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TABLE OF CONTENTS

Acknowledgements i
 Table of Contents iii
 Index of Figures iii
 Index of Tables v
 Index of Appendices vii
 Glossary of Acronyms viii
 Executive Summary 1
 Section One – Introduction 6
 Section Two – Decommissioning Cost Assumptions and Scenarios 10
 Section Three – Decommissioning Methodology 15
 Section Four – Project Management, Engineering and Planning 17
 Section Five – Permitting and Regulatory Compliance 20
 Section Six – Well Plug and Abandonment 34
 Section Seven – Pipeline & Power Cable Abandonment 49
 Section Eight – Platform Preparation 56
 Section Nine – Preservation and Maintenance 59
 Section Ten – Platform & Structure Removal 69
 Section Eleven – Transportation and Disposal 83
 Section Twelve – Site Clearance 91
 Section Thirteen – Inflation, Market Dynamics, and Escalation Assessment 94
 Section Fourteen – References 98

INDEX OF FIGURES

Figure ES-1 – Allocated Cost of Decommissioning by Phase 5
 Figure ES-2 – Cost of Decommissioning by Phase by Study Year 5
 Figure 1-1 – Typical POCSR Shallow Water Platform 9
 Figure 6-1 – Typical Wellbore Schematic (Current) 46
 Figure 6-2 – Typical Wellbore Schematic (P&A) 47
 Figure 10-1 – Heavy Lift Vessel DB Thor 74
 Figure 11-1 – Platform Locations to POEM Transit Map 83
 Figure 11-2 – Marine Growth Removal Station 85
 Figure 11-3 – POCSR Platform Locations to GoA Transit Map 86
 Figure 13-1 – Gulf of America Decommissioning History and 5 Year Rolling Average 94





Figure 13-2 – Employment Cost Index (ECI) & Minimum Wage References	96
Figure H-1 – Cost of Decommissioning by Phase by Study Year	123
Figure H-2 – Cost of Decommissioning Tasks by Study Year – Platform A	124
Figure H-3 – Cost of Decommissioning Tasks by Study Year - Platform B	125
Figure H-4 – Cost of Decommissioning Tasks by Study Year - Platform C	126
Figure H-5 – Cost of Decommissioning Tasks by Study Year - Platform Edith	127
Figure H-6 – Cost of Decommissioning Tasks by Study Year - Platform Ellen	128
Figure H-7 – Cost of Decommissioning Tasks by Study Year - Platform Elly	129
Figure H-8 – Cost of Decommissioning Tasks by Study Year – Platform Eureka	130
Figure H-9 – Cost of Decommissioning Tasks by Study Year - Platform Gail	131
Figure H-10 – Cost of Decommissioning Tasks by Study Year - Platform Gilda	132
Figure H-11 – Cost of Decommissioning Tasks by Study Year - Platform Gina	133
Figure H-12 – Cost of Decommissioning Tasks by Study Year - Platform Grace	134
Figure H-13 – Cost of Decommissioning Tasks by Study Year - Platform Habitat	135
Figure H-14 – Cost of Decommissioning Tasks by Study Year - Platform Harmony	136
Figure H-15 – Cost of Decommissioning Tasks by Study Year - Platform Harvest	137
Figure H-16 – Cost of Decommissioning Tasks by Study Year - Platform Henry	138
Figure H-17 – Cost of Decommissioning Tasks by Study Year - Platform Heritage	139
Figure H-18 – Cost of Decommissioning Tasks by Study Year - Platform Hermosa	140
Figure H-19 – Cost of Decommissioning Tasks by Study Year - Platform Hidalgo	141
Figure H-20 – Cost of Decommissioning Tasks by Study Year – Platform Hillhouse	142
Figure H-21 – Cost of Decommissioning Tasks by Study Year - Platform Hogan	143
Figure H-22 – Cost of Decommissioning Tasks by Study Year - Platform Hondo	144
Figure H-23 – Cost of Decommissioning Tasks by Study Year - Platform Houchin	145
Figure H-24 – Cost of Decommissioning Tasks by Study Year – Platform Irene	146
Figure H-25 – Campaign 1 Estimated Costs	147
Figure H-26 – Campaign 2 Estimated Costs	148
Figure H-27 – Campaign 3 Estimated Costs	149
Figure H-28 - Regulatory & Permitting Costs by Platform	150
Figure H-29– Project Management, Engineering, and Planning Costs by Platform	151
Figure H-30 – Misc. Work Provision Costs by Platform	152
Figure H-31 – Weather Contingency Costs by Platform	153
Figure H-32 – Costs of Platform Preparation by Platform	154



Figure H-33– Costs of Preservation and Maintenance by Platform 155
 Figure H-34 – Costs of Well Abandonment by Platform 156
 Figure H-35 – Costs of Pipeline Decommissioning by Platform 157
 Figure H-36 – Costs of Power Cable Decommissioning by Platform 158
 Figure H-37 – Cost of Platform Removal by Platform..... 159
 Figure H-38 – Cost of Transportation and Disposal by Platform 160
 Figure H-39 – Cost of Site Clearance by Platform..... 161
 Figure H-40 – Cost of HLV Mob/Demob 162

INDEX OF TABLES

Table ES-1 – Total Cost per Platform 4
 Table 4-1 – Cost of Project Management, Engineering and Planning..... 19
 Table 5-1 – Federal Permitting Requirements Applicable to Decommissioning Projects 23
 Table 5-2 – State and Local Permitting Requirements Applicable to Decommissioning Projects..... 27
 Table 5-3 – Permitting and Regulatory Compliance Costs – Base Case 31
 Table 5-4 – Regulatory and Permitting Cost Factor Variations with Number of Platforms per Campaign . 32
 Table 5-5 – Permitting and Regulatory Cost per Platform 33
 Table 5-6 – Permitting and Regulatory Cost per Campaign 33
 Table 6-1 – Well Abandonment Classification Criteria 38
 Table 6-2 – Well Count by Platform 40
 Table 6-3 – Well Count by Category 40
 Table 6-4 – Cut and Recover Cost per Conductor 41
 Table 6-5 – Well Abandonment Cost 41
 Table 6-6 – Well Abandonment Duration by Category 41
 Table 7-1 – Pipeline Decommissioning Cost 51
 Table 8-1 – Platform Preparation Costs..... 56
 Table 9-1 – Applicable Federal Regulations and BSEE Guidance Documents 59
 Table 9-2 – Monthly Well Monitoring Activities and Regulatory Requirements 61
 Table 9-3 – Preservation and Maintenance Phase One Costs..... 62
 Table 9-4 – Preservation and Maintenance Phase Two Costs..... 64
 Table 9-5 – Preservation and Maintenance Phase Three Costs 65
 Table 9-6 – Preservation and Maintenance Phase Four Costs 67
 Table 9-7 – Total Preservation and Maintenance Costs..... 68
 Table 10-1 – Platform Campaign Sequencing 71





Table 10-2 – Total Platform Weight	75
Table 10-3 – Topside Section and Average Lift Weight	77
Table 10-4 – Jacket Section and Average Lift Weight.....	78
Table 10-5 – Heavy Lift Vessel (HLV) Mob/Demob per Platform	79
Table 10-6 – Topside and Jacket Removal Cost.....	80
Table 11-1 – Campaign Removal Volume Summary	87
Table 11-2 – POEM Processing Volume	88
Table 11-3 – Disposal Cost for Tonnage Processed in POEM.....	88
Table 11-4 – Disposal Cost for Tonnage Processed in GoA	88
Table 12-1 – Site Clearance Cost.....	92
Table A-1 – Decommissioning Cost Estimates in \$ USD by Platform.....	101
Table B-1 – Removal Weights by Platform	102
Table C-1 – Platform, Deck, and Jacket Removal Details for Campaign 1	103
Table C-2 – Platform, Deck, and Jacket Removal Details for Campaign 2	103
Table C-3 – Platform, Deck, and Jacket Removal Details for Campaign 3	103
Table D-1 – Well Categorization by Platform.....	104
Table E-1 – Pipeline Removal Cost.....	106
Table F-1 – Power Cable Removal Cost	108
Table G-1 – POCSR Shell Mound Inventory	114
Table G-2 – Shell Mound Removal Volume.....	119
Table G-3 – Shell Mound Removal Duration and Cost Estimate Range.....	119
Table G-4 – Shell Mound Volume Calculation Confidence.....	120



INDEX OF APPENDICES

Appendix A – Decommissioning Cost Estimates 101
 Appendix B – Platform Removal Weights 102
 Appendix C – Platform, Deck, and Jacket Removal Details 103
 Appendix D – Well Risk Categorization 104
 Appendix E – Pipeline Removal..... 105
 Appendix F – Power cable Removal..... 108
 Appendix G – Shell Mound Removal 110
 Appendix H – Comparison of Decommissioning Costs by Study Year 123



GLOSSARY OF ACRONYMS

Acronym	Description
APCD	Air Pollution Control Board
ATC	Authority to Construct
BOEM	Bureau of Ocean Energy Management
BOP	Blow-out Preventer
BSEE	Bureau of Safety and Environmental Enforcement
CalGEM	California Geologic Energy Management Division
CBL	Cement Bond Log
CCC	California Coastal Commission
CDFW	California Department of Fish and Wildlife
CDP	Coastal Development Permit
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CHNMS	Chumash Heritage National Marine Sanctuary
CIBP	Cast Iron Bridge Plug
CIT	Casing Integrity Test
CPI	Consumer Price Index
CR	Cement Retainer
CSLC	California State Lands Commission
CTU	Coiled Tubing Unit
DB	Derrick Barge
DOI	US Department of the Interior
DP	Dynamically Positioned
DP2	Dynamic Positioning Class II
ECI	Employment Cost Index
EIS/EIR	Environmental Impact Statement/Environmental Impact Report
EPA	Environmental Protection Agency
ER	Extended Reach
ESP	Electronic Submersible Pump
FSW	Feet of Seawater
GoA	Gulf of America
H2S	Hydrogen Sulfide
HLV	Heavy Lift Vessel
HSE	Health Safety and Environment
IDWG	Interagency Decommissioning Working Group
JRP	Joint Review Panel
L123	Longitude 123, Inc.



Acronym	Description
LD	Lay Down
LEL	Lower Explosive Limit
LFL	Lower Flammable Limit
LO/TO	Lock Out / Tag Out
MIRU	Move-in Rig Up
MU	Make-up
MWP	Miscellaneous Work Provision
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Services
NOAA	National Oceanic and Atmospheric Administration
NOD	Notice of Determination
NOI	Notice of Intention
NORM	Naturally Occurring Radioactive Material
NTL	Notice to Lessees
OCS	Outer Continental Shelf
OSPR	Office of Spill Prevention & Response
P&A	Plug and Abandonment
P&M	Preservation and Maintenance
PBTD	Plugback Total Depth
PCP	Progressive Cavity Pump
PEIS	Programmatic Environmental Impact Statement
PMEP	Project Management, Engineering, and Planning
POCSR	Pacific Outer Continental Shelf Region
POEM	Port of Ensenada, Mexico
POLA	Port of Los Angeles
POLB	Port of Long Beach
POOH	Pull out of Hole
PTO	Permit to Operate
RD	Rig-Down
RDMO	Rig-Down Move Off
RIH	Rin-in-Hole
ROD	Record of Decision
ROV	Remotely Operated Vehicle
RU	Rig-Up
RWQCB	Regional Water Resource Control Board
SCP	Sustained Casing Pressure
SHPO	State Historic Preservation Office



Acronym	Description
SSCV	Semi-Submersible Crane Vessel
SWQCB	State Water Resource Control Board
SYU	Santa Ynez Unit
TD	Total Depth
TOC	Top of Cement
UHLV	Ultra-Heavy Lift Vessel
USACE	US Army Corps of Engineers
USCG	United States Coast Guard
USFWS	US Fish and Wildlife Service



EXECUTIVE SUMMARY

Longitude 123, Inc. (L123) has prepared this report for the Bureau of Safety and Environmental Enforcement (BSEE) as a follow-on to prior Pacific Outer Continental Shelf Region (POCSR) decommissioning cost studies. The 2016 Decommissioning Cost Update for Pacific OCS Region Facilities was prepared by TSB Offshore, Inc., and the 2020 update was prepared by InterAct PMTI, Inc. Building on the methodologies and assumptions established in those earlier reports, this study incorporates updated technical understanding, observed execution data, and current market and operational conditions specific to the Pacific OCS Region.

BSEE commissioned this 2025 study to support its statutory responsibility for overseeing the safe and environmentally responsible decommissioning of offshore oil and gas infrastructure on the federal Outer Continental Shelf. BSEE is required to maintain current, reasonable, and technically defensible cost estimates to inform regulatory oversight, financial assurance determinations, and long-term planning for offshore facilities approaching the end of their productive life. Periodic updates to these cost studies ensure that assumptions, methodologies, and cost inputs continue to reflect evolving market conditions, execution experience, regulatory requirements, and regional constraints unique to the POCSR.

The 2016 and 2020 studies established a consistent and progressive framework for estimating decommissioning costs in the POCSR, drawing on a combination of regional assumptions, Gulf of America experience, and global offshore benchmarks. At the time those studies were prepared, few Pacific OCS decommissioning projects had been executed, well P&A activity was limited, and no established West Coast heavy-lift or disposal pathway existed to support large-scale offshore removals. Methodologies included in those studies were therefore necessarily forward-looking and relied heavily on non-West Coast vessels, service providers, and recycling facilities.

Since the last published study in 2020, several POCSR platforms have advanced further through the decommissioning lifecycle. As of the time of writing this report, facilities across the POCSR are in various stages of decommissioning, with several platforms progressing toward preservation and maintenance (P&M) status while others have already transitioned into P&M pending final decommissioning activities and removal.

This progression includes platforms on expired and active leases that have completed or substantially advanced well plug and abandonment (P&A) activities, as well as facilities where P&A operations remain ongoing as part of the broader transition from active operations toward final decommissioning. Platforms Habitat, Hogan, Houchin, Gail, Grace, Harvest, Hermosa, Hidalgo, and Irene are representative of these varying stages of transition within the current POCSR inventory.

These milestones reflect meaningful progress toward full facility removal. Meanwhile, the remaining platforms in the region continue to operate in active production or support roles. Collectively, these differing platform statuses highlight the phased and staggered nature of decommissioning in the POCSR, with well P&A activities serving as a leading indicator of forthcoming platform and infrastructure removal efforts.

A new element to this study is the inclusion of a separate Preservation and Maintenance (P&M) cost category (see Section Nine), defined as the activities required to monitor and maintain non-operational offshore facilities in a safe and compliant condition between cessation of production and final decommissioning. The P&M phase explicitly addresses the monitoring and reporting requirements associated with wells that are shut-in prior to temporary abandonment, as well as those in the interval between temporary abandonment and P&A.



Consistent with the structure of previous studies, this report provides a comprehensive estimate of the costs associated with decommissioning offshore oil and gas facilities in the POCSR. The analysis is organized by major decommissioning activity and reflects the sequence in which these activities are typically executed, from planning and permitting through final removal and site clearance. The cost categories are intended to capture the full scope of work required to safely and efficiently decommission offshore facilities in compliance with applicable federal, state, and local requirements. Specifically, the report includes cost estimates for the following decommissioning categories:

- Section Four – Project management, engineering, and planning
- Section Five – Permitting and regulatory compliance, including applicable federal, state, and local requirements and California-specific considerations
- Section Six – Well plug and abandonment, including conductor removal and associated transportation and disposal
- Section Seven – Pipeline and power cable abandonment or removal
- Section Eight – Platform preparation
- Section Nine – Platform preservation and maintenance during non-operational periods
- Section Ten – Platform and structure removal, including topsides and jacket removal and the mobilization and demobilization of marine assets
- Section Eleven – Transportation and disposal of removed materials
- Section Twelve – Site clearance

The methodologies presented in this study are intended to provide a consistent, reasonable, and defensible cost framework that can be applied uniformly across all platforms, pipelines, and associated offshore infrastructure within the Pacific OCS. Its purpose is to establish a transparent baseline for evaluating decommissioning liabilities under regulatory conditions at the time of this study. It is not intended to represent the only technically viable execution model, nor does it presume that all operators or liability holders will adopt identical strategies.

PRIMARY COST DRIVERS AND VARIANCES FROM PRIOR STUDIES

As shown in Table ES-1 and Figure ES-2 below, the principal cost variances between this study and the 2016 and 2020 analyses are driven by changes in execution strategy, logistics assumptions, updated labor indices, and refined sequencing methodology.

A significant driver of cost variance is the elimination of the prior assumption that all heavy components and material barges must transit the Panama Canal and return to the Gulf of America for processing. This study instead assumes greater utilization of West Coast–accessible assets and regional processing capacity, including routing to the Port of Ensenada, Mexico (POEM) as a primary recycling facility. Such assumption reflects currently available regional commercial capabilities and does not imply regulatory pre-approval of any specific disposal pathway. Avoiding repeated long-distance transits substantially reduces transportation exposure and associated marine transit time, which is reflected in the significant decrease in Transportation and Disposal costs relative to prior studies.

A secondary driver of cost variance is the introduction of the Preservation and Maintenance phase. This new phase introduces roughly \$254 million in additional cost that was not included in previous studies. The Preservation and Maintenance cost category represents 14.5% of the total allocated cost. The timeframe for preservation and maintenance activities spans multiple years and is driven by regulatory requirements for reporting well status and well condition. Platform condition monitoring is also included in the Preservation and Maintenance phase.



Heavy-lift costs reflect a more nuanced change. Heavy-lift vessel day rates are modestly higher in this update, which accounts for the slight increase in this category from the 2020 study. At the same time, lift segmentation strategies, the use of locally available marine assets, and the avoidance of a deepwater lowering winch configuration, for the representative execution scenarios modeled in this study, reduce certain time elements while preserving realistic offshore execution durations. The net effect is a modest increase in Platform Removal costs driven by vessel and labor rate escalation, partially offset by more efficient sequencing assumptions.

Regulatory and Permitting costs increased relative to prior studies due to longer anticipated review durations and elevated personnel rates. Labor escalation was normalized using Employment Cost Index (ECI) data rather than general consumer indices, resulting in modest increases to regulatory support, engineering, and technical staffing categories. More details on cost escalations are described in Section Thirteen.

Weather contingency also increased proportionally, reflecting slightly extended heavy-lift exposure and higher associated marine spread costs from the 2020 study. For this 2025 study, weather contingency assumptions were developed using Pacific OCS operational weather windows and marine spread exposure durations.

Project Management, Engineering, and Planning (PMEP) costs increased marginally in absolute terms, compared to previous studies, consistent with the increase in 2025 total decommissioning cost and incorporating updated personnel escalation aligned with ECI trends. See Section Four for further descriptions of PMEP cost calculations.

Miscellaneous Work Provision (MWP) costs increased in parallel with total 2025 cost increases and are set at 15% of total costs for all work phases. No MWP was added to weather contingencies. PMEP costs are also excluded from the MWP costs.

Platform Preparation costs decreased relative to prior studies due to a refinement of the scope of this phase. Certain activities previously included in Platform Preparation have been realigned under Preservation and Maintenance, yielding a more comprehensive representation of pre-removal readiness activities.

Well abandonment costs have decreased on a net basis due to the plugging and abandonment activities completed since the previous study. This reduction is partially offset by changes to the well inventory resulting from continued field development activities, including sidetracked wellbores. As a result, a greater number of wells are now classified within higher-risk categories under the methodology described in Section 6.1.5, particularly those exhibiting complex sidetracked or extended-reach geometries that increase abandonment difficulty and cost.

Pipeline and Power Cable Decommissioning 2025 costs decreased as this study eliminates prior assumptions requiring shoreward removals and instead incorporates more efficient ROV-based execution spreads, refined depth cycle types, and pipeline-diameter-specific cutting duration factors. This approach reflects practical offshore methodologies that reduce unnecessary marine exposure. In addition, at BSEE's request, cost estimates for the complete removal of the pipelines and power cables are included in Appendix E and Appendix F, respectively. These costs are supplemental and provided for informational purposes for BSEE use as necessary; they are not incorporated into the 2025 cost estimates.

Site Clearance 2025 costs increased slightly due to the inclusion of a dedicated ROV support vessel to ensure full coverage and execution reliability. Additionally, at BSEE's request, estimates for the removal of shell mounds at the base of the POCSR platforms are included in Appendix G. These estimates are



built upon the most recent publicly available information and are subject to change as additional survey, study, and removal methodology refinement work is completed.

The variances presented in this study reflect updated market conditions, refined execution strategy, improved logistical assumptions, and more granular duration modeling. The resulting estimates maintain the same regulatory end-state assumptions as prior analyses while aligning cost inputs with contemporary offshore execution realities.

Table ES-1 – Total Cost per Platform

Platform Name	2016 Costs \$Million	2020 Costs \$Million	2025 Costs \$Million	2020 vs. 2016 Change	2025 vs. 2020 Change
A	\$36.20	\$49.60	\$84.62	37.10%	70.61%
B	\$32.50	\$49.10	\$72.94	50.90%	48.54%
C	\$27.50	\$39.40	\$66.91	43.40%	69.83%
Edith	\$30.90	\$43.50	\$45.22	40.70%	3.95%
Ellen	\$42.00	\$63.90	\$87.37	52.20%	36.74%
Elly	\$24.60	\$34.40	\$30.47	39.90%	-11.42%
Eureka	\$124.00	\$116.90	\$126.18	-5.70%	7.94%
Gail	\$103.80	\$99.60	\$79.34	-4.00%	-20.34%
Gilda	\$59.20	\$73.30	\$90.65	23.90%	23.67%
Gina	\$16.70	\$19.20	\$24.54	14.80%	27.81%
Grace	\$43.20	\$53.00	\$30.94	22.70%	-41.63%
Habitat	\$34.50	\$44.30	\$35.59	28.30%	-19.66%
Harmony	\$185.70	\$185.80	\$212.03	0.10%	14.12%
Harvest	\$99.70	\$94.20	\$77.94	-5.50%	-17.26%
Henry	\$21.60	\$32.00	\$42.00	48.40%	31.25%
Heritage	\$173.60	\$188.70	\$213.85	8.70%	13.33%
Hermosa	\$94.00	\$88.80	\$76.26	-5.60%	-14.12%
Hidalgo	\$73.90	\$75.60	\$56.53	2.30%	-25.22%
Hillhouse	\$31.30	\$46.60	\$68.27	48.90%	46.49%
Hogan	\$38.10	\$44.80	\$42.94	17.60%	-4.16%
Hondo	\$100.10	\$97.10	\$100.21	-3.00%	3.20%
Houchin	\$36.20	\$40.80	\$42.35	12.60%	3.81%
Irene	\$37.30	\$53.90	\$50.65	44.60%	-6.03%
Total	\$1,466.60	\$1,634.70	\$1,757.80	11.50%	7.53%

Figure ES-1 below shows the allocated decommissioning cost by category or phase. The three decommissioning phases that have the largest portions of this cost study include platform removal (28.0%), well abandonment (19.1%), and preservation and maintenance (14.5%). Compared to the previous study from 2020, platform removal has increased by 1% from 27% of total decommissioning cost, and well abandonment has decreased 1.9% from 21% of total decommissioning cost, as illustrated in Figure ES-2.

