2.0	74.7	70.2	1,750.0	0.0	403.4	3,014.2	3,014.2	2,786.2
12-31-2026	2	2.0	83.7	78.7	0.0	0.0	454.7	5,339.7	8,353.8	7,416.8
12-31-2027	2	2.0	82.3	77.4	0.0	0.0	449.1	5,246.4	13,600.2	11,553.1
12-31-2028	2	2.0	80.7	75.8	0.0	0.0	442.6	5,138.3	18,738.6	15,235.9
12-31-2029	2	2.0	78.9	74.1	0.0	0.0	435.6	5,021.8	23,760.4	18,508.1
12-31-2030	2	2.0	77.0	72.3	0.0	0.0	428.2	4,896.7	28,657.1	21,408.8
12-31-2031	2	2.0	74.9	70.4	0.0	0.0	420.1	4,762.5	33,419.6	23,973.6
12-31-2032	2	2.0	72.8	68.4	0.0	0.0	411.7	4,621.5	38,041.1	26,236.2
12-31-2033	2	2.0	70.5	66.2	0.0	0.0	402.9	4,474.8	42,516.0	28,227.9
12-31-2034	2	2.0	68.2	64.1	0.0	0.0	393.9	4,323.8	46,839.7	29,977.4
12-31-2035	2	2.0	66.0	62.0	0.0	0.0	396.1	4,170.3	51,010.0	31,511.4
12-31-2036	3	3.0	64.4	60.5	0.0	0.0	443.1	4,010.0	55,020.0	32,852.4
12-31-2037	3	3.0	61.9	58.1	0.0	0.0	433.4	3,847.8	58,867.8	34,022.2
12-31-2038	3	3.0	59.7	56.1	0.0	0.0	440.9	3,687.5	62,555.3	35,041.3
12-31-2039	4	4.0	57.9	54.4	0.0	0.0	482.2	3,525.6	66,080.8	35,927.2
SUBTOTAL			1,073.5	1,008.7	1,750.0	0.0	6,437.9	66,080.8	66,080.8	35,927.2
REMAINING			873.7	820.6	0.0	0.0	44,647.2	15,773.4	81,854.3	38,850.5
TOTAL OF 24.0 YRS			1,947.2	1,829.4	1,750.0	0.0	51,085.1	81,854.3	81,854.3	38,850.5

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	43,980.7
12.000	34,663.7
15.000	29,697.7
20.000	23,797.8
25.000	19,757.9
30.000	16,851.1
35.000	14,673.1
40.000	12,986.5
45.000	11,644.4
50.000	10,552.4

Figure 7.9.3
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

DOS CUADRAS OFFSHORE RESOURCES, LLC INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	407.1	74.6	336.9	62.1	0.0	72.15	5.288	0.00	24,304.9	328.5	0.0	0.0	24,633.4
12-31-2026	410.5	75.3	339.6	62.8	0.0	72.15	5.288	0.00	24,503.6	331.9	0.0	0.0	24,835.5
12-31-2027	383.1	70.3	317.0	58.6	0.0	72.15	5.288	0.00	22,868.7	309.7	0.0	0.0	23,178.4
12-31-2028	357.9	65.7	296.2	54.7	0.0	72.15	5.288	0.00	21,367.2	289.3	0.0	0.0	21,656.6
12-31-2029	334.8	61.4	277.0	51.2	0.0	72.15	5.288	0.00	19,984.1	270.6	0.0	0.0	20,254.7
12-31-2030	313.3	57.5	259.2	47.9	0.0	72.15	5.288	0.00	18,702.0	253.2	0.0	0.0	18,955.2
12-31-2031	293.3	53.8	242.7	44.8	0.0	72.15	5.288	0.00	17,507.8	237.1	0.0	0.0	17,744.8
12-31-2032	274.6	50.4	227.2	42.0	0.0	72.15	5.288	0.00	16,394.7	222.0	0.0	0.0	16,616.6
12-31-2033	257.2	47.2	212.8	39.3	0.0	72.15	5.288	0.00	15,355.5	207.9	0.0	0.0	15,563.5
12-31-2034	241.0	44.2	199.4	36.8	0.0	72.15	5.288	0.00	14,384.5	194.8	0.0	0.0	14,579.3
12-31-2035	225.8	41.4	186.8	34.5	0.0	72.15	5.288	0.00	13,477.0	182.5	0.0	0.0	13,659.5
12-31-2036	211.5	38.8	175.0	32.3	0.0	72.15	5.288	0.00	12,628.6	171.0	0.0	0.0	12,799.6
12-31-2037	198.3	36.4	164.0	30.3	0.0	72.15	5.288	0.00	11,835.4	160.3	0.0	0.0	11,995.7
12-31-2038	185.8	34.1	153.8	28.4	0.0	72.15	5.288	0.00	11,093.6	150.3	0.0	0.0	11,243.9
12-31-2039	174.2	32.0	144.1	26.6	0.0	72.15	5.288	0.00	10,399.8	140.9	0.0	0.0	10,540.7
SUBTOTAL	4,268.4	782.9	3,531.6	652.4	0.0	72.15	5.288	0.00	254,807.3	3,450.2	0.0	0.0	258,257.5
REMAINING	1,139.3	209.0	942.7	174.1	0.0	72.15	5.288	0.00	68,014.6	920.8	0.0	0.0	68,935.4
TOTAL	5,407.7	991.9	4,474.3	826.6	0.0	72.15	5.288	0.00	322,822.0	4,371.0	0.0	0.0	327,192.9
CUM PROD	27,122.9	4,218.4											
ULTIMATE	32,530.6	5,210.3											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	23	23.0	346.5	325.4	7,550.0	0.0	6,676.8	9,734.7	9,734.7	8,998.6
12-31-2026	23	23.0	349.4	328.1	0.0	0.0	6,714.5	17,443.6	27,178.3	24,135.0
12-31-2027	23	23.0	326.0	306.2	0.0	0.0	6,623.9	15,922.3	43,100.6	36,695.3
12-31-2028	23	23.0	304.6	286.1	0.0	0.0	6,540.6	14,525.2	57,625.8	47,111.9
12-31-2029	23	23.0	284.9	267.6	0.0	0.0	6,463.9	13,238.3	70,864.1	55,742.7
12-31-2030	23	23.0	266.6	250.4	0.0	0.0	6,392.8	12,045.3	82,909.4	62,881.8
12-31-2031	23	23.0	249.6	234.4	0.0	0.0	6,326.6	10,934.2	93,843.5	68,773.4
12-31-2032	23	23.0	233.7	219.5	0.0	0.0	6,264.9	9,898.5	103,742.0	73,622.2
12-31-2033	23	23.0	218.9	205.6	0.0	0.0	6,207.3	8,931.6	112,673.7	77,599.7
12-31-2034	23	23.0	205.1	192.6	0.0	0.0	6,153.4	8,028.2	120,701.8	80,850.0
12-31-2035	23	23.0	192.1	180.5	0.0	0.0	6,103.1	7,183.8	127,885.6	83,494.2
12-31-2036	23	23.0	180.0	169.1	0.0	0.0	6,056.1	6,394.4	134,280.0	85,633.9
12-31-2037	23	23.0	168.7	158.5	0.0	0.0	6,012.1	5,656.4	139,936.4	87,354.6
12-31-2038	23	23.0	158.2	148.5	0.0	0.0	5,971.0	4,966.2	144,902.6	88,728.2
12-31-2039	23	23.0	148.3	139.3	0.0	0.0	5,932.5	4,320.6	149,223.2	89,814.7
SUBTOTAL			3,632.8	3,412.0	7,550.0	0.0	94,439.5	149,223.2	149,223.2	89,814.7
REMAINING			969.7	910.7	0.0	0.0	50,958.6	16,096.4	165,319.6	92,812.5
TOTAL OF 24.0 YRS			4,602.5	4,322.7	7,550.0	0.0	145,398.1	165,319.6	165,319.6	92,812.5

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	102,240.5
12.000	84,864.6
15.000	75,077.0
20.000	62,806.2
25.000	53,887.3
30.000	47,143.9
35.000	41,880.5
40.000	37,664.3
45.000	34,214.1
50.000	31,339.7

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

CALIFORNIA RESOURCES CORPORATION INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING M-D-Y	OIL MBBL	GAS MMCF	OIL MBBL	GAS MMCF	NGL MBBL	OIL $/BBL	GAS $/MCF	NGL $/BBL	OIL M$	GAS M$	NGL M$	OTHER M$	TOTAL M$
12-31-2025	1,040.1	304.8	816.3	193.0	0.0	75.41	5.257	0.00	61,558.5	1,014.6	0.0	0.0	62,573.1
12-31-2026	1,020.4	310.1	800.8	196.3	0.0	75.41	5.257	0.00	60,389.5	1,032.1	0.0	0.0	61,421.6
12-31-2027	1,027.3	323.4	806.2	204.8	0.0	75.41	5.257	0.00	60,797.7	1,076.4	0.0	0.0	61,874.2
12-31-2028	1,044.5	323.7	819.8	205.0	0.0	75.41	5.257	0.00	61,818.9	1,077.5	0.0	0.0	62,896.4
12-31-2029	1,071.0	328.9	840.6	208.3	0.0	75.41	5.257	0.00	63,391.4	1,094.9	0.0	0.0	64,486.3
12-31-2030	1,024.8	317.4	804.3	200.9	0.0	75.41	5.257	0.00	60,653.9	1,056.3	0.0	0.0	61,710.1
12-31-2031	936.5	290.0	735.0	183.6	0.0	75.41	5.257	0.00	55,426.4	965.1	0.0	0.0	56,391.5
12-31-2032	870.6	269.3	683.3	170.5	0.0	75.41	5.257	0.00	51,526.7	896.5	0.0	0.0	52,423.1
12-31-2033	810.2	250.4	635.8	158.5	0.0	75.41	5.257	0.00	47,949.4	833.5	0.0	0.0	48,782.9
12-31-2034	759.3	234.6	596.0	148.5	0.0	75.41	5.257	0.00	44,942.7	780.7	0.0	0.0	45,723.4
12-31-2035	719.5	221.2	564.7	140.1	0.0	75.41	5.257	0.00	42,583.6	736.3	0.0	0.0	43,319.9
12-31-2036	679.3	208.8	533.2	132.2	0.0	75.41	5.257	0.00	40,206.6	695.1	0.0	0.0	40,901.7
12-31-2037	641.2	197.2	503.3	124.9	0.0	75.41	5.257	0.00	37,952.3	656.5	0.0	0.0	38,608.8
12-31-2038	604.1	186.4	474.1	118.0	0.0	75.41	5.257	0.00	35,755.4	620.3	0.0	0.0	36,375.7
12-31-2039	574.4	177.4	450.9	112.3	0.0	75.41	5.257	0.00	33,999.4	590.3	0.0	0.0	34,589.8
SUBTOTAL	12,823.3	3,943.7	10,064.3	2,496.9	0.0	75.41	5.257	0.00	758,952.3	13,126.2	0.0	0.0	772,078.5
REMAINING	1,943.6	601.8	1,525.5	381.0	0.0	75.41	5.257	0.00	115,037.5	2,003.1	0.0	0.0	117,040.6
TOTAL	14,766.9	4,545.5	11,589.8	2,877.9	0.0	75.41	5.257	0.00	873,989.8	15,129.3	0.0	0.0	889,119.1
CUM PROD	323,342.8	196,342.8											
ULTIMATE	338,109.7	200,888.3											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING M-D-Y	GROSS	NET	PRODUCTION M$	AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	PERIOD M$	CUM M$	CUM M$
12-31-2025	104	100.1	844.0	2,654.4	15,385.7	0.0	30,423.6	13,265.4	13,265.4	12,545.6
12-31-2026	111	106.8	828.7	2,605.5	14,130.1	0.0	30,567.3	13,290.0	26,555.4	24,125.3
12-31-2027	113	108.8	835.0	2,624.7	11,161.9	0.0	31,134.2	16,118.4	42,673.8	36,799.7
12-31-2028	118	113.6	848.7	2,668.1	14,988.7	0.0	31,588.2	12,802.8	55,476.6	45,995.5
12-31-2029	123	118.4	870.1	2,735.5	16,764.5	0.0	32,152.0	11,964.3	67,440.9	53,691.0
12-31-2030	124	119.4	832.7	2,617.7	769.7	0.0	32,107.3	25,382.7	92,823.5	68,725.9
12-31-2031	122	117.4	760.9	2,392.1	0.0	0.0	31,555.5	21,683.1	114,506.6	80,417.1
12-31-2032	122	117.4	707.3	2,223.8	96.2	0.0	31,199.9	18,195.9	132,702.5	89,333.6
12-31-2033	119	114.5	658.2	2,069.4	0.0	0.0	30,795.3	15,260.1	147,962.6	96,133.6
12-31-2034	119	114.5	616.9	1,939.6	0.0	0.0	30,515.7	12,651.2	160,613.8	101,258.9
12-31-2035	119	114.5	584.5	1,837.6	673.5	0.0	30,259.4	9,964.8	170,578.6	104,919.9
12-31-2036	116	111.7	551.9	1,735.0	0.0	0.0	29,955.0	8,659.8	179,238.4	107,820.0
12-31-2037	116	111.7	520.9	1,637.8	0.0	0.0	29,606.5	6,843.6	186,082.0	109,904.0
12-31-2038	111	106.8	490.8	1,543.1	0.0	0.0	29,122.0	5,219.9	191,301.8	111,349.5
12-31-2039	109	104.9	466.7	1,467.3	0.0	0.0	28,905.7	3,750.0	195,051.9	112,294.2
SUBTOTAL			10,417.2	32,751.4	73,970.4	0.0	459,887.6	195,051.9	195,051.9	112,294.2
REMAINING			1,579.2	4,964.8	0.0	0.0	107,543.5	2,953.1	198,004.9	112,987.5
TOTAL OF 18.8 YRS			11,996.4	37,716.3	73,970.4	0.0	567,431.1	198,004.9	198,004.9	112,987.5

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	124,728.6
12.000	102,942.3
15.000	90,414.9
20.000	74,553.6
25.000	63,026.1
30.000	54,398.5
35.000	47,773.4
40.000	42,570.1
45.000	38,401.8
50.000	35,003.8

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	966.7	291.3	758.7	184.4	0.0	75.41	5.257	0.00	57,215.8	969.6	0.0	0.0	58,185.4
12-31-2026	883.1	266.8	693.1	168.9	0.0	75.41	5.257	0.00	52,267.4	888.0	0.0	0.0	53,155.5
12-31-2027	817.9	248.1	642.0	157.1	0.0	75.41	5.257	0.00	48,413.4	825.9	0.0	0.0	49,239.3
12-31-2028	764.2	232.4	599.8	147.1	0.0	75.41	5.257	0.00	45,230.4	773.6	0.0	0.0	46,003.9
12-31-2029	716.4	217.9	562.3	138.0	0.0	75.41	5.257	0.00	42,404.2	725.2	0.0	0.0	43,129.4
12-31-2030	674.6	205.3	529.5	130.0	0.0	75.41	5.257	0.00	39,930.6	683.3	0.0	0.0	40,613.9
12-31-2031	635.9	193.3	499.1	122.4	0.0	75.41	5.257	0.00	37,640.3	643.6	0.0	0.0	38,283.9
12-31-2032	601.4	183.3	472.1	116.1	0.0	75.41	5.257	0.00	35,599.8	610.2	0.0	0.0	36,210.0
12-31-2033	570.0	173.8	447.4	110.0	0.0	75.41	5.257	0.00	33,740.5	578.4	0.0	0.0	34,318.9
12-31-2034	542.9	165.6	426.1	104.8	0.0	75.41	5.257	0.00	32,134.9	551.1	0.0	0.0	32,686.0
12-31-2035	516.2	157.9	405.2	100.0	0.0	75.41	5.257	0.00	30,557.9	525.7	0.0	0.0	31,083.6
12-31-2036	491.7	150.8	386.0	95.5	0.0	75.41	5.257	0.00	29,107.7	501.9	0.0	0.0	29,609.7
12-31-2037	468.2	143.8	367.5	91.1	0.0	75.41	5.257	0.00	27,711.9	478.7	0.0	0.0	28,190.6
12-31-2038	443.6	136.9	348.2	86.7	0.0	75.41	5.257	0.00	26,258.4	455.8	0.0	0.0	26,714.2
12-31-2039	425.0	131.4	333.7	83.2	0.0	75.41	5.257	0.00	25,160.6	437.6	0.0	0.0	25,598.2
SUBTOTAL	9,517.9	2,898.6	7,470.8	1,835.3	0.0	75.41	5.257	0.00	563,373.8	9,648.4	0.0	0.0	573,022.3
REMAINING	1,477.8	457.4	1,160.1	289.7	0.0	75.41	5.257	0.00	87,481.7	1,522.7	0.0	0.0	89,004.4
TOTAL	10,995.8	3,356.0	8,630.9	2,125.0	0.0	75.41	5.257	0.00	650,855.5	11,171.2	0.0	0.0	662,026.6
CUM PROD	291,200.9	184,087.5											
ULTIMATE	302,196.7	187,443.5											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	98	94.3	784.9	2,468.2	0.0	0.0	29,766.3	25,165.9	25,165.9	24,037.9
12-31-2026	96	92.4	717.1	2,254.8	0.0	0.0	29,068.8	21,114.7	46,280.6	42,371.4
12-31-2027	93	89.5	664.3	2,088.7	0.0	0.0	28,676.7	17,809.5	64,090.2	56,429.1
12-31-2028	92	88.6	620.7	1,951.5	0.0	0.0	28,417.0	15,014.9	79,105.0	67,203.7
12-31-2029	91	87.6	581.9	1,829.5	0.0	0.0	28,117.9	12,600.1	91,705.1	75,423.9
12-31-2030	91	87.6	547.9	1,722.8	0.0	0.0	27,859.5	10,483.6	102,188.7	81,642.1
12-31-2031	89	85.7	516.5	1,624.0	0.0	0.0	27,528.3	8,615.1	110,803.8	86,288.0
12-31-2032	88	84.7	488.5	1,536.0	0.0	0.0	27,243.1	6,942.3	117,746.1	89,692.1
12-31-2033	85	81.8	463.0	1,455.8	0.0	0.0	26,964.7	5,435.4	123,181.5	92,115.7
12-31-2034	85	81.8	441.0	1,386.5	0.0	0.0	26,793.6	4,064.9	127,246.3	93,764.1
12-31-2035	84	80.9	419.4	1,318.6	0.0	0.0	26,531.0	2,814.6	130,061.0	94,802.6
12-31-2036	81	78.0	399.5	1,256.0	0.0	0.0	26,284.9	1,669.2	131,730.2	95,363.6
12-31-2037	81	78.0	380.4	1,195.8	0.0	0.0	26,002.9	611.5	132,341.7	95,551.8
12-31-2038	76	73.2	360.4	1,133.2	0.0	0.0	25,575.9	-355.4	131,986.2	95,455.7
12-31-2039	74	71.2	345.4	1,085.9	0.0	0.0	25,415.4	-1,248.5	130,737.8	95,143.8
SUBTOTAL			7,730.9	24,307.5	0.0	0.0	410,246.1	130,737.8	130,737.8	95,143.8
REMAINING			1,200.9	3,775.5	0.0	0.0	89,456.3	-5,428.4	125,309.3	94,046.1
TOTAL OF 18.8 YRS			8,931.8	28,083.1	0.0	0.0	499,702.4	125,309.3	125,309.3	94,046.1

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	99,176.1
12.000	89,385.8
15.000	83,173.2
20.000	74,545.5
25.000	67,609.7
30.000	61,952.5
35.000	57,271.6
40.000	53,345.8
45.000	50,012.3
50.000	47,149.7

Figure 7.9.4
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	6.8	0.1	5.4	0.1	0.0	75.41	5.257	0.00	403.8	0.3	0.0	0.0	404.1
12-31-2026	18.4	1.3	14.4	0.8	0.0	75.41	5.257	0.00	1,088.2	4.2	0.0	0.0	1,092.4
12-31-2027	30.7	4.6	24.1	2.9	0.0	75.41	5.257	0.00	1,818.4	15.2	0.0	0.0	1,833.6
12-31-2028	35.8	7.1	28.2	4.5	0.0	75.41	5.257	0.00	2,122.8	23.6	0.0	0.0	2,146.4
12-31-2029	45.4	9.9	35.7	6.3	0.0	75.41	5.257	0.00	2,694.5	33.1	0.0	0.0	2,727.6
12-31-2030	57.4	14.9	45.1	9.4	0.0	75.41	5.257	0.00	3,402.8	49.6	0.0	0.0	3,452.4
12-31-2031	50.6	12.6	39.8	8.0	0.0	75.41	5.257	0.00	2,999.4	41.9	0.0	0.0	3,041.3
12-31-2032	50.0	11.8	39.2	7.5	0.0	75.41	5.257	0.00	2,958.7	39.2	0.0	0.0	2,997.9
12-31-2033	44.7	10.1	35.1	6.4	0.0	75.41	5.257	0.00	2,648.5	33.8	0.0	0.0	2,682.3
12-31-2034	40.3	8.8	31.6	5.6	0.0	75.41	5.257	0.00	2,384.0	29.3	0.0	0.0	2,413.4
12-31-2035	43.0	8.4	33.7	5.3	0.0	75.41	5.257	0.00	2,545.0	28.0	0.0	0.0	2,573.0
12-31-2036	40.8	7.7	32.0	4.9	0.0	75.41	5.257	0.00	2,416.2	25.6	0.0	0.0	2,441.8
12-31-2037	37.9	7.0	29.7	4.4	0.0	75.41	5.257	0.00	2,242.9	23.2	0.0	0.0	2,266.1
12-31-2038	35.4	6.4	27.8	4.0	0.0	75.41	5.257	0.00	2,094.8	21.2	0.0	0.0	2,116.0
12-31-2039	33.1	5.8	26.0	3.7	0.0	75.41	5.257	0.00	1,958.8	19.4	0.0	0.0	1,978.2
SUBTOTAL	570.4	116.3	447.9	73.7	0.0	75.41	5.257	0.00	33,778.9	387.6	0.0	0.0	34,166.4
REMAINING	98.8	15.4	77.5	9.7	0.0	75.41	5.257	0.00	5,847.8	51.1	0.0	0.0	5,898.9
TOTAL	669.3	131.7	525.5	83.5	0.0	75.41	5.257	0.00	39,626.6	438.7	0.0	0.0	40,065.4
CUM PROD	32,141.9	12,255.3											
ULTIMATE	32,811.2	12,387.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	1	1.0	5.4	17.1	625.4	0.0	104.9	-348.7	-348.7	-359.9
12-31-2026	5	4.8	14.7	46.3	1,314.3	0.0	298.3	-581.3	-930.0	-863.1
12-31-2027	6	5.8	24.6	77.8	336.8	0.0	602.4	792.0	-138.0	-247.1
12-31-2028	7	6.7	28.9	91.1	776.8	0.0	673.1	576.6	438.6	167.4
12-31-2029	8	7.7	36.7	115.7	865.9	0.0	838.3	871.0	1,309.6	715.6
12-31-2030	9	8.7	46.5	146.5	769.7	0.0	980.1	1,509.6	2,819.2	1,589.8
12-31-2031	9	8.7	41.0	129.0	0.0	0.0	955.5	1,915.8	4,735.0	2,622.8
12-31-2032	10	9.6	40.4	127.2	96.2	0.0	1,026.0	1,708.2	6,443.2	3,457.7
12-31-2033	10	9.6	36.1	113.8	0.0	0.0	1,008.7	1,523.7	7,966.9	4,136.6
12-31-2034	10	9.6	32.5	102.4	0.0	0.0	988.2	1,290.3	9,257.2	4,659.2
12-31-2035	11	10.6	34.6	109.2	673.5	0.0	1,067.6	688.2	9,945.4	4,903.1
12-31-2036	11	10.6	32.9	103.6	0.0	0.0	1,071.0	1,234.4	11,179.7	5,316.2
12-31-2037	11	10.6	30.5	96.1	0.0	0.0	1,057.5	1,081.9	12,261.7	5,645.4
12-31-2038	11	10.6	28.5	89.8	0.0	0.0	1,046.1	951.7	13,213.4	5,908.6
12-31-2039	11	10.6	26.6	83.9	0.0	0.0	1,030.8	836.9	14,050.2	6,119.0
SUBTOTAL			459.9	1,449.4	5,458.6	0.0	12,748.4	14,050.2	14,050.2	6,119.0
REMAINING			79.3	250.2	0.0	0.0	5,413.4	156.0	14,206.2	6,159.3
TOTAL OF 18.8 YRS			539.2	1,699.6	5,458.6	0.0	18,161.8	14,206.2	14,206.2	6,159.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	7,205.8
12.000	5,286.5
15.000	4,232.2
20.000	2,962.8
25.000	2,098.2
30.000	1,491.6
35.000	1,055.0
40.000	733.5
45.000	492.1
50.000	307.6

Figure 7.9.4
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROVED UNDEVELOPED RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	66.6	13.4	52.2	8.5	0.0	75.41	5.257	0.00	3,938.9	44.7	0.0	0.0	3,983.6
12-31-2026	118.9	42.1	93.3	26.6	0.0	75.41	5.257	0.00	7,033.8	139.9	0.0	0.0	7,173.8
12-31-2027	178.6	70.7	140.1	44.8	0.0	75.41	5.257	0.00	10,566.0	235.3	0.0	0.0	10,801.2
12-31-2028	244.5	84.3	191.8	53.3	0.0	75.41	5.257	0.00	14,465.6	280.4	0.0	0.0	14,746.0
12-31-2029	309.2	101.2	242.6	64.0	0.0	75.41	5.257	0.00	18,292.8	336.6	0.0	0.0	18,629.3
12-31-2030	292.8	97.2	229.7	61.5	0.0	75.41	5.257	0.00	17,320.5	323.4	0.0	0.0	17,643.9
12-31-2031	249.9	84.0	196.1	53.2	0.0	75.41	5.257	0.00	14,786.7	279.6	0.0	0.0	15,066.4
12-31-2032	219.2	74.3	172.0	47.0	0.0	75.41	5.257	0.00	12,968.2	247.1	0.0	0.0	13,215.3
12-31-2033	195.4	66.5	153.3	42.1	0.0	75.41	5.257	0.00	11,560.4	221.3	0.0	0.0	11,781.7
12-31-2034	176.2	60.2	138.2	38.1	0.0	75.41	5.257	0.00	10,423.7	200.3	0.0	0.0	10,624.0
12-31-2035	160.2	54.9	125.7	34.7	0.0	75.41	5.257	0.00	9,480.6	182.6	0.0	0.0	9,663.2
12-31-2036	146.8	50.4	115.1	31.9	0.0	75.41	5.257	0.00	8,682.7	167.6	0.0	0.0	8,850.3
12-31-2037	135.2	46.5	106.1	29.4	0.0	75.41	5.257	0.00	7,997.5	154.7	0.0	0.0	8,152.1
12-31-2038	125.1	43.1	98.2	27.3	0.0	75.41	5.257	0.00	7,402.2	143.3	0.0	0.0	7,545.5
12-31-2039	116.3	40.1	91.2	25.4	0.0	75.41	5.257	0.00	6,880.0	133.4	0.0	0.0	7,013.4
SUBTOTAL	2,734.9	928.8	2,145.6	587.8	0.0	75.41	5.257	0.00	161,799.6	3,090.2	0.0	0.0	164,889.8
REMAINING	366.9	129.0	287.9	81.7	0.0	75.41	5.257	0.00	21,708.1	429.2	0.0	0.0	22,137.3
TOTAL	3,101.8	1,057.9	2,433.5	669.5	0.0	75.41	5.257	0.00	183,507.7	3,519.4	0.0	0.0	187,027.1
CUM PROD	0.0	0.0											
ULTIMATE	3,101.8	1,057.9											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	5	4.8	53.6	169.0	14,760.3	0.0	552.5	-11,551.8	-11,551.8	-11,132.5
12-31-2026	10	9.6	96.9	304.3	12,815.8	0.0	1,200.2	-7,243.5	-18,795.3	-17,383.0
12-31-2027	14	13.5	146.0	458.2	10,825.1	0.0	1,855.0	-2,483.1	-21,278.4	-19,382.3
12-31-2028	19	18.3	199.1	625.5	14,211.9	0.0	2,498.1	-2,788.7	-24,067.1	-21,375.6
12-31-2029	24	23.1	251.5	790.2	15,898.6	0.0	3,195.8	-1,506.8	-25,573.9	-22,448.5
12-31-2030	24	23.1	238.2	748.4	0.0	0.0	3,267.8	13,389.5	-12,184.4	-14,505.9
12-31-2031	24	23.1	203.4	639.1	0.0	0.0	3,071.6	11,152.2	-1,032.2	-8,493.7
12-31-2032	24	23.1	178.4	560.6	0.0	0.0	2,930.9	9,545.4	8,513.2	-3,816.2
12-31-2033	24	23.1	159.1	499.8	0.0	0.0	2,821.9	8,301.0	16,814.2	-118.6
12-31-2034	24	23.1	143.5	450.7	0.0	0.0	2,733.9	7,296.0	24,110.2	2,835.6
12-31-2035	24	23.1	130.5	409.9	0.0	0.0	2,660.9	6,462.0	30,572.2	5,214.1
12-31-2036	24	23.1	119.5	375.4	0.0	0.0	2,599.1	5,756.2	36,328.4	7,140.2
12-31-2037	24	23.1	110.1	345.8	0.0	0.0	2,546.1	5,150.2	41,478.6	8,706.8
12-31-2038	24	23.1	101.9	320.1	0.0	0.0	2,500.0	4,623.6	46,102.2	9,985.3
12-31-2039	24	23.1	94.7	297.5	0.0	0.0	2,459.5	4,161.6	50,263.9	11,031.5
SUBTOTAL			2,226.4	6,994.5	68,511.8	0.0	36,893.2	50,263.9	50,263.9	11,031.5
REMAINING			299.0	939.0	0.0	0.0	12,673.7	8,225.5	58,489.4	12,782.1
TOTAL OF 18.8 YRS			2,525.4	7,933.6	68,511.8	0.0	49,566.9	58,489.4	58,489.4	12,782.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	18,346.6
12.000	8,270.0
15.000	3,009.5
20.000	-2,954.8
25.000	-6,681.7
30.000	-9,045.6
35.000	-10,553.2
40.000	-11,509.3
45.000	-12,102.6
50.000	-12,453.5

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROBABLE RESERVES

CALIFORNIA RESOURCES CORPORATION INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING M-D-Y	OIL MBBL	GAS MMCF	OIL MBBL	GAS MMCF	NGL MBBL	OIL $/BBL	GAS $/MCF	NGL $/BBL	OIL M$	GAS M$	NGL M$	OTHER M$	TOTAL M$
12-31-2025	183.6	51.2	144.0	32.4	0.0	75.41	5.257	0.00	10,861.5	170.4	0.0	0.0	11,031.9
12-31-2026	256.4	83.8	201.2	53.0	0.0	75.41	5.257	0.00	15,169.0	278.8	0.0	0.0	15,447.8
12-31-2027	281.3	91.3	220.7	57.8	0.0	75.41	5.257	0.00	16,645.3	303.9	0.0	0.0	16,949.2
12-31-2028	315.1	93.2	247.2	59.0	0.0	75.41	5.257	0.00	18,644.1	310.3	0.0	0.0	18,954.4
12-31-2029	299.4	88.6	235.0	56.1	0.0	75.41	5.257	0.00	17,719.0	294.9	0.0	0.0	18,013.9
12-31-2030	270.9	80.7	212.6	51.1	0.0	75.41	5.257	0.00	16,030.7	268.6	0.0	0.0	16,299.3
12-31-2031	254.1	75.3	199.4	47.7	0.0	75.41	5.257	0.00	15,040.1	250.6	0.0	0.0	15,290.6
12-31-2032	242.8	70.5	190.5	44.6	0.0	75.41	5.257	0.00	14,366.6	234.6	0.0	0.0	14,601.2
12-31-2033	229.2	66.1	179.9	41.8	0.0	75.41	5.257	0.00	13,566.5	220.0	0.0	0.0	13,786.5
12-31-2034	218.7	62.7	171.6	39.7	0.0	75.41	5.257	0.00	12,940.9	208.7	0.0	0.0	13,149.6
12-31-2035	212.1	60.5	166.4	38.3	0.0	75.41	5.257	0.00	12,551.6	201.2	0.0	0.0	12,752.8
12-31-2036	203.2	57.7	159.5	36.5	0.0	75.41	5.257	0.00	12,026.1	191.9	0.0	0.0	12,218.0
12-31-2037	198.0	55.8	155.4	35.3	0.0	75.41	5.257	0.00	11,719.2	185.8	0.0	0.0	11,905.0
12-31-2038	194.2	53.7	152.4	34.0	0.0	75.41	5.257	0.00	11,491.5	178.7	0.0	0.0	11,670.3
12-31-2039	187.5	51.3	147.2	32.5	0.0	75.41	5.257	0.00	11,098.2	170.7	0.0	0.0	11,268.9
SUBTOTAL	3,546.5	1,042.4	2,783.1	659.9	0.0	75.41	5.257	0.00	209,870.2	3,469.2	0.0	0.0	213,339.4
REMAINING	4,252.0	1,256.9	3,337.1	795.8	0.0	75.41	5.257	0.00	251,652.8	4,183.3	0.0	0.0	255,836.1
TOTAL	7,798.4	2,299.3	6,120.2	1,455.7	0.0	75.41	5.257	0.00	461,523.0	7,652.5	0.0	0.0	469,175.5
CUM PROD	274.8	85.5											
ULTIMATE	8,073.2	2,384.7											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING M-D-Y	GROSS	NET	PRODUCTION M$	AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	PERIOD M$	CUM M$	CUM M$
12-31-2025	2	1.9	148.7	468.0	216.5	0.0	988.0	9,210.7	9,210.7	8,768.7
12-31-2026	7	6.7	208.5	655.3	1,474.0	0.0	1,796.5	11,313.5	20,524.2	18,563.5
12-31-2027	10	9.6	228.8	719.0	2,942.3	0.0	2,098.1	10,961.0	31,485.2	27,242.0
12-31-2028	12	11.5	255.7	804.0	625.4	0.0	2,359.9	14,909.3	46,394.5	37,925.4
12-31-2029	13	12.5	243.0	764.1	336.8	0.0	2,402.1	14,268.0	60,662.5	47,243.1
12-31-2030	14	13.5	219.9	691.4	336.8	0.0	2,304.8	12,746.5	73,409.0	54,803.8
12-31-2031	16	15.4	206.3	648.6	153.9	0.0	2,489.1	11,792.8	85,201.7	61,155.0
12-31-2032	18	17.3	196.9	619.4	481.1	0.0	2,557.5	10,746.3	95,948.1	66,412.8
12-31-2033	19	18.3	185.9	584.8	0.0	0.0	2,482.8	10,533.0	106,481.0	71,101.9
12-31-2034	18	17.3	177.3	557.8	336.8	0.0	2,447.7	9,630.0	116,111.0	74,999.3
12-31-2035	19	18.3	172.0	541.0	0.0	0.0	2,544.7	9,495.1	125,606.1	78,492.5
12-31-2036	20	19.3	164.8	518.3	0.0	0.0	2,484.0	9,051.0	134,657.1	81,519.4
12-31-2037	19	18.3	160.5	505.0	0.0	0.0	2,587.2	8,652.3	143,309.4	84,149.9
12-31-2038	23	22.1	157.3	495.1	0.0	0.0	2,742.9	8,274.9	151,584.3	86,436.9
12-31-2039	23	22.1	151.9	478.0	0.0	0.0	2,712.5	7,926.4	159,510.7	88,428.5
SUBTOTAL			2,877.5	9,049.9	6,903.4	0.0	34,997.9	159,510.7	159,510.7	88,428.5
REMAINING			3,450.9	10,852.6	0.0	0.0	202,603.8	38,928.8	198,439.5	95,650.6
TOTAL OF 25.3 YRS			6,328.4	19,902.4	6,903.4	0.0	237,601.7	198,439.5	198,439.5	95,650.6

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	107,943.1
12.000	85,607.1
15.000	73,676.7
20.000	59,467.4
25.000	49,708.6
30.000	42,670.0
35.000	37,388.4
40.000	33,296.3
45.000	30,041.7
50.000	27,396.7

Figure 7.9.4
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED + PROBABLE (2P) RESERVES

CALIFORNIA RESOURCES CORPORATION INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	1,223.7	356.0	960.4	225.4	0.0	75.41	5.257	0.00	72,420.0	1,184.9	0.0	0.0	73,605.0
12-31-2026	1,276.7	393.9	1,002.0	249.4	0.0	75.41	5.257	0.00	75,558.4	1,311.0	0.0	0.0	76,869.4
12-31-2027	1,308.6	414.8	1,027.0	262.6	0.0	75.41	5.257	0.00	77,443.0	1,380.3	0.0	0.0	78,823.3
12-31-2028	1,359.6	417.0	1,067.0	264.0	0.0	75.41	5.257	0.00	80,463.0	1,387.8	0.0	0.0	81,850.8
12-31-2029	1,370.4	417.5	1,075.6	264.4	0.0	75.41	5.257	0.00	81,110.4	1,389.8	0.0	0.0	82,500.2
12-31-2030	1,295.7	398.1	1,016.9	252.0	0.0	75.41	5.257	0.00	76,684.6	1,324.9	0.0	0.0	78,009.5
12-31-2031	1,190.6	365.2	934.4	231.2	0.0	75.41	5.257	0.00	70,466.5	1,215.7	0.0	0.0	71,682.2
12-31-2032	1,113.4	339.8	873.8	215.2	0.0	75.41	5.257	0.00	65,893.3	1,131.1	0.0	0.0	67,024.4
12-31-2033	1,039.4	316.5	815.8	200.4	0.0	75.41	5.257	0.00	61,515.9	1,053.5	0.0	0.0	62,569.4
12-31-2034	978.0	297.3	767.6	188.2	0.0	75.41	5.257	0.00	57,883.6	989.4	0.0	0.0	58,873.0
12-31-2035	931.6	281.7	731.1	178.3	0.0	75.41	5.257	0.00	55,135.1	937.6	0.0	0.0	56,072.7
12-31-2036	882.5	266.5	692.6	168.7	0.0	75.41	5.257	0.00	52,232.7	887.0	0.0	0.0	53,119.7
12-31-2037	839.3	253.1	658.7	160.2	0.0	75.41	5.257	0.00	49,671.5	842.3	0.0	0.0	50,513.8
12-31-2038	798.3	240.1	626.5	152.0	0.0	75.41	5.257	0.00	47,246.9	799.1	0.0	0.0	48,046.0
12-31-2039	762.0	228.6	598.0	144.8	0.0	75.41	5.257	0.00	45,097.6	761.0	0.0	0.0	45,858.6
SUBTOTAL	16,369.7	4,986.1	12,847.4	3,156.8	0.0	75.41	5.257	0.00	968,822.5	16,595.4	0.0	0.0	985,417.9
REMAINING	6,195.6	1,858.7	4,862.6	1,176.8	0.0	75.41	5.257	0.00	366,690.3	6,186.5	0.0	0.0	372,876.7
TOTAL	22,565.3	6,844.8	17,710.0	4,333.6	0.0	75.41	5.257	0.00	1,335,512.8	22,781.8	0.0	0.0	1,358,294.6
CUM PROD	323,617.6	196,428.3											
ULTIMATE	346,182.8	203,273.1											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	106	102.0	992.7	3,122.3	15,602.2	0.0	31,411.7	22,476.1	22,476.1	21,314.2
12-31-2026	118	113.6	1,037.2	3,260.8	15,604.1	0.0	32,363.8	24,603.5	47,079.5	42,688.8
12-31-2027	123	118.4	1,063.7	3,343.7	14,104.2	0.0	33,232.3	27,079.4	74,159.0	64,041.7
12-31-2028	130	125.1	1,104.3	3,472.1	15,614.1	0.0	33,948.1	27,712.1	101,871.1	83,920.9
12-31-2029	136	130.9	1,113.0	3,499.6	17,101.3	0.0	34,554.0	26,232.2	128,103.3	100,934.1
12-31-2030	138	132.8	1,052.5	3,309.1	1,106.5	0.0	34,412.1	38,129.2	166,232.5	123,529.7
12-31-2031	138	132.8	967.1	3,040.7	153.9	0.0	34,044.5	33,475.8	199,708.3	141,572.1
12-31-2032	140	134.8	904.3	2,843.2	577.3	0.0	33,757.4	28,942.2	228,650.6	155,746.4
12-31-2033	138	132.8	844.2	2,654.2	0.0	0.0	33,278.0	25,793.0	254,443.6	167,235.5
12-31-2034	137	131.9	794.3	2,497.4	336.8	0.0	32,963.4	22,281.2	276,724.8	176,258.3
12-31-2035	138	132.8	756.5	2,378.6	673.5	0.0	32,804.2	19,460.0	296,184.7	183,412.4
12-31-2036	136	130.9	716.6	2,253.3	0.0	0.0	32,439.0	17,710.8	313,895.5	189,339.4
12-31-2037	135	129.9	681.5	2,142.8	0.0	0.0	32,193.7	15,495.8	329,391.4	194,053.9
12-31-2038	134	129.0	648.2	2,038.1	0.0	0.0	31,864.9	13,494.8	342,886.1	197,786.5
12-31-2039	132	127.0	618.6	1,945.3	0.0	0.0	31,618.3	11,676.4	354,562.6	200,722.7
SUBTOTAL			13,294.7	41,801.3	80,873.8	0.0	494,885.5	354,562.6	354,562.6	200,722.7
REMAINING			5,030.1	15,817.4	0.0	0.0	310,147.3	41,881.9	396,444.5	208,638.0
TOTAL OF 25.3 YRS			18,324.8	57,618.7	80,873.8	0.0	805,032.8	396,444.5	396,444.5	208,638.0

