Baker & O'Brien

CITY OF LOS ANGELES
OIL AND GAS DRILLING ORDINANCE

STUDY 2: AMORTIZATION OF CAPITAL INVESTMENT STUDY FOR THE MURPHY DRILL SITE

PREPARED FOR:

The City of Los Angeles

Board of Public Works

Office of Petroleum and Natural Gas Administration and Safety

DATE:

July 12, 2024

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

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

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

2. EXECUTIVE SUMMARY

5. *Location*: The Murphy Drill Site (the "Site") is located at 2126 W. Adams Blvd. in South Los Angeles . The Site extends from W. Adams about 360 feet south to between W. Adams Blvd. and W. 27th Street. A park is located south of the Site, which extends to W. 27th Street. The fence-line of the Site that contains wells and surface facilities is approximately 1,100 feet in length and encloses an area of about 1.5 acres. The Site extracts oil and gas from the Las Cienegas oil field under one lease.

6. *Zoning*: The Site is located within Council District 10 and the South Los Angeles Community Plan area. The Site is zoned [Q]R4-1-O-HPOZ, Multiple Dwelling, having height limitations, and within an Oil Drilling District and Historic Preservation Overlay Zone.[1]

7. *History*: A predecessor to Unocal Corporation ("Unocal"), drilled and completed wells at the Site between 1961 and 1995. Unocal commenced oil and gas operations at the Site with completion of the lease facilities in 1962 and used waterflood operations at the Site beginning in 1962, with peak production occurring in 1973 after the last well was completed. Operating interests in the Site were transferred sequentially from Unocal to Torch Operating Company in 1996, to Nuevo Energy Company in 1997, to Bentley-Simonson, Inc. in 2000, to Plains Exploration & Production Company in 2005, to Freeport McMoRan Oil and Gas LLC in 2013, to Sentinel Peak Resources California, LLC, in 2016, and to E&B Natural Resources Management Corporation in late 2019. E&B Natural Resources Management Corporation currently owns the operating interests in the Site.

8. *Site Status*: A total of 32 wells were drilled at the Site between 1961 and 2014. Of these, 21 production wells and 8 injection wells operated at the Site during 2022, while one well was idle and two wells were plugged. Surface facilities at the Site include lease equipment, several buildings, and various site improvements.

9. *Capital Investment*: The original cost to drill and complete wells and install lease facilities at the Site amounted to about $10.5 million. In addition to the original capital investment, sustaining capital investment in well equipment and lease equipment

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

amounted to $11.8 million. The cumulative estimated capital investment in the Site was about $22.3 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 1973 at nearly 580,000 barrels annually, or 1,588 barrels per day. Natural gas production peaked in 1981 at more than 190,000 oil equivalent barrels annually, or 533 barrels per day. Production of crude oil and natural gas declined steadily from 1996 until 2022, when the Site produced about 90,000 barrels of oil (251 barrels per day) and about 7,500 barrels of oil equivalent annually (21 barrels per day) of natural gas. Crude oil produced at the Site is a medium-sour crude with a market value greater than Alaskan North Slope ("ANS") 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 $198 million between 1961 and 2022.

11. *Base Case Conclusion*: In the Base Case, the capital investment in wells and lease facilities at the Site was amortized by 1963, within two years of the original capital investment. The cumulative internal rate of return for the Site in 2022 is significantly 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 larger capital investment. A market rate of return of 12% resulted in no change 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 one year. Over a reasonable range of assumptions, these factors do not significantly change the time required 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 that are located 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 Murphy 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 Murphy Drill Site (the "Site"), which is a group of oil wells and surface facilities located at 2126 W. Adams Blvd. in South Los Angeles.

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

17. This Study presents a detailed economic analysis for the 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 invested capital achieved by oil and gas production companies to 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

[2] City of Los Angeles Ordinance 187709.

historical data and reasonable estimates of capital investment, revenues, and operating costs. The sensitivity cases consider the extent to which alternative assumptions that may be used in the income analysis, including a higher market rate of return, a lower oil price, and larger capital investment, might change the Base Case amortization period.

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

19. The 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 2126 W. Adams Blvd. in South Los Angeles. The Site extends from W. Adams to about 360 feet south between W. Adams Blvd. and W. 27th Street. A park is located south of the Site, which extends to W. 27th Street. The fence-line of the Site that contains wells and surface facilities is approximately 1,100 feet in length and encloses an area of about 1.5 acres. The Site extracts oil and gas from the Las Cienegas oil field under one lease. An aerial photograph of the Site is presented in **Exhibit B**.[3] Additional location-specific details are provided in **Exhibit 5** of the Summary Report.

4.2 HISTORY

21. Oil was discovered at the Site in 1961 and the Union Oil Company of California, a predecessor to Unocal Corporation ("Unocal"),[4] drilled and completed wells at the Site between 1961 and 1973.[5] Unocal commenced oil and gas operations at the Site with completion of the lease facilities in 1962 with peak production occurring in 1973 after the last well was completed. Although some of the original wells were installed as "gas-lift" wells, Unocal used waterflood operations at the Site beginning in 1962.[6]

22. Unocal transferred its operating interests in the Site to Torch Operating Company ("Torch") in April 1996.[7] During 1996, 17 production wells and 4 injection wells were active, and the Site produced an average of 1,007 barrels per day ("B/D") of crude oil and 145 barrels of oil equivalent per day ("BOE/D") of natural gas.[8]

23. Torch transferred its operating interests in the Site to Nuevo Energy Company ("Nuevo") in April 1997.[9] Nuevo was an affiliate of Torch and there are no records of an arms-length transaction. During 1997, 17 production wells and 4 injection wells were active,

[3] Google Earth.
[4] Unocal was acquired by Chevron Corporation in 2005.
[5] **Exhibit C**.
[6] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[7] For example, Well Transfer Notice, April 22, 1996, 03700370_2014-12-11_DATA, p. 145/217.
[8] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[9] For example, Well Transfer Notice, April 3, 1997, 03700370_2014-12-11_DATA, p. 144/217.

and the Site produced an average of 831 B/D of crude oil and 135 BOE/D of natural gas.[10]

24. Nuevo transferred its operating interests in the Site to Bentley-Simonson, Inc., ("BSI") in July 2000.[11] During 2000, 19 production wells and 3 injection wells were active, and the Site produced an average of 502 B/D of crude oil and 63 BOE/D of natural gas.[12]

25. BSI transferred its operating interests in the Site to Plains Exploration & Production Company ("PXP") in April 2005.[13] During 2005, 19 production wells and 6 injection wells were active, and the Site produced an average of 659 B/D of crude oil and 67 BOE/D of natural gas.[14] PXP changed its name to Freeport McMoRan Oil and Gas LLC ("FMOG") in 2013.[15]

26. FMOG transferred its operating interests in the Site to Sentinel Peak Resources California, LLC, ("SPR") in December 2016.[16] During 2016, 21 production and 8 injection wells were active, and the Site produced an average of 343 B/D of crude oil and 41 BOE/D of natural gas.[17]

27. SPR transferred its operating interests in the Site to E&B Natural Resources Management Corporation ("E&B") in late 2019.[18] During 2019, 20 production and 8 injection wells were active and the Site produced an average of 231 B/D of crude oil and 30 BOE/D of natural gas.[19] E&B currently owns the operating interests in the Site.

