Baker & O'Brien

CITY OF LOS ANGELES
OIL AND GAS DRILLING ORDINANCE

STUDY 22: AMORTIZATION OF CAPITAL INVESTMENT STUDY FOR THE PACKARD DRILL SITE

PREPARED FOR:

The City of Los Angeles

Board of Public Works

Office of Petroleum and Natural Gas Administration and Safety

DATE:

December 23, 2024

Baker & O'Brien, Inc.

12001 N. Central Expressway

Suite 1200

Dallas, TX 75423

CONFIDENTIAL

TABLE OF CONTENTS

TABLES

FIGURES

1. LEGAL NOTICE

1. The City of Los Angeles (the "City"), through its Board of Public Works' Office of Petroleum and Natural Gas Administration and Safety ("OPNGAS"), has retained Baker & O'Brien, Inc. ("Baker & O'Brien") to conduct this Amortization of Capital Investment Study under Contract Number C-142695.

2. This *Amortization of Capital Investment Study for the Packard Drill Site* (the "Study") presents the basis and conclusions for the time required to amortize capital investment for this group of oil wells and surface facilities. The Effective Date for this Study is December 31, 2022 (the "Study Effective Date").

3. Baker & O'Brien prepared this Study for the sole benefit of the City. Baker & O'Brien makes no warranty, either express or implied, and assumes no liability with respect to the use of any information or methods disclosed herein. Any use, reproduction, or distribution of this information by others requires Baker & O'Brien's prior written consent. Baker & O'Brien expressly disclaims all liability for the use, reproduction, distribution, or disclosure of this information to or by any third party.

4. The analysis, opinions, and findings presented in this Study are based on the experience, expertise, and skills of Baker & O'Brien consultants, as well as their research, analysis, discussions, and related work in preparing this Study. In preparing this Study, Baker & O'Brien has relied upon public and proprietary information available for use in this assignment. All conclusions, forecasts, and projections presented in this Study represent Baker & O'Brien's best judgment based upon information available as of the Study Effective Date. Forecasts, backcasts, and projections prepared for this Study are inherently uncertain due to the potential impact of factors or events that are unknowable, unforeseeable, or beyond Baker & O'Brien's control. Baker & O'Brien reserves the right to supplement or amend this Study if additional information should subsequently become available that is material to the conclusions presented herein.

2. EXECUTIVE SUMMARY

5. *Location*: E & B Natural Resources Management Corporation ("E & B") operates oil and gas production facilities (the "Sites") in the Wilshire and West Los Angeles area of Los Angeles. The operator extracts oil and gas from the Beverly Hills and Salt Lake South Oil Fields under two areas, which include:

   i. Unspecified lease known as the Packard Drill Site ("Packard"): 1353 S. Spaulding Ave.

   ii. S.E.A. Lease: 9101 W. Pico Blvd.

6. *Zoning*: Packard is located within Council District 10 and the Wilshire Community Plan area. Packard is zoned as C4-1-O, Commercial with height limitations in an Oil Drilling District, and R1R3-RG-O, One-Family Residential Rear-Mass with rear detached garage in an Oil Drilling District.[1] The S.E.A. Lease is located within Council District 5 and the West Los Angeles Community Plan Area. The S.E.A. lease site is zoned as C4-1VL-O, Commercial with height limitations in an Oil Drilling District.[2]

7. *History*: Packard was developed by Standard Oil Company of California ("Chevron") mainly between 1966 and 1974, when 70 wells were drilled and completed. Packard began its waterflood operations in 1968; the last well was drilled in 1988. Occidental Petroleum Corporation ("Oxy") drilled the S.E.A. Lease well in 1970. Stocker Resources, Inc. ("Stocker") acquired the Packard Drill Site in 1990 and the S.E.A. Lease well in 1992. The Sites passed through two other operators before the current operator, E & B, took control in 2018.

8. *Sites Status*: The Sites include 72 oil and gas wells. In 2022, the Sites had 38 active production wells, 28 idle production wells, and six active injection wells. Surface facilities at the Sites include lease equipment and various improvements.

9. *Capital Investment*: The original cost to drill and complete wells and install lease facilities at the Sites amounted to about $8.82 million. In addition to the original capital investment, sustaining capital investment in well equipment and lease equipment

[1] Department of City Planning, R1 Variation Zones, https://planning.lacity.gov/ordinances/docs/R1VariationZones/QA_10-6-16.pdf

[2] City zone definitions are found at https://planning.lacity.gov/odocument/eadcb225-a16b-4ce6-bc94-c915408c2b04/Zoning_Code_Summary.pdf

amounted to more than $21.72 million. The cumulative estimated capital investment in the Sites was about $30.55 million as of December 31, 2022.

10. *Sites Income*: The Sites generated revenue from the sale of crude oil and natural gas. Crude oil production from the Sites peaked in 1969 at about 11.15 million barrels annually, or 30,552 barrels per day. Natural gas production peaked in 2000 at more than 416,000 barrels of oil equivalent annually, or just over 1,137 barrels per day. Production of crude oil and natural gas declined from 1969 until 2022 when the Sites produced about 175,000 barrels of oil (478 barrels per day) and about 82,000 barrels of oil equivalent (less than 224 barrels per day) of natural gas. Crude oil produced at the Sites is medium-sour crude with a market value comparable to Alaskan North Slope crude oil. After deductions for payments of royalties, operating costs, income taxes, and sustaining capital investment, the Sites generated a cumulative net cash flow of about $522.00 million between 1966 and 2022.

11. *Base Case Conclusion*: In the Base Case, the capital investment in wells and lease facilities at the Sites was amortized by 1967, within one year of the original capital investment. The cumulative internal rate of return for the Sites in 2022 is higher than the market rate of return of 8%.

12. *Sensitivity Case Conclusions*: Sensitivity cases were prepared to consider reasonable ranges in alternative assumptions in the income analysis, including a higher market rate of return, a lower value received for crude oil, and a higher capital investment. A market rate of return of 12% resulted in no change in the time to amortize the capital investment. Deducting $0.50 per barrel of crude oil resulted in no change in the time to amortize capital investment. Increasing the capital investment to drill and complete new wells by 50% did not lengthen the time required to amortize capital investment. Over a reasonable range of assumptions, these factors do not significantly change the time required to amortize capital investment at the Sites.

3. INTRODUCTION

13. The production of oil and gas has played a major role in the history and development of the City of Los Angeles (the "City"). The legacy of more than 100 years of oil and gas production can be counted in 26 oil and gas fields and more than 5,000 oil and gas wells that are located throughout the City.

14. The Los Angeles City Council passed Oil and Gas Drilling Ordinance 187709[3] (the "Ordinance") that prohibits new oil and gas extraction facilities and makes existing extraction activities in the City a nonconforming land use, with an Ordinance Effective Date of January 18, 2023.

15. The City, through its Board of Public Works' Office of Petroleum and Natural Gas Administration and Safety ("OPNGAS"), retained Baker & O'Brien, Inc. ("Baker & O'Brien") to determine the time required for amortization of capital investment in oil and gas production facilities located within the City under Contract Number C-142695. This *Amortization of Capital Investment Study for the Packard Drill Site* (the "Study") presents the basis and conclusions for Baker & O'Brien's determination of the time required to amortize capital investment for the consolidated operations at two sites where small-scale oil and gas operations are conducted (the "Sites") in the Wilshire and West Los Angeles area of Los Angeles.

16. This Study is incorporated into a larger amortization study that addresses all of the active and idle wells in the City, which is presented in Baker & O'Brien's *Summary Report on the Amortization of Capital Investment Study* (the "Summary Report"). The Summary Report presents Baker & O'Brien's scope of work and qualifications, the methodology used in the amortization analysis, and other reference information that is generally common to the analysis of the various drill sites.

17. This Study presents a detailed economic analysis for the Sites that considers capital investment in existing wells and surface facilities, revenues produced from sales of oil and gas, operating costs associated with the production of oil and gas, and determination of year-to-year financial returns for the Sites. Financial returns for the Sites are compared to market returns on the invested capital achieved by oil and gas production

[3] Los Angeles City Ordinance No. 187709; https://clkrep.lacity.org/onlinedocs/2017/17-0447-S2_ord_187709_1-18-23.pdf

companies to determine the time required for amortization of capital investment. A Base Case determines the time required to amortize capital investment at the Sites, based on historical data and reasonable estimates of capital investment, revenues, and operating costs. The sensitivity cases consider the extent to which alternative assumptions that may be used in the income analysis, including a higher market rate of return, a lower oil price, and larger capital investment, might change the Base Case amortization period.

18. This Study refers to various abbreviations and terms that are used in the oil and gas industry. These abbreviations, terms, and a brief definition for each item are listed for convenience in **Exhibit 1** of the Summary Report.

19. The Study Effective Date for this Study is December 31, 2022. The Study Effective Date represents the cut-off date for historical information that was considered to represent historical capital investment, production volumes, and operating costs used in this Study. In preparing this Study, Baker & O'Brien has relied upon public and proprietary information about the Sites that were available at the Study Effective Date. Reference materials that have been considered in preparing this Study are listed in **Exhibit A**.

4. ABOUT THE SITES

4.1 LOCATION

20. E & B operates oil and gas production facilities in the Wilshire area and West Los Angeles area of Los Angeles (the "Sites"). The operator extracts oil and gas from the Beverly Hills Oil Field and Salt Lake South Oil Field under two leases, which include:

    i. An unspecified lease known as Packard: 1353 S. Spaulding Ave.

    ii. S.E.A. Lease: 9101 W. Pico Blvd.

21. Packard represents most of the wells operated by E & B and is located at the W. Pico Blvd. and S. Spaulding Ave intersection in the Wilshire area. The S.E.A. Lease is located 34 blocks west of Packard at W. Pico Blvd. and S. Doheny Dr. intersection in the West Los Angeles area. The S.E.A. Lease is located inside the West Pico Drill Site and is operated by another operator on E & B's behalf. Aerial photographs of the Sites are shown in **Exhibit B**.[4] Additional location-specific details are provided in **Exhibit 5** of the Summary Report.

4.2 HISTORY

22. Chevron drilled most of the Packard wells between 1966 and 1974 when 70 wells were drilled and completed. Chevron's Packard wells were drilled into the Beverly Hills Oil Field until 1970 after which they began drilling into the nearby Salt Lake South Oil Field. Waterflood operations began in 1968, shortly after the first wells were drilled. Chevron drilled the final well in 1988. In 1990, the site was transferred to Stocker.[5]

23. Oxy drilled and completed the only S.E.A. Lease well in 1970 produced from the Beverly Hills Oil Field. Stocker acquired this well in 1992.

[4] Google Earth.
[5] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit C**.

24. The Sites were transferred to Plains Exploration and Production Company in 2002.[6] Sentinel Peak Resources California, LLC took over the Sites in 2016. The current operator, E & B, took control of the Sites in 2018.[7]

4.3 LEASES

25. The two Sites operate wells that produce oil and gas from two leases, the unspecified name lease at Packard and the "S.E.A. Lease."[8]

26. The status of the wells operating in each of the two leases in 2022 is listed in **Exhibit C** and summarized as follows:

- *Packard*: This lease includes 71 wells. During 2022, 38 production wells were active, 27 production wells were idle, and six injection wells were active.
- *S.E.A. Lease*: This lease includes one well. During 2022, the production well was idle.