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	232,671.7
12.000	188,549.3
15.000	164,091.6
20.000	134,021.0
25.000	112,734.7
30.000	97,068.5
35.000	85,161.8
40.000	75,866.3
45.000	68,443.4
50.000	62,400.4

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
WEST MONTALVO LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	41.0	31.8	34.2	6.1	0.0	73.10	3.101	0.00	2,498.0	18.9	0.0	0.0	2,516.9
12-31-2026	37.1	28.9	30.9	5.5	0.0	73.10	3.101	0.00	2,257.3	17.1	0.0	0.0	2,274.4
12-31-2027	30.8	24.0	25.7	4.6	0.0	73.10	3.101	0.00	1,875.8	14.3	0.0	0.0	1,890.1
12-31-2028	26.5	20.8	22.1	4.0	0.0	73.10	3.101	0.00	1,616.4	12.3	0.0	0.0	1,628.7
12-31-2029	24.0	18.8	20.0	3.6	0.0	73.10	3.101	0.00	1,461.4	11.2	0.0	0.0	1,472.6
12-31-2030	21.3	16.8	17.8	3.2	0.0	73.10	3.101	0.00	1,299.7	10.0	0.0	0.0	1,309.7
12-31-2031	12.8	8.1	10.7	1.6	0.0	73.10	3.101	0.00	780.1	4.8	0.0	0.0	784.9
12-31-2032	10.2	5.4	8.5	1.0	0.0	73.10	3.101	0.00	622.5	3.2	0.0	0.0	625.7
12-31-2033	5.5	4.0	4.6	0.8	0.0	73.10	3.101	0.00	333.7	2.4	0.0	0.0	336.1
12-31-2034	4.6	3.5	3.8	0.7	0.0	73.10	3.101	0.00	280.8	2.1	0.0	0.0	282.9
03-31-2035	1.1	0.8	0.9	0.2	0.0	73.10	3.101	0.00	65.7	0.5	0.0	0.0	66.2
SUBTOTAL	215.0	163.0	179.1	31.2	0.0	73.10	3.101	0.00	13,091.4	96.8	0.0	0.0	13,188.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	215.0	163.0	179.1	31.2	0.0	73.10	3.101	0.00	13,091.4	96.8	0.0	0.0	13,188.2
CUM PROD	5,685.9	3,678.0											
ULTIMATE	5,900.9	3,841.0											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	5	5.0	35.1	9.9	0.0	0.0	1,341.3	1,130.6	1,130.6	1,080.2
12-31-2026	5	5.0	31.7	9.0	0.0	0.0	1,330.6	903.1	2,033.7	1,864.7
12-31-2027	5	5.0	26.4	7.5	0.0	0.0	1,149.6	706.7	2,740.4	2,422.9
12-31-2028	4	4.0	22.7	6.4	0.0	0.0	1,056.0	543.5	3,283.9	2,813.3
12-31-2029	4	4.0	20.6	5.8	0.0	0.0	1,049.1	397.1	3,681.0	3,072.7
12-31-2030	4	4.0	18.3	5.2	0.0	0.0	1,021.4	264.9	3,945.9	3,230.2
12-31-2031	3	3.0	10.9	3.1	0.0	0.0	606.6	164.3	4,110.1	3,318.9
12-31-2032	2	2.0	8.7	2.5	0.0	0.0	516.8	97.8	4,207.9	3,367.0
12-31-2033	2	2.0	4.7	1.3	0.0	0.0	281.0	49.1	4,257.0	3,389.0
12-31-2034	1	1.0	3.9	1.1	0.0	0.0	258.3	19.5	4,276.5	3,396.9
03-31-2035	1	1.0	0.9	0.3	0.0	0.0	64.4	0.6	4,277.1	3,397.2
SUBTOTAL			184.0	52.0	0.0	0.0	8,675.1	4,277.1	4,277.1	3,397.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	4,277.1	3,397.2
TOTAL OF 10.3 YRS			184.0	52.0	0.0	0.0	8,675.1	4,277.1	4,277.1	3,397.2

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	3,541.8
12.000	3,264.6
15.000	3,085.4
20.000	2,830.3
25.000	2,618.3
30.000	2,439.7
35.000	2,287.5
40.000	2,156.4
45.000	2,042.3
50.000	1,942.2

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
WEST MONTALVO LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	5.3	3.9	4.4	0.8	0.0	73.10	3.101	0.00	321.6	2.3	0.0	0.0	323.9
12-31-2026	5.5	4.2	4.6	0.8	0.0	73.10	3.101	0.00	337.4	2.5	0.0	0.0	339.9
12-31-2027	8.6	6.6	7.1	1.3	0.0	73.10	3.101	0.00	522.4	3.9	0.0	0.0	526.3
12-31-2028	10.0	7.7	8.3	1.5	0.0	73.10	3.101	0.00	607.3	4.6	0.0	0.0	611.9
12-31-2029	7.8	6.0	6.5	1.2	0.0	73.10	3.101	0.00	476.9	3.6	0.0	0.0	480.5
12-31-2030	6.2	4.8	5.2	0.9	0.0	73.10	3.101	0.00	380.4	2.8	0.0	0.0	383.2
12-31-2031	12.9	12.1	10.7	2.3	0.0	73.10	3.101	0.00	783.6	7.2	0.0	0.0	790.8
12-31-2032	13.7	13.5	11.4	2.6	0.0	73.10	3.101	0.00	833.0	8.0	0.0	0.0	841.0
12-31-2033	15.4	12.5	12.8	2.4	0.0	73.10	3.101	0.00	935.6	7.5	0.0	0.0	943.1
12-31-2034	12.1	9.8	10.1	1.9	0.0	73.10	3.101	0.00	737.6	5.8	0.0	0.0	743.4
12-31-2035	11.0	6.4	9.2	1.2	0.0	73.10	3.101	0.00	672.4	3.8	0.0	0.0	676.2
12-31-2036	9.9	5.6	8.3	1.1	0.0	73.10	3.101	0.00	603.9	3.3	0.0	0.0	607.2
12-31-2037	5.9	4.5	4.9	0.9	0.0	73.10	3.101	0.00	357.6	2.7	0.0	0.0	360.2
12-31-2038	5.5	4.2	4.6	0.8	0.0	73.10	3.101	0.00	336.1	2.5	0.0	0.0	338.6
12-31-2039	5.2	3.9	4.3	0.8	0.0	73.10	3.101	0.00	315.9	2.3	0.0	0.0	318.3
SUBTOTAL	135.0	105.8	112.5	20.3	0.0	73.10	3.101	0.00	8,221.6	62.8	0.0	0.0	8,284.5
REMAINING	12.4	9.4	10.3	1.8	0.0	73.10	3.101	0.00	752.9	5.6	0.0	0.0	758.5
TOTAL	147.4	115.2	122.8	22.1	0.0	73.10	3.101	0.00	8,974.5	68.4	0.0	0.0	9,042.9
CUM PROD	9.9	7.2											
ULTIMATE	157.3	122.4											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	0	0.0	4.5	1.3	0.0	0.0	14.3	303.8	303.8	289.7
12-31-2026	0	0.0	4.7	1.3	0.0	0.0	15.0	318.8	622.6	566.0
12-31-2027	0	0.0	7.3	2.1	0.0	0.0	187.3	329.5	952.1	825.8
12-31-2028	1	1.0	8.5	2.4	0.0	0.0	273.1	327.8	1,279.9	1,060.7
12-31-2029	1	1.0	6.7	1.9	0.0	0.0	144.3	327.5	1,607.5	1,274.0
12-31-2030	0	0.0	5.3	1.5	0.0	0.0	37.6	338.8	1,946.3	1,474.6
12-31-2031	1	1.0	11.1	3.1	0.0	0.0	447.1	329.5	2,275.7	1,652.1
12-31-2032	2	2.0	11.8	3.3	0.0	0.0	532.2	293.8	2,569.5	1,796.1
12-31-2033	2	2.0	13.2	3.7	0.0	0.0	677.7	248.5	2,818.0	1,906.8
12-31-2034	2	2.0	10.4	2.9	0.0	0.0	525.2	205.0	3,023.0	1,989.9
12-31-2035	2	2.0	9.4	2.7	0.0	0.0	499.0	165.1	3,188.1	2,050.7
12-31-2036	2	2.0	8.5	2.4	0.0	0.0	475.5	120.9	3,309.0	2,091.2
12-31-2037	1	1.0	5.0	1.4	0.0	0.0	261.8	92.0	3,401.0	2,119.3
12-31-2038	1	1.0	4.7	1.3	0.0	0.0	260.8	71.7	3,472.7	2,139.1
12-31-2039	1	1.0	4.4	1.3	0.0	0.0	259.9	52.7	3,525.4	2,152.4
SUBTOTAL			115.6	32.7	0.0	0.0	4,610.8	3,525.4	3,525.4	2,152.4
REMAINING			10.6	3.0	0.0	0.0	689.1	55.8	3,581.2	2,164.7
TOTAL OF 17.7 YRS			126.2	35.7	0.0	0.0	5,299.8	3,581.2	3,581.2	2,164.7

PRESENT WORTH PROFILE	
DISC RATE %	CUM PW M$
8.000	2,363.8
12.000	1,993.1
15.000	1,777.0
20.000	1,499.0
25.000	1,293.0
30.000	1,135.9
35.000	1,013.0
40.000	914.9
45.000	835.0
50.000	769.0

BASED ON COMMISSION PRICE AND COST PARAMETERS

PRELIMINARY – FOR REVIEW ONLY

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

CALIFORNIA RESOURCES CORPORATION INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
WEST MONTALVO LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	46.3	35.8	38.6	6.9	0.0	73.10	3.101	0.00	2,819.6	21.2	0.0	0.0	2,840.9
12-31-2026	42.6	33.0	35.5	6.3	0.0	73.10	3.101	0.00	2,594.7	19.6	0.0	0.0	2,614.3
12-31-2027	39.4	30.6	32.8	5.9	0.0	73.10	3.101	0.00	2,398.2	18.2	0.0	0.0	2,416.4
12-31-2028	36.5	28.5	30.4	5.5	0.0	73.10	3.101	0.00	2,223.7	16.9	0.0	0.0	2,240.6
12-31-2029	31.8	24.9	26.5	4.8	0.0	73.10	3.101	0.00	1,938.2	14.8	0.0	0.0	1,953.0
12-31-2030	27.6	21.6	23.0	4.1	0.0	73.10	3.101	0.00	1,680.1	12.8	0.0	0.0	1,692.9
12-31-2031	25.7	20.2	21.4	3.9	0.0	73.10	3.101	0.00	1,563.7	12.0	0.0	0.0	1,575.7
12-31-2032	23.9	18.9	19.9	3.6	0.0	73.10	3.101	0.00	1,455.5	11.2	0.0	0.0	1,466.8
12-31-2033	20.8	16.5	17.4	3.2	0.0	73.10	3.101	0.00	1,269.4	9.8	0.0	0.0	1,279.2
12-31-2034	16.7	13.3	13.9	2.5	0.0	73.10	3.101	0.00	1,018.4	7.9	0.0	0.0	1,026.3
12-31-2035	12.1	7.2	10.1	1.4	0.0	73.10	3.101	0.00	738.1	4.3	0.0	0.0	742.4
12-31-2036	9.9	5.6	8.3	1.1	0.0	73.10	3.101	0.00	603.9	3.3	0.0	0.0	607.2
12-31-2037	5.9	4.5	4.9	0.9	0.0	73.10	3.101	0.00	357.6	2.7	0.0	0.0	360.2
12-31-2038	5.5	4.2	4.6	0.8	0.0	73.10	3.101	0.00	336.1	2.5	0.0	0.0	338.6
12-31-2039	5.2	3.9	4.3	0.8	0.0	73.10	3.101	0.00	315.9	2.3	0.0	0.0	318.3
SUBTOTAL	350.0	268.7	291.6	51.5	0.0	73.10	3.101	0.00	21,313.1	159.7	0.0	0.0	21,472.7
REMAINING	12.4	9.4	10.3	1.8	0.0	73.10	3.101	0.00	752.9	5.6	0.0	0.0	758.5
TOTAL	362.4	278.1	301.9	53.3	0.0	73.10	3.101	0.00	22,065.9	165.2	0.0	0.0	22,231.2
CUM PROD	5,695.8	3,685.2											
ULTIMATE	6,058.1	3,963.4											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	5	5.0	39.6	11.2	0.0	0.0	1,355.6	1,434.4	1,434.4	1,369.9
12-31-2026	5	5.0	36.5	10.3	0.0	0.0	1,345.6	1,221.9	2,656.3	2,430.7
12-31-2027	5	5.0	33.7	9.5	0.0	0.0	1,336.9	1,036.2	3,692.5	3,248.7
12-31-2028	5	5.0	31.3	8.8	0.0	0.0	1,329.1	871.3	4,563.9	3,874.0
12-31-2029	5	5.0	27.3	7.7	0.0	0.0	1,193.4	724.6	5,288.5	4,346.7
12-31-2030	4	4.0	23.6	6.7	0.0	0.0	1,058.9	603.7	5,892.1	4,704.8
12-31-2031	4	4.0	22.0	6.2	0.0	0.0	1,053.8	493.7	6,385.9	4,971.0
12-31-2032	4	4.0	20.5	5.8	0.0	0.0	1,049.0	391.5	6,777.4	5,163.1
12-31-2033	4	4.0	17.9	5.0	0.0	0.0	958.7	297.6	7,075.0	5,295.8
12-31-2034	3	3.0	14.3	4.0	0.0	0.0	783.5	224.5	7,299.5	5,386.8
12-31-2035	3	3.0	10.3	2.9	0.0	0.0	563.4	165.8	7,465.2	5,447.9
12-31-2036	2	2.0	8.5	2.4	0.0	0.0	475.5	120.9	7,586.1	5,488.4
12-31-2037	1	1.0	5.0	1.4	0.0	0.0	261.8	92.0	7,678.1	5,516.4
12-31-2038	1	1.0	4.7	1.3	0.0	0.0	260.8	71.7	7,749.8	5,536.3
12-31-2039	1	1.0	4.4	1.3	0.0	0.0	259.9	52.7	7,802.5	5,549.6
SUBTOTAL			299.7	84.7	0.0	0.0	13,285.8	7,802.5	7,802.5	5,549.6
REMAINING			10.6	3.0	0.0	0.0	689.1	55.8	7,858.4	5,561.9
TOTAL OF 17.7 YRS			310.3	87.7	0.0	0.0	13,974.9	7,858.4	7,858.4	5,561.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	5,905.6
12.000	5,257.7
15.000	4,862.3
20.000	4,329.3
25.000	3,911.3
30.000	3,575.6
35.000	3,300.5
40.000	3,071.2
45.000	2,877.3
50.000	2,711.2

BASED ON COMMISSION PRICE AND COST PARAMETERS

7.10 FIGURES – SUMMARY PROJECTIONS OF RESERVES AND REVENUE TO THE STATE OF CALIFORNIA INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

TOTAL PROVED (1P) RESERVES

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	142.1	50.9	25.4	6.4	0.0	69.24	3.087	0.00	1,759.6	19.9	0.0	0.9	1,780.3
12-31-2026	134.1	46.5	24.0	5.9	0.0	69.24	3.087	0.00	1,659.9	18.2	0.0	0.9	1,679.0
12-31-2027	131.3	44.1	23.5	5.6	0.0	69.24	3.087	0.00	1,625.8	17.2	0.0	0.9	1,643.9
12-31-2028	116.5	38.5	20.8	4.9	0.0	69.24	3.087	0.00	1,441.9	15.0	0.0	0.9	1,457.9
12-31-2029	102.8	33.4	18.4	4.2	0.0	69.24	3.087	0.00	1,272.1	13.0	0.0	0.9	1,286.0
12-31-2030	90.5	29.0	16.2	3.7	0.0	69.24	3.087	0.00	1,120.2	11.3	0.0	0.9	1,132.4
12-31-2031	80.8	25.8	14.5	3.3	0.0	69.24	3.087	0.00	1,000.8	10.0	0.0	0.9	1,011.7
12-31-2032	70.4	22.3	12.6	2.8	0.0	69.24	3.087	0.00	871.0	8.7	0.0	0.9	880.5
12-31-2033	63.5	20.2	11.4	2.5	0.0	69.24	3.087	0.00	786.5	7.8	0.0	0.9	795.3
12-31-2034	56.2	17.8	10.0	2.2	0.0	69.24	3.087	0.00	695.7	6.9	0.0	0.9	703.5
12-31-2035	51.0	16.2	9.1	2.0	0.0	69.24	3.087	0.00	631.8	6.3	0.0	0.9	639.0
12-31-2036	46.4	14.7	8.3	1.9	0.0	69.24	3.087	0.00	574.0	5.7	0.0	0.9	580.7
12-31-2037	42.1	13.4	7.5	1.7	0.0	69.24	3.087	0.00	521.7	5.2	0.0	0.9	527.8
02-28-2038	6.6	2.1	1.2	0.3	0.0	69.24	3.087	0.00	82.2	0.8	0.0	0.1	83.2
SUBTOTAL	1,134.4	374.8	202.8	47.3	0.0	69.24	3.087	0.00	14,043.2	146.1	0.0	11.8	14,201.1
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	1,134.4	374.8	202.8	47.3	0.0	69.24	3.087	0.00	14,043.2	146.1	0.0	11.8	14,201.1
CUM PROD	16,616.1	3,411.6											
ULTIMATE	17,750.5	3,786.4											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	20	0.0	0.0	17.8	0.0	0.0	0.0	1,762.5	1,762.5	1,683.0
12-31-2026	19	0.0	0.0	16.8	0.0	0.0	0.0	1,662.2	3,424.7	3,123.1
12-31-2027	19	0.0	0.0	16.4	0.0	0.0	0.0	1,627.4	5,052.2	4,407.0
12-31-2028	19	0.0	0.0	14.6	0.0	0.0	0.0	1,443.3	6,495.5	5,442.5
12-31-2029	17	0.0	0.0	12.9	0.0	0.0	0.0	1,273.1	7,768.6	6,272.7
12-31-2030	16	0.0	0.0	11.3	0.0	0.0	0.0	1,121.1	8,889.7	6,937.3
12-31-2031	15	0.0	0.0	10.1	0.0	0.0	0.0	1,001.6	9,891.3	7,477.2
12-31-2032	13	0.0	0.0	8.8	0.0	0.0	0.0	871.7	10,763.1	7,904.2
12-31-2033	13	0.0	0.0	7.9	0.0	0.0	0.0	787.3	11,550.4	8,254.9
12-31-2034	12	0.0	0.0	7.0	0.0	0.0	0.0	696.5	12,246.9	8,536.8
12-31-2035	12	0.0	0.0	6.4	0.0	0.0	0.0	632.7	12,879.5	8,769.7
12-31-2036	12	0.0	0.0	5.8	0.0	0.0	0.0	574.9	13,454.4	8,962.0
12-31-2037	12	0.0	0.0	5.3	0.0	0.0	0.0	522.5	13,976.9	9,120.9
02-28-2038	12	0.0	0.0	0.8	0.0	0.0	0.0	82.3	14,059.2	9,144.6
SUBTOTAL			0.0	141.9	0.0	0.0	0.0	14,059.2	14,059.2	9,144.6
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	14,059.2	9,144.6
TOTAL OF 13.2 YRS			0.0	141.9	0.0	0.0	0.0	14,059.2	14,059.2	9,144.6

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	9,855.0
12.000	8,525.3
15.000	7,735.5
20.000	6,700.5
25.000	5,915.8
30.000	5,304.7
35.000	4,817.3
40.000	4,420.7
45.000	4,092.3
50.000	3,816.2

Figure 7.10.1
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

STATE OF CALIFORNIA INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	142.1	50.9	25.4	6.4	0.0	69.24	3.087	0.00	1,759.6	19.9	0.0	0.9	1,780.3
12-31-2026	125.7	44.6	22.5	5.6	0.0	69.24	3.087	0.00	1,556.7	17.4	0.0	0.9	1,575.0
12-31-2027	112.6	39.8	20.1	5.0	0.0	69.24	3.087	0.00	1,394.1	15.5	0.0	0.9	1,410.5
12-31-2028	99.4	34.7	17.8	4.4	0.0	69.24	3.087	0.00	1,231.1	13.5	0.0	0.9	1,245.5
12-31-2029	87.3	29.9	15.6	3.8	0.0	69.24	3.087	0.00	1,080.2	11.7	0.0	0.9	1,092.8
12-31-2030	76.4	25.8	13.7	3.3	0.0	69.24	3.087	0.00	945.6	10.0	0.0	0.9	956.6
12-31-2031	68.0	22.9	12.2	2.9	0.0	69.24	3.087	0.00	841.9	8.9	0.0	0.9	851.7
12-31-2032	58.7	19.7	10.5	2.5	0.0	69.24	3.087	0.00	726.4	7.6	0.0	0.9	734.9
12-31-2033	52.9	17.8	9.5	2.2	0.0	69.24	3.087	0.00	655.0	6.9	0.0	0.9	662.8
12-31-2034	46.5	15.7	8.3	2.0	0.0	69.24	3.087	0.00	575.9	6.1	0.0	0.9	582.9
12-31-2035	42.2	14.2	7.6	1.8	0.0	69.24	3.087	0.00	522.9	5.5	0.0	0.9	529.3
12-31-2036	38.4	12.9	6.9	1.6	0.0	69.24	3.087	0.00	474.9	5.0	0.0	0.9	480.8
12-31-2037	34.8	11.8	6.2	1.5	0.0	69.24	3.087	0.00	431.4	4.6	0.0	0.9	436.9
02-28-2038	5.5	1.9	1.0	0.2	0.0	69.24	3.087	0.00	68.0	0.7	0.0	0.1	68.8
SUBTOTAL	990.6	342.4	177.1	43.2	0.0	69.24	3.087	0.00	12,263.7	133.4	0.0	11.8	12,408.8
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	990.6	342.4	177.1	43.2	0.0	69.24	3.087	0.00	12,263.7	133.4	0.0	11.8	12,408.8
CUM PROD	16,405.8	3,365.1											
ULTIMATE	17,396.4	3,707.6											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	20	0.0	0.0	17.8	0.0	0.0	0.0	1,762.5	1,762.5	1,683.0
12-31-2026	18	0.0	0.0	15.7	0.0	0.0	0.0	1,559.3	3,321.8	3,036.3
12-31-2027	18	0.0	0.0	14.1	0.0	0.0	0.0	1,396.4	4,718.3	4,138.0
12-31-2028	18	0.0	0.0	12.4	0.0	0.0	0.0	1,233.1	5,951.3	5,022.8
12-31-2029	16	0.0	0.0	10.9	0.0	0.0	0.0	1,081.8	7,033.2	5,728.2
12-31-2030	15	0.0	0.0	9.6	0.0	0.0	0.0	947.0	7,980.2	6,289.7
12-31-2031	14	0.0	0.0	8.5	0.0	0.0	0.0	843.2	8,823.4	6,744.2
12-31-2032	12	0.0	0.0	7.3	0.0	0.0	0.0	727.6	9,550.9	7,100.6
12-31-2033	12	0.0	0.0	6.6	0.0	0.0	0.0	656.1	10,207.1	7,392.8
12-31-2034	11	0.0	0.0	5.8	0.0	0.0	0.0	577.1	10,784.2	7,626.5
12-31-2035	11	0.0	0.0	5.3	0.0	0.0	0.0	524.0	11,308.2	7,819.3
12-31-2036	11	0.0	0.0	4.8	0.0	0.0	0.0	476.0	11,784.2	7,978.5
12-31-2037	11	0.0	0.0	4.4	0.0	0.0	0.0	432.5	12,216.7	8,110.1
02-28-2038	11	0.0	0.0	0.7	0.0	0.0	0.0	68.2	12,284.9	8,129.7
SUBTOTAL			0.0	124.0	0.0	0.0	0.0	12,284.9	12,284.9	8,129.7
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	12,284.9	8,129.7
TOTAL OF 13.2 YRS			0.0	124.0	0.0	0.0	0.0	12,284.9	12,284.9	8,129.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	8,732.5
12.000	7,603.4
15.000	6,930.7
20.000	6,046.2
25.000	5,372.9
30.000	4,846.2
35.000	4,424.5
40.000	4,079.9
45.000	3,793.5
50.000	3,551.9

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROVED DEVELOPED NON-PRODUCING RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
12-31-2026	8.3	1.9	1.5	0.2	0.0	69.24	3.087	0.00	103.2	0.7	0.0	0.0	103.9
12-31-2027	18.7	4.2	3.3	0.5	0.0	69.24	3.087	0.00	231.7	1.7	0.0	0.0	233.4
12-31-2028	17.0	3.8	3.0	0.5	0.0	69.24	3.087	0.00	210.8	1.5	0.0	0.0	212.4
12-31-2029	15.5	3.5	2.8	0.4	0.0	69.24	3.087	0.00	191.9	1.4	0.0	0.0	193.2
12-31-2030	14.1	3.2	2.5	0.4	0.0	69.24	3.087	0.00	174.6	1.2	0.0	0.0	175.8
12-31-2031	12.8	2.9	2.3	0.4	0.0	69.24	3.087	0.00	158.9	1.1	0.0	0.0	160.0
12-31-2032	11.7	2.6	2.1	0.3	0.0	69.24	3.087	0.00	144.6	1.0	0.0	0.0	145.6
12-31-2033	10.6	2.4	1.9	0.3	0.0	69.24	3.087	0.00	131.6	0.9	0.0	0.0	132.5
12-31-2034	9.7	2.2	1.7	0.3	0.0	69.24	3.087	0.00	119.7	0.9	0.0	0.0	120.6
12-31-2035	8.8	2.0	1.6	0.3	0.0	69.24	3.087	0.00	109.0	0.8	0.0	0.0	109.7
12-31-2036	8.0	1.8	1.4	0.2	0.0	69.24	3.087	0.00	99.2	0.7	0.0	0.0	99.9
12-31-2037	7.3	1.6	1.3	0.2	0.0	69.24	3.087	0.00	90.2	0.6	0.0	0.0	90.9
02-28-2038	1.1	0.3	0.2	0.0	0.0	69.24	3.087	0.00	14.2	0.1	0.0	0.0	14.3
SUBTOTAL	143.8	32.3	25.7	4.1	0.0	69.24	3.087	0.00	1,779.5	12.7	0.0	0.0	1,792.3
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	143.8	32.3	25.7	4.1	0.0	69.24	3.087	0.00	1,779.5	12.7	0.0	0.0	1,792.3
CUM PROD	210.4	46.5											
ULTIMATE	354.1	78.8											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	1	0.0	0.0	1.0	0.0	0.0	0.0	102.9	102.9	86.7
12-31-2027	1	0.0	0.0	2.3	0.0	0.0	0.0	231.0	333.9	269.0
12-31-2028	1	0.0	0.0	2.1	0.0	0.0	0.0	210.2	544.1	419.8
12-31-2029	1	0.0	0.0	1.9	0.0	0.0	0.0	191.3	735.4	544.5
12-31-2030	1	0.0	0.0	1.8	0.0	0.0	0.0	174.1	909.5	647.7
12-31-2031	1	0.0	0.0	1.6	0.0	0.0	0.0	158.4	1,067.9	733.0
12-31-2032	1	0.0	0.0	1.5	0.0	0.0	0.0	144.2	1,212.1	803.6
12-31-2033	1	0.0	0.0	1.3	0.0	0.0	0.0	131.2	1,343.3	862.1
12-31-2034	1	0.0	0.0	1.2	0.0	0.0	0.0	119.4	1,462.7	910.4
12-31-2035	1	0.0	0.0	1.1	0.0	0.0	0.0	108.6	1,571.3	950.4
12-31-2036	1	0.0	0.0	1.0	0.0	0.0	0.0	98.9	1,670.2	983.4
12-31-2037	1	0.0	0.0	0.9	0.0	0.0	0.0	90.0	1,760.1	1,010.8
02-28-2038	1	0.0	0.0	0.1	0.0	0.0	0.0	14.2	1,774.3	1,014.9
SUBTOTAL			0.0	17.9	0.0	0.0	0.0	1,774.3	1,774.3	1,014.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	1,774.3	1,014.9
TOTAL OF 13.2 YRS			0.0	17.9	0.0	0.0	0.0	1,774.3	1,774.3	1,014.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	1,122.5
12.000	922.0
15.000	804.8
20.000	654.3
25.000	543.0
30.000	458.5
35.000	392.8
40.000	340.7
45.000	298.7
50.000	264.3

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROBABLE RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	18.9	7.7	3.4	1.0	0.0	69.24	3.087	0.00	233.8	3.0	0.0	0.0	236.9
12-31-2026	19.8	7.6	3.5	1.0	0.0	69.24	3.087	0.00	244.9	3.0	0.0	0.0	247.9
12-31-2027	20.4	7.4	3.6	0.9	0.0	69.24	3.087	0.00	252.7	2.9	0.0	0.0	255.6
12-31-2028	22.3	8.4	4.0	1.1	0.0	69.24	3.087	0.00	276.3	3.3	0.0	0.0	279.6
12-31-2029	24.4	9.4	4.4	1.2	0.0	69.24	3.087	0.00	302.1	3.7	0.0	0.0	305.8
12-31-2030	24.2	9.0	4.3	1.1	0.0	69.24	3.087	0.00	299.9	3.5	0.0	0.0	303.4
12-31-2031	23.0	8.1	4.1	1.0	0.0	69.24	3.087	0.00	284.9	3.2	0.0	0.0	288.1
12-31-2032	24.7	8.6	4.4	1.1	0.0	69.24	3.087	0.00	305.2	3.4	0.0	0.0	308.6
12-31-2033	19.3	6.1	3.4	0.8	0.0	69.24	3.087	0.00	238.8	2.4	0.0	0.0	241.2
12-31-2034	19.2	6.0	3.4	0.8	0.0	69.24	3.087	0.00	238.1	2.3	0.0	0.0	240.5
12-31-2035	17.3	5.3	3.1	0.7	0.0	69.24	3.087	0.00	214.5	2.1	0.0	0.0	216.6
12-31-2036	15.7	4.8	2.8	0.6	0.0	69.24	3.087	0.00	194.2	1.9	0.0	0.0	196.1
12-31-2037	15.3	4.6	2.7	0.6	0.0	69.24	3.087	0.00	189.5	1.8	0.0	0.0	191.3
12-31-2038	46.6	14.6	8.3	1.8	0.0	69.24	3.087	0.00	576.3	5.7	0.0	0.7	582.7
12-31-2039	49.0	15.3	8.8	1.9	0.0	69.24	3.087	0.00	606.1	6.0	0.0	0.9	612.9
SUBTOTAL	360.1	123.0	64.4	15.6	0.0	69.24	3.087	0.00	4,457.3	48.1	0.0	1.6	4,507.1
REMAINING	107.0	33.4	19.1	4.2	0.0	69.24	3.087	0.00	1,324.6	13.0	0.0	2.3	1,339.9
TOTAL	467.1	156.5	83.5	19.8	0.0	69.24	3.087	0.00	5,781.9	61.1	0.0	3.9	5,847.0
CUM PROD	26.4	10.7											
ULTIMATE	493.4	167.2											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	1	0.0	0.0	2.4	0.0	0.0	0.0	234.5	234.5	223.7
12-31-2026	1	0.0	0.0	2.5	0.0	0.0	0.0	245.5	480.0	436.4
12-31-2027	0	0.0	0.0	2.6	0.0	0.0	0.0	253.0	733.0	635.8
12-31-2028	0	0.0	0.0	2.8	0.0	0.0	0.0	276.8	1,009.8	833.9
12-31-2029	2	0.0	0.0	3.1	0.0	0.0	0.0	302.8	1,312.6	1,031.0
12-31-2030	3	0.0	0.0	3.0	0.0	0.0	0.0	300.4	1,613.0	1,209.0
12-31-2031	2	0.0	0.0	2.9	0.0	0.0	0.0	285.2	1,898.1	1,362.4
12-31-2032	4	0.0	0.0	3.1	0.0	0.0	0.0	305.5	2,203.6	1,512.1
12-31-2033	1	0.0	0.0	2.4	0.0	0.0	0.0	238.8	2,442.4	1,618.3
12-31-2034	2	0.0	0.0	2.4	0.0	0.0	0.0	238.1	2,680.5	1,714.7
12-31-2035	1	0.0	0.0	2.2	0.0	0.0	0.0	214.4	2,894.9	1,793.7
12-31-2036	0	0.0	0.0	2.0	0.0	0.0	0.0	194.1	3,088.9	1,858.6
12-31-2037	0	0.0	0.0	1.9	0.0	0.0	0.0	189.4	3,278.3	1,916.1
12-31-2038	0	0.0	0.0	5.8	0.0	0.0	0.0	576.9	3,855.2	2,074.7
12-31-2039	12	0.0	0.0	6.1	0.0	0.0	0.0	606.8	4,462.0	2,227.3
SUBTOTAL			0.0	45.1	0.0	0.0	0.0	4,462.0	4,462.0	2,227.3
REMAINING			0.0	13.4	0.0	0.0	0.0	1,326.5	5,788.5	2,509.9
TOTAL OF 17.6 YRS			0.0	58.4	0.0	0.0	0.0	5,788.5	5,788.5	2,509.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	2,889.7
12.000	2,205.0
15.000	1,851.3
20.000	1,446.1
25.000	1,181.1
30.000	998.3
35.000	866.1
40.000	766.8
45.000	689.7
50.000	628.2

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED + PROBABLE (2P) RESERVES

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSORE (186) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	161.0	58.6	28.8	7.4	0.0	69.24	3.087	0.00	1,993.4	22.9	0.0	0.9	2,017.2
12-31-2026	153.9	54.2	27.5	6.9	0.0	69.24	3.087	0.00	1,904.9	21.2	0.0	0.9	1,926.9
12-31-2027	151.7	51.4	27.1	6.5	0.0	69.24	3.087	0.00	1,878.5	20.1	0.0	0.9	1,899.5
12-31-2028	138.8	46.9	24.8	5.9	0.0	69.24	3.087	0.00	1,718.3	18.3	0.0	0.9	1,737.5
12-31-2029	127.2	42.8	22.7	5.4	0.0	69.24	3.087	0.00	1,574.2	16.7	0.0	0.9	1,591.8
12-31-2030	114.7	38.0	20.5	4.8	0.0	69.24	3.087	0.00	1,420.1	14.8	0.0	0.9	1,435.8
12-31-2031	103.9	33.9	18.6	4.3	0.0	69.24	3.087	0.00	1,285.7	13.2	0.0	0.9	1,299.8
12-31-2032	95.0	30.9	17.0	3.9	0.0	69.24	3.087	0.00	1,176.2	12.0	0.0	0.9	1,189.1
12-31-2033	82.8	26.3	14.8	3.3	0.0	69.24	3.087	0.00	1,025.3	10.2	0.0	0.9	1,036.4
12-31-2034	75.4	23.8	13.5	3.0	0.0	69.24	3.087	0.00	933.8	9.3	0.0	0.9	944.0
12-31-2035	68.4	21.5	12.2	2.7	0.0	69.24	3.087	0.00	846.3	8.4	0.0	0.9	855.6
12-31-2036	62.1	19.5	11.1	2.5	0.0	69.24	3.087	0.00	768.2	7.6	0.0	0.9	776.7
12-31-2037	57.4	18.0	10.3	2.3	0.0	69.24	3.087	0.00	711.2	7.0	0.0	0.9	719.1
12-31-2038	53.2	16.7	9.5	2.1	0.0	69.24	3.087	0.00	658.5	6.5	0.0	0.9	665.9
12-31-2039	49.0	15.3	8.8	1.9	0.0	69.24	3.087	0.00	606.1	6.0	0.0	0.9	612.9
SUBTOTAL	1,494.4	497.8	267.2	62.9	0.0	69.24	3.087	0.00	18,500.6	194.2	0.0	13.4	18,708.2
REMAINING	107.0	33.4	19.1	4.2	0.0	69.24	3.087	0.00	1,324.6	13.0	0.0	2.3	1,339.9
TOTAL	1,601.4	531.3	286.3	67.1	0.0	69.24	3.087	0.00	19,825.2	207.2	0.0	15.7	20,048.1
CUM PROD	16,642.5	3,422.3											
ULTIMATE	18,243.9	3,953.6											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	21	0.0	0.0	20.2	0.0	0.0	0.0	1,997.0	1,997.0	1,906.7
12-31-2026	20	0.0	0.0	19.3	0.0	0.0	0.0	1,907.6	3,904.7	3,559.5
12-31-2027	19	0.0	0.0	19.0	0.0	0.0	0.0	1,880.5	5,785.2	5,042.9
12-31-2028	19	0.0	0.0	17.4	0.0	0.0	0.0	1,720.1	7,505.3	6,276.4
12-31-2029	19	0.0	0.0	15.9	0.0	0.0	0.0	1,575.9	9,081.2	7,303.8
12-31-2030	19	0.0	0.0	14.3	0.0	0.0	0.0	1,421.4	10,502.6	8,146.3
12-31-2031	17	0.0	0.0	13.0	0.0	0.0	0.0	1,286.8	11,789.4	8,839.6
12-31-2032	17	0.0	0.0	11.9	0.0	0.0	0.0	1,177.2	12,966.7	9,416.3
12-31-2033	14	0.0	0.0	10.4	0.0	0.0	0.0	1,026.1	13,992.8	9,873.2
12-31-2034	14	0.0	0.0	9.4	0.0	0.0	0.0	934.5	14,927.3	10,251.5
12-31-2035	13	0.0	0.0	8.5	0.0	0.0	0.0	847.1	15,774.4	10,563.3
12-31-2036	12	0.0	0.0	7.8	0.0	0.0	0.0	769.0	16,543.3	10,820.5
12-31-2037	12	0.0	0.0	7.2	0.0	0.0	0.0	711.9	17,255.2	11,037.0
12-31-2038	12	0.0	0.0	6.6	0.0	0.0	0.0	659.2	17,914.4	11,219.3
12-31-2039	12	0.0	0.0	6.1	0.0	0.0	0.0	606.8	18,521.2	11,371.8
SUBTOTAL			0.0	186.9	0.0	0.0	0.0	18,521.2	18,521.2	11,371.8
REMAINING			0.0	13.4	0.0	0.0	0.0	1,326.5	19,847.7	11,654.4
TOTAL OF 17.6 YRS			0.0	200.3	0.0	0.0	0.0	19,847.7	19,847.7	11,654.4

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	12,744.6
12.000	10,730.3
15.000	9,586.8
20.000	8,146.5
25.000	7,097.0
30.000	6,302.9
35.000	5,683.4
40.000	5,187.5
45.000	4,781.9
50.000	4,444.3

