# CITY OF LOS ANGELES

# OIL AND GAS DRILLING ORDINANCE

## STUDY 12: AMORTIZATION OF CAPITAL INVESTMENT STUDY FOR THE TORRANCE COOPER & BRAIN OIL LEASE

**PREPARED FOR:**

The City of Los Angeles

Board of Public Works

Office of Petroleum and Natural Gas Administration and Safety

**DATE:**

November 14, 2024


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# 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 Torrance Cooper & Brain Oil Lease* (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*: Cooper & Brain ("C&B") operates oil and gas production facilities in the Wilmington – Harbor City area of Los Angeles (the "Site"). The Site extracts oil and gas from the Torrance oil field under the Brown Bevis Lease. The Site is adjacent to 1520 W. Pacific Coast Hwy., located to the southwest of the Harbor Freeway and Pacific Coast Highway interchange, on the western side of the Solimar Apartments.

6. *Zoning*: The Site is located within Council District 15 and the Wilmington - Harbor City Community Plan area. The parcel is zoned as OS-1XL-O, Open Space with height limitations situated in an Oil Drilling District.[1]

7. *History*: Drilling at the Site began in 1957 when C&B drilled and completed three wells. C&B followed up the next year with an additional three wells. The seventh well was drilled and completed in 1962. In 1973, one of the producers was converted into a waste disposal well to reinject produced water.[2] C&B has been the only operator of the Site and is currently still operating the Site.

8. *Site Status*: A total of seven wells were drilled at this Site between 1957 and 1962. Of these, six operated as production wells, and one operated as a waste disposal well during 2022. Surface facilities at the Site include lease equipment and various improvements.

9. *Capital Investment*: The original cost to drill and complete wells and install lease facilities at the Site amounted to about $0.6 million. In addition to the original capital investment, sustaining capital investment in well equipment and lease equipment amounted to about $1.2 million. The cumulative estimated capital investment in the Site was about $1.8 million as of December 31, 2022.

10. *Site Income*: The Site generated revenue from the sale of crude oil and natural gas. Production of crude oil from the Site peaked in 1959 at about 75,000 barrels annually, or 205 barrels per day. Natural gas production peaked in 1978 at more than 1,000 barrels of oil equivalent annually, or 3 barrels per day. Production of crude oil and natural gas declined from 1959 until 2022, when the Site produced about 10,000 barrels of oil (28 barrels per day) with no reportable amounts of natural gas. Crude oil produced at the Site

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

[2] See waste disposal well definition in Exhibit 1 of the Summary Report.

is heavy-sour crude with a market value comparable to Kern River crude oil. After deductions for payments of royalties, operating costs, income taxes, and sustaining capital investment, the Site generated a cumulative net cash flow of more than $12.9 million between 1957 and 2022.

11. *Base Case Conclusion*: In the Base Case, the capital investment in wells and lease facilities at the Site were amortized by 1965, within eight years of the original capital investment. The cumulative internal rate of return for the Site 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 three additional years in the time required to amortize the capital investment. Deducting $0.50 per barrel of crude oil resulted in no change in the time required to amortize capital investment. Increasing the capital investment to drill and complete new wells by 50% lengthened the time required to amortize capital investment by 13 years. Over a reasonable range of assumptions, the time required to amortize capital investment was many years before the Study Effective Date.

# 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 Torrance Cooper & Brain Oil Lease* (the "Study") presents the basis and conclusions for Baker & O'Brien's determination of the time required to amortize capital investment for the Cooper & Brain Oil Lease (the "Site"), which is a group of oil wells and surface facilities located adjacent to 1520 W. Pacific Coast Hwy. in the Wilmington – Harbor City area of Los Angeles.

16. This Study is incorporated into a larger amortization study that addresses all 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 Site 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 Site. Financial returns for the Site are compared to market returns on the invested capital achieved by oil and gas production companies to

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

determine the time required for amortization of capital investment. A Base Case determines the time required to amortize capital investment at the Site, 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 a 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 Site that was available at the Study Effective Date. Reference materials that have been considered in preparing this Study are listed in **Exhibit A**.

# 4. ABOUT THE SITE

## 4.1 LOCATION

20. C&B operates oil and gas production facilities in the Wilmington – Harbor City area of Los Angeles (the "Site"). The Site extracts oil and gas from the Torrance oil field under the Brown Bevis Lease. The Site is adjacent to 1520 W. Pacific Coast Hwy., located to the southwest of the Harbor Freeway and Pacific Coast Highway interchange, on the western side of the Solimar Apartments. An aerial photograph of the Site is presented in **Exhibit B**.[4] Additional location-specific details are provided in **Exhibit 5** of the Summary Report.

## 4.2 HISTORY

21. Drilling at the Site began in 1957 when C&B drilled and completed three wells. C&B followed up the next year with an additional three wells. The seventh well was drilled and completed in 1962. In 1973, one of the producers was converted into a waste disposal well to reinject produced water. C&B has been the only operator of the Site and is currently still operating the Site.[5]

## 4.3 LEASES

22. The Site operates seven wells that produce oil and gas from one lease called the Brown Bevis Lease. The lease appears to have production facilities located onsite. The status in 2022 of wells operating in the lease is listed in **Exhibit C** and summarized as follows: six production wells and one waste disposal well.

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

## 4.4 SURFACE FACILITIES

23. Surface facilities at the Site include tanks, pumps, and pipelines used for the collection and processing of well fluids (the “lease equipment”), as well as various site improvements. The surface facilities can be seen in **Exhibit B** and **Exhibit D**.[6]

24. The wellheads at the Site are generally located at grade and pump-jacks lift oil from the wells. No records are available to document the methods or costs associated with the disposal of produced water, but it is generally believed that all produced water has been handled onsite and reinjected into the ground since 1973.