4.4 SURFACE FACILITIES

27. Since the well at the S.E.A. Lease is contracted out to the West Pico Drill Site operator, it is assumed that E & B does not own any of the facilities used to produce oil and gas for that well.[9]

28. Packard surface facilities include tanks, pumps, and pipelines for collecting and processing well fluids (the "lease equipment"), buildings, and various site improvements.

29. The wellheads at the Sites are generally located in concrete cellars. No records document the methods or costs associated with disposing of produced water.[10] Still, it is generally believed that produced water has been handled onsite and injected back into the ground at Packard since 1968.

[6] Plains Exploration and Production Company changed its name to Freeport-McMoRan Oil & Gas LLC in 2013.
[7] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit A**.
[8] The full name of S.E.A. was not provided.
[9] CalGEM records for well 0403720908, p. 4.
[10] See waste disposal definition in Exhibit 1 of the Summary Report.

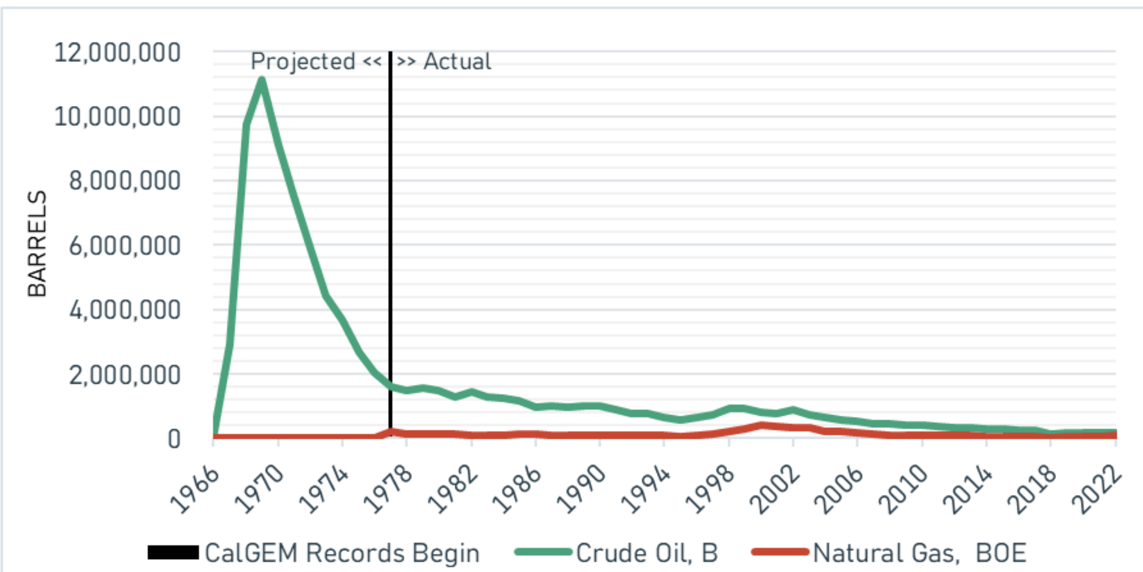
30. For Packard, some lease equipment (mainly storage tanks) is visible in **Exhibit B**. While the equipment shown in the aerial photographs appear typical, it is impossible to determine its condition, or which equipment remains in operation or has been abandoned in place. No records document the size, capacity, or cost of lease equipment when installed.

31. Three structures are visible in the aerial photographs at Packard.[11] The wells at Packard are housed inside the largest structure on the site. It is surrounded by cinderblock walls, wrought-iron fencing, and gates to control access.

4.5 HISTORICAL OIL AND GAS PRODUCTION

32. Oil and gas production from the Sites is shown below in **Figure 1**.[12]

Figure 1 – Sites Oil and Gas Production



33. Production rates at the Sites peaked in 1969 and generally declined. Between 1966 and 1976, production averaged 16,177 barrels per day ("B/D") of oil. This Study assumes that natural gas production before 1977 was negligible and contributed no material income to the Sites.

[11] **Exhibit B** and **Exhibit D**.
[12] CalGEM Production Records.

34. Production declined until 2022, with only a slight bump in the late 1990s. Since 1977, the Sites have averaged 2,029 B/D of oil and 374 barrels of oil equivalent per day ("BOE/D") of natural gas.

4.6 OIL AND GAS QUALITY

35. The Sites produced medium-sour crude oil averaging 27 degrees API ("°API") since 1977.[13] The sulfur content of crude oil was not documented. However, crude oil produced from the Beverly Hills Oil Field is reported to have a sulfur content of approximately 2.45%.[14] The Sites' crude oil quality compares to Alaskan North Slope ("ANS") crude oil, which has market specifications of 31.9°API and a sulfur content of 0.93%.

36. Natural gas produced at the Sites is assumed to have been treated to meet pipeline quality specifications and injected into the Southern California Gas Company ("SoCalGas") system at the Sites' boundaries. Natural gas must be treated to pipeline quality before being injected into a local distribution system.

4.7 LOGISTICS

37. No record is available to confirm how crude oil was delivered from the Sites to local refineries or costs paid to third parties for the delivery of crude oil. The Los Angeles Municipal Code requires that all oil produced from wells in the City will be transported by underground pipeline.[15] This Study assumes that crude oil is injected into a common carrier pipeline for customer delivery through a custody transfer meter at the Sites' boundary. This Study estimates that transportation costs to deliver crude oil from the Sites to Long Beach by a common carrier pipeline were $1.50 per barrel ("/B") in 2022.

38. Since small amounts of natural gas were produced at the Sites, it is assumed that the Sites are connected to a pipeline to deliver natural gas into the SoCalGas system (or another

---

[13] CalGEM Production Records.

[14] The Salt Lake South Oil Field sulfur content was not reported, but the nearby Salt Lake Oil Field was reported to have a sulfur content of 2.73%, which in line with the Beverly Hills Oil Field reported sulfur content. *Sulfur Content of Crude Oils*, Bureau of Mines Information Circular 8676, 1975. https://dggs.alaska.gov/webpubs/usbm/ic/text/ic8676.pdf

[15] Los Angeles Municipal Code Section 13.01.F.2 and 54.

local distribution company). A producer generally injects natural gas into a local distribution company pipeline through a custody transfer meter at the Sites' boundaries.

5. CAPITAL INVESTMENT

39. The capital investment to be amortized at the Sites is the total investment in the plant, property, and equipment used to produce income from the Sites. For this Study, the total capital investment to be amortized includes the original capital investment, sustaining capital investment in well equipment, and sustaining capital investment in lease equipment.[16]

5.1 ORIGINAL CAPITAL INVESTMENT

40. Original capital investment is an operator's investment to acquire lease rights, drill new wells, construct new surface facilities, and start producing oil and gas. Capital investment that adds production capacity to an existing facility (such as drilling and completion of a new production well) is also considered an original investment. Records of capital investment at the Sites are not available; thus, this Study estimates original capital investment for wells, lease equipment, and site improvements.

41. The original capital investment is included in the income analysis in the appropriate year of the cash flow analysis, corresponding to when new facilities were completed.

5.1.1 PRODUCTION AND INJECTION WELLS

42. Original capital investment for production wells at the Sites was estimated based on drilling and completion costs reported by California operators. Costs that are relevant to drill and complete new wells at the Sites are summarized below in **Table 1**. The developments listed in **Table 1** are representative of the wells drilled in the City from reservoirs found below 2,000 feet in depth. These wells are used for primary and waterflood operations, similar to wells found in the City. California Resources Corporation ("CRC") reported various drilling and completion costs for its developments in 2016 and 2022. These costs were normalized to 2022 using the United States ("U.S.") Bureau of Labor Statistics ("BLS") Producer Price Index Oil and Gas Drilling ("PPI-OGD") cost index.[17] The average of the normalized costs in 2022 is $1,397,866 per well.

---

[16] Capital investment does not include operating costs or termination costs. See Section 5.4 of the Summary Report.
[17] Cost indices are discussed in Section 5.2.4 of the Summary Report.

This Study uses an average cost of $1.4 million per well as the original capital investment to drill and complete a production or an injection well during 2022.

Table 1 – Drilling and Completion Costs

Original Cost to Drill and Complete a New Well							
		Reported			Normalized to 2022		
Operator	Location	Year	PPI-OGD [1]	Cost, $/Well	Year	PPI-OGD [1]	Cost, $/Well
CRC	Elk Hills [2]	2016	316.7	$500,000	2022	371.8	$586,980
CRC	Long Beach [2]	2016	316.7	$1,400,000	2022	371.8	$1,643,543
CRC	Wellbore/Stacked Reservoirs [3]	2016	316.7	$1,500,000	2022	371.8	$1,760,939
CRC	Los Angeles Basin [4]	2022	371.8	$1,600,000	2022	371.8	$1,600,000
	Average			**$1,250,000**	**2022**		**$1,397,866**
Cost Used In Model					**2022**		**$1,400,000**

Notes:
1. PPI OGD is BLS Series ID PCU213111213111. June index values are used to reflect mid-year costs.
2. California Resources Corp. 2017 Analyst Day Presentation, p. 36. Includes horizontal component.
3. California Resources Corp. 2017 Analyst Day Presentation, p. 67.
4. California Resources Corp. 2022 Analyst Day Presentation, p. 10. Includes horizontal component.

43. The California Department of Conservation's California Geologic Energy Management Division ("CalGEM") records identify completion dates for wells at the Sites. In the cash flow analysis, capital investment in a well is recorded during the year in which the well was completed. The original capital investment to drill and complete wells before 2022 was estimated by adjusting costs in 2022 for historical changes in drilling costs to the year when a well was completed.[18] Original capital investment for wells at the Sites amounted to about $7.37 million.

5.1.2 LEASE EQUIPMENT

44. Lease equipment generally includes the flowlines, separators, pumps, and metering equipment used to separate the well fluids into oil, gas, and water; treat crude oil and natural gas for sale and treat water for reinjection or disposal.

45. The U.S. Department of Energy's Energy Information Administration ("EIA") published annual capital investment estimates for lease equipment between 1976 and 2009.[19] These estimates included representative costs for lease equipment used in waterflood operations. Lease equipment is typically sized to accommodate the anticipated production rates of well fluids. The EIA costs for lease equipment were adjusted to account for the peak well fluid rates produced at the Sites by applying a standard cost-

[18] See Section 5.2.4 of the Summary Report.
[19] See Section 5.2.2 of the Summary Report.

capacity relationship.[20] The original capital investment in lease facilities was allocated in the cash flow analysis to years when new wells were completed between 1966 and 1988. The original capital investment for lease equipment at the Sites amounted to about $1.38 million.

5.1.3 SITE IMPROVEMENTS

46. Site improvements include permanent buildings, perimeter fences, electrical distribution equipment, safety, and security facilities.

47. For this Study, the original investment in site improvements was estimated to be 5% of the cost for lease facilities.[21] The original site improvements are assumed to have occurred at various times and are allocated to the years when new wells were completed. The original capital investment for site improvements amounted to about $69,000.

5.2 SUSTAINING CAPITAL INVESTMENT

48. Sustaining capital is invested from time to time to maintain the productive capacity of an oil and gas development to produce income. Sustaining capital investment for the Sites includes well modifications, replacement of well equipment, and lease equipment that reaches the end of life. Routine maintenance, testing expenses, and maintenance of site improvements are considered operating costs and are not included in sustaining capital investment.[22]

49. The income analysis considers sustaining capital investment in two ways. First, sustaining capital is deducted from income to calculate the net cash flow available for amortizing capital investment. Second, sustaining capital investment is added to the original capital investment to determine the total capital investment to be amortized. Sustaining capital investment is recorded in the cash flow analysis in the year that well modifications were completed and annually for capital replacement of well equipment and lease equipment.