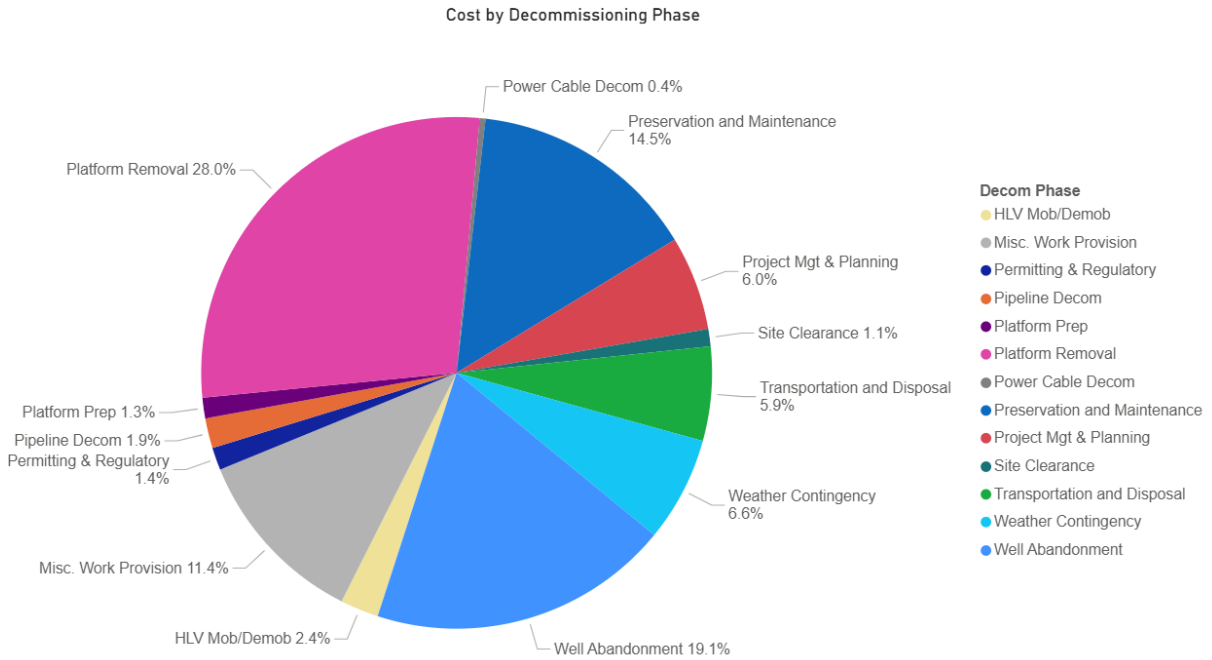


Figure ES-1 – Allocated Cost of Decommissioning by Phase

Cost of Decommissioning by Phase by Study Year

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

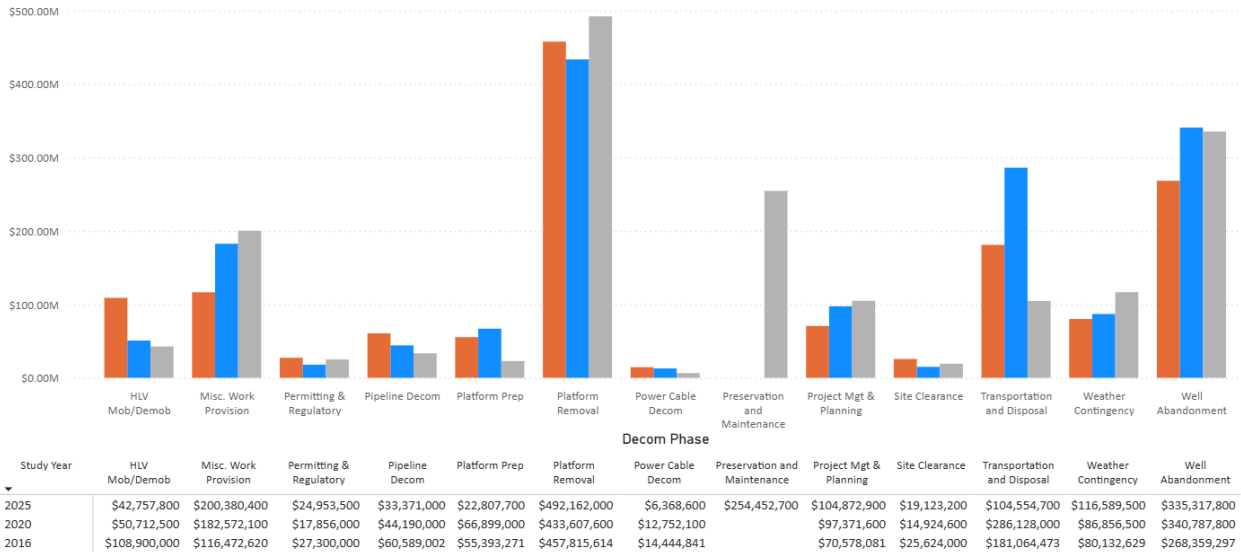


Figure ES-2 – Cost of Decommissioning by Phase by Study Year



SECTION ONE – INTRODUCTION

1.1 BACKGROUND AND HISTORY OF WEST COAST OFFSHORE INFRASTRUCTURE

L123, together with its engineering subsidiary, Thomas & Beers Engineering, LLC, is a marine-focused project management and engineering firm specializing in planning and executing decommissioning and marine construction projects, supported by more than 40 years of experience operating within California's unique regulatory and environmental landscape, including direct management experience in the only oil and gas related decommissioning campaigns to have occurred offshore California.

Along with our strategic partners in Trident Group, LLC, the team brings extensive offshore decommissioning experience, with authors having managed and continuing to support decommissioning campaigns in the Gulf of America, as well as prior international offshore decommissioning efforts in diverse operating environments. This experience provides a practical foundation for evaluating Pacific OCS decommissioning scenarios, reconciling prior study assumptions with real-world execution outcomes, and developing cost and schedule estimates that reflect both regional constraints and global best practices.

In support of this study, L123 conducted targeted stakeholder engagement to obtain technical insight and a practical perspective relevant to Pacific OCS decommissioning activities. Engagement included discussions with marine construction contractors, heavy-lift vessel operators, disposal and recycling facilities, and other service providers, who were able to provide detailed, experience-based input on execution methods, sequencing considerations, and general capacity constraints based on their respective areas of practice. This information was used to inform scenario development, identify potential bottlenecks, and assess the reasonableness of assumed methodologies.

Engagement with oil and gas operators and liability holders was conducted at a deliberately high level and was focused on understanding general perspective rather than project-specific detail. These discussions were intended to identify whether there were material considerations, constraints, or viewpoints that may not be fully captured through engineering analysis or publicly available information alone. Input from these stakeholders was qualitative in nature and limited to broad observations and perspective, serving as a supplemental reasonableness check on the study assumptions rather than a source of detailed technical or commercial data.

Federal offshore oil and gas development off the coast of California began in earnest in the late 1960s and expanded through the 1970s and 1980s, resulting in a concentrated inventory of fixed steel platforms in three primary offshore areas: the Santa Barbara Channel, the Santa Maria Basin, and the San Pedro Basin (see Figures 1-1 and 1-2). In total, 23 offshore oil and gas production facilities were installed in federal waters offshore California, representing the full Federal Pacific OCS facility inventory that is the subject of BSEE's Pacific decommissioning program and cost studies. These facilities were developed under federal leases, commonly organized into units, and supported by interdependent offshore and onshore infrastructure, including production flowlines, export pipelines, power cables, subsea appurtenances, and onshore processing and transportation systems.

Over time, production declined across portions of the region as reservoirs matured and operating economics changed. The result today is a mixed population of facilities ranging from active producing platforms to late-life assets that are idle, managed under preservation programs, or progressing through early decommissioning steps. That late-life status is heavily influenced by California's regulatory environment, including layered federal, state, and local oversight for offshore work, pipeline systems, ports, air quality, coastal permitting, and environmental review.



Within the Pacific Outer Continental Shelf Region, offshore platforms span a range of operational states reflecting differing stages of late-life management and decommissioning progression. Consistent with observations documented in the 2016 and 2020 BSEE decommissioning cost studies, several platforms have transitioned beyond active production and are no longer supporting routine operations. At the time of this study, the platforms Gail, Grace, Harvest, Hermosa, and Hidalgo are in the later phases of Preservation and Maintenance (P&M) status, with wells plugged and abandoned indicating that production has ceased, and the facilities are being maintained in a safe, non-operational condition pending future decommissioning activities. During this phase, systems are preserved to meet regulatory requirements while active production and associated operational loads have been removed.

The Santa Ynez Unit (SYU) represents a distinct case within the Pacific OCS, encompassing the offshore platforms Harmony, Heritage, and Hondo, together with the associated production, pipeline, and onshore processing infrastructure that supports unitized operations. Following transfer of ownership and operating responsibility under a multi-year agreement, the current asset holder has obtained the necessary approvals to resume operations and has returned the facilities to production. Offshore production activities are ongoing, utilizing existing infrastructure and export pathways. For purposes of this study, the SYU platforms are treated as active producing facilities. While future production levels and asset life remain subject to operational, regulatory, and market considerations, the facilities are presently in service and are not assumed to be in immediate decommissioning status.

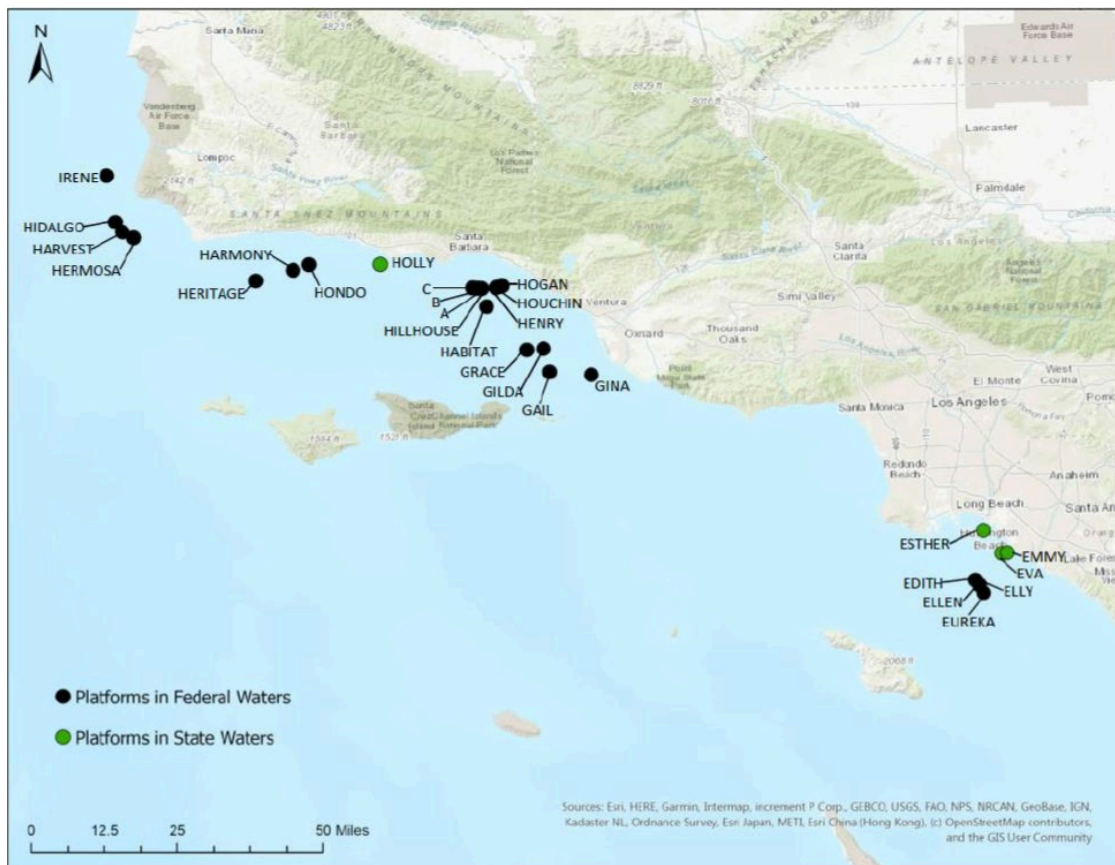


Figure 1-1 – Locations of POC SR Platforms



1.2 DECOMMISSIONING HISTORY ON THE WEST COAST

Compared to the Gulf of America, the Pacific OCS has seen relatively limited full-structure decommissioning. The most notable removals occurred in state waters, where early projects demonstrated technical feasibility but also highlighted cost drivers and the operational complexity of working in California’s nearshore environment. Historical examples include the abandonment and removal of Platforms Helen and Herman in the late 1980s, followed by the larger 1996 Chevron “4-H” removal campaign involving Platforms Hope, Heidi, Hilda, and Hazel. These state-water removals are frequently referenced in published literature and prior BSEE studies because they remain among the few complete removals executed in the region, and they provide real-world context for lifting, cutting, transportation, and disposal logistics on the California coast.

In federal waters, decommissioning has progressed more slowly and has largely involved enabling activities rather than complete removals, such as late-life facility management, well work, and planning for eventual abandonment and removal. In 2023, BSEE completed a programmatic environmental review to support future decisions for platform, pipeline, and associated infrastructure decommissioning on the Pacific OCS, reflecting the scale of the upcoming workload and the need for consistent decision support for removal and disposal actions.

1.3 CURRENT STATUS AND EXISTING INFRASTRUCTURE

Today, the Pacific OCS inventory remains an interconnected system of offshore platforms, wells, pipelines, power cables, subsea components, and onshore processing and transportation assets. The platforms are operated by a limited number of operators, and the operator-platform groupings are publicly documented. The region includes platforms that remain operational, platforms in preservation and maintenance programs, and platforms undergoing active well abandonment. As described in this report subsequent sections, a subset of facilities has transitioned into Preservation and Maintenance (P&M) status, indicating production has ceased and the facilities are maintained in a controlled, non-operational condition pending future decommissioning activities. Other facilities are in active well plugging and abandonment (P&A), which is typically the leading indicator of broader decommissioning progression toward eventual removal.

Separately, the region also includes infrastructure where operating status depends on the ability to maintain a viable transportation pathway for produced hydrocarbons and to maintain or regain required authorizations for restart. A prominent example is the unitized system in the Santa Barbara Channel that includes offshore platforms, an onshore processing facility, and an associated pipeline network. Public actions and reporting show continuing efforts by the current asset holder to re-establish transportation options and restart operations, with approvals and constraints evolving through ongoing regulatory and legal processes. For purposes of this cost study, facilities under active restart intent and ongoing regulatory engagement are treated as active in order to reflect operational alternative and to avoid prematurely assuming decommissioning timing where restart remains a plausible near-term pathway.

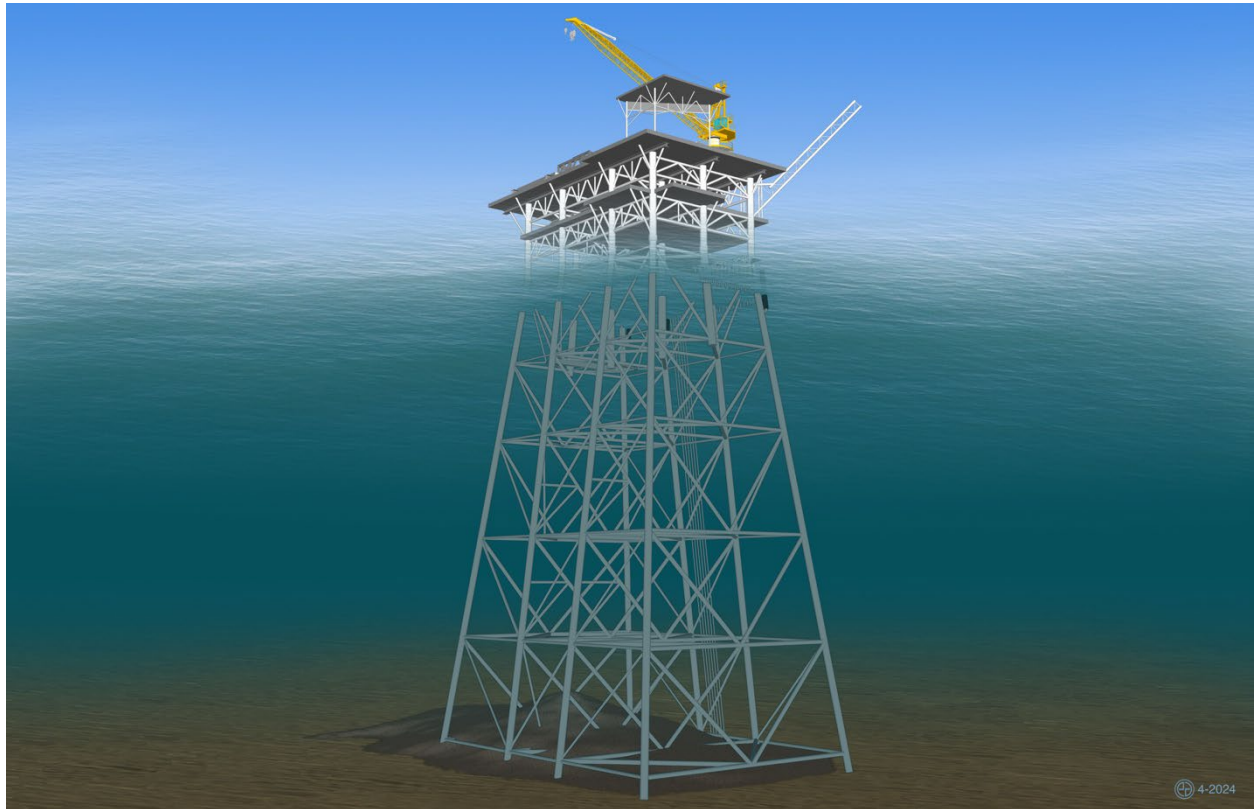


Figure 1-1 – Typical POCSR Shallow Water Platform



SECTION TWO – DECOMMISSIONING COST ASSUMPTIONS AND SCENARIOS

As discussed in prior BSEE decommissioning cost studies, offshore oil and gas facilities in the Pacific OCS operate within a broader and evolving energy, regulatory, and policy context. California remains a significant consumer of petroleum products, with continued demand driven by transportation, aviation, maritime commerce, and industrial activity, even as in-state production has declined and reliance on imported crude oil has increased. At the same time, offshore infrastructure in the region is aging and progressively transitioning toward late-life management and decommissioning.

Since the publication of those studies, additional well-plugging and abandonment work has been performed in the Pacific OCS, and operators have reported associated execution costs. These self-reported costs reflect a range of contracting strategies, operational methodologies, and operator-based internal risk strategies and mitigation. Accordingly, these data were reviewed and qualitatively considered to inform assumptions regarding equipment selection, duration, contingency, and risk-based well categorization. This approach allows recent Pacific OCS execution experience to inform the update while maintaining a consistent and defensible estimating methodology. Within California, regulatory processes and public policy considerations generally favor retirement of offshore oil and gas facilities once production ceases, rather than extension of field life or redevelopment. This dynamic, combined with the layered permitting and environmental review requirements applicable to offshore activities, has influenced the pace and sequencing of decommissioning in the Pacific OCS. As a result, the timing of decommissioning activities can be subject to uncertainty, with progression driven not only by technical readiness but also by regulatory processes, infrastructure constraints, and market conditions. These factors underscore the need for decommissioning cost estimates that are flexible, scenario-based, and grounded in current execution realities to support federal oversight and planning.

Individual operators maintain distinct corporate governance structures, internal risk tolerances, contracting philosophies, timing considerations, and commercial leverage positions. Some operators are currently advancing platform removal planning for facilities addressed in this report, and their selected methodologies may differ materially from the standardized framework modeled herein. These differences may arise from operator-specific risk mitigation preferences, commercial negotiations, sequencing strategies, capital allocation priorities, or strategic campaign bundling decisions. The methodology used in this study is therefore best understood as a consistent analytical basis for cost estimation rather than a prescriptive execution directive.

2.1 METHODOLOGY APPLIED IN THIS STUDY

This report is a follow-on to BSEE's prior Pacific OCS decommissioning cost updates and applies the same basic structure used in those efforts, with cost estimates organized by major decommissioning category and by facility, then rolled up at the regional level. The 2016 study (TSB Offshore) and the 2020 study (InterAct PMTI) established the baseline approach for platform-by-platform estimating, including assumptions for engineering and planning, permitting, platform preparation, well P&A, conductor and pipeline work, removals, transportation, disposal, and site clearance.

This update retains that framework but makes several deliberate refinements based on execution experience and current market realities:

2.1.1 West Coast Execution and Disposal Alternatives

Prior studies necessarily leaned more heavily on non-West Coast equipment and disposal pathways, reflecting limited regional capacity and limited recent precedent. This study explicitly incorporates the



alternative to utilize a West Coast recycling and disposal facility as a primary disposition pathway, supported by West Coast-based marine assets currently available for key scopes. This includes local DP2 vessels for diving and ROV support, and local material barges to shuttle steel to West Coast scrap and recycling facilities.

2.1.2 Overflow and Specialty Support from the Gulf of America

Gulf of America service providers and recycling facilities remain a viable backstop for specialty scopes or capacity overflow, and this study includes that capability on an as-needed basis where West Coast capacity, schedule constraints, or specialized tooling requirements drive an alternate pathway. This blended approach is intended to reflect practical execution planning rather than assume a single constrained solution.

2.1.3 New Cost Category: Preservation and Maintenance

This study introduces a discrete Preservation and Maintenance (P&M) cost category to capture the costs of monitoring and reporting well conditions prior to well abandonment operations and costs of maintaining non-operational offshore facilities in a safe and compliant state between cessation of production and final decommissioning. This includes the ongoing inspection, monitoring, maintenance, staffing or periodic attendance, and supporting logistics required to keep facilities in an acceptable condition while awaiting major decommissioning campaigns or resolution of constraints such as vessel availability, recycling throughput, or permitting.

2.1.4 Qualitative Integration of Actual, Self-reported Well P&A Outcomes

Since the last study, well abandonment activity in the Pacific OCS has generated actual cost and duration data that can be compared to prior assumptions. This update considers those self-reported outcomes as a qualitative benchmark to inform the calibration of equipment selection, expected durations, and risk-based well categorization. The intent is not to replicate operator-specific results or overfit a limited data set, but rather to test prior assumptions against observed field performance. In doing so, the study recognizes that Pacific OCS well abandonment performance can differ materially from earlier estimates due to well condition, heavy oil context, shallow formations, cement and age of construction, and the presence of sustained casing pressure, each of which can increase intervention complexity and time on well. The self-reported data reflect a range of operator methodologies and internal risk tolerances, and therefore serve as contextual reference points rather than prescriptive inputs.

Across all categories, the estimating approach retains the scenario-based structure used in prior studies, with transparent assumptions for equipment spreads, durations, and disposal pathways, and with sensitivity applied where constraints are expected to govern schedule, such as recycling and disposal facility throughput.

As part of this study, L123 drew upon a combination of internal execution experience and targeted engagement with service contractors across the major decommissioning disciplines. This approach was intended to ground study assumptions in practical field experience and current market conditions while preserving the high-level, planning-focused framework that has characterized prior BSEE decommissioning cost studies.

2.1.5 Structural Engineering and Offshore Infrastructure Experience

A significant portion of the technical basis for this study is informed by the experience of L123 and its affiliated structural engineering company, which has provided structural engineering, analysis, inspection support, and planning services for offshore platforms and associated infrastructure for approximately four decades. This includes extensive work on Pacific OCS platforms and related marine infrastructure, as



well as experience supporting platform modifications, late-life integrity evaluations, and decommissioning planning. This internal capability was applied across platform preparation, structural removal sequencing, load paths, cutting strategies, and removability considerations for both topsides and jackets.

2.1.6 Prior Decommissioning Project Experience

The study also reflects direct involvement in prior West Coast decommissioning efforts, including project management and planning support for the removal of the state-water “4H” platforms and work associated with the Belmont Island decommissioning. These projects provide real-world context for California-specific permitting, marine logistics, heavy-lift execution, transportation, disposal, and stakeholder coordination, and informed assumptions related to sequencing, interfaces, and schedule drivers.

2.1.7 Well-plugging and Abandonment Contractors

Engagement with well P&A contractors focused on execution approaches, equipment selection, intervention methods, and challenges specific to Pacific OCS well conditions. These discussions were informed by actual well abandonment activity conducted since the previous studies and were used to calibrate assumptions related to well categorization, duration, and cost drivers, particularly where heavy oil, well age, shallow formations, or sustained casing pressure are present.