25. For this lease, some lease equipment (mainly storage tanks) is visible in **Exhibit B.** While the equipment shown in the aerial photograph appears to be typical, it is not possible to determine the condition of the equipment, nor which equipment remains in operation or has been abandoned in place. No records are available that document the size, capacity, or cost of lease equipment when it was originally installed.

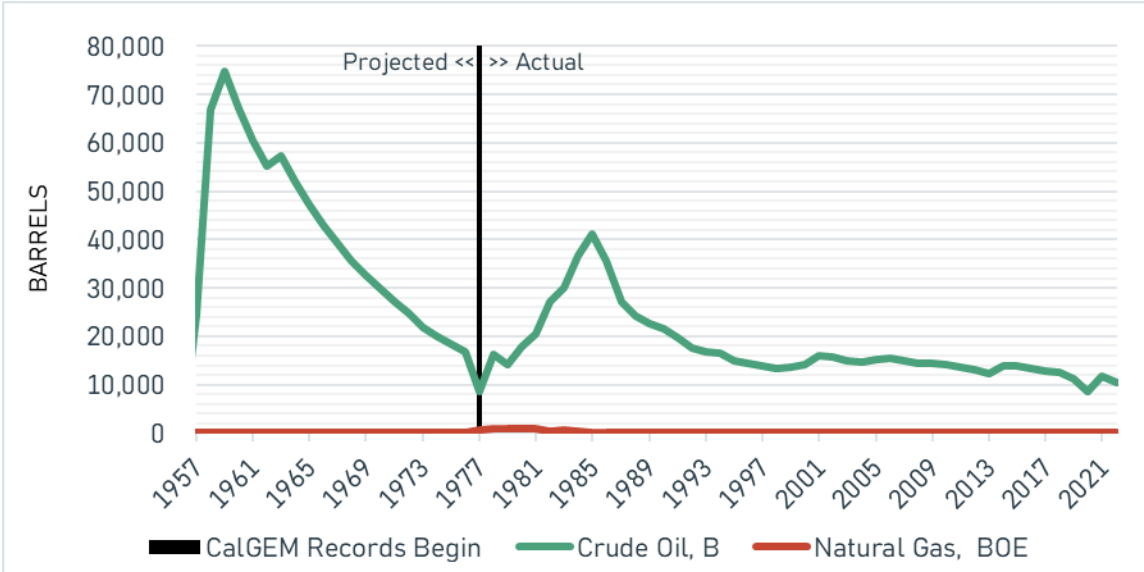
26. No production related buildings are visible in the satellite photos of the Site. The Site is surrounded by chain-link fencing with gates to control access.

## 4.5 HISTORICAL OIL AND GAS PRODUCTION

27. Oil and gas production from the Site are shown below in **Figure 1**.[7]

[6] The assessment of surface facilities in this Study is based upon an aerial photo since physical access to the Site was not authorized.
[7] CalGEM Production Records.

**Figure 1 – Site Oil and Gas Production**




28. Production rates at the Site peaked in 1959 shortly after the first wells were drilled and then generally declined afterwards until 1980. Production rates from 1957 to 1977 were projected based on a type-curve that was prepared from documented production rates following new production wells and well modifications. Production rates were also documented prior to well modifications. Between 1957 and 1977, production averaged 112 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 Site.

29. After 1977, production rebounded in the 1980s and peaked in 1985 before entering a general decline trend. Since 1977, the Site has averaged 47 B/D of oil and less than 1 barrel of oil equivalent per day ("BOE/D") of natural gas.

## 4.6 OIL AND GAS QUALITY

30. Crude oil produced at the Site is heavy-sour crude, averaging 15.1 degrees API ("°API") since 1977.[8] While the sulfur content of crude oil produced at the Site is not documented, crude oil produced from the Torrance oil field is reported to have a sulfur content of approximately 1.62%.[9] The quality of crude oil produced at the Site is

[8] CalGEM Production Records.
[9] *Sulfur Content of Crude Oils*, Bureau of Mines Information Circular 8676, 1975. https://dggs.alaska.gov/webpubs/usbm/ic/text/ic8676.pdf.

comparable to Kern River ("Kern") crude oil, which has market specifications of 13.3°API and a sulfur content of 1.10%.

31. Natural gas produced at the Site is assumed to have been treated to meet pipeline quality specifications and injected into the Southern California Gas Company ("SoCalGas") system at the Site's boundary.

## 4.7 LOGISTICS

32. No record is available to confirm how crude oil was delivered from the Site to local refineries or costs actually 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.[10] The Site is near major Los Angeles refineries and terminals in Long Beach. This Study estimates that transportation costs to deliver crude oil from the Site to a nearby refinery were $0.50 per barrel ("/B") in 2022.

33. Since small amounts of natural gas were produced at the Site, it is assumed that the Site is connected to a pipeline for delivery of natural gas into the SoCalGas system (or another local distribution company). A producer generally injects natural gas into a local distribution company pipeline through a custody transfer meter at the Site's boundary.

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

# 5. CAPITAL INVESTMENT

34. The capital investment to be amortized at the Site is the total investment in plant, property, and equipment used to produce income from the Site. 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.[11]

## 5.1 ORIGINAL CAPITAL INVESTMENT

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

36. 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

37. Original capital investment for production and injection wells at the Site was estimated based on drilling and completion costs reported by California operators. Costs that are relevant to drill and complete new wells at the Site 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 both 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.[12] The average of the normalized costs in 2022 is $1,397,866 per well.

[11] Capital investment does not include operating costs or termination costs. See Section 5.4 of the Summary Report.
[12] 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.

38. The California Department of Conservation's California Geologic Energy Management Division's ("CalGEM") records identify completion dates for wells at the Site. 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 prior to 2022 was estimated by adjusting costs in 2022 for historical changes in drilling costs to the year when a well was completed.[13] Original capital investment for wells at the Site amounted to about $561,000.