[20] This relationship, commonly referred to as the Rule of Six-Tenths, is an empirical relationship between the cost and the capacity of a manufacturing facility. The estimated cost = $((\text{capacity}) / (\text{base capacity}))^{0.6}$ x (base cost).
[21] See Section 5.2.3 of the Summary Report.
[22] Operating costs are discussed below in Section 6.3.

5.2.1 WELL MODIFICATIONS

50. Modifications to wells generally include redrill, rework, recompletion, and casing alterations, and other work intended to improve or extend the useful life of a well. These activities require a permit from a California regulator and are documented in CalGEM records. Well modifications often restore or increase production rates that characteristically decline over time by opening wells to different productive zones, converting wells from one use to another, or correcting mechanical issues.

51. CalGEM records present a history of well modifications for each well at the Sites from 1966 to the present.[23] These records may include the nature of the work, the time it was done, and changes in production rates and crude oil quality.

52. California operators have reported the costs for well modifications, and those costs that are relevant to the Sites are listed below in **Table 2**. CRC reported the costs for three types of well modifications,[24] while Sentinel Peak Resources California, LLC, ("SPR") reported an average cost for these activities.[25] Costs reported by CRC and SPR were normalized to 2022 and averaged $207,734 per activity. This Study uses an average cost for well modifications of $210,000 per activity in 2022.

Table 2 – Well Modification Costs

Capital Workover and Modification Costs for an Existing Well							
		Reported			Normalized to 2022		
Operator	Activity	Year	PPI-OGD [1]	Cost, $/Activity	Year	PPI-OGD [1]	Cost, $/Activity
CRC	Convert to Injection [2]	2016	316.7	$150,000	2022	371.8	$176,094
CRC	Addpay [2]	2016	316.7	$200,000	2022	371.8	$234,792
CRC	Deepening [2]	2016	316.7	$200,000	2022	371.8	$234,792
SPR	Recompletion [3]	2021	321.1	$160,000	2022	371.8	$185,260
	Average			**$177,500**	**2022**		**$207,734**
Cost Used In Model					**2022**		**$210,000**

Notes:
1. PPI OGD is BLS Series ID PCU213111213111. June index values are used to reflect mid-year costs.
2. California Resources Corp. 2017 Analyst Day Presentation, p. 67. Additional pay zone work is abbreviated "Addpay."
3. Sentinel Peak Resources, Report of Robert Lang, Alvarez & Marsal, June 17, 2021, Exhibit 1.

---

23 See CalGEM records for each of the wells at the Sites, which are listed in **Exhibit C**.
24 California Resources Corp. 2017 Analyst Day Presentation, p. 67; https://www.sec.gov/Archives/edgar/data/1609253/000160925317000055/crc2017analystday032017.htm
25 Sentinel Peak Resources, Report of Robert Lang, Alvarez & Marsal, June 17, 2021, Exhibit 1. https://www.culvercity.org/files/assets/public/v/1/documents/city-attorney/writtenpubliccomments_2021-6-17_citycouncil-p.pdf

53. CalGEM records identify the completion dates for modifications to wells.[26] Sustaining capital investment in well modifications is recorded in the cash flow analysis during the year the modification is completed. Between 1968 and 2016, the total sustaining capital investment for well modifications amounted to $6.52 million.

5.2.2 WELL EQUIPMENT

54. Sustaining capital investment is needed to replace well equipment, such as pumps and wellheads, when the original equipment reaches the end of its mechanical life. The Study estimates that 10% of the original capital investment to drill and complete production wells and 5% of the original capital investment to drill and complete injection wells are well equipment subject to capital replacement. The remainder of the drilling and completion costs are drill rig and casing costs. Well equipment has an average mechanical life of 30 years with proper maintenance.

55. The Study allows for the replacement of an average of 3.33% of the original capital investment for lease equipment each year.[27] This sustaining capital investment is based on the cost to drill and complete wells, adjusted annually for changes in these activities' costs.[28] The total sustaining capital investment for well equipment amounted to $4.80 million between 1967 and 2022.

5.2.3 LEASE EQUIPMENT

56. Sustaining capital investment is needed to replace original lease equipment that reaches the end of its mechanical life. In addition, the installation of mandated safety and environmental equipment is considered as sustaining capital investment. Lease equipment has an average mechanical life of 30 years with proper maintenance.

57. The Study allows for replacement of an average of 3.33% of the original capital investment for lease equipment each year. This sustaining capital investment is adjusted for changes in lease equipment costs.[29] The total sustaining capital investment for lease equipment amounted to about $10.40 million between 1967 and 2022.

---

[26] See CalGEM records for each of the wells at the Sites, which are listed in **Exhibit C**.

[27] Oil fields typically have longer economic lives than the original equipment. Theoretically, to maintain operations, 3.33% of the cost of the equipment will be replaced each year over a 30-year life. See Section 5.3.2 of the Summary Report.

[28] See Section 5.2.4 of the Summary Report.

[29] See Section 5.2.4 of the Summary Report.

5.3 SUMMARY OF CAPITAL INVESTMENT

58. The total capital investment at the Sites to be amortized is $30.55 million, as summarized below in **Table 3**. This includes $8.82 million of original capital investment between 1966 and 1988 and $21.72 million sustaining capital between 1967 and 2022. These dollar amounts represent the capital investment incurred by operators from 1966 to 2022.

Table 3 – Summary of Site Capital Investment

Summary of Site Capital Investment		
	Investment	Time
Original Capital Investment		
New Wells	$7,374,102	1966-1988
Lease Equipment	$1,380,851	1966-1988
Site Improvements	$69,043	1966-1988
Subtotal	**$8,823,995**	
Sustaining Capital Investment		
Well Modifications	$6,524,593	1968-2016
Well Equipment	$4,795,193	1967-2022
Lease Equipment	$10,404,234	1967-2022
Subtotal	**$21,724,019**	
Capital Investment to be Amortized	**$30,548,015**	

6. INCOME ANALYSIS

59. Capital investment is amortized by the net cash flow generated from sales of oil and gas. This Study prepared a consolidated income analysis that calculates the annual net cash flow beginning with the start of drilling operations at the Sites. In the income analysis, gross revenues are realized from sales of crude oil and natural gas. Net income is calculated by deducting royalties, operating costs, and income taxes from gross revenues. Finally, annual net cash flow is determined by deducting capital investment from net income.

60. The income analysis calculates net cash flow by considering revenues, operating costs, and capital investment each year in “nominal dollars." Nominal dollars (or “dollars of the day”) represent the amount of money spent or earned in a particular year. This Study uses nominal dollar amounts in the income analysis to represent the amounts that an operator spent for capital investment and received as income during each year of the income analysis.

6.1 REVENUES

61. Revenues from oil and gas operations are realized as sales volumes of crude oil and natural gas that are valued at market prices. Sales volumes of crude oil and natural gas from the Sites are the production volumes reported by CalGEM or estimated as discussed below. Market prices for crude oil and natural gas, net of quality adjustments and delivery costs, are the values that the operator of the Sites receives for these sales, which are referred to as “netback” prices.

6.1.1 PRODUCTION VOLUMES

62. Operators in California are required to report production volumes of crude oil and natural gas to CalGEM, which maintains production records for individual wells beginning from 1977 to the present. This information is available for the wells at the Sites.[30]

63. Some of the wells at the Sites were completed and in operation before 1977. This Study backcasts pre-1977 annual well fluid production by utilizing type-curves derived from

[30] CalGEM Production Records.

available production data. Type-curves are developed using standard engineering calculations applied in oil and gas reservoir management and historical data from operating wells.[31] This standard approach assumes that characteristics of the reservoir dictate production rates, which is evident in the type-curves.[32]

64. Annual crude oil and natural gas production volumes from individual wells are aggregated for the Sites to determine income. Annual production volumes from the Sites are summarized above in **Figure 1**, **Section 4.5**.

6.1.2 NETBACK PRICES FOR CRUDE OIL

65. Netback prices for crude oil represent the market price the operator receives for sales of crude oil produced at the Sites, net of quality adjustments, and transportation costs. The netback price is generally determined as the market price for a benchmark crude, plus a quality adjustment, less delivery costs from the drill site to the consumer. Netback prices for crude oil depend upon market values for crude oil of similar quality available in southern California, its quality, and transportation costs to deliver the crude oil to a Los Angeles area refinery.

66. No records are available that document netback prices received for Packard crude oil.[33] However, Packard crude oil is typically 27.0°API with a sulfur content of about 2.45%. Packard crude oil quality is comparable to ANS crude oil, with 31.9°API and 0.93% sulfur.

67. This Study estimated netback prices for Packard crude oil based on market prices for ANS crude oil delivered to Long Beach.[34] Historical price assessments for ANS crude were used as a benchmark for the value of Packard crude from 1988 to the present. ANS price assessments are not available before 1988. Thus, Packard crude prices were estimated by applying a market differential to Brent crude oil between 1979 and 1987, and a market differential to West Texas Intermediate ("WTI") crude oil between 1947 and 1978.[35]

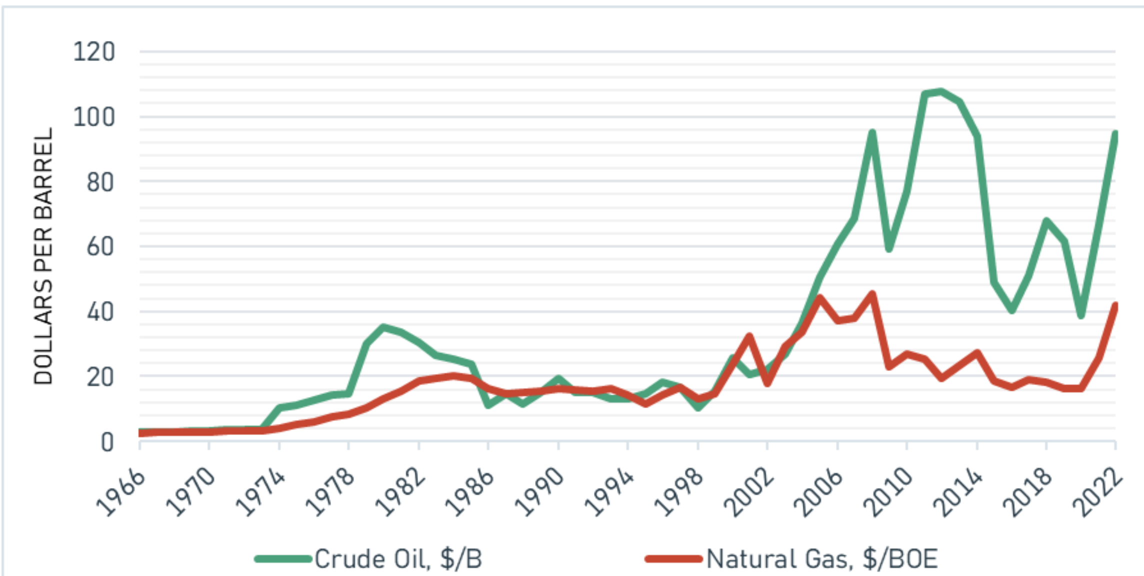
[31] A type-curve is also referred to as a "decline curve."
[32] See Section 6.2 of the Summary Report.
[33] "Packard" crude oil is used in this Study to refer to crude oil produced from the Sites.
[34] ANS crude is delivered by marine tanker to Long Beach.
[35] See Section 6.3 of the Summary Report.