2.1.8 Cutting and Severance Contractors

Discussions were held with cutting service providers, including contractors specializing in abrasive water jet cutting and other internal cutting techniques. This includes experience with internal abrasive cutting methods utilized on conductors removed to date in the Pacific OCS. Input from these contractors informed assumptions regarding cutting productivity, tooling limitations, and applicability to different structural components. Internal abrasive water jet, diamond wire and specialty sheering companies are not currently located in the West Coast region; however, the equipment and personnel are easily mobilized from the Gulf of America. Explosives were not considered as an option in this study.

2.1.9 Marine Vessel Operators and Support Fleets

The study includes engagement with vessel operators providing marine construction support, including DP2 vessels used for diving, ROV, and inspection support; general offshore support vessels; and specialized marine assets. These discussions addressed vessel availability, typical spreads, weather limitations, and integration with other offshore activities.

2.1.10 Material Barge and Tug Operators

Material barge operators and towing companies were consulted regarding barge availability, load-out configurations, tow logistics, port interfaces, and typical operational constraints. These discussions were used to inform assumptions related to offshore-to-shore transportation of removed materials and integration with disposal and recycling facilities.

2.1.11 Derrick Barge and Heavy-lift Contractors

Engagement with derrick barge operators focused on lift capacities, spread configurations, mobilization and demobilization considerations, and practical limits for topsides and jackets handling using West Coast–available assets. These discussions supported evaluation of lift sequencing, campaign sizing, and integration with material handling and disposal constraints.

2.1.12 Diving and ROV Contractors

L123 engaged with diving and ROV service providers regarding inspection, preparation, cutting support, and site clearance activities. These discussions addressed crew composition, operational limits, safety



considerations, and coordination with heavy-lift and abandonment operations. There are diving contractors located on the West Coast, and surface diving equipment (Air and Gas spreads that allow diving to ~300 FSW); however, there is no operating saturation diving system ready to be deployed on the West Coast. Mobilization of a DP2 Saturation Diving Vessel from the Gulf of America as well as the mobilization of a modular saturation diving system to be installed on the DB Thor was considered.

2.1.13 Pipeline Pigging, Flushing, and Abandonment Specialists

Specialty contractors with experience in pipeline pigging, flushing, and abandonment were consulted to inform assumptions related to pipeline preparation, decommissioning sequencing, and regulatory expectations. This input was supplemented by L123's own experience supporting pipeline abandonment and removal projects in both federal and state waters.

2.1.14 Site Clearance Contractors

Engagement with specialty contractors performing site clearance activities informed assumptions related to debris surveys, seabed clearance methods, verification approaches, and post-removal inspection requirements. These discussions supported the development of site clearance scopes consistent with regulatory expectations and prior West Coast experience. Specifically, we modeled the use of a DP2 ROV spread for Site Clearance. Though there will be a DP2 vessel located on the West Coast by the time decommissioning happens, L123 did include the mobilization and demobilization of an ROV Vessel with 2 Work Class ROV's from the Gulf of America.

2.1.15 Site Visits and Facility Engagement

Site visits were conducted with representatives across these contractor categories, including visits to recycling and disposal facilities, i.e., the Port of Ensenada, MX (POEM). Most of the contractor classes which require engagement are well known to the authors. These visits were used to understand physical layouts, throughput constraints, cutting and processing workflows, and logistical interfaces that could influence decommissioning schedule and cost.

Across all categories, contractor engagement was focused on understanding general capabilities, execution practices, and constraints based on experience, rather than soliciting project-specific pricing, commitments, or proprietary information. Input from these engagements was used to validate assumptions, identify key schedule drivers, and support development of realistic decommissioning scenarios consistent with current market conditions and regulatory frameworks.

2.2 DECOMMISSIONING EXECUTION SCENARIO AND HEAVY LIFT MODELING FRAMEWORK

This study evaluates decommissioning costs using a defined execution scenario intended to represent a practical and defensible full removal pathway under current Pacific OCS regulatory conditions. The selected reference case assumes complete removal of topsides and jacket structures to the required depth below mudline, followed by transportation to a regional recycling or disposal facility accessible from the West Coast. Partial removal or reefing alternatives were not modeled as baseline assumptions.

The reference execution scenario assumes campaign-based removal utilizing a heavy lift derrick barge mobilized from elsewhere then operating continuously within the Pacific OCS Region for the duration of a multi-platform program. Structural sections are cut subsea using mechanical or abrasive methods, lifted in discrete modules, placed and secured onto material barges, and transported to a designated West Coast recycling facility. This configuration was selected to reflect a balance between realistic vessel availability, logistical efficiency, and regional disposal throughput constraints.



In developing the cost model, multiple heavy lift configurations were evaluated to understand their influence on cost, schedule, and operational exposure. These scenarios included variations in lifting capacity, vessel mobilization strategy, and disposal routing assumptions.

The primary heavy lift scenarios considered were:

- Use of a 1,600-ton class conventional derrick barge mobilized from the Gulf of America then operating continuously on the West Coast for the duration of the campaign,
- Mobilization of higher-capacity heavy lift vessels from outside the region on a campaign basis,
- Use of an 800-ton class conventional derrick barge mobilized from the Northern West Coast then operating continuously on the West Coast for the duration of the campaign.

Evaluation of these alternatives indicated that sustained presence of a 1,600-ton class derrick barge provides the most balanced and scalable solution under Pacific OCS conditions. While larger-capacity heavy lift vessels can reduce the number of individual lifts, their limited availability on the West Coast, high mobilization and demobilization costs and higher day rates introduce schedule and mobilization risk. These larger class vessels will also surge the West Coast disposal capacity, including reduction and recycling capacity, which would cause additional costs of sending material barges and assist tugs through the Panama Canal to the Gulf of America. Further, the number of barges that would need to be sent to the GoA in this scenario, and its roughly 80-day round trip cycle, would severely strain the material barge and tug market.

Conversely, smaller lift spreads increase cutting duration and lift frequency, extending offshore exposure and total campaign time.

The selected reference case therefore assumes a 1,000 to 1,600-ton class derrick barge supported by material barges and assist tugs, operating in coordination with disposal throughput capacity. This configuration reflects the practical constraint that recycling facility annual tonnage limits, rather than lift capacity alone, ultimately govern campaign pacing under a full removal scenario.

Alternative heavy lift configurations were retained for sensitivity evaluation and comparative analysis; however, the cost estimates presented in this report are based on the defined reference scenario to ensure internal consistency across all platforms and infrastructure categories.



SECTION THREE – DECOMMISSIONING METHODOLOGY

This study reviews and updates the decommissioning methodology described in the 2016 and 2020 Bureau of Safety and Environmental Enforcement (BSEE) Pacific OCS Region cost assessments. The general structure and baseline execution philosophy from prior studies are retained, establishing a consistent framework grounded in conventional offshore decommissioning practices widely applied in the United States. No experimental or unproven technologies have been incorporated.

Within that established framework, this update introduces several targeted refinements and scope expansions reflecting both current market conditions and regulatory context. First, a distinct Preservation and Maintenance (P&M) phase is included to account for the interim period between cessation of operations and final removal. Second, in response to increased regulatory options identified in the 2023 Programmatic Environmental Impact Statement (PEIS), this study evaluates full removal of pipelines and power cables as an additional modeled scenario alongside the base-case assumption of abandonment in place. Third, also at BSEE's request, this study addresses the potential removal of shell mounds, which are generally understood as accumulations of shell material and associated deposits, potentially including biologically harmful elements, that have formed on the seafloor adjacent to offshore facilities. These features represent a sensitive seabed irregularity from both environmental and regulatory perspectives. While the PEIS broadly addresses seabed obstructions, it does not explicitly define shell mound removal as a standard requirement or prescribe specific methodologies.

Accordingly, there are no well-established industry precedents or accepted technical standards governing shell mound removal, and applicable regulatory requirements remain uncertain and project-specific. A proposed methodology, technical approach, and order-of-magnitude cost range have been developed based on publicly available information and a range of conservative assumptions. These are presented in Appendix G but are not included in the total 2025 study costs.

In prior studies, structural removal scenarios were influenced significantly by assumptions regarding long-haul transport through the Panama Canal and processing at Gulf of America recycling facilities. Based on current market conditions, this study finds that reliance on Gulf of America transport introduces significant constraints related to cost, transit duration, and availability of tugs and material barges required to support simultaneous campaign execution.

In contrast, this update anchors the execution model to a West Coast-accessible recycling and disposal pathway. Structural materials generated from Pacific OCS decommissioning campaigns are assumed to be transported to and processed at a facility in Ensenada, MX, capable of handling offshore steel volumes under a phased campaign structure. This approach is supported by site visits conducted by the study team to verify facility applicability and to quantify realistic annual throughput.

While this represents a viable regional solution, disposal throughput is more limited than the capacity historically assumed in the Gulf of America. As a result, disposal throughput becomes the governing pacing variable for the decommissioning effort. Heavy lift operations, module sizing, marine support requirements, and campaign durations are therefore calibrated to align with realistic annual tonnage limits at regional facilities. This disposal-driven framework materially influences both cost distribution and schedule logic compared to prior modeling assumptions, while remaining fully consistent with conventional removal practices.

The methodology also reflects current West Coast capabilities, incorporating regional marine assets including DP2 vessels for diving and ROV support, locally available material barges for transport, and optional derrick barges operating in the region, though not explicitly relied upon in the baseline model.



Gulf of America service providers and recycling facilities remain available and are assumed to be utilized on an as-needed or overflow basis where specialized capability or additional capacity is required.

Well plugging and abandonment methodology remains grounded in established regulatory requirements and conventional offshore execution practice. A hybrid abandonment sequence is assumed, utilizing a platform-based rig or workover unit for high-mechanical-demand operations, followed by a standardized rig-less spread consisting of coiled tubing and modular cementing equipment to complete internal and annular barrier placement. This approach reflects common offshore sequencing and avoids assuming full-time rig deployment for phases that can be safely executed with modular systems.

Pipeline and power cable methodology represents a refinement relative to earlier modeling scenarios. The base-case assumption remains abandonment in place, with pipelines flushed, cut, and buried or otherwise stabilized, and power cables disconnected, cut, and buried to eliminate potential conflicts. In addition, full removal of pipelines and power cables has been evaluated as an optional scenario, recognizing that such removal would significantly increase offshore duration, subsea excavation scope, and marine support requirements relative to abandonment in place.

Structural removal methodology is developed in alignment with the governing disposal constraint. Topsides and jackets are removed using conventional derrick barges supported by material barges and assist tugs. Structural severance is assumed to occur using mechanical cutting systems, with lift planning and module sizing coordinated to match disposal throughput capacity rather than optimized solely for maximum lift efficiency.

Site clearance methodology has also been refined to align with this execution philosophy. Rather than assuming full-field trawl sweeping, this study adopts a survey-based approach utilizing multibeam bathymetry and side scan sonar to identify discrete debris. Anomalies are investigated and recovered using ROV systems and conventional lifting equipment. This targeted approach minimizes benthic disturbance and avoids unnecessary recovery of long-established seabed material, while remaining consistent with modern offshore practice.

In summary, the principal refinements in this update include the explicit anchoring of execution to West Coast recycling capacity, incorporation of a Preservation and Maintenance phase, evaluation of full removal scenarios for pipelines and power cables, and the introduction of shell mound removal as a requested, non-baseline consideration. These refinements reflect practical execution planning under current Pacific OCS conditions and are presented for review and concurrence prior to finalization of detailed cost assessments.



SECTION FOUR – PROJECT MANAGEMENT, ENGINEERING AND PLANNING

Project Management, Engineering, and Planning (PMEP) encompass the activities required to develop, coordinate, and manage offshore decommissioning work through all phases. These activities include development of engineering solutions, definition of execution sequencing, coordination of contractors and marine assets, management of technical and commercial interfaces, and implementation of project controls necessary to support safe and compliant execution. PMEP enables decommissioning activities but does not include construction, marine operations, or other field execution costs, which are addressed within separate cost categories. Consistent with prior BSEE decommissioning cost studies, PMEP is treated as a discrete cost element and is accounted for separately from Permitting and Regulatory Compliance.

Decommissioning engineering is inherently asset-specific. Offshore platforms and associated infrastructure vary significantly in structural configuration, foundation design, well architecture, water depth, and modification history, all of which influence decommissioning approach and execution strategy. Engineering activities include definition of structural segmentation and lift configurations, evaluation of load paths and stability during removal, development of execution sequencing, and selection of appropriate separation techniques and marine assets. These activities require integration of structural behavior, lifting methodology, equipment capacity, and operational constraints. While common methodologies and equipment classes are employed across facilities, the resulting engineering solutions must be tailored to individual asset conditions and therefore cannot be fully standardized or reused.

Offshore decommissioning in California exhibits characteristics of both greenfield and brownfield project environments. From a technical standpoint, assets are well documented, global decommissioning methodologies are established, and execution technologies have been applied successfully in other offshore operating areas. However, from a planning and regulatory perspective, decommissioning in California retains several greenfield-like characteristics. Limited precedent for large-scale federal offshore platform removals in California waters, combined with evolving regulatory expectations and ongoing evaluation of acceptable end states, introduces uncertainty that must be addressed through upfront engineering and planning. Continued consideration of full removal, partial removal, and alternative disposition concepts requires development and evaluation of multiple execution scenarios prior to finalizing project scope.

Many operators and liability holders maintain internal project management organizations and subject matter expertise focused on decommissioning planning and execution. These internal capabilities are embedded within operator cost structures and reflect sunk effort associated with long-term asset stewardship, option screening, and preliminary engineering evaluation. This embedded knowledge provides a strong foundation for execution planning and reduces uncertainty related to technical feasibility and sequencing. Nevertheless, external engineering and project management support remains necessary to develop detailed engineering deliverables, coordinate contractors, and manage execution interfaces. Relative to a replacement-operator or cold-start scenario, reliance on third-party resources is moderated by the presence of internal capability, but not eliminated.

Decommissioning in California is further distinguished by the complexity of its operational and regulatory environment. Although offshore facilities are located in federal waters, execution is influenced by a layered framework of federal, state, and local considerations that extend beyond formal permitting requirements. Planning and execution activities often require coordination across multiple agencies, ports, service providers, and stakeholders, as well as accommodation of regional labor practices, logistics constraints, and environmental sensitivities. Processes that may be comparatively routine in other offshore operating areas frequently require additional documentation, sequencing, and stakeholder



engagement when performed in or adjacent to California. These factors increase planning duration and project management effort, particularly during early phases of decommissioning.

Previous studies recognized the benefit of engaging third-party resources with California-specific experience to support decommissioning planning and execution. Since completion of those studies, the decommissioning market has continued to mature, with the emergence of more integrated and specialized teams capable of bridging offshore engineering, permitting, planning, and field execution disciplines. Firms and practitioners are now available that combine global and Gulf of America decommissioning experience with a practical understanding of how offshore work is executed in California and along the U.S. West Coast. This blended expertise supports more realistic planning assumptions, improved alignment between engineering and execution strategies, more effective contractor integration, and stronger management of technical and regulatory interfaces, reducing inefficiencies often associated with first-of-kind execution in a complex operating environment.

Project Management, engineering, and planning effort is expected to be elevated during early stages of decommissioning as execution approaches are defined, regulatory expectations are clarified, and coordination practices are established. While engineering solutions such as structural segmentation, lift definition, and execution sequencing remain project-specific throughout the program, broader planning, coordination, and project controls benefit from repetition and increasing familiarity with contractors, equipment capabilities, and regulatory interfaces. Over time, planning and project management effort becomes more predictable, even as asset-specific engineering requirements persist.

4.1 COST MODEL AND ANALYTICAL APPROACH

For purposes of this study, PMEP costs are assumed to scale approximately linearly during early decommissioning campaigns, reflecting the effort required to establish acceptable execution pathways and coordination practices within the California operating environment. Incremental effort is assumed to taper as execution patterns, regulatory expectations, and interface requirements become better understood. These effects are reflected implicitly in cost development rather than through explicit modeling of campaign-level learning curves, consistent with the study's objective of maintaining transparency, simplicity, and defensibility.

Accordingly, a single blended PMEP allowance of 8% of applicable costs is applied consistently across all decommissioning phases excluding any work provision or weather contingencies. This blended approach captures the combined effects of early-stage uncertainty, California-specific operational complexity, and later-stage efficiency gains, while avoiding unnecessary analytical complexity. The approach aligns with prior BSEE study methodology and supports the study's objective of ensuring adequate financial assurance for decommissioning under a range of execution scenarios.

PMEP costs exclude formal permitting and regulatory compliance activities, which are addressed separately in the Permitting and Regulatory Compliance section. PMEP includes planning for regulatory uncertainty and execution coordination but does not include preparation, processing, or agency review of permit applications. Engineering associated with well abandonment, conductor removal, and structural removal is addressed within the respective technical sections to avoid double-counting.

In summary, PMEP costs shown in Table 4-1 below reflect a balance between asset-specific engineering requirements, the operational and regulatory complexity of executing offshore decommissioning in California, and program-level efficiencies associated with increasing market maturity and experience. This approach supports realistic, conservative, and explainable cost development without assuming either perpetual inefficiency or full standardization of customized engineering activities.



It is recognized that anecdotal PMEP costs from prior project benchmarks and certain recent campaigns can appear materially higher than the values presented in Table 4-1. Several factors may account for this difference. Primarily, the 8% allowance applied in this study represents the external project management, engineering, and planning effort necessary to execute decommissioning within the California operating environment. It does not capture sunk operator costs associated with asset stewardship, and any preliminary engineering evaluations, which may be embedded in internal operator cost structures and may be incurred prior to decommissioning execution. Secondly, formal permitting and regulatory compliance activities, which may be bundled into operator-reported PMEP, are addressed separately in the Permitting and Regulatory Compliance section of this report. Lastly, the 8% allowance reflects current market conditions in which hybrid third-party expertise combining global, Gulf of America, and California-specific experience has reduced inefficiencies compared to anecdotal benchmarks. The 8% rate is also consistent with prior BSEE decommissioning cost studies and with industry benchmarks for execution-phase project management on comparable offshore programs. When the cost elements excluded from this study’s PMEP definition are reattributed, the cost estimate of project management, engineering, and planning is consistent with prevailing industry experience, including recent campaigns conducted at significant water depths and on aging facilities.

Table 4-1 – Cost of Project Management, Engineering and Planning

Platform	PMEP
A	5,215,700
B	4,485,100
C	4,108,700
Edith	2,752,900
Ellen	5,387,600
Elly	1,831,200
Eureka	7,813,000
Gail	4,702,100
Gilda	5,385,200
Gina	1,460,400
Grace	1,790,400
Habitat	2,142,000
Harmony	12,686,500
Harvest	4,453,800
Henry	2,551,700
Heritage	12,335,100
Hermosa	4,356,300
Hidalgo	3,212,600
Hillhouse	4,193,300
Hogan	2,606,900
Hondo	5,960,300
Houchin	2,570,500
Irene	2,871,600
Total	\$104,872,900



SECTION FIVE – PERMITTING AND REGULATORY COMPLIANCE

This section describes permitting and environmental review requirements and associated costs for the decommissioning of the POCSR oil and gas platforms, pipelines, and power cables. The process remains the same as that described in the 2020 report with a few updates for modified regulations. The cost estimate for permitting and regulatory compliance is based on the platforms being completely removed. Potentially controversial issues that could extend the environmental review process, such as a proposal for an artificial reef pursuant to the State of California's Rigs to Reef legislation or the disposition of shell mounds (if present), were not assumed in this analysis. Consistent with the study direction provided by BSEE, these potential alternative pathways and related considerations were excluded from the cost modeling basis.

Regulatory agencies with permit authority are engaging in an Interagency Decommissioning Working Group (IDWG) to prepare for upcoming decommissioning work offshore California. The IDWG seeks to coordinate their processes and mitigation requirements so that all agency policies and regulations are met.

Permitting and regulatory compliance costs will be incurred to obtain the necessary Federal, State, and local permits required for decommissioning operations and to prepare the environmental documentation necessary to satisfy the requirements of the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA). The costs to satisfy environmental mitigation measures that are typically placed on offshore projects, such as marine mammal protection measures, air emissions mitigation, commercial fishermen preclusion agreements, pre- and post-decommissioning biological surveys, were included in the cost estimates. Other costs, such as bathymetric surveys for anchor positioning and post-decommissioning seafloor surveys to ensure there are no obstructions that could interfere with other ocean users, were included elsewhere in the report. For decommissioning projects offshore California, mitigation costs can be significant.

5.1 REGULATORY AGENCY JURISDICTION

The decommissioning of a Federal OCS oil and gas platform(s) will involve the removal of the structure and associated offshore oil and gas pipelines and power cables that connect the platforms and onshore processing facilities and electrical grids. The project may also involve the decommissioning of an associated onshore processing facility if it is the only facility servicing those platform(s). The agencies that have primary regulatory jurisdiction over such a project are BOEM and BSEE, which regulate oil and gas activities on the Federal OCS, the California State Lands Commission (CSLC) which has authority over State Tidelands located within 3 miles from the coastline, and the County/City agency regulating the related onshore facilities. In addition, the California Coastal Commission has permit authority over all aspects of the decommissioning program within the State's recognized Coastal Zone Boundary.

In addition to BOEM and BSEE, several other Federal agencies have regulatory authority over various aspects of decommissioning projects including: U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, U.S. Environmental Protection Agency, U.S. Coast Guard, National Oceanic and Atmospheric Administration's National Marine Fisheries Service and Office of National Marine Sanctuaries, and the U.S. Pipeline and Hazardous Materials Safety Administration. Additional State and local agencies having regulatory jurisdiction over decommissioning operations in California include the California Department of Fish and Wildlife, California Geologic Energy Management Division, Regional Water Quality Management District, California State Fire Marshal, County Planning and Resource Management Departments, and



regional Air Pollution Control Districts. Tables 5.1 and 5.2 list the major regulatory agencies and their permitting requirements and authority.

5.1.1 Chumash Heritage National Marine Sanctuary

The Chumash Heritage National Marine Sanctuary (CHNMS) was established on November 30, 2024. The sanctuary encompasses 4,543 square miles of Central California's coastal and ocean waters and is administered by the National Oceanic and Atmospheric Administration's Office of National Marine Sanctuaries. The sanctuary's objective is protection of natural, cultural, and historical resources, and sanctuary regulations prohibit specific activities within the sanctuary in pursuit of that objective.

Oil and gas production from existing leases or lease units in effect on the effective date of CHNMS designation (Nov. 30, 2024) is excepted from several prohibitions in the CHNMS regulations. Specifically, 15 CFR 922.232(a)(1) excepts oil and gas production (including well abandonment) generally; 15 CFR 922.232(a)(2)(i)(H) excepts discharges incidental and necessary to oil and gas production, including well abandonment, from Platform Irene or Platform Heritage; and 15 CFR 922.232(a)(3)(vi) excepts drilling, maintaining, or abandoning a well necessary for oil and gas production from those same platforms. Platform decommissioning (e.g., heavy-lift removal of the platform itself) is not enumerated among these exceptions. Based on communications with sanctuary staff, decommissioning operations including heavy lift operations, would be approved, but would require an authorization issued by the sanctuary.

5.2 PERMITTING PROCESS

The procurement of federal, state, and local decommissioning permits is a multi-jurisdictional process, typically spanning a two-to-five-year timeframe. To mitigate the substantial costs of "idle iron" and ensure a seamless transition from production to removal, decommissioning planning must be integrated into the asset's lifecycle at least three years prior to ending production. Operators should leverage the final years of production and the concurrent Well P&A (Plug and Abandonment) phase to advance the structural removal permitting process. Many preparatory activities, such as HazMat mapping and initial site surveys, can and should be executed during active operations to compress the regulatory approval schedule. The industry standard is to engage specialized regulatory consulting firms to manage the regulatory process. These experts provide the necessary technical, environmental, and jurisdictional experience required to navigate the overlapping frameworks of various agencies without triggering costly project delays.