4.3 LEASES

28. The Site operates wells that produce oil and gas from the Murphy lease.

[10] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[11] For example, Well Transfer Notice, July 7, 2000, 03700370_2014-12-11_DATA, p. 142/217.
[12] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[13] For example, Report of Property and Well Transfer, April 18, 2005, 03700370_2014-12-11_DATA, p. 139/217.
[14] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[15] CalGEM Records, 03700370_2014-12-11_DATA, pp. 67, 70.
[16] For example, Report of Property and Well Transfer, December 30, 2016, 03700371_2015-11-06_DATA, p. 1/126.
[17] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[18] https://www.dailynews.com/2022/01/25/la-city-council-may-take-step-toward-halting-new-oil-and-gas-drilling, p. 3/7; https://www.desertsun.com/story/news/environment/2021/03/11/south-los-angeles-group-sues-l-a-fire-department-over-oil-wells/6914195002/, p. 5/7
[19] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.

29. The Catholic Archdiocese of Los Angeles is reported to be the owner of the Site and the mineral rights for the Murphy lease.[20] Records of ownership of mineral rights or royalty payments for these leases were not available for this Study.

4.4 STATUS OF WELLS

30. The California Department of Conservation's California Geologic Energy Management Division ("CalGEM") reports that 32 wells were drilled at the Site for the production of oil and gas and injection of water, as shown in **Exhibit C**. The wells at the Site were originally spudded and completed during three periods, including: 19 wells were completed during 1961 and 1962; 8 additional wells were completed between 1969 and 1973; and 5 additional wells were completed between 2007 and 2014.

31. The wells at the Site are generally situated along a line through the middle of the Site, as shown in **Exhibit D**.[21] The status of each of the wells at the Site during 2022 is listed in **Exhibit C** and summarized as follows: 21 production wells and 8 injection wells were active at the Site, one well was idle, and two wells were plugged.[22]

4.5 SURFACE FACILITIES

32. 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 several buildings and other site improvements. The surface facilities can be seen in **Exhibit B**.[23]

33. Lease equipment is designed to separate well fluids into crude oil, natural gas, and produced water. This equipment generally includes pipelines from well-heads, tanks to separate crude oil and natural gas from water, pumps to inject crude oil into a pipeline, pumps to inject produced water back to the formation, storage tanks, gas treating equipment, and gas compression equipment. Some of this equipment is visible in the center of the Site, while other equipment is located along the southern perimeter wall, inside of buildings, and beneath shed roofs.[24] The equipment shown in the aerial

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[20] https://www.desertsun.com/story/news/environment/2021/03/11/south-los-angeles-group-sues-l-a-fire-department-over-oil-wells/6914195002/, p. 3-4/7.
[21] CalGEM Well Finder website.
[22] See CalGEM records for each of the wells at the Site, which are listed in **Exhibit A**.
[23] The assessment of surface facilities in this Study is based upon aerial photos since physical access to the Site was not authorized.
[24] **Exhibit B**.

photograph appears to be typical, but it is not possible to determine the condition of the equipment, which equipment remains in operation, or if equipment has been abandoned in place. No records are available that document the size, capacity, or cost of lease equipment when it was originally installed.

34. Well-heads at the Site are located in two concrete "cellars" that are about 10 feet wide, with one extending 200 feet and the other extending 130 feet, as required by the Los Angeles Municipal Code,[25] which are visible in **Exhibit B**. The cellars appear to be fully covered with steel plates in the aerial photograph.[26] In a letter dated September 14, 2007, the City of Los Angeles Department of Building and Safety approved an expansion to an existing "well cellar" to accommodate a total of 38 well slots.[27] The letter states that the existing cellar and the expansion were to comply with various municipal codes.

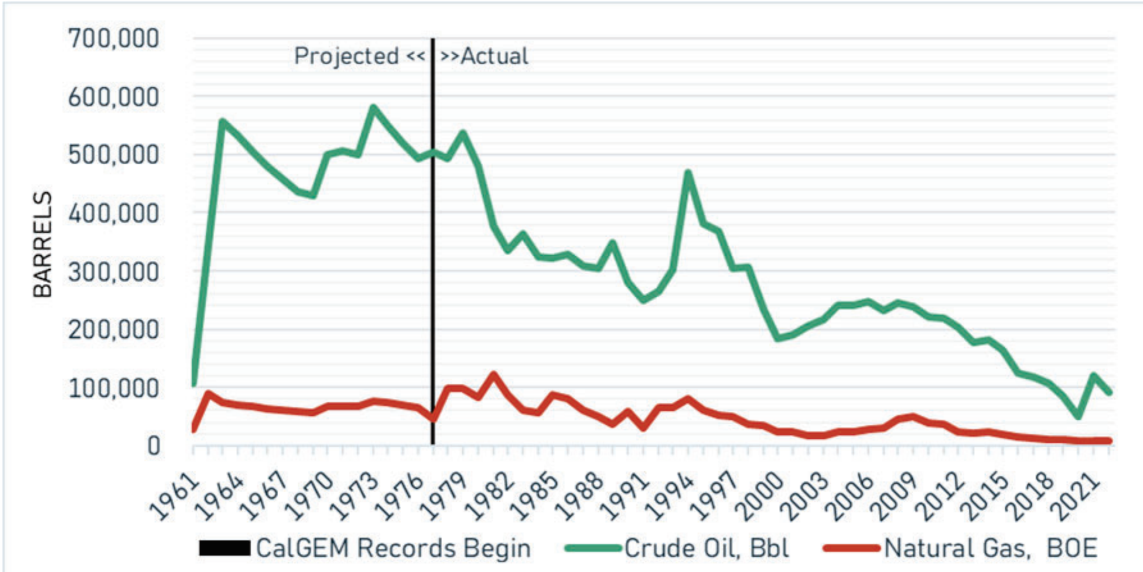
35. Four buildings are located on the Site.[28] A one-story building at the southeast corner of the Site appears to house lease equipment. A large one-story building just to the north appears to house lease equipment and may provide warehouse space. A one-story building in the middle of the Site appears to house lease equipment. A one-story building along the eastern wall appears to be an administrative office. In addition to these buildings, there are structures that cover equipment located along the southwestern wall. The Site is surrounded by a 10-foot block wall with two gated entrances on Adams Blvd. Other site improvements include extensive paving on the Site, along with safety and security systems.

4.6 HISTORICAL OIL AND GAS PRODUCTION

36. Oil and gas production from the Site is shown below in **Figure 1**.[29] Oil and gas production trends at the Site can be considered during two periods: 1961 to 1995; and 1996 to the present.

[25] Los Angeles Municipal Code Section 13.01.F.
[26] **Exhibit B**.
[27] City of Los Angeles Letter, September 14, 2007, 03726956_2014-08-29_DATA, p. 61.
[28] **Exhibit B**.
[29] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.

Figure 1 – Site Oil and Gas Production



37. Production rates at the Site were highest between 1961 and 1995, when Unocal was the operator. These rates are characteristic of a new oil and gas development. Production rates from 1961 to 1976 were projected based upon a type-curve that was prepared from historical production data. Between 1961 and 1995, production averaged 1,132 B/D of oil and 330 BOE/D of natural gas.