68. A quality adjustment to the benchmark price assessment reflects the difference in refining value between crude oil and the benchmark.[36] As noted above, Packard crude oil is lower in API Gravity and has a higher sulfur content than ANS crude and would be less valuable to a refiner. Based on reasonable industry adjustments for API Gravity, a quality discount of $2.48/B reflects the lower market value of Packard crude oil.[37]

69. Crude oil from the Sites is assumed to be delivered to nearby refineries by pipeline. Due to this proximity, transportation costs to deliver crude oil from the Sites to nearby refineries are estimated at $1.50/B in 2022, based on common carrier tariffs.[38]

70. Annual average netback prices for Packard crude oil are shown below in **Figure 2**.

Figure 2 – Netback Prices for Crude Oil and Natural Gas



6.1.3 NETBACK PRICES FOR NATURAL GAS

71. Netback prices for natural gas represent the market price that an operator receives for natural gas produced at the Sites, less delivery costs. The Sites are assumed to have a connection for delivering natural gas to the SoCalGas system or another local distribution

[36] See Section 6.3 of the Summary Report.
[37] The quality discount of $2.48/B consists of a $1.72/B discount for the API Gravity difference and $0.76/B discount for the sulfur content difference.
[38] Crimson California Pipeline L.P. trunkline tariff, August 1, 2022; Crimson California Pipeline L.P. gathering line tariff, August 1, 2022.

company serving the Los Angeles area. Natural gas must meet pipeline quality specifications before it can be injected into a local distribution system.[39]

72. This Study estimated netback prices for natural gas based on market prices for delivery to the SoCalGas "City Gate," which is a virtual Los Angeles-area trading location. Historical City Gate price assessments for natural gas were used as a benchmark from 1989 to the present. City Gate price assessments are not available before 1989. Thus, Los Angeles area natural gas prices were estimated by applying a historical market differential to Henry Hub natural gas price assessments between 1964 and 1988.[40] No discount for transportation costs was applied to these sales, which would be delivered into a pipeline.

73. Annual average netback prices for Packard natural gas are shown above in **Figure 2**.[41]

6.2 ROYALTIES

74. Owners of mineral rights earn a royalty on commercial volumes of oil and gas produced from their property.[42] These arrangements are set out in lease agreements between the mineral rights owner and the operator, which can vary from lease to lease. The operator pays royalties to the owner of the mineral rights out of revenues, and this cash is not available to amortize the operator's capital investment. No records are available to document royalty rates paid on leases at the Sites.

75. The income analysis deducts royalties and other land lease costs equal to 16.660% of revenues. This is the same royalty rate applicable to leases for oil and gas extraction on California state lands.[43]

6.3 OPERATING COSTS

76. Lease operating costs generally include labor, utilities, operating materials, maintenance materials, spare parts, general and administrative expenses, insurance, and permits. Direct operating costs include costs to separate the oil, gas, and produced water, treat

---

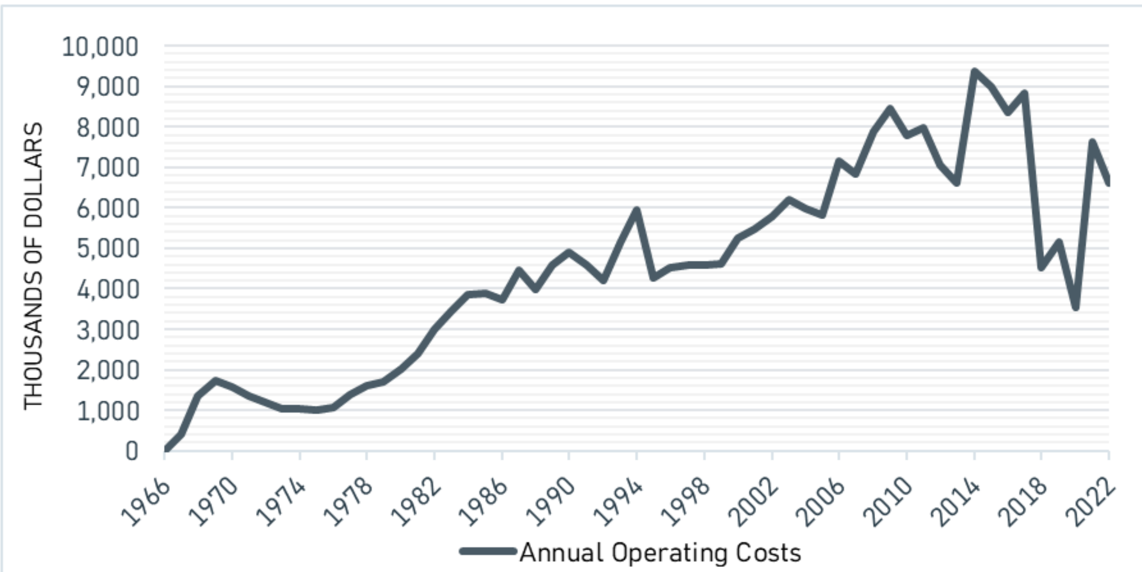
[39] https://www.socalgas.com/documents/news-room/fact-sheets/PipelineBasics.pdf
[40] See Section 6.4 and Exhibit 1 of the Summary Report.
[41] "Packard" natural gas is used in this Study to refer to natural gas produced from the Sites.
[42] Owners of mineral rights and landowners may or may not be the same person/entity.
[43] *Report on the Federal Oil and Gas Leasing Program*, U.S. Department of the Interior, November 2021.

crude oil and natural gas to market specifications, and treat produced water for reinjection or disposal.

77. The EIA published annual estimates of oil lease operating costs between 1976 and 2009.[44] Operating costs for the Sites were estimated by normalizing EIA figures to the Sites' design production rate of well fluids and applying these costs to the reported production of well fluids from the Sites. Prior to 1976 and after 2009, the EIA operating costs were adjusted for historical changes in operating costs.[45]

78. Annual operating costs for the Sites are summarized below in **Figure 3**.

Figure 3 – Sites Operating Costs



6.4 INCOME TAXES

79. The income analysis deducts income taxes from revenues to determine the net cash flow available for the amortization of capital investment. Income before taxes is adjusted for depreciation of capital investment and for tax loss carry-forward (where applicable) to calculate taxable income.

[44] See Section 6.6 of the Summary Report

[45] See Section 5.2.4 of the Summary Report.

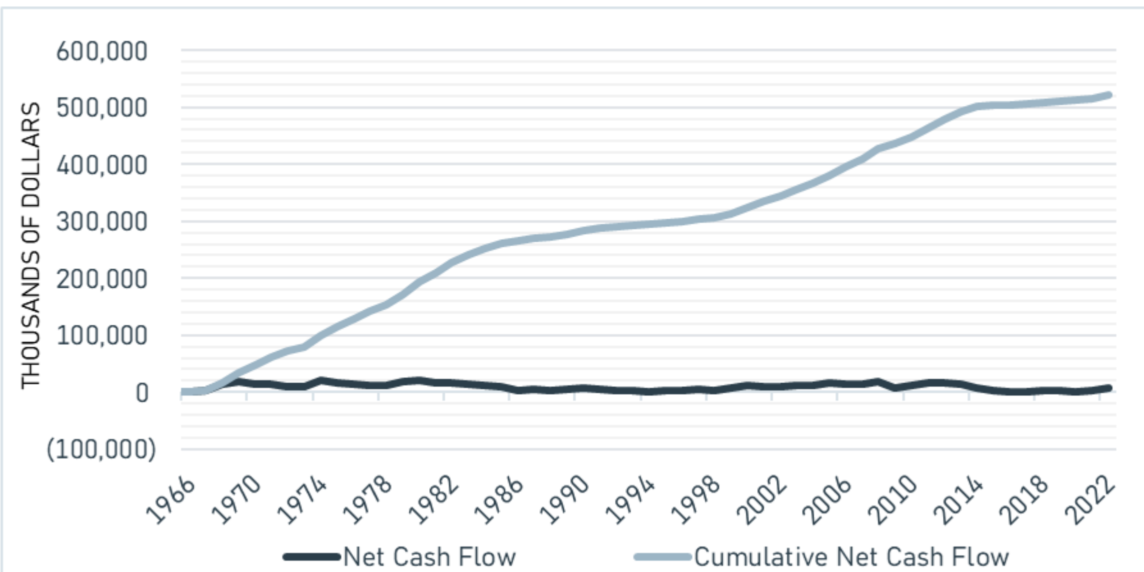
80. Federal and state income taxes on taxable income are calculated using the highest corporate tax brackets in effect each year. Federal income tax rates range from 21% to 46%, and California state income tax rates range from 8.8% to 9.6%.[46]

6.5 NET CASH FLOW FOR AMORTIZATION

81. Annual net income is calculated by deducting royalties, operating costs, and income taxes from revenues. Annual net cash flow is determined by deducting capital investment from net income. Annual net cash flow from the Sites averaged about $9.16 million, and the cumulative net cash flow between 1966 and 2022 amounted to about $522.00 million. These dollar amounts represent the cash flow generated from 1966 to 2022.

82. The annual and cumulative net cash flow from the Sites are shown in **Figure 4**.

Figure 4 – Sites Net Cash Flow



[46] See Section 6.7 of the Summary Report.

7. MARKET RATE OF RETURN ON INVESTMENT

83. The tests for amortization of capital investment use a "market" rate of return on investment characteristic of oil and gas production companies.[47] The market rate of return on investment is a total rate of return that is realized by public companies in this industry sector.

84. This Study refers to an analysis of the Weighted Average Cost of Capital ("WACC") for public companies that has been published annually since 1998.[48] For each year, the cost of equity, cost of debt, capital structure, and WACC are reported for companies in the oil and gas industry sector that are mainly structured as corporations. The number of oil and gas production companies included in the annual report varied from 92 to 411 firms. For this group, the WACC has ranged between 6% and 10% since 1998 (see **Exhibit 4** of the Summary Report).

85. The income analysis for this Study assumes a market rate of return of 8%, which is near the median of companies engaged in oil and gas production from 1998 through 2022. This industry rate of return is characteristic of returns on capital investment to a corporation that pays income taxes on net operating income.

---

[47] See Section 4.3 of the Summary Report.
[48] See Section 7.1 of the Summary Report.

8. CONCLUSIONS

86. The income analysis was used in the amortization model to determine the time required to achieve amortization of capital investment using the Base Case assumptions discussed above. The income analysis was also used to test the impact of alternative assumptions on the time to achieve amortization.

87. The Base Case and Sensitivity assumptions and results for this Study are summarized below in **Table 4**. The alternative assumptions used in each of the sensitivity cases are highlighted.

8.1 BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

88. In the Base Case, capital investment in wells and lease facilities at the Sites was amortized by 1967, within one year of the original capital investment.

89. The results of the Base Case income analysis are summarized in **Exhibit E**. The Internal Rate of Return ("IRR") test for amortization was achieved in 1967 when the cumulative IRR exceeded the 8% market rate of return. The Net Present Value ("NPV") test for amortization was also achieved in 1967 when the cumulative net present value exceeded zero.

90. The total capital investment of $30.55 million was amortized by $522.00 million of net cash flow between 1966 and 2022. The original capital investment was amortized within one year of commencement of operations. The cumulative IRR increased to about 3,145% by 1969 and remained at that level through 2022.

8.2 SENSITIVITY CASE A: MARKET RETURN ON CAPITAL INVESTMENT

91. Case A sensitivity analysis demonstrates that the capital investment amortization time did not change over a reasonable range of the market rate of return assumptions.

