Baker & O'Brien

CITY OF LOS ANGELES OIL AND GAS DRILLING ORDINANCE

STUDY 8: AMORTIZATION OF CAPITAL INVESTMENT STUDY FOR THE FILIPINOTOWN DRILL SITE

PREPARED FOR:

The City of Los Angeles

Board of Public Works

Office of Petroleum and Natural Gas Administration and Safety

DATE:

November 17, 2024

Baker & O'Brien, Inc.

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CONFIDENTIAL

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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 Filipinotown Drill Site* (the "Study") presents the basis and conclusions for our determination of 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*: The Filipinotown Drill Site (the "Site") is located at 181 S. Mountain View Ave. in the Westlake area of Los Angeles, just north of the intersection of S Alvarado St. and Miramar St. in the Filipinotown area. The Site produces oil and gas from the Los Angeles City Oil Field. The lease name is not specified.

6. *Zoning*: The Site is within Council District 1 and the Westlake Community Plan area. The Site is zoned C2-1, Commercial, having height limitations.[1]

7. *History*: The original wells at the Site were likely drilled in the late 1890s. The well records began in 1938 when the Site was initially reported to have been transferred to Harriet E. Johnson when the prior owner, her father, Parley H. Johnson, passed away in 1938. In 1949, the property was sold to Harold H. Gartner and Vivian Marie Gartner. In 1996, the ownership was transferred to Chaim Nathan and Edie Bato, who currently own the remaining well.

8. *Site Status*: One production well operated at the Site during 2022. Surface facilities at the Site include lease equipment and various site improvements.

9. *Capital Investment*: The original cost for drilling and completing wells and installing lease facilities was $10,000. In addition to the original capital investment, sustaining capital investment in wells and lease equipment was $262,000. As of December 31, 2022, the cumulative estimated capital investment in the Site from 1938 to 2022 was $273,000.

10. *Site Income*: The Site generated revenue from selling crude oil and natural gas. Production of crude oil from the Site peaked in 1984 at about 4,700 barrels annually or 13 barrels per day. No natural gas production has been reported at the Site. Crude oil produced at the Site is a heavy-sour crude with a market value comparable to Kern 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 about $1.1 million from 1938 to 2022.

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

11. *Base Case Conclusion*: In the Base Case, the original capital investment at the Site was amortized in 1948, with an amortization period of ten years. The total capital investment between 1938 and 2022 of $273,000 was amortized by $1.1 million of net cash flow over this period. 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 more significant capital investment. A market rate of return of 12 % extended the time required to amortize the capital investment by two years. Deducting $0.50 per barrel of crude oil did not change the time required to amortize the capital investment. Increasing the capital investment to drill and complete new wells by 50% did not impact the time required to amortize capital investment. Over a reasonable range of assumptions, these factors do not change the time needed to amortize capital investment at the Site.

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 throughout the City.

14. The Los Angeles City Council passed Oil and Gas Drilling Ordinance 187709[2] (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 Filipinotown 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 Filipinotown Drill Site (the "Site"), which is an oil well and surface facility located at 181 S. Mountain View Ave. in the Westlake 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 analyzing 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 oil and gas production, and determination of year-to-year financial returns for the Site. Financial returns for the Site are compared to market returns on invested capital achieved by oil and gas production companies to

[2] City of Los Angeles 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 more significant capital investment, might change the Base Case amortization period.

18. This Study refers to various abbreviations and terms 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. The Site is located at 181 S. Mountain View Ave. in the Westlake area of Los Angeles, just north of the intersection of S Alvarado St. and Miramar St. in the Filipinotown area. The Site produces oil and gas from the Los Angeles City Oil Field. Aerial photographs of the Site are presented in **Exhibit B**.[3] Additional location-specific details are provided in **Exhibit 5** of the Summary Report.

4.2 HISTORY

21. The well at the Site is believed to have been drilled during the late 1890s when the Los Angeles City Oil Field was initially developed; however, no records exist before 1938 when the California Department of Conservation's California Geologic Energy Management Division ("CalGEM") first provided a well file for the well.

22. The Site was initially reported to have been transferred to Harriet E. Johnson when the prior owner, her father, Parley H. Johnson, passed away in 1938. In 1949, the property was sold to Harold H. Gartner and Vivian Marie Gartner. In 1996, the well was transferred to Chaim Nathan and Edie Bato, who currently owns the well.[4]

4.3 LEASES

23. The Site operated a well in 2022 that produced oil and gas from an unspecified lease. The lease appears to have production facilities located on-site. The status of the Site's well is listed in **Exhibit C**.

4.4 SURFACE FACILITIES

24. The surface facilities at the Site include tanks, pumps, and pipelines used for collecting and processing well fluids (the "lease equipment"), as well as various site improvements.

[3] Google Earth.
[4] See CalGEM records for the well at the Site listed in **Exhibit C**.

25. The wellhead at the Site is generally located at grade, and a pump jack lifts oil from the well. No records are available to document the methods or costs associated with the disposal of produced water.[5]

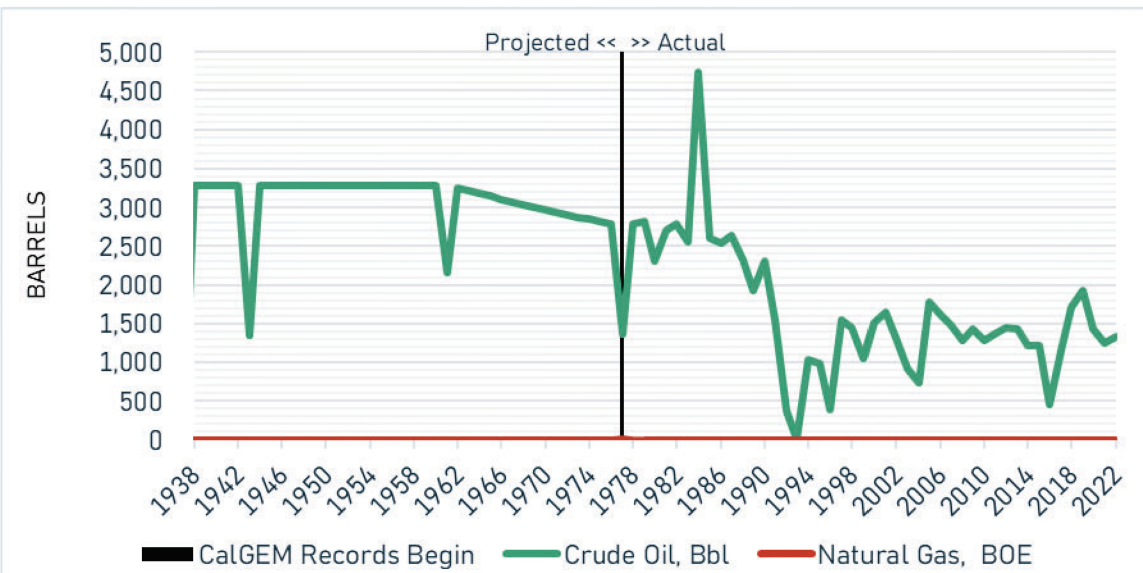
26. For the Site, some lease equipment (mainly storage tanks) is visible in **Exhibit B**. While the equipment shown in aerial photographs appears to be typical, it is not possible to determine the condition of the equipment, nor which equipment remains in operation or has been abandoned in place. No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

27. No buildings are visible in the aerial photo of the Site. Wrought iron fencing and walls with gates surround the Site to control access.