Under the Outer Continental Shelf Lands Act, BSEE mandates a structured, two-phased application process to vet and approve platform removal methodologies. This process begins at least two years prior to the cessation of production with the submission of an Initial Platform Removal Application under 30 CFR 250.1726. This document serves as the formal "project description" for the entire decommissioning campaign, detailing every operational facet from cutting techniques and equipment spreads to pipeline flushing and site restoration. Because this plan outlines the project's physical footprint and mechanical execution, it effectively functions as the baseline for environmental reviews required under CEQA and NEPA.

Within two years of that initial filing the submission of the Final Platform Removal Plan under 30 CFR 250.1727 is required. This second stage triggers the formal submittal of all necessary permit materials to the Federal, State, and local agencies overseeing the project. The application must be supported by a robust suite of technical data, including geotechnical, marine biological, archaeological, and seafloor surveys. These studies are critical for establishing the environmental baseline and identifying sensitive resources, such as fish habitats or cultural artifacts, that could be impacted during the removal process.



While BSEE maintains primary administrative authority over this process, they may involve BOEM at their discretion to assist with specific environmental or resource evaluations.

As the lead federal agency, BSEE retains responsibility for government-to-government consultation with federally recognized Tribes on its permitting decisions and policies on decommissioning, consistent with DOI policy to consult on a government-to-government basis with federally recognized Tribes whenever there is an agency action with tribal implications. Relevant authorities and guidance include DOI Departmental Manual 512 DM 4 (Policy on Consultation with Indian Tribes) and 512 DM 5 (Procedures for Consultation with Indian Tribes). This framework is grounded in the Federal Government's general trust relationship with each Tribe — as defined by treaties, statutes, executive orders, and federal regulations — and in federal consultation requirements under Executive Order 13175, subsequent Executive Orders and Presidential Memoranda, and statutes.

Quantitative cost estimates for required consultation would be speculative and are not appropriate for inclusion. Tribal consultation may add time to the permitting process, and Tribes may request technical assistance and/or compensation to participate in consultations and analyses, as well as surveys, monitoring, and/or mitigation measures to protect important resources. Tribes may participate in NEPA reviews as cooperating agencies with special expertise with respect to the environmental issues involved in decommissioning. With tribal consent and to the greatest extent practicable, tribal consultation should be coordinated among partner agencies to maximize efficiency and reduce the consultation burden on both Tribes and agencies.

The California Coastal Commission (CCC) must issue a Federal Consistency Determination to ensure all activities in POCS waters align with the California Coastal Act. Furthermore, any operations extending into State waters or the adjacent onshore coastal zone necessitate a formal Coastal Development Permit (CDP). Once the CCC has finalized its action, BSEE issues the Record of Decision (ROD) at the federal level, while the lead CEQA agency files the Notice of Determination (NOD), effectively authorizing the commencement of the decommissioning campaign.

Environmental reviews under NEPA are executed either on a project-specific basis or through a broader Programmatic Environmental Impact Statement (PEIS). NEPA compliance will follow the Department of Interiors (DOI) NEPA Handbook published in February 2026. The programmatic approach is particularly effective for establishing a high-level framework of environmental impacts and mitigation strategies for large-scale federal decisions, such as new rulemakings, policy shifts, or regional decommissioning plans. By analyzing the cumulative effects of several connected projects within a single geographical area, such as the anticipated removal of multiple platforms across the Pacific Outer Continental Shelf (POCS), this high-level review provides a standardized roadmap for regulatory consistency.

The Programmatic EIS (PEIS) serves as a foundational analytical framework that BSEE utilizes to evaluate future decommissioning actions and determine the necessity for further site-specific study. Such a programmatic approach was completed for future Pacific OCS decommissioning projects (BSEE/BOEM, 2023). In instances where a proposed action deviates from the baseline established in the PEIS, the agency can execute a supplemental, "tiered" analysis. This tiered approach is a significant procedural advantage, as it allows operators to incorporate the programmatic data by reference rather than duplicating broad environmental findings, substantially compressing the permitting timeline. These programmatic reviews are designed to foster a more transparent decision-making environment while providing a standardized, expedited pathway toward final project authorization.

The programmatic approach provides flexibility to advance federal projects based on established data while deferring site-specific nuances to later stages. This framework significantly streamlines the



mandatory consultation process with key resource agencies, including the U.S. Fish and Wildlife Service (USFWS), the National Marine Fisheries Service (NMFS), and the State Historic Preservation Office (SHPO). By establishing a broad Programmatic Agreement under the Endangered Species Act, for instance, a project can satisfy high-level regional requirements upfront; this allows subsequent, tiered NEPA reviews to focus exclusively on narrow, site-specific consultations, thereby reducing redundant inter-agency cycles.

Despite the efficiencies offered by programmatic tiering, BSEE has indicated that the complexity of offshore decommissioning coupled with the need to satisfy state and local mandates will likely necessitate site-specific NEPA review for each campaign, including joint EIS/EIRs where infrastructure extends into state waters and CEQA applies. While Executive Order 13807 (2017) established a two-year goal for completion of federal environmental reviews, and Secretarial Order 3355 (2017) limited NEPA documents to 150–300 pages benchmarks since codified by the Fiscal Responsibility Act of 2023, the realities of a combined federal-state review remain more demanding.

Table 5-1 – Federal Permitting Requirements Applicable to Decommissioning Projects

Agency	Permit/Approval	Regulated Activity	Applicable Project Components	Review Period*	Authority
Bureau of Ocean Energy Management (BOEM)	Coordinates NEPA Analysis	Responsible for OCS lease administration (including lease adjudication), and ensuring compliance with bonding requirements and lease terms and conditions. Performs environmental analysis on behalf of BSEE.	OCS facilities including platforms, wells and pipelines.	Conducted in coordination with BSEE NEPA review	Outer Continental Shelf Lands Act, 30 CFR § 550 and 30 CFR § 556
Bureau of Safety and Environmental Enforcement (BSEE)	Approval of Final Decommissioning Application	Responsible for approving OCS decommissioning applications and enforcing safety and environmental regulations.	OCS facilities including platforms, wells and pipelines	Approximately 6 months to 3 years to complete NEPA review and project component decommissioning procedures. (Duration mainly depends on external reviews.)	Outer Continental Shelf Lands Act 30 CFR 250 Subpart Q, Decommissioning Activities NTL 2009-P04 NTL 2010-P-05 43 U.S. Code 1334



Agency	Permit/Approval	Regulated Activity	Applicable Project Components	Review Period*	Authority
US Army Corps of Engineers (USACE)	Section 404 permit Section 10 permit	Responsible for: (1) issuing permits for discharges of dredged or fill material in U.S. waters; (2) issuing permits for construction of any structure in or over the navigable waters of the U.S.	Marine components	6-8 months including certification of NEPA/CEQA document	Clean Water Act, Section 404 Rivers and Harbors Act, Section 10
United States Fish & Wildlife Service (USFWS)	Incidental Take Permit; Finding of No Jeopardy	Responsible for ensuring protection of threatened and endangered species (e.g., sea otters and certain bird species), pursuant to the Endangered Species Act (ESA).	Marine activities that could impact threatened or endangered species not otherwise regulated by NMFS (i.e., white abalone, seabirds)	Unspecified	Endangered Species Act 16 USCA 1513 50 CFR Section 17
Environmental Protection Agency (EPA)	National Pollution Discharge Elimination System (NPDES) Permit	Responsible for issuing National Pollution Discharge Elimination System (NPDES) permits for discharges of pollutants from point sources to surface waters.	Conductor cutting, depending on method used; Discharge of final pipeline flush waters, if fluids meet strict standards	Unspecified	Clean Water Act



Agency	Permit/Approval	Regulated Activity	Applicable Project Components	Review Period*	Authority
United States Coast Guard (USCG)	Navigation consultation Notice to Mariners	Responsible for ensuring navigation safety, proper use of aids to navigation, and managing responses to any unauthorized discharges including oil spills.	All marine decommissioning activities; issues notices to mariners of preclusion areas during work for purposes of safety; enforces said notices	Unspecified	Ports and Waterways Safety Act Oil Pollution Act of 1990 33 CFR – Coast Guard
U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration	Pipeline abandonment applications	Responsible for ensuring pipeline safety and overseeing abandonment of pipelines for DOT jurisdictional pipelines.	Pipeline components Hazardous materials	Unspecified	Natural Gas Pipeline Safety Act Hazardous Liquid Pipeline Safety Act Hazardous Materials Transportation Act
National Marine Fisheries Service (NMFS)	ESA, Section 7 for marine species Marine Mammal Protection Act Essential Fish Habitat Assessment	Impacts to federally-listed and species proposed for listing. Protection of Marine Mammals including impacts associated with explosives use. Managed Marine Fish Resources	Marine components	Review period: 6 months to 1 year Review period: 18 months or more Review period: Similar to ESA Completed prior to NEPA completion	Endangered Species Act Marine Mammal Protection Act Magnuson-Stevens Fishery Conservation and Management Act
NOAA National Marine Sanctuary - Chumash Heritage NMS	ONMS Permit/Authorization	Authorization for activities within the designated marine sanctuary boundaries	Marine components associated with Point Arguello and Point Pedernales.	Est. 6 months	15 C.F.R - NOAA



Agency	Permit/Approval	Regulated Activity	Applicable Project Components	Review Period*	Authority
Advisory Council on Historic Preservation (ACHP)	Section 106 review and compliance	Impacts to historic properties.	Marine Components that could impact submerged cultural and historic resources	3-6 months .	National Historic Preservation Act 36 CFR 800

*The Review Period is an estimated duration. The actual time required may be longer or shorter.



Table 5-2 – State and Local Permitting Requirements Applicable to Decommissioning Projects

Agency	Permit/Approval	Regulated Activity	Applicable project Components	Review Period*	Authority
California State Lands Commission (CSLC)	Lead agency for CEQA documentation. Pipeline lease Agreement termination	Review of environmental impacts in area of jurisdiction. Removal of components in State Territorial Waters.	All decommissioning activities in state waters to mean high tide line. Review impacts of all decommissioning activities.	10-12 months for certification of CEQA document. Lease termination agreement	Public Trust Doctrine, Public Resources Code Sections 6301, 6500. California Environmental Quality Act (CEQA)
California Coastal Commission (CCC)	Coastal Development Permit/Federal Consistency	Ensures any development (including decommissioning activity) within the coastal zone complies with the CA Coastal Act and CZMA.	All decommissioning activities within the Coastal Zone	4-6 month review process, partially concurrent with CEQA review.	California Coastal Act; Coastal Zone Management Act
California Department of Fish and Wildlife (CDFW) Office of Spill Prevention & Response (CDFW OSPR)	Endangered Species Act Consultation, Finding of No Jeopardy; Section 1603 Permit; Oil Spill Contingency Plan approval	Activities affecting State Waters resources. Onshore activities affecting onshore resources including streams and wetlands. State lead for response to oil spills affecting state waters and resources.	Decommissioning activities that could impact CA fish and wildlife resources, including listed threatened or endangered species or species of special concern.	4-6 month review process, partially concurrent with CEQA review.	CA Endangered Species Act; CA Dept. of Fish & Game Code Section 1603; Senate Bill 861
State Water Resources Control Board (SWQCB) or Regional Water Quality Control Board (RWQCB)	Section 401 Water Quality Certification	Discharges that may affect surface and ground water quality.	Any activity that could result in a discharge to waters of the state	Concurrent with USACE review and approval.	Clean Water Act (CWA) Porter-Cologne State Water Quality Act (1969).
State Historical Preservation Officer (SHPO)	Section 106 review and compliance	Impacts to historic properties.	None identified at this time.	3-6 months after certification of CEQA document.	National Historic Preservation Act 36 CFR 800
California Geologic Energy Management Division (CalGEM)	Notice of Intention (NOI)	Well Plugging and Abandonment	Platform well plugging abandonment (prior to platform decommissioning)		California Public Resources Code Section 3106



Agency	Permit/Approval	Regulated Activity	Applicable project Components	Review Period*	Authority
County Department of Planning and Building and Safety (County)	Conditional Use Permit; Coastal Development Permit	Removal of project components located landward of State Lease within unincorporated portions of County (beach & onshore segments). Activities within designated coastal zone.	Onshore facilities within Coastal Zone.	2-3 month review process, partially concurrent with CEQA review.	County General Plan / Coastal Plan
Air Pollution Control Board (APCD)	Air quality emissions review; Permit to Operate/ Authority to Construct (PTO/ATC) and Portable Engine Permits	Air emission outputs associated with project decommissioning activities.	All decommissioning activities with equipment require engines (i.e., derrick barge, tugs, cranes, crew and supply vessels, portable equipment, generators, trucks, etc.)	6-8 months review process, concurrent with CEQA review.	1990 Clean Air Act CEQA review

5.3 PERMITTING AND REGULATORY COMPLIANCE COST INPUTS

The permitting and regulatory compliance cost framework used in this study follows the same general structure as prior Pacific OCS analyses, with refinements reflecting current regulatory practice, updated labor indices, and recent California project experience. Individual cost elements were reviewed and adjusted based on observed mitigation requirements, agency coordination experience, and contemporary staffing rates. Total campaign-level costs were then allocated across platforms based on the number of facilities included within each decommissioning sequence. The principal cost components included in this category are summarized below and shown in Table 5.3, Table 5.4, Table 5.5, and Table 5.6.

5.3.1 Initial and Final Decommissioning Plan

The project proponent, supported by qualified engineering and regulatory consultants, would prepare a comprehensive Decommissioning Plan describing proposed activities, equipment spreads, sequencing, personnel requirements, and anticipated schedule. These submittals are typically developed using detailed engineering packages prepared by firms with marine decommissioning and offshore construction expertise. The Plan serves as the primary technical document supporting regulatory review and approval.

5.3.2 Baseline Data Compilation and Field Surveys

An environmental consulting team would assemble available baseline environmental information and conduct site-specific surveys to characterize existing conditions and identify sensitive marine resources that could be affected by offshore operations. Surveys would include both pre-activity and post-activity data collection consistent with agency expectations for offshore California projects. The scope reflects regulatory precedent established during prior platform and marine construction removals in the region.



The costs shown below are based on the use of existing or historical survey information. Additional survey costs are provided as a range in Table 5.3 below.

5.3.3 NEPA and CEQA Documentation

Project proponents are responsible for funding preparation of environmental review documents under federal and state law. While existing programmatic analyses provide regional context and establish broad policy considerations, project-specific environmental documentation remains necessary to evaluate localized impacts and mitigation measures. Upon determination that an application package is complete, the responsible federal agency, in coordination with the appropriate state lead agency, would oversee preparation of an Environmental Impact Statement and Environmental Impact Report conducted by an independent third-party consultant under agency direction.

5.3.4 Agency Review, Processing Fees, and Staff Reimbursement

Applicants are required to reimburse federal, state, and local agencies for permit processing costs and associated staff time. This includes direct application fees as well as reimbursement for agency personnel and retained consultants involved in technical review, coordination, and approval activities. Such cost recovery mechanisms are standard practice for offshore and coastal development projects in California.

5.3.5 Environmental Mitigation Measures

Project-related mitigation requirements may include compensation for temporary loss of commercial fishing access, air quality mitigation measures, and development of resource protection plans. Compensation to fishermen is typically supported by documented catch history, while air quality mitigation may involve contributions to approved emission reduction or technology demonstration programs. Additional requirements can include preparation of Marine Wildlife Protection Plans and deployment of trained protected species observers during offshore operations. These types of measures are consistent with conditions historically applied to offshore removals and other marine construction projects in California waters.

5.3.6 Mitigation Monitoring and Compliance Verification

Environmental review documents require development of a Mitigation Monitoring and Reporting Program to ensure implementation of adopted mitigation measures. Project proponents must prepare and execute compliance plans addressing environmental conditions imposed by approving agencies. Monitoring is generally performed by qualified consultants, with oversight by regulatory personnel. Documentation is required to demonstrate compliance before, during, and following offshore execution activities.

5.4 PERMITTING COST BASE CASE AND COST VARIABLES

The Base Case presented in Table 5-3 is intended to represent a single, standalone POCSR decommissioning project executed under the regulatory framework in place as of the publication of this report, using historical baseline data and a representative scope. Actual project costs are sensitive to several variables that drive the total cost, and the cost factors do not all respond to those variables in a uniform way.

The principal cost drivers that produce variation from the Base Case are:

- The number of platforms permitted concurrently within a campaign, which scales Cost Factors 1, 2, 5, and 6 approximately linearly and Cost Factors 3 and 4 as step functions (see Table 5-4 and Table 5-6)
- The availability of historical survey data.



- The location of the platform relative to the Chumash Heritage National Marine Sanctuary, which adds an ONMS authorization workstream for Platform Irene and the Point Arguello platforms (Hermosa, Harvest, and Hidalgo)
- The eligibility of the project for tiered NEPA analysis under the 2023 Pacific OCS Programmatic EIS, which can compress the EIS/EIR effort captured in Cost Factor 3
- The magnitude of fisheries and air quality impacts in the affected lease blocks, which drive the mitigation fees captured in Cost Factor 5
- The depth, complexity, and number of Tribal consultations triggered under DOI Departmental Manual 512 DM 4/5 and Executive Order 13175
- The scope of environmental impact attached to the project. For example, a Rigs-to-Reefs proposal under California's Marine Resources Legacy Act or the disposition of shell mounds
- Escalation of labor and consultant billing rates between the date of this report and the date of permit application, addressed more generally in Section 13

Conversely, Base Case costs can be reduced on a per platform basis where multiple platforms are processed under a single coordinated application, where existing PEIS coverage is accepted by the lead agencies without supplementation, where prior survey data is current and acceptable, and where mitigation measures already negotiated for predecessor POCSR decommissioning projects can be carried forward without re-evaluation.



Table 5-3 – Permitting and Regulatory Compliance Costs – Base Case

Cost Factors ⁽¹⁾	Cost Per Activity
1. Initial and Final Platform Removal Plan (Decommissioning Plan Preparation) ⁽²⁾	650,000
2. Data Collection and Field Surveys ⁽³⁾	550,000
3. Prepare NEPA and CEQA Documents (EIS/EIR)	2,500,000
4. Agency Processing Fees and Staff Time	
• Application Fees	450,000
• Agency Staff Time	500,000
• Application Consultant Support	500,000
5. Environmental Mitigation Requirements	
• Mitigation Fees (Air and Fisheries)	1,000,000
• Marine Mammal Monitoring	250,000
6. Mitigation Monitoring and Compliance	650,000
Total Cost per Project	\$ 7,050,000

(1) The cost factors 1, 2, 5, and 6 vary due to number of platforms. This is due to the additional locations and processes required to generate the required documentation. Table 5-4 shows the values for the factors that vary with the number of platforms.

(2) Does not include decommissioning engineering cost

(3) Cost assumes no additional survey data is required, and applications are based on historically available data. If full survey activities were required, costs would range from an estimated \$850,000 to \$1,200,000.



Table 5-4 shows the regulatory and permitting cost factor variations with the number of platforms being permitted concurrently. The cost rates do not necessarily increase linearly for certain permitting activities.

Table 5-4 – Regulatory and Permitting Cost Factor Variations with Number of Platforms per Campaign

Cost Factors	Base Case	2	3	4	5	6	7	8	9	10	11
1. Initial and Final Platform Removal Plan (Decommissioning Plan) Preparation (does not include decommissioning engineering costs)	\$650,000	\$670,000	\$690,000	\$710,000	\$730,000	\$750,000	\$770,000	\$790,000	\$810,000	\$830,000	\$850,000
2. Data Collection and Field Surveys	\$550,000	\$580,000	\$610,000	\$640,000	\$670,000	\$700,000	\$730,000	\$760,000	\$790,000	\$820,000	\$850,000
3. Prepare NEPA and CEQA Documents (EIS/EIR)	\$2,500,000	\$2,500,000	\$2,500,000	\$3,000,000	\$3,000,000	\$3,000,000	\$3,500,000	\$3,500,000	\$3,500,000	\$3,500,000	\$3,500,000
4. Agency Processing Fees and Staff Time											
• Application Fees	\$450,000	\$450,000	\$450,000	\$500,000	\$500,000	\$500,000	\$550,000	\$550,000	\$550,000	\$600,000	\$600,000
• Agency Staff Time	\$500,000	\$500,000	\$500,000	\$540,000	\$540,000	\$540,000	\$580,000	\$580,000	\$580,000	\$620,000	\$620,000
• Application Consultant Support	\$500,000	\$500,000	\$500,000	\$550,000	\$550,000	\$550,000	\$600,000	\$600,000	\$600,000	\$650,000	\$650,000
5. Environmental Mitigation Requirements											
• Mitigation Fees (Air and Fisheries)	\$1,000,000	\$1,120,000	\$1,240,000	\$1,360,000	\$1,480,000	\$1,600,000	\$1,720,000	\$1,840,000	\$1,960,000	\$2,080,000	\$2,200,000
• Marine Mammal Monitoring	\$250,000	\$280,000	\$300,000	\$320,000	\$340,000	\$360,000	\$380,000	\$400,000	\$420,000	\$440,000	\$460,000
6. Mitigation Monitoring and Compliance	\$650,000	\$670,000	\$690,000	\$710,000	\$730,000	\$750,000	\$770,000	\$790,000	\$810,000	\$830,000	\$850,000
Total	\$7,050,000	\$7,270,000	\$7,480,000	\$8,330,000	\$8,540,000	\$8,750,000	\$9,600,000	\$9,810,000	\$10,020,000	\$10,370,000	\$10,580,000



Table 5-5 summarizes the estimate for permitting and regulatory costs per platform as defined by the platform's campaign.

Table 5-5 – Permitting and Regulatory Cost per Platform

Platform	Campaign	Permitting & Regulatory
A	2	\$1,066,700
B	2	\$1,066,700
C	2	\$1,066,700
Edith	3	\$1,066,700
Ellen	3	\$1,066,700
Elly	3	\$1,066,700
Eureka	3	\$1,066,700
Gail	1	\$1,113,300
Gilda	2	\$1,066,700
Gina	2	\$1,066,700
Grace	1	\$1,113,300
Habitat	1	\$1,113,300
Harmony	3	\$1,066,700
Harvest	1	\$1,113,300
Henry	2	\$1,066,700
Heritage	3	\$1,066,700
Hermosa	1	\$1,113,300
Hidalgo	1	\$1,113,300
Hillhouse	2	\$1,066,700
Hogan	1	\$1,113,300
Hondo	3	\$1,066,700
Houchin	1	\$1,113,300
Irene	1	\$1,113,300
Total		\$24,953,500

Table 5-6 is the total cost of permitting and regulatory activities by campaign.

Table 5-6 – Permitting and Regulatory Cost per Campaign

Campaign	Cost per Campaign	Platform Count
1	\$10,020,000	9
2	\$9,600,000	7
3	\$9,600,000	7



SECTION SIX – WELL PLUG AND ABANDONMENT

The 2016 study largely relied on Gulf of America (GOA) analogs for well abandonment. It assumed the use of standard rigless P&A techniques, reflecting common GOA practices, and applied an average duration of approximately seven days per well. These assumptions implicitly incorporated GOA formation characteristics, oil properties, and well construction practices, including generally lighter oil, deeper and more uniform formations, and more modern cementing and completion standards. While appropriate for broad benchmarking at the time, these assumptions did not fully account for the geologic and operational characteristics unique to the Pacific OCS Region.

The 2020 study modified this approach by assuming that well P&A activities on the West Coast would predominantly utilize existing platform drilling rigs, supplemented by coiled tubing. Well durations were increased relative to the 2016 study to reflect anticipated operational complexity, logistical constraints, and limited regional experience. This shift in methodology resulted in higher estimated P&A durations and costs on a per-well basis; however, the approach remained largely predictive, as it was developed in advance of meaningful modern P&A execution in the POCSR.

Since publication of the 2020 study, actual well P&A operations have been conducted in the POCSR, and operator self-reported data demonstrate that execution durations vary significantly from the assumptions in either prior study. In practice, abandonment methods have ranged from rig-based to hybrid and specialized interventions, with durations exceeding earlier estimates in many cases.