Figure 7.10.1
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	174.0	119.2	29.4	11.1	0.0	72.13	4.843	0.00	2,119.6	53.6	0.0	53.0	2,226.3
12-31-2026	156.4	106.5	26.4	9.9	0.0	72.13	4.843	0.00	1,904.1	47.9	0.0	53.0	2,005.0
12-31-2027	273.0	126.4	46.1	11.7	0.0	72.13	4.843	0.00	3,324.7	56.8	0.0	53.0	3,434.6
12-31-2028	295.0	126.7	49.8	11.8	0.0	72.13	4.843	0.00	3,592.3	57.0	0.0	53.0	3,702.4
12-31-2029	243.0	107.9	41.0	10.0	0.0	72.13	4.843	0.00	2,959.8	48.5	0.0	53.0	3,061.3
12-31-2030	207.5	93.7	35.0	8.7	0.0	72.13	4.843	0.00	2,527.5	42.1	0.0	53.0	2,622.7
12-31-2031	182.2	83.6	30.8	7.8	0.0	72.13	4.843	0.00	2,219.4	37.6	0.0	53.0	2,310.0
12-31-2032	162.6	75.3	27.4	7.0	0.0	72.13	4.843	0.00	1,979.7	33.8	0.0	53.0	2,066.6
12-31-2033	145.8	68.0	24.6	6.3	0.0	72.13	4.843	0.00	1,775.2	30.6	0.0	53.0	1,858.8
12-31-2034	131.4	61.2	22.2	5.7	0.0	72.13	4.843	0.00	1,600.4	27.5	0.0	53.0	1,680.9
12-31-2035	117.9	54.3	19.9	5.0	0.0	72.13	4.843	0.00	1,436.2	24.4	0.0	53.0	1,513.7
11-30-2036	91.9	43.9	15.5	4.1	0.0	72.13	4.843	0.00	1,119.0	19.7	0.0	48.6	1,187.3
SUBTOTAL	2,180.7	1,066.8	368.2	99.0	0.0	72.13	4.843	0.00	26,557.9	479.6	0.0	632.1	27,669.6
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	2,180.7	1,066.8	368.2	99.0	0.0	72.13	4.843	0.00	26,557.9	479.6	0.0	632.1	27,669.6
CUM PROD	14,675.0	5,878.7											
ULTIMATE	16,855.8	6,945.5											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	18	0.0	0.0	15.9	0.0	0.0	0.0	2,210.4	2,210.4	2,110.2
12-31-2026	18	0.0	0.0	14.2	0.0	0.0	0.0	1,990.8	4,201.2	3,837.7
12-31-2027	24	0.0	0.0	24.7	0.0	0.0	0.0	3,409.9	7,611.1	6,505.6
12-31-2028	24	0.0	0.0	26.6	0.0	0.0	0.0	3,675.7	11,286.8	9,144.2
12-31-2029	24	0.0	0.0	22.0	0.0	0.0	0.0	3,039.4	14,326.2	11,126.9
12-31-2030	24	0.0	0.0	18.8	0.0	0.0	0.0	2,603.9	16,930.1	12,670.7
12-31-2031	24	0.0	0.0	16.5	0.0	0.0	0.0	2,293.6	19,223.7	13,906.8
12-31-2032	24	0.0	0.0	14.7	0.0	0.0	0.0	2,051.9	21,275.5	14,911.9
12-31-2033	24	0.0	0.0	13.2	0.0	0.0	0.0	1,845.6	23,121.2	15,733.8
12-31-2034	23	0.0	0.0	11.9	0.0	0.0	0.0	1,669.1	24,790.2	16,409.6
12-31-2035	22	0.0	0.0	10.7	0.0	0.0	0.0	1,503.0	26,293.2	16,962.8
11-30-2036	20	0.0	0.0	8.3	0.0	0.0	0.0	1,179.0	27,472.2	17,359.2
SUBTOTAL			0.0	197.4	0.0	0.0	0.0	27,472.2	27,472.2	17,359.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	27,472.2	17,359.2
TOTAL OF 11.9 YRS			0.0	197.4	0.0	0.0	0.0	27,472.2	27,472.2	17,359.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	18,842.5
12.000	16,061.1
15.000	14,399.3
20.000	12,214.9
25.000	10,558.9
30.000	9,273.6
35.000	8,255.2
40.000	7,433.4
45.000	6,759.5
50.000	6,199.1

Figure 7.10.2
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PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROVED DEVELOPED PRODUCING RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	174.0	119.2	29.4	11.1	0.0	72.13	4.843	0.00	2,119.6	53.6	0.0	53.0	2,226.3
12-31-2026	156.4	106.5	26.4	9.9	0.0	72.13	4.843	0.00	1,904.1	47.9	0.0	53.0	2,005.0
12-31-2027	141.5	96.1	23.9	8.9	0.0	72.13	4.843	0.00	1,723.5	43.2	0.0	53.0	1,819.8
12-31-2028	128.7	87.1	21.7	8.1	0.0	72.13	4.843	0.00	1,567.1	39.2	0.0	53.0	1,659.3
12-31-2029	117.0	78.9	19.8	7.3	0.0	72.13	4.843	0.00	1,425.3	35.5	0.0	53.0	1,513.9
12-31-2030	106.0	71.0	17.9	6.6	0.0	72.13	4.843	0.00	1,291.5	31.9	0.0	53.0	1,376.5
12-31-2031	97.0	64.9	16.4	6.0	0.0	72.13	4.843	0.00	1,181.8	29.2	0.0	53.0	1,264.1
12-31-2032	88.9	59.4	15.0	5.5	0.0	72.13	4.843	0.00	1,082.8	26.7	0.0	53.0	1,162.5
12-31-2033	81.5	54.4	13.8	5.1	0.0	72.13	4.843	0.00	993.1	24.5	0.0	53.0	1,070.6
12-31-2034	74.1	49.1	12.5	4.6	0.0	72.13	4.843	0.00	902.9	22.1	0.0	53.0	978.0
12-31-2035	66.3	43.4	11.2	4.0	0.0	72.13	4.843	0.00	807.0	19.5	0.0	53.0	879.6
11-30-2036	54.5	35.5	9.2	3.3	0.0	72.13	4.843	0.00	664.3	16.0	0.0	48.6	728.8
SUBTOTAL	1,286.1	865.7	217.1	80.4	0.0	72.13	4.843	0.00	15,663.0	389.2	0.0	632.1	16,684.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	1,286.1	865.7	217.1	80.4	0.0	72.13	4.843	0.00	15,663.0	389.2	0.0	632.1	16,684.2
CUM PROD	8,425.5	3,505.9											
ULTIMATE	9,711.6	4,371.6											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	18	0.0	0.0	15.9	0.0	0.0	0.0	2,210.4	2,210.4	2,110.2
12-31-2026	18	0.0	0.0	14.2	0.0	0.0	0.0	1,990.8	4,201.2	3,837.7
12-31-2027	18	0.0	0.0	12.9	0.0	0.0	0.0	1,806.9	6,008.0	5,263.1
12-31-2028	18	0.0	0.0	11.7	0.0	0.0	0.0	1,647.6	7,655.6	6,444.6
12-31-2029	18	0.0	0.0	10.7	0.0	0.0	0.0	1,503.2	9,158.8	7,424.7
12-31-2030	18	0.0	0.0	9.7	0.0	0.0	0.0	1,366.8	10,525.6	8,234.7
12-31-2031	18	0.0	0.0	8.8	0.0	0.0	0.0	1,255.2	11,780.8	8,911.0
12-31-2032	18	0.0	0.0	8.1	0.0	0.0	0.0	1,154.4	12,935.3	9,476.4
12-31-2033	18	0.0	0.0	7.4	0.0	0.0	0.0	1,063.1	13,998.4	9,949.8
12-31-2034	18	0.0	0.0	6.8	0.0	0.0	0.0	971.3	14,969.6	10,343.0
12-31-2035	17	0.0	0.0	6.0	0.0	0.0	0.0	873.5	15,843.2	10,664.6
11-30-2036	15	0.0	0.0	5.0	0.0	0.0	0.0	723.9	16,567.1	10,907.7
SUBTOTAL			0.0	117.2	0.0	0.0	0.0	16,567.1	16,567.1	10,907.7
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	16,567.1	10,907.7
TOTAL OF 11.9 YRS			0.0	117.2	0.0	0.0	0.0	16,567.1	16,567.1	10,907.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	11,736.8
12.000	10,181.9
15.000	9,252.3
20.000	8,027.9
25.000	7,096.1
30.000	6,368.9
35.000	5,788.6
40.000	5,316.5
45.000	4,925.8
50.000	4,597.6

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROVED UNDEVELOPED RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING M-D-Y	OIL MBBL	GAS MMCF	OIL MBBL	GAS MMCF	NGL MBBL	OIL $/BBL	GAS $/MCF	NGL $/BBL	OIL M$	GAS M$	NGL M$	OTHER M$	TOTAL M$
12-31-2025	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
12-31-2026	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
12-31-2027	131.5	30.4	22.2	2.8	0.0	72.13	4.843	0.00	1,601.2	13.6	0.0	0.0	1,614.8
12-31-2028	166.3	39.6	28.1	3.7	0.0	72.13	4.843	0.00	2,025.3	17.8	0.0	0.0	2,043.1
12-31-2029	126.0	29.0	21.3	2.7	0.0	72.13	4.843	0.00	1,534.5	13.0	0.0	0.0	1,547.5
12-31-2030	101.5	22.7	17.1	2.1	0.0	72.13	4.843	0.00	1,236.0	10.2	0.0	0.0	1,246.2
12-31-2031	85.2	18.7	14.4	1.7	0.0	72.13	4.843	0.00	1,037.6	8.4	0.0	0.0	1,046.0
12-31-2032	73.6	15.9	12.4	1.5	0.0	72.13	4.843	0.00	896.9	7.1	0.0	0.0	904.0
12-31-2033	64.2	13.6	10.8	1.3	0.0	72.13	4.843	0.00	782.1	6.1	0.0	0.0	788.3
12-31-2034	57.3	12.1	9.7	1.1	0.0	72.13	4.843	0.00	697.5	5.4	0.0	0.0	702.9
12-31-2035	51.7	10.9	8.7	1.0	0.0	72.13	4.843	0.00	629.2	4.9	0.0	0.0	634.1
11-30-2036	37.3	8.3	6.3	0.8	0.0	72.13	4.843	0.00	454.7	3.8	0.0	0.0	458.5
SUBTOTAL	894.6	201.1	151.0	18.7	0.0	72.13	4.843	0.00	10,894.9	90.4	0.0	0.0	10,985.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	894.6	201.1	151.0	18.7	0.0	72.13	4.843	0.00	10,894.9	90.4	0.0	0.0	10,985.4
CUM PROD	0.0	0.0											
ULTIMATE	894.6	201.1											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING M-D-Y	GROSS	NET	PRODUCTION M$	AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	PERIOD M$	CUM M$	CUM M$
12-31-2025	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2026	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12-31-2027	6	0.0	0.0	11.8	0.0	0.0	0.0	1,603.0	1,603.0	1,242.5
12-31-2028	6	0.0	0.0	14.9	0.0	0.0	0.0	2,028.2	3,631.2	2,699.5
12-31-2029	6	0.0	0.0	11.3	0.0	0.0	0.0	1,536.2	5,167.4	3,702.2
12-31-2030	6	0.0	0.0	9.1	0.0	0.0	0.0	1,237.1	6,404.5	4,436.0
12-31-2031	6	0.0	0.0	7.6	0.0	0.0	0.0	1,038.4	7,442.8	4,995.8
12-31-2032	6	0.0	0.0	6.6	0.0	0.0	0.0	897.4	8,340.3	5,435.5
12-31-2033	6	0.0	0.0	5.8	0.0	0.0	0.0	782.5	9,122.8	5,784.1
12-31-2034	5	0.0	0.0	5.1	0.0	0.0	0.0	697.8	9,820.6	6,066.6
12-31-2035	5	0.0	0.0	4.6	0.0	0.0	0.0	629.5	10,450.0	6,298.2
11-30-2036	5	0.0	0.0	3.3	0.0	0.0	0.0	455.1	10,905.2	6,451.6
SUBTOTAL			0.0	80.2	0.0	0.0	0.0	10,905.2	10,905.2	6,451.6
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	10,905.2	6,451.6
TOTAL OF 11.9 YRS			0.0	80.2	0.0	0.0	0.0	10,905.2	10,905.2	6,451.6

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	7,105.7
12.000	5,879.2
15.000	5,147.0
20.000	4,186.9
25.000	3,462.8
30.000	2,904.7
35.000	2,466.6
40.000	2,116.9
45.000	1,833.7
50.000	1,601.5

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROBABLE RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING M-D-Y	OIL MBBL	GAS MMCF	OIL MBBL	GAS MMCF	NGL MBBL	OIL $/BBL	GAS $/MCF	NGL $/BBL	OIL M$	GAS M$	NGL M$	OTHER M$	TOTAL M$
12-31-2025	32.4	24.6	5.5	2.3	0.0	72.13	4.843	0.00	394.3	11.1	0.0	0.0	405.4
12-31-2026	30.8	22.9	5.2	2.1	0.0	72.13	4.843	0.00	374.9	10.3	0.0	0.0	385.2
12-31-2027	69.1	46.7	11.7	4.3	0.0	72.13	4.843	0.00	841.6	21.0	0.0	0.0	862.6
12-31-2028	76.7	54.4	12.9	5.1	0.0	72.13	4.843	0.00	933.9	24.5	0.0	0.0	958.4
12-31-2029	63.6	43.5	10.7	4.0	0.0	72.13	4.843	0.00	774.9	19.6	0.0	0.0	794.5
12-31-2030	56.3	37.8	9.5	3.5	0.0	72.13	4.843	0.00	685.2	17.0	0.0	0.0	702.2
12-31-2031	50.5	33.4	8.5	3.1	0.0	72.13	4.843	0.00	615.1	15.0	0.0	0.0	630.1
12-31-2032	45.0	28.9	7.6	2.7	0.0	72.13	4.843	0.00	547.6	13.0	0.0	0.0	560.6
12-31-2033	42.0	26.6	7.1	2.5	0.0	72.13	4.843	0.00	511.2	11.9	0.0	0.0	523.1
12-31-2034	39.7	25.3	6.7	2.3	0.0	72.13	4.843	0.00	483.1	11.4	0.0	0.0	494.5
12-31-2035	39.5	25.4	6.7	2.4	0.0	72.13	4.843	0.00	480.6	11.4	0.0	0.0	492.0
12-31-2036	53.2	29.7	9.0	2.8	0.0	72.13	4.843	0.00	648.4	13.3	0.0	4.4	666.2
12-31-2037	133.2	67.6	22.5	6.3	0.0	72.13	4.843	0.00	1,622.4	30.4	0.0	53.0	1,705.8
12-31-2038	121.6	61.8	20.5	5.7	0.0	72.13	4.843	0.00	1,480.4	27.8	0.0	53.0	1,561.2
07-31-2039	56.9	32.2	9.6	3.0	0.0	72.13	4.843	0.00	693.2	14.5	0.0	30.9	738.6
SUBTOTAL	910.4	560.8	153.7	52.1	0.0	72.13	4.843	0.00	11,086.8	252.1	0.0	141.4	11,480.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	910.4	560.8	153.7	52.1	0.0	72.13	4.843	0.00	11,086.8	252.1	0.0	141.4	11,480.4
CUM PROD	39.8	28.7											
ULTIMATE	950.2	589.5											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING M-D-Y	GROSS	NET	PRODUCTION M$	AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	PERIOD M$	CUM M$	CUM M$
12-31-2025	0	0.0	0.0	3.0	0.0	0.0	0.0	402.4	402.4	384.0
12-31-2026	0	0.0	0.0	2.8	0.0	0.0	0.0	382.4	784.8	715.7
12-31-2027	0	0.0	0.0	6.3	0.0	0.0	0.0	856.3	1,641.1	1,384.6
12-31-2028	0	0.0	0.0	7.0	0.0	0.0	0.0	951.4	2,592.5	2,067.6
12-31-2029	0	0.0	0.0	5.8	0.0	0.0	0.0	788.7	3,381.2	2,582.0
12-31-2030	0	0.0	0.0	5.1	0.0	0.0	0.0	697.1	4,078.3	2,995.2
12-31-2031	0	0.0	0.0	4.6	0.0	0.0	0.0	625.5	4,703.8	3,332.2
12-31-2032	0	0.0	0.0	4.1	0.0	0.0	0.0	556.5	5,260.2	3,604.8
12-31-2033	0	0.0	0.0	3.8	0.0	0.0	0.0	519.3	5,779.5	3,836.0
12-31-2034	0	0.0	0.0	3.6	0.0	0.0	0.0	490.9	6,270.4	4,034.6
12-31-2035	1	0.0	0.0	3.6	0.0	0.0	0.0	488.4	6,758.8	4,214.1
12-31-2036	3	0.0	0.0	4.8	0.0	0.0	0.0	661.3	7,420.2	4,433.3
12-31-2037	23	0.0	0.0	12.1	0.0	0.0	0.0	1,693.8	9,114.0	4,948.4
12-31-2038	22	0.0	0.0	11.0	0.0	0.0	0.0	1,550.2	10,664.2	5,377.1
07-31-2039	20	0.0	0.0	5.2	0.0	0.0	0.0	733.5	11,397.6	5,565.1
SUBTOTAL			0.0	82.8	0.0	0.0	0.0	11,397.6	11,397.6	5,565.1
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	11,397.6	5,565.1
TOTAL OF 14.6 YRS			0.0	82.8	0.0	0.0	0.0	11,397.6	11,397.6	5,565.1

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	6,301.9
12.000	4,955.7
15.000	4,224.6
20.000	3,348.1
25.000	2,747.5
30.000	2,318.3
35.000	2,000.1
40.000	1,756.8
45.000	1,565.5
50.000	1,411.9

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
BELMONT OFFSHORE (ESTHER) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	206.4	143.8	34.9	13.4	0.0	72.13	4.843	0.00	2,514.0	64.7	0.0	53.0	2,631.7
12-31-2026	187.1	129.4	31.6	12.0	0.0	72.13	4.843	0.00	2,279.0	58.2	0.0	53.0	2,390.2
12-31-2027	342.1	173.1	57.8	16.1	0.0	72.13	4.843	0.00	4,166.3	77.8	0.0	53.0	4,297.1
12-31-2028	371.7	181.2	62.8	16.8	0.0	72.13	4.843	0.00	4,526.3	81.5	0.0	53.0	4,660.7
12-31-2029	306.7	151.4	51.8	14.1	0.0	72.13	4.843	0.00	3,734.7	68.1	0.0	53.0	3,855.8
12-31-2030	263.8	131.6	44.5	12.2	0.0	72.13	4.843	0.00	3,212.7	59.2	0.0	53.0	3,324.9
12-31-2031	232.7	117.0	39.3	10.9	0.0	72.13	4.843	0.00	2,834.5	52.6	0.0	53.0	2,940.1
12-31-2032	207.5	104.2	35.0	9.7	0.0	72.13	4.843	0.00	2,527.2	46.8	0.0	53.0	2,627.1
12-31-2033	187.7	94.6	31.7	8.8	0.0	72.13	4.843	0.00	2,286.4	42.5	0.0	53.0	2,381.9
12-31-2034	171.1	86.5	28.9	8.0	0.0	72.13	4.843	0.00	2,083.5	38.9	0.0	53.0	2,175.4
12-31-2035	157.4	79.7	26.6	7.4	0.0	72.13	4.843	0.00	1,916.8	35.8	0.0	53.0	2,005.7
12-31-2036	145.1	73.5	24.5	6.8	0.0	72.13	4.843	0.00	1,767.4	33.1	0.0	53.0	1,853.5
12-31-2037	133.2	67.6	22.5	6.3	0.0	72.13	4.843	0.00	1,622.4	30.4	0.0	53.0	1,705.8
12-31-2038	121.6	61.8	20.5	5.7	0.0	72.13	4.843	0.00	1,480.4	27.8	0.0	53.0	1,561.2
07-31-2039	56.9	32.2	9.6	3.0	0.0	72.13	4.843	0.00	693.2	14.5	0.0	30.9	738.6
SUBTOTAL	3,091.1	1,627.6	521.9	151.1	0.0	72.13	4.843	0.00	37,644.7	731.8	0.0	773.5	39,150.0
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	3,091.1	1,627.6	521.9	151.1	0.0	72.13	4.843	0.00	37,644.7	731.8	0.0	773.5	39,150.0
CUM PROD	14,714.9	5,907.4											
ULTIMATE	17,806.0	7,535.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	18	0.0	0.0	18.8	0.0	0.0	0.0	2,612.8	2,612.8	2,494.2
12-31-2026	18	0.0	0.0	17.1	0.0	0.0	0.0	2,373.2	4,986.0	4,553.5
12-31-2027	24	0.0	0.0	31.0	0.0	0.0	0.0	4,266.2	9,252.2	7,890.2
12-31-2028	24	0.0	0.0	33.6	0.0	0.0	0.0	4,627.1	13,879.3	11,211.7
12-31-2029	24	0.0	0.0	27.8	0.0	0.0	0.0	3,828.1	17,707.4	13,708.9
12-31-2030	24	0.0	0.0	23.9	0.0	0.0	0.0	3,301.0	21,008.4	15,665.9
12-31-2031	24	0.0	0.0	21.1	0.0	0.0	0.0	2,919.0	23,927.4	17,239.0
12-31-2032	24	0.0	0.0	18.8	0.0	0.0	0.0	2,608.3	26,535.7	18,516.7
12-31-2033	24	0.0	0.0	17.0	0.0	0.0	0.0	2,364.9	28,900.7	19,569.8
12-31-2034	23	0.0	0.0	15.5	0.0	0.0	0.0	2,160.0	31,060.6	20,444.1
12-31-2035	23	0.0	0.0	14.3	0.0	0.0	0.0	1,991.4	33,052.1	21,176.9
12-31-2036	23	0.0	0.0	13.1	0.0	0.0	0.0	1,840.4	34,892.4	21,792.5
12-31-2037	23	0.0	0.0	12.1	0.0	0.0	0.0	1,693.8	36,586.2	22,307.7
12-31-2038	22	0.0	0.0	11.0	0.0	0.0	0.0	1,550.2	38,136.4	22,736.3
07-31-2039	20	0.0	0.0	5.2	0.0	0.0	0.0	733.5	38,869.9	22,924.4
SUBTOTAL			0.0	280.1	0.0	0.0	0.0	38,869.9	38,869.9	22,924.4
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	38,869.9	22,924.4
TOTAL OF 14.6 YRS			0.0	280.1	0.0	0.0	0.0	38,869.9	38,869.9	22,924.4

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	25,144.4
12.000	21,016.8
15.000	18,623.9
20.000	15,563.0
25.000	13,306.4
30.000	11,591.9
35.000	10,255.3
40.000	9,190.1
45.000	8,325.0
50.000	7,610.9

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

Figure 7.10.2

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	319.2	60.8	55.1	10.1	0.0	72.15	5.288	0.00	3,974.6	53.5	0.0	165.6	4,193.8
12-31-2026	311.8	59.6	53.8	9.9	0.0	72.15	5.288	0.00	3,883.4	52.5	0.0	165.6	4,101.6
12-31-2027	286.1	54.7	49.4	9.1	0.0	72.15	5.288	0.00	3,563.4	48.2	0.0	165.6	3,777.3
12-31-2028	263.0	50.3	45.4	8.4	0.0	72.15	5.288	0.00	3,274.6	44.3	0.0	165.6	3,484.6
12-31-2029	241.9	46.3	41.8	7.7	0.0	72.15	5.288	0.00	3,012.3	40.8	0.0	165.6	3,218.8
12-31-2030	222.7	42.6	38.4	7.1	0.0	72.15	5.288	0.00	2,773.0	37.6	0.0	165.6	2,976.2
12-31-2031	205.1	39.3	35.4	6.5	0.0	72.15	5.288	0.00	2,554.1	34.6	0.0	165.6	2,754.4
12-31-2032	189.0	36.2	32.6	6.0	0.0	72.15	5.288	0.00	2,353.6	31.9	0.0	165.6	2,551.2
12-31-2033	174.2	33.4	30.1	5.6	0.0	72.15	5.288	0.00	2,169.9	29.4	0.0	165.6	2,365.0
12-31-2034	160.7	30.8	27.7	5.1	0.0	72.15	5.288	0.00	2,001.3	27.2	0.0	165.6	2,194.1
12-31-2035	148.1	28.4	25.6	4.7	0.0	72.15	5.288	0.00	1,844.0	25.1	0.0	165.6	2,034.7
12-31-2036	135.8	26.1	23.4	4.4	0.0	72.15	5.288	0.00	1,691.0	23.0	0.0	165.6	1,879.7
12-31-2037	125.4	24.2	21.6	4.0	0.0	72.15	5.288	0.00	1,562.0	21.3	0.0	165.6	1,749.0
12-31-2038	115.6	22.3	20.0	3.7	0.0	72.15	5.288	0.00	1,439.7	19.6	0.0	165.6	1,625.0
12-31-2039	106.0	20.5	18.3	3.4	0.0	72.15	5.288	0.00	1,320.5	18.1	0.0	165.6	1,504.2
SUBTOTAL	3,004.7	575.7	518.6	95.9	0.0	72.15	5.288	0.00	37,417.5	507.4	0.0	2,484.7	40,409.6
REMAINING	112.6	21.8	19.4	3.6	0.0	72.15	5.288	0.00	1,402.8	19.2	0.0	193.3	1,615.2
TOTAL	3,117.3	597.5	538.0	99.6	0.0	72.15	5.288	0.00	38,820.2	526.6	0.0	2,678.0	42,024.8
CUM PROD	27,102.2	4,214.3											
ULTIMATE	30,219.5	4,811.8											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	21	0.0	0.0	1.1	0.0	0.0	0.0	4,192.7	4,192.7	3,994.1
12-31-2026	21	0.0	0.0	1.0	0.0	0.0	0.0	4,100.6	8,293.2	7,552.1
12-31-2027	21	0.0	0.0	1.0	0.0	0.0	0.0	3,776.3	12,069.6	10,530.8
12-31-2028	21	0.0	0.0	0.9	0.0	0.0	0.0	3,483.7	15,553.3	13,028.9
12-31-2029	21	0.0	0.0	0.8	0.0	0.0	0.0	3,218.0	18,771.2	15,126.6
12-31-2030	21	0.0	0.0	0.7	0.0	0.0	0.0	2,975.5	21,746.7	16,889.9
12-31-2031	21	0.0	0.0	0.7	0.0	0.0	0.0	2,753.7	24,500.4	18,373.4
12-31-2032	21	0.0	0.0	0.6	0.0	0.0	0.0	2,550.6	27,051.0	19,622.6
12-31-2033	21	0.0	0.0	0.6	0.0	0.0	0.0	2,364.4	29,415.4	20,675.3
12-31-2034	21	0.0	0.0	0.5	0.0	0.0	0.0	2,193.6	31,608.9	21,563.1
12-31-2035	21	0.0	0.0	0.5	0.0	0.0	0.0	2,034.3	33,643.2	22,311.7
12-31-2036	20	0.0	0.0	0.5	0.0	0.0	0.0	1,879.3	35,522.5	22,940.3
12-31-2037	20	0.0	0.0	0.4	0.0	0.0	0.0	1,748.6	37,271.0	23,472.0
12-31-2038	20	0.0	0.0	0.4	0.0	0.0	0.0	1,624.6	38,895.6	23,921.1
12-31-2039	19	0.0	0.0	0.4	0.0	0.0	0.0	1,503.9	40,399.5	24,299.1
SUBTOTAL			0.0	10.1	0.0	0.0	0.0	40,399.5	40,399.5	24,299.1
REMAINING			0.0	0.4	0.0	0.0	0.0	1,614.8	42,014.3	24,665.3
TOTAL OF 16.2 YRS			0.0	10.4	0.0	0.0	0.0	42,014.3	42,014.3	24,665.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	26,994.8
12.000	22,687.3
15.000	20,237.1
20.000	17,151.2
25.000	14,906.8
30.000	13,214.1
35.000	11,897.8
40.000	10,847.7
45.000	9,991.4
50.000	9,280.3

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	247.9	48.3	42.8	8.1	0.0	72.15	5.288	0.00	3,086.7	42.6	0.0	165.6	3,295.0
12-31-2026	225.2	44.0	38.9	7.3	0.0	72.15	5.288	0.00	2,804.3	38.7	0.0	165.6	3,008.7
12-31-2027	205.3	40.1	35.4	6.7	0.0	72.15	5.288	0.00	2,556.8	35.4	0.0	165.6	2,757.8
12-31-2028	187.5	36.7	32.4	6.1	0.0	72.15	5.288	0.00	2,335.3	32.3	0.0	165.6	2,533.2
12-31-2029	171.5	33.5	29.6	5.6	0.0	72.15	5.288	0.00	2,135.6	29.6	0.0	165.6	2,330.8
12-31-2030	156.9	30.7	27.1	5.1	0.0	72.15	5.288	0.00	1,954.5	27.1	0.0	165.6	2,147.2
12-31-2031	143.7	28.1	24.8	4.7	0.0	72.15	5.288	0.00	1,789.7	24.8	0.0	165.6	1,980.1
12-31-2032	131.7	25.8	22.7	4.3	0.0	72.15	5.288	0.00	1,639.5	22.7	0.0	165.6	1,827.9
12-31-2033	120.7	23.6	20.8	3.9	0.0	72.15	5.288	0.00	1,502.6	20.8	0.0	165.6	1,689.0
12-31-2034	110.6	21.7	19.1	3.6	0.0	72.15	5.288	0.00	1,377.5	19.1	0.0	165.6	1,562.3
12-31-2035	101.2	19.9	17.5	3.3	0.0	72.15	5.288	0.00	1,260.8	17.5	0.0	165.6	1,444.0
12-31-2036	92.0	18.1	15.9	3.0	0.0	72.15	5.288	0.00	1,145.6	16.0	0.0	165.6	1,327.2
12-31-2037	84.5	16.6	14.6	2.8	0.0	72.15	5.288	0.00	1,051.7	14.7	0.0	165.6	1,232.1
12-31-2038	77.3	15.2	13.3	2.5	0.0	72.15	5.288	0.00	962.2	13.4	0.0	165.6	1,141.2
12-31-2039	70.1	13.9	12.1	2.3	0.0	72.15	5.288	0.00	873.5	12.2	0.0	165.6	1,051.4
SUBTOTAL	2,126.1	416.3	367.0	69.4	0.0	72.15	5.288	0.00	26,476.2	366.9	0.0	2,484.7	29,327.8
REMAINING	73.6	14.6	12.7	2.4	0.0	72.15	5.288	0.00	917.0	12.9	0.0	193.3	1,123.1
TOTAL	2,199.7	430.9	379.7	71.8	0.0	72.15	5.288	0.00	27,393.2	379.7	0.0	2,678.0	30,450.9
CUM PROD	24,596.9	3,885.0											
ULTIMATE	26,796.6	4,315.9											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES TAXES					FUTURE NET REVENUE UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	19	0.0	0.0	1.1	0.0	0.0	0.0	3,293.8	3,293.8	3,144.0
12-31-2026	19	0.0	0.0	1.0	0.0	0.0	0.0	3,007.6	6,301.5	5,753.8
12-31-2027	19	0.0	0.0	1.0	0.0	0.0	0.0	2,756.8	9,058.3	7,928.4
12-31-2028	19	0.0	0.0	0.9	0.0	0.0	0.0	2,532.3	11,590.6	9,744.3
12-31-2029	19	0.0	0.0	0.8	0.0	0.0	0.0	2,330.0	13,920.6	11,263.3
12-31-2030	19	0.0	0.0	0.7	0.0	0.0	0.0	2,146.4	16,067.0	12,535.3
12-31-2031	19	0.0	0.0	0.7	0.0	0.0	0.0	1,979.4	18,046.5	13,601.7
12-31-2032	19	0.0	0.0	0.6	0.0	0.0	0.0	1,827.3	19,873.7	14,496.6
12-31-2033	19	0.0	0.0	0.6	0.0	0.0	0.0	1,688.5	21,562.2	15,248.4
12-31-2034	19	0.0	0.0	0.5	0.0	0.0	0.0	1,561.7	23,123.9	15,880.5
12-31-2035	19	0.0	0.0	0.5	0.0	0.0	0.0	1,443.5	24,567.4	16,411.7
12-31-2036	18	0.0	0.0	0.5	0.0	0.0	0.0	1,326.8	25,894.2	16,855.5
12-31-2037	18	0.0	0.0	0.4	0.0	0.0	0.0	1,231.6	27,125.8	17,230.1
12-31-2038	18	0.0	0.0	0.4	0.0	0.0	0.0	1,140.9	28,266.7	17,545.5
12-31-2039	17	0.0	0.0	0.4	0.0	0.0	0.0	1,051.0	29,317.7	17,809.6
SUBTOTAL			0.0	10.1	0.0	0.0	0.0	29,317.7	29,317.7	17,809.6
REMAINING			0.0	0.4	0.0	0.0	0.0	1,122.8	30,440.5	18,064.3
TOTAL OF 16.2 YRS			0.0	10.4	0.0	0.0	0.0	30,440.5	30,440.5	18,064.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	19,730.8
12.000	16,647.6
15.000	14,890.3
20.000	12,672.3
25.000	11,055.2
30.000	9,832.9
35.000	8,880.5
40.000	8,119.3
45.000	7,497.6
50.000	6,980.6

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROVED DEVELOPED NON-PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	42.3	6.6	7.3	1.1	0.0	72.15	5.288	0.00	527.0	5.8	0.0	0.0	532.8
12-31-2026	54.4	9.2	9.4	1.5	0.0	72.15	5.288	0.00	677.9	8.1	0.0	0.0	686.0
12-31-2027	51.2	8.7	8.8	1.4	0.0	72.15	5.288	0.00	637.5	7.7	0.0	0.0	645.2
12-31-2028	48.2	8.2	8.3	1.4	0.0	72.15	5.288	0.00	599.7	7.2	0.0	0.0	606.9
12-31-2029	45.3	7.8	7.8	1.3	0.0	72.15	5.288	0.00	564.3	6.8	0.0	0.0	571.1
12-31-2030	42.6	7.3	7.4	1.2	0.0	72.15	5.288	0.00	531.1	6.5	0.0	0.0	537.5
12-31-2031	40.1	6.9	6.9	1.2	0.0	72.15	5.288	0.00	500.0	6.1	0.0	0.0	506.1
12-31-2032	37.8	6.5	6.5	1.1	0.0	72.15	5.288	0.00	470.8	5.8	0.0	0.0	476.6
12-31-2033	35.6	6.2	6.1	1.0	0.0	72.15	5.288	0.00	443.5	5.5	0.0	0.0	448.9
12-31-2034	33.6	5.8	5.8	1.0	0.0	72.15	5.288	0.00	417.8	5.2	0.0	0.0	423.0
12-31-2035	31.6	5.5	5.5	0.9	0.0	72.15	5.288	0.00	393.7	4.9	0.0	0.0	398.6
12-31-2036	29.8	5.2	5.1	0.9	0.0	72.15	5.288	0.00	371.1	4.6	0.0	0.0	375.8
12-31-2037	28.1	5.0	4.8	0.8	0.0	72.15	5.288	0.00	349.9	4.4	0.0	0.0	354.3
12-31-2038	26.5	4.7	4.6	0.8	0.0	72.15	5.288	0.00	330.0	4.1	0.0	0.0	334.1
12-31-2039	25.0	4.4	4.3	0.7	0.0	72.15	5.288	0.00	311.3	3.9	0.0	0.0	315.2
SUBTOTAL	572.2	98.1	98.8	16.4	0.0	72.15	5.288	0.00	7,125.5	86.5	0.0	0.0	7,212.0
REMAINING	27.4	4.9	4.7	0.8	0.0	72.15	5.288	0.00	341.0	4.3	0.0	0.0	345.3
TOTAL	599.6	103.0	103.5	17.2	0.0	72.15	5.288	0.00	7,466.6	90.8	0.0	0.0	7,557.3
CUM PROD	2,505.3	329.3											
ULTIMATE	3,104.9	432.3											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	1	0.0	0.0	0.0	0.0	0.0	0.0	532.8	532.8	503.6
12-31-2026	1	0.0	0.0	0.0	0.0	0.0	0.0	686.0	1,218.8	1,098.7
12-31-2027	1	0.0	0.0	0.0	0.0	0.0	0.0	645.2	1,864.0	1,607.5
12-31-2028	1	0.0	0.0	0.0	0.0	0.0	0.0	606.9	2,470.9	2,042.7
12-31-2029	1	0.0	0.0	0.0	0.0	0.0	0.0	571.1	3,042.0	2,414.9
12-31-2030	1	0.0	0.0	0.0	0.0	0.0	0.0	537.5	3,579.5	2,733.4
12-31-2031	1	0.0	0.0	0.0	0.0	0.0	0.0	506.1	4,085.6	3,006.0
12-31-2032	1	0.0	0.0	0.0	0.0	0.0	0.0	476.6	4,562.2	3,239.4
12-31-2033	1	0.0	0.0	0.0	0.0	0.0	0.0	448.9	5,011.1	3,439.2
12-31-2034	1	0.0	0.0	0.0	0.0	0.0	0.0	423.0	5,434.0	3,610.4
12-31-2035	1	0.0	0.0	0.0	0.0	0.0	0.0	398.6	5,832.6	3,757.0
12-31-2036	1	0.0	0.0	0.0	0.0	0.0	0.0	375.8	6,208.4	3,882.7
12-31-2037	1	0.0	0.0	0.0	0.0	0.0	0.0	354.3	6,562.7	3,990.4
12-31-2038	1	0.0	0.0	0.0	0.0	0.0	0.0	334.1	6,896.8	4,082.8
12-31-2039	1	0.0	0.0	0.0	0.0	0.0	0.0	315.2	7,212.0	4,162.0
SUBTOTAL			0.0	0.0	0.0	0.0	0.0	7,212.0	7,212.0	4,162.0
REMAINING			0.0	0.0	0.0	0.0	0.0	345.3	7,557.3	4,240.3
TOTAL OF 16.2 YRS			0.0	0.0	0.0	0.0	0.0	7,557.3	7,557.3	4,240.3

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	4,679.8
12.000	3,869.1
15.000	3,412.3
20.000	2,842.6
25.000	2,433.1
30.000	2,127.5
35.000	1,892.1
40.000	1,705.8
45.000	1,555.1
50.000	1,430.8

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROVED UNDEVELOPED RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	29.0	5.8	5.0	1.0	0.0	72.15	5.288	0.00	360.9	5.1	0.0	0.0	366.0
12-31-2026	32.2	6.4	5.6	1.1	0.0	72.15	5.288	0.00	401.3	5.7	0.0	0.0	406.9
12-31-2027	29.6	5.9	5.1	1.0	0.0	72.15	5.288	0.00	369.2	5.2	0.0	0.0	374.4
12-31-2028	27.3	5.5	4.7	0.9	0.0	72.15	5.288	0.00	339.6	4.8	0.0	0.0	344.4
12-31-2029	25.1	5.0	4.3	0.8	0.0	72.15	5.288	0.00	312.5	4.4	0.0	0.0	316.9
12-31-2030	23.1	4.6	4.0	0.8	0.0	72.15	5.288	0.00	287.5	4.1	0.0	0.0	291.5
12-31-2031	21.2	4.2	3.7	0.7	0.0	72.15	5.288	0.00	264.5	3.7	0.0	0.0	268.2
12-31-2032	19.5	3.9	3.4	0.7	0.0	72.15	5.288	0.00	243.3	3.4	0.0	0.0	246.7
12-31-2033	18.0	3.6	3.1	0.6	0.0	72.15	5.288	0.00	223.8	3.2	0.0	0.0	227.0
12-31-2034	16.5	3.3	2.9	0.6	0.0	72.15	5.288	0.00	205.9	2.9	0.0	0.0	208.8
12-31-2035	15.2	3.0	2.6	0.5	0.0	72.15	5.288	0.00	189.5	2.7	0.0	0.0	192.1
12-31-2036	14.0	2.8	2.4	0.5	0.0	72.15	5.288	0.00	174.3	2.5	0.0	0.0	176.8
12-31-2037	12.9	2.6	2.2	0.4	0.0	72.15	5.288	0.00	160.4	2.3	0.0	0.0	162.6
12-31-2038	11.8	2.4	2.0	0.4	0.0	72.15	5.288	0.00	147.5	2.1	0.0	0.0	149.6
12-31-2039	10.9	2.2	1.9	0.4	0.0	72.15	5.288	0.00	135.7	1.9	0.0	0.0	137.6
SUBTOTAL	306.4	61.3	52.9	10.2	0.0	72.15	5.288	0.00	3,815.8	54.0	0.0	0.0	3,869.8
REMAINING	11.6	2.3	2.0	0.4	0.0	72.15	5.288	0.00	144.7	2.0	0.0	0.0	146.7
TOTAL	318.0	63.6	54.9	10.6	0.0	72.15	5.288	0.00	3,960.5	56.1	0.0	0.0	4,016.5
CUM PROD	0.0	0.0											
ULTIMATE	318.0	63.6											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	1	0.0	0.0	0.0	0.0	0.0	0.0	366.0	366.0	346.5
12-31-2026	1	0.0	0.0	0.0	0.0	0.0	0.0	406.9	773.0	699.6
12-31-2027	1	0.0	0.0	0.0	0.0	0.0	0.0	374.4	1,147.3	994.9
12-31-2028	1	0.0	0.0	0.0	0.0	0.0	0.0	344.4	1,491.8	1,241.9
12-31-2029	1	0.0	0.0	0.0	0.0	0.0	0.0	316.9	1,808.6	1,448.4
12-31-2030	1	0.0	0.0	0.0	0.0	0.0	0.0	291.5	2,100.2	1,621.2
12-31-2031	1	0.0	0.0	0.0	0.0	0.0	0.0	268.2	2,368.4	1,765.7
12-31-2032	1	0.0	0.0	0.0	0.0	0.0	0.0	246.7	2,615.1	1,886.6
12-31-2033	1	0.0	0.0	0.0	0.0	0.0	0.0	227.0	2,842.1	1,987.6
12-31-2034	1	0.0	0.0	0.0	0.0	0.0	0.0	208.8	3,051.0	2,072.2
12-31-2035	1	0.0	0.0	0.0	0.0	0.0	0.0	192.1	3,243.1	2,142.9
12-31-2036	1	0.0	0.0	0.0	0.0	0.0	0.0	176.8	3,419.9	2,202.0
12-31-2037	1	0.0	0.0	0.0	0.0	0.0	0.0	162.6	3,582.5	2,251.5
12-31-2038	1	0.0	0.0	0.0	0.0	0.0	0.0	149.6	3,732.1	2,292.8
12-31-2039	1	0.0	0.0	0.0	0.0	0.0	0.0	137.6	3,869.8	2,327.4
SUBTOTAL			0.0	0.0	0.0	0.0	0.0	3,869.8	3,869.8	2,327.4
REMAINING			0.0	0.0	0.0	0.0	0.0	146.7	4,016.5	2,360.7
TOTAL OF 16.2 YRS			0.0	0.0	0.0	0.0	0.0	4,016.5	4,016.5	2,360.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	2,584.2
12.000	2,170.6
15.000	1,934.5
20.000	1,636.3
25.000	1,418.5
30.000	1,253.7
35.000	1,125.3
40.000	1,022.5
45.000	938.7
50.000	868.9