### 5.1.2 LEASE EQUIPMENT

39. 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.

40. The U.S. Department of Energy's Energy Information Administration ("EIA") published annual estimates of capital investment for lease equipment between 1976 and 2009.[14] 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 Site by applying a standard cost-

[13] See Section 5.2.4 of the Summary Report.
[14] See Section 5.2.2 of the Summary Report.

capacity relationship.[15] The original capital investment in lease facilities was allocated in the cash flow analysis to years when new wells were completed between 1957 and 1962. The original capital investment for lease equipment at the Site amounted to about $45,000.

### 5.1.3 SITE IMPROVEMENTS

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

42. For this Study, the original investment in site improvements was estimated as 5% of the cost for lease facilities.[16] The original site improvements are assumed to have occurred at various times and are allocated to the years in which new wells were completed. Overall, the original capital investment for site improvements amounted to about $2,000.

## 5.2 SUSTAINING CAPITAL INVESTMENT

43. 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 Site includes well modifications and replacement of well equipment and lease equipment that reaches end of life. Routine maintenance, testing expenses, and maintenance of site improvements are considered operating costs and are not included in sustaining capital investment.[17]

44. 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 amortization of 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.

[15] 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 = ((capacity) / (base capacity))$^{0.6}$ x (base cost).
[16] See Section 5.2.3 of the Summary Report.
[17] Operating costs are discussed below in Section 6.3.

### 5.2.1 WELL MODIFICATIONS

45. Modifications to wells generally include redrill, rework, recompletion, and casing alterations, and other work that is 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.

46. CalGEM records present a history of well modifications for each of the wells at the Site from 1957 to the present.[18] These records may include the nature of the work, the time when the work was done, and changes in production rates and crude oil quality.

47. California operators have reported the costs for well modifications, and those costs that are relevant to the Site are listed below in **Table 2**. CRC reported the costs for three types of well modifications,[19] while Sentinel Peak Resources California, LLC, ("SPR") reported an average cost for these activities.[20] 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.

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

[19] California Resources Corp. 2017 Analyst Day Presentation, p. 67, https://www.sec.gov/Archives/edgar/data/1609253/000160925317000055/crc2017analystday032017.htm.

[20] 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

48. CalGEM records identify the completion dates for modifications to wells.[21] Sustaining capital investment in well modifications is recorded in the cash flow analysis during the year in which the modification is completed. The total sustaining capital investment for well modifications amounted to $44,000.

### 5.2.2 WELL EQUIPMENT

49. Sustaining capital investment is needed to replace well equipment, such as pumps and wellheads, when 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 is well equipment that is subject to capital replacement. The remainder of drilling and completion costs are drill rig and casing costs. Well equipment has an average mechanical life of 30 years with proper maintenance.

50. The Study allows for 3.33% of the replacement cost of well equipment as sustaining capital investment each year.[22] This sustaining capital investment is based on the cost to drill and complete wells, which is adjusted annually for changes in the costs of these activities.[23] The total sustaining capital investment for well equipment amounted to $678,000 between 1957 and 2022.

### 5.2.3 LEASE EQUIPMENT

51. 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.

52. The Study allows for the 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.[24] The total sustaining capital investment for lease equipment amounted to about $464,000 between 1957 and 2022.

[21] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit C**.
[22] 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.
[23] See Section 5.2.4 of the Summary Report.
[24] See Section 5.2.4 of the Summary Report.

## 5.3 SUMMARY OF CAPITAL INVESTMENT

53. The total capital investment at the Site to be amortized is $1.79 million, as summarized below in **Table 3**. This amount includes $0.61 million of original capital investment that occurred between 1957 and 1962, and $1.19 million of sustaining capital investment that occurred between 1957 and 2022. These dollar amounts represent the capital investment incurred by operators from 1957 to 2022.

### Table 3 – Summary of Site Capital Investment

| Summary of Site Capital Investment | | |
|---|---|---|
| | **Investment** | **Time** |
| Original Capital Investment | | |
| New Wells | $561,258 | 1957-1962 |
| Lease Equipment | $44,830 | 1957-1962 |
| Site Improvements | $2,241 | 1957-1962 |
| **Subtotal** | **$608,329** | |
| Sustaining Capital Investment | | |
| Well Modifications | $43,901 | 1973-1982 |
| Well Equipment | $677,563 | 1957-2022 |
| Lease Equipment | $464,018 | 1957-2022 |
| **Subtotal** | **$1,185,482** | |
| **Capital Investment to be Amortized** | **$1,793,811** | |

# 6. INCOME ANALYSIS

54. Capital investment is amortized by the net cash flow generated from sales of oil and gas. This Study prepared an income analysis that calculates the annual net cash flow beginning with the start of drilling operations at the Site. In the income analysis, gross revenues are realized from the sale 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.

55. 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

56. 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 Site 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 Site receives for these sales, which are referred to as "netback" prices.

### 6.1.1 PRODUCTION VOLUMES

57. Operators in California are required to report production volumes of crude oil and natural gas to CalGEM, which maintains records of production rates for individual wells from 1977 to the present. This information is available for the wells at the Site.[25]

58. All of the wells at the Site were completed and in operation prior to 1977. This Study estimates annual production rates prior to 1977 by backcasting production rates of well fluids utilizing type-curves derived from available production data. Type-curves are

[25] CalGEM Production Records.

developed using standard engineering calculations applied in oil and gas reservoir management, using historical data from operating wells.[26] This standard approach assumes that characteristics of the reservoir dictate production rates evident in the type-curves.[27]

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

### 6.1.2 NETBACK PRICES FOR CRUDE OIL

60. Netback prices for crude oil represent the market price that the operator receives for the sales of crude oil produced at the Site, 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.