38. Since 1996, operating interests at the Site have been owned by seven different operators, and oil and gas production declined steadily over the period. Between 1996 and 2022, production rates averaged 539 B/D, while natural gas production averaged 70 BOE/D. Well fluid rates during this period were more than double the rates reported by Unocal due to higher produced water rates from waterflood operations.

4.7 OIL AND GAS QUALITY

39. Crude oil produced at the Site is medium-sour crude, averaging about 31.2 degrees API ("°API") since 1977.[30] The sulfur content of crude oil produced at the Site is reported to be 0.58%.[31] The quality of crude oil produced at the Site is comparable to Alaskan North Slope ("ANS") crude oil, which has market specifications of 31.9°API and a sulfur

[30] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.
[31] *Sulfur Content of Crude Oils*, Bureau of Mines Information Circular 8676, 1975.

content of 0.93%. Due to the lower API Gravity, crude oil produced at the Site would be less valuable to a refiner than the market value of ANS crude.

40. 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 boundary. Natural gas must meet pipeline quality specifications before it can be injected into a local distribution system.

4.8 LOGISTICS

41. The Site is connected to underground pipelines for the delivery of crude oil and natural gas. Los Angeles City Ordinance 150017 granted a pipeline franchise to the Union Oil Company of California, a predecessor of Unocal, to build and operate various pipelines in the City.[32] This ordinance lists two 6-inch pipelines located in 27th Street (the southern border of the Site).[33] One of these pipelines is used to deliver crude oil and the other pipeline is used to deliver natural gas.

42. A U.S. Department of Transportation map shows that the crude pipeline remains active.[34] No records of tariffs actually paid to third parties for the delivery of crude oil were available for this Study.

43. Crimson publishes common carrier tariffs for its Las Cienegas Line 600 for both gathering and trunkline operations. In 2022, the common carrier tariff for gathering and transportation to Long Beach was about $1.50 per barrel ("/B").[35] This tariff was used to estimate transportation costs for delivery of crude oil from the Site to Los Angeles area refineries.

44. Available records of pipeline franchise ordinances indicate that Unocal transferred ownership of the pipeline to Nuevo, which transferred ownership to BSI in 2000.[36] The pipeline is 5.85 miles in length and receives natural gas from the Jefferson, Murphy, and

[32] City of Los Angeles Ordinance 150017.
[33] City of Los Angeles Ordinance 150017, p. 6/21.
[34] https://pvnpms.phmsa.dot.gov/PublicViewer/
[35] Crimson California Pipeline LP Las Cienegas Gathering Tariff, August 1, 2022; Crimson California Pipeline LP Las Cienegas Trunk Line Tariff, August 1, 2022.
[36] Board Report, City of Los Angeles Department of Transportation, January 9, 2003, p. 1.

Fourth Avenue drill sites for delivery to a Pacific Electric site near the intersection of Venice Blvd. and Longwood Ave.[37]

45. In summary, operators of the Site owned rights to deliver crude oil by pipeline until 2001. After 2001, it appears that the crude oil pipeline became a common carrier pipeline. Operators of the Site also owned rights to deliver natural gas by pipeline until at least 2005, after which natural gas was delivered by a common carrier pipeline.

[37] Board Report, City of Los Angeles Department of Transportation, January 9, 2003, p. 2.

5. CAPITAL INVESTMENT

46. The capital investment to be amortized at the Site 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.[38]

5.1 ORIGINAL CAPITAL INVESTMENT

47. 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.

48. 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

49. Original capital investment for production and injection wells was estimated based upon 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 U.S. Bureau of Labor Statistics ("BLS") Producer Price Index Oil and Gas Drilling ("PPI-OGD") cost index.[39] The average of the normalized costs in 2022 is $1,397,866 per well. This Study uses an

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

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.

50. 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.[40] Original capital investment for wells at the Site amounted to $9.1 million.

5.1.2 LEASE EQUIPMENT

51. 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.

52. The U.S. Department of Energy's Energy Information Administration ("EIA") published annual estimates of capital investment for lease equipment between 1976 and 2009.[41] These estimates included representative costs for lease equipment used in waterflood operations. Lease equipment is normally 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-

[40] See Section 5.2.4 of the Summary Report.
[41] See Section 5.2.2 of the Summary Report.

capacity relationship.[42] The original capital investment in lease facilities was allocated in the cash flow analysis to years when new wells were completed between 1961 and 2014. The original capital investment for lease equipment at the Site amounted to $1.3 million.

5.1.3 SITE IMPROVEMENTS

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

54. For this Study, the original investment in site improvements was estimated as 5% of the cost for lease facilities.[43] The original site improvements are allocated to the years when new wells were completed. The original capital investment for site improvements amounted to about $67,000.

5.2 SUSTAINING CAPITAL INVESTMENT

55. 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 as operating costs and are not included in sustaining capital investment.[44]

56. 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.

[42] This relationship, commonly referred to as the Rule of Six-Tenths, is an empirical relationship between the cost and the capacity of a manufacturing facility. The estimated cost = $((\text{capacity}) / (\text{base capacity}))^{0.6}$ x (base cost).
[43] See Section 5.2 of the Summary Report.
[44] Operating costs are discussed below in Section 6.3.

5.2.1 WELL MODIFICATIONS

57. 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.

58. CalGEM records present a history of well modifications for each of the wells at the Site from 1961 to the present.[45] 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.

59. California operators have reported costs for well modifications and those relevant to the Site are listed below in **Table 2**. CRC reported the costs for three types of well modifications,[46] while SPR reported an average cost for these activities.[47] Costs reported by CRC and SPR were normalized to 2022, which averaged $207,734 per activity. This Study uses an average cost of $210,000 per well modification 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.

60. CalGEM records identify the completion dates for modifications to wells.[48] Sustaining capital investment in well modifications is recorded in the cash flow analysis during the

45 See CalGEM records for each of the wells at the Site, which are listed in **Exhibit A**.
46 California Resources Corp. 2017 Analyst Day Presentation, p. 67.
47 Sentinel Peak Resources, Report of Robert Lang, Alvarez & Marsal, June 17, 2021, ¶52.
48 See CalGEM records for each of the wells at the Site, which are listed in **Exhibit A**.

year in which the modification is completed. The total sustaining capital investment for well modifications amounted to $5.0 million between 1963 and 2016.

5.2.2 WELL EQUIPMENT

61. 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.

62. The Study allows for 3.33% of the replacement cost of well equipment as sustaining capital investment each year.[49] 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.[50] The total sustaining capital investment for well equipment amounted to about $2.4 million between 1961 and 2022.

5.2.3 LEASE EQUIPMENT

63. 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.

64. 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.[51] The total sustaining capital investment for lease equipment amounted to $4.4 million between 1961 and 2022.

[49] 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.
[50] See Section 5.2.4 of the Summary Report.
[51] See Section 5.2.4 of the Summary Report.

5.3 SUMMARY OF CAPITAL INVESTMENT

65. The total capital investment at the Site to be amortized is about $22.3 million, as summarized below in **Table 3**. This amount includes $10.5 million of original capital investment that occurred between 1961 and 2014, and $11.8 million of sustaining capital investment that occurred between 1961 and 2022. These dollar amounts represent the capital investment incurred by operators from 1961 to 2022.