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	88.0	13.8	15.2	2.3	0.0	72.15	5.288	0.00	1,095.5	12.2	0.0	0.0	1,107.7
12-31-2026	98.6	15.7	17.0	2.6	0.0	72.15	5.288	0.00	1,228.2	13.9	0.0	0.0	1,242.0
12-31-2027	96.9	15.6	16.7	2.6	0.0	72.15	5.288	0.00	1,207.1	13.7	0.0	0.0	1,220.8
12-31-2028	95.0	15.3	16.4	2.6	0.0	72.15	5.288	0.00	1,182.7	13.5	0.0	0.0	1,196.3
12-31-2029	92.9	15.1	16.0	2.5	0.0	72.15	5.288	0.00	1,156.5	13.3	0.0	0.0	1,169.8
12-31-2030	90.6	14.8	15.6	2.5	0.0	72.15	5.288	0.00	1,128.3	13.1	0.0	0.0	1,141.4
12-31-2031	88.2	14.5	15.2	2.4	0.0	72.15	5.288	0.00	1,098.1	12.8	0.0	0.0	1,110.9
12-31-2032	85.6	14.1	14.8	2.4	0.0	72.15	5.288	0.00	1,066.4	12.5	0.0	0.0	1,078.9
12-31-2033	83.0	13.8	14.3	2.3	0.0	72.15	5.288	0.00	1,033.4	12.1	0.0	0.0	1,045.5
12-31-2034	80.3	13.4	13.9	2.2	0.0	72.15	5.288	0.00	999.4	11.8	0.0	0.0	1,011.2
12-31-2035	77.7	13.0	13.4	2.2	0.0	72.15	5.288	0.00	967.3	11.4	0.0	0.0	978.8
12-31-2036	75.8	12.7	13.1	2.1	0.0	72.15	5.288	0.00	943.3	11.2	0.0	0.0	954.5
12-31-2037	72.8	12.2	12.6	2.0	0.0	72.15	5.288	0.00	906.9	10.8	0.0	0.0	917.7
12-31-2038	70.2	11.8	12.1	2.0	0.0	72.15	5.288	0.00	874.5	10.4	0.0	0.0	884.9
12-31-2039	68.2	11.5	11.8	1.9	0.0	72.15	5.288	0.00	848.9	10.1	0.0	0.0	859.0
SUBTOTAL	1,263.7	207.3	218.1	34.5	0.0	72.15	5.288	0.00	15,736.7	182.7	0.0	0.0	15,919.4
REMAINING	1,026.7	187.2	177.2	31.2	0.0	72.15	5.288	0.00	12,785.5	165.0	0.0	1,297.6	14,248.0
TOTAL	2,290.4	394.4	395.3	65.7	0.0	72.15	5.288	0.00	28,522.1	347.6	0.0	1,297.6	30,167.4
CUM PROD	20.7	4.1											
ULTIMATE	2,311.1	398.5											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	2	0.0	0.0	0.1	0.0	0.0	0.0	1,107.6	1,107.6	1,051.7
12-31-2026	2	0.0	0.0	0.1	0.0	0.0	0.0	1,242.0	2,349.6	2,128.7
12-31-2027	2	0.0	0.0	0.1	0.0	0.0	0.0	1,220.8	3,570.3	3,091.2
12-31-2028	2	0.0	0.0	0.1	0.0	0.0	0.0	1,196.2	4,766.5	3,948.5
12-31-2029	2	0.0	0.0	0.1	0.0	0.0	0.0	1,169.7	5,936.2	4,710.7
12-31-2030	2	0.0	0.0	0.1	0.0	0.0	0.0	1,141.3	7,077.5	5,386.8
12-31-2031	2	0.0	0.0	0.1	0.0	0.0	0.0	1,110.8	8,188.3	5,984.9
12-31-2032	2	0.0	0.0	0.1	0.0	0.0	0.0	1,078.7	9,267.0	6,513.1
12-31-2033	2	0.0	0.0	0.1	0.0	0.0	0.0	1,045.4	10,312.4	6,978.4
12-31-2034	2	0.0	0.0	0.1	0.0	0.0	0.0	1,011.1	11,323.5	7,387.5
12-31-2035	2	0.0	0.0	0.1	0.0	0.0	0.0	978.6	12,302.2	7,747.4
12-31-2036	3	0.0	0.0	0.1	0.0	0.0	0.0	954.4	13,256.5	8,066.6
12-31-2037	3	0.0	0.0	0.1	0.0	0.0	0.0	917.5	14,174.1	8,345.5
12-31-2038	3	0.0	0.0	0.1	0.0	0.0	0.0	884.8	15,058.8	8,590.0
12-31-2039	4	0.0	0.0	0.1	0.0	0.0	0.0	858.9	15,917.7	8,805.8
SUBTOTAL			0.0	1.6	0.0	0.0	0.0	15,917.7	15,917.7	8,805.8
REMAINING			0.0	2.9	0.0	0.0	0.0	14,245.1	30,162.9	11,088.3
TOTAL OF 24.0 YRS			0.0	4.5	0.0	0.0	0.0	30,162.9	30,162.9	11,088.3

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	12,986.5
12.000	9,630.5
15.000	8,012.8
20.000	6,251.6
25.000	5,143.8
30.000	4,391.2
35.000	3,848.1
40.000	3,437.4
45.000	3,115.4
50.000	2,855.7

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED + PROBABLE (2P) RESERVES

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (EVA) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	407.1	74.6	70.3	12.4	0.0	72.15	5.288	0.00	5,070.1	65.7	0.0	165.6	5,301.5
12-31-2026	410.5	75.3	70.8	12.6	0.0	72.15	5.288	0.00	5,111.6	66.4	0.0	165.6	5,343.6
12-31-2027	383.1	70.3	66.1	11.7	0.0	72.15	5.288	0.00	4,770.5	61.9	0.0	165.6	4,998.1
12-31-2028	357.9	65.7	61.8	10.9	0.0	72.15	5.288	0.00	4,457.3	57.9	0.0	165.6	4,680.8
12-31-2029	334.8	61.4	57.8	10.2	0.0	72.15	5.288	0.00	4,168.8	54.1	0.0	165.6	4,388.6
12-31-2030	313.3	57.5	54.1	9.6	0.0	72.15	5.288	0.00	3,901.3	50.6	0.0	165.6	4,117.6
12-31-2031	293.3	53.8	50.6	9.0	0.0	72.15	5.288	0.00	3,652.2	47.4	0.0	165.6	3,865.3
12-31-2032	274.6	50.4	47.4	8.4	0.0	72.15	5.288	0.00	3,420.0	44.4	0.0	165.6	3,630.1
12-31-2033	257.2	47.2	44.4	7.9	0.0	72.15	5.288	0.00	3,203.2	41.6	0.0	165.6	3,410.5
12-31-2034	241.0	44.2	41.6	7.4	0.0	72.15	5.288	0.00	3,000.7	39.0	0.0	165.6	3,205.3
12-31-2035	225.8	41.4	39.0	6.9	0.0	72.15	5.288	0.00	2,811.4	36.5	0.0	165.6	3,013.5
12-31-2036	211.5	38.8	36.5	6.5	0.0	72.15	5.288	0.00	2,634.4	34.2	0.0	165.6	2,834.2
12-31-2037	198.3	36.4	34.2	6.1	0.0	72.15	5.288	0.00	2,468.9	32.1	0.0	165.6	2,666.6
12-31-2038	185.8	34.1	32.1	5.7	0.0	72.15	5.288	0.00	2,314.2	30.1	0.0	165.6	2,509.9
12-31-2039	174.2	32.0	30.1	5.3	0.0	72.15	5.288	0.00	2,169.4	28.2	0.0	165.6	2,363.3
SUBTOTAL	4,268.4	782.9	736.7	130.5	0.0	72.15	5.288	0.00	53,154.2	690.0	0.0	2,484.7	56,328.9
REMAINING	1,139.3	209.0	196.6	34.8	0.0	72.15	5.288	0.00	14,188.2	184.2	0.0	1,490.8	15,863.2
TOTAL	5,407.7	991.9	933.4	165.3	0.0	72.15	5.288	0.00	67,342.4	874.2	0.0	3,975.6	72,192.1
CUM PROD	27,122.9	4,218.4											
ULTIMATE	32,530.6	5,210.3											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	NET DEDUCTIONS/EXPENDITURES TAXES AD VALOREM M$	NET DEDUCTIONS/EXPENDITURES CAPITAL COST M$	NET DEDUCTIONS/EXPENDITURES ABDNMNT COST M$	NET DEDUCTIONS/EXPENDITURES OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	FUTURE NET REVENUE UNDISCOUNTED CUM M$	FUTURE NET REVENUE DISC AT 10.000% CUM M$
12-31-2025	23	0.0	0.0	1.2	0.0	0.0	0.0	5,300.3	5,300.3	5,045.8
12-31-2026	23	0.0	0.0	1.1	0.0	0.0	0.0	5,342.5	10,642.8	9,680.8
12-31-2027	23	0.0	0.0	1.0	0.0	0.0	0.0	4,997.1	15,639.9	13,622.0
12-31-2028	23	0.0	0.0	1.0	0.0	0.0	0.0	4,679.9	20,319.8	16,977.4
12-31-2029	23	0.0	0.0	0.9	0.0	0.0	0.0	4,387.7	24,707.4	19,837.3
12-31-2030	23	0.0	0.0	0.8	0.0	0.0	0.0	4,116.8	28,824.2	22,276.7
12-31-2031	23	0.0	0.0	0.8	0.0	0.0	0.0	3,864.5	32,688.7	24,358.4
12-31-2032	23	0.0	0.0	0.7	0.0	0.0	0.0	3,629.3	36,318.0	26,135.6
12-31-2033	23	0.0	0.0	0.7	0.0	0.0	0.0	3,409.8	39,727.8	27,653.6
12-31-2034	23	0.0	0.0	0.7	0.0	0.0	0.0	3,204.6	42,932.4	28,950.6
12-31-2035	23	0.0	0.0	0.6	0.0	0.0	0.0	3,012.9	45,945.3	30,059.1
12-31-2036	23	0.0	0.0	0.6	0.0	0.0	0.0	2,833.7	48,779.0	31,006.8
12-31-2037	23	0.0	0.0	0.5	0.0	0.0	0.0	2,666.1	51,445.1	31,817.5
12-31-2038	23	0.0	0.0	0.5	0.0	0.0	0.0	2,509.4	53,954.5	32,511.1
12-31-2039	23	0.0	0.0	0.5	0.0	0.0	0.0	2,362.8	56,317.2	33,104.9
SUBTOTAL			0.0	11.7	0.0	0.0	0.0	56,317.2	56,317.2	33,104.9
REMAINING			0.0	3.2	0.0	0.0	0.0	15,860.0	72,177.2	35,753.6
TOTAL OF 24.0 YRS			0.0	14.9	0.0	0.0	0.0	72,177.2	72,177.2	35,753.6

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
8.000	39,981.4
12.000	32,317.8
15.000	28,249.9
20.000	23,402.8
25.000	20,050.6
30.000	17,605.3
35.000	15,746.0
40.000	14,285.1
45.000	13,106.8
50.000	12,136.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

TOTAL PROVED (1P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	1,040.1	304.8	192.0	66.8	0.0	75.41	5.257	0.00	14,479.8	351.3	0.0	11.9	14,843.1
12-31-2026	1,020.4	310.1	188.4	68.0	0.0	75.41	5.257	0.00	14,205.0	357.4	0.0	11.9	14,574.3
12-31-2027	1,027.3	323.4	189.6	70.9	0.0	75.41	5.257	0.00	14,301.2	372.8	0.0	11.9	14,685.9
12-31-2028	1,044.5	323.7	192.8	71.0	0.0	75.41	5.257	0.00	14,541.0	373.1	0.0	11.9	14,926.1
12-31-2029	1,071.0	328.9	197.7	72.1	0.0	75.41	5.257	0.00	14,910.3	379.1	0.0	11.9	15,301.3
12-31-2030	1,024.8	317.4	189.2	69.6	0.0	75.41	5.257	0.00	14,266.8	365.8	0.0	11.9	14,644.4
12-31-2031	936.5	290.0	172.9	63.6	0.0	75.41	5.257	0.00	13,037.1	334.2	0.0	11.9	13,383.3
12-31-2032	870.6	269.3	160.7	59.1	0.0	75.41	5.257	0.00	12,119.9	310.4	0.0	11.9	12,442.2
12-31-2033	810.2	250.4	149.6	54.9	0.0	75.41	5.257	0.00	11,278.5	288.6	0.0	11.9	11,579.1
12-31-2034	759.3	234.6	140.2	51.4	0.0	75.41	5.257	0.00	10,571.2	270.3	0.0	11.9	10,853.5
12-31-2035	719.5	221.2	132.8	48.5	0.0	75.41	5.257	0.00	10,016.3	255.0	0.0	11.9	10,283.2
12-31-2036	679.3	208.8	125.4	45.8	0.0	75.41	5.257	0.00	9,457.2	240.7	0.0	11.9	9,709.8
12-31-2037	641.2	197.2	118.4	43.2	0.0	75.41	5.257	0.00	8,926.8	227.3	0.0	11.9	9,166.1
12-31-2038	604.1	186.4	111.5	40.9	0.0	75.41	5.257	0.00	8,410.0	214.8	0.0	11.9	8,636.8
12-31-2039	574.4	177.4	106.0	38.9	0.0	75.41	5.257	0.00	7,997.0	204.4	0.0	11.9	8,213.3
SUBTOTAL	12,823.3	3,943.7	2,367.3	864.7	0.0	75.41	5.257	0.00	178,518.1	4,545.5	0.0	178.6	183,242.3
REMAINING	1,943.6	601.8	358.8	131.9	0.0	75.41	5.257	0.00	27,058.0	693.7	0.0	45.7	27,797.3
TOTAL	14,766.9	4,545.5	2,726.1	996.6	0.0	75.41	5.257	0.00	205,576.1	5,239.2	0.0	224.3	211,039.6
CUM PROD	323,342.8	196,342.8											
ULTIMATE	338,109.7	200,888.3											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
ENDING	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	104	0.0	0.0	116.6	0.0	0.0	0.0	14,726.4	14,726.4	14,048.0
12-31-2026	111	0.0	0.0	116.4	0.0	0.0	0.0	14,457.9	29,184.4	26,584.4
12-31-2027	113	0.0	0.0	119.4	0.0	0.0	0.0	14,566.5	43,750.9	38,068.5
12-31-2028	118	0.0	0.0	123.5	0.0	0.0	0.0	14,802.5	58,553.4	48,672.9
12-31-2029	123	0.0	0.0	128.3	0.0	0.0	0.0	15,173.1	73,726.4	58,557.8
12-31-2030	124	0.0	0.0	123.0	0.0	0.0	0.0	14,521.4	88,247.9	67,164.3
12-31-2031	122	0.0	0.0	111.6	0.0	0.0	0.0	13,271.6	101,519.5	74,314.5
12-31-2032	122	0.0	0.0	103.6	0.0	0.0	0.0	12,338.6	113,858.1	80,357.3
12-31-2033	119	0.0	0.0	96.0	0.0	0.0	0.0	11,483.1	125,341.2	85,469.5
12-31-2034	119	0.0	0.0	89.7	0.0	0.0	0.0	10,763.8	136,105.0	89,825.8
12-31-2035	119	0.0	0.0	84.9	0.0	0.0	0.0	10,198.3	146,303.3	93,577.8
12-31-2036	116	0.0	0.0	79.9	0.0	0.0	0.0	9,629.8	155,933.2	96,798.5
12-31-2037	116	0.0	0.0	75.2	0.0	0.0	0.0	9,090.9	165,024.0	99,562.8
12-31-2038	111	0.0	0.0	70.6	0.0	0.0	0.0	8,566.1	173,590.1	101,930.4
12-31-2039	109	0.0	0.0	67.0	0.0	0.0	0.0	8,146.3	181,736.4	103,977.3
SUBTOTAL			0.0	1,505.9	0.0	0.0	0.0	181,736.4	181,736.4	103,977.3
REMAINING			0.0	225.3	0.0	0.0	0.0	27,571.9	209,308.4	109,540.9
TOTAL OF 18.8 YRS			0.0	1,731.2	0.0	0.0	0.0	209,308.4	209,308.4	109,540.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	122,053.9
12.000	99,161.8
15.000	86,632.8
20.000	71,397.5
25.000	60,717.6
30.000	52,896.5
35.000	46,958.6
40.000	42,314.2
45.000	38,590.6
50.000	35,543.1

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

STATE OF CALIFORNIA INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	966.7	291.3	178.5	63.9	0.0	75.41	5.257	0.00	13,457.9	335.8	0.0	11.9	13,805.6
12-31-2026	883.1	266.8	163.0	58.5	0.0	75.41	5.257	0.00	12,293.7	307.5	0.0	11.9	12,613.1
12-31-2027	817.9	248.1	151.0	54.4	0.0	75.41	5.257	0.00	11,387.0	286.0	0.0	11.9	11,684.9
12-31-2028	764.2	232.4	141.1	51.0	0.0	75.41	5.257	0.00	10,638.2	267.9	0.0	11.9	10,918.0
12-31-2029	716.4	217.9	132.3	47.8	0.0	75.41	5.257	0.00	9,973.4	251.1	0.0	11.9	10,236.4
12-31-2030	674.6	205.3	124.5	45.0	0.0	75.41	5.257	0.00	9,391.5	236.6	0.0	11.9	9,640.0
12-31-2031	635.9	193.3	117.4	42.4	0.0	75.41	5.257	0.00	8,852.7	222.8	0.0	11.9	9,087.5
12-31-2032	601.4	183.3	111.0	40.2	0.0	75.41	5.257	0.00	8,372.7	211.3	0.0	11.9	8,595.9
12-31-2033	570.0	173.8	105.2	38.1	0.0	75.41	5.257	0.00	7,935.5	200.3	0.0	11.9	8,147.7
12-31-2034	542.9	165.6	100.2	36.3	0.0	75.41	5.257	0.00	7,557.9	190.8	0.0	11.9	7,760.6
12-31-2035	516.2	157.9	95.3	34.6	0.0	75.41	5.257	0.00	7,186.9	182.0	0.0	11.9	7,380.8
12-31-2036	491.7	150.8	90.8	33.1	0.0	75.41	5.257	0.00	6,845.8	173.8	0.0	11.9	7,031.5
12-31-2037	468.2	143.8	86.4	31.5	0.0	75.41	5.257	0.00	6,517.4	165.7	0.0	11.9	6,695.1
12-31-2038	443.6	136.9	81.9	30.0	0.0	75.41	5.257	0.00	6,175.5	157.8	0.0	11.9	6,345.2
12-31-2039	425.0	131.4	78.5	28.8	0.0	75.41	5.257	0.00	5,917.3	151.5	0.0	11.9	6,080.7
SUBTOTAL	9,517.9	2,898.6	1,757.1	635.5	0.0	75.41	5.257	0.00	132,503.6	3,340.9	0.0	178.6	136,023.1
REMAINING	1,477.8	457.4	272.8	100.3	0.0	75.41	5.257	0.00	20,573.7	527.2	0.0	45.7	21,146.6
TOTAL	10,995.8	3,356.0	2,029.9	735.8	0.0	75.41	5.257	0.00	153,077.3	3,868.1	0.0	224.3	157,169.7
CUM PROD	291,200.9	184,087.5											
ULTIMATE	302,196.7	187,443.5											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	98	0.0	0.0	106.3	0.0	0.0	0.0	13,699.3	13,699.3	13,076.1
12-31-2026	96	0.0	0.0	96.8	0.0	0.0	0.0	12,516.4	26,215.7	23,936.2
12-31-2027	93	0.0	0.0	89.4	0.0	0.0	0.0	11,595.5	37,811.2	33,081.9
12-31-2028	92	0.0	0.0	83.5	0.0	0.0	0.0	10,834.5	48,645.8	40,850.1
12-31-2029	91	0.0	0.0	78.2	0.0	0.0	0.0	10,158.2	58,804.0	47,471.1
12-31-2030	91	0.0	0.0	73.6	0.0	0.0	0.0	9,566.4	68,370.4	53,139.6
12-31-2031	89	0.0	0.0	69.3	0.0	0.0	0.0	9,018.2	77,388.6	57,997.1
12-31-2032	88	0.0	0.0	65.7	0.0	0.0	0.0	8,530.2	85,918.8	62,174.2
12-31-2033	85	0.0	0.0	62.3	0.0	0.0	0.0	8,085.5	94,004.3	65,773.3
12-31-2034	85	0.0	0.0	59.3	0.0	0.0	0.0	7,701.3	101,705.6	68,889.8
12-31-2035	84	0.0	0.0	56.4	0.0	0.0	0.0	7,324.5	109,030.0	71,584.5
12-31-2036	81	0.0	0.0	53.7	0.0	0.0	0.0	6,977.8	116,007.9	73,918.0
12-31-2037	81	0.0	0.0	51.0	0.0	0.0	0.0	6,644.1	122,651.9	75,938.2
12-31-2038	76	0.0	0.0	48.2	0.0	0.0	0.0	6,297.0	128,949.0	77,678.6
12-31-2039	74	0.0	0.0	46.2	0.0	0.0	0.0	6,034.5	134,983.5	79,194.8
SUBTOTAL			0.0	1,039.6	0.0	0.0	0.0	134,983.5	134,983.5	79,194.8
REMAINING			0.0	160.4	0.0	0.0	0.0	20,986.2	155,969.7	83,424.5
TOTAL OF 18.8 YRS			0.0	1,200.1	0.0	0.0	0.0	155,969.7	155,969.7	83,424.5

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	92,492.8
12.000	75,907.8
15.000	66,836.9
20.000	55,800.3
25.000	48,044.9
30.000	42,342.8
35.000	37,991.0
40.000	34,566.6
45.000	31,803.3
50.000	29,526.3

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED DEVELOPED NON-PRODUCING RESERVES

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	6.8	0.1	1.3	0.0	0.0	75.41	5.257	0.00	95.0	0.1	0.0	0.0	95.1
12-31-2026	18.4	1.3	3.4	0.3	0.0	75.41	5.257	0.00	256.1	1.5	0.0	0.0	257.5
12-31-2027	30.7	4.6	5.7	1.0	0.0	75.41	5.257	0.00	427.9	5.3	0.0	0.0	433.2
12-31-2028	35.8	7.1	6.6	1.5	0.0	75.41	5.257	0.00	498.8	8.1	0.0	0.0	507.0
12-31-2029	45.4	9.9	8.4	2.2	0.0	75.41	5.257	0.00	632.4	11.4	0.0	0.0	643.8
12-31-2030	57.4	14.9	10.6	3.3	0.0	75.41	5.257	0.00	799.5	17.1	0.0	0.0	816.7
12-31-2031	50.6	12.6	9.3	2.8	0.0	75.41	5.257	0.00	704.9	14.5	0.0	0.0	719.4
12-31-2032	50.0	11.8	9.2	2.6	0.0	75.41	5.257	0.00	695.5	13.6	0.0	0.0	709.1
12-31-2033	44.7	10.1	8.3	2.2	0.0	75.41	5.257	0.00	622.7	11.7	0.0	0.0	634.4
12-31-2034	40.3	8.8	7.4	1.9	0.0	75.41	5.257	0.00	560.5	10.2	0.0	0.0	570.7
12-31-2035	43.0	8.4	7.9	1.8	0.0	75.41	5.257	0.00	598.5	9.7	0.0	0.0	608.2
12-31-2036	40.8	7.7	7.5	1.7	0.0	75.41	5.257	0.00	568.2	8.8	0.0	0.0	577.1
12-31-2037	37.9	7.0	7.0	1.5	0.0	75.41	5.257	0.00	527.5	8.0	0.0	0.0	535.5
12-31-2038	35.4	6.4	6.5	1.4	0.0	75.41	5.257	0.00	492.7	7.3	0.0	0.0	500.0
12-31-2039	33.1	5.8	6.1	1.3	0.0	75.41	5.257	0.00	460.7	6.7	0.0	0.0	467.5
SUBTOTAL	570.4	116.3	105.3	25.5	0.0	75.41	5.257	0.00	7,941.0	134.0	0.0	0.0	8,075.1
REMAINING	98.8	15.4	18.2	3.4	0.0	75.41	5.257	0.00	1,376.1	17.7	0.0	0.0	1,393.8
TOTAL	669.3	131.7	123.6	28.9	0.0	75.41	5.257	0.00	9,317.1	151.7	0.0	0.0	9,468.8
CUM PROD	32,141.9	12,255.3											
ULTIMATE	32,811.2	12,387.0											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES TAXES					FUTURE NET REVENUE UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	1	0.0	0.0	1.0	0.0	0.0	0.0	94.2	94.2	89.5
12-31-2026	5	0.0	0.0	2.6	0.0	0.0	0.0	254.9	349.1	308.6
12-31-2027	6	0.0	0.0	4.3	0.0	0.0	0.0	428.8	777.9	646.2
12-31-2028	7	0.0	0.0	5.1	0.0	0.0	0.0	501.9	1,279.8	1,004.2
12-31-2029	8	0.0	0.0	5.9	0.0	0.0	0.0	637.9	1,917.7	1,420.0
12-31-2030	9	0.0	0.0	7.5	0.0	0.0	0.0	809.2	2,726.9	1,899.2
12-31-2031	9	0.0	0.0	6.6	0.0	0.0	0.0	712.8	3,439.7	2,283.4
12-31-2032	10	0.0	0.0	6.5	0.0	0.0	0.0	702.6	4,142.3	2,627.5
12-31-2033	10	0.0	0.0	5.8	0.0	0.0	0.0	628.6	4,770.9	2,907.5
12-31-2034	10	0.0	0.0	5.2	0.0	0.0	0.0	565.5	5,336.4	3,136.4
12-31-2035	11	0.0	0.0	5.6	0.0	0.0	0.0	602.6	5,939.0	3,357.9
12-31-2036	11	0.0	0.0	5.3	0.0	0.0	0.0	571.8	6,510.9	3,549.2
12-31-2037	11	0.0	0.0	4.9	0.0	0.0	0.0	530.7	7,041.5	3,710.5
12-31-2038	11	0.0	0.0	4.5	0.0	0.0	0.0	495.5	7,537.0	3,847.5
12-31-2039	11	0.0	0.0	4.2	0.0	0.0	0.0	463.2	8,000.3	3,964.0
SUBTOTAL			0.0	74.8	0.0	0.0	0.0	8,000.3	8,000.3	3,964.0
REMAINING			0.0	12.3	0.0	0.0	0.0	1,381.5	9,381.7	4,243.6
TOTAL OF 18.8 YRS			0.0	87.1	0.0	0.0	0.0	9,381.7	9,381.7	4,243.6

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	4,875.1
12.000	3,725.4
15.000	3,108.7
20.000	2,377.0
25.000	1,881.7
30.000	1,532.1
35.000	1,276.5
40.000	1,084.0
45.000	935.3
50.000	818.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED UNDEVELOPED RESERVES

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	66.6	13.4	12.3	2.9	0.0	75.41	5.257	0.00	926.9	15.5	0.0	0.0	942.4
12-31-2026	118.9	42.1	21.9	9.2	0.0	75.41	5.257	0.00	1,655.2	48.5	0.0	0.0	1,703.6
12-31-2027	178.6	70.7	33.0	15.5	0.0	75.41	5.257	0.00	2,486.3	81.5	0.0	0.0	2,567.8
12-31-2028	244.5	84.3	45.1	18.5	0.0	75.41	5.257	0.00	3,403.9	97.1	0.0	0.0	3,501.1
12-31-2029	309.2	101.2	57.1	22.2	0.0	75.41	5.257	0.00	4,304.5	116.6	0.0	0.0	4,421.1
12-31-2030	292.8	97.2	54.0	21.3	0.0	75.41	5.257	0.00	4,075.7	112.0	0.0	0.0	4,187.8
12-31-2031	249.9	84.0	46.1	18.4	0.0	75.41	5.257	0.00	3,479.5	96.9	0.0	0.0	3,576.4
12-31-2032	219.2	74.3	40.5	16.3	0.0	75.41	5.257	0.00	3,051.6	85.6	0.0	0.0	3,137.2
12-31-2033	195.4	66.5	36.1	14.6	0.0	75.41	5.257	0.00	2,720.3	76.7	0.0	0.0	2,797.0
12-31-2034	176.2	60.2	32.5	13.2	0.0	75.41	5.257	0.00	2,452.8	69.4	0.0	0.0	2,522.2
12-31-2035	160.2	54.9	29.6	12.0	0.0	75.41	5.257	0.00	2,230.9	63.3	0.0	0.0	2,294.2
12-31-2036	146.8	50.4	27.1	11.0	0.0	75.41	5.257	0.00	2,043.1	58.1	0.0	0.0	2,101.2
12-31-2037	135.2	46.5	25.0	10.2	0.0	75.41	5.257	0.00	1,881.9	53.6	0.0	0.0	1,935.5
12-31-2038	125.1	43.1	23.1	9.4	0.0	75.41	5.257	0.00	1,741.8	49.7	0.0	0.0	1,791.5
12-31-2039	116.3	40.1	21.5	8.8	0.0	75.41	5.257	0.00	1,619.0	46.2	0.0	0.0	1,665.2
SUBTOTAL	2,734.9	928.8	504.9	203.6	0.0	75.41	5.257	0.00	38,073.5	1,070.6	0.0	0.0	39,144.1
REMAINING	366.9	129.0	67.7	28.3	0.0	75.41	5.257	0.00	5,108.2	148.7	0.0	0.0	5,256.9
TOTAL	3,101.8	1,057.9	572.6	231.9	0.0	75.41	5.257	0.00	43,181.7	1,219.3	0.0	0.0	44,401.0
CUM PROD	0.0	0.0											
ULTIMATE	3,101.8	1,057.9											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	5	0.0	0.0	9.4	0.0	0.0	0.0	932.9	932.9	882.4
12-31-2026	10	0.0	0.0	17.0	0.0	0.0	0.0	1,686.6	2,619.5	2,339.6
12-31-2027	14	0.0	0.0	25.7	0.0	0.0	0.0	2,542.1	5,161.7	4,340.4
12-31-2028	19	0.0	0.0	35.0	0.0	0.0	0.0	3,466.1	8,627.8	6,818.5
12-31-2029	24	0.0	0.0	44.2	0.0	0.0	0.0	4,376.9	13,004.7	9,666.7
12-31-2030	24	0.0	0.0	41.9	0.0	0.0	0.0	4,145.9	17,150.6	12,125.5
12-31-2031	24	0.0	0.0	35.8	0.0	0.0	0.0	3,540.6	20,691.2	14,033.9
12-31-2032	24	0.0	0.0	31.4	0.0	0.0	0.0	3,105.8	23,797.0	15,555.6
12-31-2033	24	0.0	0.0	28.0	0.0	0.0	0.0	2,769.0	26,566.0	16,788.7
12-31-2034	24	0.0	0.0	25.2	0.0	0.0	0.0	2,497.0	29,063.0	17,799.6
12-31-2035	24	0.0	0.0	22.9	0.0	0.0	0.0	2,271.2	31,334.3	18,635.4
12-31-2036	24	0.0	0.0	21.0	0.0	0.0	0.0	2,080.2	33,414.5	19,331.3
12-31-2037	24	0.0	0.0	19.4	0.0	0.0	0.0	1,916.1	35,330.6	19,914.0
12-31-2038	24	0.0	0.0	17.9	0.0	0.0	0.0	1,773.6	37,104.2	20,404.3
12-31-2039	24	0.0	0.0	16.7	0.0	0.0	0.0	1,648.5	38,752.7	20,818.6
SUBTOTAL			0.0	391.4	0.0	0.0	0.0	38,752.7	38,752.7	20,818.6
REMAINING			0.0	52.6	0.0	0.0	0.0	5,204.3	43,957.0	21,872.7
TOTAL OF 18.8 YRS			0.0	444.0	0.0	0.0	0.0	43,957.0	43,957.0	21,872.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	24,686.1
12.000	19,528.6
15.000	16,687.2
20.000	13,220.2
25.000	10,790.9
30.000	9,021.6
35.000	7,691.1
40.000	6,663.6
45.000	5,852.0
50.000	5,198.9

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	183.6	51.2	33.9	11.2	0.0	75.41	5.257	0.00	2,555.3	59.0	0.0	0.0	2,614.3
12-31-2026	256.4	83.8	47.3	18.4	0.0	75.41	5.257	0.00	3,568.9	96.6	0.0	0.0	3,665.5
12-31-2027	281.3	91.3	51.9	20.0	0.0	75.41	5.257	0.00	3,916.3	105.3	0.0	0.0	4,021.6
12-31-2028	315.1	93.2	58.2	20.4	0.0	75.41	5.257	0.00	4,386.2	107.5	0.0	0.0	4,493.6
12-31-2029	299.4	88.6	55.3	19.4	0.0	75.41	5.257	0.00	4,168.1	102.1	0.0	0.0	4,270.2
12-31-2030	270.9	80.7	50.0	17.7	0.0	75.41	5.257	0.00	3,771.1	93.0	0.0	0.0	3,864.1
12-31-2031	254.1	75.3	46.9	16.5	0.0	75.41	5.257	0.00	3,538.1	86.8	0.0	0.0	3,624.9
12-31-2032	242.8	70.5	44.8	15.5	0.0	75.41	5.257	0.00	3,379.7	81.3	0.0	0.0	3,461.0
12-31-2033	229.2	66.1	42.3	14.5	0.0	75.41	5.257	0.00	3,191.3	76.2	0.0	0.0	3,267.5
12-31-2034	218.7	62.7	40.4	13.7	0.0	75.41	5.257	0.00	3,044.1	72.3	0.0	0.0	3,116.4
12-31-2035	212.1	60.5	39.2	13.3	0.0	75.41	5.257	0.00	2,952.6	69.7	0.0	0.0	3,022.3
12-31-2036	203.2	57.7	37.5	12.6	0.0	75.41	5.257	0.00	2,829.0	66.5	0.0	0.0	2,895.4
12-31-2037	198.0	55.8	36.6	12.2	0.0	75.41	5.257	0.00	2,756.8	64.3	0.0	0.0	2,821.2
12-31-2038	194.2	53.7	35.8	11.8	0.0	75.41	5.257	0.00	2,703.4	61.9	0.0	0.0	2,765.3
12-31-2039	187.5	51.3	34.6	11.2	0.0	75.41	5.257	0.00	2,610.9	59.1	0.0	0.0	2,670.0
SUBTOTAL	3,546.5	1,042.4	654.7	228.6	0.0	75.41	5.257	0.00	49,371.7	1,201.5	0.0	0.0	50,573.2
REMAINING	4,252.0	1,256.9	785.0	275.6	0.0	75.41	5.257	0.00	59,193.3	1,448.7	0.0	77.4	60,719.4
TOTAL	7,798.4	2,299.3	1,439.7	504.1	0.0	75.41	5.257	0.00	108,565.1	2,650.2	0.0	77.4	111,292.6
CUM PROD	274.8	85.5											
ULTIMATE	8,073.2	2,384.7											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	2	0.0	0.0	21.3	0.0	0.0	0.0	2,593.0	2,593.0	2,466.5
12-31-2026	7	0.0	0.0	31.6	0.0	0.0	0.0	3,633.9	6,226.9	5,611.2
12-31-2027	10	0.0	0.0	35.2	0.0	0.0	0.0	3,986.3	10,213.2	8,751.1
12-31-2028	12	0.0	0.0	40.0	0.0	0.0	0.0	4,453.6	14,666.8	11,941.7
12-31-2029	13	0.0	0.0	37.8	0.0	0.0	0.0	4,232.3	18,899.2	14,702.5
12-31-2030	14	0.0	0.0	34.0	0.0	0.0	0.0	3,830.1	22,729.3	16,972.3
12-31-2031	16	0.0	0.0	31.7	0.0	0.0	0.0	3,593.2	26,322.5	18,907.9
12-31-2032	18	0.0	0.0	29.9	0.0	0.0	0.0	3,431.0	29,753.5	20,587.8
12-31-2033	19	0.0	0.0	28.1	0.0	0.0	0.0	3,239.4	32,993.0	22,030.0
12-31-2034	18	0.0	0.0	26.6	0.0	0.0	0.0	3,089.8	36,082.8	23,280.1
12-31-2035	19	0.0	0.0	25.8	0.0	0.0	0.0	2,996.5	39,079.3	24,382.3
12-31-2036	20	0.0	0.0	24.8	0.0	0.0	0.0	2,870.6	41,949.9	25,342.4
12-31-2037	19	0.0	0.0	24.1	0.0	0.0	0.0	2,797.1	44,747.0	26,192.4
12-31-2038	23	0.0	0.0	23.6	0.0	0.0	0.0	2,741.7	47,488.7	26,950.2
12-31-2039	23	0.0	0.0	22.7	0.0	0.0	0.0	2,647.3	50,136.0	27,615.3
SUBTOTAL			0.0	437.3	0.0	0.0	0.0	50,136.0	50,136.0	27,615.3
REMAINING			0.0	496.9	0.0	0.0	0.0	60,222.5	110,358.5	35,919.2
TOTAL OF 25.3 YRS			0.0	934.2	0.0	0.0	0.0	110,358.5	110,358.5	35,919.2

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	42,731.4
12.000	30,813.8
15.000	25,286.4
20.000	19,434.0
25.000	15,827.7
30.000	13,398.0
35.000	11,647.7
40.000	10,323.3
45.000	9,284.1
50.000	8,445.9