4.5 HISTORICAL OIL AND GAS PRODUCTION

28. Overall oil and gas production from the Site is shown below in **Figure 1.**[6]

Figure 1 – Site Oil and Gas Production



29. Production rates at the Site before 1977 are estimated based on available production data documented in CalGEM's well files. CalGEM records show that the Site produced 9 barrels per day ("B/D") before a workover in 1961, which was slightly higher than the

[5] See waste disposal well definition in Exhibit 1 of the Summary Report.
[6] See CalGEM records for the wells at the Site, which are listed in **Exhibit C**.

rate produced when CalGEM's records became available in 1977. This Study assumes the Site produced 9 B/D from 1938 to 1961 outside of documented downtime for workovers.[7] After 1961, production declined to the 1977-1990 average of 7 B/D.

30. After 1977, the Site's production peaked at 13 B/D in 1984. Production fell off significantly in the early 1990s while the well was offline for workovers. Since 1977, the Site has averaged 5 B/D of oil and produced no natural gas.

4.6 OIL AND GAS QUALITY

31. Crude oil produced at the Site is heavy-sour crude, averaging about 14.9 degrees API ("°API") since 1977.[8] While the sulfur content of the crude oil produced at the Site is not documented, crude oil produced from the Los Angeles City Oil Field is reported to have a sulfur content of approximately 1.1%.[9] The quality of crude oil produced at the Site is comparable to Kern River ("Kern") crude oil, which has market specifications of 13.3°API and a sulfur content of 1.10%.

32. No natural gas is documented as having been produced over the life of the Site.

4.7 LOGISTICS

33. 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 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] This Study assumes that crude oil is injected into a common carrier pipeline for delivery to customers through a custody transfer meter at the Site's boundaries. This Study estimates that transportation costs to deliver crude oil from the Site to Long Beach by a common carrier pipeline were $1.50 per barrel ("/B") in 2022.[11]

34. No natural gas is documented as having been produced over the life of the Site.

[7] Los Angeles City Oil Field has a history of low-volume production with little decline over long periods.
[8] CalGEM Production Records.
[9] *Petroleum in Southern California*, Prutzman, Paul W. (1913), California State Mining Bureau. pp. 207-210.
[10] Los Angeles Municipal Code Section 13.01.F.2 and 54.
[11] Crimson California Pipeline L.P. trunkline tariff, August 1, 2022; Crimson California Pipeline L.P. gathering line tariff, August 1, 2022.

5. CAPITAL INVESTMENT

35. The capital investment at the Site to be amortized is the total investment in the 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.[12]

5.1 ORIGINAL CAPITAL INVESTMENT

36. Original capital investment is an operator's investment to acquire lease rights, drill new wells, construct new surface facilities, and commence oil and gas production. 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.

37. 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

38. Original capital investment for production wells at the Site was estimated based on drilling and completion costs reported by California operators. Berry Corporation ("Berry") reported a range of drilling and completion costs in California during 2019, and California Resources Corporation ("CRC") reported drilling and completion costs for its Lost Hills developments in 2016, which are summarized below in **Table 1**. Costs reported by Berry and CRC were normalized to the Study Effective Date using the U.S. Bureau of Labor Statistics ("BLS") Producer Price Index ("PPI") Oil and Gas Drilling cost index ("PPI-OGD").[13]

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

[13] U.S. Bureau of Labor Statistics, Producer Price Index by Industry: Drilling Oil and Gas Wells [PCU213111213111], retrieved from FRED, Federal Reserve Bank of St. Louis.

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
Berry	Elk Hills[2]	2019	337.4	$300,000	2022	371.8	$330,581
CRC	Lost Hills[3]	2016	316.7	$150,000	2022	371.8	$176,094
	Average			**$225,000**			**$253,337**
Cost Used In Model					**2022**		**$250,000**

Notes:

1. PPI OGD is BLS Series ID PCU213111213111. June index values are used to reflect mid-year costs.
2. Berry Corp. 2020 Investor Presentation, p. 12.
3. California Resources Corp. 2017 Analyst Day Presentation, p. 36.

39. The developments listed in **Table 1** use steam flood operations to produce heavy crude oil from oil fields in the San Joaquin Basin. Although steam flood operations are much different than the primary recovery used at the Site, drilling and completion costs for shallow steam flood wells are comparable to the costs to drill wells at the Site. Like steam flood wells, the wells at the Site are shallow, averaging 1,200 feet in depth, and pump jacks are used to lift crude oil from the wells. Most wells in the City use a higher average cost per well than $250,000, however, Los Angeles City Oil Field wells are shallower and, therefore, less expensive than other wells in the City.[14]

40. Original drilling costs for the wells completed at the Site during the 1890s are not included in the income analysis. As noted above, capital investment at the Site is considered from Ms. Johnson's acquisition of operating interests in 1938. Moreover, capital investment in wells drilled during the 1890s is not material to the income analysis since drilling and completion costs in the Los Angeles City Oil Field were reported to have been less than $1,500 per well.[15] Sustaining capital investment is included in the income analysis to maintain these wells in service.[16]

41. CalGEM records do not identify any wells drilled and completed at the Site after 1938. Therefore, the original capital investment for new wells after those dates at the Site amounted to $0.

[14] Because they are shallower, the Site's wells are estimated to cost roughly 20% of the other wells in the City. See Section 5.2.1 of the Summary Report.
[15] *The Los Angeles City Oil Field*, Stephen M. Testa, 2005, p. 85.
[16] See Section 5.2.2 below.

5.1.2 LEASE EQUIPMENT

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

43. The U.S. Department of Energy's Energy Information Administration ("EIA") published annual estimates of capital investment for lease equipment between 1976 and 2009.[17] These estimates included representative costs for lease equipment used in primary recovery 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-capacity relationship.[18] The original capital investment in lease facilities was allocated in the cash flow analysis in 1938 when the old well was reactivated.[19] The original capital investment for lease equipment at the Site amounted to about $10,000.