Furthermore, in certain instances, operators or liability holders have elected to apply internal standards that exceed minimum regulatory requirements, further increasing execution duration and cost variability relative to prior study assumptions.

Consistent with the methodology used in earlier studies, all remaining wells requiring abandonment have been reviewed in detail. Relevant information has been extracted from available well status reports and historical records, and wells have been categorized into TA-To Surface, low-, medium-low-, medium-, and high-risk classifications. For this study, P&A equipment spreads, intervention methods, and execution durations have been assigned based on these risk categories.

6.1 INTRODUCTION

Well Plugging and Abandonment (P&A) represents a technically complex and risk-sensitive component of the entire decommissioning scope. The approach adopted for this study reflects a deliberate balance between operational conservatism, cost discipline, consistency with previous studies and evolving industry practices observed across recent POCSR offshore abandonment programs.

For purposes of this study, the base-case P&A framework assumes the use of existing drilling and intervention assets where available and appropriate, recognizing that no single execution method is optimal across the full range of well types, construction histories, and risk profiles present in the POCSR inventory. Wells exhibiting greater complexity, including extended reach profiles, uncertain barrier integrity, or elevated intervention history, are assumed to require higher-capability intervention systems such as platform-based rigs, modified land rigs, or modular rigs. Coiled tubing units (CTU) and heavy workover or snubbing units are planned to be used after the most complicated well abandonment activities are complete. Final selection of execution method at the time of abandonment remains contingent upon well-specific conditions and continues to be refined as additional data and engineering evaluation progresses.



A core objective of this approach is to avoid unnecessarily inflating or diminishing abandonment costs through premature or overly conservative equipment selection while maintaining alignment with regulatory requirements and accepted industry standards. This philosophy reflects current operator practices observed in the POCSR and other mature offshore regions.

Recent operator feedback and qualitative cost data provided by P&A service providers indicate measurable efficiency gains associated with self-performed and campaign-based well abandonment programs. These gains are attributed to improved procedural standardization, enhanced understanding of basin-specific well conditions, and learning-curve effects realized through repeated execution of similar abandonment scopes. This study acknowledges those efficiencies and incorporates them qualitatively in the P&A framework, while remaining conservative in the absence of finalized well-by-well execution plans.

Risk remains a central organizing principle for well P&A cost development in this study. Wells are categorized using established risk ranking methodologies consistent with prior POCSR studies, while allowing for refinement driven by more comprehensive data review. Unlike prior efforts that relied primarily on spot-checking or limited sampling of available well records, this study leverages advances in data analytics and artificial intelligence to evaluate nearly the full population of available well files and data. This expanded review supports more consistent identification of complexity-determining criteria, enabling more defensible differentiation between TA-To Surface, low-, medium-, and high-risk abandonment scenarios.

In addition to technical risk, this study recognizes the influence of operator risk tolerance on abandonment scope and cost. Self-reported well abandonment costs provided by operators tend to reflect a conservative risk tolerance driven by a preference for enhanced barrier redundancy and long-term risk mitigation. Some operators elect to exceed baseline abandonment standards to minimize the likelihood of future re-entry or remedial intervention, accepting higher upfront costs in exchange for increased long-term certainty. Where applicable, this operator risk preference is considered qualitatively in the interpretation of reported cost data and benchmark comparisons.

The removal of well conductors is treated as a discrete scope within the broader well P&A function and is addressed in dedicated portions of this report. This separation reflects both execution sequencing considerations and the distinct cost drivers associated with conductor and casing removal activities.

6.1.1 Objective and Analytical Approach

6.1.1.1 Objective

The objective of the permanent well abandonment portions of this study is to provide a reasonable cost per well to temporarily and permanently abandon according to 30 CFR Part 250 (Subpart Q) 1715-1716. These regulations mandate critical placement of cement and other barriers to:

- a. provide downhole isolation of hydrocarbon and sulfur zones;
- b. protect freshwater aquifers; and
- c. prevent migration of fluids to the sea floor in accordance with 30 CFR 250.1714-1715.

This study and the developed cost models are predicated on all well abandonment operations being conducted in accordance with the requirements of 30 CFR Part 250 (Subpart Q), and all relevant Notices to Lessees (NTL).

The final stage of abandonment includes cutting and recovering all conductors 15ft below the mudline in accordance with 30 CFR 250.1716



6.1.1.2 Analytical Approach

The BSEE Well Data Query system ([Well Data Query](#)) was used to request any well documents and permits with created dates, run dates, and released dates from January 1, 2020 until present. These documents were then analyzed using a generative AI agent to summarize the operational narrative, summarize listed tasks, extract relevant dates, and determine other document metadata. The results from the Gen AI agentic analysis were then reviewed for accuracy. Variations in previously identified well status and complexity were further investigated. If no documents for a given well were available in the BSEE Well Data Query system, the operators were contacted and documents detailing the status of the wells were requested. Additionally supplemental recent data was provided by BSEE as part of a clarification request that improved the accuracy of well counts and status. This data is dated March 23, 2026. Based on the categorization criteria listed in Section 6.1.5, the well abandonment complexity was established.

6.1.2 Well Abandonment Methodology

There are numerous well abandonment methodologies that satisfy the requirements of 30 CFR Part 250 (Subpart Q) 1715. These methods include the use of rigs to place all required plugs and perform all tests, partial use of a rig/workover unit, use of coiled tubing units, and fully modular/rigless equipment spreads. To maintain consistency in the methodology applied to this study a hybrid approach similar to the approach analyzed in the 2020 study was chosen. This hybrid approach includes the use of the platform-based rig or temporary rig deployments and the use of a coiled tubing equipment spread to complete all required operations.

This POCSR Decommissioning study and the studies completed in 2016, and 2020 were conducted by applying the governing requirements of 30 CFR Part 250 (Subpart Q) to develop a cost to permanently abandon each well at current market rates for services, equipment, and consumable items.

Summary expenditure reports were provided to BSEE for well abandonment activities for the period starting January 2018 and ending January 2024. These summary expenditures have shown significant variation to estimated costs as determined in the 2016 and 2020 studies. These variations can be most reasonably attributed to operator risk tolerance leading to additional abandonment activities being undertaken.

6.1.3 Operator Risk Tolerance

While 30 CFR Part 250 (Subpart Q) describes the standards to safely seal and abandon an oil and gas well to protect the environment and people using the waters around it. A specific operator may desire to include additional mechanical or cement plugs or undertake other non-regulation required permanent abandonment activities to mitigate future risks of re-entering a permanently abandoned well after the wellhead and conductor have been severed 15ft below the mudline and removed. This study and previous studies cannot reasonably estimate the operator's tolerance for future risks that may be posed by changes in the well condition after permanent abandonment. These changes may include mechanical and barrier integrity degradation, dynamic reservoir & geologic changes, and carbon capture and sequestration activities in the area.

6.1.4 General Well Abandonment Procedures

The permanent well abandonment procedure is split into three distinct phases.

1. Well Preparation and Initial Isolation
2. Internal Plugging and Zonal Isolation



3. Conductor Severing and Removal

6.1.4.1 Well Preparation and Initial Isolation

The scope and objective of the Well Preparation and Initial Isolation phase is to recover downhole equipment and resolve complex well remediation activities. Recovery of the downhole equipment includes the removal of electric submersible, rod, of hydraulic pumps and recovery of the production tubing and packer assemblies. Complex well remediation activities include the removal of obstructions through fishing or milling and the remediation of any sustained pressure in the casing string annuli. Initial isolation includes the setting of a plug for any open perforated zone not previously squeezed or isolated according to 30 CFR Part 250 Subpart Q 1715 (a)(3)(i) or(ii) or (iii)

6.1.4.2 Internal Plugging and Zonal Isolation

The scope and objective of the Internal Plugging and Zonal Isolation phase is to place all remaining internal plugs. Remaining internal plugs include all cement and mechanical plugs according to 30 CFR Part 250 Subpart Q 1715 (a)(4), (6), (8). Zonal Isolations include any needed casing perforations and squeezing of annular cement plugs.

6.1.4.3 Conductor Severing and Removal

The scope and objective of the Conductor Severing and Removal phase is to completely remove the conductor and wellhead from the well slot in its entirety to 15ft below the mudline according to 30 CFR Part 250 Subpart Q 1716 (a). The well conductor and all casing strings will be severed below mudline using a high-pressure abrasive waterjet cutting method. Marine growth will be removed from the wellhead and conductor while being lifted and sectioned for layout and disposal.

Deeper water depths have an impact on the efficacy of high-pressure abrasive jet cutting. To date, the deepest subsea multi-string conductor cut is ~1000ft. High-pressure abrasive waterjet cutting providers have stated that the cuts will be successful in deeper water depths with additional equipment components and longer cutting times. For the purposes of this study, cutting times are increased by 100% if the conductor length is greater than 800ft. Conductors on the Gail, Hondo, Heritage, and Harmony platforms have had subsea conductor cutting times increased accordingly.

6.1.5 Well Abandonment Categorization Criteria

To establish a defensible cost estimate, a comprehensive diagnostic audit was performed to categorize the wells based on mechanical complexity and risk profiles. The primary data inputs were generated from previous study data, BSEE databases, and information provided by POCSR operators.

The technical assessment utilized the documents, permits, and information provided to determine the following factors:

- Total well depth
- Extended Reach (ER)
- Sustained Casing Pressure
- Injection strings / downhole pumps
- Obstructions requiring fishing or milling

Table 6-1 describes the criteria for each risk categorization in a tabular format.



6.1.5.1 Operational Assumptions

The cost models in this study assume that the condition of the wellheads and wellbores will remain consistent until the time of P&A. It is assumed that the wellhead remains intact and will be maintained by ongoing maintenance programs. Additionally, any emergent issues that arise with the wellhead, wellbore, tubing/casing integrity, or changes in sustained casing pressure will be remediated immediately and are excluded from the scope of this study.

Table 6-1 – Well Abandonment Classification Criteria

Criteria	High	Medium	Medium-Low	Low	TA-To Surface	Conductor Removal Only
Total Well Depth	>16000ft	>8000ft and <16000ft	>4000ft and <8000ft	<4,000ft	N/A	N/A
Extended Reach	>3	>3	>2 and <3	<2	N/A	N/A
Sustained Casing Pressure	Present	Present	Not Present	Not Present	N/A	N/A
Isolation of HC or FW Zones	N/A	Yes	No	No	N/A	N/A
Pump or Injection	N/A	ESP, ESPCP, RDPCP, HRP	N/A	GLV or Injection String	N/A	N/A
Fish or Milling	Yes	No	No	No	N/A	N/A

Conductor Removal Only Complexity

- The well only requires severing the well conductor 15ft BML and removal of the wellhead.
- The well is temporarily abandoned at surface with two independent barriers positioned just below the mudline, including a central mechanical barrier.
- All previous abandonment plugs are tested and meet BSEE 30 CFR 250.1715(b) requirements.

TA - To Surface Complexity

- Well is temporarily abandoned but does not have all necessary plugs to surface to meet 30 CFR 250.1715 requirements

Low Complexity

- Total Depth (TD) or Plugback Total Depth (PBSD) does not exceed 4,000 feet.
- Does not meet Extended Reach (ER) criteria (ER ratio less than 2).
- No sustained casing pressure and all annuli can bleed down to zero psi.
- No fish or obstructions are present in the wellbore.
- No rod pump, ESP, or hydraulic pump present; gas lift valves, injection strings, or kill strings may be present.
- Annular cement squeeze work is not required.

Medium-Low Complexity



- Total Depth or Plugback Total Depth is greater than 4,000 ft but less than 8,000 feet.
- Meets ER criteria with a ratio greater than or equal to 2 and less than 3.
- All other requirements for a low-cost well are satisfied.

Medium Complexity

- Total Depth or Plugback Total Depth is greater than 8,000 ft but less than 16,000 feet.
- Includes a rod pump, ESP, hydraulic pump, or equipment that requires a rig or specialized lift system to remove from the well.
- ER criteria exceeds 3.
- Sustained casing pressure (SCP) is present.
- Annular cement placement is required.
- Drilling out plugs is necessary for operations.
- Fulfills all remaining requirements for a medium-low cost well.

High Complexity

- Total Depth or Plugback Total Depth is greater than 16,000 feet.
- Fishing operations are needed to retrieve downhole equipment or obstructions.
- Milling operations are required.
- The well is known to have significant downhole or borehole integrity issues.

6.1.6 Cost Estimation Methodology & Benchmarking

The decommissioning cost estimate per well was developed by determining the well complexity, as described in Section 6.1.5, applying the well abandonment methodology described in Section 6.2, and finally applying service, equipment, and consumable rates to the prognosis. The service, equipment, and consumable item prices were based on the following inputs:

- Equipment spread and personnel rates were gathered from recently completed actual costs incurred for similar operations from POCSR operators. Additionally, equipment spread and personnel rates as well as consumable rates were gathered from service providers.
- An average was taken from the market rates gathered from both the POCSR operators and the service providers. These averages were used as the basis for the estimates.
- As noted in the previous 2020 study, operational efficiency and volume-based discounts may impact day rates for equipment spreads and per use item costs. It is not reasonable to calculate these discounts as part of the study. Therefore, the application of discounts is excluded from the cost models.

6.1.7 Well Count by Category

Based on the established criteria, a total of 694 wells have been categorized into one of five categories noted above. The total well counts of each platform is shown in Table 6-2. Table 6-3 shows the count of well for each category. Category classifications by platform are shown in Appendix D – Well Risk Categorization.



Table 6-2 – Well Count by Platform

Platform	Water Depth (feet)	Wells To P&A	Conductor Removal Only	Total Count
A	188	55	2	57
B	190	53	3	56
C	192	45	3	48
Edith	161	20	9	29
Ellen	265	63	1	64
Eureka	700	50	10	60
Gilda	205	63	0	63
Gina	95	12	0	12
Habitat	290	20	0	20
Harmony	1,198	35	5	40
Henry	173	24	0	24
Heritage	1,075	49	0	49
Hillhouse	190	49	0	49
Hogan	154	23	17	40
Hondo	842	28	0	28
Houchin	163	27	9	36
Irene	242	19	0	19
Total		635	59	694

The well count and complexity classifications in Table 6-3, the platform-level cost build-up in Table 6-5, and the operational durations in Table 6-6 are interdependent. Table 6-3 establishes the total well count of 694 wells in scope and assigns a category based on the criteria defined in Table 6-1. Each category carries an average per-well cost that reflects the underlying spread rates, consumables, and the activity duration shown in Table 6-6. Table 6-5 establishes the platform level cost. Each well on each platform is first classified per Table 6-1, then priced using the corresponding cost per category. A sum of the per well produces the “Well P&A Costs”. Appendix D shows the well counts by category by platform.

Table 6-3 – Well Count by Category

Category	Well Count	Average Cost ¹
High	52	\$959,800
Med	412	\$440,100
Med-Low	87	\$295,300
Low	45	\$241,800
TA -To Surface	39	\$154,100
Conductor Removal Only	59	\$67,900

(1) Includes average Cut and Recover Cost across all conductor lengths



The total cost of cut and recovery operations for conductors varies and is dependent on the total conductor length and water depth. Greater water depth increases the time needed to complete cuts below the mudline and increases the number of required topside conductor cuts for layout and disposal. Table 6-4 below shows the variance in average cost for the cut and recovery driven by conductor length.

Table 6-4 – Cut and Recover Cost per Conductor

Conductor Length	Conductor Count	Average Cost
< 800ft	577	\$69,600
>800ft	117	\$177,400

Table 6-5 below shows the total well P&A cost made up of the well abandonment operation activities and the total cut and recover cost for all conductors. Transportation and disposal of the conductor materials are excluded from these costs but included in Section Eleven - Transportation and Disposal

Table 6-5 – Well Abandonment Cost

Platform	Wells and Conductors to P&A	Average Well Depth (feet)	Well P&A Costs	Well C&R Cost	Well Total P&A Cost
A	57	3,714	\$28,854,900	\$3,801,700.00	\$32,656,600
B	56	3,123	\$20,797,600	\$3,735,000.00	\$24,532,600
C	48	3,337	\$19,305,000	\$3,201,400.00	\$22,506,400
Edith	29	5,371	\$7,795,200	\$1,934,200.00	\$9,729,400
Ellen	64	7,127	\$24,546,800	\$4,474,700.00	\$29,021,500
Eureka	60	6,639	\$19,385,600	\$5,257,900.00	\$24,643,500
Gilda	63	7,855	\$24,585,800	\$4,303,300.00	\$28,889,100
Gina	12	6,474	\$4,412,400	\$761,700.00	\$5,174,100
Habitat	20	11,609	\$5,693,000	\$1,430,500.00	\$7,123,500
Harmony	40	12,908	\$19,040,600	\$7,706,700.00	\$26,747,300
Henry	24	4,142	\$10,130,700	\$1,600,700.00	\$11,731,400
Heritage	49	15,098	\$29,879,500	\$9,083,000.00	\$38,962,500
Hillhouse	49	3,421	\$20,226,700	\$3,268,100.00	\$23,494,800
Hogan	40	5,346	\$8,148,400	\$2,603,400.00	\$10,751,800
Hondo	28	13,064	\$13,881,000	\$4,319,600.00	\$18,200,600
Houchin	36	3,664	\$7,778,900	\$2,578,800.00	\$10,357,700
Irene	19	11,208	\$9,341,500	\$1,453,500.00	\$10,795,000
Total	694		\$273,803,600	\$61,514,200.00	\$335,317,800

All wells on the Harvest, Hermosa, Hidalgo, Gail and Grace platforms are currently reported as permanently abandoned

Table 6-6 below shows the duration of operations used as a main input to the total cost calculation by category.

Table 6-6 – Well Abandonment Duration by Category



Category	Estimated Duration (in days)
High	20.5
Med	7.5
Med-Low	4.5
Low	3.5
TA-To Surface	2.5

6.1.8 Cost Variance

The 2020 study applied a 150% escalation to daily personnel and equipment rates for "High" category wells. Though this application achieves an escalation of cost, this comprehensive rate escalation is technically inconsistent with operational dynamics from a project controls perspective. Equipment day rates (spread costs) are typically fixed by contract or market availability and do not fluctuate based solely on the complexity of a specific wellbore. Additional special equipment may be needed based on the complexity of the well, but this does not constitute a standard 150% escalation.

This study applied an approach that adjusts the operational duration rather than the unit cost. Wellbore complexity—specifically in high-category wells—primarily impacts the time-to-complete, particularly during high-risk interventions such as:

- retrieving lost or stuck equipment,
- clearing obstructions or milling out packers/retainers,
- additional circulations or scraper runs required to ensure a competent bond for regulatory compliance.

By adjusting the activity durations rather than the daily spread cost rate, the cost model more accurately reflects the mechanical risks inherent in Phase I and Phase II operations. The activity durations for specific well abandonment activities have been increased accordingly.

The rig and coiled tubing equipment and personnel spreads are the largest driver of well abandonment costs. Daily equipment spread rates have fluctuated from the 2020 study. Through interviews with service providers and POCSR Operators, the standard rig rate for platform-based rig equipment and personnel has increased from \$15,000 per day to \$20,500 per day. This applied rig rate has been derived from a POCSR operator that has converted idle land-based rigs for use as platform-based rigs. The coiled tubing equipment spread has increased from \$21,600 per day to an average of \$23,750 across all rates gathered for this study.

Consumable items such as cement, cast iron bridge plugs, cement retainers, and setting tools have seen price increases of roughly 22%. Marine gas oil has increased in price by roughly 45% since 2020. Well fluids have also seen increases of roughly 20% since 2020.

Other ancillary rentals and services such as fishing equipment, cement bond logging, and topside cutting services have remained consistent with only roughly 20% increases since 2020.

6.1.9 Variances in Average Well Cost by Category

Conductor Only Removal: This category is most closely related to the Cut and Recover costs defined in the 2020 study. This category is made up of empty conductors or wells that are in TA status with all



required plugs to surface. When comparing the current average cost of this category to the Cut and Recover cost from the 2020 Study, we see an approximate reduction of 43%.

TA-To Surface: This category is a refinement of the TA-Low category from the 2020 study. The previous TA-Low category included both empty conductors and wells that have all necessary plugs installed to just below the mudline and tested according to 30 CFR 250.1715. This designation includes wells that are in TA status but do not have all necessary plugs to the just below the mudline according to the regulations. Therefore, requiring additional well work to be completed including setting additional plugs and testing. This difference describes a roughly 140% increase in cost for a comparable category across study years.

Low Categorization: This category has an average estimated cost decrease of 15%. This is mainly attributed to the increase in service rates.

Medium-Low Categorization: The 12% decrease in average costs can be attributed to adjusted prognosis and increased market rates for services.

Medium Categorization: The average for this category decreased by 2% and can be attributed to the increase in service rates.

High Categorization: This average per well decreased by 4% due to changes in prognosis for key activities such as fishing/milling, and the application of the daily rates for services. As previously described, in the previous study, a standard 150% increase in day rates was applied to all well abandonment activities for high category wells. This has been changed to only increasing the duration of key steps in the well abandonment procedure.

6.1.10 Well Abandonment Procedures

The following is a general well abandonment procedure that outlines the main steps to permanently abandon the well according to 30 CFR Part 250, Subpart Q. This procedure is not prescriptive for all wells in the inventory. Detailed and specific well abandonment procedures are required as a component of the permitting process for each well abandonment. For the purposes of this study, this procedure is the basis for prognosis and total activity duration calculations. Figure 6-1 and Figure 6-2 are representative schematics of the well abandonment procedures described below.

6.1.11 Phase I: Primary Plug & Abandonment (High/medium Risk Wells)

1. Skid workover rig, MU, riser, and BOP stack.
2. Perform function/pressure tests on BOPs.
3. Confirm well is statically dead and monitored.
4. Retrieve rod pumps, ESPs, or PCP equipment.
5. Note: Injection and gas lift completion strings are to remain in situ for Phase II.
6. RIH with workstring and bit/scrapper to the liner top or deepest production interval. Displace wellbore fluid, clean out to PBTD, and perform a casing integrity test (CIT).
7. If necessary, execute fishing or milling operations to clear the wellbore for plug placement
8. Run a Cement Bond Log (CBL) to PBTD to verify existing zonal isolation.
9. Spot a 200' cement plug no more than 100' above top perforations) via displacement.
10. Alternate: If wellbore stability is compromised, Set CR or CIBP and place 200ft cement plug.



11. LD workstring and RDMO workover rig.

6.1.12 Phase II: Secondary Isolation & Casing Recovery

6.1.12.1 A. High/medium Risk Category Wells

1. MIRU CTU and pressure test surface equipment.
2. If SCP (Sustained Casing Pressure) is present or annular cement is deficient, perforate and establish circulation.
3. Pump cement to isolate the annulus and prevent fluid migration to the mudline.
4. Establish circulation
5. POOH with CTU nozzle
6. Set a cement retainer ~75' above the liner top. Squeeze/displace 200' of cement into the annulus/casing per 30 CFR 250.1715. Tag and pressure test.
7. Place additional internal cement plugs (two for High-Category wells) to satisfy 30 CFR 250.1715(a)(4).
8. RIH and Tag TOC and pressure test.
9. RIH with CTU nozzle. Sever production casing 225' BML (Below Mudline). Recover casing using CTU or hydraulic casing jacks.
10. RIH with bit/scrapper to top of casing stub.
11. POOH and lay down scrapper
12. RIH with bridge plug and set 75' above the casing stub in the intermediate string.
13. Cap with a 150' cement plug.
14. Tag and wash top of cement (TOC) to prepare for final Cut & Recover (C&R). Test
15. POOH with CTU and RD

6.1.12.2 B. Medium-low/low Risk Category Wells

1. RU CTU and test.
2. RIH with CTU 50ft above completed interval. Place 200' cement plug via displacement no more than 100' above perforations). Tag and test. POOH
3. RIH with CTU and CTU nozzle 75 feet above the liner top and perforate production tubing.
4. Mix and pump 200-foot internal cement plug (two plugs for a medium-low category well) per 30 CFRs 250.1715(a)(4) and 250.1715(a)(6). Test plug integrity per 30 CFR 250.1715(b). POH with CTU.
5. RIH with CTU nozzle. Sever production casing 225' BML (Below Mudline). Recover casing using CTU or hydraulic casing jacks.
6. RIH with bit/scrapper to top of casing stub.
7. POOH and lay down scrapper



8. RIH with bridge plug and set 75' above the casing stub in the intermediate string.
9. Cap with a 150' cement plug.
10. Tag and wash top of cement (TOC) to prepare for final Cut & Recover (C&R). Test
11. POOH with CTU and RD

6.1.13 Phase III: Conductor Removal & Site Clearance

1. MIRU workover rig and riser or casing jacks. Verify all annuli bleed to zero pressure.
2. Nipple down and remove the surface wellhead assembly.
3. Deploy abrasive casing cutters. Perform a multi-string cut of all casing and conductors at 15' BML per 30 CFR 250.1716.
4. Pull conductor and casing strings. Clean marine growth during retrieval to manage deck weight and cleanliness.
5. Section tubulars using topside cutting equipment into 40' joints.
6. Layout and sea fasten conductor sections on barge or workboat for disposal
7. RD workover rig/casing jacks.