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
HUNTINGTON BEACH (NEAR SHORE) LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	1,223.7	356.0	225.9	78.1	0.0	75.41	5.257	0.00	17,035.1	410.3	0.0	11.9	17,457.4
12-31-2026	1,276.7	393.9	235.7	86.4	0.0	75.41	5.257	0.00	17,773.8	454.0	0.0	11.9	18,239.8
12-31-2027	1,308.6	414.8	241.6	90.9	0.0	75.41	5.257	0.00	18,217.5	478.1	0.0	11.9	18,707.5
12-31-2028	1,359.6	417.0	251.0	91.4	0.0	75.41	5.257	0.00	18,927.2	480.6	0.0	11.9	19,419.7
12-31-2029	1,370.4	417.5	253.0	91.5	0.0	75.41	5.257	0.00	19,078.3	481.3	0.0	11.9	19,571.5
12-31-2030	1,295.7	398.1	239.2	87.3	0.0	75.41	5.257	0.00	18,037.9	458.8	0.0	11.9	18,508.6
12-31-2031	1,190.6	365.2	219.8	80.1	0.0	75.41	5.257	0.00	16,575.3	421.0	0.0	11.9	17,008.2
12-31-2032	1,113.4	339.8	205.5	74.5	0.0	75.41	5.257	0.00	15,499.6	391.7	0.0	11.9	15,903.2
12-31-2033	1,039.4	316.5	191.9	69.4	0.0	75.41	5.257	0.00	14,469.8	364.8	0.0	11.9	14,846.6
12-31-2034	978.0	297.3	180.6	65.2	0.0	75.41	5.257	0.00	13,615.4	342.6	0.0	11.9	13,969.9
12-31-2035	931.6	281.7	172.0	61.8	0.0	75.41	5.257	0.00	12,968.9	324.7	0.0	11.9	13,305.5
12-31-2036	882.5	266.5	162.9	58.4	0.0	75.41	5.257	0.00	12,286.1	307.2	0.0	11.9	12,605.2
12-31-2037	839.3	253.1	154.9	55.5	0.0	75.41	5.257	0.00	11,683.7	291.7	0.0	11.9	11,987.3
12-31-2038	798.3	240.1	147.4	52.6	0.0	75.41	5.257	0.00	11,113.4	276.7	0.0	11.9	11,402.1
12-31-2039	762.0	228.6	140.7	50.1	0.0	75.41	5.257	0.00	10,607.9	263.5	0.0	11.9	10,883.3
SUBTOTAL	16,369.7	4,986.1	3,022.0	1,093.2	0.0	75.41	5.257	0.00	227,889.9	5,747.0	0.0	178.7	233,815.5
REMAINING	6,195.6	1,858.7	1,143.8	407.5	0.0	75.41	5.257	0.00	86,251.3	2,142.3	0.0	123.1	88,516.7
TOTAL	22,565.3	6,844.8	4,165.8	1,500.7	0.0	75.41	5.257	0.00	314,141.2	7,889.3	0.0	301.7	322,332.2
CUM PROD	323,617.6	196,428.3											
ULTIMATE	346,182.8	203,273.1											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	106	0.0	0.0	137.9	0.0	0.0	0.0	17,319.5	17,319.5	16,514.6
12-31-2026	118	0.0	0.0	148.0	0.0	0.0	0.0	18,091.8	35,411.2	32,195.6
12-31-2027	123	0.0	0.0	154.7	0.0	0.0	0.0	18,552.8	53,964.1	46,819.6
12-31-2028	130	0.0	0.0	163.6	0.0	0.0	0.0	19,256.1	73,220.2	60,614.5
12-31-2029	136	0.0	0.0	166.1	0.0	0.0	0.0	19,405.4	92,625.6	73,260.3
12-31-2030	138	0.0	0.0	157.0	0.0	0.0	0.0	18,351.6	110,977.2	84,136.6
12-31-2031	138	0.0	0.0	143.3	0.0	0.0	0.0	16,864.8	127,842.0	93,222.4
12-31-2032	140	0.0	0.0	133.5	0.0	0.0	0.0	15,769.7	143,611.6	100,945.1
12-31-2033	138	0.0	0.0	124.1	0.0	0.0	0.0	14,722.5	158,334.2	107,499.6
12-31-2034	137	0.0	0.0	116.3	0.0	0.0	0.0	13,853.6	172,187.8	113,105.9
12-31-2035	138	0.0	0.0	110.6	0.0	0.0	0.0	13,194.8	185,382.6	117,960.1
12-31-2036	136	0.0	0.0	104.7	0.0	0.0	0.0	12,500.5	197,883.1	122,140.8
12-31-2037	135	0.0	0.0	99.3	0.0	0.0	0.0	11,887.9	209,771.0	125,755.2
12-31-2038	134	0.0	0.0	94.2	0.0	0.0	0.0	11,307.8	221,078.8	128,880.7
12-31-2039	132	0.0	0.0	89.8	0.0	0.0	0.0	10,793.6	231,872.4	131,592.6
SUBTOTAL			0.0	1,943.1	0.0	0.0	0.0	231,872.4	231,872.4	131,592.6
REMAINING			0.0	722.2	0.0	0.0	0.0	87,794.4	319,666.8	145,460.1
TOTAL OF 25.3 YRS			0.0	2,665.4	0.0	0.0	0.0	319,666.8	319,666.8	145,460.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	164,785.3
12.000	129,975.6
15.000	111,919.2
20.000	90,831.5
25.000	76,545.3
30.000	66,294.5
35.000	58,606.3
40.000	52,637.5
45.000	47,874.7
50.000	43,989.0

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
WEST MONTALVO LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROVED DEVELOPED PRODUCING RESERVES

PERIOD ENDING M-D-Y	GROSS RESERVES OIL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL MBBL	NET RESERVES GAS MMCF	NET RESERVES NGL MBBL	AVERAGE PRICES OIL $/BBL	AVERAGE PRICES GAS $/MCF	AVERAGE PRICES NGL $/BBL	GROSS REVENUE OIL M$	GROSS REVENUE GAS M$	GROSS REVENUE NGL M$	GROSS REVENUE OTHER M$	GROSS REVENUE TOTAL M$
12-31-2025	41.0	31.8	6.9	1.2	0.0	73.10	3.101	0.00	500.8	3.8	0.0	5.0	509.6
12-31-2026	37.1	28.9	6.2	1.1	0.0	73.10	3.101	0.00	452.5	3.4	0.0	5.0	461.0
12-31-2027	30.8	24.0	5.1	0.9	0.0	73.10	3.101	0.00	376.1	2.9	0.0	5.0	383.9
12-31-2028	26.5	20.8	4.4	0.8	0.0	73.10	3.101	0.00	324.1	2.5	0.0	5.0	331.5
12-31-2029	24.0	18.8	4.0	0.7	0.0	73.10	3.101	0.00	293.0	2.2	0.0	5.0	300.2
12-31-2030	21.3	16.8	3.6	0.6	0.0	73.10	3.101	0.00	260.6	2.0	0.0	5.0	267.6
12-31-2031	12.8	8.1	2.1	0.3	0.0	73.10	3.101	0.00	156.4	1.0	0.0	5.0	162.4
12-31-2032	10.2	5.4	1.7	0.2	0.0	73.10	3.101	0.00	124.8	0.6	0.0	5.0	130.4
12-31-2033	5.5	4.0	0.9	0.2	0.0	73.10	3.101	0.00	66.9	0.5	0.0	5.0	72.4
12-31-2034	4.6	3.5	0.8	0.1	0.0	73.10	3.101	0.00	56.3	0.4	0.0	5.0	61.7
03-31-2035	1.1	0.8	0.2	0.0	0.0	73.10	3.101	0.00	13.2	0.1	0.0	1.3	14.5
SUBTOTAL	215.0	163.0	35.9	6.3	0.0	73.10	3.101	0.00	2,624.6	19.4	0.0	51.3	2,695.2
REMAINING	0.0	0.0	0.0	0.0	0.0	0.00	0.000	0.00	0.0	0.0	0.0	0.0	0.0
TOTAL	215.0	163.0	35.9	6.3	0.0	73.10	3.101	0.00	2,624.6	19.4	0.0	51.3	2,695.2
CUM PROD	5,685.9	3,678.0											
ULTIMATE	5,900.9	3,841.0											

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2025	5	0.0	0.0	0.0	0.0	0.0	0.0	509.6	509.6	486.5
12-31-2026	5	0.0	0.0	0.0	0.0	0.0	0.0	461.0	970.6	886.5
12-31-2027	5	0.0	0.0	0.0	0.0	0.0	0.0	383.9	1,354.5	1,189.8
12-31-2028	4	0.0	0.0	0.0	0.0	0.0	0.0	331.5	1,686.0	1,427.6
12-31-2029	4	0.0	0.0	0.0	0.0	0.0	0.0	300.2	1,986.3	1,623.3
12-31-2030	4	0.0	0.0	0.0	0.0	0.0	0.0	267.6	2,253.8	1,782.0
12-31-2031	3	0.0	0.0	0.0	0.0	0.0	0.0	162.4	2,416.2	1,869.8
12-31-2032	2	0.0	0.0	0.0	0.0	0.0	0.0	130.4	2,546.6	1,933.7
12-31-2033	2	0.0	0.0	0.0	0.0	0.0	0.0	72.4	2,619.0	1,966.0
12-31-2034	1	0.0	0.0	0.0	0.0	0.0	0.0	61.7	2,680.7	1,991.0
03-31-2035	1	0.0	0.0	0.0	0.0	0.0	0.0	14.5	2,695.2	1,996.5
SUBTOTAL			0.0	0.0	0.0	0.0	0.0	2,695.2	2,695.2	1,996.5
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	2,695.2	1,996.5
TOTAL OF 10.3 YRS			0.0	0.0	0.0	0.0	0.0	2,695.2	2,695.2	1,996.5

PRESENT WORTH PROFILE DISC RATE %	CUM PW M$
8.000	2,107.0
12.000	1,896.9
15.000	1,764.8
20.000	1,581.9
25.000	1,434.8
30.000	1,314.4
35.000	1,214.4
40.000	1,130.2
45.000	1,058.4
50.000	996.7

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
WEST MONTALVO LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PROBABLE RESERVES

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	5.3	3.9	0.9	0.2	0.0	73.10	3.101	0.00	64.5	0.5	0.0	0.0	64.9
12-31-2026	5.5	4.2	0.9	0.2	0.0	73.10	3.101	0.00	67.6	0.5	0.0	0.0	68.1
12-31-2027	8.6	6.6	1.4	0.3	0.0	73.10	3.101	0.00	104.7	0.8	0.0	0.0	105.5
12-31-2028	10.0	7.7	1.7	0.3	0.0	73.10	3.101	0.00	121.7	0.9	0.0	0.0	122.7
12-31-2029	7.8	6.0	1.3	0.2	0.0	73.10	3.101	0.00	95.6	0.7	0.0	0.0	96.3
12-31-2030	6.2	4.8	1.0	0.2	0.0	73.10	3.101	0.00	76.3	0.6	0.0	0.0	76.8
12-31-2031	12.9	12.1	2.1	0.5	0.0	73.10	3.101	0.00	157.1	1.4	0.0	0.0	158.5
12-31-2032	13.7	13.5	2.3	0.5	0.0	73.10	3.101	0.00	167.0	1.6	0.0	0.0	168.6
12-31-2033	15.4	12.5	2.6	0.5	0.0	73.10	3.101	0.00	187.6	1.5	0.0	0.0	189.1
12-31-2034	12.1	9.8	2.0	0.4	0.0	73.10	3.101	0.00	147.9	1.2	0.0	0.0	149.0
12-31-2035	11.0	6.4	1.8	0.2	0.0	73.10	3.101	0.00	134.8	0.8	0.0	3.8	139.3
12-31-2036	9.9	5.6	1.7	0.2	0.0	73.10	3.101	0.00	121.1	0.7	0.0	5.0	126.7
12-31-2037	5.9	4.5	1.0	0.2	0.0	73.10	3.101	0.00	71.7	0.5	0.0	5.0	77.2
12-31-2038	5.5	4.2	0.9	0.2	0.0	73.10	3.101	0.00	67.4	0.5	0.0	5.0	72.9
12-31-2039	5.2	3.9	0.9	0.2	0.0	73.10	3.101	0.00	63.3	0.5	0.0	5.0	68.8
SUBTOTAL	135.0	105.8	22.5	4.1	0.0	73.10	3.101	0.00	1,648.3	12.6	0.0	23.8	1,684.6
REMAINING	12.4	9.4	2.1	0.4	0.0	73.10	3.101	0.00	150.9	1.1	0.0	13.3	165.4
TOTAL	147.4	115.2	24.6	4.4	0.0	73.10	3.101	0.00	1,799.2	13.7	0.0	37.1	1,850.0
CUM PROD	9.9	7.2											
ULTIMATE	157.3	122.4											

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	0	0.0	0.0	0.0	0.0	0.0	0.0	64.9	64.9	61.9
12-31-2026	0	0.0	0.0	0.0	0.0	0.0	0.0	68.1	133.1	121.0
12-31-2027	0	0.0	0.0	0.0	0.0	0.0	0.0	105.5	238.6	203.7
12-31-2028	1	0.0	0.0	0.0	0.0	0.0	0.0	122.7	361.3	291.6
12-31-2029	1	0.0	0.0	0.0	0.0	0.0	0.0	96.3	457.6	354.8
12-31-2030	0	0.0	0.0	0.0	0.0	0.0	0.0	76.8	534.4	400.1
12-31-2031	1	0.0	0.0	0.0	0.0	0.0	0.0	158.5	692.9	485.2
12-31-2032	2	0.0	0.0	0.0	0.0	0.0	0.0	168.6	861.6	567.8
12-31-2033	2	0.0	0.0	0.0	0.0	0.0	0.0	189.1	1,050.6	652.1
12-31-2034	2	0.0	0.0	0.0	0.0	0.0	0.0	149.0	1,199.7	712.4
12-31-2035	2	0.0	0.0	0.0	0.0	0.0	0.0	139.3	1,339.0	763.6
12-31-2036	2	0.0	0.0	0.0	0.0	0.0	0.0	126.7	1,465.7	806.1
12-31-2037	1	0.0	0.0	0.0	0.0	0.0	0.0	77.2	1,542.9	829.6
12-31-2038	1	0.0	0.0	0.0	0.0	0.0	0.0	72.9	1,615.8	849.8
12-31-2039	1	0.0	0.0	0.0	0.0	0.0	0.0	68.8	1,684.6	867.1
SUBTOTAL			0.0	0.0	0.0	0.0	0.0	1,684.6	1,684.6	867.1
REMAINING			0.0	0.0	0.0	0.0	0.0	165.4	1,850.0	902.1
TOTAL OF 17.7 YRS			0.0	0.0	0.0	0.0	0.0	1,850.0	1,850.0	902.1

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	1,022.9
12.000	801.8
15.000	681.0
20.000	535.4
25.000	435.3
30.000	363.8
35.000	311.2
40.000	271.3
45.000	240.2
50.000	215.6

Figure 7.10.5
Page 2 of 3

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF DECEMBER 31, 2024

PROVED + PROBABLE (2P) RESERVES

STATE OF CALIFORNIA INTEREST

SUMMARY - CERTAIN PROPERTIES LOCATED IN THE
WEST MONTALVO LEASE AREA
STATE WATERS OFFSHORE CALIFORNIA

PERIOD	GROSS RESERVES		NET RESERVES			AVERAGE PRICES			GROSS REVENUE				
ENDING	OIL	GAS	OIL	GAS	NGL	OIL	GAS	NGL	OIL	GAS	NGL	OTHER	TOTAL
M-D-Y	MBBL	MMCF	MBBL	MMCF	MBBL	$/BBL	$/MCF	$/BBL	M$	M$	M$	M$	M$
12-31-2025	46.3	35.8	7.7	1.4	0.0	73.10	3.101	0.00	565.3	4.3	0.0	5.0	574.5
12-31-2026	42.6	33.0	7.1	1.3	0.0	73.10	3.101	0.00	520.2	3.9	0.0	5.0	529.1
12-31-2027	39.4	30.6	6.6	1.2	0.0	73.10	3.101	0.00	480.8	3.6	0.0	5.0	489.4
12-31-2028	36.5	28.5	6.1	1.1	0.0	73.10	3.101	0.00	445.8	3.4	0.0	5.0	454.2
12-31-2029	31.8	24.9	5.3	1.0	0.0	73.10	3.101	0.00	388.6	3.0	0.0	5.0	396.5
12-31-2030	27.6	21.6	4.6	0.8	0.0	73.10	3.101	0.00	336.8	2.6	0.0	5.0	344.4
12-31-2031	25.7	20.2	4.3	0.8	0.0	73.10	3.101	0.00	313.5	2.4	0.0	5.0	320.9
12-31-2032	23.9	18.9	4.0	0.7	0.0	73.10	3.101	0.00	291.8	2.2	0.0	5.0	299.1
12-31-2033	20.8	16.5	3.5	0.6	0.0	73.10	3.101	0.00	254.5	2.0	0.0	5.0	261.4
12-31-2034	16.7	13.3	2.8	0.5	0.0	73.10	3.101	0.00	204.2	1.6	0.0	5.0	210.8
12-31-2035	12.1	7.2	2.0	0.3	0.0	73.10	3.101	0.00	148.0	0.9	0.0	5.0	153.8
12-31-2036	9.9	5.6	1.7	0.2	0.0	73.10	3.101	0.00	121.1	0.7	0.0	5.0	126.7
12-31-2037	5.9	4.5	1.0	0.2	0.0	73.10	3.101	0.00	71.7	0.5	0.0	5.0	77.2
12-31-2038	5.5	4.2	0.9	0.2	0.0	73.10	3.101	0.00	67.4	0.5	0.0	5.0	72.9
12-31-2039	5.2	3.9	0.9	0.2	0.0	73.10	3.101	0.00	63.3	0.5	0.0	5.0	68.8
SUBTOTAL	350.0	268.7	58.5	10.3	0.0	73.10	3.101	0.00	4,272.8	32.0	0.0	75.0	4,379.9
REMAINING	12.4	9.4	2.1	0.4	0.0	73.10	3.101	0.00	150.9	1.1	0.0	13.3	165.4
TOTAL	362.4	278.1	60.5	10.7	0.0	73.10	3.101	0.00	4,423.8	33.1	0.0	88.3	4,545.2
CUM PROD	5,695.8	3,685.2											
ULTIMATE	6,058.1	3,963.4											

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE		
ENDING	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2025	5	0.0	0.0	0.0	0.0	0.0	0.0	574.5	574.5	548.4
12-31-2026	5	0.0	0.0	0.0	0.0	0.0	0.0	529.1	1,103.7	1,007.5
12-31-2027	5	0.0	0.0	0.0	0.0	0.0	0.0	489.4	1,593.1	1,393.5
12-31-2028	5	0.0	0.0	0.0	0.0	0.0	0.0	454.2	2,047.3	1,719.2
12-31-2029	5	0.0	0.0	0.0	0.0	0.0	0.0	396.5	2,443.8	1,978.1
12-31-2030	4	0.0	0.0	0.0	0.0	0.0	0.0	344.4	2,788.2	2,182.2
12-31-2031	4	0.0	0.0	0.0	0.0	0.0	0.0	320.9	3,109.1	2,355.0
12-31-2032	4	0.0	0.0	0.0	0.0	0.0	0.0	299.1	3,408.2	2,501.5
12-31-2033	4	0.0	0.0	0.0	0.0	0.0	0.0	261.4	3,669.6	2,618.1
12-31-2034	3	0.0	0.0	0.0	0.0	0.0	0.0	210.8	3,880.4	2,703.4
12-31-2035	3	0.0	0.0	0.0	0.0	0.0	0.0	153.8	4,034.2	2,760.2
12-31-2036	2	0.0	0.0	0.0	0.0	0.0	0.0	126.7	4,160.9	2,802.7
12-31-2037	1	0.0	0.0	0.0	0.0	0.0	0.0	77.2	4,238.2	2,826.1
12-31-2038	1	0.0	0.0	0.0	0.0	0.0	0.0	72.9	4,311.0	2,846.3
12-31-2039	1	0.0	0.0	0.0	0.0	0.0	0.0	68.8	4,379.9	2,863.6
SUBTOTAL			0.0	0.0	0.0	0.0	0.0	4,379.9	4,379.9	2,863.6
REMAINING			0.0	0.0	0.0	0.0	0.0	165.4	4,545.2	2,898.7
TOTAL OF 17.7 YRS			0.0	0.0	0.0	0.0	0.0	4,545.2	4,545.2	2,898.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
8.000	3,129.9
12.000	2,698.7
15.000	2,445.8
20.000	2,117.3
25.000	1,870.1
30.000	1,678.2
35.000	1,525.6
40.000	1,401.4
45.000	1,298.7
50.000	1,212.2

PRELIMINARY – FOR REVIEW ONLY

BASED ON COMMISSION PRICE AND COST PARAMETERS

8.0 PRELIMINARY DECOMMISSIONING ESTIMATES

This section summarizes TSB's preliminary analysis of the decommissioning costs. Further detail on TSB's data sources and methodology is provided in Appendix 3.

8.1 DATA AVAILABLE

8.1.1 Commission- and Lessee-Provided Information

TSB reviewed several documents as background for its analysis. The Commission provided well listings and previous abandonment cost studies on the wells and facilities covered by this study. The lessees provided facility and wellbore drawings, specifications, and inspection reports.

8.1.2 Site Visits

TSB conducted two site visits to verify asset information and clarify missing data points. In June 2023, TSB visited the properties operated by DCOR, including Platform Eva, Platform Esther, and several onshore sites. In August 2023, TSB visited certain properties operated by CRC, including Platform Emmy, the Bolsa Leases, and the Huntington Beach Highlands Facility. Because CRC does not bear any abandonment liability for the surface facilities on Island Chaffee, a site visit to that location was not deemed necessary for this study.

8.1.3 TSB Platform Abandonment Estimate System Database

In addition to site-specific data, TSB also used data from its proprietary database program, Platform Abandonment Estimate System (PAES). TSB developed PAES to provide reliable cost estimates for abandoning offshore platforms, pipelines, and wells. PAES contains profiles of over 2,000 domestic and international platforms. The equipment rates used in PAES are derived from actual projects and contractor supplied data and are updated at least yearly. Spread cost data are stored in the system for various regions of the world, including California.

8.2 METHODOLOGY

8.2.1 Decommissioning Estimate Methodology

TSB's offshore decommissioning estimates are deterministic estimates that are a function of time and resource rate (the cost per unit of time). TSB systematically calculates and tallies the time required to perform each necessary decommissioning task, which is then multiplied by the resource rate for that task according to the appropriate working vessel, equipment, and personnel.

TSB's onshore decommissioning estimates are deterministic estimates that are a function of the total weight or volume of facilities components. TSB tabulates an estimated tonnage of all equipment, volume of fluids required to flush all vessels and pipelines, and quantities of consumable products required for decommissioning operations.

The decommissioning operations can generally be divided into four categories: well plug and abandonment, pipeline and subsea facilities decommissioning, platform decommissioning, and onshore facilities decommissioning (including site remediation). The general steps to decommissioning facilities similar to the facilities present on the leases included in this study are described in more detail in Appendix 3.

8.2.2 Estimate Accuracy

The accuracy range of each of TSB's estimates aligns with that of an Association for the Advancement of Cost Engineering Class 4 estimate, which allows for a low range of -15 to -30 percent and a high range of +20 to +50 percent.

TSB has aimed to make its decommissioning cost estimates as accurate as reasonably possible. TSB has taken a conventional approach to estimating decommissioning costs based on known facts and by use of industry standard decommissioning assumptions. However, changes in cost or duration elements at any given facility may cause the actual decommissioning costs to be higher or lower than the estimated costs. All decommissioning cost estimates in this status update are based on current market conditions in California.

TSB developed its estimates in a manner that satisfy the reporting and audit requirements of Financial Accounting Standards Board Accounting Standards Codification 410-20, "Asset Retirement Obligations". TSB's cost estimates are not bids or proposals to perform work. At the time of decommissioning, a decommissioning contractor will be responsible for developing execution strategies, work plans, and detailed cost estimates to perform actual work.

8.3 PRELIMINARY DECOMMISSIONING COST ESTIMATES

TSB's preliminary decommissioning cost estimates for the lease areas included in this study are as follows:

Lease Area	Lessee	Decommissioning Cost (M$)
Belmont Offshore (186)	CRC	11,900.0
Belmont Offshore (Esther)	DCOR	80,000.0
Huntington Beach (Eva)	DCOR	79,300.0
Huntington Beach (Near Shore)	CRC	197,600.0
West Montalvo	CRC	7,000.0

The decommissioning cost estimate for the Huntington Beach (Near Shore) lease area does not include the cost to decommission the onshore wells producing from the Bolsa Leases. It does include the cost to decommission the onshore facilities that serve both the Huntington Beach (Near Shore) lease area and the Bolsa Leases.

8.4 POTENTIAL CARBON CREDITS ASSOCIATED WITH DECOMMISSIONING

As requested by the Commission, we have investigated the possibility of generating carbon credits and related revenue to offset a portion of the revenue lost from prematurely decommissioning these leases. In general, carbon credits can be generated by project operators by following certain standard methodologies which quantify the greenhouse gas emissions that are reduced, avoided, or removed from the atmosphere. Such emissions are typically quantified in terms of the equivalent global warming potential of a metric ton of CO_2 (tCO_2e).

8.4.1 Voluntary Carbon Markets

There are a number of active voluntary carbon markets; examples include Verra, American Carbon Registry, Climate Action Reserve, The Gold Standard, and the International Carbon Registry. At this time, NSAI has not found a widely recognized voluntary carbon registry that has an approved methodology applicable to the premature abandonment of offshore oil and gas leases prior to the end of their economic lives. However, NSAI met with several market participants pursuing the sale of credits for smaller-scale abandonment of individual onshore wells; we understand that various entities have sold these credits at prices in the approximate range of $10 to $30 per tCO_2e.

8.4.2 AB 2257 Carbon Credit Estimate

For the purposes of this status update, we have estimated the carbon credits that may be associated with voluntary relinquishment of the leases under one proposed methodology: the May 2023 Production Reserves Carbon Offset Protocol proposed by ZeroSix. Documentation describing the methodology is included as Appendix 4. The quantity of credits that may be generated and sold will ultimately depend on the specific methodology used and the market for such credits. The quantity of credits will also depend on the economic reserves of the properties, which may change over time because of production, economic conditions, or actual reservoir performance. Therefore, the carbon credit estimates and values contained in this report are for illustrative purposes only and should not be construed as exact values; the estimates contained herein are subject to potentially significant revisions as crediting methodologies and carbon markets develop in the future.

There is no certainty that any credits could be generated from the premature abandonment of these offshore leases and, if credits are generated, there is no guarantee that such credits could be sold for any particular price.

As requested, we have included calculations based on a price assumption of \$30 per tCO_2e to illustrate the potential carbon credit revenue. The following table shows our estimates of potential carbon credits by lease area and their potential revenue:

Lease Area	Potential Carbon Credits (million tCO_2e)	Potential Carbon Credit Revenue (MM$)
Belmont Offshore (186)	0.6	18.3
Belmont Offshore (Esther)	0.7	21.9
Huntington Beach (Eva)	1.5	44.3
Huntington Beach (Near Shore)	6.3	187.7
West Montalvo	0.1	3.7

8.5 WORK OUTSTANDING

In 2024, TSB will revise its estimates as needed to account for the latest market conditions before completion of the final cost study report. TSB will also refine its estimates by considering additional factors, such as material disposal locations and the cost of final environmental assessments. As specified by the Commission, TSB will generate probabilistic estimates to supplement the deterministic estimates in this preliminary status update and will study the potential cost savings of grouping the decommissioning activities into campaigns to reduce mobilization and demobilization costs.

9.0 RECOMMENDATIONS

AB 2257 requires this preliminary status update to include preliminary recommendations. Based on the data available at the time this status update was prepared, we present our preliminary recommendations for the next stages of the project.

9.1 EXPECTED DURATION OF PRODUCTION AT TIME OF LEASING

As discussed in Section 5.1, documents from the time of leasing indicating the expected duration of production have not been made available to date, and even if they were provided, such documents would have very limited usefulness in achieving the core objectives of the cost study. Therefore, we recommend that the Commission limit discussion of this topic in the final report to a comment regarding the lack of available data.

9.2 MISSING RENT DATA

As discussed in Section 5.2, we recommend no further action be taken to resolve the few missing rent payment data points. We recommend proceeding under the assumption that the payments were received as required by the lease agreements.

APPENDIX 1
SUMMARY OF PUBLIC COMMENTS RECEIVED BY THE STATE LANDS COMMISSION

NETHERLAND, SEWELL & ASSOCIATES, INC.

APPENDIX 1
SUMMARY OF PUBLIC COMMENTS RECEIVED BY THE STATE LANDS COMMISSION
DECEMBER 5, 2023 PUBLIC HEARING

Placeholder

APPENDIX 2
PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

NETHERLAND, SEWELL & ASSOCIATES, INC.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS
Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the SPE, World Petroleum Council, American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers, Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts, and European Association of Geoscientists & Engineers.

Preamble

Petroleum resources are the quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resources assessments estimate quantities in known and yet-to-be-discovered accumulations. Resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating projects, and presenting results within a comprehensive classification framework.

This updated PRMS provides fundamental principles for the evaluation and classification of petroleum reserves and resources. If there is any conflict with prior SPE and PRMS guidance, approved training, or the Application Guidelines, the current PRMS shall prevail. It is understood that these definitions and guidelines allow flexibility for entities, governments, and regulatory agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein must be clearly identified. The terms "shall" or "must" indicate that a provision herein is mandatory for PRMS compliance, while "should" indicates a recommended practice and "may" indicates that a course of action is permissible. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

1.0.0.1 A classification system of petroleum resources is a fundamental element that provides a common language for communicating both the confidence of a project's resources maturation status and the range of potential outcomes to the various entities. The PRMS provides transparency by requiring the assessment of various criteria that allow for the classification and categorization of a project's resources. The evaluation elements consider the risk of geologic discovery and the technical uncertainties together with a determination of the chance of achieving the commercial maturation status of a petroleum project.

1.0.0.2 The technical estimation of petroleum resources quantities involves the assessment of quantities and values that have an inherent degree of uncertainty. These quantities are associated with exploration, appraisal, and development projects at various stages of design and implementation. The commercial aspects considered will relate the project's maturity status (e.g., technical, economical, regulatory, and legal) to the chance of project implementation.

1.0.0.3 The use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios. The application of PRMS must consider both technical and commercial factors that impact the project's feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

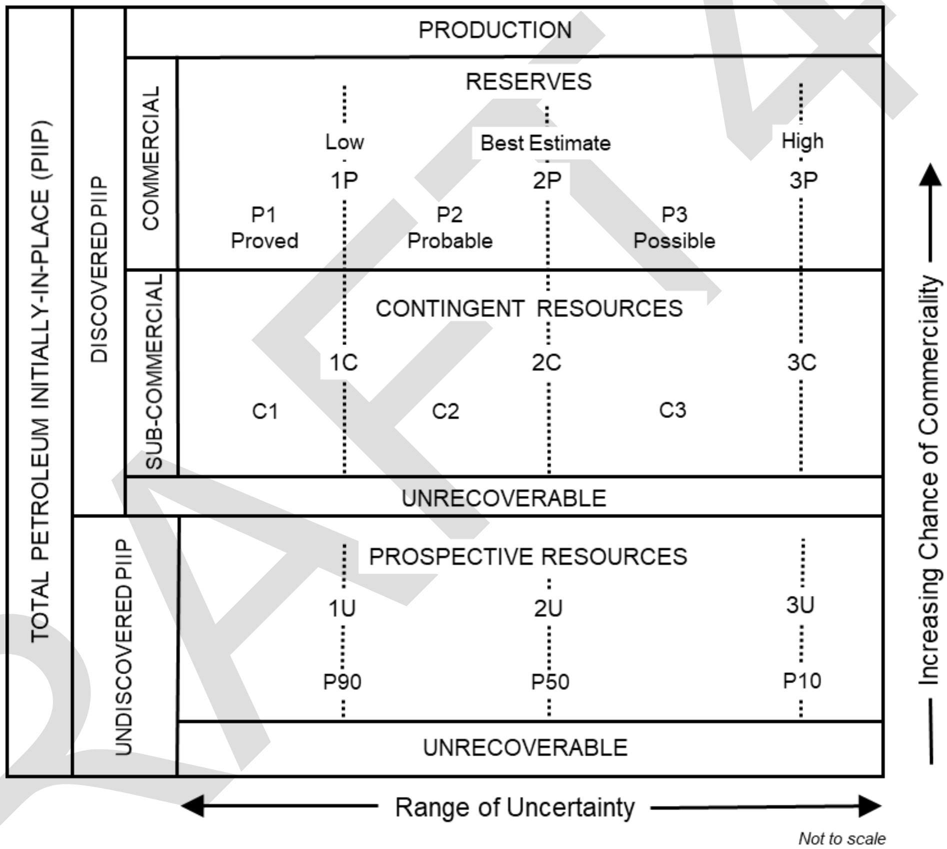

Figure 1.1—Resources classification framework

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Resources.

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, P_3, which is the chance that a project will be committed for development and reach commercial producing status.

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS
Excerpted from the 2018 Petroleum Resources Management System (PRMS), version 1.03
Approved by the Society of Petroleum Engineers (SPE) Board of Directors

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

A. **Total Petroleum Initially-In-Place** (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

B. **Discovered PIIP** is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

C. **Production** is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. **Reserves** are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

2. Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO) (see Section 3.2.2), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

3. Reserves are further categorized in accordance with the range of uncertainty and should be sub-classified based on project maturity and/or characterized by development and production status.

B. **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

C. **Undiscovered PIIP** is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. **Prospective Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. **Unrecoverable Resources** are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.1.0.7 The sum of Reserves, Contingent Resources, and Prospective Resources may be referred to as "remaining recoverable resources." Importantly, these quantities should not be aggregated without due consideration of the technical and commercial risk involved with their classification. When such terms are used, each classification component of the summation must be provided.

1.1.0.8 Other terms used in resource assessments include the following:

A. **Estimated Ultimate Recovery (EUR)** is not a resources category or class, but a term that can be applied to an accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities already produced from the accumulation or group of accumulations. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.

B. **Technically Recoverable Resources (TRR)** are those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial considerations. TRR may be used for specific Projects or for groups of Projects, or, can be an undifferentiated estimate within an area (often basin-wide) of recovery potential.

1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

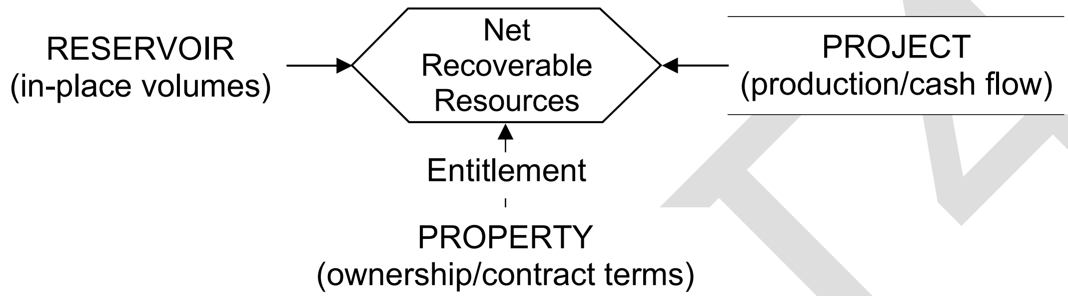

Figure 1.2—Resources evaluation

1.2.0.3 **The reservoir** (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 **The project:** A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 **The property** (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class (See Section 2.1.3.5, Project Maturity Sub-Classes) at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project (See Section 2.2.1, Range of Uncertainty). For completeness, a developed field is also considered to be a project.

1.2.0.8 An accumulation or potential accumulation of petroleum is often subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resources classes simultaneously.

1.2.0.10 Not all technically feasible development projects will be commercial. The commercial viability of a development project within a field's development plan is dependent on a forecast of the conditions that will exist during the time period encompassed by the project (see Section 3.1, Assessment of Commerciality). Conditions include technical, economic (e.g., hurdle rates, commodity prices), operating and capital costs, marketing, sales route(s), and legal, environmental, social, and governmental factors forecast to exist and impact the project during the time period being evaluated. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions (e.g., inflation, market factors, and contingencies), exchange rates, transportation and processing infrastructure, fiscal terms, and taxes.

1.2.0.11 The resources being estimated are those quantities producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Section 3.2.1, Reference Point) and may permit forecasts of CiO quantities (see Section 3.2.2., Consumed in Operations). The cumulative production forecast from the effective date forward to cessation of production is the remaining recoverable resources quantity (see Section 3.1.1, Net Cash-Flow Evaluation).

1.2.0.12 The supporting data, analytical processes, and assumptions describing the technical and commercial basis used in an evaluation must be documented in sufficient detail to allow, as needed, a qualified reserves evaluator or qualified reserves auditor to clearly understand each project's basis for the estimation, categorization, and classification of recoverable resources quantities and, if appropriate, associated commercial assessment.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

2.1.0.1 The PRMS classification establishes criteria for the classification of the total PIIP. A determination of a discovery differentiates between discovered and undiscovered PIIP. The application of a project further differentiates the recoverable from unrecoverable resources. The project is then evaluated to determine its maturity status to allow the classification distinction between commercial and sub-commercial projects. PRMS requires the project's recoverable resources quantities to be classified as either Reserves, Contingent Resources, or Prospective Resources.

2.1.1 Determination of Discovery Status

2.1.1.1 A discovered petroleum accumulation is determined to exist when one or more exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In the absence of a flow test or sampling, the discovery determination requires confidence in the presence of hydrocarbons and evidence of producibility, which may be supported by suitable producing analogs (see Section 4.1.1, Analogs). In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place quantity demonstrated by the well(s) and for evaluating the potential for commercial recovery.

2.1.1.2 Where a discovery has identified potentially recoverable hydrocarbons, but it is not considered viable to apply a project with established technology or with technology under development, such quantities may be classified as Discovered Unrecoverable with no Contingent Resources. In future evaluations, as appropriate for petroleum resources management purposes, a portion of these unrecoverable quantities may become recoverable resources as either commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

2.1.2.1 Discovered recoverable quantities (Contingent Resources) may be considered commercially mature, and thus attain Reserves classification, if the entity claiming commerciality has demonstrated a firm intention to proceed with development. This means the entity has satisfied the internal decision criteria (typically rate of return at or above the weighted average cost-of-capital or the hurdle rate). Commerciality is achieved with the entity's commitment to the project and all of the following criteria:

A. Evidence of a technically mature, feasible development plan.
B. Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
C. Evidence to support a reasonable time-frame for development.
D. A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made (see Section 3.1.1, Net Cash-Flow Evaluation).
E. A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
F. Evidence that the necessary production and transportation facilities are available or can be made available.
G. Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

2.1.2.2 The commerciality test for Reserves determination is applied to the best estimate (P50) forecast quantities, which upon qualifying all commercial and technical maturity criteria and constraints become the 2P Reserves. Stricter cases [e.g., low estimate (P90)] may be used for decision purposes or to investigate the range of commerciality (see Section 3.1.2, Economic Criteria). Typically, the low- and high-case project scenarios may be evaluated for sensitivities when considering project risk and upside opportunity.

2.1.2.3 To be included in the Reserves class, a project must be sufficiently defined to establish both its technical and commercial viability as noted in Section 2.1.2.1. There must be a reasonable expectation that all required internal and external approvals will be forthcoming and evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where justifiable; for example, development of economic projects that take longer than five years to be developed or are deferred to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

2.1.2.4 While PRMS guidelines require financial appropriations evidence, they do not require that project financing be confirmed before classifying projects as Reserves. However, this may be another external reporting requirement. In many cases, financing is conditional upon the same criteria as above. In general, if there is not a reasonable expectation that financing or other forms of commitment (e.g., farm-outs) can be arranged so that the development will be initiated within a reasonable time-frame, then the project should be classified as Contingent Resources. If financing is reasonably expected to be in place at the time of the final investment decision (FID), the project's resources may be classified as Reserves.

2.2 Resources Categorization

2.2.0.1 The horizontal axis in the resources classification in Figure 1.1 defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project or group of projects. These estimates include the uncertainty components as follows:

A. The total petroleum remaining within the accumulation (in-place resources).
B. The technical uncertainty in the portion of the total petroleum that can be recovered by applying a defined development project or projects (i.e., the technology applied).
C. Known variations in the commercial terms that may impact the quantities recovered and sold (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) are part of project's scope and are included in the horizontal axis, while the chance of satisfying the commercial terms is reflected in the classification (vertical axis).

2.2.0.2 The uncertainty in a project's recoverable quantities is reflected by the 1P, 2P, 3P, Proved (P1), Probable (P2), Possible (P3) reserves; 1C, 2C, 3C, C1, C2, and C3 contingent resources; or 1U, 2U, and 3U prospective resources categories. The chance of commerciality is associated with resources classes or sub-classes and not with the resources categories reflecting the range of recoverable quantities.

2.2.1 Range of Uncertainty

2.2.1.1 Uncertainty is inherent in a project's resources estimation and is communicated in PRMS by reporting a range of category outcomes. The range of uncertainty of the recoverable and/or potentially recoverable quantities may be represented by either deterministic scenarios or by a probability distribution (see Section 4.2, Resources Assessment Methods).

2.2.1.2 When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

A. There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
B. There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C. There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

2.2.1.3 In some projects, the range of uncertainty may be limited, and the three scenarios may result in resources estimates that are not significantly different. In these situations, a single value estimate may be appropriate to describe the expected result.

2.2.1.4 When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental method, quantities for each confidence segment are estimated discretely (see Section 2.2.2, Category Definitions and Guidelines).

2.2.1.5 Project resources are initially estimated using the above uncertainty range forecasts that incorporate the subsurface elements together with technical constraints related to wells and facilities. The technical forecasts then have additional commercial criteria applied (e.g., economics and license cutoffs are the most common) to estimate the entitlement quantities attributed and the resources classification status: Reserves, Contingent Resources, and Prospective Resources.

2.2.2 Category Definitions and Guidelines

2.2.2.1 Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental method, the deterministic scenario (cumulative) method, geostatistical methods, or probabilistic methods (see Section 4.2, Resources Assessment Methods). Also, combinations of these methods may be used.