5.1.3 SITE IMPROVEMENTS

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

45. For this Study, the original investment in site improvements was estimated as 5% of the cost for lease facilities.[20] The original site improvements are allocated to the years when the wells were reactivated. The original capital investment for site improvements amounted to about $500.

5.2 SUSTAINING CAPITAL INVESTMENT

46. 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, replacement of well equipment, and lease equipment that reaches end-of-life. Routine maintenance, testing expenses, and maintenance of site

[17] See Section 5.2.2 of the Summary Report.
[18] This relationship, commonly referred to as the Rule of Six-Tenths, is an empirical relationship between a manufacturing facility's cost and capacity. The estimated cost = ((capacity) / (base capacity))$^{0.6}$ x (base cost).
[19] Since the Site was initially composed of one well, drilled in the 1890s, capital was allocated under the well modification category when this well began producing for this Study in 1938.
[20] See Section 5.2 of the Summary Report.

improvements are considered operating costs and are not included in sustaining capital investment.[21]

47. 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.

5.2.1 WELL MODIFICATIONS

48. Modifications to wells generally include redrill, rework, recompletion, and casing alterations. 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.

49. CalGEM records present a history of well modifications for each well at the Site from 1938 to the present.[22] 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. However, CalGEM records indicate little sustaining capital was invested in well modifications at the Site.

50. 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,[23] while Sentinel Peak Resources ("SPR") reported an average cost for these activities.[24] Costs reported by CRC and SPR were normalized to 2022 and averaged $207,734 per activity, rounded to $210,000 per activity in 2022.

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[21] Operating costs are discussed below in Section 6.3.
[22] See CalGEM records for the well at the Site, which are listed in **Exhibit C**.
[23] California Resources Corp. 2017 Analyst Day Presentation, p. 67, https://www.sec.gov/Archives/edgar/data/1609253/000160925317000055/crc2017analystday032017.htm.
[24] 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.

51. This Study uses 20% of the $210,000 estimated well modification cost, or $42,000.[25] This 20% is the same percentage used for Site's drilling and completion cost, as discussed in Section 5.1.1 above and Section 5.2.1 of the Summary Report.

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	321.06	$160,000	2022	371.8	$185,280
	Average			**$177,500**	**2022**		**$207,740**
Cost Reduction Factor [4]	$250,000 LA City Oil Field Well Cost / $1,400,000 Standard City Well Cost[5] =						20%
Cost Used In Model					**2022**		**$42,000**

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.
4 The cost reduction factor is multiplied by the standard City workover cost of $210,000 found in other Studies.
5 The Standard City Well cost can be found in Section 5.2.1 of the Summary Report.

52. 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 in which the modification is completed. The total sustaining capital investment for well modifications amounted to about $16,000.[27]

5.2.2 WELL EQUIPMENT

53. 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 is for well equipment subject to capital replacement. The remainder of drilling and completion costs result from drill rig and casing costs. Well equipment has an average mechanical life of 30 years with proper maintenance.

[25] Because it is shallower, the Site's well is estimated to cost roughly 20% of the other wells in the City. The 20% factor comes from the average difference in cost for LA City Oil Field wells as compared to the deeper well costs in the City, as discussed in Section 5.1.1.
[26] See CalGEM records for the well at the Site, which are listed in **Exhibit C**.
[27] Although this well was likely drilled in the 1890s, the initial capital was modeled using records from 1938. Capital workover costs were allocated in 1938.

54. This Study allows for 3.33% of the replacement cost of well equipment as sustaining capital investment each year.[28] 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. The total sustaining capital investment for well equipment amounted to about $19,000 between 1938 and 2022.

5.2.3 LEASE EQUIPMENT

55. Sustaining capital investment is needed to replace original lease equipment that reaches the end of its mechanical life. In addition, capital investment related to new regulatory mandates for site improvements, safety, and environmental equipment is considered as sustaining capital investment. Lease equipment has an average mechanical life of 30 years with proper maintenance.

56. 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 $227,000 between 1938 and 2022.

5.3 SUMMARY OF CAPITAL INVESTMENT

57. The total capital investment at the Site to be amortized is about $273,000, as summarized below in **Table 3**. This amount includes about $10,000 of original capital investment that occurred in 1938 and about $262,000 of sustaining capital investment that occurred between 1938 and 2022. These dollar amounts represent the capital investment incurred by operators from 1938 to 2022.

[28] 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.

[29] See Section 5.2.4 of the Summary Report.

Table 3 – Summary of Site Capital Investment

Summary of Site Capital Investment		
	Investment	Time
Original Capital Investment		
New Wells	$0	1938-1938
Lease Equipment	$9,977	1938-1938
Site Improvements	$499	1938-1938
Subtotal	**$10,475**	
Sustaining Capital Investment		
Well Modifications	$16,369	1938-1994
Well Equipment	$19,269	1938-2022
Lease Equipment	$226,848	1938-2022
Subtotal	**$262,486**	
Capital Investment to be Amortized	**$272,962**	

6. INCOME ANALYSIS

58. Capital investment is amortized by the net cash flow generated from the sale of oil and gas. This Study prepared an income analysis that calculates the annual net cash flow beginning with the first CalGEM records for 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 gross revenues from royalties, operating costs, and income taxes. Finally, annual net cash flow is determined by deducting capital investment from net income.

59. 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 illustrate the amounts that an operator spent for capital investment and received as income during each year of the income analysis.

6.1 REVENUES

60. Revenues from oil and gas operations are realized as sales volumes of crude oil and natural gas 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 value that the operator of the Site receives for these sales, which are referred to as "netback" prices.

6.1.1 PRODUCTION VOLUMES

61. 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 well at the Site.[30]

62. The well at the Site was in operation before 1977. This Study uses historical records to estimate annual production rates for this well before 1977.[31]

[30] CalGEM Production Records.
[31] See Section 4.4.

63. Annual crude oil and natural gas production volumes of 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

64. Netback prices for crude oil represent the market price the operator receives for the sale 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, the quality of crude oil, and transportation costs to move crude oil to a Los Angeles area refinery.