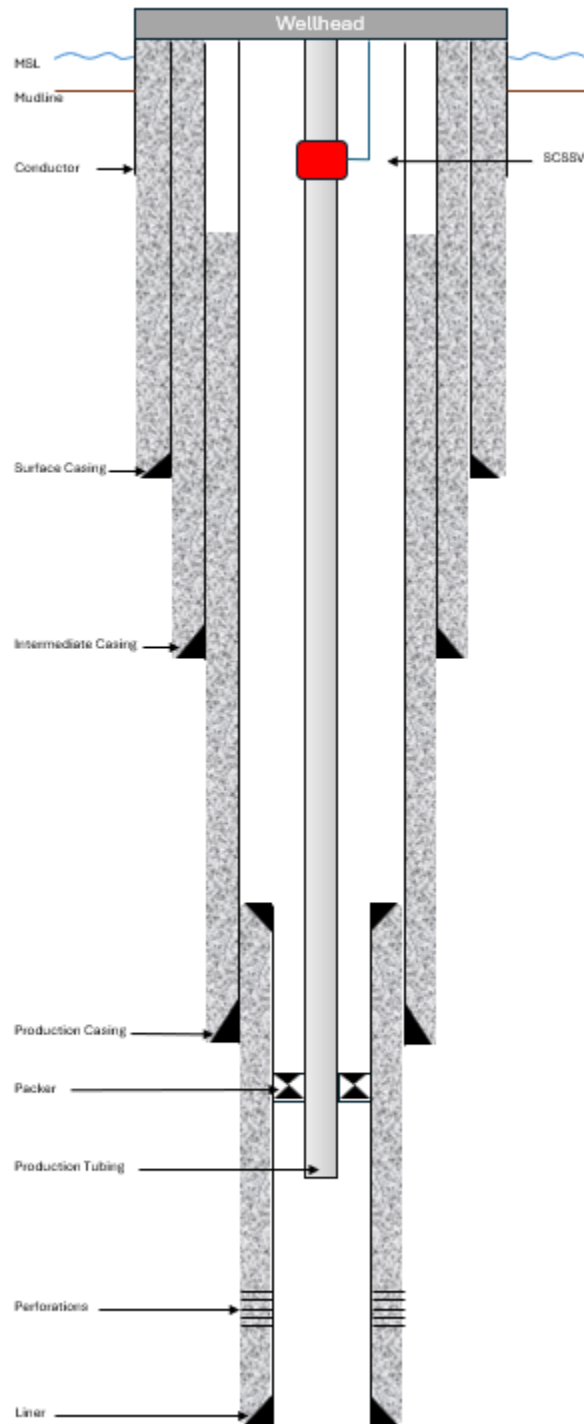


Figure 6-1 – Typical Wellbore Schematic (Current)

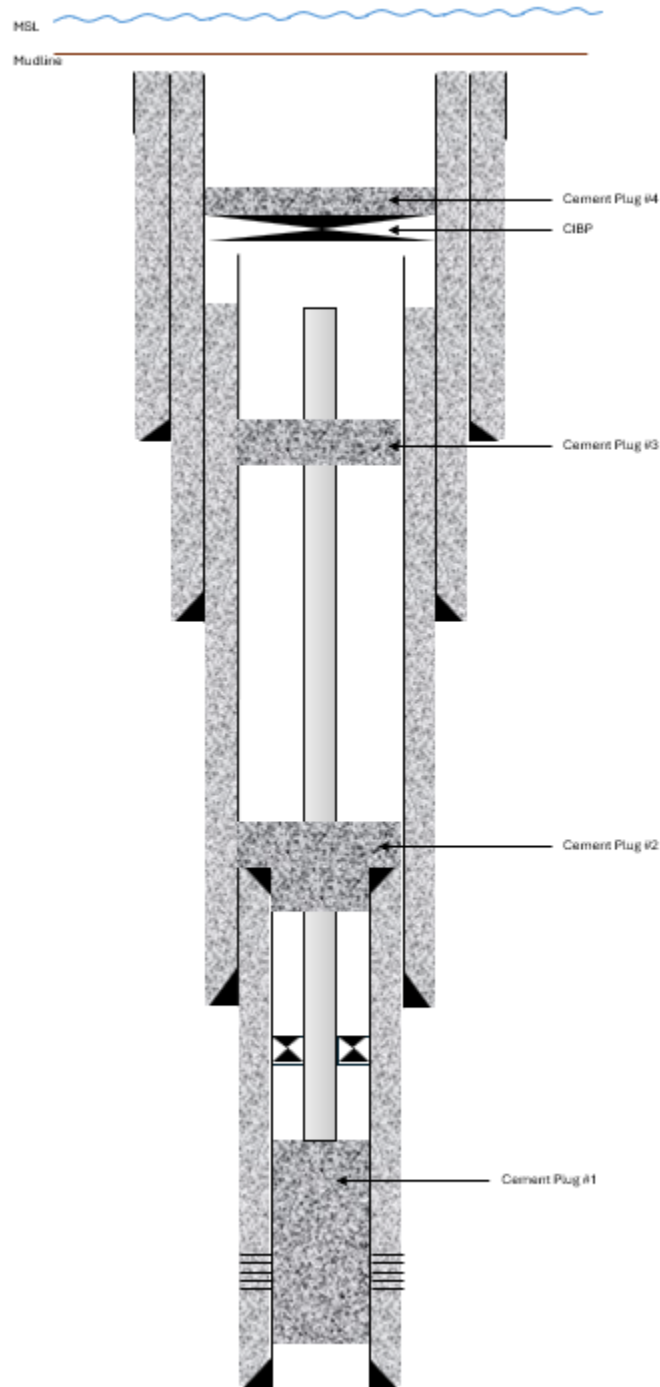


Figure 6-2 – Typical Wellbore Schematic (P&A)

6.1.14 Well Plug and Abandonment Cost Estimate Assumptions

- The subsea well that does not have an assigned API number that was described in the scope of Platform B well abandonments of the 2020 report are excluded at the time of this draft submittal.



- All Permanent Abandonment (P&A) operations were analyzed to be executed in strict accordance with BSEE 30 CFR Part 250, Subpart Q standards to ensure long-term zonal isolation and seafloor clearance.
- A rig will be utilized for high-torque/high-pull operations, including the retrieval of production strings, wellbore clean-out, and the placement of the primary completion plug.
- Post-initial isolation, a standardized rig less spread (CTU and modular pumping units) will be utilized across all assets to set internal and annular/tribute cement plugs, optimizing deck space and operational efficiency.
- All casing and conductor strings will be severed via abrasive waterjet cutting. Cuts will be verified at a minimum of 15 feet below the original mudline (BML) per decommissioning requirements.
- Conductors will undergo external mechanical cleaning/scraping during recovery to mitigate weight discrepancies and environmental transfer.
- Conductors and wellheads will be recovered in 40-foot joints, with a maximum lift weight of 50 short tons to stay within the safe working load of the recovery vessel's crane.
- Wellbore P&A is designated as the critical path activity and must be finalized prior to the commencement of structural topside or jacket decommissioning.



SECTION SEVEN – PIPELINE & POWER CABLE ABANDONMENT

Decommissioning of platforms in the Pacific Outer Continental Shelf Region (POCSR) requires proper disposition of associated pipelines and power cables that facilitate the transfer of hydrocarbons, produced water, utilities, and electricity between offshore facilities and onshore reception points. These systems include both inter-platform connections and export lines routed to shore.

The pipeline inventory utilized in this study is based exclusively on the most current inventory list provided directly by BSEE. That inventory reflects a total of 63 pipelines, with cost estimates herein directly tied to the BSEE-provided inventory and do not assume additional segments beyond those identified in that dataset.

Detailed specifications and assumptions for pipelines and cables evaluated in this study are provided in the appendices of this report.

7.1 REGULATORY FRAMEWORK

Pipeline and power cable decommissioning requirements are outlined in 30 CFR 250.1750–1754, which provide criteria for decommissioning in place versus removal. The Regional Supervisor retains discretion to determine whether a pipeline or cable may be abandoned in place or must be removed, based on whether it constitutes or may become a hazard to navigation, commercial fishing, or the marine environment.

During development of this study, no regulatory requirement was identified that mandates automatic removal of pipelines routed to shore. As such, this study does not assume removal of shore-connected export pipelines as a default condition. However, removal costs for these pipelines and power cables have been independently estimated and are included in Appendix E and Appendix F respectively.

Consistent with federal and state practice, environmental review would accompany any decommissioning project. Coordination with federal and state agencies, including USACE, USCG, and applicable state entities, would occur as required under project-specific permitting.

7.2 PRE-ABANDONMENT PIPELINE AND POWER CABLE SURVEY REQUIREMENTS

Prior to pipeline and power cable abandonment activities in federal waters offshore California, pre-abandonment surveys are required to establish the as-found condition of the assets and to support the proposed abandonment method, whether removal or leave-in-place. These surveys provide the technical basis for regulatory approval and are intended to confirm current asset configuration, seabed interaction, and potential environmental or navigational risks.

The Bureau of Safety and Environmental Enforcement (BSEE) serve as the primary regulatory authority for pipelines and power cables in federal waters, with environmental review and plan consistency oversight provided by the Bureau of Ocean Energy Management (BOEM). Where seabed disturbance or sediment relocation may occur, coordination with the U.S Army Corps of Engineers (USACE) may also be required. While state agencies may have jurisdiction over nearshore or state-water segments, the scope described herein focuses on federal obligations.

At a minimum, pre-abandonment surveys are expected to address three primary objectives: (1) confirmation of asset location and configuration, (2) characterization of seafloor conditions, and (3) assessment of burial or exposure relevant to the proposed abandonment approach.



An as-found route survey is required to confirm the current position of pipelines and power cables. This survey establishes whether historical records remain accurate and identifies features such as free spans, crossings, exposures, and tie-in locations. Typical survey methods include multibeam bathymetry and side-scan sonar and occasionally supplemented by sub-bottom profiling where burial depth is a consideration. These surveys apply to both pipelines and power cables and form the foundational dataset for abandonment planning.

A seafloor condition and debris survey is required to identify seabed features, debris, fishing gear, anchor scars, or other obstructions that may affect abandonment activities or represent post-abandonment hazards. This survey is often conducted concurrently with the as-found route survey using high-resolution side-scan sonar. Where anomalies or areas of concern are identified, targeted inspection using remotely operated vehicles (ROVs) may be performed to further characterize conditions; however, the ROV costs to validate survey characterizations are not included in this study. This study assumes that the seafloor condition and debris survey will also serve as important data for platform removal and site clearance functions mentioned later in this paper.

Pre-abandonment surveys are not intended to include internal inspections, cathodic protection surveys, or post-work verification activities unless specifically justified by asset condition or regulatory request. Rather, the scope is focused on establishing sufficient as-found information to support abandonment method selection, environmental review, and post-abandonment risk evaluation.

Pre-abandonment surveys for pipelines and power cables in federal waters are expected to confirm asset location, characterize seabed conditions, and assess burial or exposure status consistent with the proposed abandonment approach. These surveys provide the technical basis for regulatory approvals and establish baseline conditions against which post-abandonment outcomes may be evaluated.

7.3 FLUSHING AND PIGGING

For pipeline cleaning and flushing operations, this study assumes a coordinated two-vessel execution strategy consisting of a pump vessel and a dedicated catch and separation vessel. This configuration is intended to provide operational flexibility, efficient platform-to-platform mobilization, and controlled fluid management throughout the campaign.

Under this approach, a relatively small push vessel mobilizes to each platform location and establishes connection to the pipeline riser or tube turn. This vessel is responsible for pumping seawater through the pipeline to initiate flushing and displacement of residual hydrocarbons and fluids. Operating in coordination, a second vessel is equipped with containment, temporary storage, and oil-water separation capabilities. The catch vessel receives displaced fluids and manages initial returns, allowing for offshore separation and controlled handling of recovered materials.

This division of functions allows pumping operations to be optimized independently from fluid handling and separation activities. The use of smaller, purpose-specific vessels supports efficient movement between platforms, reduces spread complexity, and maintains continuous workflow during cleaning operations.

For pipelines routed to shore, the methodology incorporates a push-to-shore cleaning strategy. After initial stabilization flushing, a cleaning pig is launched offshore and driven toward the onshore reception facility. The pig serves to displace the majority of remaining seawater within the line, thereby reducing the total volume of water requiring separation, transport, and disposal. By minimizing residual water volumes



through pig displacement, waste handling requirements are reduced while maintaining effective cleaning performance.

At the onshore facility, displaced fluids are received into controlled containment systems where final separation, testing, and disposal occur in accordance with applicable regulatory standards. This integrated offshore pumping, offshore catch and separation, and pig-assisted push-to-shore strategy forms the basis of the pipeline cleaning methodology assumed in this study.

7.4 PIPELINE CUTTING AND RETRIEVAL METHODOLOGY

Pipeline disconnection, cutting, and retrieval activities in this study are assumed to be performed using a DP2 ROV support vessel rather than surface-supplied or saturation diving systems. The use of a dynamically positioned ROV vessel provides precise station-keeping capability without the need for anchor spreads and allows subsea cutting operations to be conducted efficiently across varying water depths.

At each platform location, the ROV will be deployed to access the pipeline at the tube turn and jacket interface. The pipeline will be cut subsea at the appropriate location to allow for full disconnection from the platform structure. Following the initial cut, the ROV will expose and uncover the pipeline on the seafloor as necessary to create sufficient working clearance. A secondary cut will then be performed several feet outboard of the jacket to isolate the removable section. The isolated segment, which includes the tube turn and associated spool, will be rigged subsea and retrieved to the surface for proper handling and disposal.

The removal length is governed by the physical configuration of the tube turn and the requirement to eliminate obstructions at the platform. No specific minimum footage is prescribed by regulation; therefore, the recovered section consists of the tube turn and sufficient adjacent pipeline to allow safe cutting, lifting, and subsequent burial of the remaining pipeline end. The remaining pipeline will then be capped or plugged and buried in accordance with regulatory requirements.

All cutting operations are assumed to be performed using ROV-deployed mechanical or hydraulic cutting tools appropriate for the pipe diameter and wall thickness. Where required, minimal diver intervention may be utilized for verification or contingency purposes; however, the baseline methodology assumes ROV execution.

Because task complexity and operational efficiency are influenced by water depth, this study incorporates a depth-compensation variable within the cost model. Task durations are incrementally increased based on working depth to account for additional ROV deployment time, tool handling time, umbilical management, and reduced operational efficiency at greater depths. This depth-based adjustment is applied consistently across all pipeline cutting and burial activities to reflect realistic offshore execution conditions.

This ROV-based methodology forms the basis for duration and cost assumptions associated with pipeline disconnection and retrieval in this study.

Cost estimates for the abandonment in place of the pipeline inventory is shown in Table 7-1

Table 7-1 – Pipeline Decommissioning Cost

Platform	Segment 1	Segment 2	Segment 3	Segment 4	Segment 5	Total
A	\$537,700.00	\$537,700.00	\$296,700.00	\$306,500.00	\$306,500.00	\$1,985,100.00



Platform	Segment 1	Segment 2	Segment 3	Segment 4	Segment 5	Total
B	\$318,500.00	\$318,500.00	\$361,900.00	\$537,700.00	\$537,700.00	\$2,074,300.00
C	\$306,600.00	\$306,600.00	\$306,600.00	\$309,200.00		\$1,229,000.00
Edith	\$490,500.00					\$490,500.00
Elly	\$656,900.00					\$656,900.00
Eureka	\$545,400.00	\$490,200.00	\$545,500.00	\$574,800.00	\$545,500.00	\$2,701,400.00
Gail	\$552,900.00	\$555,600.00	\$552,300.00			\$1,660,800.00
Gilda	\$515,900.00	\$454,800.00	\$356,300.00			\$1,327,000.00
Gina	\$406,500.00	\$405,200.00				\$811,700.00
Grace	\$653,200.00	\$563,700.00				\$1,216,900.00
Habitat	\$627,900.00					\$627,900.00
Harmony	\$1,342,300.00	\$863,400.00	\$955,300.00	\$1,045,700.00		\$4,206,700.00
Harvest	\$661,000.00	\$593,900.00				\$1,254,900.00
Henry	\$327,700.00	\$346,000.00	\$338,300.00			\$1,012,000.00
Heritage	\$1,497,900.00	\$1,019,100.00				\$2,517,000.00
Hermosa	\$708,300.00	\$1,109,100.00				\$1,817,400.00
Hidalgo	\$831,200.00	\$572,600.00				\$1,403,800.00
Hillhouse	\$318,500.00	\$305,400.00	\$305,400.00	\$318,500.00		\$1,247,800.00
Hogan	\$377,300.00	\$416,400.00	\$377,300.00	\$287,900.00		\$1,458,900.00
Hondo	\$691,700.00					\$691,700.00
Houchin	\$274,900.00	\$312,900.00	\$312,900.00	\$326,600.00		\$1,227,300.00
Irene	\$932,400.00	\$409,800.00	\$409,800.00			\$1,752,000.00
Total						\$33,371,000.00

7.5 POWER CABLE ABANDONMENT

For the purposes of this study, power cable decommissioning is assumed to be executed concurrently with pipeline decommissioning activities using the same DP2 ROV support vessel and general operational framework. Survey, cutting, and burial operations for both pipelines and power cables are integrated within a single subsea campaign to maximize efficiency and minimize repeated mobilization to the same platform locations.

Under this integrated approach, the ROV vessel will perform pre-cut verification and visual survey of both pipelines and power cables at each platform. Where burial has been reduced over time due to sediment migration or marine growth, the ROV will expose the lines as necessary to provide adequate working clearance. Cutting operations for pipelines and power cables will then be sequenced during the same work window while the vessel remains on station.

At the platform interface, power cables will be confirmed de-energized and isolated prior to subsea intervention. The ROV will then cut the cable at the structure, consistent with the same mechanical or hydraulic cutting techniques used for pipeline disconnection. Where required, short sections may be retrieved to the surface to eliminate protrusions and ensure proper isolation of the remaining cable end. Following platform-side disconnection, the ROV will locate the cable at the required termination point, typically near the state–federal boundary demarcation, and perform uncovering, cutting, and burial in the same manner as assumed for pipelines.



Burial of remaining cable ends will be achieved using ROV-deployed jetting or mechanical trenching tools consistent with seabed conditions, targeting a minimum burial depth consistent with regulatory expectations. The objective is to ensure that no portion of the remaining cable presents an obstruction or hazard to other uses of the seafloor.

By performing survey, cutting, and burial of pipelines and power cables within the same campaign and vessel spread, this methodology reduces duplicated vessel time, minimizes repeated site access, and streamlines subsea task sequencing. Duration assumptions for power cable activities are incorporated within the same operational framework as pipelines, including application of the depth-compensation variable that incrementally increases task duration based on working depth. This ensures consistent treatment of subsea efficiency impacts associated with water depth across both pipelines and power cables.

This integrated ROV-based execution model forms the basis for the duration and cost assumptions associated with subsea pipeline and power cable decommissioning in this study.

Table 7-3 – Power Cable Decommissioning Cost

Cable Origin	Cable Terminus	Length (ft)	Depth (ft)	Campaign	Survey Cost	Cut & Bury Cost	Total Cost
Habitat	A	19,536	292-188	1	\$39,000	\$223,000	\$262,000
Hogan	Shore	4,752	150-0	1	\$39,000	\$216,500	\$255,500
Houchin	Hogan	3,800	176-150	1	\$39,000	\$199,200	\$238,200
A	B	2,640	188-200	2	\$46,000	\$202,300	\$248,300
Ellen**							
Elly							
Eureka*	Ellen x 2 cables	2,640	200-193	3	\$46,700	\$509,500	\$556,200
Gail							
Irene	Shore	14,784	242-0	1	\$39,000	\$216,200	\$255,200
Gilda	Shore	36,960	205-0	2	\$38,900	\$194,500	\$233,400
Grace							
C	Shore	26,400	193-0	2	\$38,900	\$241,400	\$280,300
Henry	Shore x 2 cables	13,200	170-189	2	\$46,600	\$655,200	\$701,800
Harvest							
Gina	Shore	1,584	90-0	2	\$38,900	\$209,900	\$248,800
Hillhouse	Shore	17,952	189-0	2	\$38,900	\$709,000	\$747,900
Heritage	Shore	104,544	1075-0	3	\$39,600	\$427,700	\$467,300
Hermosa							
Hidalgo							
Heritage	Harmony	39,072	1075-1200	3	\$39,600	\$427,700	\$467,300
Edith	Shore	36,960	150-0	3	\$39,600	\$191,100	\$230,700
Hondo	Harmony	47,520	842-1200	3	\$39,600	\$636,800	\$676,400
Eureka	Ellen	15,297	700-265	3	\$39,600	\$197,700	\$237,300
Harmony	Shore	59,664	1200-0	3	\$39,600	\$459,700	\$499,300
Total							\$6,605,900

7.6 COMPARISON TO PRIOR COST STUDIES AND BASIS FOR COST DIFFERENTIALS

Pipeline and power cable decommissioning costs were evaluated in prior BSEE-sponsored studies, including the 2016 TSB Offshore update and the 2020 InterAct PMTI update. While the governing regulatory framework remains consistent, the present study reflects several material differences in



removal philosophy, execution methodology, flushing strategy, duration modeling, and inventory basis as applied to both pipelines and subsea power cables. These refinements directly influence the cost comparisons.

A primary distinction between this study and prior assessments is the treatment of shore-connected export pipelines and associated subsea power cables. Earlier studies incorporated removal of certain export segments to provide uniformity across evaluated scenarios. In contrast, the present study does not assume automatic removal of pipelines or power cables routed to shore. Under 30 CFR 250.1750–1754, removal is not prescribed as a default condition; rather, the Regional Supervisor retains discretion to determine whether a pipeline or cable may be abandoned in place or must be removed based on navigational risk, environmental impact, or other site-specific considerations.

No regulatory requirement was identified that mandates complete removal of export pipelines or power cables. Accordingly, removal of shore-connected lines was not embedded in the base-case cost model. However, at BSEE's request the complete removal cost has been estimated and included. This approach is further informed by environmental considerations documented in BSEE's Pacific Outer Continental Shelf Programmatic Environmental Impact Study (PEIS) analysis, which recognizes the ecological sensitivity of West Coast benthic habitats. The Pacific OCS seafloor supports biologically productive hard-bottom communities, complex benthic assemblages, and localized shell mound formations associated with historic operations. Broad mechanical retrieval of pipelines or cables across these environments has the potential to generate greater seafloor disturbance than controlled leave-in-place abandonment with localized burial and stabilization. For that reason, this study aligns the cost basis with a regulatory and environmental framework that evaluates removal on a case-by-case basis rather than presuming universal recovery. This change in methodology represents a meaningful contributor to cost differentials relative to prior studies.