Table 3 – Summary of Site Capital Investment

Summary of Site Capital Investment		
	Investment	Time
Original Capital Investment		
New Wells	$9,112,585	1961-2014
Lease Equipment	$1,349,277	1961-2014
Site Improvements	$67,464	1961-2014
Subtotal	**$10,529,326**	
Sustaining Capital Investment		
Well Modifications	$5,001,266	1963-2016
Well Equipment	$2,392,252	1961-2022
Lease Equipment	$4,410,913	1961-2022
Subtotal	**$11,804,432**	
Capital Investment to be Amortized	**$22,333,758**	

6. INCOME ANALYSIS

66. 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 commencement 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.

67. 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

68. 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. The 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

69. 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.[52]

70. Most 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

[52] See CalGEM production records, CALGEMs_Well_Data_Formatting_Murphy.

fluids utilizing "type-curves" derived from available production data. Type-curves are developed using standard engineering calculations applied in oil and gas reservoir management, using historical data from operating wells.[53] This standard approach assumes that characteristics of the reservoir dictate production rates evident in the type-curves.[54]

71. Annual production volumes of crude oil and natural gas from individual wells are aggregated for the Site to determine income. Annual production volumes from the Site are summarized above in **Figure 1, Section 4.6**.

6.1.2 NETBACK PRICES FOR CRUDE OIL

72. Netback prices for crude oil represent the market price that 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.

73. No records are available that document netback prices received for Murphy crude oil.[55] However, Murphy crude oil is typically 31.2°API and 0.58% sulfur, which is comparable in quality to ANS crude oil that is typically 31.9°API and 0.93% sulfur.[56]

74. This Study estimated netback prices for Murphy crude oil based upon market prices for ANS crude oil delivered to Long Beach,[57] plus a quality adjustment, less delivery costs from the Site to Long Beach. Historical price assessments for ANS crude were used as a benchmark for the value of Murphy crude from 1988 to the present. Since ANS price assessments are not available before 1988, Murphy 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 1961 and 1978.[58]

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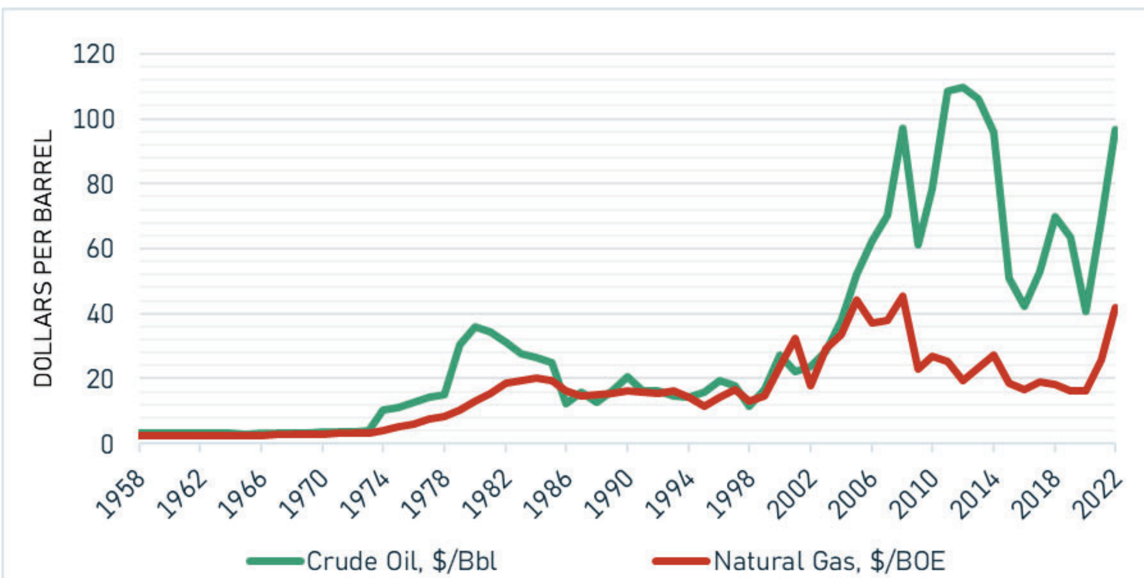
[53] A type-curve is also referred to as a "decline curve."
[54] See Section 6.2 of the Summary Report.
[55] "Murphy" crude oil is used in this Study to refer to crude oil produced from the Site.
[56] The quality of Murphy crude oil is compared to ANS crude oil in Section 4.8.
[57] ANS crude oil is delivered to Long Beach by marine tanker.
[58] See Section 6.3 of the Summary Report.

75. A quality adjustment to the benchmark price assessment reflects the difference in refining value between Murphy crude oil and the benchmark.[59] As noted above, Murphy crude oil is lower in API Gravity to ANS and may be less valuable to a refiner. Based on reasonable industry adjustments for API Gravity, a quality discount of $0.25/B reflects the lower market value of Murphy crude oil.

76. The Site delivered crude oil to customers by either a proprietary pipeline or a common carrier pipeline, both of which connect to a common carrier pipeline for delivery of crude oil to terminals in Long Beach. Although operators of the Site operated and maintained a proprietary pipeline until 2001,[60] these costs are not included in the Site operating costs and are not available for this Study. Transportation costs to deliver crude oil from the Site to Long Beach were estimated as $1.50/B in 2022, based on common carrier tariffs.[61]

77. Annual average netback prices for Murphy 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

78. 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

[59] See Section 6.3 of the Summary Report.
[60] City of Los Angeles Ordinance 174125.
[61] Crimson California Pipeline L.P. trunkline tariff, August 1, 2022; Crimson California Pipeline L.P. gathering line tariff, August 1, 2022.

connection for sales of natural gas to the SoCalGas system or another local distribution company that serves the Los Angeles area. Natural gas must meet pipeline quality specifications before it can be injected into a local distribution system.[62]

79. 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.[63] No discount for transportation costs was applied on these sales, which would be delivered into a pipeline.

80. Annual average netback prices for Murphy natural gas are shown above in **Figure 2**.[64]

6.2 ROYALTIES

81. Owners of mineral rights earn a royalty on commercial volumes of oil and gas produced from their property.[65] 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.

82. 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.[66]

6.3 OPERATING COSTS

83. Lease operating costs generally include labor, utilities, operating materials, maintenance materials, spare parts, general and administrative expenses, insurance, and permits.

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

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.

84. The EIA published annual estimates of oil lease operating costs between 1976 and 2009.[67] 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.[68]

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

Figure 3 – Site Operating Costs

6.4 INCOME TAXES

86. 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.

[67] See Section 6.6 of the Summary Report
[68] See Section 5.2.4 of the Summary Report.