2.2.2.2 Use of consistent terminology (Figures 1.1 and 2.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high forecasts are used to estimate the resulting 1P/2P/3P quantities, respectively. The associated incremental quantities are termed Proved (P1), Probable (P2) and Possible (P3). Reserves are a subset of, and must be viewed within the context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, the criteria can be equally applied to Contingent and Prospective Resources. Upon satisfying the commercial maturity criteria for discovery and/or development, the project quantities will then move to the appropriate resources sub-class. Table 3 provides criteria for the Reserves categories determination.

2.2.2.3 For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

2.2.2.4 For Prospective Resources, the general cumulative terms low/best/high estimates also apply and are used to estimate the resulting 1U/2U/3U quantities. No specific terms are defined for incremental quantities within Prospective Resources.

2.2.2.5 Quantities in different classes and sub-classes cannot be aggregated without considering the varying degrees of technical uncertainty and commercial likelihood involved with the classification(s) and without considering the degree of dependency between them (see Section 4.2.1, Aggregating Resources Classes).

2.2.2.6 Without new technical information, there should be no change in the distribution of technically recoverable resources and the categorization boundaries when conditions are satisfied to reclassify a project from Contingent Resources to Reserves.

2.2.2.7 All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Section 3.1, Assessment of Commerciality).

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Table 1—Recoverable Resources Classes and Sub-Classes

Class/ Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

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Class/ Sub-Class	Definition	Guidelines
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame). There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

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Class/ Sub-Class	Definition	Guidelines
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

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Class/ Sub-Class	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited commercial potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

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Class/ Sub-Class	Definition	Guidelines
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

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Table 2—Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

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Table 3—Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

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Category	Definition	Guidelines
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

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Category	Definition	Guidelines
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

APPENDIX 3
TSB OFFSHORE CALIFORNIA STATE LANDS COMMISSION AB 2257
DECOMMISSIONING STUDY

CALIFORNIA STATE LANDS COMMISSION
AB 2257 DECOMMISSIONING STUDY

CONDUCTED BY:

TSB OFFSHORE

PROJECT NUMBER:

P-23-006

FINAL

REV. 1

CALIFORNIA STATE LANDS COMMISSION
AB 2257 DECOMMISSIONING STUDY

DOCUMENT CONTROL:

Revision:	Date:	Prepared By:	Checked By:	Approved By:	Description of Change:
0	20-Oct-2023	Jimmy Tran	Steve Spease	Will Speck	Draft
1	29-Nov-2023	Jimmy Tran	Steve Spease	Will Speck	Final

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1 EXECUTIVE SUMMARY

1.1 BACKGROUND

California State Lands Commission engaged TSB Offshore, Inc. (TSB) to estimate decommissioning costs for the following properties:

- Leases 3314, 735, West Montalvo Field.
- Lease 186, Belmont Offshore Field (Wellheads on Island Chaffee directionally drilled to offshore Belmont field)
- Leases 91, 163, 392, 425, and 426, Huntington Beach Field - Platform Emmy wellheads and some onshore wellheads directionally drilled to offshore.
- Leases 3033, 3095, and 3413, Belmont Offshore Field, wellheads on Platforms Eva, and Esther

1.2 DATA REVIEWED

TSB reviewed drawings, specifications, inspection reports, and abandonment reports provided by CLSC, DCOR, and CRC. Data provided is summarized below:

- CSLC-provided data:
  - 00-SB 1147 Offshore Abandonment Legislative Report Final 2022
  - 01-ABANDONMENT COST ESTIMATE FOR OIL AND GAS ASSET IN CALIFORNIA STATE WATERS DRILTEK 04282020
  - 2022_CRC HB Well PA Cost Estimate REPORT
  - 2022_CRC Well PA Emmy Cost Estimate REPORT
  - Well listings for West Montalvo, CRC Huntington Beach and Belmont, and DCOR Huntington Beach and Belmont
- DCOR-provided data:
  - DCOR California Blueprint
  - Fort Apache P&IDs and plot plan
  - Offshore and onshore pipeline specifications
  - Platforms Eva and Esther general arrangement drawings, jacket elevation drawings, inspection reports
  - Wellbore schematics for Eva and Esther platform wells
- CRC-provided data:
  - Wellbore schematics for Belmont, Huntington Beach, and Montalvo
  - Huntington Beach Highlands Suracce Facility drawings
  - Platform Emmy Surface Facilities drawings

1.3 SITE VISITS

In preparation of conducting decommissioning estimates, TSB conducted (2) site visits to verify asset information and clarify missing data points. The dates and locations visited are summarized below:

- June 13th – 16th
    - Fort Apache, Los Patos, Wolden West Vault, Warner Vault, 1st Street Vault, PCH Crossing Meter
    - Platform Eva
    - Platform Esther
- August 29th – September 1st
    - Huntington Beach Highlands Facility
    - Bolsa Field
    - Platform Emmy

1.4 REPORT PURPOSE AND ESTIMATE ACCURACY

The cost estimates have been developed with the objective of producing estimates that are as accurate as reasonably possible. TSB has taken a conventional approach to decommissioning based on what is known and by use of industry standard decommissioning assumptions. However, a potential increase or decrease in decommissioning costs may be driven by changes in cost and duration elements at any given facility. All costs presented herein are based on current market conditions in the region.

The estimates were developed in a manner that will satisfy the reporting and audit requirements of Financial Accounting Standards Board (FASB) Accounting Standards Codification 410-20, “Asset Retirement Obligations” (“ASC 410-20”). As such, it is important to note that the cost estimates **are not** bids or proposals to perform work. At the time of decommissioning, a decommissioning contractor will be responsible for developing execution strategies, work plans, and detailed cost estimates to perform actual work. A gain or loss (the difference between the liability measured at fair value and the actual costs incurred) may be recognized upon completion of the retirement activities.

The accuracy range of TSB’s estimate aligns with an AACE Class 4 estimate, which allows for a “Low” range of -15% to -30% and a “High” range of +20% to +50%.

More information on the AACE classes is shown in the following table.

Table 1.1 | AACE Classes

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

1.5 FURTHER UPDATES TO STUDY

This report is intended to serve as a preliminary update for the AB 2257 Decommissioning Study. TSB will further develop this report to:

1. Expand on decommissioning methodology:
    a. Clarify decommissioning methodology options and cost implications.
    b. Clarify vessel choices and cost implications.
    c. Provide a complete list of study assumptions
2. Further review and classification of onshore wells.
3. Further develop Highlands Facility Estimate.
4. Provide commentary on environmental concerns for operational and decommissioning activities.
    a. Subsurface contamination.
    b. Impact on Recreational / Habitat uses.
5. Expand on cost estimate methodology:
    a. Review lessee vs state costs scenarios.
    b. Environmental assessment & site remediation costs.
    c. Probabilistic Estimate – Wells.
    d. Probabilistic Estimate – Platforms.
    e. Probabilistic Estimate – Pipelines.

2 ASSET DESCRIPTIONS

2.1 OFFSHORE PLATFORMS

Platform Emmy is a drilling and production platform composed of a four-pile main platform and a four-pile smaller satellite platform. The platform is located approximately 1.25 miles from Huntington Beach, California in 45 feet of water depth. It is currently operated by California Resources Corporation.

Figure 2.1 | Platform Emmy

Platform Esther is a sixteen-pile drilling and production platform. The platform is located approximately 1.5 miles from Seal Beach, California in 38 feet of water depth. It is currently operated by Dos Cuadras Offshore Resources, LLC.

Figure 2.2 | Platform Esther

Platform Eva is a twelve-legged drilling and production platform. The platform is located approximately 2.0 miles from Huntington Beach, California in 58 feet of water depth. It is currently operated by Dos Cuadras Offshore Resources, LLC.

Figure 2.3 | Platform Eva

The platforms are generally comprised of multiple deck levels, each housing production and processing equipment. Below are the jacket structures, containing piles which support the structure and penetrate into the seafloor. The table below lists the major component weights of each platform.

Table 2.1 | Platform Lift Weights

Platform	Topsides Weight	Jacket Weight
Eva	1,560	1,126
Esther	2,397	1,126
Emmy	1,635	1,250

2.2 OFFSHORE PIPELINES

The following pipelines support Platform Emmy:

- One 6” casing containing the following lines that run to the onshore Highlands Facility
  - One 3.5” gas line
  - One 4.5” gas line
- One 12.75” oil line hat runs to the onshore Highlands Facility
- Four 3” utility lines contained within a 14” casing hat run to the onshore Highlands Facility.

The following pipelines support Platform Esther:

- One 10” gas pipeline to onshore sales points.
- One 3.5” oil pipeline to onshore sales points.
- One 4” water pipeline from the local municipality to the offshore platform.

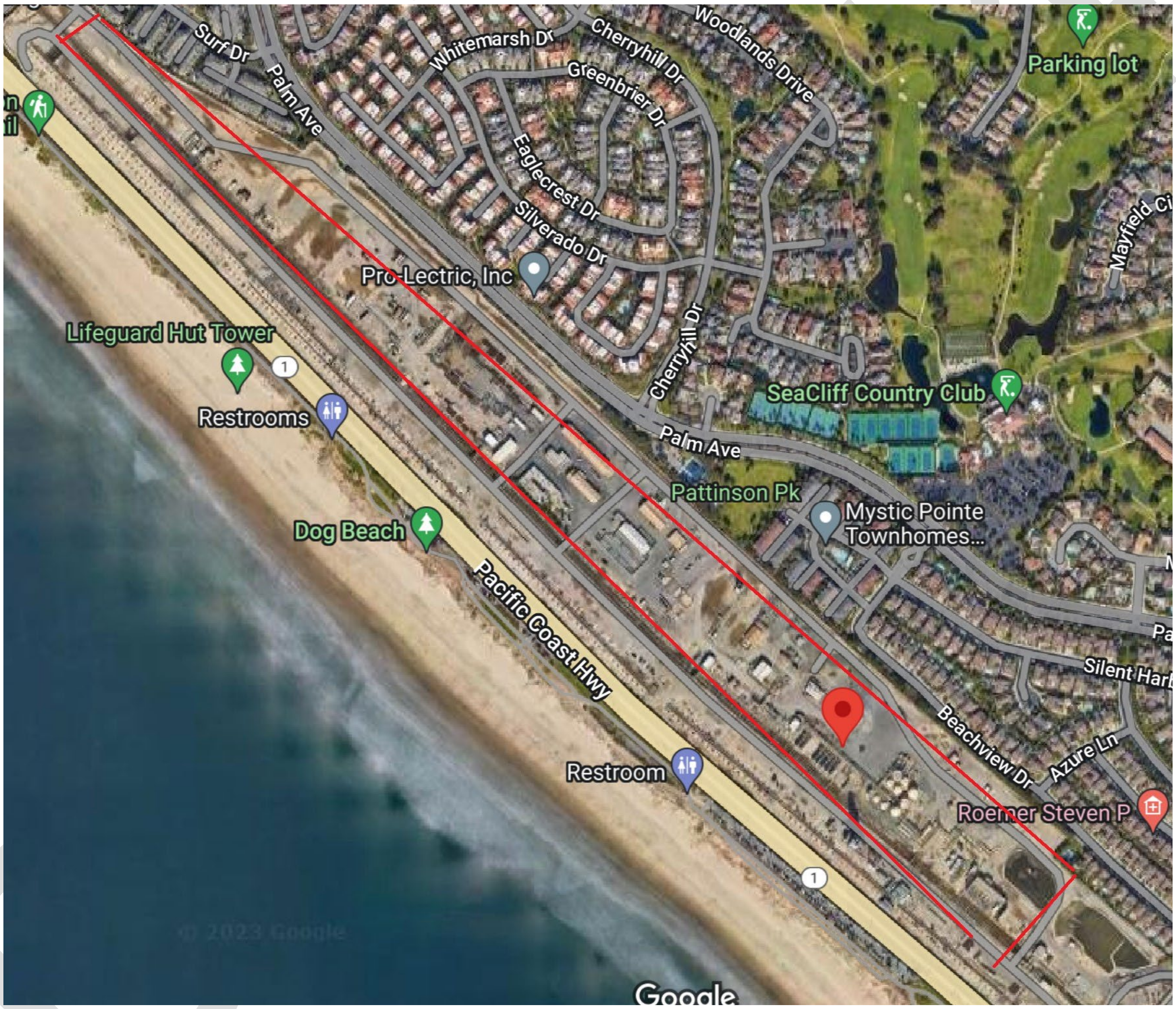
The following pipelines support Platform Eva:

- Two 8” pipelines transfer oil and gas production to onshore facilities.
- One 4” freshwater line from the local municipality to the offshore platform.
- One subsea power cable from the local municipality to the offshore platform.

2.3 ONSHORE FACILITIES

Production from Platform Emmy is routed to the Highlands Facility, located in Huntington Beach. The facility houses knockout tanks, separators, knockout drums, gas scrubbers, and other treatment vessels for production.

Figure 2.4 | HB Highlands Facility



Production from Platform Eva is mostly handled on the platform itself. However, the product is routed to the onshore Fort Apache facility for further processing and subsequent metering stations for sales.

Figure 2.5 | Fort Apache

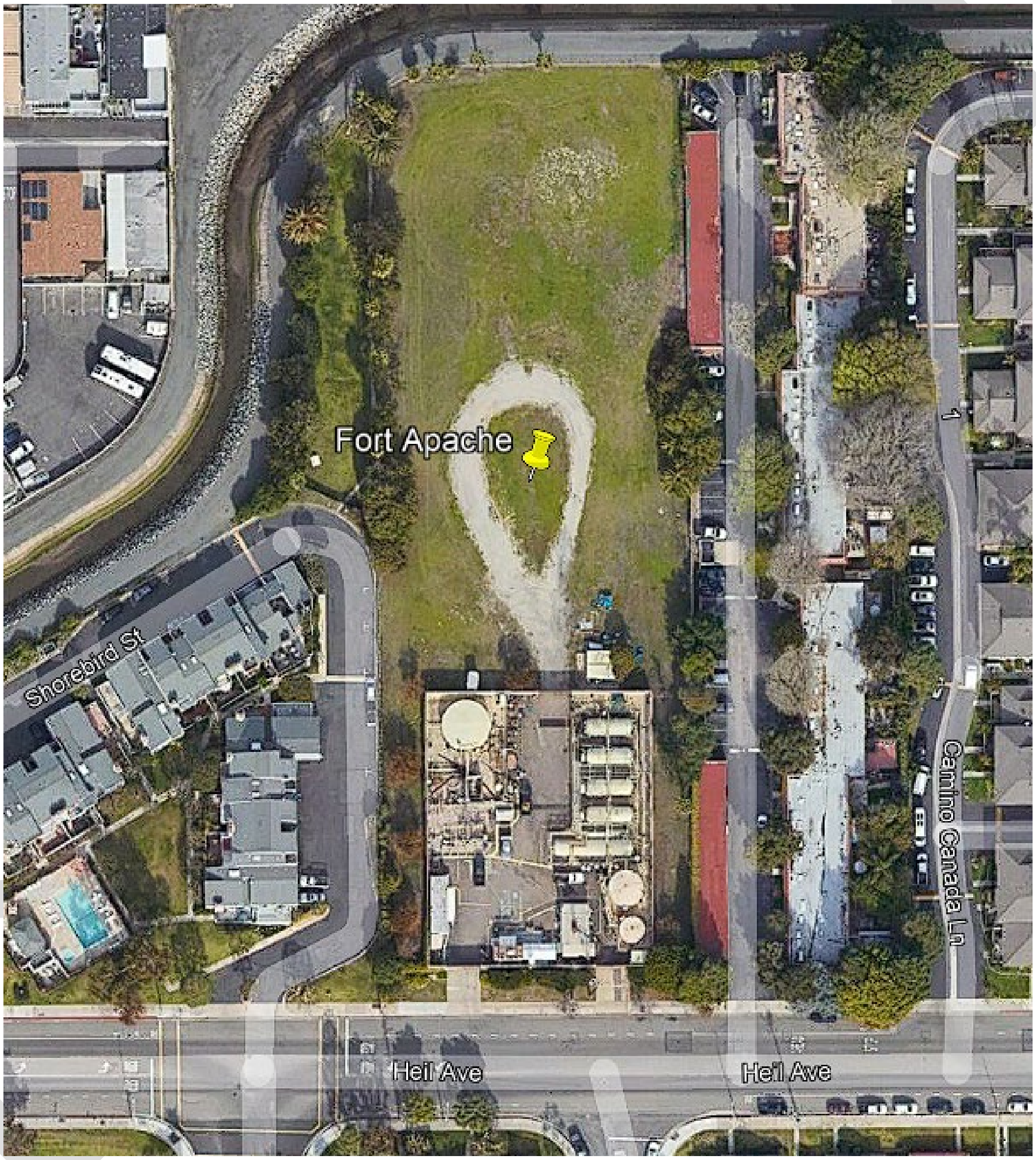


Figure 2.6 | Los Patos Meter

Figure 2.7 | Eva Pipeline Vault

Figure 2.8 | Goldenwest Vault

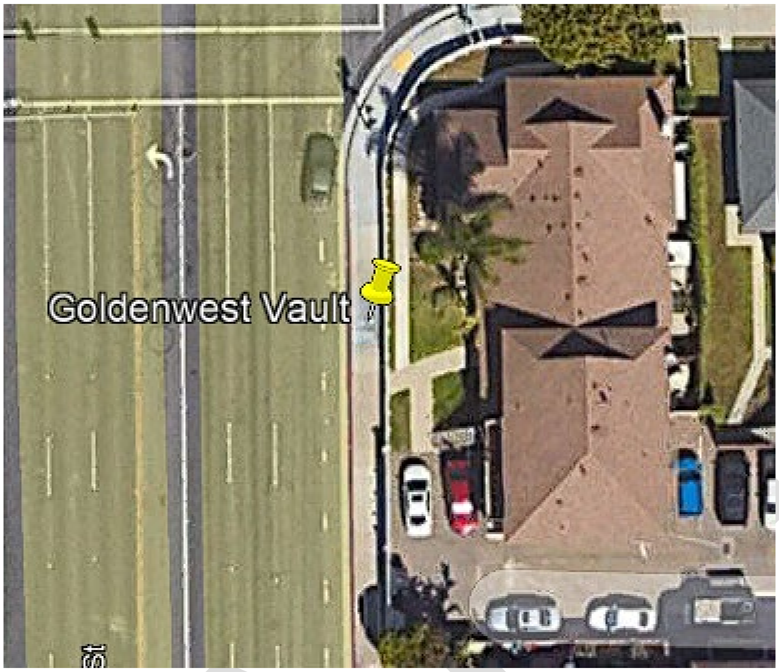


Figure 2.9 | 1st Street Vault

2.4 WELLS

The three offshore platforms house a number of wells, each with a conductor pipe penetrating into the seafloor and reservoir that must be removed.

Onshore wells, however, require only that the wellbore be properly plugged and that surface equipment be removed.

It should be noted that a large number of wells on both the platforms and onshore sites have already been plugged and abandoned. These wells were not considered in this study.

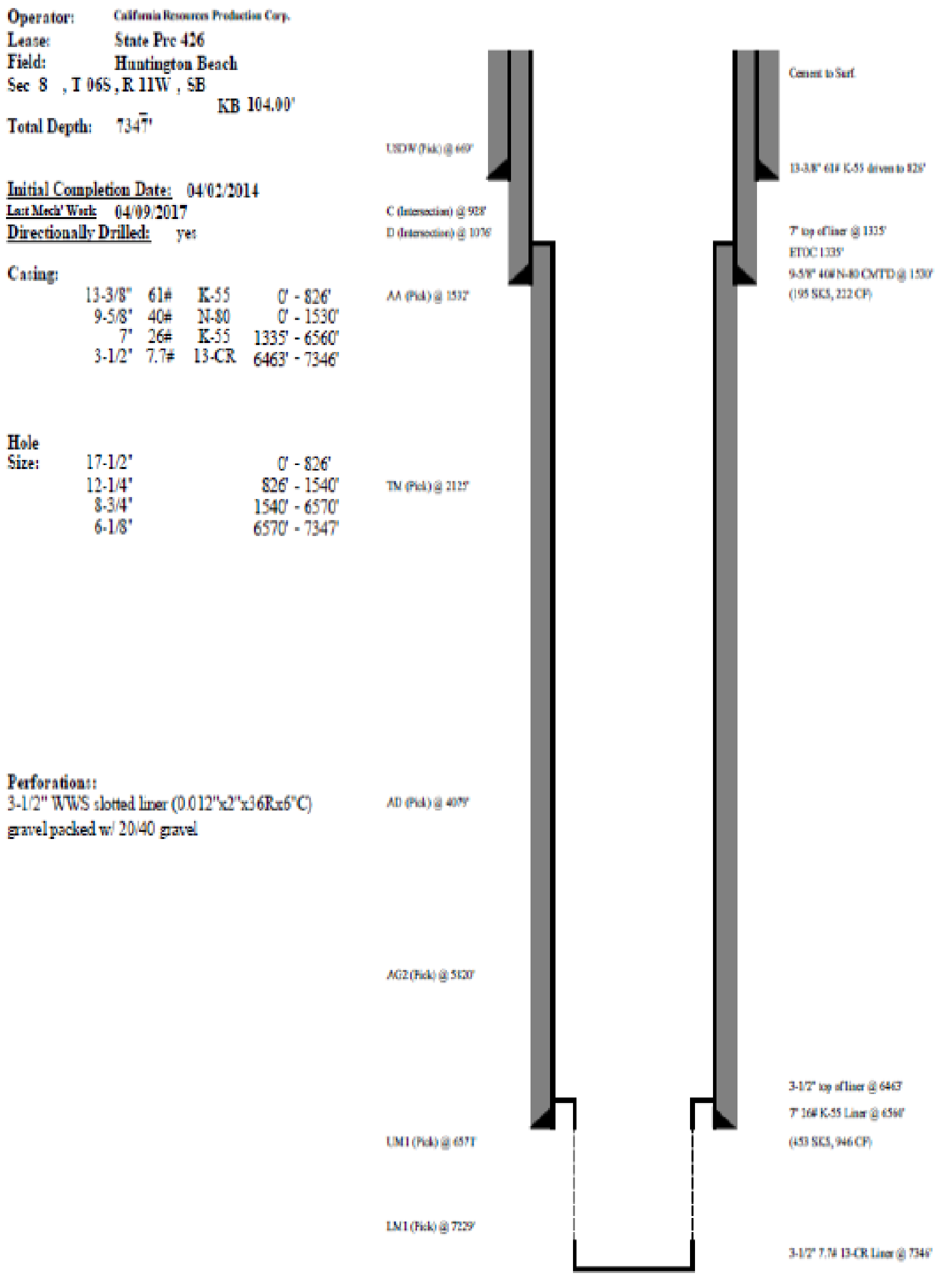
The number of wells considered can be found in the following table.

Table 2.2 | Well Counts

	Wells to P&A	Wells Abandoned
Platform Eva	42	15
Platform Esther	30	119
Platform Emmy	47	17
Huntington Beach	270	525
Belmont	36	3
West Montalvo	21	0

Wellbore diagrams, describing the make-up and state of each well, were examined to determine plug and abandonment methodology and duration.

Figure 2.10 | Typical Wellbore Diagram



3 OFFSHORE DECOMMISSIONING METHODOLOGY

3.1 WELL P&A METHODOLOGY

Once all production ceases from the platform, the wells will be plugged and abandoned. The crew mobilizes and sets up on the platform. Once the equipment is onboard and rigged up, diagnostics (establish injection rates & wireline surveys) are made to determine each well status. Having finished the diagnostics work, the well is ready for P&A. Squeeze all perforations with cement. Set intermediate plugs. Cut and remove the tubing +/- 300-ft below the mudline. If the production / surface casing annulus is not grouted, then a cement plug is set to isolate the casing. A Cast Iron Bridge Plug (CIBP) is set above the point the tubing is cut. A 200-ft balance plug is set above the CIBP and tested. Once tested, all strings are cut at 15' below the mudline.

The well P&A estimates assume operations proceed without significant problems or complications. Should wellbore conditions change over the well life or should complications arise during the well P&A operation, actual costs could increase significantly over the estimates contained herein.

3.2 PIPELINE ABANDONMENT METHODOLOGY

The pipelines and umbilicals are flushed with 150% of the line volume using low flow, high pressure triplex pumps that are fed with centrifugal pumps. The product and seawater is treated through a series of carbon filters, then discharged overboard, while the hydrocarbons are captured in tanks. The high-pressure pigging spread is located onboard a Dive Support Vessel (DSV), while the filtration spread is located onboard a workboat at the platform end.

Once the pipeline has been flushed and a sheen test has been approved, divers will then cut the pipeline approximately 20’ from the platform. The diver will then insert a plumbers plug into the cut end of the pipeline and cover it with one pallet of 3:1 sand cement bags or concrete mattresses.

3.3 FIXED PLATFORM DECOMMISSIONING METHODOLOGY

3.3.1 Platform Preparation

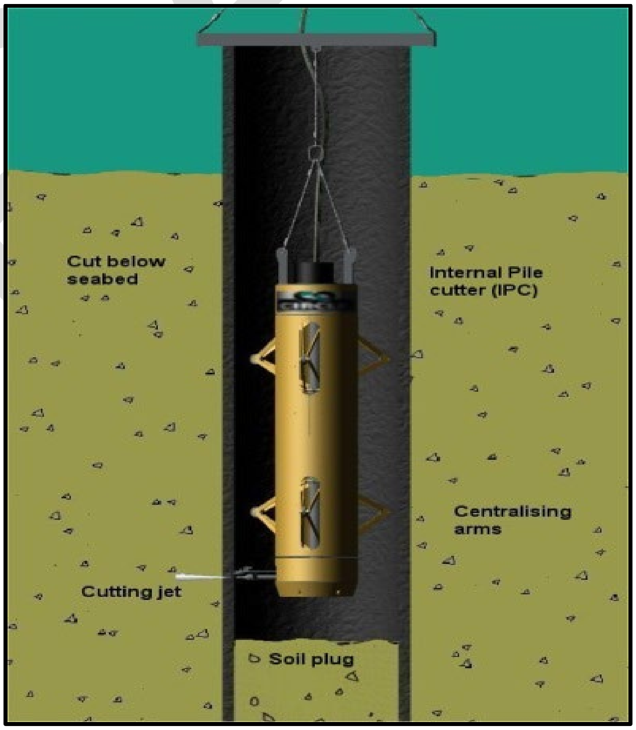
All work that can be performed prior to the arrival of the derrick barge is done during the decommissioning phase. All personnel and equipment are mobilized to the platform on a work boat. The decommissioning crew will be housed in the existing quarters or temporary quarters.

In this phase, the crew flushes all piping and equipment which contain hydrocarbons. All equipment that will be removed separately from the deck is cut loose using oxygen-acetylene torches. The piping, electrical, and tubing interconnections between equipment are also cut. All work needed to prepare the components for lifting (such as installing lifting eyes, etc.) is completed during this phase.

3.3.2 Conductor Severing and Removal

All conductors are completely removed to a minimum of 15 feet below the mudline. Conductors may be severed below the mudline during the platform preparation phase or during the platform removal operations using an abrasive cutter.

Figure 3.1 | Severing Using Abrasives



3.3.3 Mobilization

Cargo barges are outfitted at a fabrication yard with steel pads (load spreaders) to support the point loads of the deck and jacket. More than one cargo barge may be outfitted depending on the size of the platform being removed. A tug boat then tows each cargo barge to the offshore location. Another tug boat moves the derrick barge (with its crew and equipment) to the offshore location.

3.3.4 Setting Up Derrick Barge

When the derrick barge arrives on site, the derrick barge's anchor handling tug boat sets up the anchoring system. This anchoring system holds the derrick barge in position during the platform removal process. The derrick barge's anchoring system consists of eight anchors, each connected to a mooring winch by a cable. Each anchor is equipped with a pendant wire that is long enough to reach from the seabed to the surface where it is supported by a buoy (Figure 3.3). The anchor handling tug picks up the anchors by securing the pendant wire and winching up the anchor. The anchor handling tug then carries the anchor to the desired location. This process is repeated for each of the derrick barge's anchors.

3.3.5 Removing Equipment and Deck

Each piece of equipment that is on the top deck of the platform and needs to be removed due to weight shedding requirements or interference with the main deck lift is removed and placed on a cargo barge. The equipment is secured by welding pieces of steel pipe (or plate) from the equipment to the deck of the cargo barge.

The deck is then removed by cutting the welded connections between the piles and the deck legs with oxygen-acetylene torches. Depending on the size of the deck, it may be cut into sections for removal. Slings are attached to the deck lifting eyes and to the derrick barge crane. The derrick barge's crane lifts the deck (or deck sections) from the piles. The platform deck is then seated in the load spreaders and secured by welding steel pipe from the platform's deck legs to the deck of the cargo barge.

Figure 3.2 | Setting Deck on Cargo Barge

3.3.6 Severing Piles

Structures are completely removed to a minimum of 15 feet below the mudline using an abrasive cutting tool. A jetting process is necessary to clear the mud plug inside the caisson or jacket pile to allow the abrasive equipment to be placed inside the jacket leg, fifteen to twenty feet below the mudline. Once clear, the vessel crane inserts the abrasive cutting tool into caisson or pile interior, where a high pressure stream of slurry penetrates and cuts the pile.

3.3.7 Setting the Jacket on Cargo Barge

After severing the main piles, the jacket is lifted, set, and secured onto cargo barges. The cargo barge transporting the jacket travels to an onshore disposal yard. Skid rails and winches are rigged up, and the jacket is skidded off the barge into the yard. The jacket is cut into small pieces and disposed of as scrap.

3.3.8 Clearing the Site

After a platform is removed, the area is cleared of debris by using specially equipped trawlers with nets, commonly called "Gorilla Nets". The trawlers remove all debris from around the platform site and send the debris to shore for disposal. Trawling is required for platforms located in less than or equal to 300 feet of water depth (Figure 3.5). Platforms that are located in water depths greater than 300 feet are required to have sonar images taken. Figure 3.6 is an example of a sonar shot. Each sonar photo only has a maximum radius of 300 feet; therefore, multiple sonar shots will be required to be taken. The average duration for one sonar shot with an ROV is 1 hour. After all of the required sonar shots have been taken, the survey contractor will create a mosaic by combining all of the shots. Figure 3.7 is a sample mosaic of a sonar image. If there is any debris remaining on the seafloor, then an ROV will be sent down to recover the debris.

Figure 3.3 | Trawling Grid

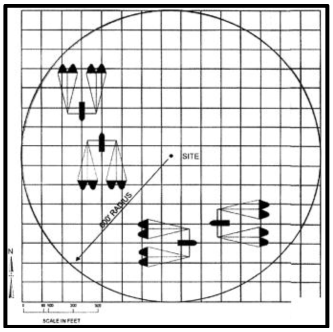


Figure 3.4 | Sonar Image

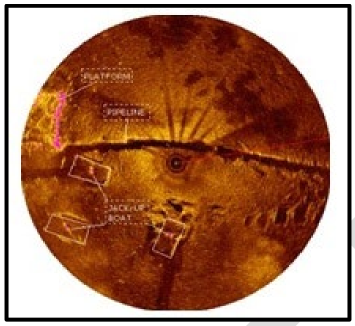
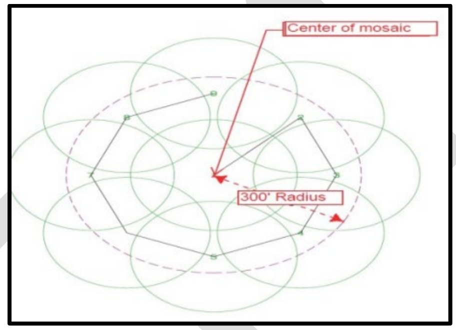


Figure 3.5 | Sonar Mosaic



4 ONSHORE DECOMMISSIONING METHODOLOGY

4.1 SURVEYS AND PLANNING

Prior to decommissioning activities, the following survey and planning activities are conducted:

1. **Building and site survey**: Buildings, equipment packages, and process piping are examined and different characteristics of buildings, such as the materials, building usage, method of construction, condition, and draining conditions are noted. This information helps dictate the best demolition/dismantle method.
2. **Demolition/dismantle plan**: A detailed plan will be created, illustrating what will be involved in the demolition, how it will be carried out, the equipment that will be used, and how much debris they will need to clean up. Most materials will be scrapped at a landfill, but some equipment may be preserved and sold for reuse.
3. **Health, safety, and environmental survey:** Site workers, supervisors, operators, and engineers are advised of potential hazards such as flammable materials and exposure to noise and dust. The demolition company must also secure the proper permits.

Once the area is surveyed and a demolition/dismantle plan is laid out, equipment and process piping can be prepared for decommissioning. Flowlines and piping are flushed through filtration equipment with 250% of the line volume using low flow, high pressure triplex pumps that are fed with centrifugal pumps. The product is treated through a series of carbon filters and the hydrocarbons are captured in tanks.

4.2 BUILDING DEMOLITION

For smaller buildings offices, an excavator is often used to dismantle the structure. However, buildings made of masonry, concrete and steel will require a larger machine like a high reach excavator. High reach demolition is considered a cleaner, safer way to dismantle structures, as it causes less flying debris, dust, noise, and risk to the operator.

The building itself is demolished mainly from the attachments affixed to the excavator. The most common are shears, crushers, and hydraulic hammers. The tool-equipped arm pulls down and breaks the structure from the top down. Special ground crews then use hammers, sledgehammers, and crushers to reduce the pieces to rubble.

Once the building is torn down, any supporting foundation is demolished with hammers and crushers.

The following figures depict demolition using excavators and foundation demolition with excavators and hydraulic hammers.

Figure 4.1 | Building Demolition

Figure 4.2 | Foundation Demolition

4.3 STATIC EQUIPMENT DECOMMISSIONING

Static equipment is typically removed in one piece using a crane or hoist. They are disconnected from the inlet and outlet piping and lifted onto a truck trailer to be sent to a disposal site. The general steps to decommissioning static equipment are:

1. **Prepare for removal.** Interferences within the work area, such as grating, piping, and other components are removed to create sufficient laydown space for removal of the equipment.

2. **Disconnect inlet and outlet lines.** Flanged connections are unbolted. Depending on the size of the lines, hydraulic shears, diamond wire, or torch-cutting methods may be used to section the piping. The inlet and outlet lines and other openings are then capped to prevent fluid or debris from entering.

3. **Rigging and removal.** The equipment is unbolted from its mounts. Any welded connections are also cut. The equipment is rigged to the crane or hoist and maneuvered into the open area where it is lowered onto a dolly or trailer. The equipment is placed onto a multi-wheeled vehicle for transport to disposal.

4. **Area clean-up.** Process equipment is typically laid on concrete blocks, which must be excavated from the soil and subsequently removed. Any supporting structure or foundation are demolished and removed.

The size weight, and equipment location ultimately determines the exact removal strategy. For example, larger equipment, such as turbines or compressors, might first be dismantled using conventional maintenance procedures. Inner components, such as rotors and shafts, may be removed to a laydown area to reduce the overall weight for crane or hoist operations. As previously described, the material is then prepared for transportation to an off-site recycling facility.

Figure 4.3 | Static Equipment Decommissioning

4.4 ABOVE-GROUND PIPELINE DECOMMISSIONING

Above-ground piping, such as those contained in process facilities and field pipelines, are dismantled by first cutting into sections. Depending on the size of the piping, hydraulic shears, diamond wire, or torch-cutting methods may be used to section the piping. Any supporting piping racks, concrete blocks, and foundation are also demolished.

The figure below depicts pipe sectioning with hydraulic shears.

Figure 4.4 | Pipe Sectioning

4.5 BELOW-GROUND PIPELINE DECOMMISSIONING

Buried pipelines, except those contained within facility grounds, are to be abandoned in place. These pipelines include the field pipelines and export pipelines.

Pipelines that are buried within facility grounds and deemed necessary for removal must first be excavated before they can be sectioned. Workers will dig along the length of pipeline, being mindful to not damage other lines that are to remain in place. Once a sufficient length of pipeline is exposed, the pipeline can be lifted through the soil and sectioned.

In some cases, such as when a pipeline passes under roads or obstructions, the pipeline may be cut on either side of the obstruction and grouted with cement. The normal process of excavating and sectioning pipe is continued on the other side.

The figure below depicts pipeline excavation in preparation of a pipeline removal.

Figure 4.5 | Pipeline Excavation

4.6 REMOVAL / DISPOSAL OF MATERIAL

Once buildings are demolished and piping is cut into sections, the site can be cleared of rubble and debris. Dump trucks are loaded with cranes and excavators, where they transport the rubble to landfills or scrap yards. Multiple trucks are often used to maximize productivity of the loading crew.

The figure below depicts the loading of a dump truck in preparation of transport to a landfill.

Figure 4.6 | Removal of Rubble Material

For the purpose of this study, it is assumed all debris, including vessels, piping, equipment and skids, steel and steel buildings, will be cut up, loaded into 20' shipping containers and transported to a nearby landfill.

4.7 SITE CLEARANCE AND REMEDIATION

Once the area is cleared of buildings and equipment and the soil is leveled, workers will perform a final sweep of the area to ensure the area is clear of debris and demolition waste. Dump trucks will backfill soil to the area to level the soil to its natural local conditions.

Finally, the area is hydroseeded to restore the natural vegetation of the facility site.

5 DECOMMISSIONING ESTIMATE RESULTS

The decommissioning estimate results are summarized in the following tables:

Table 5.1 | Platform Emmy and Highlands Cost

	Activity	Well P&A	Platform	Pipeline and Subsea	Onshore Facilities
Platform Emmy	Well P&A Mobilizations	$ 1,200,000			
	Well P&A Work	$ 33,700,000			
	Conductor Removal*	$ 3,800,000			
	Platform Mobilizations**		$ -		
	Platform Preparation		$ 5,400,000		
	Topsides Removal		$ 14,500,000		
	Jacket Removal		$ 4,800,000		
	Site Clearance		$ 1,500,000		
	Pipeline Mobilizations			$ 400,000	
	Pipeline Decommissioning			$ 1,000,000	
	Disposal of Material			$ 5,600,000	
	Highlands Facility				$ 35,000,000
	Misc. (Permitting, Regulatory, etc.)	$ 800,000	$ 500,000	$ 100,000	$ 700,000
	SUBTOTALS	$ 39,500,000	$ 26,700,000	$ 7,100,000	$ 35,700,000
	TOTAL	$109,000,000			

Table 5.2 | Platform Esther Cost

	Activity	Well P&A	Platform	Pipeline and Subsea	Onshore Facilities
Platform Esther	Well P&A Mobilizations	$ 1,200,000			
	Well P&A Work	$ 26,900,000			
	Conductor Removal*	$ 5,600,000			
	Platform Mobilizations**		$ -		
	Platform Preparation		$ 6,500,000		
	Topsides Removal		$ 17,500,000		
	Jacket Removal		$ 7,600,000		
	Site Clearance		$ 4,400,000		
	Pipeline Mobilizations			$ 600,000	
	Pipeline Decommissioning			$ 1,100,000	
	Disposal of Material		$ 7,000,000		
	Misc. (Permitting, Regulatory, etc.)	$ 700,000	$ 900,000	$ -	
	SUBTOTALS	$ 34,400,000	$ 43,900,000	$ 1,700,000	$ -
	TOTAL	$80,000,000			

Table 5.3 | Platform Eva and Fort Apache Cost

	Activity	Well P&A	Platform	Pipeline and Subsea	Onshore Facilities
Platform Eva	Well P&A Mobilizations	$ 1,200,000			
	Well P&A Work	$ 34,300,000			
	Conductor Removal*	$ 3,900,000			
	Platform Mobilizations**		$ -		
	Platform Preparation		$ 3,500,000		
	Topsides Removal		$ 15,900,000		
	Jacket Removal		$ 7,600,000		
	Site Clearance		$ 2,600,000		
	Pipeline Mobilizations			$ 400,000	
	Pipeline Decommissioning			$ 2,000,000	
	Onshore Facilities Decommissioning				$ 1,200,000
	Disposal of Material		$ 5,200,000		
	Misc. (Permitting, Regulatory, etc.)	$ 800,000	$ 700,000	$ -	$ -
SUBTOTALS		$ 40,200,000	$ 35,500,000	$ 2,400,000	$ 1,200,000
TOTAL		$79,300,000			

Table 5.4 | Onshore Well P&A Cost

	Wells to P&A	Base Cost	Engineering/PM	Work Contingency	Total Cost
Huntington Beach	270	$ 75,100,000	$ 6,000,000	$ 7,500,000	**$ 88,600,000**
Belmont	36	$ 10,100,000	$ 800,000	$ 1,000,000	**$ 11,900,000**
West Montalvo	21	$ 5,900,000	$ 500,000	$ 600,000	**$ 7,000,000**

APPENDIX 4
ZEROSIX MAY 2023 PRODUCTION RESERVES CARBON OFFSET PROTOCOL

ZERØSIX

Production Reserves Carbon Offset Protocol

Methodology for the generation of carbon credit offsets from the avoided GHG emissions of oil and gas proved developed reserves

15 May 2023

ZeroSix // v.1.0

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In November 2022 at COP27, world leaders stressed that this decade is pivotal for climate action – the imperative is to ensure global warming remains below 1.5ºC. Achieving a net-zero future by 2050, will require swift and committed action.