92. In Sensitivity Case A, the Base Case market rate of return of 8% was replaced with a rate of return of 12%. This alternative assumption was selected as the highest cost of equity

for oil and gas companies reported since 1998 and is the upper limit of a reasonable range of market rates of return.[49]

93. The results of Sensitivity Case A income analysis are summarized in **Exhibit F**. The IRR test for amortization was achieved in 1967 when the cumulative IRR exceeded the 12% rate of return. The NPV test for amortization was also achieved in 1967 when the cumulative net present value exceeded zero. Even with a higher market return on capital, the capital investment in wells and lease facilities at the Sites was amortized by 1967.

8.3 SENSITIVITY CASE B: COMMODITY PRICE

94. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment did not change over a reasonable range of assumptions related to the price of crude oil.

95. In Sensitivity Case B, the Base Case quality discount of $2.48/B was changed to a discount of $2.98/B. This assumption reduces the netback price received by the operator by $0.50/B, which is a lower limit for a reasonable range of values for Packard crude oil.

96. The results of the Sensitivity Case B income analysis are summarized in **Exhibit G**. The IRR test for amortization was achieved in 1967 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1967 when the cumulative net present value exceeded zero. The capital investment in wells and lease facilities at the Sites was amortized by 1967, even with lower crude oil netback prices.

8.4 SENSITIVITY CASE C: ORIGINAL CAPITAL INVESTMENT

97. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment did not change, even with a larger original capital investment.

98. In Sensitivity Case C, the Base Case cost to drill and complete a well was increased by 50%, from $1.4 million to $2.1 million. This assumed investment for an oil well exceeds

[49] See Exhibit 4 of the Summary Report.

the maximum cost for a new well reported by CRC by more than 19%.[50] The Case C scenario represents the upper limit for a reasonable range of original capital costs.

99. The results of the Sensitivity Case C income analysis are summarized in **Exhibit H**. The IRR test for amortization was achieved in 1967 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1967 when the cumulative net present value exceeded zero. Even with a larger capital investment in wells and lease facilities at the Sites, this capital investment was amortized by 1967.

8.5 INCOME ANALYSES SUMMARY

100. The Base Case and Sensitivity assumptions and results for this Study are summarized below in **Table 4**. The sensitivity cases are calculated to test the potential impact of alternative assumptions on the Base Case conclusion of the time required to achieve amortization of capital investment. As discussed in Section 8 of the Summary Report, the alternative assumptions include a 4% higher market return on capital investment, a $0.50/B lower price of crude oil, and an increase of 50% to the costs to drill and complete the wells. The alternative assumptions used in each of the sensitivity cases are highlighted.

[50] See **Table 1** above.

Table 4 – Income Analyses Assumptions

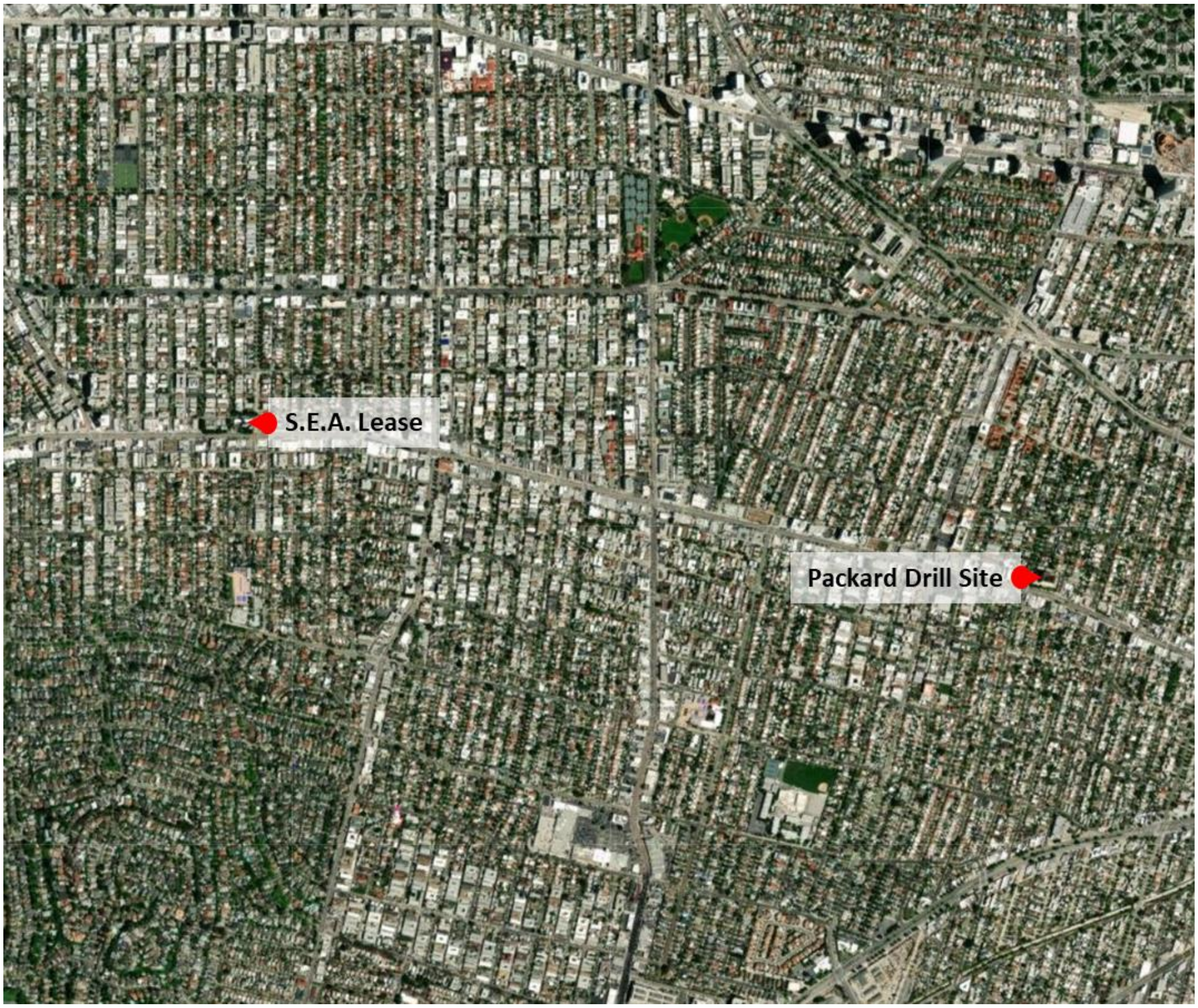
Model Assumptions	Base Case	Case A	Case B	Case C
Market Return on Capital Investment, %				
Oil and Gas Production Companies	8.00%	12.00%	8.00%	8.00%
Commodity Price Factors, 2022 ($/B)				
Crude Oil Transportation - Site to Long Beach	1.50	1.50	1.50	1.50
Crude Oil Quality Adjustment	(2.48)	(2.48)	(2.98)	(2.48)
Royalty and Lease Costs, % Revenue				
Royalty Rate	16.660%	16.660%	16.660%	16.660%
Site Operating Costs, 2022 ($/B)				
Basis: Total Produced Liquids	1.53	1.53	1.53	1.53
Capital Expenditures, 2022 ($ Thousands)				
Drilling and Completion Cost per Well	1,400	1,400	1,400	2,100
Well Modification Cost per Event	210	210	210	210
Results, 2022				
IRR, %	3145.21%	3145.21%	3089.57%	1945.52%
NPV, ($ Thousands)	132,003	89,100	130,586	130,027
Years to Amortization, IRR	1	1	1	1
Years to Amortization, NPV	1	1	1	1