The execution methodology assumed in this study also differs in several important respects. Subsea disconnection, cutting, retrieval of tube turns or cable terminations, and burial preparation activities are based on the use of a modern DP2 ROV support vessel equipped with two onboard work-class ROV systems. This configuration provides precise station-keeping without anchor spreads and supports continuous subsea operations using a primary and secondary ROV system, improving efficiency and reducing non-productive time. Mobilization is conservatively assumed from the Gulf of America, consistent with the availability of high-specification vessels currently operating in that market. However, it is recognized that at least one comparable DP2 asset is presently positioned on the West Coast and could be utilized at similar commercial day rates. As such, the assumed sourcing strategy reflects realistic market flexibility rather than an inflated cost basis.

Earlier assessments relied more heavily on diver-based subsea execution assumptions in certain scenarios. Advances in ROV tooling and cutting systems now allow pipeline and power cable disconnection and burial preparation to be performed efficiently without saturation diving spreads. While ROV-based vessels may carry higher nominal day rates than small diving spreads in shallow water, the elimination of dive support systems, hyperbaric infrastructure, and associated safety contingencies results in a more stable and scalable cost profile across the POCSR water depth range.

In addition to subsea execution changes, this study reflects a refined methodology for pipeline flushing and pigging operations. A coordinated push-and-receive vessel strategy is assumed, utilizing smaller, locally available support vessels for seawater displacement and pig launch operations. Under this approach, a pump vessel mobilizes to each platform location and displaces residual hydrocarbons using seawater, while a dedicated catch vessel equipped with containment and oil-water separation capability



manages returns. This two-vessel configuration supports efficient platform-to-platform transitions and reduces the need for larger, more complex spreads.

For pipelines routed to shore, a pig-assisted push-to-shore methodology is incorporated. Following stabilization flushing offshore, a cleaning pig is launched and driven toward the onshore reception facility to displace remaining fluids. At the shore facility, displaced fluids are received into controlled containment systems where separation, testing, and disposal occur in accordance with regulatory requirements. Unlike prior studies, this model explicitly includes the cost of transporting and disposing of treated water generated during pigging operations. Treated water requiring trucking, testing, or permitted discharge handling represents a measurable cost component. It is not clear from earlier studies whether these downstream handling and disposal costs were fully captured as discrete line items. The present study includes them explicitly to reflect realistic operational obligations associated with onshore receipt and processing.

While power cables do not require pigging operations, similar cost differentiation principles apply to cable disconnection, cutting, retrieval, and burial activities. Cable diameters, armoring, burial condition, and water depth influence handling complexity and task duration in a manner comparable to pipelines. Accordingly, the same DP2 ROV-based execution methodology, depth-compensation modeling, and parameter-based duration scaling have been applied to power cable activities to maintain consistency across subsea asset types.

Task durations within this study are driven primarily by water depth and asset size characteristics. Increased water depth directly affects ROV deployment cycle time, tool handling efficiency, umbilical management, and general subsea productivity. A structured depth-compensation factor is incorporated within the cost model, incrementally increasing duration as water depth increases. This adjustment is applied consistently across cutting, retrieval, and burial activities for both pipelines and power cables. Pipeline outside diameter and wall thickness, as well as power cable diameter and construction, further influence cutting time, stabilization requirements, and handling complexity. Rather than applying uniform durations across all assets, this study scales task time based on these physical characteristics, producing a parameter-driven duration model grounded in realistic offshore execution constraints.

In summary, differences in pipeline and power cable decommissioning costs relative to prior studies are attributable to the elimination of assumed wholesale export line removal, alignment with benthic habitat sensitivity considerations identified in BSEE environmental analyses, adoption of a DP2 dual work-class ROV execution strategy, refinement of flushing methodology using local push-and-receive assets, explicit inclusion of treated water transport and disposal costs, implementation of depth-compensation modeling, parameter-based duration scaling, and use of the updated BSEE inventory. The resulting cost differential reflects refined scope definition and current execution practices rather than arbitrary variance.



SECTION EIGHT – PLATFORM PREPARATION

Following completion of well plugging and abandonment activities, the focus shifts from subsurface risk elimination to surface and structural risk reduction. With all wells permanently secured in accordance with regulatory requirements, the remaining objective is to prepare the platform itself for safe removal.

Prior to any structural removal activities, each platform must be made safe for offshore operations and configured for heavy lift and dismantling. Platform preparation activities are intended to reduce environmental, health, and safety risks while transitioning the facility from a producing asset to a decommissioning asset.

Before structural removal can commence, all stored energy and hazardous fluids and gases within the process flowstream must be removed. All flowlines, separators, and heat exchangers are flushed and pigged to a zero-hydrocarbon condition. Physical blinds are installed on all gas and liquid pathways to prevent migration of residual vapors and to ensure proper LFL and LEL management. Production chemicals including corrosion inhibitors, biocides, and glycols are evacuated from storage and service systems. Non-essential rental or reusable production equipment is removed to reduce structural dead load and simplify subsequent lifting operations.

Each platform will undergo Level 1 inspections in accordance with API RP 2SIM to validate the current condition of primary structural members. Particular attention is given to fatigue-sensitive connections and potential loss of wall thickness that could contribute to structural instability during dynamic loading associated with heavy lift operations or during the interim preservation and maintenance phase.

If hazardous materials are identified, a Hazardous Materials Remediation Plan will be developed to address potential NORM, lead-based coatings, asbestos-containing materials, or other regulated substances. The intent is to ensure that the structure is delivered to the salvage or recycling yard in a compliant condition and to prevent environmental discharge during cutting, transport, and disposal.

Throughout this phase, the platform must be maintained in a safe working condition. Periodic inspections, minor repairs, Level 1 structural reviews, and other preservation activities are conducted as necessary to maintain structural integrity and safe access until removal operations begin. Additional detail regarding preservation and maintenance is provided in Section Nine – Preservation and Maintenance.

8.1 COST ESTIMATION AND BENCHMARKING METHODOLOGY

To determine a per-platform cost for Platform Preparation, a complexity factor was generated by comparing the platforms in the inventory to one another. Platform A was used as the basis for this comparison. The methodology compares the deck weight, leg count, well count, age, and water depth of each platform relative to Platform A. This will provide a relative escalation metric that can be applied to other platforms to determine the estimated duration of platform preparation activities.

Table 8-1 – Platform Preparation Costs

Platform	Complexity	# Days	Initial Prep Costs	Overhead Costs	H2S Support	Total Costs
A	1.00	15	\$276,800	\$117,300	\$-	\$394,100
B	1.02	15	\$281,800	\$119,400	\$-	\$401,200
C	0.90	14	\$249,500	\$105,700	\$-	\$355,200
Edith	2.03	31	\$562,900	\$238,600	\$-	\$801,500
Ellen	2.79	42	\$773,300	\$327,700	\$-	\$1,101,000
Elly	2.17	32	\$599,800	\$254,200	\$-	\$854,000



Platform	Complexity	# Days	Initial Prep Costs	Overhead Costs	H2S Support	Total Costs
Eureka	3.91	59	\$1,081,100	\$458,100	\$-	\$1,539,200
Gail	3.64	55	\$1,007,800	\$427,100	\$150,200	\$1,585,100
Gilda	2.14	32	\$593,000	\$251,300	\$88,400	\$932,700
Gina	0.33	5	\$92,200	\$39,100	\$13,700	\$145,000
Grace	1.94	29	\$536,400	\$227,300	\$79,900	\$843,600
Habitat	1.74	26	\$483,000	\$204,700	\$-	\$687,700
Harmony	4.62	69	\$1,280,000	\$542,400	\$190,700	\$2,013,100
Harvest	4.17	63	\$1,154,700	\$489,300	\$172,100	\$1,816,100
Henry	0.82	12	\$227,800	\$96,500	\$-	\$324,300
Heritage	4.70	71	\$1,301,600	\$551,600	\$193,900	\$2,047,100
Hermosa	3.61	54	\$998,600	\$423,200	\$148,800	\$1,570,600
Hidalgo	3.73	56	\$1,033,000	\$437,800	\$153,900	\$1,624,700
Hillhouse	0.91	14	\$252,700	\$107,100	\$-	\$359,800
Hogan	1.33	20	\$369,200	\$156,500	\$-	\$525,700
Hondo	3.98	60	\$1,101,800	\$466,900	\$164,200	\$1,732,900
Houchin	1.44	22	\$400,000	\$169,500	\$-	\$569,500
Irene	1.34	20	\$371,100	\$157,200	\$55,300	\$583,600
Total						\$22,807,700

The initial preparation costs include tasks to make the platform safe for removal and reduce ongoing costs. These actions include:

1. Flushing all lines and vessels
2. Purging lines of all non-essential fluids and chemicals
3. Sealing all gas pathways with blind flanges
4. Discarding of all waste, residue, trash and scrap
5. Shutting down and LO/TO all non-essential systems.
6. Conduct crane inspections and repairs, where applicable.
7. Conduct a Level 1 inspection of the platform
8. Perform Hazardous Materials Inspection and Remediation Plan

Overhead costs encompass various disciplines needed to support the platform preparation activities including transportation and logistics for personnel and equipment as well as maintenance supplies for operations.

8.1.1 Estimating Assumptions

- The platform preparation crews will be housed onshore and will have daily transport to and from location.
- Three platforms will undertake preparation activities concurrently and therefore, overhead costs will be divided across the three platforms.
- H2S will be continually monitored during operations on site according to HSE standards.



8.1.2 H2S Support Cost Inclusion

As shown in Table 8-1, eleven platforms include the cost of H2S monitoring and safety equipment within their total platform preparation price, while twelve platforms do not. These costs were excluded for platforms that have not reported H2S concentrations exceeding the reportable threshold of >100 ppm, based on information from Table 1.1 (p. 3) of the 2009 study *Hydrogen Sulfide Gas Dispersion Potentials & Release Scenarios for Pacific OCS Region Oil & Gas Platforms & Pipelines Located in the Santa Barbara Channel and Santa Maria Basin, California*. Regardless of reported concentrations, H2S risk mitigation measures should be implemented at all times in accordance with applicable safety standards and regulations.



SECTION NINE – PRESERVATION AND MAINTENANCE

The timeframe between cessation of operations and the removal of the topsides and jacket of the platform may take several years. Therefore, a Preservation and Maintenance program is standard practice in decommissioning lifecycles. This program is split into four main phases:

- Phase One: Continued monitoring of wells that are shut-in but are not permanently abandoned.
- Phase Two: Begins after wells are temporarily abandoned and are no longer produced. During this phase the well conductors may remain in place or may have been previously removed. This phase includes the removal of reusable equipment and initial underwater inspections of the jacket sections in the splash zone.
- Phase Three: A continual, longer-term effort to ensure the topside and jacket remain in a condition suitable for removal.
- Phase Four: The removal of marine growth and preparation for topside and jacket removal.

9.1 PHASE ONE - PRESERVATION AND MAINTENANCE

The Pacific OCS Region currently has multiple platforms and associated well that are shut-in and pending final well abandonment operations. Federal regulations require active monitoring and reporting programs for all wells until plugging and abandonment (P&A) is complete. The following outlines the specific federal requirements that drive those monitoring obligations of wells that are shut-in, temporarily abandoned, and pending final P&A operations.

9.1.1 Introduction

These monitoring requirements apply to all wells within the POCSR that are in one or more of the following categories:

- Shut-in wells (mechanical shut-in, regulatory shut-in, or market shut-in)
- Temporarily abandoned wells (TA status per 30 CFR Part 250, Subpart Q)
- Wells undergoing decommissioning preparation, including wells awaiting plug and abandonment (P&A) operations

The monitoring and reporting obligations described are mandatory under applicable federal regulations and BSEE guidance documents. OCS oil and gas well operations—including monitoring and reporting requirements for inactive, shut-in, and decommissioning-phase wells—are governed by the Outer Continental Shelf Lands Act (OCSLA), 43 U.S.C. 1331 and implemented through regulations by BSEE under Title 30 of the Code of Federal Regulations (CFR), Part 250. The primary regulatory provisions applicable to monthly well monitoring and reporting are summarized in Table 9-1 below.

Table 9-1 – Applicable Federal Regulations and BSEE Guidance Documents

Regulation / Citation	Title / Subject	Key Requirement
30 CFR 250.1 et seq.	OCS Oil and Gas Operations – General	Establishes BSEE authority over all OCS oil and gas operations, including well safety, monitoring, and decommissioning.
30 CFR 250.188–250.190	Incident Reporting Requirements	Requires immediate and periodic reporting of incidents, including anomalies in well pressure or integrity.



Regulation / Citation	Title / Subject	Key Requirement
30 CFR Part 250, Subpart G (250.700–250.803)	Well Operations and Equipment	Requires operators to secure wells, maintain BOP equipment, conduct visual inspections, and implement real-time monitoring plans (§ 250.724).
30 CFR 250.720	Well Security / Securing a Well	Requires specific procedures when a well is temporarily abandoned or shut-in, including installation and monitoring of approved barriers.
30 CFR 250.724	Real-Time Monitoring Requirements	Operators must develop and implement a real-time monitoring plan; data must be available to BSEE upon request.
30 CFR Part 250, Subpart H (250.800–250.803)	Oil and Gas Production Safety Systems	Governs testing, inspection, and monitoring of production safety systems including subsurface safety valves (SSSVs) and surface safety systems.
30 CFR 250.880	Production Safety System Testing	Requires testing at specified intervals per API RP 14C, Appendix D; records must be maintained and available for BSEE inspection.
30 CFR Part 250, Subpart K (250.1100–250.1170)	Oil and Gas Production Requirements	Operators must submit monthly well test reports detailing daily fluid volumes.
30 CFR Part 250, Subpart Q (250.1700–250.1754)	Decommissioning Activities	Governs all decommissioning obligations; § 250.1708 requires operators who receive a decommissioning order to begin maintaining and monitoring all facilities within 30 days.
30 CFR 250.1708	Decommissioning Orders – Maintenance and Monitoring	Upon receipt of a BSEE decommissioning order, operators must commence monitoring of wells within 30 days; a decommissioning plan must be submitted within 150 days.
NTL 2018-G03	Idle Iron Decommissioning Guidance	BSEE guidance on monitoring, inspection, and reporting obligations for idle iron (shut-in, temporarily abandoned, and decommissioning-phase wells and structures).
43 U.S.C. 1331 et seq. (OC SLA)	Outer Continental Shelf Lands Act	Primary statutory authority for federal oversight of OCS oil and gas operations; mandates environmental protection and safe operations.

To satisfy these regulatory obligations in the event that an operator is unable to maintain a structured monthly well monitoring program. This section describes the specific monitoring activities, data collection requirements, and reporting deliverables that were used as the basis for the cost estimate of this phase.

9.1.2 Monitoring Activities and Schedule

The monthly monitoring program includes the activities set forth in Table 9-2. Each activity is mapped to its regulatory requirement, the required frequency, and the associated deliverable or record. These activities apply to each individual well subject to the monitoring program. Monthly monitoring of wellhead pressure is required to assess the integrity of primary and secondary well barriers. Pressure readings must be taken at tubing, annulus (A, B, and C annuli as applicable), and surface casing locations. Readings must be compared against baseline values established during the well's initial shut-in or temporary abandonment. Pressure monitoring logs must be maintained as part of the well's permanent records file. Electronic monitoring systems may be used in lieu of manual gauging, provided the system is calibrated and maintains a continuous electronic log accessible. Function tests (open/closed position, pressure integrity) of the SSSV at the intervals shown in Table 9-2. Surface wellhead equipment,



including the Christmas tree (where installed), must be visually inspected monthly. Inspection activities must include, at a minimum:

- Assessment of all valve stem conditions and packing integrity
- Verification of pressure gauge operability and calibration
- Visual inspection for corrosion, coating degradation, or evidence of seepage or release
- Confirmation that all cap and plug connections are in place and properly torqued
- Documentation of the physical condition of the wellhead in the monthly inspection log

Monthly inspections are to be conducted during scheduled platform visits. Photographs of the wellhead condition is recommended and must be retained for a minimum of three years or for the duration of the well's decommissioning program.

Table 9-2 – Monthly Well Monitoring Activities and Regulatory Requirements

Monitoring Activity	Regulatory Basis	Frequency	Deliverable / Record
Well pressure integrity check (annulus/tubing/casing pressure readings)	30 CFR § 250.720; NTL 2018-G03	Monthly	Pressure monitoring log; anomalies reported per § 250.188
Subsurface safety valve (SSSV) function test and status verification	30 CFR § 250.880; Subpart H	Monthly / Semi-annually	SSSV test record; submitted to BSEE upon request
Surface wellhead and Christmas tree visual inspection	30 CFR § 250.724; Subpart G	Monthly	Inspection report; photograph log maintained onsite
Well barrier integrity assessment (primary and secondary barriers)	30 CFR § 250.720; Subpart Q	Monthly	Barrier status report included in monthly well status submittal
Chemical injection / corrosion inhibitor monitoring (where applicable)	30 CFR § 250.880; NTL 2018-G03	Monthly	Chemical injection log; corrosion survey records
Monthly Well Status Report preparation and submittal to BSEE	30 CFR Part 250, Subpart K; § 250.188	Monthly	BSEE-0133 / BSEE-0134 forms or equivalent; submitted to District Manager
Wellhead leak detection and spill response readiness check	30 CFR § 250.188; OCSLA § 1331	Monthly	Spill prevention/containment checklist; maintained in operations file
Idle Iron status review and BSEE compliance status update	NTL 2018-G03; 30 CFR § 250.1708	Monthly	Idle Iron status update submitted to BSEE; integrated into POCSR decommissioning schedule



9.1.3 Cost Methodology

The cost estimate for the monthly well monitoring and reporting program is developed on a per-well, per-month basis and scaled to the total number of wells subject to the program in the POCSR. This section describes the cost methodology and key assumptions underpinning the estimate. Estimated monthly monitoring costs are organized into the following primary cost categories:

- Labor – Engineering and Technical
 - This category captures the engineering and technical labor required to review pressure monitoring data, analyze SSSV test results, and prepare and certify the Monthly Well Status Report.
- Labor – Field Operations and Inspection
 - Field personnel required to conduct physical wellhead inspections and collect pressure monitoring data
- Travel and Mobilization
 - Transportation to and from the platform (helicopter or crew boat, as applicable), per diem for offshore operations, and any equipment mobilization required to support monitoring activities.
- Equipment and Instrumentation
 - Monitoring instruments, calibration services, and consumable items (e.g., pressure gauges, calibration equipment, photographic documentation equipment).
- Administration and Reporting
 - Document management, electronic submission fees (where applicable), records retention, and the cost of maintaining the BSEE-required well records file.

Table 9-3 below shows a summary of the estimated cost for monitoring and reporting over a 60-month period by platform.

Table 9-3 – Preservation and Maintenance Phase One Costs

Platform	Wells	Months	Per Well Per Month Cost	Total Phase One
A	55	60	\$4,900	\$16,170,000
B	52	60	\$4,900	\$15,288,000
C	45	60	\$4,900	\$13,230,000
Edith	18	60	\$4,900	\$5,292,000
Ellen	60	60	\$4,900	\$17,640,000
Eureka	48	60	\$4,900	\$14,112,000
Gail	0	60	\$4,900	-
Gilda	59	60	\$4,900	\$17,346,000
Gina	12	60	\$4,900	\$3,528,000
Grace	0	60	\$4,900	-
Habitat	6	60	\$4,900	\$1,764,000
Harmony	35	60	\$4,900	\$10,290,000
Harvest	0	60	\$4,900	-
Henry	23	60	\$4,900	\$6,762,000
Heritage	49	60	\$4,900	\$14,406,000
Hermosa	0	60	\$4,900	-



Platform	Wells	Months	Per Well Per Month Cost	Total Phase One
Hidalgo	0	60	\$4,900	-
Hillhouse	48	60	\$4,900	\$14,112,000
Hogan	17	60	\$4,900	\$4,998,000
Hondo	28	60	\$4,900	\$8,232,000
Houchin	20	60	\$4,900	\$5,880,000
Irene	19	60	\$4,900	\$5,586,000
Total				\$174,636,000

9.1.4 Cost Estimate Basis and Assumptions

The following key assumptions form the basis of the monthly well monitoring cost estimate:

- Estimates are developed as a per-well, per-month unit cost and are intended to be applied across the full population of POCSR wells subject to the monitoring program. The per activity cost may vary depending on the number of wells subject to monitoring at any given time.
- Helicopter access is assumed for all offshore platform visits; crew boat access may be substituted where platform water depth and vessel availability permit at lower cost.
- The estimate assumes one physical platform visit per well per month for field inspection activities.
- Subsurface safety valve (SSSV) function tests are assumed to be conducted semi-annually as required by API RP 14C; the monthly estimate includes a pro-rated allocation for the semi-annual test cost.

9.2 PHASE TWO – EQUIPMENT REMOVAL AND INSPECTIONS

Following cessation of production and completion of well plugging and abandonment activities, the platform enters the Preservation and Maintenance phase. The objective during this period is to maintain the facility in a safe and stable condition pending final removal, while reducing unnecessary structural loading and identifying any degradation that could impact future lift operations.

The first phase of Preservation and Maintenance includes the removal of reusable and non-essential equipment to reduce topside dead load and eliminate loose or unsecured materials. Concurrently, initial underwater inspections of the jacket, with emphasis on splash zone members and critical load-bearing components, are conducted to establish a structural baseline condition. These inspections are intended to identify corrosion, coating failure, fatigue cracking, or section loss that may require monitoring or interim repair prior to heavy lift execution.

Because the effort required for Phase Two activities varies significantly depending on platform size, configuration, age, and environmental exposure, a relative complexity metric was developed to estimate duration and cost across the inventory. The complexity factor was generated by comparing the platforms in the inventory to one another. This provides a relative metric that can be applied to determine the estimated duration of Phase Two activities.

9.2.1 Phase Two Cost Estimation and Benchmarking Methodology

The complexity factor described above establishes the relative duration of Phase Two activities for each platform. The following methodology translates that relative duration into estimated cost components associated with equipment removal and underwater inspection services.



The removal of reusable production equipment is estimated based on review of platform configuration, historical operating details, and industry experience with similar facilities. For purposes of this study, a scale metric was applied to a standard labor and crane utilization rate to account for cutting free, rigging, lifting, placing, and securing reusable equipment using the platform’s installed crane capacity. The assigned rate reflects typical offshore labor productivity and assumes no specialized access or structural constraints.

Underwater inspections of the jackets are critical during this initial phase to establish a structural baseline for comparison throughout the Preservation and Maintenance period. Inspection costs are based on current market rates for ROV-based subsea inspection services applicable to Pacific OCS water depths. Since the 2020 study, underwater inspection rates have increased by approximately 38%, and this escalation has been incorporated into the Phase Two cost estimate.

Table 9-4 – Preservation and Maintenance Phase Two Costs

Platform	Complexity Factor	Topside Weight (Tons)	Underwater Inspection Cost	Removal of Reusable Equipment Cost	Total Topside Work Time (Days)	Total Phase Two
A	1	1,357	\$36,500	\$750,000	19	\$786,500
B	1	1,357	\$36,500	\$750,000	19	\$786,500
C	1	1,357	\$36,500	\$750,000	18	\$786,500
Edith	1	4,134	\$37,300	\$450,000	43	\$487,300
Ellen	1	5,300	\$53,200	\$500,000	58	\$553,200
Elly	1	4,700	\$53,200	\$750,000	47	\$803,200
Eureka	2	8,000	\$53,200	\$500,000	83	\$553,200
Gail	2	7,693	\$49,300	\$1,000,000	78	\$1,049,300
Gilda	1	3,792	\$57,100	\$450,000	44	\$507,100
Gina	1	447	\$38,700	\$300,000	7	\$338,700
Grace	1	3,800	\$49,300	\$750,000	40	\$799,300
Habitat	1	3,514	\$57,100	\$450,000	37	\$507,100
Harmony	2	9,839	\$57,100	\$1,400,000	99	\$1,457,100
Harvest	2	9,024	\$49,300	\$1,400,000	90	\$1,449,300
Henry	1	1,371	\$36,500	\$750,000	16	\$786,500
Heritage	2	9,826	\$57,100	\$1,400,000	100	\$1,457,100
Hermosa	2	7,830	\$49,300	\$1,400,000	78	\$1,449,300
Hidalgo	2	8,100	\$49,300	\$1,400,000	80	\$1,449,300
Hillhouse	1	1,200	\$36,500	\$750,000	17	\$786,500
Hogan	1	2,259	\$41,400	\$750,000	27	\$791,400
Hondo	2	8,450	\$57,100	\$1,400,000	85	\$1,457,100
Houchin	1	2,591	\$41,400	\$750,000	29	\$791,400
Irene	1	2,500	\$49,300	\$1,050,000	28	\$1,099,300
Total						\$20,932,200



9.3 PHASE THREE – MONITORING AND MANAGEMENT

Phase Two of the Preservation and Maintenance program consists of long-term monitoring and condition management of the platform until final removal activities commence. During this period, the platform remains in a non-producing but structurally-reliable maintained state, requiring routine inspections and limited system support to ensure continued safety and regulatory compliance.