65. No records document netback prices received for the Filipinotown crude oil.[32] However, Filipinotown crude oil is typically 14.9°API with a sulfur content of about 1.10%, which is comparable in quality to Kern crude oil, which is 13.3°API and 1.10% sulfur.[33]

66. This Study estimated netback prices for Filipinotown crude oil based on market prices for Kern crude oil delivered to Long Beach,[34] plus a quality adjustment, less delivery costs from the Site to Long Beach. Historical price assessments for Kern crude were used as a benchmark for the value of Filipinotown crude from 1988. Since Kern price assessments were not available before 1988, Filipinotown crude prices were estimated by applying a market differential to Brent crude oil between 1979 and 1987 and by applying a market differential to West Texas Intermediate ("WTI") crude oil between 1947 and 1978.[35]

67. A quality adjustment to the benchmark price assessment reflects the difference in refining value between Filipinotown crude oil and the benchmark.[36] As noted above, Filipinotown crude oil is higher in API Gravity than Kern crude, which would result in a higher value to a refiner. The sulfur content of the Filipinotown crude oil is about the same as Kern crude, which would result in no difference in value. Based on reasonable

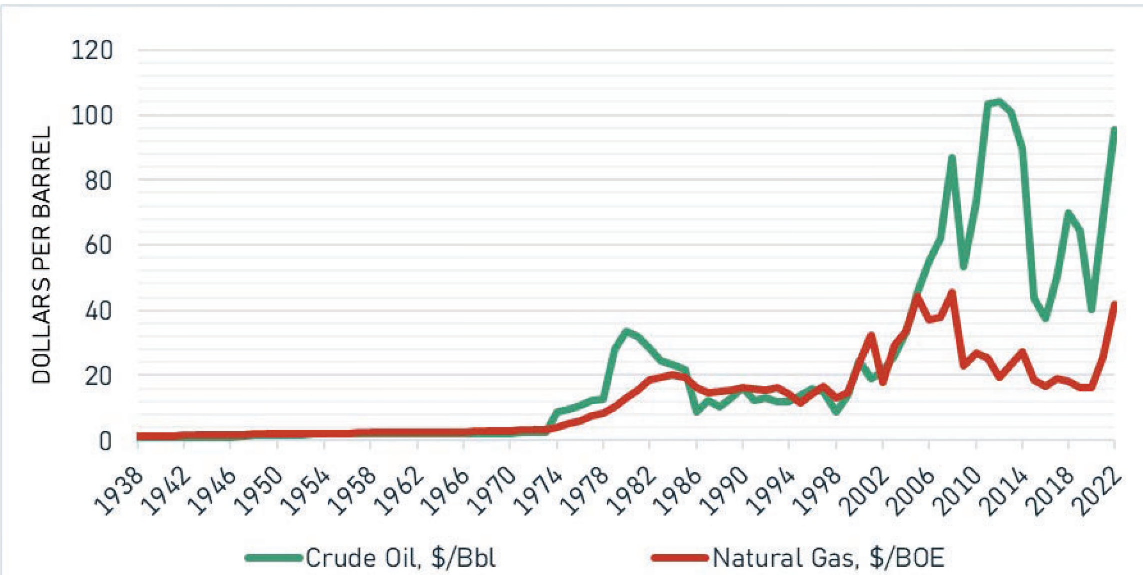
[32] "Filipinotown" crude oil is used in this Study to refer to crude oil produced from the Site.
[33] The Filipinotown crude oil quality is compared to Kern crude oil in Section 4.8.
[34] Kern crude is delivered by pipeline to Long Beach.
[35] See Section 6.3 of the Summary Report.
[36] See Section 6.3 of the Summary Report.

adjustments for API Gravity, a quality premium of $0.56/B reflects the higher market value of Filipinotown crude oil.[37]

68. The Site is assumed to deliver crude oil to customers by a common carrier pipeline for delivery to terminals in Long Beach. Transportation costs to deliver crude oil from the Site to Long Beach were estimated at $1.50/B in 2022, based on common carrier tariffs.[38]

69. Annual average netback prices for Filipinotown 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

70. 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 natural gas sales to the SoCalGas system or another local distribution company that serves the Los Angeles area. Natural gas must meet pipeline quality before it can be injected into a local distribution system.[39]

[37] Chevron Crude Oil Marketing, Posted Pricing – California, California – Bulletin 2023-CA176, https://crudemarketing.chevron.com/crude/north_american/california.aspx.

[38] Crimson California Pipeline L.P. trunkline tariff, August 1, 2022; Crimson California Pipeline L.P. gathering line tariff, August 1, 2022.

[39] https://www.socalgas.com/documents/news-room/fact-sheets/PipelineBasics.pdf

71. 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. Since City Gate price assessments are not available before 1989, the natural gas prices of the Los Angeles area 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.

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

6.2 ROYALTIES

73. 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 Site.

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

6.3 OPERATING COSTS

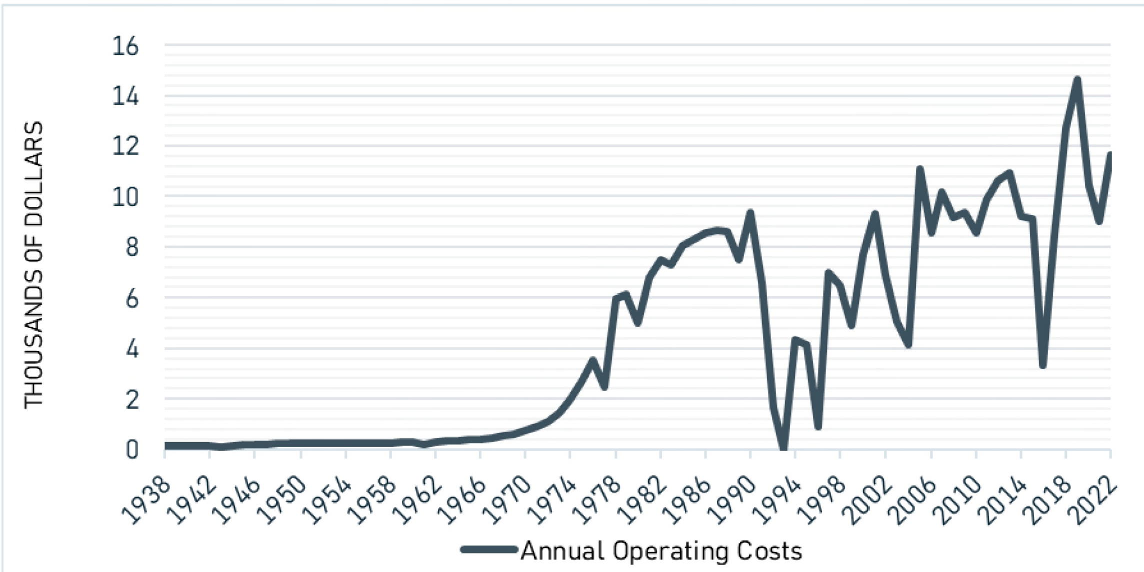
75. Lease operating costs generally include labor, utilities, operating materials, maintenance materials, spare parts, general and administrative expenses, insurance, and permits. Direct operating costs include costs for operations to: separate well fluids into oil, gas, and produced water; treat crude oil and natural gas to market specifications; and treat produced water for reinjection or disposal.