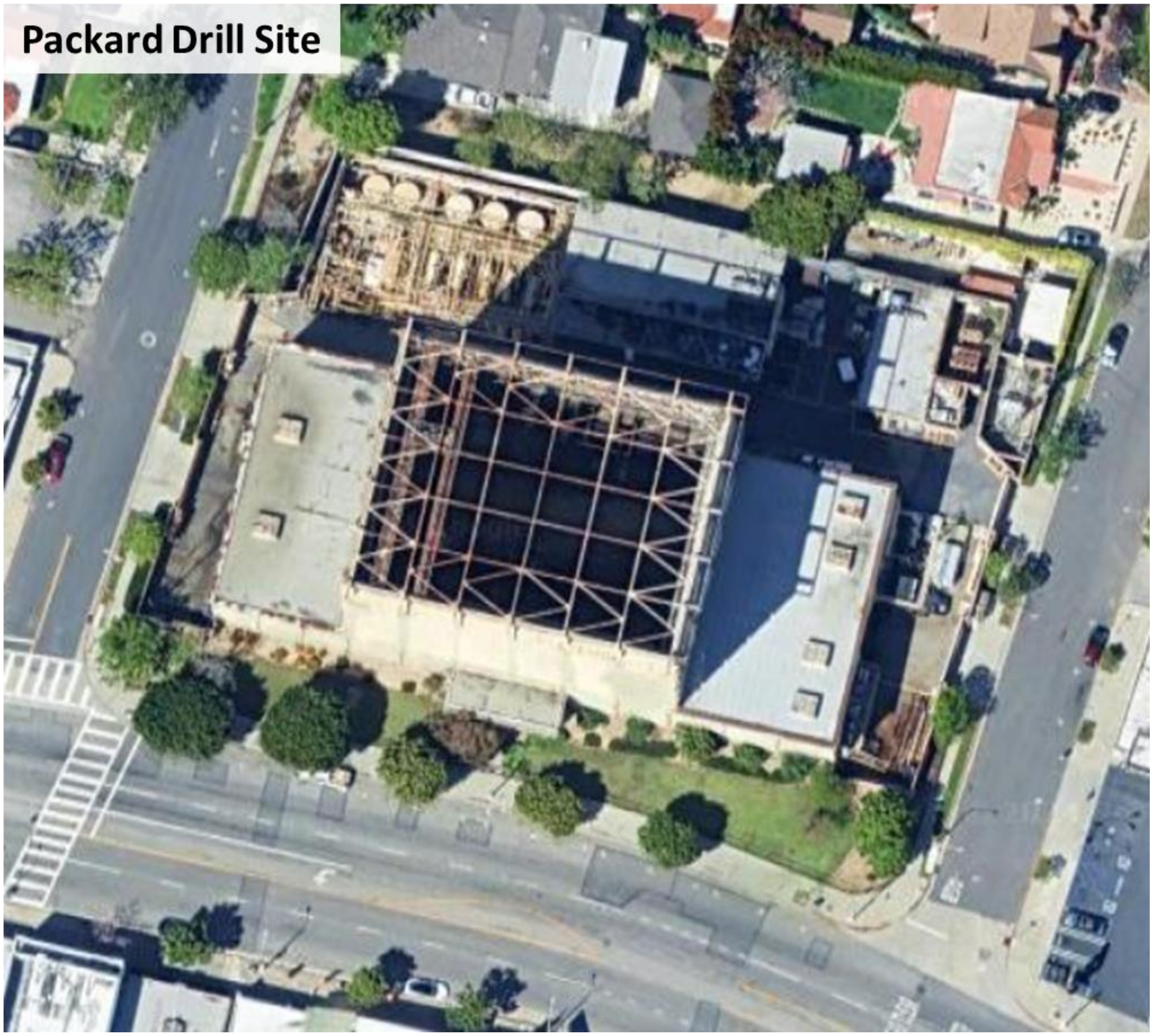
EXHIBIT A: LIST OF REFERENCE DOCUMENTS

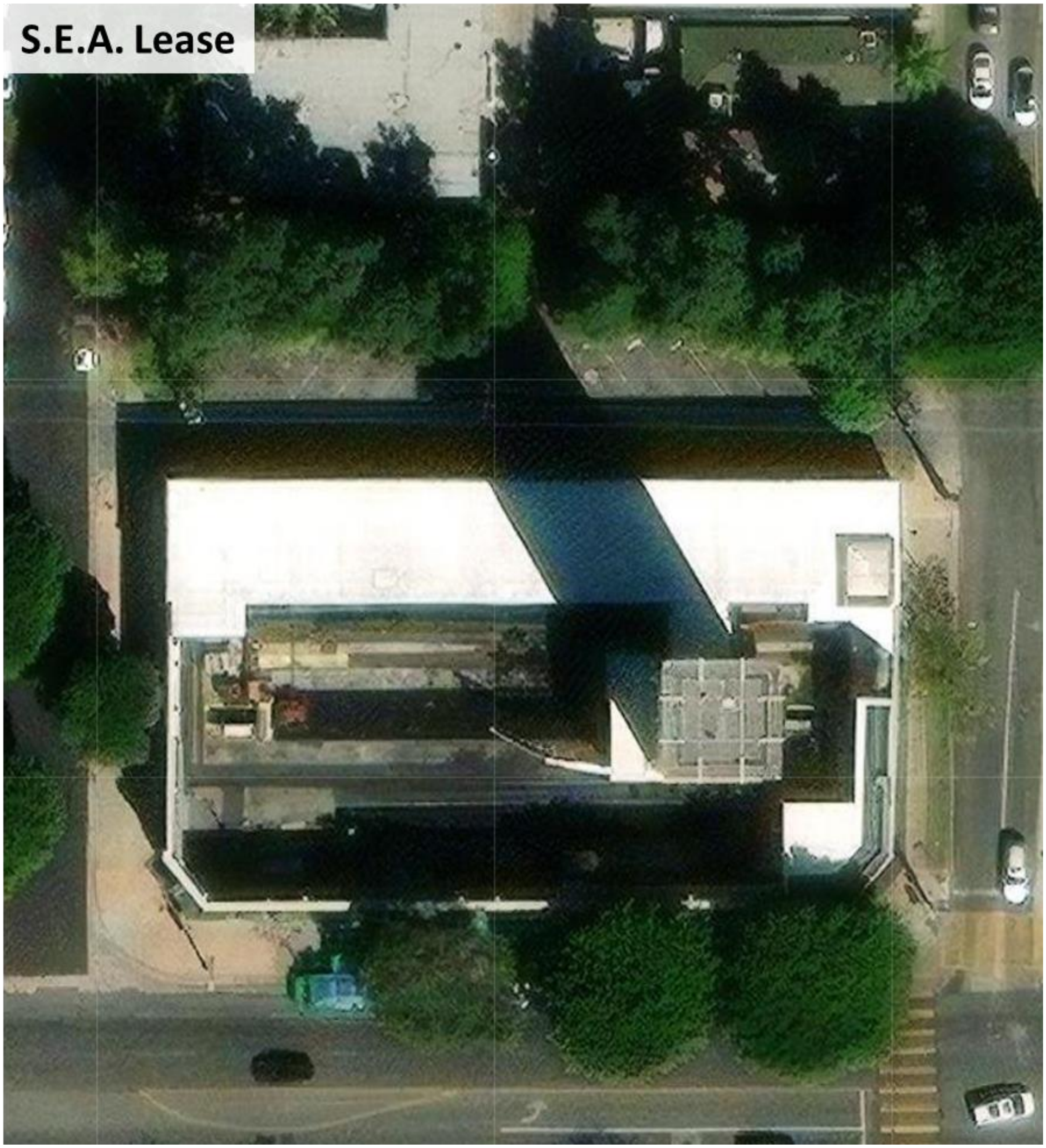
Title	Date
Bureau of Mines Information Circular 8676, Sulfur Content of Crude Oils	January 1, 1975
Costs and Indices for Domestic Oil and Gas Field Equipment and Operations , DOE/EIA-0185(95)	August 1, 1996
2010 EIA Lease Equip Cost Cost Study Data File	September 28, 2010
Oil and Gas Lease Equipment and Operating Costs 1994 through 2009 , DOE/EIA	September 28, 2010
Department of City Planning, R1 Variation Zones	October 6, 2016
California Resources Corporation 2017 Analyst Day Presentation	March 22, 2017
Report of R Lang, Alvarez & Marsal, for Sentinel Peak Resources	June 17, 2021
US. Department of the Interior, Report on the Federal Oil and Gas Leasing Program	November 1, 2021
California Resources Corporation Investor Presentation	June 1, 2022
Crimson California Pipeline L.P. Local Tariff for Gathering of Crude Petroleum	August 1, 2022
Crimson California Pipeline L.P. Local Tariff for Transportation of Crude Petroleum	August 1, 2022
https://crudemarketing.chevron.com/crude/north_american/california.aspx	September 14, 2023
Official City of Los Angeles Municipal Code	June 30, 2023
CalGEM Records for API 403700029, File 03700029_DATA_2014-08-19	Various
CalGEM Records for API 403720011, File 03720011_2017-11-16_DATA	Various
CalGEM Records for API 403720044, File 03720044_2018-06-19_DATA	Various
CalGEM Records for API 403720055, File 03720055_2018-06-19_DATA	Various
CalGEM Records for API 403720090, File 03720090_2017-12-04_DATA	Various
CalGEM Records for API 403720100, File 03720100_2018-06-19_DATA	Various
CalGEM Records for API 403720104, File 03720104_2018-05-29_DATA	Various
CalGEM Records for API 403720196, File 03720196_2018-08-30_DATA	Various
CalGEM Records for API 403720232, File 03720232_2018-06-19_DATA	Various
CalGEM Records for API 403720234, File 03720234_2018-06-19_DATA	Various
CalGEM Records for API 403720268, File 03720268_2018-06-19_DATA	Various
CalGEM Records for API 403720292, File 03720292_2019-04-30_DATA	Various
CalGEM Records for API 403720293, File 03720293_2018-06-22_DATA	Various
CalGEM Records for API 403720323, File 03720323_2018-06-19_DATA	Various
CalGEM Records for API 403720360, File 03720360_2018-06-19_DATA	Various
CalGEM Records for API 403720362, File 03720362_2018-05-29_DATA	Various
CalGEM Records for API 403720363, File 03720363_2018-05-29_DATA	Various
CalGEM Records for API 403720365, File 03720365_2018-05-29_DATA	Various
CalGEM Records for API 403720429, File 03720429_2018-06-19_DATA	Various
CalGEM Records for API 403720441, File 03720441_2018-06-27_DATA	Various
CalGEM Records for API 403720463, File 03720463_2017-08-01_DATA	Various
CalGEM Records for API 403720477, File 03720477_2018-06-19_DATA	Various
CalGEM Records for API 403720512, File 03720512_2018-06-27_DATA	Various
CalGEM Records for API 403720520, File 03720520_2016-01-26_DATA	Various
CalGEM Records for API 403720547, File 03720547_2019-04-09_DATA	Various
CalGEM Records for API 403720553, File 03720553_2018-06-28_DATA	Various
CalGEM Records for API 403720562, File 03720562_2018-05-29_DATA	Various
CalGEM Records for API 403720603, File 03720603_2018-05-29_DATA	Various
CalGEM Records for API 403720624, File 03720624_2018-05-29_DATA	Various
CalGEM Records for API 403720625, File 03720625_2018-06-28_DATA	Various
CalGEM Records for API 403720643, File 03720643_2018-05-29_DATA	Various
CalGEM Records for API 403720660, File 03720660_2018-09-07_DATA	Various
CalGEM Records for API 403720664, File 03720664_2018-06-29_DATA	Various
CalGEM Records for API 403720672, File 03720672_2018-06-19_DATA	Various
CalGEM Records for API 403720688, File 03720688_2018-05-29_DATA	Various
CalGEM Records for API 403720715, File 03720715_2018-06-29_DATA	Various
CalGEM Records for API 403720729, File 03720729_2018-06-20_DATA	Various
CalGEM Records for API 403720759, File 03720759_2017-11-16_DATA	Various
CalGEM Records for API 403720760, File 03720760_2015-03-04_DATA	Various
CalGEM Records for API 403720769, File 03720769_2018-06-29_DATA	Various
CalGEM Records for API 403720777, File 03720777_2018-04-25_DATA	Various

CalGEM Records for API 403720779, File 03720779_2018-05-29_DATA	Various
CalGEM Records for API 403720790, File 03720790_2018-06-29_DATA	Various
CalGEM Records for API 403720831, File 03720831_2018-06-28_DATA	Various
CalGEM Records for API 403720896, File 03720896_2018-06-29_DATA	Various
CalGEM Records for API 403720904, File 03720904_2018-06-29_DATA	Various
CalGEM Records for API 403720908, File 03720908_2018-06-21_DATA	Various
CalGEM Records for API 403720915, File 03720915_2018-06-20_DATA	Various
CalGEM Records for API 403720916, File 03720916_2018-06-29_DATA	Various
CalGEM Records for API 403720936, File 03720936_2018-05-29_DATA	Various
CalGEM Records for API 403720946, File 03720946_2018-06-29_DATA	Various
CalGEM Records for API 403720972, File 03720972_2018-07-02_DATA	Various
CalGEM Records for API 403721009, File 03721009_2018-06-19_DATA	Various
CalGEM Records for API 403721056, File 03721056_2014-03-21_DATA	Various
CalGEM Records for API 403721097, File 03721097_2015-04-15_DATA_	Various
CalGEM Records for API 403721114, File 03721114_2018-06-22_DATA	Various
CalGEM Records for API 403721117, File 03721117_2014-03-21_DATA	Various
CalGEM Records for API 403721125, File 03721125_2014-03-21_DATA	Various
CalGEM Records for API 403721132, File 03721132_2014-03-21_DATA	Various
CalGEM Records for API 403721135, File 03721135_2014-03-27_DATA	Various
CalGEM Records for API 403721144, File 03721144_2014-12-17_DATA	Various
CalGEM Records for API 403721167, File 03721167_2018-03-14_DATA	Various
CalGEM Records for API 403721172, File 03721172_2015-03-04_DATA	Various
CalGEM Records for API 403721192, File 03721192_2014-08-25_DATA	Various
CalGEM Records for API 403721210, File 03721210_2014-03-21_DATA	Various
CalGEM Records for API 403721236, File 03721236_2014-03-21_DATA	Various
CalGEM Records for API 403721414, File 03721414_2017-12-08_DATA	Various
CalGEM Records for API 403721422, File 03721422_2018-10-17_DATA	Various
CalGEM Records for API 403721425, File 03721425_2018-02-13_DATA	Various
CalGEM Records for API 403721437, File 03721437_2017-12-08_DATA	Various
CalGEM Records for API 403721448, File 03721448_2017-12-08_DATA	Various
CalGEM Records for API 403723490, File 03723490_2018-01-04_DATA	Various
CalGEM Production Records, File CALGEMs_Well_Data_Formatting_Packard	Various

EXHIBIT B: AERIAL PHOTOGRAPHS OF THE SITE




Packard Drill Site



Source: Google Earth.