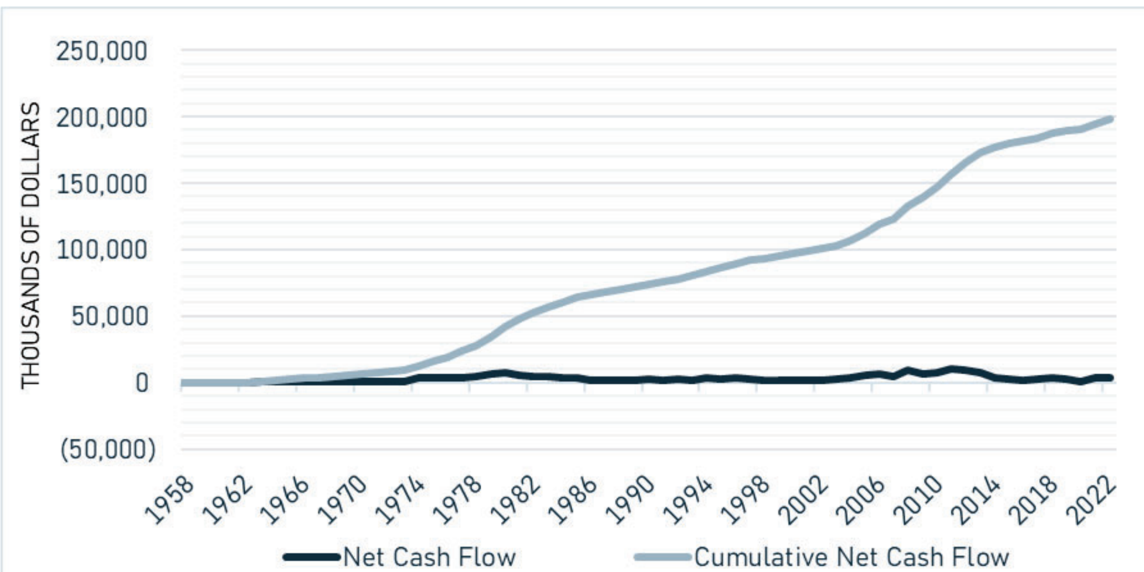
87. Federal and state income taxes on taxable income are calculated using the highest corporate tax brackets in effect each year. Federal income tax rates range from 21% to 46%, and California state income tax rates range from 8.8% to 9.6%.[69]

6.5 NET CASH FLOW FOR AMORTIZATION

88. 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 $3.2 million and cumulative net cash flow between 1961 and 2022 amounted to more than $198 million. These nominal dollar amounts represent the cash flow generated from 1961 to 2022.

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

Figure 4 – Site Net Cash Flow



[69] See Section 6.7 of the Summary Report.

7. MARKET RATE OF RETURN ON INVESTMENT

90. The tests for amortization of capital investment use a "market" rate of return on investment that is characteristic of oil and gas production companies.[70] The market rate of return on investment is a total rate of return that is realized by public companies in this industry sector.

91. This Study refers to an analysis of the Weighted Average Cost of Capital ("WACC") for public companies that has been published annually since 1998.[71] 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.

92. 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.

[70] See Section 4.3 of the Summary Report.
[71] See Section 7.1 of the Summary Report.

8. CONCLUSIONS

93. 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.

8.1 BASE CASE AMORTIZATION OF CAPITAL INVESTMENT

94. In the Base Case, capital investment in wells and lease facilities at the Site was amortized by 1963, within two years of the original capital investment.

95. 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 1963 when the cumulative IRR exceeded the 8% market rate of return. The Net Present Value ("NPV") test for amortization was also achieved in 1963 when the cumulative net present value exceeded zero.

96. The total capital investment of $22.3 million was amortized by $197.8 million of net cash flow between 1961 and 2022. Original capital investment was amortized within two years of commencement of operations. The cumulative IRR increased to about 109% by 1969 and remained at that level through 2022.

8.2 SENSITIVITY CASE A: MARKET RETURN ON CAPITAL INVESTMENT

97. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment does not change over a reasonable range of assumptions in the market rate of return.

98. 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.[72]

99. The results of the Sensitivity Case A income analysis are summarized in **Exhibit F**. The IRR test for amortization was achieved in 1963 when the cumulative IRR exceeded the 12% rate of return. The NPV test for amortization was also achieved in 1963 when the cumulative net present value exceeded zero. Even with a much higher market return on capital, the capital investment in wells and lease facilities at the Site was amortized by 1963.

8.3 SENSITIVITY CASE B: COMMODITY PRICE

100. 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.

101. In Sensitivity Case B, the Base Case quality discount of $0.25/B for Murphy crude oil was changed to a quality discount of $0.75/B. This adjustment may be appropriate if the sulfur content of Murphy crude oil was the same as for ANS crude oil. 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 Murphy crude oil.

102. The results of the Sensitivity Case B income analysis are summarized in **Exhibit G**. The IRR test for amortization was achieved in 1963 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1963 when the cumulative net present value exceeded zero. Even with lower netback prices for Murphy crude oil, the capital investment in wells and lease facilities at the Site was amortized by 1963.

8.4 SENSITIVITY CASE C: ORIGINAL CAPITAL INVESTMENT

103. This sensitivity analysis demonstrates that the time required to achieve amortization of capital investment is extended by one year with a much larger original capital investment.

[72] See Exhibit 4 of the Summary Report.

104. In Sensitivity Case C, the Base Case cost to drill and complete a well of $1.4 million was increased by 50% to $2.1 million. This cost for an oil well exceeds the maximum cost for a new well reported by CRC by more than 19%.[73] This cost is an upper limit for a reasonable range of original capital costs.

105. The results of the Sensitivity Case C income analysis are summarized in **Exhibit H**. The IRR test for amortization was achieved in 1964 when the cumulative IRR exceeded the 8% market rate of return. The NPV test for amortization was also achieved in 1964 when the cumulative net present value exceeded zero. Even with a much larger capital investment in wells and lease facilities at the Site, this capital investment was amortized by 1964, extending the amortization period by one year.

8.5 INCOME ANALYSES SUMMARY

106. The Base Case and 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.

[73] 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 ($/Bbl)				
Crude Oil Transportation – Site to Long Beach	1.50	1.50	1.50	1.50
Crude Oil Quality Adjustment	(0.25)	(0.25)	(0.75)	(0.25)
Royalty and Lease Costs, % Revenue				
Royalty Rate	16.660%	16.660%	16.660%	16.660%
Site Operating Costs, 2022 ($/Bbl)				
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, %	109.21%	109.21%	107.36%	65.74%
NPV, ($ Thousands)	22,262	11,281	22,064	21,601
Years to Amortization, IRR	2	2	2	3
Years to Amortization, NPV	2	2	2	3