61. No records are available that document netback prices received for Torrance crude oil.[28] However, Torrance crude oil is typically 15.1°API with a sulfur content of about 1.62%. Torrance crude oil quality is comparable to Kern crude oil with 13.3°API and 1.10% sulfur.

62. This Study estimated netback prices for Torrance crude oil based on market prices for Kern crude oil delivered to Long Beach.[29] Historical price assessments for Kern crude were used as a benchmark for the value of Torrance crude from 1988 to the present. Kern price assessments are not available before 1988. Thus, Torrance 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.[30]

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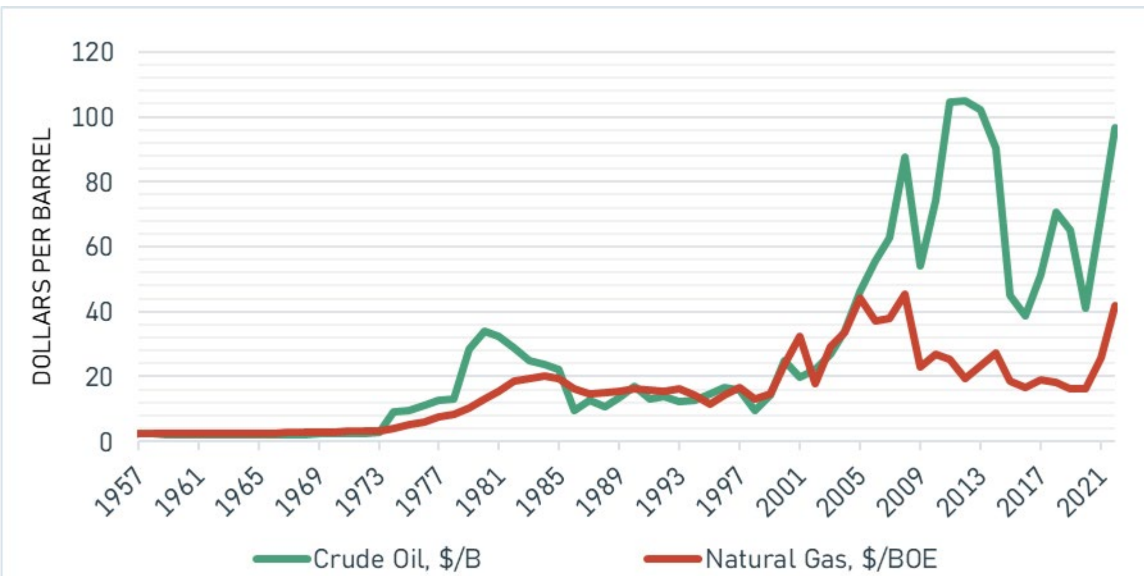
[26] A type-curve is also referred to as a "decline curve."
[27] See Section 6.2 of the Summary Report.
[28] "Torrance CB" crude oil is used in this Study to refer to crude oil produced from the Site.
[29] Kern crude is delivered by pipeline to Long Beach.
[30] See Section 6.3 of the Summary Report.

63. A quality adjustment to the benchmark price assessment reflects the difference in refining value between Torrance crude oil and the benchmark.[31] As noted above, Torrance crude oil is higher in API Gravity than Kern crude and would be more valuable to a refiner. Based on reasonable industry adjustments for API Gravity, a quality premium of $0.63/B reflects the higher market value of Torrance crude oil.

64. Crude oil from the Site is assumed to be delivered to nearby refineries by pipeline. The Site is located near refineries in Wilmington and Torrance and terminals in Long Beach. Due to this proximity, transportation costs to deliver crude oil are estimated as $0.50/B in 2022.

65. Annual average netback prices for Torrance 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

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

[31] See Section 6.3 of the Summary Report.

company that serves the Los Angeles area. Natural gas must meet pipeline quality specifications before it can be injected into a local distribution system.[32]

67. This Study estimated netback prices for natural gas based upon 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. Since City Gate price assessments are not available prior to 1989, 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.[33] No discount for transportation costs was applied on these sales, which would be delivered into a pipeline.

68. Annual average netback prices for Torrance natural gas are shown above in **Figure 2**.[34]

## 6.2 ROYALTIES

69. Owners of mineral rights earn a royalty on commercial volumes of oil and gas produced from their property.[35] 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 Site.

70. 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.[36]

## 6.3 OPERATING COSTS

71. 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 for operations to separate well fluids into oil, gas, and

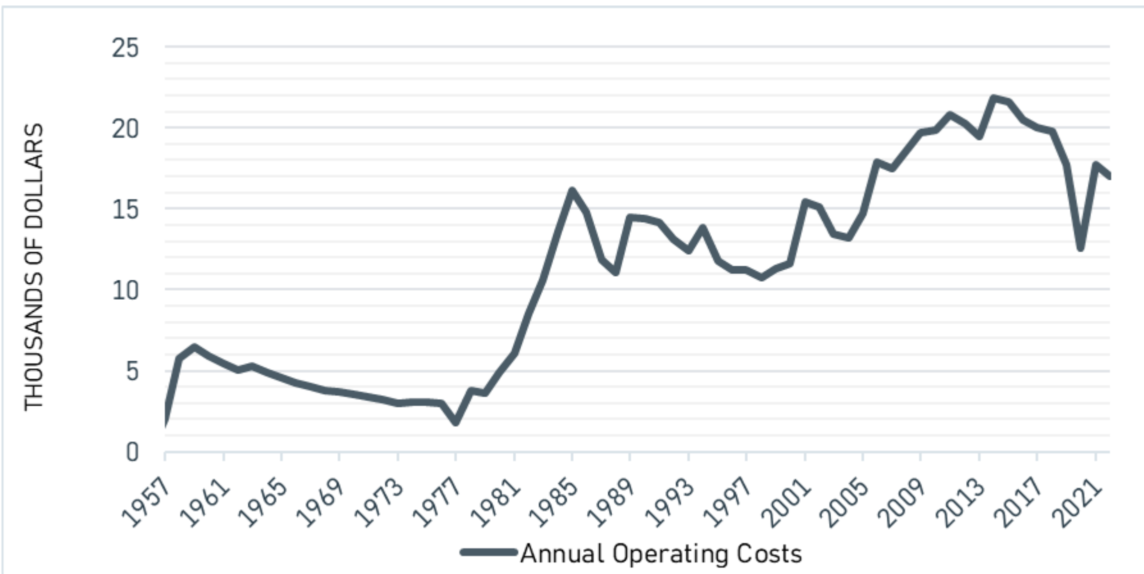
[32] https://www.socalgas.com/documents/news-room/fact-sheets/PipelineBasics.pdf
[33] See Section 6.4 and Exhibit 1 of the Summary Report.
[34] "Torrance CB" natural gas is used in this Study to refer to natural gas produced from the Site.
[35] Owners of mineral rights and landowners may or may not be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