[40] See Section 6.4 and Exhibit 1 of the Summary Report.
[41] "Filipinotown" natural gas is used in this Study to refer to natural gas produced from the Site.
[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.

76. The EIA published annual estimates of oil lease operating costs between 1976 and 2009.[44] The Site's operating costs 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. Before 1976 and after 2009, the EIA operating costs were adjusted for historical changes in operating costs.[45]

77. The annual Site's operating costs are summarized below in **Figure 3**.

Figure 3 – Site Operating Costs



6.4 INCOME TAXES

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

79. 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]

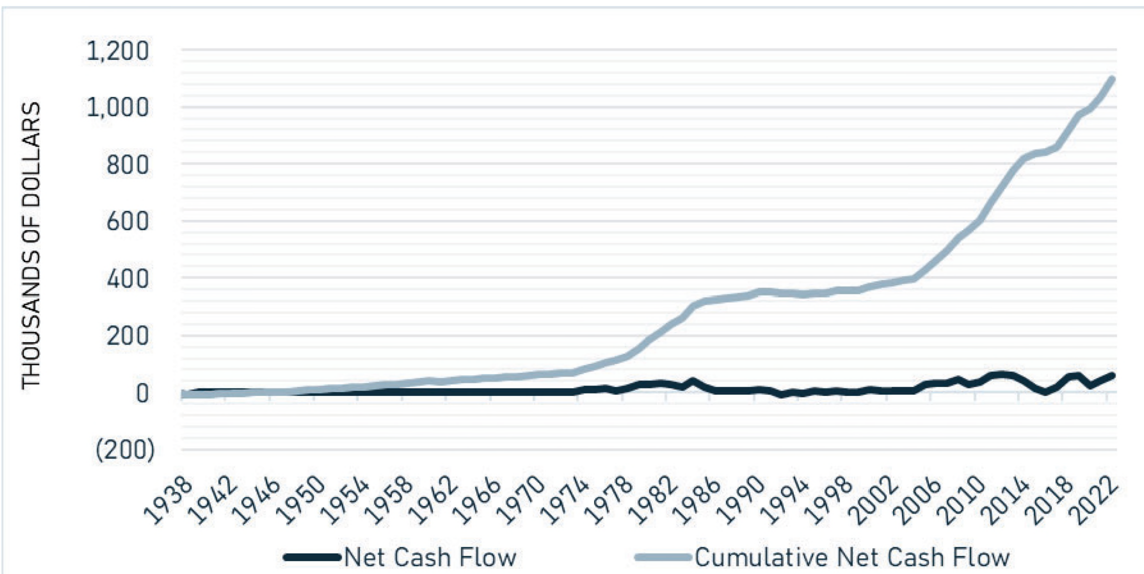
[44] See Section 6.6 of the Summary Report.
[45] See Section 5.2.4 of the Summary Report.
[46] See Section 6.7 of the Summary Report.

6.5 NET CASH FLOW FOR AMORTIZATION

80. 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 $13,000 during the years that the Site produced oil, with a cumulative net cash flow of about $1.1 million. These dollar amounts represent the cash flow generated from 1938 to 2022.

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

Figure 4 – Site Net Cash Flow



7. MARKET RATE OF RETURN ON INVESTMENT

82. 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 the total rate of return realized by public companies in this industry sector.

83. This Study refers to an analysis of the Weighted Average Cost of Capital ("WACC") for public companies 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 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.

84. 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

85. 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 needed to achieve amortization.

8.1 BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

86. In the Base Case, capital investment in the well and lease facilities at the Site were amortized within ten years in 1948.

87. 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 1948 when the cumulative IRR exceeded the 8% market rate of return. The Net Present Value ("NPV") test for amortization was also achieved in 1948 when the cumulative net present value exceeded zero.

88. The total capital investment of $273,000 was amortized by $1.1 million of net cash flow between 1938 and 2022. Original capital investment was amortized within ten years of the resumption of operations. The cumulative IRR increased to about 18% by 1960 and remained at that level through 2022.

8.2 SENSITIVITY CASE A: MARKET RETURN ON CAPITAL INVESTMENT

89. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment increases by two years over a reasonable range of assumptions in the market rate of return.

90. 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]

91. The results of the Sensitivity Case A income analysis are summarized in **Exhibit F**. The IRR test for amortization was achieved in 1950 when the cumulative IRR exceeded the 12% rate of return. The NPV test for amortization was achieved in 1950 when the cumulative net present value exceeded zero. Even with a higher market return on capital, the original investment in the well and lease facilities at the Site was amortized by 1950.

8.3 SENSITIVITY CASE B: COMMODITY PRICE

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

93. In Sensitivity Case B, the Base Case quality premium of $0.56/B for Filipinotown crude oil was changed to a premium of $0.06/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 the Filipinotown crude oil.

94. The results of the Sensitivity Case B income analysis are summarized in **Exhibit G.** The IRR test for amortization was achieved in 1948 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1948 when the cumulative net present value exceeded zero. Even with lower netback prices for the Filipinotown crude oil, the capital investment in the well and lease facilities at the Site was amortized by 1948.

8.4 SENSITIVITY CASE C: ORIGINAL CAPITAL INVESTMENT

95. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment does not change with a larger original capital investment.

96. In Sensitivity Case C, the Base Case cost to drill and complete a well of $250,000 was increased by 50% to $375,000. This cost is within the range of costs reported by Berry

[49] See **Exhibit 4** of the Summary Report.

for production wells and is an upper limit for a reasonable range of original capital costs for the well at the Site.

97. The results of the Sensitivity Case C income analysis are summarized in **Exhibit H**. The IRR test for amortization was achieved in 1948 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1948 when the cumulative net present value exceeded zero. Even with a larger capital investment in the well and lease facilities at the Site, this capital investment was amortized by 1948.