EXHIBIT A: LIST OF REFERENCE DOCUMENTS

Title	Date
Bureau of Mines Information Circular 8676, Sulfur Content of Crude Oils	January 1, 1975
City of Los Angeles, Ordinance No. 150017	August 5, 1977
Costs and Indices for Domestic Oil and Gas Field Equipment and Operations, DOE/EIA-0185(95)	August 1, 1996
City of Los Angeles, Ordinance No. 174125	September 2, 2001
Los Angeles Department of Transportation, Board Report	January 9, 2003
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
North America Midstream Infrastructure through 2035, ICF International/INGAA Foundation	April 12, 2016
California Resources Corporation 2017 Analyst Day Presentation	March 22, 2017
California Resources Corporation 2018 Corporate Presentation	November 1, 2018
OPNGAS Report for Termination of Ordinance 184966	April 5, 2019
Desert Sun, "South Los Angeles oil wells worry neighbors, spark lawsuit"	March 12, 2021
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
Los Angeles Daily News, "LA City Council may take step toward halting new oil and gas drilling"	January 25, 2022
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
Official City of Los Angeles Municipal Code	June 30, 2023
CalGEM Records for API 403700291, File 03700291_2019-03-15_DATA	Various
CalGEM Records for API 403700322, File 03700322_2014-12-09_DATA	Various
CalGEM Records for API 403700369, File 03700369_2015-11-06_DATA	Various
CalGEM Records for API 403700371, File 03700371_2015-11-06_DATA	Various
CalGEM Records for API 403700372, File 03700372_2015-11-06_DATA	Various
CalGEM Records for API 403700373, File 03700373_2015-11-03_DATA	Various
CalGEM Records for API 403700375, File 03700375_DATA_2014-12-04	Various
CalGEM Records for API 403700376, File 03700376_2017-09-19_DATA	Various
CalGEM Records for API 403700376, File 03700376_2018-03-21_SUM,HISTORY	Various
CalGEM Records for API 403700376, File 03700376_2019-08-06_WellCancellation	Various
CalGEM Records for API 403700376, File 03700376_2019-10-30_WellSummaryNotice	Various
CalGEM Records for API 403700378, File 03700378_2018-10-17_DATA	Various
CalGEM Records for API 403700379, File 03700379_2018-10-17_DATA	Various
CalGEM Records for API 403700381, File 03700381_2016-08-30_DATA	Various
CalGEM Records for API 403700382, File 03700382_2017-08-30_DATA	Various
CalGEM Records for API 403700383, File 03700383_2018-10-17_DATA	Various
CalGEM Records for API 403700384, File 03700384_2018-10-17_DATA	Various
CalGEM Records for API 403700385, File 03700385_2018-10-17_DATA	Various
CalGEM Records for API 403720955, File 03720955_2018-10-17_DATA	Various
CalGEM Records for API 403720967, File 03720967_2018-10-17_DATA	Various
CalGEM Records for API 403721072, File 03721072_2018-10-17_DATA	Various
CalGEM Records for API 403721221, File 03721221_2018-10-17_DATA	Various
CalGEM Records for API 403721222, File 03721222_2019-01-18_DATA	Various
CalGEM Records for API 403721223, File 03721223_2018-10-17_DATA	Various
CalGEM Records for API 403721224, File 03721224_2018-09-26_DATA	Various
CalGEM Records for API 403726596, File 03726596_2019-01-09_DATA	Various
CalGEM Records for API 403726956, File 03726956_2014-08-29_DATA	Various
CalGEM Records for API 403726957, File 03726957_2016-11-03_DATA	Various
CalGEM Records for API 403727007, File 03727007_2014-08-29_DATA	Various
CalGEM Records for API 403730129, File 03730129_2018-09-25_DATA	Various
CalGEM Records for API 403730129, File 03730129_2019-03-18_Accepted_Test Results	Various
CalGEM Records for API 403730170, File 03730170_2016-08-29_DATA	Various
CalGEM Production Records, File CALGEMs_Well_Data_Formatting_Murphy	Various

EXHIBIT B: AERIAL PHOTOGRAPH OF THE SITE

Source: Google Earth.