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

72. The EIA published annual estimates of oil lease operating costs between 1976 and 2009.[37] Operating costs for the Site were estimated by normalizing EIA operating costs for its design production rate of well fluids and applying these costs to the reported production of well fluids from the Site. Prior to 1976 and after 2009, the EIA operating costs were adjusted for historical changes in operating costs.[38]

73. Annual Site operating costs are summarized below in **Figure 3**.

**Figure 3 – Site Operating Costs**




## 6.4 INCOME TAXES

74. 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.

[37] See Section 6.6 of the Summary Report.
[38] See Section 5.2.4 of the Summary Report.

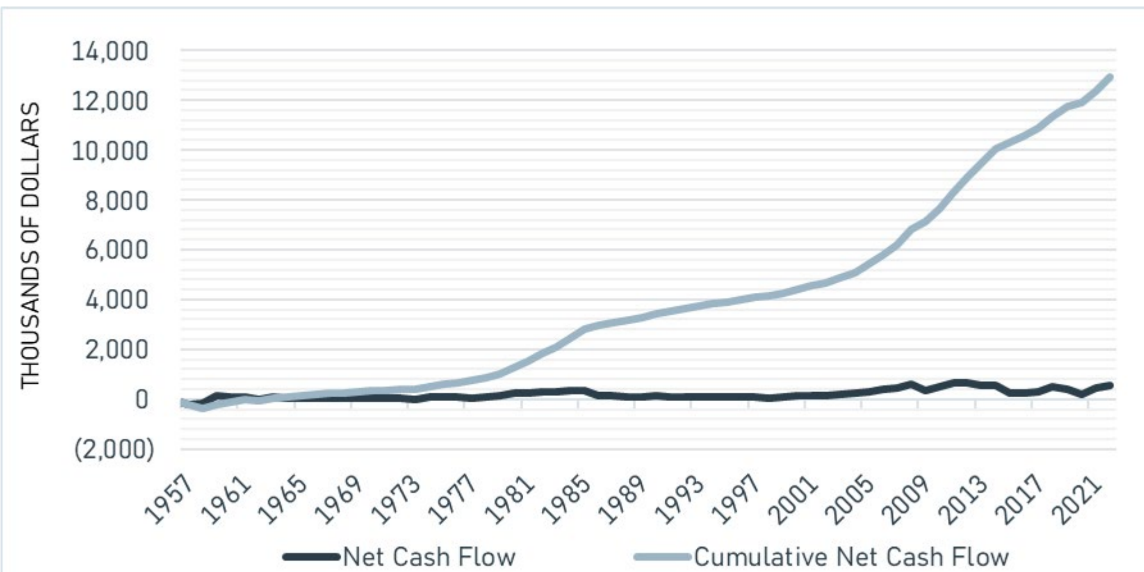
75. Federal and state income taxes on taxable income are calculated using the highest corporate tax brackets in effect each year. Federal income tax rates range from 21% to 46%, and California state income tax rates range from 8.8% to 9.6%.[39]

## 6.5 NET CASH FLOW FOR AMORTIZATION

76. 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 Site averaged about $196,000, and the cumulative net cash flow between 1957 and 2022 amounted to more than $12.9 million. These dollar amounts represent the cash flow generated from 1957 to 2022.

77. The annual and cumulative net cash flow from the Site are shown below in **Figure 4**.

### Figure 4 – Site Net Cash Flow




[39] See Section 6.7 of the Summary Report.

# 7. MARKET RATE OF RETURN ON INVESTMENT

78. The tests for amortization of capital investment use a "market" rate of return on investment that is characteristic of oil and gas production companies.[40] The market rate of return on investment is a total rate of return that is realized by public companies in this industry sector.

79. This Study refers to an analysis of the Weighted Average Cost of Capital ("WACC") for public companies that has been published annually since 1998.[41] 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, as shown in **Exhibit 4** of the Summary Report.

80. 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.

[40] See Section 4.3 of the Summary Report.
[41] See Section 7.1 of the Summary Report.

# 8. CONCLUSIONS

81. 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.

82. 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

83. In the Base Case, capital investment in wells and lease facilities at the Site were amortized by 1965, within eight years of the original capital investment.

84. 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 1965 when the cumulative IRR exceeded the 8% market rate of return. The Net Present Value ("NPV") test for amortization was also achieved in 1965 when the cumulative net present value exceeded zero.

85. The total capital investment of $1.8 million was amortized by $12.9 million of net cash flow between 1957 and 2022. Original capital investment was amortized within eight years of commencement of operations. The cumulative IRR increased to about 18% by 1983 and remained at that level through 2022.

## 8.2 SENSITIVITY CASE A: MARKET RETURN ON CAPITAL INVESTMENT

86. Case A sensitivity analysis demonstrates that capital investment increases by three years over a reasonable range of the market rate of return assumptions.