EXHIBIT C: WELLS AT THE SITE

Well API No.	Lease Name	Well Designation	Spudded	Complete	Current Type	Current Status
403700029	Unspecified	P-1	12/29/1966	2/16/1967	Oil & Gas	Active
403720011	Unspecified	P-2	1/10/1967	2/11/1967	Oil & Gas	Idle
403720044	Unspecified	P-7	2/14/1967	3/11/1967	Oil & Gas	Active
403720055	Unspecified	P-5	2/22/1967	4/3/1967	Oil & Gas	Active
403720090	Unspecified	P-3	3/12/1967	4/6/1967	Oil & Gas	Idle
403720100	Unspecified	P-8	3/30/1967	5/4/1967	Oil & Gas	Idle
403720104	Unspecified	P-6	4/3/1967	6/17/1967	Waterflood	Active
403720196	Unspecified	P-13	7/1/1967	8/6/1967	Oil & Gas	Active
403720232	Unspecified	P-16A	8/7/1967	9/3/1967	Oil & Gas	Active
403720234	Unspecified	P-15	8/23/1967	9/19/1967	Oil & Gas	Active
403720268	Unspecified	P-17	9/3/1967	9/26/1967	Oil & Gas	Active
403720292	Unspecified	P-18	9/20/1967	11/20/1967	Waterflood	Active
403720293	Unspecified	P-19	9/27/1967	10/24/1967	Oil & Gas	Active
403720323	Unspecified	P-14	10/24/1967	11/19/1967	Oil & Gas	Active
403720360	Unspecified	P-22	3/5/1968	4/10/1968	Oil & Gas	Idle
403720362	Unspecified	P-20	9/3/1968	9/28/1968	Oil & Gas	Idle
403720363	Unspecified	P-23	11/21/1967	1/14/1968	Oil & Gas	Active
403720365	Unspecified	P-21	11/19/1967	12/15/1967	Oil & Gas	Active
403720429	Unspecified	P-25	1/15/1968	2/8/1968	Oil & Gas	Active
403720441	Unspecified	P-26	2/5/1968	2/24/1968	Oil & Gas	Active
403720463	Unspecified	P-27	2/9/1968	3/4/1968	Waterflood	Active
403720477	Unspecified	P-24	2/25/1968	4/22/1968	Oil & Gas	Active
403720512	Unspecified	P-33	4/10/1968	5/27/1968	Oil & Gas	Active
403720520	Unspecified	P-32	4/22/1968	5/15/1968	Oil & Gas	Idle
403720547	Unspecified	P-34	5/15/1968	6/7/1968	Waterflood	Active
403720553	Unspecified	P-35	5/28/1968	8/8/1968	Oil & Gas	Idle
403720562	Unspecified	P-36	6/8/1968	7/2/1968	Oil & Gas	Active
403720603	Unspecified	P-37	7/25/1968	8/13/1968	Oil & Gas	Active
403720624	Unspecified	P-29	8/13/1968	9/3/1968	Oil & Gas	Active
403720625	Unspecified	P-40B	8/9/1968	9/3/1968	Oil & Gas	Idle
403720643	Unspecified	P-28	9/4/1968	9/22/1968	Oil & Gas	Active
403720660	Unspecified	P-38	9/22/1968	10/12/1968	Oil & Gas	Idle
403720664	Unspecified	P-42	9/29/1968	10/31/1968	Oil & Gas	Active
403720672	Unspecified	P-9	10/13/1968	11/25/1968	Oil & Gas	Active
403720688	Unspecified	P-31	11/1/1968	12/28/1968	Oil & Gas	Active
403720715	Unspecified	P-44	11/26/1968	12/22/1968	Oil & Gas	Idle
403720729	Unspecified	P-45	12/23/1968	1/18/1969	Oil & Gas	Active
403720759	Unspecified	P-46	1/22/1969	2/18/1969	Oil & Gas	Idle
403720760	Unspecified	P-48	1/19/1969	2/13/1969	Oil & Gas	Idle
403720769	Unspecified	P-49	2/14/1969	3/20/1969	Oil & Gas	Active
403720777	Unspecified	P-50B	2/19/1969	7/3/1969	Waterflood	Active
403720779	Unspecified	P-58	7/4/1969	10/26/1969	Oil & Gas	Active
403720790	Unspecified	P-52A	3/21/1969	4/17/1969	Oil & Gas	Active
403720831	Unspecified	P-54	4/19/1969	6/22/1969	Oil & Gas	Active
403720896	Unspecified	P-55	6/22/1969	10/23/1969	Oil & Gas	Idle
403720904	Unspecified	P-56	7/17/1969	8/15/1969	Oil & Gas	Active
403720908	S.E.A.	1	2/14/1970	3/26/1970	Oil & Gas	Idle
403720915	Unspecified	P-57	8/15/1969	9/26/1969	Oil & Gas	Active
403720916	Unspecified	P-43	10/23/1969	12/6/1969	Oil & Gas	Active
403720936	Unspecified	P-53	10/27/1969	12/2/1969	Oil & Gas	Active
403720946	Unspecified	P-59B	12/7/1969	3/31/1970	Oil & Gas	Active
403720972	Unspecified	P-62	12/14/1969	1/23/1970	Oil & Gas	Idle

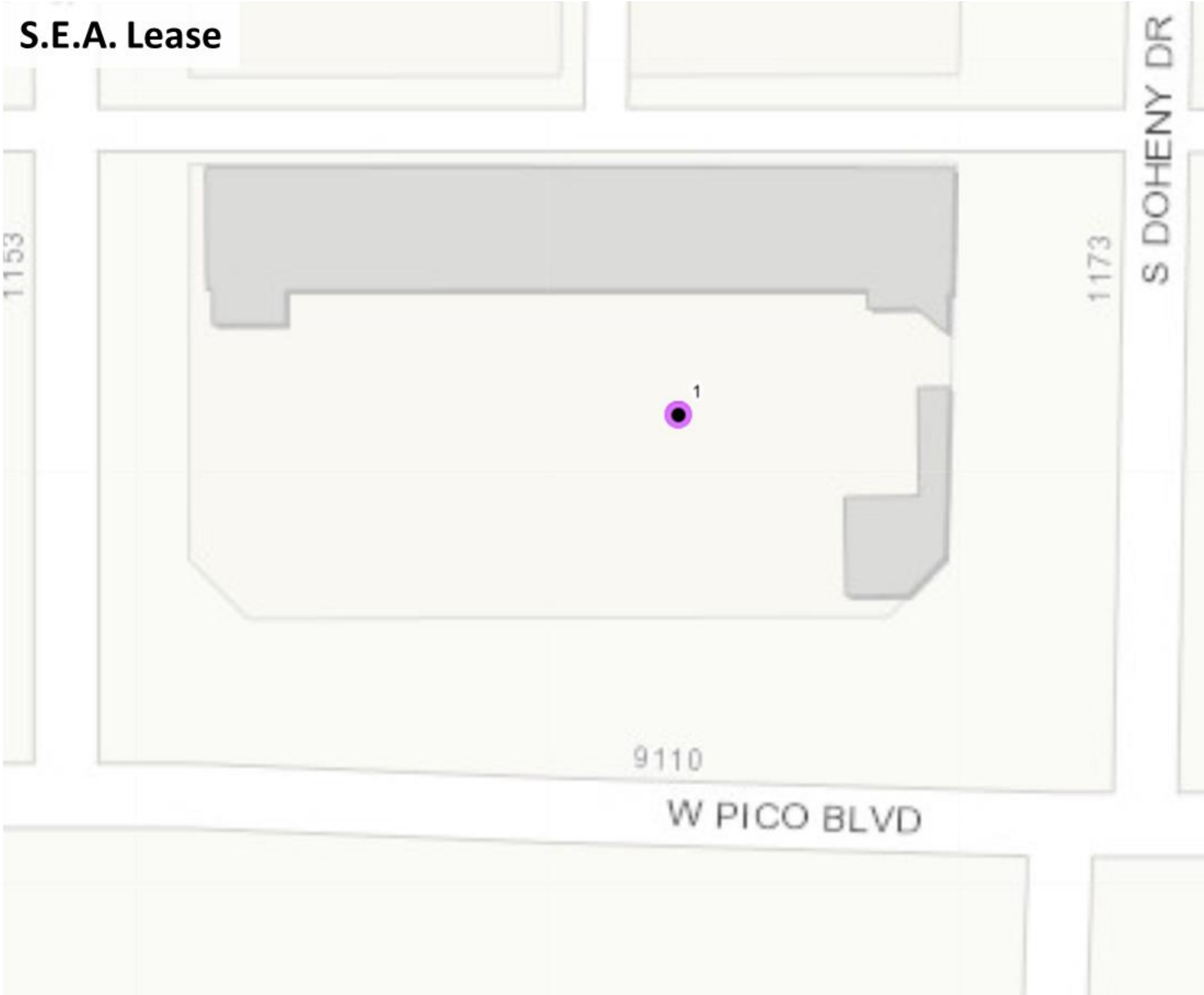
403721009	Unspecified	P-63	3/24/1970	4/24/1970	Waterflood	Active
403721056	Unspecified	P-65	9/19/1970	10/3/1970	Oil & Gas	Idle
403721097	Unspecified	P-69	12/8/1970	12/31/1970	Oil & Gas	Idle
403721114	Unspecified	P-39	1/28/1971	3/7/1971	Oil & Gas	Active
403721117	Unspecified	P-64	3/9/1971	3/30/1971	Oil & Gas	Active
403721125	Unspecified	P-66	3/31/1971	4/20/1971	Oil & Gas	Idle
403721132	Unspecified	P-67	5/16/1971	6/15/1971	Oil & Gas	Idle
403721135	Unspecified	P-68	6/24/1971	7/21/1971	Oil & Gas	Active
403721144	Unspecified	P-71	7/22/1971	8/19/1971	Oil & Gas	Active
403721167	Unspecified	P-72	9/5/1971	11/17/1971	Oil & Gas	Idle
403721172	Unspecified	P-73	11/17/1971	1/12/1972	Oil & Gas	Idle
403721192	Unspecified	P-75B	1/26/1972	2/23/1972	Oil & Gas	Idle
403721210	Unspecified	P-74	3/9/1972	4/25/1972	Oil & Gas	Idle
403721236	Unspecified	P-77	7/21/1972	8/14/1972	Oil & Gas	Idle
403721414	Unspecified	P-79	10/25/1973	11/16/1973	Oil & Gas	Idle
403721422	Unspecified	P-80	11/17/1973	12/7/1973	Oil & Gas	Active
403721425	Unspecified	P-84	12/8/1973	1/7/1974	Oil & Gas	Idle
403721437	Unspecified	P-86	1/16/1974	2/8/1974	Oil & Gas	Idle
403721448	Unspecified	P-87	2/16/1974	3/19/1974	Oil & Gas	Idle
403723490	Unspecified	P-88	3/1/1988	4/26/1988	Oil & Gas	Active

Source: CalGEM Well Finder and CalGEM Records.

* No Record found, date is an approximation

Note: “Spudded” refers to the start of drilling operations. “Complete” refers to completion of drilling operations such that the well is ready to be placed into production.