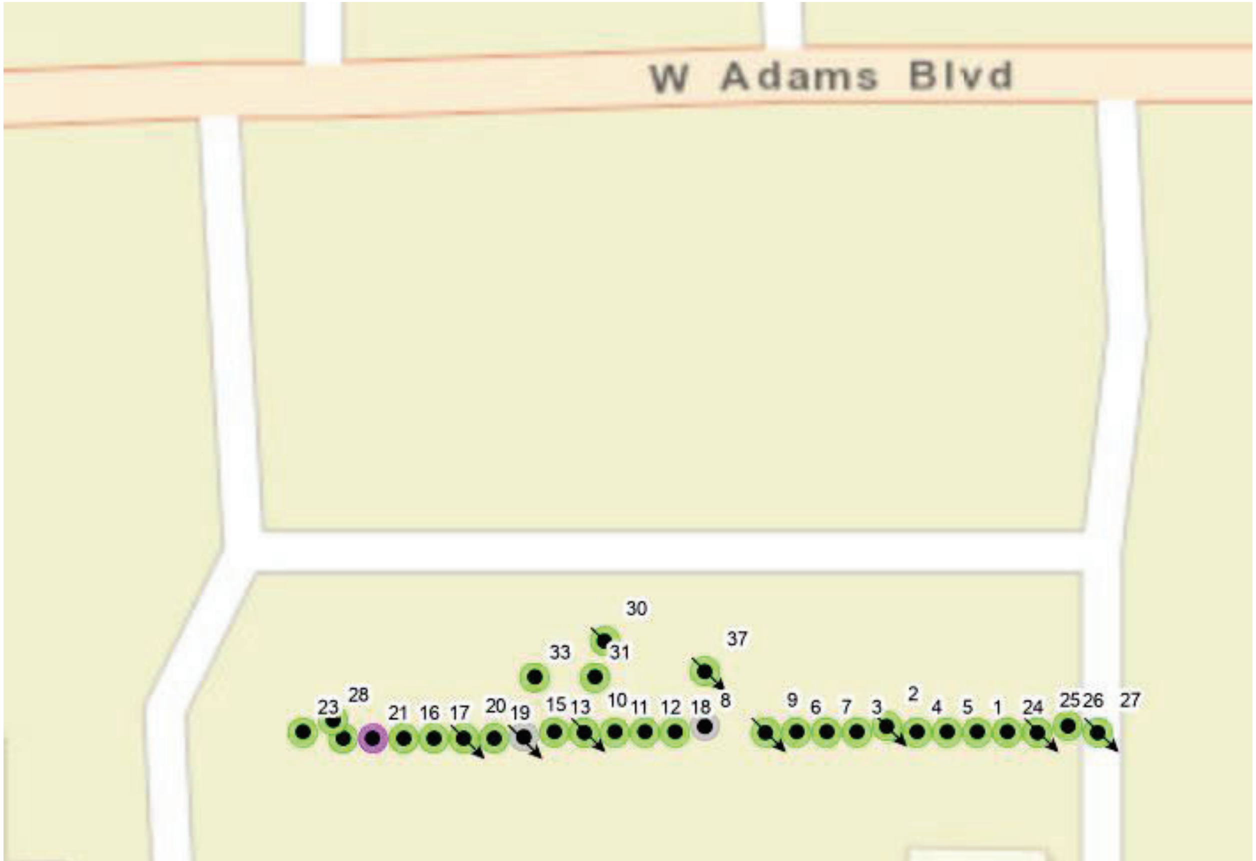
EXHIBIT C: WELLS AT THE SITE

Well API No.	Lease Name	Well Designation	Spudded	Complete	Current Type	Current Status
0403700369	Murphy	1	8/5/1961	9/30/1961	Oil & Gas	Active
0403700370	Murphy	2	10/3/1961	10/20/1961	Waterflood	Active
0403700371	Murphy	3	10/27/1961	11/8/1961	Oil & Gas	Active
0403700372	Murphy	4	11/16/1961	12/2/1961	Oil & Gas	Active
0403700373	Murphy	5	12/13/1961	12/17/1961	Oil & Gas	Active
0403700374	Murphy	6	1/4/1962	2/7/1962	Oil & Gas	Active
0403700375	Murphy	7	2/23/1962	3/11/1962	Oil & Gas	Active
0403700376	Murphy	8	3/21/1962	4/15/1962	Oil & Gas	Plugged
0403700377	Murphy	9	4/20/1962	4/29/1962	Waterflood	Active
0403700291	Murphy	10	5/9/1962	5/29/1962	Waterflood	Active
0403700378	Murphy	11	5/30/1962	6/21/1962	Oil & Gas	Active
0403700379	Murphy	12	6/22/1962	7/12/1962	Oil & Gas	Active
0403700380	Murphy	13	7/13/1962	8/13/1962	Oil & Gas	Active
0403700381	Murphy	14	8/17/1962	8/28/1962	Oil & Gas	Active
0403700382	Murphy	15	9/3/1962	9/13/1962	Gas Injection	Plugged
0403700383	Murphy	16	9/18/1962	10/1/1962	Oil & Gas	Active
0403700384	Murphy	17	10/9/1962	10/23/1962	Oil & Gas	Active
0403700385	Murphy	18	10/29/1962	11/7/1962	Oil & Gas	Active
0403700322	Murphy	19	11/13/1962	12/4/1962	Oil & Gas	Active
0403720954	Murphy	20	10/29/1969	11/12/1969	Waterflood	Active
0403720955	Murphy	21	11/14/1969	11/28/1969	Oil & Gas	Idle
0403721072	Murphy	22	12/19/1970	2/5/1971	Oil & Gas	Active
0403720967	Murphy	23	12/3/1969	12/23/1969	Oil & Gas	Active
0403721221	Murphy	24	10/9/1972	11/4/1972	Oil & Gas	Active
0403721222	Murphy	25	11/9/1972	12/8/1972	Waterflood	Active
0403721223	Murphy	26	9/1/1972	10/7/1972	Oil & Gas	Active
0403721224	Murphy	27	12/14/1972	1/20/1973	Waterflood	Active
0403726956	Murphy	28	10/27/2007	11/8/2007	Oil & Gas	Active
0403726957	Murphy	30	11/10/2007	11/23/2007	Waterflood	Active
0403727007	Murphy	31	9/5/2008	9/25/2008	Oil & Gas	Active
0403730170	Murphy	33	12/4/2013	12/25/2014	Oil & Gas	Active
0403730129	Murphy	37	12/27/2013	1/13/2014	Waterflood	Active

Source: CalGEM Well Finder and CalGEM Records.

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



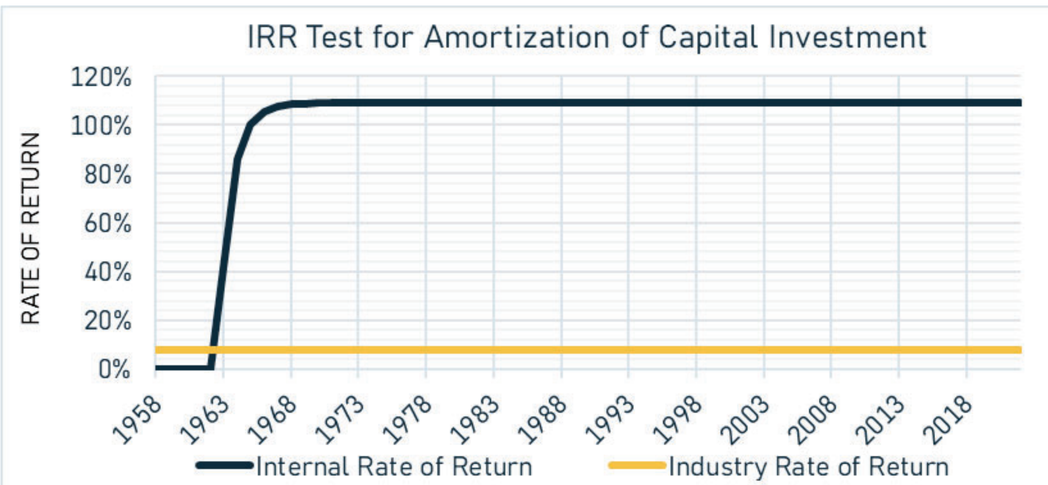
Source: CalGEM Well Finder website

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	1961
Amortization Year (IRR)	1963
Amortization Year (NPV)	1963
Years for Amortization of Capital Investment	2
Capital Investment, $thousands	22,334
Gross Revenues, $thousands	508,912
EBITDA, $thousands	363,859
Net Cash Flow, $thousands	197,815
Cumulative IRR at 2022	109.21%



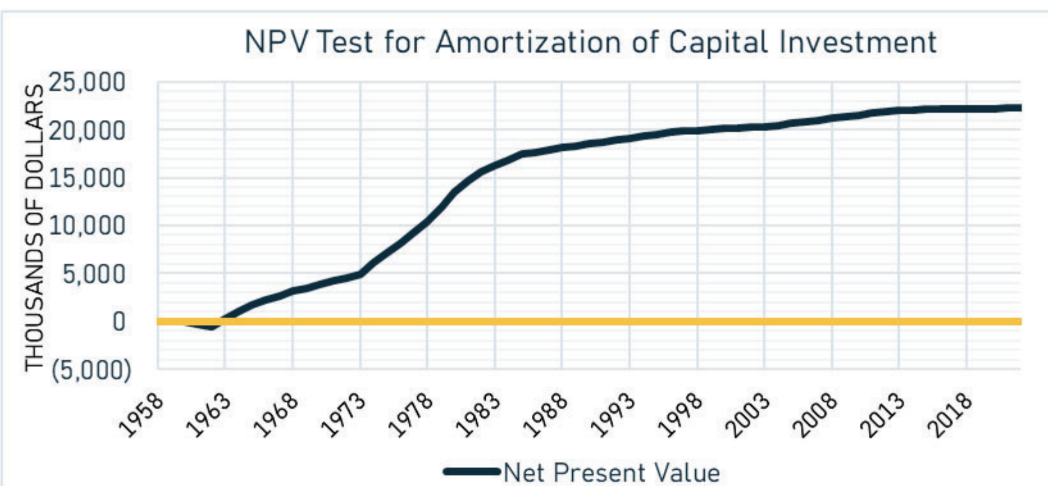
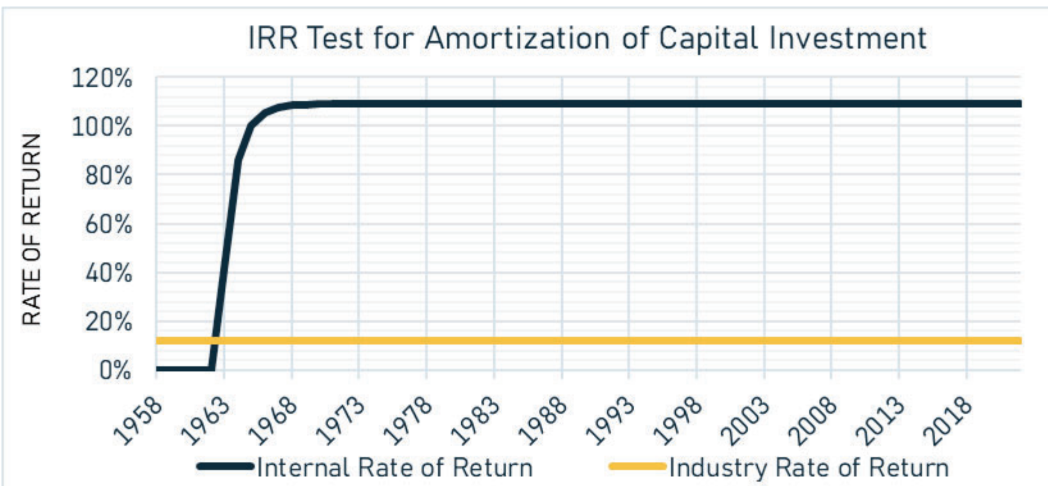