Climate specialists estimate that there are no more than 500 billion metric tons of CO_2e emissions remaining in Earth's carbon budget. Known fossil fuel reserves, the quantity of economically and technically producible hydrocarbons, total 2,900 billion tons if combusted unabated.[1] That's ~7x greater than the carbon budget, according to the Global Registry of Fossil Fuels.

In the near future, the most recent UNEP-led, collaborative Production Gap Report found that fossil fuel production is on track to be double what's needed for a 1.5ºC pathway by 2030. Climate scientists have concluded that some 60% of the world's oil and gas reserves and 90% of coal reserves must remain permanently in the ground — unextracted, unrefined, uncombusted.[2]

There are a variety of ways the world could reduce fossil fuel emissions and keep reserves in the ground, ranging from regulatory and policy interventions to market-based mechanisms. At ZeroSix, our focus is on tapping into buy-side demand in the voluntary carbon market (VCM), creating a financial incentive for oil and gas producers to retire wells early, permanently shut in the associated reserves, and convert the abandoned fossil reserves into high-quality carbon credits instead.

The ZeroSix protocol described in this technical document incorporates well-established standards and processes in the oil and gas industry (including building upon a foundation of stringent regulations from the U.S. SEC and other agencies). The protocol expands upon that foundation with further enhancements that strengthen the accuracy, additionality, and permanence claims associated with the carbon credits — all via an approach that also provides needed transparency and verifiability for VCM participants.

1. Purpose and Definition

1.1. The Protocol

The purpose of the Production Reserves Carbon Offset Protocol (protocol) is to:

- describe the process for determining the eligibility of proposed offset projects;
- quantify the amount of carbon emissions avoided;
- detail the validation needs of submitted data;
- describe the monitoring requirements of projects;
- outline the process of project execution; and,
- describe the verification requirements to generate carbon credits.

Projects must satisfy the criteria outlined by this protocol in order to qualify for credits from abated emissions associated with producible oil and gas volumes from existing operations. These volumes include any existing production that targets hydrocarbon reserves which would otherwise remain sequestered in the subsurface. The protocol outlines standards for execution and the monitoring of project operations to guarantee avoidance of forecast emissions.

This document is supported by industry technical documentation and standards referred to throughout the text and referenced in the following section 1.2.

1.2. Supporting Standards

This protocol is written to align with the latest standards and best practices regulating the relevant elements of the abatement project execution. The reserve volume calculations follow the long-established standards set forth by the United States Securities and Exchange Commission (SEC) Final Rule regulations for publicly traded oil and gas companies.[3,4,5]

The permanence requirements are tied to the current regulations of carbon sequestration, primarily the California Air Resource Board's (CARB) Carbon Capture and Storage (CCS) protocol for claiming compliant credits and the United States Environmental Protection Agency (EPA) Class VI permit requirements.[6,7]

The execution of plugging and abandonment of oil and gas wells is strictly controlled and certified by the respective state oil and gas regulatory agencies. The projects applying for abatement credits through this protocol must receive the appropriate permits and sign offs from these agencies in order to qualify for issuance. An example of state guidance for P&A can be found in section 1723 of the California Geologic Energy Management (CalGEM) Statutes and Regulations January 2022.[8] A similar regulatory permitting and verification process exists for land reclamation activities, following the permanent retirement of a production site.

The standards for execution of a project for carbon credit offset using this protocol align with the American Carbon Registry, Verra, and other existing registry standards, see Figure 1 below for a visualization of alignment. As the international community works to standardize the voluntary carbon market — per Article 6 of the Paris Agreement and further expounded upon at COP26 — this protocol will evolve to comply with relevant standards. This commitment to compliance will ensure the highest level of transparency and credibility of projects and tokens generated through the ZeroSix system.

The fundamental standards inherent in the ZeroSix design are the Core Carbon Principles (CCP), put forward by the Integrity Council for the Voluntary Carbon Market, and the guidance provided by the Voluntary Carbon Markets Integrity Initiative. The protocol is also designed to align with the International Carbon Reduction & Offset Alliance (ICROA) and will seek to become an accredited organization under these standards.

The Core Carbon Principles, developed with input from hundreds of organizations in the voluntary carbon market and launched in March 2023, set out fundamental principles for high-quality credits that create real, verifiable climate impact, based on the latest science and best practice.[9]

The 10 Core Carbon Principles are as follows:

1. Effective governance
2. Tracking
3. Transparency
4. Robust independent third-party validation and verification
5. Additionality
6. Permanence
7. Robust quantification of emission reductions and removals
8. No double counting
9. Sustainable development benefits and safeguards
10. Contribution toward net zero transition

The ZeroSix self-assessed alignment with these principles is shown in Figure 1.

	Project Eligibility Criteria	Project Boundary	Permanence			Project Execution Specifications	Carbon Offset Ownership Guidance	Additionality		Monitoring		Transparency				Quantification		Sustainable Development Goals	Contribute to Net Zero Transition
			Carbon Lockup	Legal Protection	Buffer Account			Tests	Intrinsic	Project Execution	Post-Execution	Independent 3rd Party Verification	Public Project Documentation	Immutable Tracking	Double Counting Protections	Robust Methodology	Uncertainity Evaluation		
ZeroSix Compliance	✓	✓ EPA Class VI	✓ EPA Class VI	✓ Legal Contract	✓ CARB	✓ State O&G Regulator	✓ Legal Contract	✓	✓ SEC	✓ State O&G Regulator	✓ State O&G Regulator	✓ State Licensing	✓ Immutable Blockchain	✓ Immutable Blockchain	✓ Immutable Blockchain	✓ SEC	✓ SEC	✓ UN SDG	✓
ICVCM Core Carbon Principle	✓	✓	6.	6.	✓ 6.	✓	✓	✓ 5.	5.	✓ 4.	✓ 6.	✓ 4.	✓ 3.	2.	✓ 8.	✓ 7.	✓ 7.	✓ 9.	✓ 10.
CARB LCFS	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓		✓	✓	✓		✓
ACR	✓	✓			✓	✓	✓	✓		✓	✓	✓			✓	✓	✓		✓

Figure 1: Protocol compliance against other standards.

1.3. Blockchain Implementation

This protocol is implemented using a blockchain-based decentralized application. A blockchain is a digital, immutable, and tamper-proof record of events ("ledger") replicated over multiple machines ("nodes") that uses a specific algorithm ("consensus algorithm") to update all records in a secure way.

This web-based tool utilizes smart contracts, which "are simple programs stored on a blockchain that run immutably and tamper-proof when predetermined conditions are met. They typically are used to automate the execution of an agreement so that all participants can be immediately certain of the outcome, without any intermediary's involvement or time loss. They can also automate a workflow, triggering the next action when conditions are met."[10] Executing the terms of the protocol in this way automates the actions that have historically been performed by the registries in a way that is immutable and tamper-proof; in other words, using the ZeroSix web-based tool ensures all steps are followed as intended with all proofs and digital signatures stored in a similar immutable and tamper-proof fashion. This removes the need for an intermediary to verify the status and validity of every carbon credit. This implementation allows for full transparency and consistent application of the protocol standards across all projects and removes a serious bottleneck in the global emission abatement initiative by improving on the conventional registry validation and verification process.[11]

For each project applying this protocol, the project owner and verifier will be required to upload supporting documentation. The document requirements have been established to vouchsafe the additionality and permanence characteristics of every project. All project files are stored immutably and tamper-proof on the InterPlanetary File System (IPFS), which is a distributed file storage system, thus guaranteeing public access to all documents for universal auditing and verification of the integrity of the associated carbon credits.

As an output of the decentralized digitalized protocol a digital token (ERC-1155) will be minted. This token has a fungible and non-fungible part which includes project and well specific information, such as the source well location, key dates, and a reference to the verification documentation.

1.4. Definitions

For purposes of this protocol, the following acronyms apply:

ADR – Abandonment, decommissioning, and reclamation
API – American Petroleum Institute
bbl - barrel
BLM – United States Bureau of Land Management
CARB – California Air Resources Board
CBM – Coalbed methane
CCP - ICVCM Core Carbon Principles
CCS - Carbon Capture and Sequestration
CiO – Gas consumed in operations
CO_2 - Carbon dioxide
CO_2e - Carbon dioxide equivalent
COGCC - Colorado Oil and Gas Conservation Commission
COP - Conference of Parties of the UNFCCC
DCA - Decline Curve Analysis
EDF Environmental Defence Fund
EPA – United States Environmental Protection Agency
EOR – Enhanced oil recovery
GHG – Greenhouse gas
GHV - Gas heating value
Gt - Metric gigaton
GWP - Global Warming Potential
ICROA - International Carbon Reduction & Offset Alliance
ICVCM - The Integrity Council for the Voluntary Carbon Market
IPCC – Intergovernmental Panel on Climate Change
IPFS - InterPlanetary File System
JOA - Joint Operating Agreement
LOE - Lease and operating expense
MMBtu – Million British Thermal Units
Mscf – Thousand of standard cubic feet
NGL – Natural gas liquids

NRI – Net royalty interest
P&A – Plug and abandon
PDNP - Proved Developed non-Producing
PDP - Proved Developed Producing
PIIP – Petroleum initially in place
SCADA – Supervisory control and data acquisition
SDG – United Nations Sustainable Development Goals
SEC – United States Securities and Exchange Commission
t – Metric ton
UNFCCC - United Nations Framework Convention on Climate Change
VVB - Validation and Verification Body
WI – Working interest

2. Eligibility

2.1. Types of Activities

This protocol applies to oil and gas production offset projects preventing the conversion of in-situ reserves into marketable commodities. This is achieved by executing the permanent abandonment of wellbores. The controlled mineral rights are then dedicated to protected non-recoverable resources through a legally binding declaration of restrictive covenants signed by the mineral owners, or an equally binding legal agreement. These actions prevent the future extraction of the designated resources, which are to be claimed for carbon credits.

2.2. Minimum Requirements

To be considered eligible under this protocol, a project owner must be able to:

1. Demonstrate that a conversion of project resources to a marketed commodity is imminent beyond a reasonable doubt by following the requirements establishing the project's economic reserves.
2. Verify — according to the standards of this protocol — the quality of the information submitted for the quantification of the project reserves.
3. Provide proof of resource ownership, mutual consent of royalty owners, or an equally robust mechanism for establishing a legal barrier to future extraction of hydrocarbons.
4. Demonstrate that participation in the ZeroSix project can be achieved while adhering to all relevant regulatory requirements.
5. Establish and verify the additionality of claimed carbon volumes by showing a clear baseline of business-as-usual production forecast.
6. Provide suitable justification for permanence of retired reserves. This is achieved by providing relevant geological, petrophysical, and fluid property analyses, in support of a post-execution monitoring program. Submission of regular reports over the course of the monitoring period of the project as designated by this protocol is envisaged.

Projects that adhere to these requirements are eligible for participation in the ZeroSix methodology.

2.3. Project Area

The current ZeroSix methodology is based on the United States' regulatory standards governing the execution of projects related to extraction activities, data reporting requirements for oil and gas producers, and standards used by the U.S. EPA for permitting Class VI Carbon Dioxide Injection projects.[7] The Class VI injection regulation is used as an analogue for documentary requirements used to establish subsurface permanence of mobile fluids. The project filings, validation and verification documents, regulatory compliance, and mineral rights unitization will be specific to each jurisdiction.

The project area is the region surrounding the geologically defined reservoir from which reserves are being produced. The project area is delineated using computational modeling or other best engineering practices that account for the physical and chemical properties of all phases of the produced fluids; and is based on available reservoir characterization, monitoring, and operational data. Specific project area boundaries are defined by the location of project wellbores and associated subsurface connected drainage volumes. Operations within and peripheral to this boundary will determine the permanence of the claimed emission volumes.

The project area:

1. Must be finalized by the conclusion of the full verification of project execution.
2. Must be consistent with the royalty ownership schedules of the project, and with the Declaration of Restrictive Covenants or the equally binding mechanism for establishing a legal barrier to future extraction of hydrocarbons.
3. All resources in the target reservoir must be converted to non-producible mineral resources as defined by this protocol.
4. Boundaries must be congruent with the specific subsurface connectivity structure according to the type of development, with the purpose of preventing resource migration outside the project area.
5. Must be determined according to best engineering practices for reservoir boundary definition.
6. Must be contiguous and fully inclusive of subsurface communication extent on a depletion time scale.
7. May not include mineral resources already designated as non-producible or off limits.

The project owner performs the following actions to delineate the project area and identify all wells that may require corrective action[7]:

1. Predict, using existing site characterization, monitoring, operational data, and/or computational modeling, the lateral and vertical connectivity of the formation fluids in the target reservoir. The evaluation must:
   a. Be based on detailed geologic data collected to characterize the retired production zone(s), confining zone(s), and any additional relevant zones.
   b. Account for any geologic heterogeneities, other discontinuities, data quality, and their possible impact on boundary predictions.
   c. Consider potential migration through faults, fractures, and artificial penetrations.
2. Identify all penetrations, including active and abandoned wells and underground mines, in the project area that may penetrate the reservoir(s).
3. Determine if any abandoned wells in the project area may have been plugged in a manner that might enable leakage of hydrocarbons.
4. Project owners must perform corrective action on all wells within the project area that are determined to be in need of corrective action using methods designed to prevent the movement of fluid out of the retired reservoir.

2.4. Stakeholder Obligations

Prior to project execution, the project owner must submit the working interest (WI) and mineral owner schedule of all open wells in the proposed project area. In addition, signed Declarations of Restrictive Covenants or an equally binding document must be submitted by the operator, representing the consent of all mineral owners to forgo hydrocarbon extraction rights from the target reservoir. Exceptions can be accommodated for mineral owners with missing contact data or who cannot be located to give consent, in such cases the project owner must meet the minimum standard for coverage as specified by the relevant state pooling and unitization requirements. The project owner will be responsible for acquiring the consent of their non-operating partners according to the terms of the Joint Operating Agreement (JOA).

2.5. Regulatory Compliance

The operator/owner/originator of the project must be in good standing with the relevant national and state regulatory agencies and to provide proof of a current operating license. There must be no existing state and federal government mandates for prudent recovery of oil and gas assets, which might impede efforts to shut in economic reserves for carbon crediting purposes; or the operator must provide written consent to pursue the proposed abandonment activity. The government may be compensated through royalty ownership of public resources (e.g., BLM and Tribal lands).

2.6. Additionality

The additionality test is intended to ensure that carbon offsets are an addition to reductions and/or removals that would have occurred in the absence of the project activity and without carbon market incentives. To be considered "additional," the project must demonstrate that the GHG emissions reductions and removals associated with an offset project are above and beyond the "business as usual" scenario.

Relative to alternative carbon emission offset projects, the proposal for retiring existing and future reserves must satisfy these 3 criteria. A compliant project demonstrates that it exceeds the 1) Regulatory Test: the proposed activity exceeds currently effective regulations, 2) Common Practice Test; goes beyond common practices in the oil and gas industry sector in the geographic region of operations, and 3) Implementation Barrier Test; faces one or more implementation barriers.[13]

2.6.1. Regulatory Test

1. Emission reductions achieved by foregoing expected production volumes must exceed those required by any applicable federal, Tribal, state, or local laws; regulations; ordinances; consent decrees; legal arrangements; or other legally binding mandates.
2. The project operator must have an active and valid operating license in the jurisdiction of the proposed project.
3. Legally binding mandates may include, but are not limited to, existing moratoriums on production from project land leases or mineral rights.
4. The legal requirements are satisfied if:

    a. Project activities are not legally required at the time of offset project commencement.
    b. Modeling of the project's baseline carbon stocks reflects all legal constraints and regulatory guidelines as required by SEC reserves reporting guidelines.
    c. Avoided production projects submit official documentation demonstrating that the type of operation activity proposed by the project is legally permissible, through valid activity permits.

2.6.2. Common Practice Test

The project must demonstrably depart or exceed common practice. Retirement of remaining economic production and reserves is not common practice and, therefore, with the proof of economically viable production, projects submitted under this protocol are deemed to have passed the common practice test.

2.6.3. Implementation Barriers Test

The proposed carbon offset project must fulfill at least one of three implementation barriers:

(a) Financial

Continued extraction of oil and gas volumes is deemed an economic venture, thus permanent retirement of these economic reserves faces strong financial barriers without the compensation through carbon credits or other means. The economic viability of targeted reserves is established through SEC reserves reporting standards, which must be adhered to in the quantification of carbon emission avoidance in this protocol (see Chapter 3).

(b) Technological

There are no new technological barriers to implementing the ZeroSix solution, which bolsters the case for broad industry implementation and rapid adoption. However, the value of the innovative ZeroSix blockchain enabled platform for the purpose of creating transparency and auditability of carbon emission abatement quantification and execution, is a new concept for the oil and gas sector. There is currently limited market penetration for this technology, but its relevance is the material reduction of GHG emissions.

(c) Institutional

Institutional barriers exist in the novelty of this approach and buy-in from regulators, mineral owners, and non-operating partners must be secured. Compensation through carbon credit values provides a strong incentive for project non-originating royalty owners to support the abandonment of productive reserves, rather than selling them for the purposes of refining and combustion, resulting in an ever-increasing global carbon debt.

2.7. Permanence

Projects must demonstrate permanence of avoided carbon emissions. The project owner/operator must submit a descriptive report prepared by a recognized professional organization that includes a compilation of project data (wireline logs, well tests, and structural/stratigraphic maps). In addition to the geologic permanence assessment, the project owner will need to secure legally binding contractual or legal protections against the future production of the retired resources. These protections, in addition to the digital platform mechanics, will provide assurance of:

1. Geologic Permanence: Through determination of target P&A candidate well drainage area calculations through geology, pressure transient analysis, reservoir modeling, material balance, or well interference case studies, and justification for the associated reserves remaining unproduced upon execution of the project.
2. Legal Permanence: Through proof of contractual amendment of ownership with permanent retirement of mineral extraction rights, through executed Declarations of Restrictive Covenants or equally binding legal protection against future extraction.
3. Operational Permanence: Through ongoing post-execution automated monitoring by the ZeroSix platform of state regulators for any new development permits being issued in proximity of project area.
4. Long Term Validity of Issued Credits: Through contribution to the ZeroSix buffer account funded through credit withholding to offset any detected reversals of reserve volumes claimed for the project credits.

The case for geologic permanence must be made from a technical perspective and will vary based on the type of resource operation of the submitted project. There are several broad cases of hydrocarbon extraction that are distinct in the properties of fluids, subsurface conditions, and/or development mechanics, which justify different approaches in determining permanence.

2.7.1. Conventional Resources

Conventional resources exist in porous and permeable rock under pressure equilibrium. The PIIP is trapped in discrete accumulations defined by a local geological structure, feature, and/or stratigraphic conditions. Each conventional accumulation is typically bounded by a down dip water contact, as its position is typically controlled by buoyancy of oil in water. The oil/gas is recovered through wellbores and typically requires minimal processing before transportation to market. The technical behavior of these systems is constrained with reasonable certainty and permanence can be achieved through the simultaneous abandonment of all wellbores produced from a discrete accumulation.

2.7.2. Unconventional Resources

Unconventional resources exist as petroleum accumulations that usually have a significant regional extent. They are not significantly affected by hydrodynamic influences (also referred to as a "continuous-type deposit"). Commonly, these accumulations are not defined structurally. Examples include coalbed methane (CBM), basin-centered gas (low permeability), tight gas and tight oil (low permeability), gas hydrates, natural bitumen (very high viscosity oil), and oil shale (kerogen) deposits. Note that shale gas/oil are subtypes of tight gas/oil, where the lithologies are predominantly shales or siltstones. These accumulations lack the primary connected permeability of conventional reservoirs and require subsurface stimulation to achieve economic viability.

Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, hydraulic fracturing stimulation for tight gas and tight oil, steam and/or solvents to mobilize natural bitumen for in-situ recovery, and in some cases, surface mining of oil sands). Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders). The establishment of permanence of unconventional resources will vary based on the subsurface flow and extraction mechanisms involved.

Coalbed methane (CBM) – CBM gas is generated within coal seams and gas is stored via adsorption, meaning it is tied to the coal at a chemical level and does not flow freely. There are natural fracture networks in the coal formations called cleats, which may contain free gas, but may also contain water. The development of these resources generally involves induced fracking.

This type of production is exemplified by an early period of high-water production as the coal formation dewaters, and the gas rate increases, ultimately stabilizing once the dewatering of the stimulated formation and fracture network is complete. The gas rates are characterized by a shallow rate decline for extended periods of production. Reserves are extracted at a slow and steady pace of gas desorption from each producing well's fracture network in the target coal bed. It is this fracture network which conveys liberated gas molecules to the wellbore and subsequently to the surface.

The range of reserves' extraction is controlled by the extent of the fracture network and the disequilibrium between conditions in the fracture versus the coalbed. This disequilibrium can be influenced by a variety of factors including pressure differentials, partial pressures of gasses from concentration differences, and the percentage of water content. To establish permanence, it must be demonstrated that the target fracture network is not connected to and being produced by any offset fracture networks from nearby wells. This can be done via fluid property analysis, pressure tests in offset wells designed to determine wellbore interference to provide additional support for permanence models.

Basin-centered Gas, Tight Gas, and Tight Oil (e.g., Shale) – These resources exist in low permeability deposits and are extracted through stimulation by hydraulic fracturing. To establish permanence for induced fracture flow pathways, no pressure communication must exist with adjacent wellbores producing from the same target formation. This determination may be assessed regionally showing the largest distance of observed pressure communication between offset production wells. Only volumes outside this determined radius can be classified as permanent carbon emission avoidance.

Natural Bitumen (very high viscosity oil) and Oil Shale (kerogen) – Bitumen or heavy oil does not migrate without additional subsurface treatment, such as steam flooding to reduce viscosity and increase mobility; large volume water flooding; or through mechanical mining. Due to the fluid properties of this resource, permanence can be assured by discontinuing the enhanced recovery extraction activities (e.g., steam flooding or mining).

2.7.3. Technical Documentation

The following permanence guidelines are not exhaustive but will inform operators how to generate a credible permanence case for specific projects based on the technical details of production. The case for permanence must be documented in a comprehensive report, which will include the relevant information and data necessary to verify the credibility of the permanence of the credited reserves. The analogue of the EPA Class VI carbon dioxide injection permit requirements is used in the drafting of these requirements.[7] As the requirements for establishing permanence for an active injection plume at high pressures are significantly greater than establishing permanence for a static reservoir generally under low pressures, only requirements necessary to establish static permanence are used for validation of reserve retirement.

The submitted permanence report will include information on the geologic structure, hydrogeologic properties of the project reservoir, and past interventions through development. The report should also include a brief synopsis of the geologic history of the project site, and include the names, lithologies, and depths of the abandoned formation(s) and confining zone(s). The comprehensive exhibits must consist of the following:

1. The location, orientation, and properties of known or suspected faults and fractures that may act as reservoir boundaries or transect the confining zone(s) in the project area and a determination that they would not facilitate fluid migration;
2. Data on the depth, areal extent, thickness, including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;
3. Information on the seismicity history, including the presence and depth of seismic focal depths and a determination that the seismicity would not interfere with an at minimum 50-year containment; and
4. Geologic data, including surface/depth-structure maps and cross-sections illustrating regional geology, hydrogeology, and the geologic structure of the local area showing the presence and trends of folds, and whether the proposed storage site will be bounded by faults or other compartment features.

(a) Map

A map of the project area showing the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, state- or EPA-approved subsurface clean-up sites, and deep subsurface mines. The map should also show faults, if known or suspected.[7]

1. Geological base-map (including geodetic projection parameters) that details the following:
    a. Lease boundaries.
    b. Project boundaries.
    c. Locations of all wells within project boundaries (XY or Lat/long format).
    d. If wells are horizontal or deviated, show lateral trajectory.
    e. Legend that designates status of all wells.
        i. Producing from project formation.
        ii. Producing from different formation.
        iii. Shut in and completed in project formation.
        iv. Shut in and completed in other formation.
        v. Plugged and abandoned.
        vi. Other wellbores penetrating project reservoir – but not P&A'd.
    f. Major (sealing) and minor (non-sealing) faults designated accordingly, transmissibility barriers and stratigraphic discontinuities.
        i. Above features that control project boundaries should be designated as such.
2. Isopach (thickness) map of the project formation with the same information listed above.
    a. Limits of isopach maps (pay termination) that define project boundaries should be marked as such.

(b) History Matching and Dynamic Data

Analysis of historical production and pressure data from the project formation showing any communication through faults, other adjacent formations, or with wells outside the project boundaries. Demonstrate and place into context for the dominant reservoir drive mechanism if such could either threaten the permanence of the sequestered reserves or could augment the case for permanence.

(c) Project Area Wellbore Inventory

A tabulation of all wells within the project area which penetrate the target reservoir(s). Such data must include a description of each well type, construction, date drilled, location, total depth, and record of plugging and/ or completion.

(d) Cross Sections

A combined structural/stratigraphic well-log cross section from as many wellbores as necessary to provide a representative illustration of structural trends relevant to the target reservoir. All wells should highlight the completed interval(s), designating the status of those completion intervals, e.g., open to production, shut-in, isolated, or plugged. The representative cross-sections should also show sealing faults that highlight pressure isolation.

(e) Wellbore Schematics

Wellbore schematics showing completion intervals of all wells, history of all mechanical events (workovers, recompletions, fish in hole, etc.), all perforations and status of perforations (e.g., open to production, shut-in, isolated, or plugged), and a schematic of proposed abandoned condition of wells in the project.

(f) Other Pertinent Information

Present any other tests, such as cement bond logs, interference tests, fluid analysis, well production tests, water salinity, tracer surveys, drainage radius calculations, material balance calculations, numerical simulation modeling, etc., that are pertinent to the establishment of the project as an isolated formation and area.

(g) Minimum Information Criteria

1. All analyses and tests to support the demonstration of permanence must be accurate, reproducible, and performed in accordance with established industry quality assurance standards.
2. Estimation techniques must be appropriate for each specific project operating environment as designated by industry best practices and EPA-certified test protocols must be used where available.
3. Any models must be appropriate for the specific project operation and tailored to the site conditions and fluid compositions.
4. Predictive models must be calibrated using existing information where sufficient data are available.
5. Probabilistic values and modeling assumptions must be used and disclosed whenever values are estimated based on known, historical information instead of site-specific measurements.

2.8. Abatement Period

Justification for the permanence of plugged and abandoned oil and gas reserves is that reserves remain indefinitely contained in their reservoir. Prior to containment, hydrocarbons either migrated from the source rock or, in the case of shale gas and oil, the reserves were generated in-situ. For the reserves to be exploited, significant investment must be committed to liberate the volumes. Should development of these reserves be halted, and the reservoir returned to its natural state (by effective P&A activity), the volumes will remain indefinitely contained.

The declaration of restrictive covenants with mineral owners (or an equally binding arrangement) will waive hydrocarbon extraction rights from project reservoirs for a minimum duration of 50 years or establish a reasonable expectation of a legal barrier to reserves extraction for the same duration. The stipulation does not preclude the mineral owner or operator from pursuing alternate uses of the reservoir pore space, such as carbon sequestration or geothermal energy development.

2.9. Buffer Account

The ZeroSix platform utilizes a buffer account to offset any unforeseen abatement reversal volumes to maintain the integrity of issued credits. Due to the engineered nature of this protocol and the slow rate of reserve extraction under business as usual, the amount withheld from the issued carbon credits has been set at 1%. This withholding has been deemed sufficient upon a thorough risk assessment across the full scope of projects that would be eligible to claim credits under this protocol.

The spectrum of risks considered here include:

1. Mineral ownership dispensation and potential impact on legally binding permanence.
2. Surface rights ownership dispensation and potential impact on legally binding permanence.
3. Technical risk of ongoing hydrocarbon leakage around surface wellhead post P&A.
4. Technical risk of claimed subsurface reserves being produced through offset wells.
5. Risk of current or future regulatory mandates for development and production of claimed hydrocarbon reserves.
6. Significant divergence in price of carbon credits and commodities price incentivizing future re-development of claimed reserves.
7. Potential for reservoir seal failure due to natural or artificial seismically induced activity through new fault creation or existing fault reactivation.

These are evaluated and quantified in relation to the potential impact on claimed carbon emission abatement reversals according to the standards set forth by the California Air Resource Board (CARB) and the carbon crediting industry best practices across existing registries. The scope of risks was informed by the current view of actuarial science on the insurability of carbon markets.[14]

2.10. Leakage

The risk of leakage for this protocol is the idea that shutting in producing wells and retiring the associated reserves will only result in production coming online outside of the project boundary to make up for the reduction in production. ZeroSix believes that demand side policies of the Paris Climate accord alone will result in leakage of emissions. This is due to the market mechanisms of supply and demand, and the resulting price distortions, which are taken advantage of by free-loader countries not participating in the agreement or not abiding by the emission reduction targets.

Multiple studies have demonstrated this phenomenon. For example, if there is a reduction in the demand for fossil fuels in one country due to emission caps, without reducing the supply of fuel, the price of these commodities will go down. Due to the international nature of the fossil fuel market, free-loading countries will be able to acquire and use more of these commodities at the reduced price, thus having no impact on global emissions. The only way to negate this leakage effect is to reduce the supply of fossil fuels in proportion to the reduced demand, thus eliminating the price distortions which would incentivize increased consumption in free-loader non-participating countries.[15,16]

The ZeroSix protocol creates a supply side mechanism for addressing emissions, starting with the least productive and most polluting sources first. Operators will be able to decide which production should be retired through the market mechanisms, comparing the value of abated carbon emissions to continued production. Reducing the supply alongside demand will prevent geographic leakage of emissions from both supply and demand side initiatives in participating countries abiding by emission reduction goals.

It is a daunting fact that the currently booked global reserves of hydrocarbons have a stock equivalent to 2,900 Gt CO_2e emissions.[1] If all of these are brought to market as is the current implication based on standard accounting principles of company valuations, there is a very low probability of meeting the ~500 Gt CO_2e emissions budget, set by the IPCC for keeping temperature rise to within 1.5 deg C. The mechanism proposed in this protocol permanently reduces the stock of global hydrocarbon reserves. There is also a multiplier effect from crediting only proved developed reserves and requiring the legal mandate of extraction from the associated reservoir, because this also reduced the stock of undeveloped reserves that could have potentially been brought to market in the future, as well as any volumes that would have been technically recoverable. Thus, by giving credit for volumes imminently slated for the market, the global reserve stock is reduced by an order of magnitude greater (i.e., 1,000 bbl PDP reserves credited, additional 10,000 bbl Undeveloped, Probable, and Possible reserves also permanently retired).

Beyond the systemic macro disincentives for leakage proposed, there is also a strong case at the project level due to several intrinsic mechanisms of this protocol. By crediting only proved developed reserves, operators must decommission existing operations and the associated infrastructure. By creating a financial incentive structure where operators are compensated for the abatement of immanent emissions associated with their hydrocarbon production rather than the market value of their product, they will preferentially retire the least economic and efficient operations, which are also the most polluting.[17] This also means that in order to return these volumes back to production, a significant capital investment for re-development of not only new wells, but also all associated surface infrastructure would be required. This is highly unlikely to occur due to the late life and relatively low economic viability of the production from these marginal fields, even when the required equipment is already present.

This protocol creates a means for operators to accelerate their energy transition initiatives by freeing locked up capital value in marginal polluting assets and allowing it to be reinvested in new energy sources, more efficient operations, or active carbon reduction initiatives such as CCS. This mechanism will act to deter leakage by redirecting invested capital from polluting fossil fuel projects to ones in line with the UN SDGs and creating more sustainable communities in line with global goals for the 21st century.

3. Quantification

Fossil fuels are the single largest source of GHG emissions. The lifecycle emissions from hydrocarbon production and use can be divided into three broad categories:

1. Upstream emissions: Emissions that occur during the production and extraction of hydrocarbons, including exploration, drilling, and transportation of oil and gas to the refinery or processing facility. Upstream emissions can include emissions from the use of fuels to power drilling equipment, as well as from the flaring or venting of natural gas.
2. Refining emissions: Emissions that occur during the refining of crude oils into usable products that include gasoline, diesel, and jet fuel. Refining emissions can include direct emissions from the refining process, as well as indirect emissions from the energy used to power the refineries.
3. Downstream emissions: Emissions that occur during the use of fossil fuel-based products, including the combustion of gasoline and diesel in vehicles, as well as the use of fossil fuel products for heating and electricity generation.

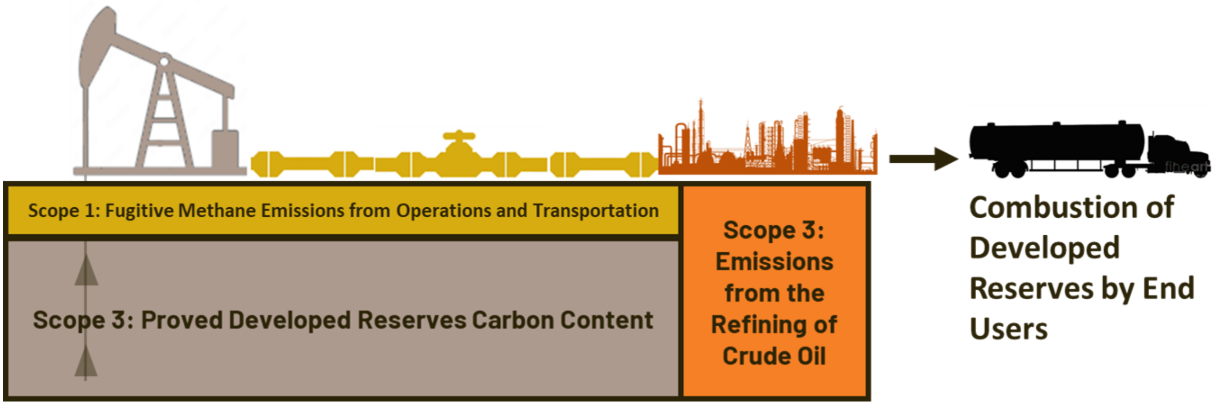


Figure 2: ZeroSix crediting boundaries.

The relative magnitude of these categories is shown in Table 1. These can be further categorized according to Scope 1, 2, or 3 relative to the party responsible for producing the hydrocarbon volumes.

1. Scope 1: Direct emissions that occur from sources owned or controlled by the operator, such as emissions from combustion of fossil fuels during production operations and emissions from flaring, venting, or fugitive leaks of methane gas.
2. Scope 2: These are indirect emissions that occur from the generation of purchased electricity, heating, and cooling that the operator consumes.
3. Scope 3: These are indirect emissions that occur from sources that are not owned or controlled by the operator, but that are associated with the produced fluid value chain. These include emissions from the combustion of the produced fluids by end-users.

The protocol enables project owners to recognize where the greatest reduction in emissions potentially resides. By targeting and crediting the largest contributing emission categories in the hydrocarbon fuel cycle, see Figure 2, project owners can implement the most effective emission reduction strategies. In order of magnitude, these are Scope 3: end use of produced oil, gas, and NGL reserves, Scope 3: refining of produced oil, and Scope 1: flaring, venting, and fugitive methane emissions.

$$GHG_{Total} = GHG_{oil} + GHG_{refining} + GHG_{gas} + GHG_{NGL}$$

$$GHG_{gas} = GHG_{combustion} + GHG_{vent}$$

Table 1: Comparative emissions across fuel cycles.

Fuel Cycle	Fuel Cycle Emissions	Scope 1	Scope 2	Scope 3
Downstream	65-80%			**End use of Produced Oil, Gas, and NGLs (Sec 3.1 & 3.2)**
Refining	5-15%			**Refining of Produced Oil (Sec 3.3)**
Upstream	15-20%	**Fugitive Methane Emissions (Sec 3.4)** **Flaring (Sec 3.4)** **Venting (Sec 3.4)** Onsite Combustion Operating Producing Facilites	Purchased Energy Materials Aquired	**Fugitive Methane during Transportation (Sec 3.4)** Transportation and Distribution Purchased Goods and Services Waste Capital Goods

3.1. Reserve Qualification

The US Securities and Exchange Commission (SEC) has established guidelines for regulating the calculation of hydrocarbon reserves. These are used by companies for their annual reporting obligations and to comply with investor and market transparency standards. The following have been established to ensure consistent definitions for both investors and market actors.[3,4,5] Project owners must engage a third party engineer qualified to prepare reserve reports according to SEC reserve quantification standards. From SEC requirements, the qualified person shall[5]:

1. Be a licensed professional engineer or a registered geologist with at least five years of relevant experience in the type of reservoir being evaluated.
2. Have experience in preparing reserve estimates or evaluating reserves that are relevant to the type of reservoir being evaluated.
3. Have familiarity with the geological and engineering principles and practices used in the industry for evaluating reserves.
4. Have a reasonable understanding of the legal and regulatory framework governing oil and gas operations.
5. Be independent of the company for which the report is being prepared, meaning that they have no direct financial interest in the company and are not an employee or officer of the company.
6. Be qualified to make engineering or geologic evaluations of the type of reserves being reported.

3.1.1. Eligible Volume Classification

Reserves are quantities of hydrocarbons anticipated to be economically recoverable in the future (as of an effective date). The criteria for project reserves are 1) they are discovered, 2) recoverable, 3) economic, and 4) remaining within the reservoir as of the evaluation date.[18] A further refinement (specific to a project's additionality criteria) is that only volumes designated as proved-developed reserves qualify as candidate volumes that currently satisfy additionality criteria according to this protocol. Standards of proved developed reserve volumes include two categories, developed producing and developed non-producing volumes.

Proved developed producing (PDP) reserves, are volumes expected to be recovered from wellbore intervals that are producing at the time of abatement project commencement.[3,4,5]

They are also determined to be economically recoverable under existing technical and commercial conditions with reasonable certainty using geoscience and engineering analysis.

Developed non-producing (PDNP) reserves, include potential volumes in shut-in wells or behind wellbore casing pipe of currently producing wells. These volumes can be economically returned to production with minor capital costs with a reasonable certainty.[3,4,5] A minor capital cost is defined as a lower expenditure than the cost of drilling and completing a new well. The quantity of incremental volumes must be supported by technical evidence with a high degree of confidence required for proved reserves categorization.

The incremental reserves associated with future workovers, treatments (including hydraulic fracturing stimulation), re-treatment, changes to existing equipment, or other mechanical procedures may be classified as developed reserves if such projects have routinely been successful in analogous reservoirs or offset operations, and it meets the criteria of a minor cost.

In addition, reduction in backpressure from the surface gas gathering system through compression can increase the portion of in-place gas that can be economically produced and, thus, included in resource estimates. If the eventual installation of compression meets commercial maturity requirements, the incremental recovery may be included in developed reserves. To receive this designation, the cost to implement compression must meet the low-cost criteria. Alternatively, there must be a reasonable expectation that compression would be implemented by a third party. If the non-producing reserves meet the conditions above, they can be considered for carbon credits based on the consistent standards as the producing volumes.

Reserves from potential enhanced oil recovery (EOR) projects are not covered by the ZeroSix protocol. These projects do not meet the minor-cost criteria and increase the deterministic uncertainty associated with quantifying the volume of avoided emissions.

3.1.2. Recoverable Reserve Volumes

The performance-based analytical procedure for estimating recoverable quantities shall be applied for PDP reserves, however, high confidence volumetrically determined reserves can be used for PDNP where historical performance data may not be available. This approach can include material balance, history matched simulation, decline-curve analysis, and/or rate-transient analysis. The confidence in results increases when the estimates are supported by more than one analytical procedure. The two most widely used are the a) material balance and b) production performance analysis methods.

a) Material Balance

Material balance methods used to estimate recoverable quantities involve the analysis of pressure depletion as reservoir fluid is withdrawn. In ideal situations — such as depletion-drive gas reservoirs in homogeneous, high-permeability reservoir rocks, and where sufficient and high-quality pressure data are available — material balance may provide highly reliable estimates of ultimate recovery at various abandonment pressures. In complex situations — such as those involving aquifer water influx, compartmentalization, multiphase behavior, and multi-layered or low-permeability reservoirs, shales or Coalbed Methane (CBM) — material balance estimates alone may provide inconclusive results. Project evaluation must accommodate the complexity of the reservoir and its pressure response to depletion in developing uncertainty profiles for the applied recovery project.