EXHIBIT D: LOCATION OF WELLS AT THE SITE



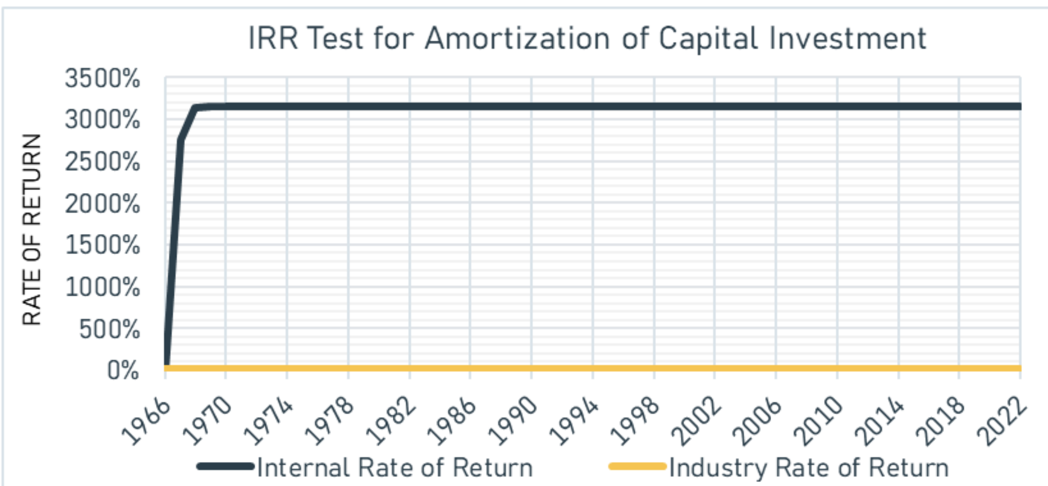
Source: CalGEM Well Finder website

The CalGEM website indicates the well status as follows:

- Wells indicated in green are active
- Wells indicated in purple are idle
- Wells indicated in grey are plugged
- Injection wells are indicated with an arrow

EXHIBIT E: BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

Model Output Summary	
Start Year	1966
Amortization Year (IRR)	1967
Amortization Year (NPV)	1967
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	30,548
Gross Revenues, $thousands	1,417,306
EBITDA, $thousands	924,690
Net Cash Flow, $thousands	522,000
Cumulative IRR at 2022	3145.21%



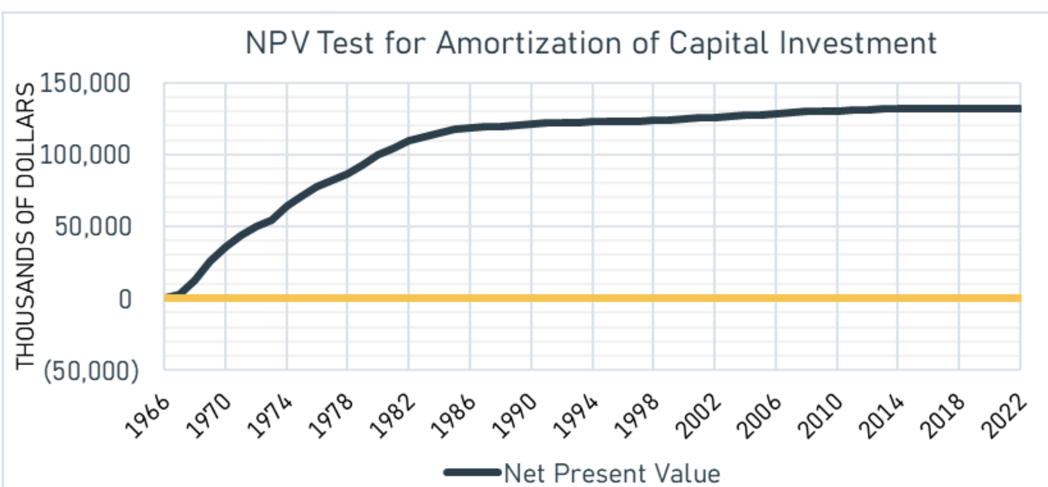
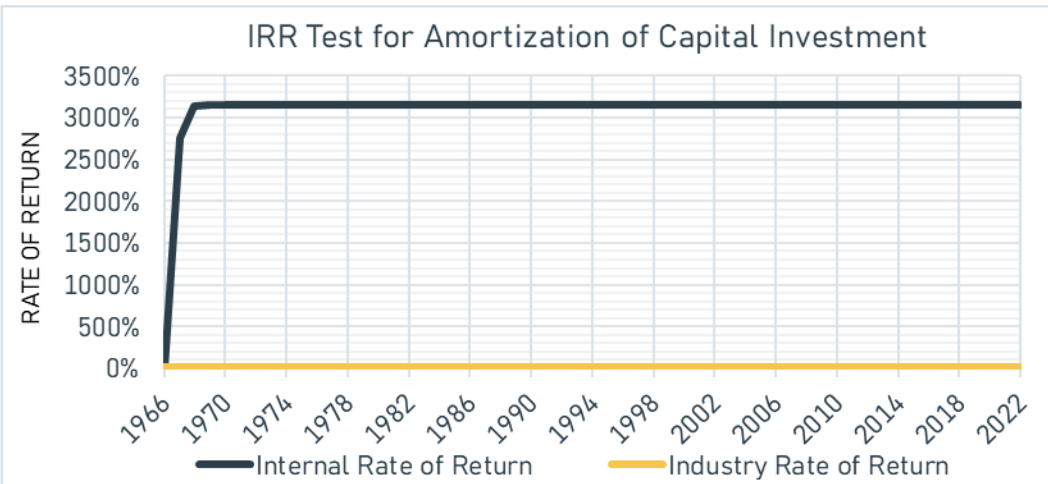


EXHIBIT F: SENSITIVITY CASE A—MARKET RETURN ON CAPITAL INVESTMENT

Model Output Summary	
Start Year	1966
Amortization Year (IRR)	1967
Amortization Year (NPV)	1967
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	30,548
Gross Revenues, $thousands	1,417,306
EBITDA, $thousands	924,690
Net Cash Flow, $thousands	522,000
Cumulative IRR at 2022	3145.21%



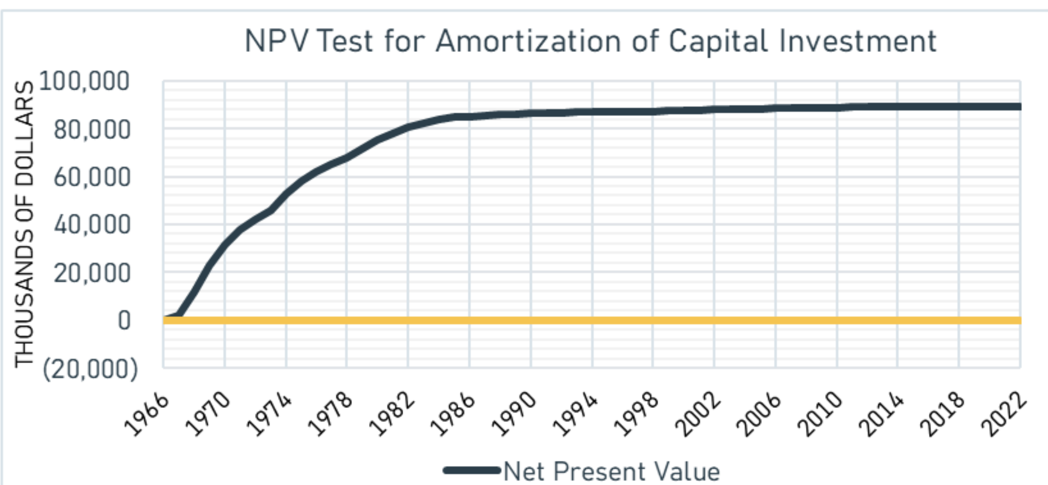
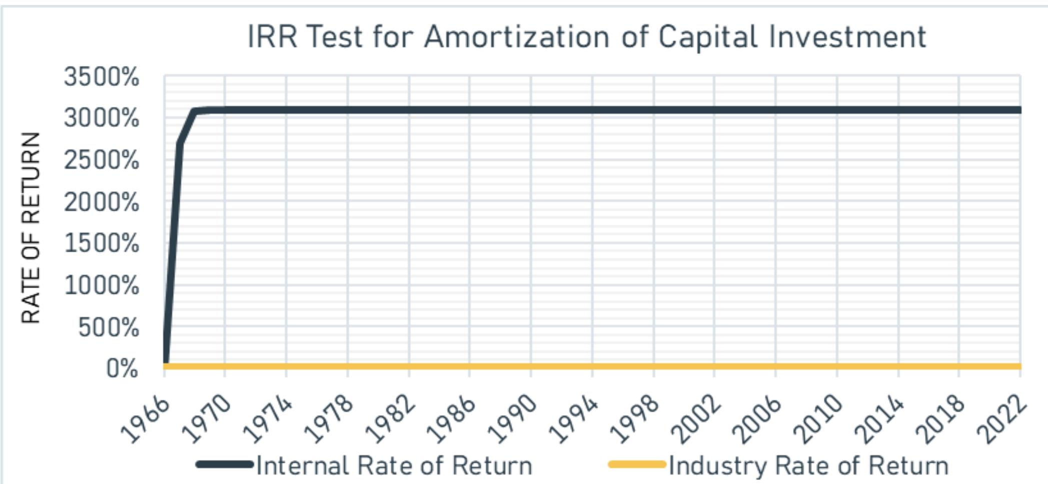


EXHIBIT G: SENSITIVITY CASE B—COMMODITY PRICE

Model Output Summary	
Start Year	1966
Amortization Year (IRR)	1967
Amortization Year (NPV)	1967
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	30,548
Gross Revenues, $thousands	1,406,064
EBITDA, $thousands	915,321
Net Cash Flow, $thousands	516,467
Cumulative IRR at 2022	3089.57%



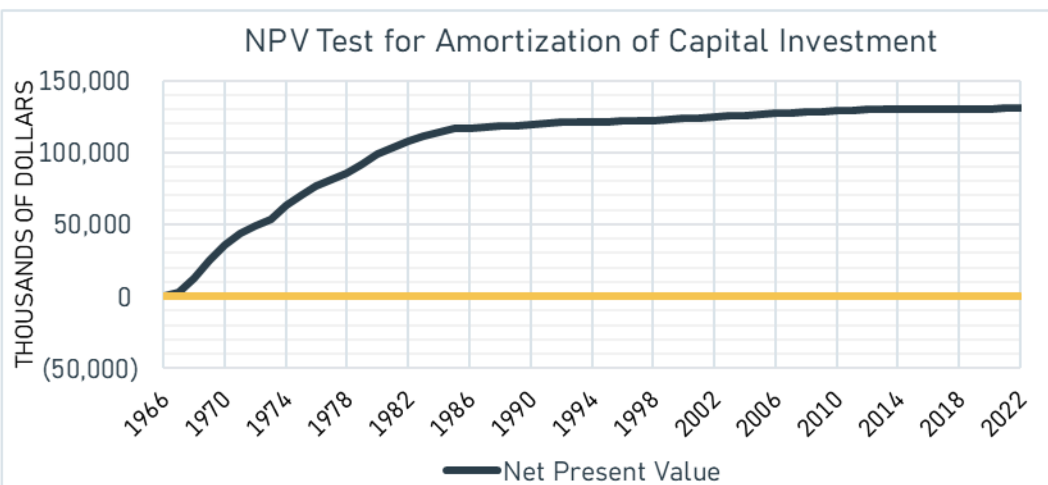


EXHIBIT H: SENSITIVITY CASE C—ORIGINAL CAPITAL INVESTMENT

Model Output Summary	
Start Year	1966
Amortization Year (IRR)	1967
Amortization Year (NPV)	1967
Years for Amortization of Capital Investment	1
Capital Investment, $thousands	36,633
Gross Revenues, $thousands	1,417,306
EBITDA, $thousands	924,690
Net Cash Flow, $thousands	517,982
Cumulative IRR at 2022	1945.52%