87. 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.[42]

88. The results of the Sensitivity Case A income analysis are summarized in **Exhibit F**. The IRR test for amortization was achieved in 1968 when the cumulative IRR exceeded the 12% rate of return. The NPV test for amortization was also achieved in 1968 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 Site was amortized by 1968.

## 8.3 SENSITIVITY CASE B: COMMODITY PRICE

89. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment remained unchanged over a reasonable range of assumptions related to the price of crude oil.

90. In Sensitivity Case B, the Base Case quality premium of $0.63/B was changed to a discount of $0.13/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 Torrance crude oil.

91. The results of the Sensitivity Case B income analysis are summarized in **Exhibit G**. The IRR test for amortization was achieved in 1965 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1965 when the cumulative net present value exceeded zero. Even with lower netback prices for Torrance crude oil, the capital investment in wells and lease facilities at the Site was amortized by 1965.

## 8.4 SENSITIVITY CASE C: ORIGINAL CAPITAL INVESTMENT

92. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment is within 21 years, even with a larger original capital investment.

93. 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

[42] See Exhibit 4 of the Summary Report.

the maximum cost for a new well reported by CRC by more than 19%.[43] The Case C scenario represents the upper limit for a reasonable range of original capital costs.

94. The results of the Sensitivity Case C income analysis are summarized in **Exhibit H**. The IRR test for amortization was achieved in 1978 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1978 when the cumulative net present value exceeded zero. Even with a larger capital investment in wells and lease facilities at the Site, this capital investment was amortized by 1978.

## 8.5 INCOME ANALYSES SUMMARY

95. The Base Case and Sensitivity assumptions and results for this Study are summarized in **Table 4** below. 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.

[43] 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 ($/B)** | | | | |
| Crude Oil Transportation - Site to Long Beach | 0.50 | 0.50 | 0.50 | 0.50 |
| Crude Oil Quality Adjustment | 0.63 | 0.63 | 0.13 | 0.63 |
| **Royalty and Lease Costs, % Revenue** | | | | |
| Royalty Rate | 16.660% | 16.660% | 16.660% | 16.660% |
| **Site Operating Costs, 2022 ($/B)** | | | | |
| Basis: Total Produced Liquids | 0.96 | 0.96 | 0.96 | 0.96 |
| **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, % | 18.73% | 18.73% | 18.39% | 12.63% |
| NPV, ($ Thousands) | 688 | 228 | 674 | 487 |
| Years to Amortization, IRR | 8 | 11 | 8 | 21 |
| Years to Amortization, NPV | 8 | 11 | 8 | 21 |

# 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 |
| California Resources Corporation 2017 Analyst Day Presentation | March 22, 2017 |
| California Resources Corporation 2018 Corporate Presentation | November 1, 2018 |
| 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 403717299, File 03717299_2005-09-20_DATA | Various |
| CalGEM Records for API 403717300, File 03717300_2005-09-20_DATA | Various |
| CalGEM Records for API 403717301, File 03717301_2005-09-20_DATA | Various |
| CalGEM Records for API 403717302, File 03717302_2005-09-20_DATA | Various |
| CalGEM Records for API 403717303, File 03717303_2005-09-20_DATA | Various |
| CalGEM Records for API 403717304, File 03717304_2019-07-24_DATA | Various |
| CalGEM Records for API 403717305, File 03717305_2005-09-20_DATA | Various |
| CalGEM Production Records, File CALGEMs_Well_Data_Formatting_Torrance_CB | Various |

# EXHIBIT B: AERIAL PHOTOGRAPH OF THE SITE


Source: Google Earth.

# EXHIBIT C: WELLS AT THE SITE

| Well API No. | Lease Name | Well Designation | Spudded | Complete | Current Type | Current Status |
|---|---|---|---|---|---|---|
| 403717299 | Brown Bevis Lease Well | 23 | 4/26/1957 | 5/2/1957 | Oil & Gas | Active |
| 403717300 | Brown Bevis Lease Well | 26 | 7/27/1957 | 8/2/1957 | Oil & Gas | Active |
| 403717301 | Brown Bevis Lease Well | 27 | 8/4/1957 | 8/11/1957 | Oil & Gas | Active |
| 403717302 | Brown Bevis Lease Well | 28 | 2/10/1958 | 2/18/1958 | Oil & Gas | Active |
| 403717303 | Brown Bevis Lease Well | 29 | 4/15/1958 | 4/24/1958 | Oil & Gas | Active |
| 403717304 | Brown Bevis Lease Well | 30 | 9/21/1958 | 9/27/1958 | Water Disposal | Active |
| 403717305 | Brown Bevis Lease Well | 31 | 11/7/1962 | 11/26/1962 | 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