8.5 INCOME ANALYSES SUMMARY

98. The Base Case and three sensitivity cases 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 in **Table 4**.

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 ($/B)				
Crude Oil Transportation - Site to Long Beach	1.50	1.50	1.50	1.50
Crude Oil Quality Adjustment	0.56	0.56	0.06	0.56
Royalty and Lease Costs, % Revenue				
Royalty Rate	16.660%	16.660%	16.660%	16.660%
Site Operating Costs, 2022 ($/B)				
Basis: Total Produced Liquids	0.71	0.71	0.71	0.71
Capital Expenditures, 2022 ($ Thousands)				
Drilling and Completion Cost per Well	250	250	250	375
Well Modification Cost per Event	42	42	42	42
Results, 2022				
IRR, %	18.33%	18.33%	17.98%	18.22%
NPV, ($ Thousands)	24	7	24	24
Years to Amortization, IRR	10	12	10	10
Years to Amortization, NPV	10	12	10	10

EXHIBIT A: LIST OF REFERENCE DOCUMENTS

Title	Date
Petroleum in Southern California, P.W. Prutzman	March 27, 1905
The Los Angeles City Oil Field, S.M Testa	June 27, 2005
Bureau of Mines Information Circular 8676, Sulfur Content of Crude Oils	January 1, 1975
Central City West Specific Plan, Ordinance #s: 166,704, 167,944. 169,110, 176,519, 179,420, 180,983 and 186,370	April 3, 1991
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	45183
Official City of Los Angeles Municipal Code	45107
CalGEM Records for API 403716578, File 03716578_1996-10-16_DATA	Various
CalGEM Production Records, File CALGEMs_Well_Data_Formatting_LAC_All	Various