EXHIBIT F: SENSITIVITY CASE A—MARKET RETURN ON CAPITAL INVESTMENT

Model Output Summary	
Start Year	1961
Amortization Year (IRR)	1963
Amortization Year (NPV)	1963
Years for Amortization of Capital Investment	2
Capital Investment, $thousands	22,334
Gross Revenues, $thousands	508,912
EBITDA, $thousands	363,859
Net Cash Flow, $thousands	197,815
Cumulative IRR at 2022	109.21%



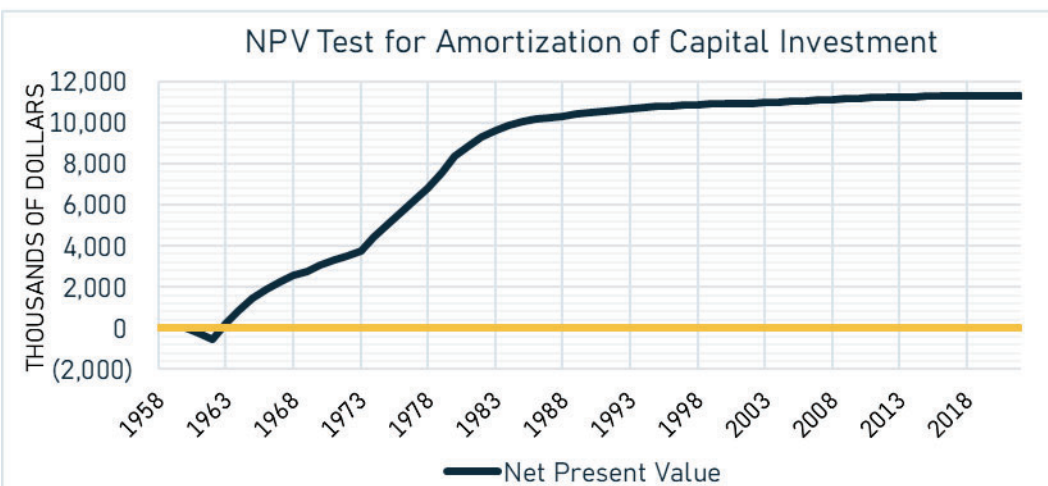
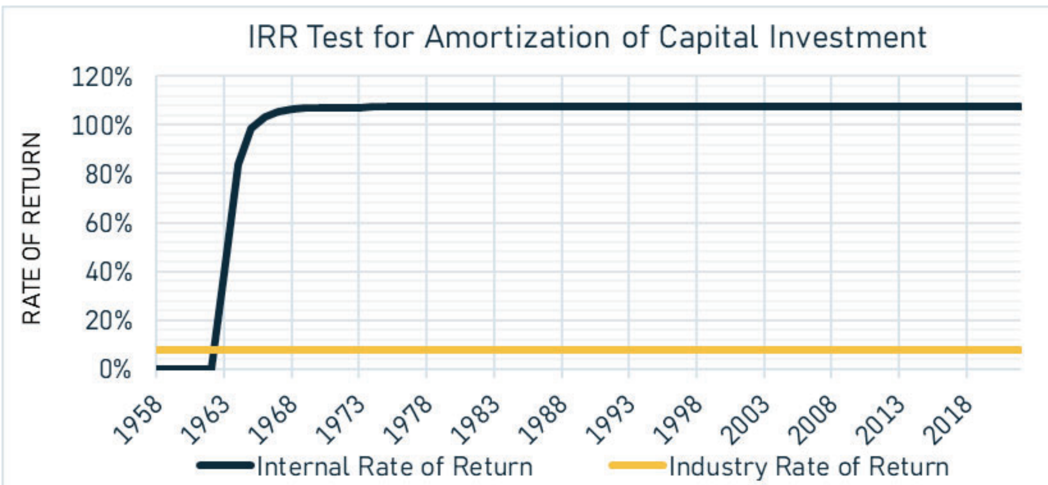


EXHIBIT G: SENSITIVITY CASE B—COMMODITY PRICE

Model Output Summary	
Start Year	1961
Amortization Year (IRR)	1963
Amortization Year (NPV)	1963
Years for Amortization of Capital Investment	2
Capital Investment, $thousands	22,334
Gross Revenues, $thousands	505,279
EBITDA, $thousands	360,831
Net Cash Flow, $thousands	196,044
Cumulative IRR at 2022	107.36%



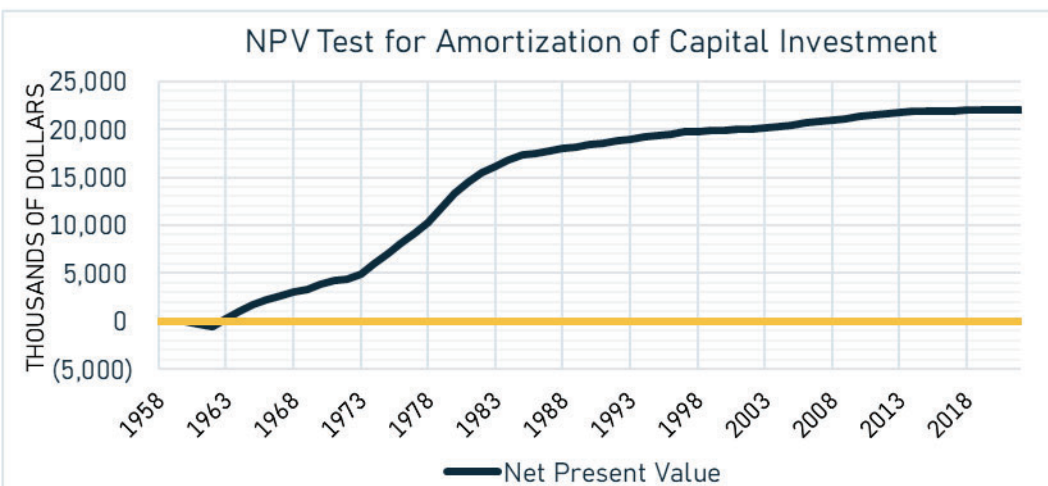


EXHIBIT H: SENSITIVITY CASE C—ORIGINAL CAPITAL INVESTMENT

Model Output Summary	
Start Year	1961
Amortization Year (IRR)	1964
Amortization Year (NPV)	1964
Years for Amortization of Capital Investment	3
Capital Investment, $thousands	28,086
Gross Revenues, $thousands	508,912
EBITDA, $thousands	363,859
Net Cash Flow, $thousands	194,236
Cumulative IRR at 2022	65.74%