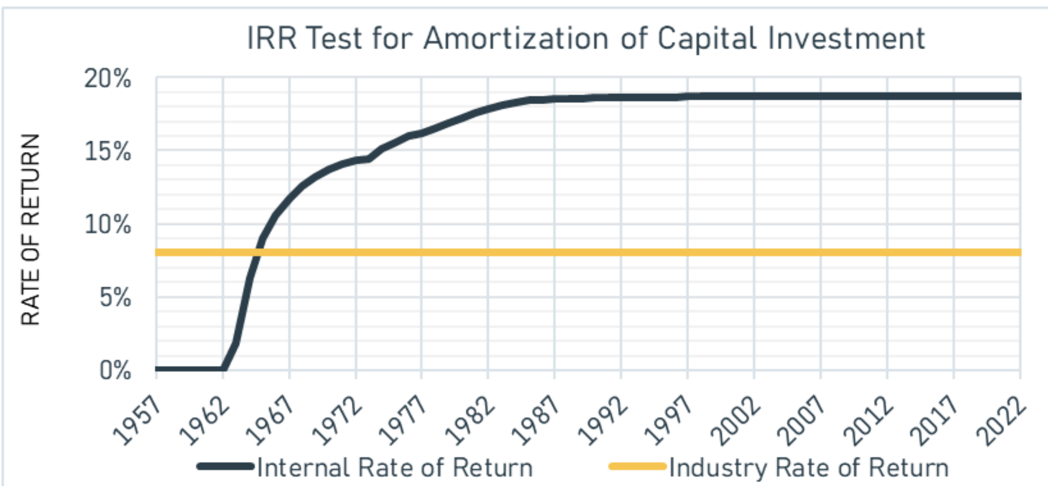

Source: CalGEM Well Finder website

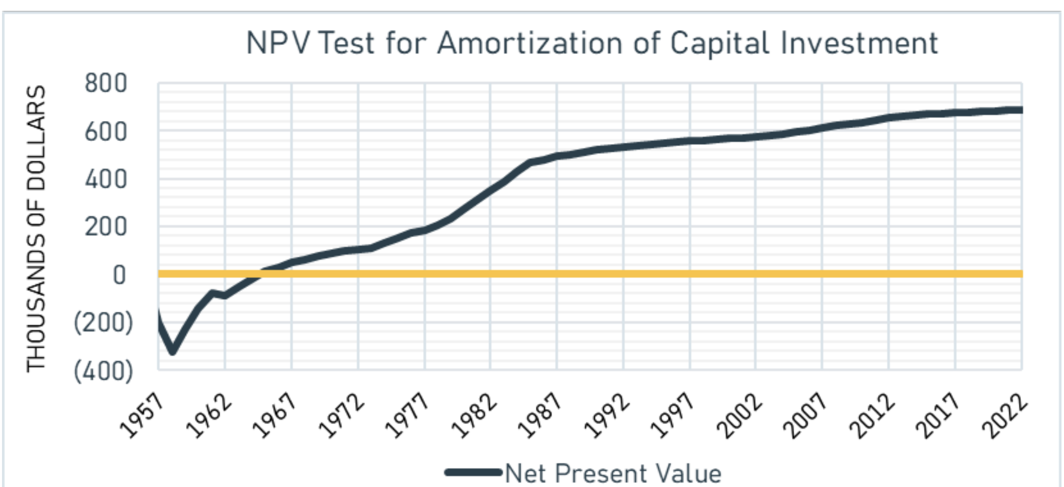
The CalGEM website indicates the well status as follows:

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

# EXHIBIT E: BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

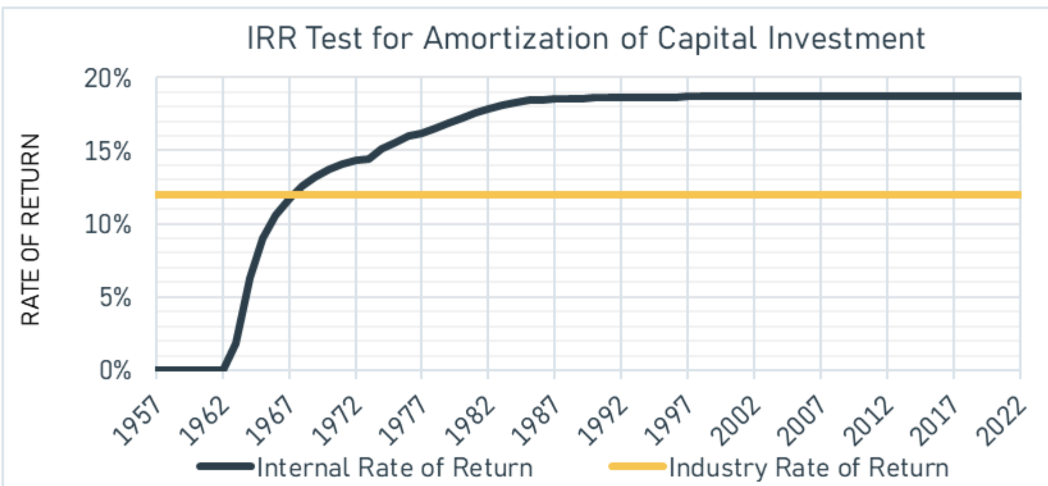
| Model Output Summary | |
|---|---|
| Start Year | 1957 |
| Amortization Year (IRR) | 1965 |
| Amortization Year (NPV) | 1965 |
| Years for Amortization of Capital Investment | 8 |
| | |
| Capital Investment, $thousands | 1,794 |
| Gross Revenues, $thousands | 29,464 |
| EBITDA, $thousands | 23,820 |
| Net Cash Flow, $thousands | 12,929 |
| | |
| Cumulative IRR at 2022 | 18.73% |