EXHIBIT B: AERIAL PHOTOGRAPH OF THE SITE

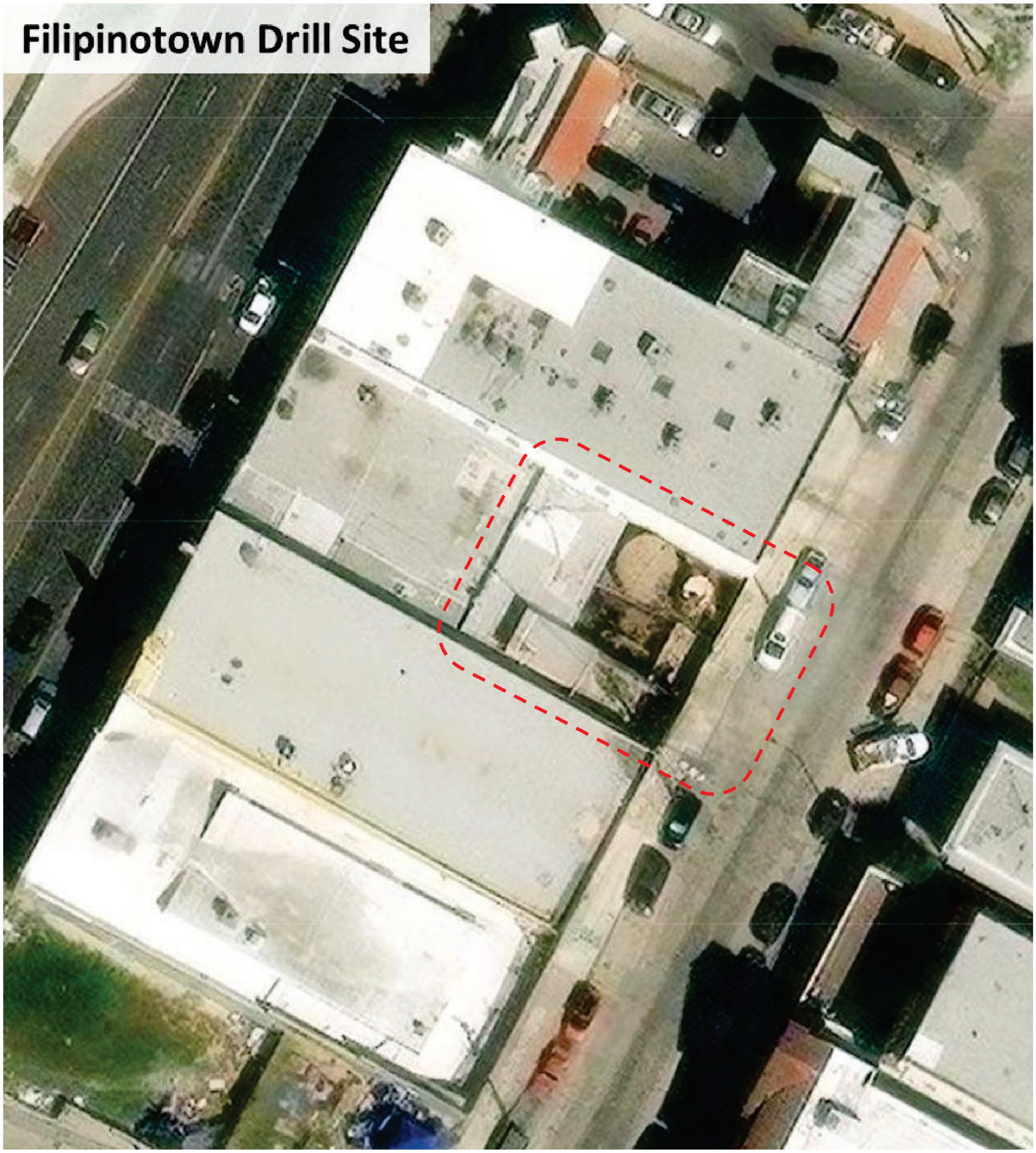


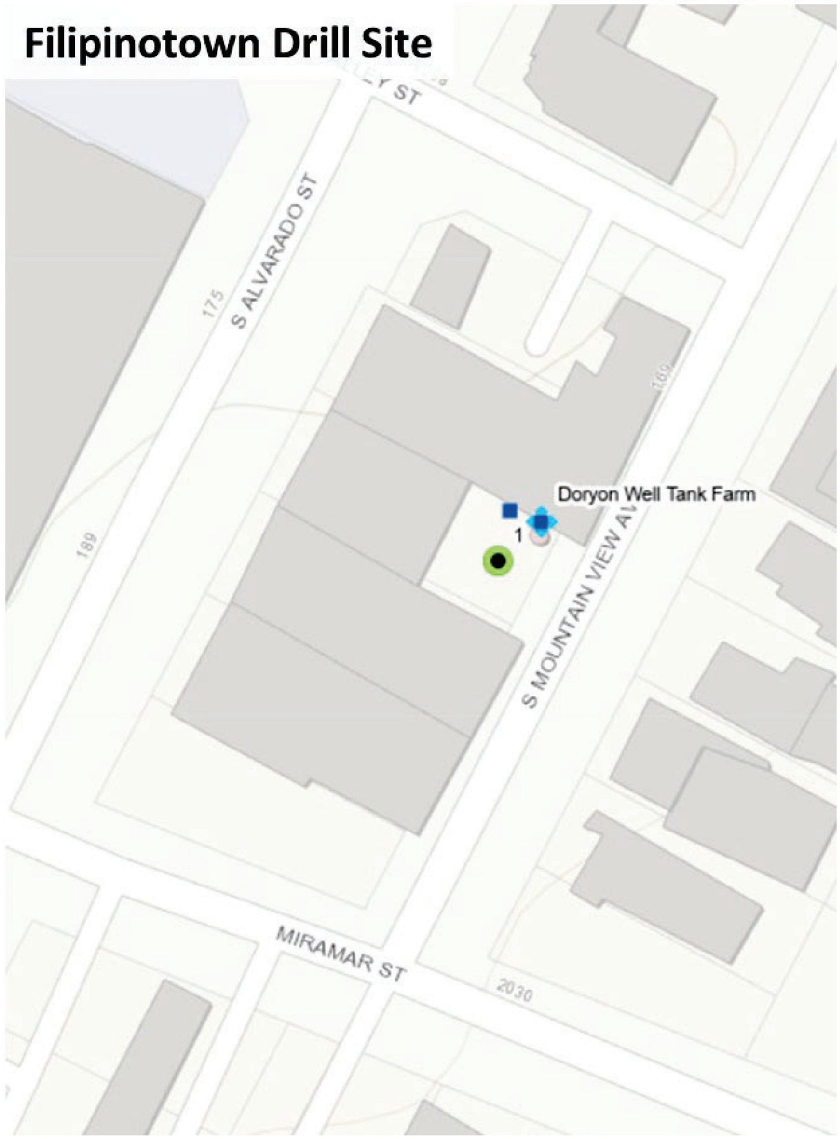
EXHIBIT C: WELLS AT THE SITE

Well API No.	Lease Name	Well Designation	Spudded	Complete	Current Type	Current Status
403716578	Unspecified	1	N/A	N/A	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: LOCATIONS OF WELLS AT THE SITE



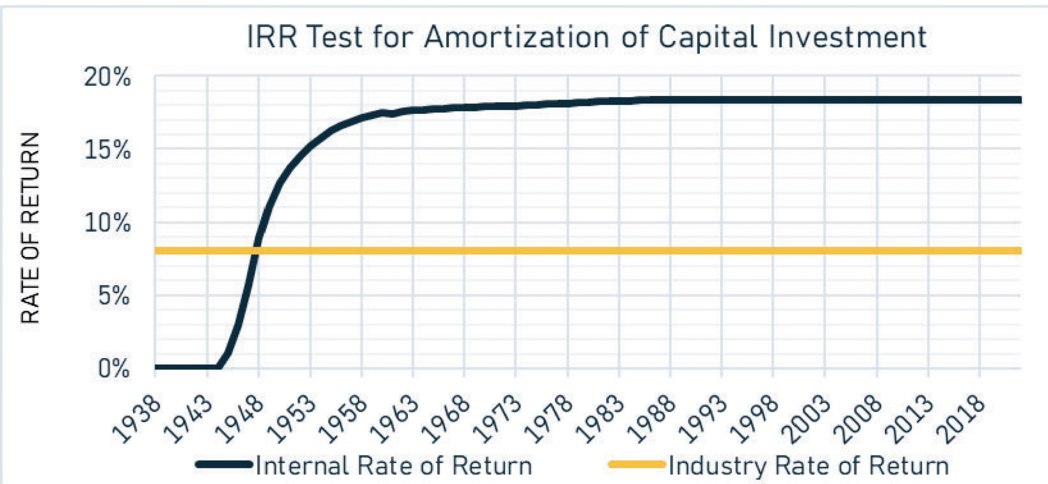
Source: CalGEM Well Finder website

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.
- Blue squares indicate above ground equipment

EXHIBIT E: BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1948
Amortization Year (NPV)	1948
Years for Amortization of Capital Investment	10
Capital Investment, $thousands	273
Gross Revenues, $thousands	2,987
EBITDA, $thousands	2,123
Net Cash Flow, $thousands	1,096
Cumulative IRR at 2022	18.33%



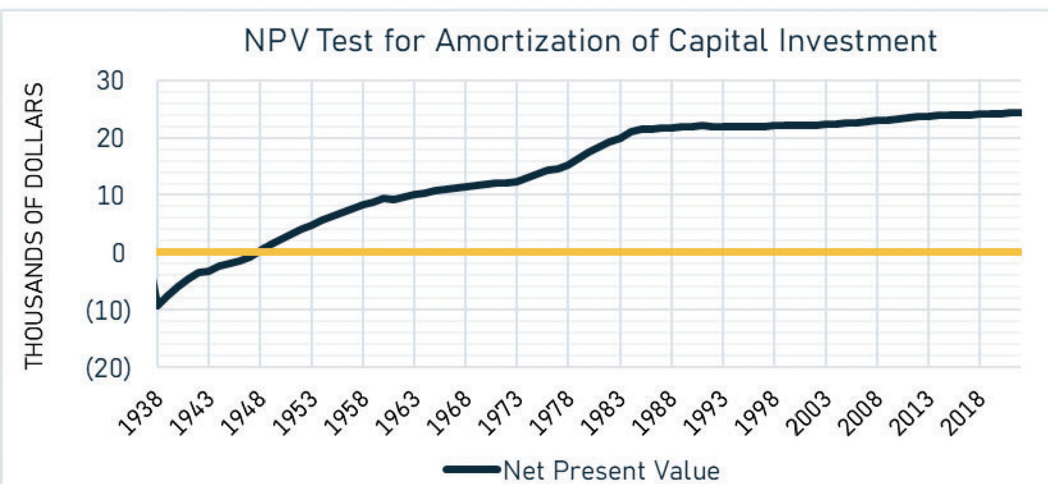
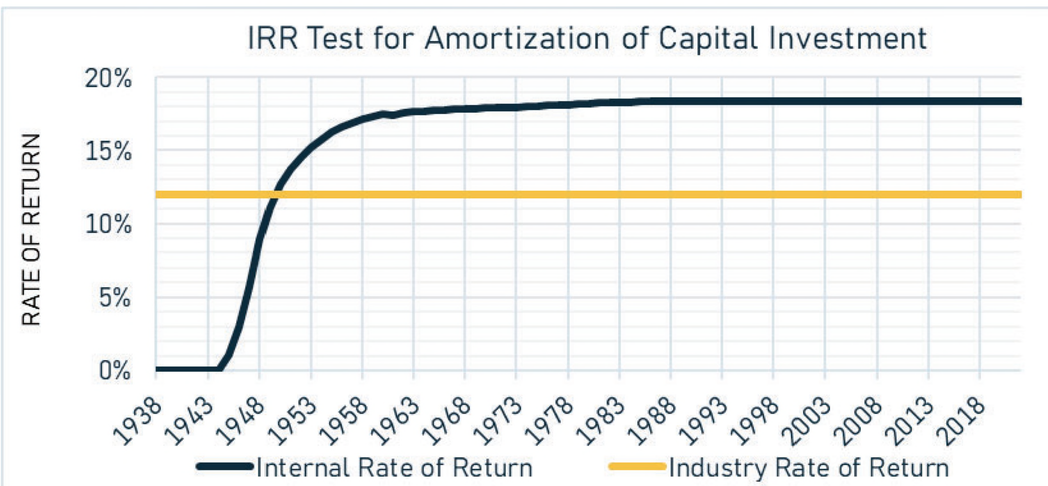