Reservoir simulation can be considered a more rigorous form of material balance analysis. While such modeling can be a reliable predictor of reservoir behavior, the origin and therefore credibility of input data including rock properties, reservoir geometry, relative permeability functions, fluid properties are critical. Predictive models are most reliable in estimating recoverable quantities when there is sufficient production history to validate the model through history matching.

b) Production Performance Analysis

Oil and gas production rates decline over time. Analysis of this change in combination with produced fluid ratios versus time and cumulative production as reservoir fluids are withdrawn, provide useful information to predict ultimate recoverable volumes. Prior to the full production rate decline profile becoming apparent in well history, trends in performance indicators such as gas/oil ratio, water/oil ratio, condensate/gas ratio, and bottomhole or flowing pressures, in combination with knowledge of the reservoir drive mechanism, can be extrapolated to the economic limit to estimate reserves. Decline curve analysis (DCA) is a graphical procedure used for analyzing production decline rates and forecasting future performance of oil and gas wells, including remaining technically recoverable volumes.

Reliable results require a su cient period of stable operating conditions after wells in a reservoir have established drainage areas. In estimating recoverable quantities, evaluators must consider additional factors affecting production performance behavior, such as variable reservoir and fluid properties, transient versus stabilized flow regimes, changes in operating conditions, interference effects from offset wells, and depletion mechanisms. In early stages of depletion, there may be significant uncertainty in both the ultimate performance profile and the other factors (e.g., operational, regulatory, contractual) that impact the abandonment rate. Such uncertainties should be reflected in the reserve's quantification.

In very low-permeability reservoirs (e.g., unconventional reservoirs), care should be taken in the production performance analyses because the lengthy period of transient flow and complex production physics can make analyses quite di cult.

3.1.3. Uncertainty

Uncertainty and risk are inherent with quantification of subsurface volumes. These can be summarized into three categories:

1. The total hydrocarbon and associated resulting emissions remaining within the accumulation.
2. The technical uncertainty in the portion of the total hydrocarbons that can be recovered by the project proposed for emission avoidance considering the technology applied.
3. Known variations in the commercial terms that may impact the recoverable volumes which can be delivered to market and result in emissions (e.g., market availability; contractual changes, such as production rate tiers or product quality specifications) as part of the project scope.

Late-life PDP reserve volumes with a well established operational history are typically estimated deterministically, while PDP volumes with a history of erratic production and PDNP volumes can be better addressed through a probabilistic estimate; the probabilistic approach can manage the range of uncertainty . In such a case, volumes are calculated with a 90% confidence of exceedance and translate to volumes expected to be recovered (applicable for carbon credit through avoidance) that will equal or surpass the stated P90 estimate. The deterministic approach for volume calculation can be more subjective, but by incorporating the qualitative expression "reasonable certainty," it is intended to convey a degree of confidence that the quantities will be recovered.

Project reserves will be estimated using the above uncertainty evaluation methods, which incorporate subsurface analyses together with technical constraints related to the operation of wells and facilities. Additional commercial criteria would then be applied to the technically recoverable reserve volume forecasts to estimate the true volume of additional abated emissions. These commercial criteria may include but are not limited to operating expenses, future commodity price, realized price differentials, royalty structure, tax burden, and lease or license duration.

3.1.4. Price Determination

Proved reserves must be economic in order to meet operational business requirements. In addition, proved reserves must satisfy the economic threshold to comply with additionality criteria to be considered for carbon credits as part of an emissions abatement program. The key metric for profitability assessment is the future looking commodity price over the expected life of the asset, which can be a significant variable. To establish a common evaluation, the SEC has standardized the reserve price forecasting methodology by using an average 12-month historical price on a go-forward basis. This standard is to be applied to all reserve determinations for the purposes of claiming emissions avoidance carbon credits.

The 12-month period starting from the most recent practical month prior to the issuance of the applicable reserve report shall be applied using an unweighted arithmetic average of the first day-of-the-month price for each month within such period. For example, the relevant 12-month period for a reserve report issued on December 31 would span from the first day of January through the first day of December of that year.[3,4,5]

3.1.5. Assessment of Economic Viability

Economic assessments are conducted on a project basis and are based on the operator's view of future conditions. Economic conditions include, but are not limited to, assumptions of general financial conditions (e.g., costs, prices, fiscal terms, taxes); organization capabilities; and marketing, legal, environmental, social, and governmental factors.[3,4,5] Project economic viability may be assessed based on cash flow analysis. Factors that may influence long-term viability and, hence, additionality of the avoided carbon emissions, such as contractual or political risks, should be recognized and addressed in the project reserve report.

(a) Net-Cash Flow Evaluation

Project reserve economics are based on estimates of future production and net-cash flow (as of an effective date), as reported in a third-party reserve report. This documentation will be uploaded to the ZeroSix platform in support of the retired carbon volume. The third-party reserve reports are industry standardized documents, prepared by state licensed engineers.

Project owners provide the following data in the third-party reserves report lease operating statement (LOS) and financial model support document:

1. Historical and forecast prices for produced gas (\$/MMBTU), oil (\$/BBL), and condensate (\$/BBL), as well as a description of any existing sales contracts.
2. Any cost or price escalation schedules and rates if stipulated in existing contracts, otherwise they are not considered under SEC standards.

3. Historical and forecast operating expenses and supporting cost model including fixed and variable costs, fuel and gas shrinkage volumes, and any plans for cost reduction.
4. Lease and operating expense (LOE) statements, including water disposal and transportation costs.
5. Ad valorem tax rates and/or other tax application-regimes as well as any special production tax exemptions.
6. Transportation, processing & handling fees.
7. Planned capital expenditures for development or workovers associated with PDNP reserves, as well as abandonment, decommissioning, and restoration (ADR) liability for all project wells.
8. Ownership interest data, including working interest, net revenue interest, reversion interest, and pay-out balances at the effective date.
9. Contract, lease, or concession expiration dates.

(b) Economic Criteria

The forecast project-production volumes are deemed economic when the revenue attributable to the project owner's interest from production exceeds the cost of operation. The abandonment, decommissioning, and restoration costs are excluded from the economically producible determination.

Economic viability is tested by evaluating cash flow estimates based on the forecast economic conditions including operating costs, product price schedules, realized price differentials, and other relevant market factors. The forecast should reflect life-cycle assumptions applicable throughout the duration of the production operation. Inflation, deflation, or market escalations may be made to forecast costs and revenues. Forecasts should be based on current economic conditions and are estimated using an average of prices and costs over the preceding 12-month period, as per SEC guidelines. If a significant departure has occurred within this time, the use of a shorter timeframe that reflects the step change must be documented. All costs are included in the project economic analysis unless specifically excluded by contractual terms.

Figure 3 illustrates a net cash flow profile for a project. The project's economic production is truncated at the economic limit when the maximum cumulative net cash flow is achieved, before consideration of abandonment, decommissioning and reclamation (ADR).

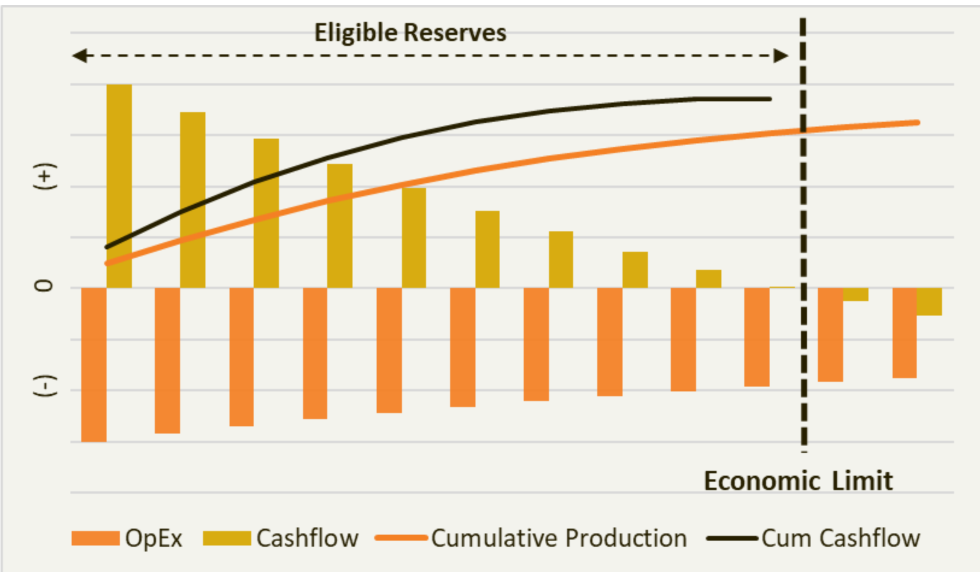


Figure 3: Eligible reserves economic limit.

(c) Economic Limit

The economic limit is defined as the production rate at the time when the maximum cumulative net-cash flow occurs for a project. The production volumes credited toward avoided emissions, are truncated at the end of the month in which either the technical, license, or economic limit is reached, whichever occurs first. In this evaluation, operating costs should include only those costs that are incremental to the project for which the economic limit is being calculated (i.e., only those costs that will be eliminated if project production ceases).

Operating costs should include fixed property-specific overhead charges if these are incremental costs attributable to the project, as well as any production and property taxes. The calculation of the economic limit should exclude depreciation, ADR costs, income tax, and any overhead not required to operate the property. Interim negative project net cash flows may be accommodated in periods of low product prices or significant operational adjustments provided that the longer-term cumulative net cash flow forecast determined from the effective date exceeds the cumulative net cash flow during periods of negative economic operation. These periods of negative cash flow will qualify as reserves if the following positive periods more than offset the negative. No sub-economic production beyond maximum future cumulative net income can be considered as reserves for the purposes of crediting avoided emissions.

3.1.6. Production Facilities

Each project must satisfy the basic needs for facilities required to maintain economic production for the foreseeable future, with no expectation of major expenditures or upgrades for at least 12 months. There must be sufficient facility infrastructure to allow for reliable export to market or disposal of all production components from project wells, consistent with the forecasted volume profile of the proved reserves.

3.1.7. Reserves Volume Documentation

The project owner must submit the following three documents to the ZeroSix platform with the hydrocarbon volume information consistent with the third-party reserves report. Once these documents are accepted by the third-party verifier for consistency with the claimed carbon credit amount, they will be immutably stored on the IPFS as a permanent record validating the amount of emissions abated and removed by the project.

Project Reserves Report - Field Monthly Forecast providing the monthly amount of hydrocarbons forecasted to be produced by all the project wells combined, abiding by all the rules and regulations specified in this protocol.

Project Reserves Report - Well Level Volumes providing total recoverable volume as a single value per well for each credited stream of hydrocarbons or other emissions.

The project owner must submit third party reserves report historical production and forecast plots in a pdf document for the purpose of verifying well forecasts and remaining recoverable volumes against historical trends, clearly showing:

1. Rate time plots for all production streams submitted for carbon offsets under this protocol at the well level.
2. Enough production history on a monthly basis to clearly justify the forecasted trend, but not less than 12 months.

3. Forecast must be shown from the project as of date, through to the economic limit of each well plus one year.
4. Decline parameters, including initial rate, b-factor, initial and terminal decline rates, and cut off rate for every forecast segment.

3.2. Carbon Stock of Reserves

Carbon-content quantification of reserves begins with fluid characterization at a specified reference point in the production flow-chain. The reference point is a defined location within a petroleum extraction and processing operation where the produced quantities are measured. This is typically the point of sale or where custody is transferred to the midstream or downstream operations. This point is envisaged to correspond with the point at which combustion of the product and emission of the associated GHGs by the end users occurs. Hence avoided emissions of the reserves will be determined in terms of quantities that would be crossing this point over the period of economic producibility under the defined operating assumptions.

It is important to have a good understanding of how historical production quantities were reported. Sales quantities are equal to raw production less non-sales quantities (those quantities produced at the wellhead but not available for sales). Non-sales quantities include petroleum consumed as fuel, flared, or lost in processing; these would also be credited for avoided conversion following a successful permanent abandonment of the designated production. The full sum of avoided emissions is the aggregation of non-sale volumes and sales.

Sales quantities may need to be adjusted to exclude components added in processing but not derived directly from project well production. Total well production measurements are necessary and form the foundation of many engineering calculations (e.g., material balance and production performance analysis) based on total reservoir voidage. Additives to the production stream for various reasons, such as diluents to enhance flow properties, are excluded from avoided emissions resources. Consumed in operations (CiO) and flared volumes are typically not included in standard reserve reports but need to be included in the avoided emissions calculation; this is generally encompassed in the gas shrinkage volume and is added back into volume determination.

3.2.1. Carbon Emissions Intensity

Once the remaining technically and economically recoverable volumes have been established for oil, gas, and natural gas liquids (NGLs), their respective volumetric carbon intensity is established. The carbon intensity is determined by the chemical composition of each fluid and is directly calibrated by standard fluid property field measurements.

Gas phase carbon content is determined using the emissions constant for methane, 52.91 kg CO_2/MMBtu, which constitutes the majority of the gas phase following the well site phase separation process.[19] The emissions factor is adjusted by the gas heating value (GHV); for pure methane it is 1.00 MMBtu/Mscf and, in some cases it may be adjusted upward to account for the presence of heavier gas components such as ethane, propane, butane, and pentane+. The factor can also be lower if there are non-reactive contaminants such as nitrogen or CO_2 present. The heating factor is to be submitted by the project owner and verified by submission of a recent gas analysis report from a third party gas analysis laboratory.

$$\boldsymbol{GHG_{combustion} = 52.91 * GHV * (1 - FE) * V_{gas}}$$

$$FE = \textbf{\textit{Fugitive Methane Emissions}}\ [\%]$$

The NGL emission factor is also verified from the gas analysis report, where the molecular weight percentage of ethane, propane, butane, and pentane+ is reported. The liquid fractions and the corresponding component emission constants as reported in the 2022 EPA Fuel Emission-Factors document can be used to determine the total emissions per barrel of natural gas liquids from the proposed project, as shown in Table 2.[19]

$$GHG_{NGL} = [x_{ethane} * 170.1 + x_{propane} * 240.24 + x_{butane} * 280.14 + x_{pentane+} * 323.4] * V_{NGL}$$

Table 2: NGL emission intensity.

NGL Component Emission Intensity		
	kg CO2/gal	kg CO2/bbl
Ethane	4.05	170.1
Propane	5.72	240.24
Butane	6.67	280.14
Pentane+	7.7	323.4

The CO_2 emissions factor for oils is variable due to the unique composition of hydrocarbons. The variability reflects organic geochemistry, depositional environment, and subsequent thermal history which could markedly impact temporal kerogen maturation. The API gravity (a measure of the density) of the oil phase is correlated with the length of its component carbon chains, the longer the carbon chains, the heavier the oil, and the larger the CO_2 emissions factor upon refining and use.

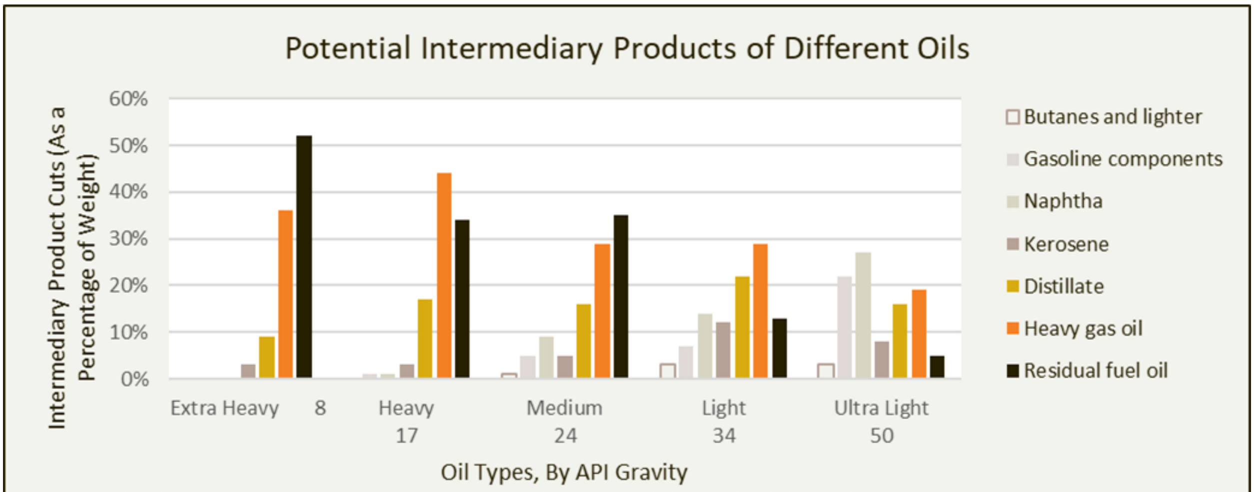
Figure 4 illustrates representative fractions of refined products from crude oils of different API measurements.[20] Emission factors of different components shown in Table 3 and their fractions were used to determine representative kg CO_2/barrel emissions at each of the represented API gravities shown in Figure 5.[19] The best-fit line with a strong R factor of 0.9828 is the relationship used to calculate CO_2 emissions and equitable issued carbon credits for the oil phase based on API. This measurement is verified by a submission of recent oil sale receipts issued by a third party offtake operator which has the API gravity of the oil clearly visible.

$$GHG_{oil} = [-0.9656 * {}^{\circ}API + 458.95] * V_{oil}$$

The CO_2 equivalent mass of avoided emissions is determined by combining the proved developed recoverable volumes of each production phase and the associated carbon content described in this section. The prevented scope 3 emissions represent the early retirement of reserves which prevents downstream combustion by end users.

Table 3: Crude oil refined product emission intensity.

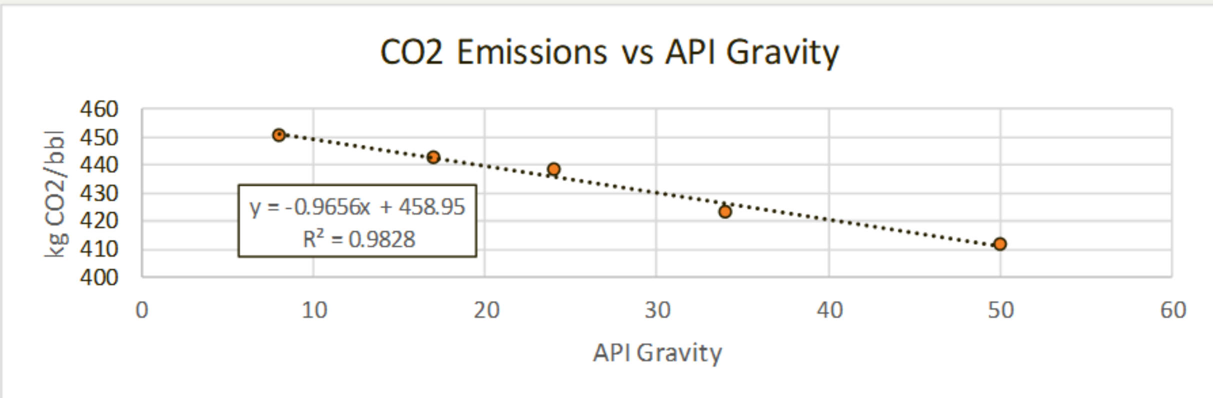
Crude Oil Refined Products Emission Intensity			
	kg CO2/MMBtu	kg CO2/gal	kg CO2/bbl
Butanes and lighter	63.04	5.8	243.6
Gasoline components	71.35	8.78	368.76
Naphtha	72.38	10.26	430.92
Kerosene	73.19	9.88	414.96
Distillate	74.14	10.19	427.98
Heavy gas oil	74.00	10.21	428.82
Residual fuel oil	75.09	11.24	472.08



Source: Crude Oil Quality Association, 2009, www.coqa-inc.org/20091022_Villalanti.pdf and The Distillation Group, 1997. http://home.earthlink.net/~villalanti/Crude.pdf

Figure 4: Intermediary products of different oils.

Oil **-0.9656*API+458.95**



API Gravity	8	17	24	34	50
kg CO2/bbl	450.82	442.39	438.47	423.13	411.54

Figure 5: Resulting CO_2 emissions based on API gravity.

3.3. Downstream Scope 3 Emissions Avoidance

In addition to the avoided emissions from combustion of the produced oil, there are fuel cycle emissions originating from the oil and gas transportation and processing. By not bringing these resources to market as final refined products, additional emissions avoidance is captured. Many of the fuel-cycle emissions have a high degree of variability based on the technical nature of the specific projects and the geographic location of the operations, which may significantly impact the associated energy and emissions of the production operations and transportation to market.

In comparison, direct emissions from refining crude oil into specific products (summarized in Figure 6), are of more significance. Brandt, et.al. propose a linear relationship between crude oil gravity and refining GHG emissions, which is here utilized to provide the basis for associated credits.[21] The emissions are accounted for in the crediting calculation since they are parameterised by a standardized property of the crude oil, rather than project specific variables. Because of the high degree of confidence of these scope 3 emissions, their inclusion is merited and therefore credited to the project owner upon successful project execution.

$$GHG_{refining} = [-0.77 * {}^{\circ}API + 86.39] * V_{oil}$$

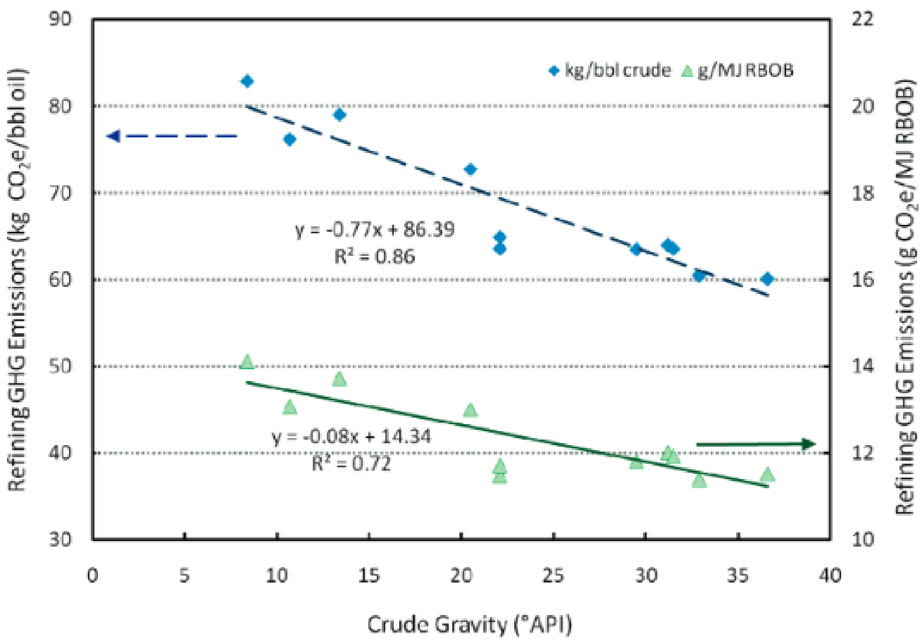


Figure 6: Refining GHG emissions based on API gravity.

3.4. Scope 1 Fugitive Methane Emissions

In addition to the scope 3 CO_2 emissions eliminated by preventing the combustion of gas reserves, there is also an associated abatement of methane release from production systems and/or leaks during transportation to the downstream market. The published results of the Environmental Defence Fund (EDF 2012-2018) study concluded that the industry supply chain rate of fugitive methane emissions is 2.3% of total domestic production.[22] The research engaged 140 independent experts, from 40 different research institutions, across 16 rigorously executed projects, with support from 50 companies.

The abated methane leakage from operations and transport of produced gas are credited to the project owner on a CO_2 equivalent basis, using the 100-year GWP. The credit for these abated emissions is included, applying the average 2.3% of the verified remaining gas reserves. The early retirement of older, marginally economic wells mainly targeted by the incentives of this methodology cumulatively only account for 6% of US domestic production, but account for approximately 50% of fugitive methane emissions. This translates to a normalized loss rate of ~10%.[23] Typical sources of operation methane leaks include:

- Fugitive equipment leaks
- Process venting
- Evaporation losses
- Disposal of waste gas stream (i.e., venting or flaring)
- Accidents and equipment failures

Due to the greater impact of methane on global warming, upon the successful abatement of these scope 1 emissions, the 2.3% of verified gas reserves shall be credited on a CO_2 equivalent basis. According to the latest IPCC AR6 report, the CO_2 equivalent global warming potential (GWP) of methane on a 100 year basis is 27.9 times greater than that of CO_2, thus for purposes of carbon credits, the fugitive methane emissions as a percentage of gas reserves is evaluated at 1,476.19 kg CO_2 equivalent/Mscf.[24]

$$GHG_{vent} = 52.91 * GHV * GWP_{CH_4} * FE * V_{gas}$$

4. Validation

4.1. Project Eligibility

For a project to be protocol compliant the operator must satisfy the following minimum requirements with documentary validation:

1. A submission of operator license issued by the respective state regulator, and confirmation of an operating record without pending investigations or inquiries.
2. Economically validated hydrocarbon volumes, (those reserves that would be produced and sold without the benefit of the carbon credits mechanism). This will be verified by an accredited engineer working under the third-party auditor, and who will certify the reserves report. This report will validate all claimed economic volumes based on standard regulatory parameters, and thus can be reasonably expected to be produced, and are considered additional emissions avoided due to the granting of carbon credits.
3. A copy of the documents outlining the legal framework, designating target reserves as off limits for production for a minimum, 50 years. This contract will be tied to the mineral ownership title, thus the current and any future mineral owner forgoes the right to extract the targeted resources in exchange for just compensation proportional to their royalty claim or other compensation as negotiated with the project operator. This will legally bind the permanence of the avoided emissions by preventing future targeted development of the impacted resources.
4. A submission of documentation validating the project owner's best technical justification that oil and gas volumes claimed for carbon credit issuance will remain in the reservoir. These volumes will not migrate to any offset wells or to the surface through any open flow conduits. This claim will be validated through submission of a comprehensive technical report corroborating such a claim, and will be independently verified by a licensed third-party technical body.

4.2. SEC Proved Reserves

The volume of reserves to be credited must meet requirements and standards as set forth by the Securities and Exchange Commission, validated by existing industry mechanisms as follows:

1. Third-party reserve report prepared by a qualified person as described in section 3.1, verified by an accredited engineer, and conforming to industry standards as laid out by the SEC.[3,4,5,18] The reserve reporting body will validate results independently of the project owner, thus mitigating any conflict of interest.
2. The eligible volumes for carbon credits will be scrutinized for consistency against third party reserve reports.
3. Well-level volumes will be submitted which must be consistent with the total volumes claimed. Internal consistency of the submission in different forms and independently verified by existing accredited auditing entities will serve as data quality validation.

4.3. Carbon Content

The carbon content of the credited volumes is representative of the geochemistry and physical properties of the hydrocarbons. These are documented using standard industry documentation issued for producing assets. The validation of this data relies on established industry reporting practices and regulation:

- Produced oil API gravity measurements are validated by the oil sales receipts from historical production.
- Produced gas heating value and NGL composition are validated by a gas analysis report from a credible testing facility. These reports are critical for safe operation of production and transportation facilities, and composition of marketed gas is often stipulated in contracts between the producer and mid-stream operator, thus the quality of the report data is largely enforced by operation contracts.

4.4. Data Quality

The data quality assurance for volumetric quantification in this protocol is provided by the legal obligations of operators to submit accurate data to regulators monthly, as well as the board-certified engineer's legal obligation to uphold industry reserve reporting standards when validating reserve reports. Third-party reserve reports provide inherent quality assurance. They are sourced from a trusted, independent organization that is accountable to the SEC.

The carbon content documentation from the midstream gas analysis report is deemed trustworthy due to pipeline safety standards requirements. The accuracy of accounting for the quantity of gas being sold is of paramount importance. The API gravity measurement on oil sales receipts must be accurate for logistics purposes, thus it is in the interest of the off-take company–as well as the producer–to have an accurate fluid characterization so that facilities and transportation equipment can be appropriately maintained.

5. Execution

The execution of the abandonment and reclamation activity will be specific to each project and must conform to the regulatory guidelines of the jurisdiction. The process flow is described, relative to regulatory obligations and verification submission requirements.

The platform also requires documented proof of appropriate notification and provision of information to such state, local, and Tribal authorities that have authority over drilling activities. This enables such authorities to impose appropriate restrictions on subsequent drilling activities that may penetrate the injection and confining zone(s).

5.1. Plugging and Abandonment (P&A) Regulatory Process

The plugging and abandonment process varies by state and is specified by the respective resource governance organizations. The correct execution of this procedure is independently verified by the state oil and gas regulatory bodies. As part of the project submission process, the project operator is required to submit a P&A permit issued by the state regulator for each well intended to be abandoned according to the project permanence documentation.

The general process to plug and abandon a wellbore is described:

1. Make decision to P&A well.
2. Identify water strata and hydrocarbon production horizons to ensure cement plugs are set to isolate each.
3. Notify surface landowners.
4. File a P&A plan with the state (e.g., Colorado Oil and Gas Conservation Commission – COGCC in Colorado) regulatory agencies.
5. Agencies may provide feedback and edits, and ultimately grant approval and plan permits for a specific period.
6. Find a state approved cementer.
7. Secure cement supply and rig for a specific date within the valid permit period.
8. Upon scheduling the operation for a specific date, inform regulatory agencies at least 48 hours prior to start of operations; they will engage an observer to witness plugging execution.
9. Project owner should follow all operations and requirements set forth by the regulator for all conditions to safely and permanently abandon the wellbore according to the approved and permitted execution plan.
10. State or federal observers witnessing the plan execution certifies the P&A if all criteria are attained.

5.2. Land Reclamation Regulatory Process

In projects where all activity is retired, the operator must perform a full site-reclamation program according to the guidelines of the state regulator. The remediation and reclamation will be documented in the final report.

6. Monitoring

The project owner must submit a monitoring plan designed to validate the proper reclamation of the project area and the permanence of the reserves. The primary means of determining the permanence of the claimed reserves is to monitor any new activity for potential development after verifying that all extraction activity has been abandoned per the project plan.

Minimum monitoring requirements:

1. Observation of production and development activity from offset operators that might be targeting or impact credited reserve volumes (see Section 6.1).
2. Progress of land reclamation (see Section 6.2).

6.1. Activity Monitoring of Project Area

The project owner shall monitor the absence of new extraction activity in the project area for the duration consistent with requirements for land reclamation by the state regulator. It shall also validate that no new permits for resource extraction within project boundaries, by project operator, landowner, or any other operator have been submitted. Lack of activity can be proven by submitting a list of permit filings for the project county from the state oil and gas regulator, with no new submissions on any leases within the project boundary. Should the county list show permitting activity for any project lease, the project must answer the following three questions:

1. Is the permit still active and valid?
2. Is the permit location inside the specific project boundary?
3. Will the activity, if permitted, have any tangible interaction with the subsurface zones targeted by the project (i.e., proposed development or drill through zones produced by the retired project wells)?

Should any of the answers be Yes, then a report must be submitted detailing why the permit(s), if approved, will not have a material impact on the credited reserves.

6.2. Land Reclamation Monitoring

The well site land reclamation process is to follow, at minimum, the plan submitted to the state regulatory body for returning the well operational area to its natural state, usually the oil and gas activity regulatory agency. Photographs documenting the wellsite in its entirety – from at least the four primary orthogonal directions prior to commencing plugging activity – shall be uploaded as part of project documentation, along with a satellite or drone overhead capture of the well site. The location and direction of the submitted photographic documentation of the wellsite shall be marked on the overhead site layout, so as to be replicated as part of annual monitoring report.

A copy of the land reclamation plan submitted to the regulator shall also be submitted to the platform along with the document ID. Any measurements or assessments required by the state regulator shall be uploaded as part of the annual monitoring report, as well as photographic documentation of the reclamation progress. The state regulator must sign off on reclamation completion after the designated state monitoring period.

6.3. Compensating for a Reversal

A reversal is defined as continuing or a renewal of extraction activity from the project reservoirs at any point, or continuing methane emissions in the vicinity of plugged wellbores. In the event of a detected or reported reversal, the extent will be quantified by an independent third party, according to best engineering practices, and a report will be submitted to the project ZeroSix platform page and stored on IPFS.

The report shall specify the amount of reserves that were released from the target project reservoir, how many more will be produced or released into the atmosphere in the future, and how the reversal will be addressed. A plan will be developed to permanently plug and abandon the infringing well and deduct any reversed credited volumes from the buffer account. If the violating well cannot be abandoned, the independent third party verifier must determine the volume of claimed project reserves expected to be produced economically from said producer or leaked from the improperly plugged well, and the corresponding number of credits shall be retired from the buffer account.

A benefit of oil and gas production reversal or leakage is that any such flow will occur slowly and consistently over time, limited by the productive capacity of the impeding well. Since the projects are to be low producing late life reservoirs with very low deliverability, this provides a large window of opportunity to resolve any identified reversal.

7. Verification

All the elements and provided information about the offsetting project are independently verified based on the source and nature of information.

7.1. Third-Party Verification of Project

An independent, state-accredited organization will verify the claimed emission volume abatement and credibility of the geologic permanence documentation of the project in a verifier report and certification statement submitted through the ZeroSix platform. At minimum, the specific engineers working within these organizations will hold a current state engineering license in a relevant engineering discipline.

The third-party verifier will review all submitted documents pertaining to geologic permanence, carbon content, and reserve volumes. Each relevant document will be verified independently through the ZeroSix platform. If the verifier has any questions or concerns about the quality of the claims or documentation they can revert back to the project owner to provide additional documentation or a revision of the project. Once all documents are consistent and meet the requirements laid out in this protocol the final certification can be issued.

7.2. Regulatory Compliance

Well-level critical project and regulatory sign offs from state regulatory bodies include:

- P&A permit filling and acceptance
- State-level confirmation of plugging and abandonment of economic reserves
- Land reclamation plan submission and approval as per regulatory requirements.

7.3. Monitoring

Monitoring of project area permitting and development activity is directly linked to state regulatory databases, hence verification is entirely linked with mandatory state fillings. Land reclamation monitoring and reporting is required by state regulators and, thus, such standards are enforced at the state level.

7.4. Execution

- P&A plan execution signed off by state observer and a copy of the document is uploaded to the ZeroSix platform
- Final land reclamation completion signoff is submitted at the time of final report

7.5. Data Quality

The quality of the verification is affirmed by the credibility of the submitted documentation from trusted public regulators. This includes the above mentioned state filings and permitting process, as well as the state agency confirmation of successful project execution according to submitted plans and in line with existing regulations. This process and documentation is already in use, is trusted, and doesn't require any additional modification.

7.6. Verification Processes and Entities

7.6.1. Trusted and Verified Information Source

The sources of the submitted documentation are verified and trusted industry third parties. This is the case with the reserve report and included volume determination, which is backed by state accreditation of the issuing engineer. The laboratory gas analysis results and oil API gravity from sales receipts are issued by third parties that have reputational or financial incentives to be accurate in their reporting.

7.6.2. Verification Process on Blockchain

The process of issuance and distribution of the calculated carbon credits to be issued for each project is governed by smart contracts that guarantee the trustworthiness of the ZeroSix platform. This process is transparent, open source, and immutable. The security of the underlying smart contracts and the platform itself have also been independently audited.

7.7. Double Counting

By registering an offset project, the project owner affirms that the eligible volumes have not been claimed for carbon offset credits on any other platform, for any other purposes for financial or other material compensation, or on the ZeroSix platform under a different project name.

Once a project has been successfully executed and the included wells have been P&A'd, their corresponding reserves no longer qualify as reserves, thus there is no risk of these volumes being claimed again for future carbon offsets — unless subsequent development of the project reservoir occurs in breach of the mineral rights limiting contract issued and tied to the mineral ownership title precluding the extraction of the relevant resources.

By tokenizing the ZeroSix credits on the blockchain, every credit can be verified through a public ledger, which holds all relevant information in a tamper-proof and immutable way, tracking the transaction history and means of generation for each metric ton of CO_2 equivalent credit. With full transparency, anyone can verify and check the credibility of the tokens, and any intentional or retiring or further transacting of already retired credits is prohibited.

8. Reporting

8.1. Initial Project Execution

The following list of documentation will be submitted to the digital solution and will be publicly available through the decentralized InterPlanetary File System (IPFS):

Table 4: Documentation requirements and issuing entity.

Document Title	Issuer
Oil Sales Receipt with API Gravity Test	3rd Party Oil Offtake Agent
Gas Analysis Report with Gas Heating Value and NGL Composition	3rd Party Gas Analysis Laboratory
Project Reserves Report - Field Monthly Forecast	Project Operator
Project Reserves Report - Well Level Volumes	Project Operator
List of All Well Penetrations Into/Through the Project Reservoir	Project Operator
Qualified Third Party Reserves Report	Licensed 3rd Party Engineering Firm
Third Party Reserves Report LOS and Financial Model Support document (xls)	Project Operator
Third Party Reserves Report Historical Production and Forecast Plots (pdf)	Project Operator
Mineral Ownership Schedule	Licensed Legal Entity
Working Interest Ownership Schedule	Licensed Legal Entity
Monitoring plan (as required by Regulations for wellbore emissions and land reclamation)	Project Operator
Permanence Report	Project Operator
P&A Plan and Regulator Permit Issuance	State Regulator
Land Reclamation Plan and Permit Issuance as Required by Regulator	State Regulator
Post-operations Report and Emissions Measurement as required by regulatory agency	Project Operator
Before and After Project Photographic or Video Documentation	Project Operator
Signatures	
Document Establishing a Legal Barrier to Future Extraction of Hydrocarbons	Licensed Legal Entity
P&A Operations Report and Regulatory Witness and Sign-off	State Regulator
Verifier Report and Certification Statement	Certified 3rd Party Verifier

The submission and verification of the necessary documentation, and successful execution of the digital signature will constitute all initial reporting requirements.

8.2. Annual Monitoring Reporting

The annual monitoring report is intended to verify the permanence of the project and the e cacy of proper abandonment and abatement of emissions from operations. The operator shall perform site specific measurements based on the nature of the historical operation and consequent environmental impacts and as required by the state regulator for land reclamation. This to include soil and water sampling from the vicinity of retired wellbores and reclamation progress as specified in the plan submitted to the state oil and gas industry authority in accordance with state reporting requirements. Any such required measurements and additional information is to be submitted annually.

8.3. Final Report

The final report must include the final measurements of air, soil, and water quality, where relevant, according to the standards of section 6.2 and consistent with the previous annual monitoring reports clearly validating the permanence of the retired reserves. Inclusive within the report will be results of land reclamation success authenticated by the state regulator. Also included can be documentation about realized co-benefits of the operation, which may be of interest to credit buyers or local stakeholders.

9. ZeroSix Credit Issuance and Crediting Period

9.1. Project Credit Ownership and Allocation

Oil and gas projects can involve complex royalty interests, thus the ownership of CO_2-equivalent credits associated with the project's emission avoidance must be clearly defined. The operating company has ownership of the credits and distributes the income–either in equivalent credits or in cash upon sale– based on the royalty interest. Alternatively, the credits can be distributed to the respective royalty owners at the point of crediting. All relevant interest owners would have to register on the ZeroSix platform as a prerequisite for this alternative to be actionable.

9.2. Buffer Account Allocation

Upon successful execution of the project, all associated carbon credits will be assigned (less the amount required for the buffer account) to offset any future unplanned reversals of retired hydrocarbon volumes. The percentage of credits withheld for the buffer account is aligned with the risk of reversals impacting the likelihood of permanence. The flat 1% withholding for the general reserve retirement project is a minimum amount arrived at upon evaluation of the risk matrix for these project types (see Section 2.9). The risks of reversal are low due to the stringent eligibility criteria and permanence requirements mandated by this protocol.

9.3. Project Credit Distribution

The full balance of carbon credit tokens will be generated and issued immediately upon the successful execution of the reserve retirement project according to the requirements governed by this protocol.

9.4. Project Credit Retirement

The issued project carbon credits will be able to be retired on the ZeroSix platform by either project owner, or any subsequent recipient of transferred credits. The retirement is executed by sending the number of credits equal to the desired amount of emission offsets to a terminal address. Subsequently a retirement certificate is issued on behalf of the claiming entity specified at the point of retirement.

10. Sustainable Development Goals (SDGs)

ZeroSix projects generate sustainable development improvements throughout the project life and beyond.

These co-benefits can include United Nations Sustainable Development Goals (SDGs) such as good health and wellbeing for the local community (SDG 3), clean water and sanitation (SDG 6), affordable and clean energy (SDG 7), responsible consumption and production (SDG 12), climate action (SDG 13), or life on land (SDG 15).[12]

Additionally, releasing the capital locked up in the most polluting operations will allow operators to transition toward cleaner energy sources more quickly through reinvestment of the revenue from gained credits into ventures such as carbon sequestration, renewable energy, or other carbon negative ventures.

The core initiative of this protocol is to accelerate society to a net-zero future, but many opportunities for co-benefits will be realized along the way.

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