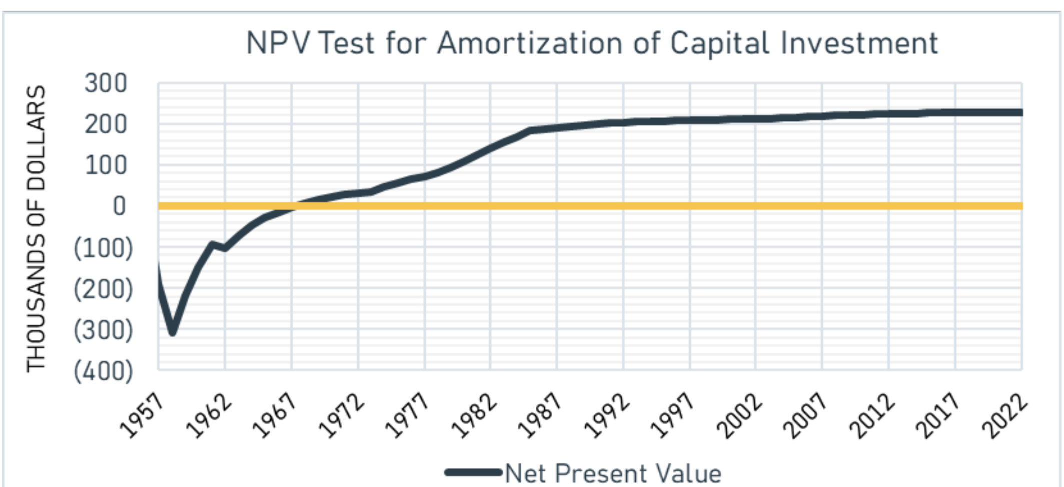


# EXHIBIT F: SENSITIVITY CASE A—MARKET RETURN ON CAPITAL INVESTMENT

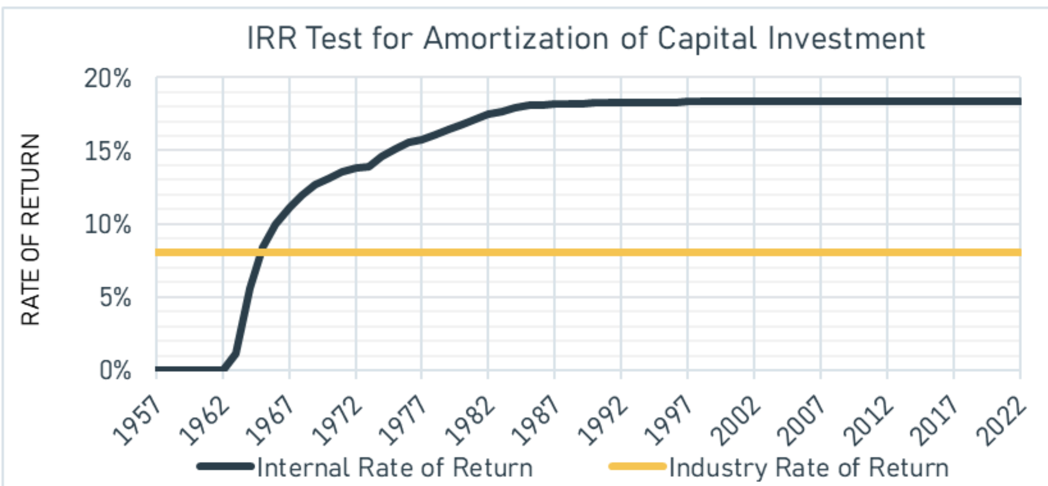
| Model Output Summary | |
|---|---|
| Start Year | 1957 |
| Amortization Year (IRR) | 1968 |
| Amortization Year (NPV) | 1968 |
| Years for Amortization of Capital Investment | 11 |
| | |
| Capital Investment, $thousands | 1,794 |
| Gross Revenues, $thousands | 29,464 |
| EBITDA, $thousands | 23,820 |
| Net Cash Flow, $thousands | 12,929 |
| | |
| Cumulative IRR at 2022 | 18.73% |

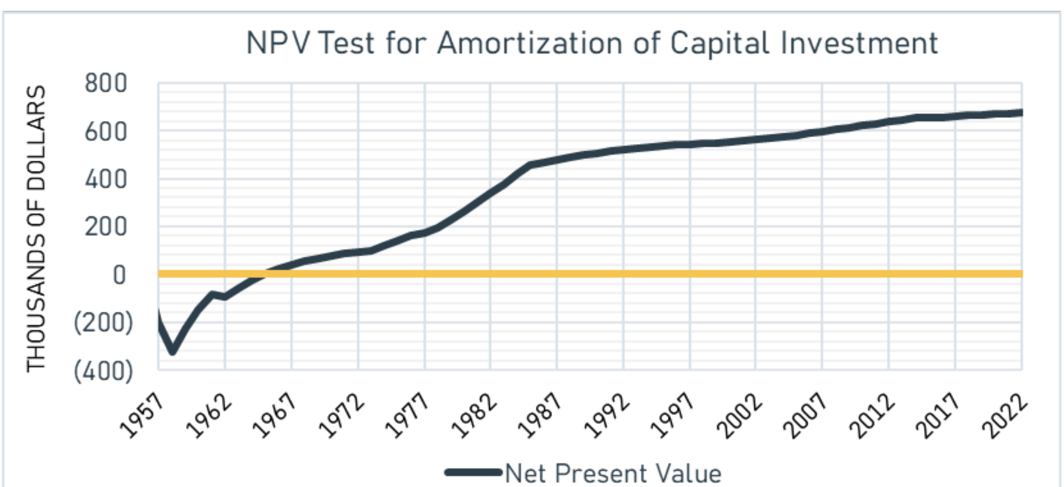


# EXHIBIT G: SENSITIVITY CASE B—COMMODITY PRICE

| Model Output Summary | |
|---|---|
| Start Year | 1957 |
| Amortization Year (IRR) | 1965 |
| Amortization Year (NPV) | 1965 |
| Years for Amortization of Capital Investment | 8 |
| | |
| Capital Investment, $thousands | 1,794 |
| Gross Revenues, $thousands | 29,203 |
| EBITDA, $thousands | 23,603 |
| Net Cash Flow, $thousands | 12,801 |
| | |
| Cumulative IRR at 2022 | 18.39% |



# EXHIBIT H: SENSITIVITY CASE C—ORIGINAL CAPITAL INVESTMENT

| Model Output Summary | |
|---|---|
| Start Year | 1957 |
| Amortization Year (IRR) | 1978 |
| Amortization Year (NPV) | 1978 |
| Years for Amortization of Capital Investment | 21 |
| | |
| Capital Investment, $thousands | 2,413 |
| Gross Revenues, $thousands | 29,464 |
| EBITDA, $thousands | 23,820 |
| Net Cash Flow, $thousands | 12,518 |
| | |
| Cumulative IRR at 2022 | 12.63% |