EXHIBIT F: SENSITIVITY CASE A—MARKET RETURN ON CAPITAL INVESTMENT

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1950
Amortization Year (NPV)	1950
Years for Amortization of Capital Investment	12
Capital Investment, $thousands	273
Gross Revenues, $thousands	2,987
EBITDA, $thousands	2,123
Net Cash Flow, $thousands	1,096
Cumulative IRR at 2022	18.33%



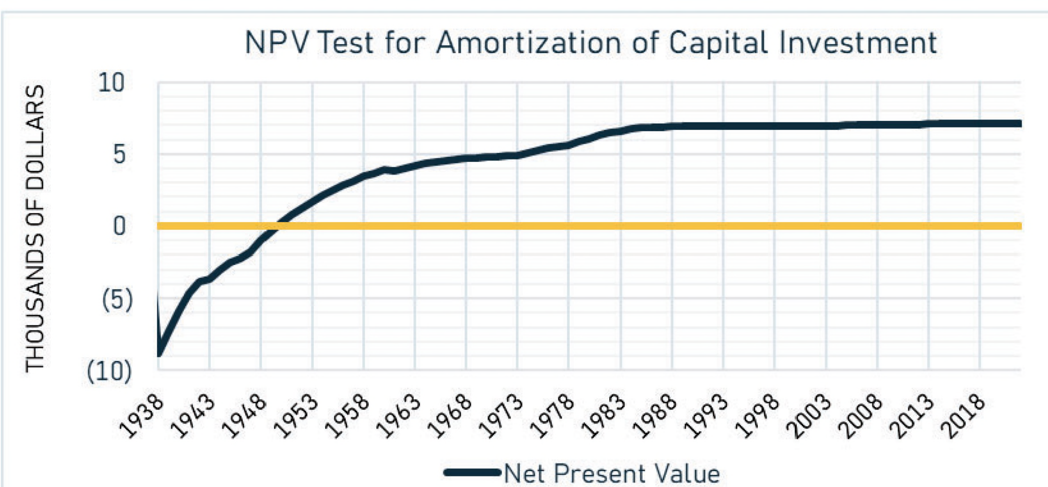
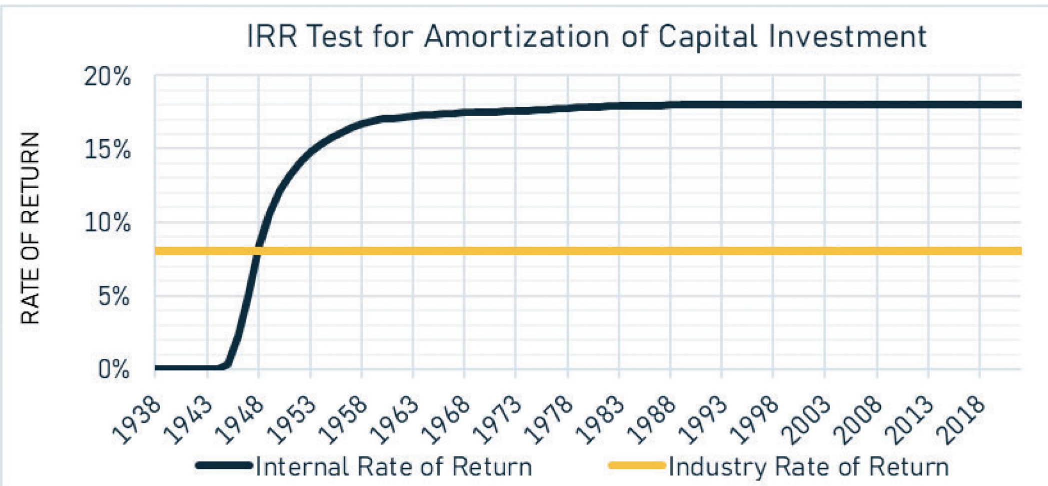


EXHIBIT G: SENSITIVITY CASE B—COMMODITY PRICE

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1948
Amortization Year (NPV)	1948
Years for Amortization of Capital Investment	10
Capital Investment, $thousands	273
Gross Revenues, $thousands	2,962
EBITDA, $thousands	2,102
Net Cash Flow, $thousands	1,084
Cumulative IRR at 2022	17.98%



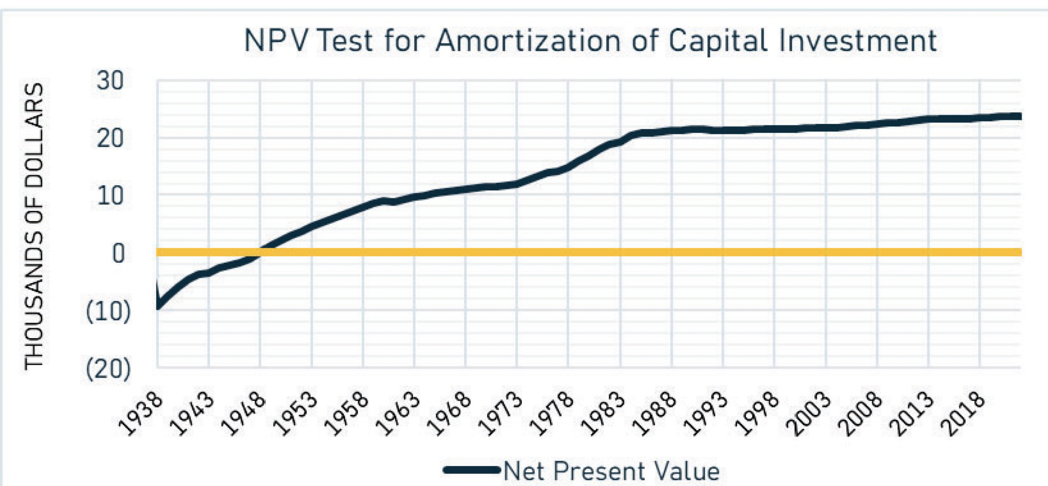


EXHIBIT H: SENSITIVITY CASE C—ORIGINAL CAPITAL INVESTMENT

Model Output Summary	
Start Year	1938
Amortization Year (IRR)	1948
Amortization Year (NPV)	1948
Years for Amortization of Capital Investment	10
Capital Investment, $thousands	283
Gross Revenues, $thousands	2,987
EBITDA, $thousands	2,123
Net Cash Flow, $thousands	1,090
Cumulative IRR at 2022	18.22%