For purposes of this study, the Phase Three duration is assumed to be 60 months and includes monthly safety inspections of the platform structure and topside areas, as well as maintenance of a safety monitoring equipment package.

It is assumed that platform power cables will have been removed or de-energized as part of earlier decommissioning activities. Accordingly, permanent power is not available during the preservation period. To maintain required navigation lighting and safety aids, solar panel systems with battery storage are assumed to be installed to provide autonomous power to navigation lights and associated safety monitoring equipment for the duration of the maintenance program.

9.3.1 Cost Estimation and Benchmarking Methodology

The cost of the long-term maintenance program was estimated using a size-based scaling factor to determine inspection duration and crew size requirements for each platform. The same relative comparison methodology described in Phase Two was applied to account for differences in deck area, structural configuration, and platform complexity.

The 60-month preservation timeframe reflects typical industry experience between cessation of production and structural removal in comparable offshore decommissioning programs. This duration captures the realistic interval required for permitting, marine contracting, heavy lift scheduling, and regulatory coordination prior to removal execution. Actual durations may vary depending on campaign sequencing and regulatory timing; however, 60 months provides a reasonable and defensible basis for estimating purposes.

Table 9-5 – Preservation and Maintenance Phase Three Costs

Platform	Platform Size Factor	Basic Safety Spread	Monitoring Equipment	Monthly Safety Spread Inspection	Months in P&M Mode	Total Inspections	Total Phase Three
A	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
B	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
C	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Edith	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Ellen	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Elly	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Eureka	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Gail	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Gilda	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Gina	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Grace	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Habitat	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500



Platform	Platform Size Factor	Basic Safety Spread	Monitoring Equipment	Monthly Safety Spread Inspection	Months in P&M Mode	Total Inspections	Total Phase Three
Harmony	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Harvest	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Henry	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Heritage	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Hermosa	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Hidalgo	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Hillhouse	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Hogan	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Hondo	2	\$50,000	\$168,000	\$8,350	60	\$501,000	\$719,000
Houchin	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Irene	1	\$25,000	\$84,000	\$4,175	60	\$250,500	\$359,500
Total							\$11,144,500

9.4 PHASE FOUR – MARINE GROWTH REMOVAL PRIOR TO STRUCTURE REMOVAL

Phase Four of the Preservation and Maintenance program occurs immediately prior to platform removal activities. This phase consists of removing marine growth that has accumulated on the jacket structure during the long-term preservation period described in Phase Three.

Marine growth removal at this stage serves multiple purposes. Accumulated biological material creates measurable additional mass to the structure, particularly within the upper water column and splash zone. Removal reduces total lift weight, improves predictability of lift loads, and reduces dynamic and hydrodynamic loading during extraction. Cleaning also mitigates uncontrolled discharge during jacket lifting and transport.

In addition, prior decommissioning activities in Southern California demonstrated that jackets transported to local recycling facilities with intact marine growth can generate odor-related public complaints during offloading and processing. Decaying biological material, once exposed to air, can create nuisance conditions at port facilities. Performing marine growth mitigation offshore and immediately prior to lift operations reduces both environmental discharge during removal and the potential for material handling impacts at receiving facilities.

The Pacific OCS Decommissioning Programmatic Environmental Impact Statement (PEIS) identifies offshore marine growth removal as resulting in localized and temporary water quality and benthic effects when conducted under appropriate regulatory controls. Timing this activity immediately before lift operations limits re-accumulation during the preservation period and ensures impacts remain short-term and controlled.

For purposes of this study, the scope of Phase Four is limited to marine growth removal within the upper 100 feet of water depth, where biological accumulation is most significant and where lift-induced discharge would be most likely to occur.



9.4.1 Cost Estimation and Benchmarking Methodology

Marine growth removal is assumed to be performed using high-pressure water blasting systems, with divers deployed from a DP2-class diving support vessel. Operations are limited to the first 100 feet of jacket depth.

To estimate the cost of Phase Four activities, a marine growth cleaning factor was developed to estimate the volume of marine growth to be removed for each platform. The volume of marine growth drives the duration of removal operations. The marine growth cleaning factor is the same metric used for underwater inspections in Phase Three and is driven by the platform jacket configuration, leg count, bracing density, and structural footprint within the upper 100 feet of water.

As a baseline assumption, smaller jackets, such as Platform A, require approximately 20 days of marine growth removal operations to clean the upper 100 feet. Larger or more complex jackets are scaled proportionally based on relative structural size and configuration. Table 9-6 summarizes the Preservation and Maintenance costs for Phase Four.

Table 9-6 – Preservation and Maintenance Phase Four Costs

Platform	Marine Growth Removal Spread Day Rate	Marine Growth Cleaning Factor (Structure)	Marine Growth Removal Days	Total Phase Four
A	\$77,000	1	20	\$1,540,000
B	\$77,000	1	20	\$1,540,000
C	\$77,000	1	20	\$1,540,000
Edith	\$77,000	1	20	\$1,540,000
Ellen	\$77,000	1	20	\$1,540,000
Elly	\$77,000	1	20	\$1,540,000
Eureka	\$77,000	2	40	\$3,080,000
Gail	\$77,000	2	40	\$3,080,000
Gilda	\$77,000	1	20	\$1,540,000
Gina	\$77,000	1	20	\$1,540,000
Grace	\$77,000	1	20	\$1,540,000
Habitat	\$77,000	1	20	\$1,540,000
Harmony	\$77,000	2	40	\$3,080,000
Harvest	\$77,000	2	40	\$3,080,000
Henry	\$77,000	1	20	\$1,540,000
Heritage	\$77,000	2	40	\$3,080,000
Hermosa	\$77,000	2	40	\$3,080,000
Hidalgo	\$77,000	2	40	\$3,080,000
Hillhouse	\$77,000	1	20	\$1,540,000
Hogan	\$77,000	1	20	\$1,540,000
Hondo	\$77,000	2	40	\$3,080,000
Houchin	\$77,000	1	20	\$1,540,000
Irene	\$77,000	1	20	\$1,540,000
Total				\$47,740,000



9.5 PRESERVATION AND MAINTENANCE SUMMARY

The four phases of Preservation and Maintenance span multiple years and the transition from production to decommissioning periods in the lifecycle of the platform assets. The total combined costs of all four phases are shown in Table 9-7.

Table 9-7 – Total Preservation and Maintenance Costs

Platform	Phase One	Phase Two	Phase 3	Phase 4	Total
A	\$16,170,000	\$786,500	\$359,500	\$1,540,000	\$18,856,000
B	\$15,288,000	\$786,500	\$359,500	\$1,540,000	\$17,974,000
C	\$13,230,000	\$786,500	\$359,500	\$1,540,000	\$15,916,000
Edith	\$5,292,000	\$487,300	\$359,500	\$1,540,000	\$7,678,800
Ellen	\$17,640,000	\$553,200	\$359,500	\$1,540,000	\$20,092,700
Elly	-	\$803,200	\$359,500	\$1,540,000	\$2,702,700
Eureka	\$14,112,000	\$553,200	\$719,000	\$3,080,000	\$18,464,200
Gail	-	\$1,049,300	\$719,000	\$3,080,000	\$4,848,300
Gilda	\$17,346,000	\$507,100	\$359,500	\$1,540,000	\$19,752,600
Gina	\$3,528,000	\$338,700	\$359,500	\$1,540,000	\$5,766,200
Grace	-	\$799,300	\$359,500	\$1,540,000	\$2,698,800
Habitat	\$1,764,000	\$507,100	\$359,500	\$1,540,000	\$4,170,600
Harmony	\$10,290,000	\$1,457,100	\$719,000	\$3,080,000	\$15,546,100
Harvest	-	\$1,449,300	\$719,000	\$3,080,000	\$5,248,300
Henry	\$6,762,000	\$786,500	\$359,500	\$1,540,000	\$9,448,000
Heritage	\$14,406,000	\$1,457,100	\$719,000	\$3,080,000	\$19,662,100
Hermosa	-	\$1,449,300	\$719,000	\$3,080,000	\$5,248,300
Hidalgo	-	\$1,449,300	\$719,000	\$3,080,000	\$5,248,300
Hillhouse	\$14,112,000	\$786,500	\$359,500	\$1,540,000	\$16,798,000
Hogan	\$4,998,000	\$791,400	\$359,500	\$1,540,000	\$7,688,900
Hondo	\$8,232,000	\$1,457,100	\$719,000	\$3,080,000	\$13,488,100
Houchin	\$5,880,000	\$791,400	\$359,500	\$1,540,000	\$8,570,900
Irene	\$5,586,000	\$1,099,300	\$359,500	\$1,540,000	\$8,584,800
Total	\$174,636,000	\$20,932,200	\$11,144,500	\$47,740,000	\$254,452,700



SECTION TEN – PLATFORM & STRUCTURE REMOVAL

10.1 INTRODUCTION

Following completion of well plugging and abandonment, pipeline & power cable abandonment, platform preparation, and preservation and maintenance activities, the platforms are assumed to be structurally prepared for final dismantling. At this stage, the remaining work shifts from stabilization and monitoring to controlled structural separation, lifting, transportation, and final disposition.

This section presents the 2025 evaluation of platform and jacket removal and disposal for facilities located within the Pacific Outer Continental Shelf Region (POCSR). The analysis builds upon the campaign structure, removal methodologies, and cost frameworks developed in the 2016 and 2020 decommissioning cost studies, incorporating updated market intelligence, revised logistics assumptions, and current disposal infrastructure conditions.

The 2025 update reflects a refinement in how governing system constraints are framed. While prior studies evaluated removal execution primarily in terms of heavy lift vessel capability, mobilization assumptions, and marine transportation logistics, the present evaluation places greater emphasis on confirmed downstream processing capacity. Scrap processing throughput is therefore treated as a pacing consideration within the integrated removal system, and offshore execution assumptions are aligned accordingly.

10.2 REGULATORY COMPLIANCE AND SCOPE

Decommissioning operations within the POCSR are governed by 30 CFR 250.1725–1731. All platforms and associated facilities are assumed to be severed and cleared to a depth of 15 feet below the mud line (BML) in accordance with federal requirements.

For purposes of this study, full removal to 15 feet BML is assumed for all jackets, piles, and conductors, and topsides are assumed to be completely removed. Pipelines and cables are addressed separately. No credit is taken for salvage value, and no reduction in scope is assumed based on potential reefing or partial jacket retention unless explicitly stated. Engineering data, including jacket weights, and site-specific parameters, are provided in Appendix B - Platform Removal Weights.

10.3 REMOVAL STRATEGY

10.3.1 Governing Constraint: Scrap Processing Throughput

Transporting all material to Gulf of America (GoA) facilities is technically feasible. However, doing so would require extended ocean transit, repeated Panama Canal passage, long barge cycle durations, and sustained tug support over multi-week voyages. These factors increase logistical complexity and introduce greater schedule sensitivity within the entire program.

In the 2016 study, material disposition was largely modeled through the Ports of Los Angeles (POLA) and Long Beach (POLB). While these ports offer significant marine infrastructure, confirmed long-term scrap dismantling throughput specific to large offshore structures has not been demonstrated at the scale required for a full POCSR decommissioning campaign. The 2025 evaluation therefore does not assume POLA/POLB as primary high-volume dismantling facilities absent verified processing capacity aligned with campaign tonnage.



On the West Coast, Infraestructura y Servicios Portuarios at the Port of Ensenada, Mexico (POEM) is the only identified facility capable of supporting large-scale offshore structure dismantling with a dedicated processing footprint. Modeled throughput is approximately 35,000 tons per year, contingent upon completion of a planned facility upgrade. Without that upgrade, effective intake capacity would be materially reduced.

The 2025 evaluation therefore assumes POEM as the primary disposal location, with annual intake limited to approximately 35,000 tons. Material exceeding this threshold during higher-volume campaigns is diverted to established GoA facilities, where processing capacity is not similarly throughput-constrained.

This framework differs from prior studies, which evaluated Gulf Coast disposal as the default pathway (2020) or local port processing at scale (2016). The present evaluation instead treats confirmed West Coast processing capacity as the pacing element within the integrated system, with Gulf facilities serving as supplemental capacity.

Disposal capacity does not constrain execution capability; it governs the rate at which campaigns can advance. Offshore removal assumptions are aligned with confirmed intake capacity, and higher-tonnage campaigns incorporate planned supplemental diversion where required.

10.3.2 Alignment of HLV Capacity with Disposal Capacity

The disposal framework described above directly informs heavy lift vessel selection and marine spread sizing. Because POEM functions as the primary processing facility within a defined annual intake capacity, offshore lift capability must be evaluated relative to downstream throughput.

In earlier studies, vessel selection was primarily informed by lift capacity, reach, and mobilization considerations. The 2020 evaluation also modeled concurrent removal spreads requiring multiple barges and tug assets operating simultaneously. Based on current West Coast marine market conditions, sustained deployment of multiple heavy transport barges and dedicated ocean-class tugs for overlapping campaigns would likely exceed available regional capacity or introduce significant rate escalation risk.

As part of the 2025 evaluation, scenarios incorporating increased lifting capacity and expanded marine spreads were modeled for cost and schedule sensitivity. These scenarios assumed higher-capacity heavy lift vessels and accelerated offshore execution rates. While technically feasible, the resulting concentration of delivered tonnage exceeded modeled West Coast intake capacity and increased reliance on long-haul diversion to Gulf facilities. When evaluated on a system-wide basis, including marine transport duration, barge cycle time, tug demand, and downstream processing limits, the accelerated removal scenarios did not demonstrate program economics improvement or logistical efficiency.

Although higher-capacity lift options were evaluated, the integrated cost and feasibility analysis ultimately supported continued use of the same class of heavy lift vessel identified in the 2016 and 2020 studies. The selected vessel class provides sufficient lift capacity for Pacific OCS jackets while maintaining compatibility with modeled disposal throughput and sustainable marine asset deployment.

Accordingly, vessel selection and transport logistics are approached as a system-level optimization. Offshore removal capability is balanced with confirmed processing capacity and realistic marine market availability to maintain controlled material flow, avoid episodic surges in delivery volume, and preserve technically sound execution practices.



10.4 CAMPAIGN STRUCTURE

The 2025 decommissioning campaign structure is organized on a field and end-of-life basis to align regulatory obligations with offshore execution efficiency. Platforms are grouped with sequencing driven by three primary factors: current end-of-life status, projected retirement windows, and water depth and structural complexity as they influence lift methodology and marine logistics. This approach prioritizes near-term decommissioning liabilities while preserving geographic cohesion and technical continuity across successive campaign phases.

Table 10-1 below summarizes the campaign assignments, water depths, field designations, and end-of-life timing for each platform. Platform removal campaigns have been aligned to the anticipated end-of-life timeframes of these assets. Campaign 1 consists of nine platforms that are at or near the production lifecycle. Campaign 2 consists of seven platforms that are expected to cease production in less than 20 years. Campaign 3 consists of seven platforms that are expected to be in production for at least the next 20 years.

Table 10-1 – Platform Campaign Sequencing

Platform	Campaign ⁽¹⁾	Water Depth (ft)	Field	Unit
Hermosa	1	603	Pt. Arguello/Rocky Point	Pt. Arguello Unit/Rocky Point Unit
Hidalgo	1	430	Pt. Arguello/Rocky Point	Pt. Arguello Unit/Rocky Point Unit
Harvest	1	675	Pt. Arguello	Pt. Arguello Unit
Gail	1	739	Sockeye	Not Unitized
Grace	1	318	Santa Clara	Santa Clara Unit
Habitat	1	290	Pitas Point	Pitas Point Unit
Hogan	1	154	Carpinteria	Not Unitized
Houchin	1	163	Carpinteria	Not Unitized
Irene	1	242	Pt Pedernales/Tranquillion Ridge	Pt Pedernales/Tranquillion Ridge Unit
A	2	188	Dos Cuadras	Not Unitized
B	2	190	Dos Cuadras	Not Unitized
C	2	192	Dos Cuadras	Not Unitized
Hillhouse	2	190	Dos Cuadras	Not Unitized
Gilda	2	205	Santa Clara	Santa Clara Unit
Gina	2	95	Hueneme	Pt. Hueneme Unit
Henry	2	173	Carpinteria	Not Unitized
Edith	3	161	Beta	Beta Unit
Elly	3	255	Beta (Processing Facility – no wells)	Beta Unit
Ellen	3	265	Beta	Beta Unit
Eureka	3	700	Beta	Beta Unit
Heritage	3	1075	Secate/Pescado	Santa Ynez Unit
Harmony	3	1198	Hondo	Santa Ynez Unit
Hondo	3	842	Hondo	Santa Ynez Unit

(1) Refer to Table 11-2 for seasons and duration of campaigns.



10.4.1 Campaign 1

Campaign 1 comprises platforms that have reached end of life and therefore drive the initial phase of removal activity. Platforms included in this campaign are several mid-to deep-water structures in the 600–740 ft range. The campaign also includes Hogan, Houchin, and Habitat all of which are in comparatively shallower water.

This configuration satisfies immediate regulatory liabilities while maintaining geographic concentration. It also provides a practical progression of lift conditions, beginning with moderate depths and incorporating both deeper and shallower structures within a single mobilization framework. Executing these removals first establishes offshore production rates and validates material flow assumptions early in the program, allowing removal and disposal pacing to be observed under live conditions.

10.4.2 Campaign 2

Campaign 2 consists of geographically clustered structures located in shallow to moderate water depths, generally between 95 and 205 feet.

Because these platforms are technically less complex than portions of the deeper inventory, this campaign represents a concentrated removal phase characterized by shorter lift cycles, limited deepwater retrieval constraints, and repetitive execution conditions. The geographic cohesion of the field supports operational efficiency while maintaining steady material throughput to disposal facilities.

The sequencing of Campaign 2 reflects assumed production decline trends and logical field-level grouping within the broader removal program. Actual execution timing may be adjusted in response to regulatory requirements, operational considerations, production performance, or confirmed downstream processing capacity at the time of removal.

10.4.3 Campaign 3

Campaign 3 represents the final and most technically demanding phase of the removal program. This campaign contains the deepest and heaviest structures in the inventory. The Santa Ynez Unit platforms, located in water depths ranging from approximately 842 to 1,198 feet, represent the most complex removals from both lift engineering and marine logistics perspectives. Eureka, at approximately 700 feet, also requires deep retrieval capability, while the remaining Beta platforms are moderate-depth shelf structures.

The sequencing of this campaign reflects technical and programmatic considerations rather than fixed calendar milestones. Deepwater lift methodology, vessel availability, and disposal infrastructure are expected to continue evolving over the program horizon. Positioning these removals in the later phase of execution preserves flexibility in vessel selection, heavy lift technology, and downstream processing alignment, and avoids premature commitment to specific deepwater execution strategies.

10.5 REMOVAL METHODOLOGY AND VESSEL STRATEGY

Topsides are assumed to be removed using reverse-installation or piece-large methodologies whereby topsides are split into modules or large sections within the safe working capacity of the vessel crane for removal. Full single-lift removal using Ultra-Heavy Lift Vessels (UHLV) or Semi-Submersible Crane Vessels (SSCV) is not adopted as the baseline approach. While technically feasible for certain structures, large single-lift operations would concentrate delivery volumes, compress transport cycles, and reduce execution flexibility relative to modeled disposal intake capacity. The assumed lift strategy therefore



favors progressive removal techniques that support controlled material flow, steady offshore productivity, and alignment with downstream processing constraints.

Within this phased framework, standard large-capacity material barges are assumed to be utilized to practical load limits consistent with marine stability and tow configuration requirements. Barge sizing and loading assumptions are optimized to maximize payload per transport cycle while maintaining compatibility with modeled annual intake capacity and sustainable tug deployment. This approach balances offshore efficiency with controlled, predictable material delivery.

Jackets are assumed to be severed and removed to fifteen (15) feet below mudline in accordance with federal requirements. Sectioning and controlled recovery techniques are incorporated into the baseline methodology. Explosive severance is not included in the standard execution assumption.

10.5.1 Comparative Evaluation of Heavy Lift Vessel Classes

The removal methodology described above establishes the baseline execution strategy. Within that framework, heavy lift vessel selection must be evaluated not only on lift capacity, but on its compatibility with campaign sequencing, marine transport logistics, and confirmed downstream processing limits.

Accordingly, three primary vessel categories were assessed for applicability to the 2025 program: mid-capacity anchored derrick barges (1,500-2,000 Ton Class), dynamically positioned semi-submersible crane vessels (DP SSCVs), and smaller sub-1,000-ton derrick barges.

10.5.1.1 Anchored Derrick Barges (1,500–2,000 Ton Class)

Anchored derrick barges in the 1,500–2,000 ton lift class provide sufficient capacity to execute modular topside removal and engineered jacket sectioning across the majority of the POCSR inventory. This class has extensive offshore construction precedent, established anchoring systems, and compatibility with staged removal methodologies.

Importantly, lift capacity within this range aligns with a phased removal approach rather than single-lift concentration. When the program duration is influenced more by transportation cycles and processing intake rates than by offshore lift speed, incremental increases in crane capacity do not translate directly into schedule compression. The 1,500–2,000 ton class therefore provides adequate technical capability while maintaining compatibility with steady material flow assumptions.

This class also retains operational flexibility, including feasibility for Panama Canal transit if required for Gulf routing.

10.5.1.2 Dynamically Positioned Semi-Submersible Crane Vessels (DP SSCVs)

DP SSCVs and ultra-heavy lift vessels offer substantially greater crane capacity and superior station-keeping performance in deepwater environments. These vessels are capable of executing large single-lift removals and reducing offshore lift counts, particularly for heavier topsides and deeper jackets.

However, their significantly higher day rates, complex mobilization requirements, and concentrated engineering exposure must be considered within the broader removal system as modeled in this study. In a program where disposal intake and transportation cycles define pacing limits, additional lift capacity does not proportionally reduce total campaign duration. Large single-lift removals would also generate concentrated delivery volumes, increasing downstream handling intensity and reliance on supplemental routing.



While technically viable and potentially appropriate for isolated high-demand applications, and in some cases possibly a preferred option by individual operators, DP SSCVs are not adopted as the baseline vessel class for the 2025 cost study.

10.5.1.3 Sub-1,000 Ton Derrick Barges

Smaller derrick barges present lower nominal day rates but would require increased segmentation, higher lift counts, and longer offshore duration for the majority of structures in the inventory. For deeper and heavier jackets, limitations in hook height and reach capability introduce additional constraints.

The cumulative effect would be increased offshore exposure and total vessel-day consumption, offsetting nominal rate advantages. As a result, sub-1,000 ton vessels are not considered suitable as primary removal units, though they may serve efficiently in individual auxiliary scopes, but are not part of this study.

10.6 BASELINE VESSEL CLASS SELECTION

Based on the comparative evaluation above, the 1,000–1,600 ton anchored derrick barge class is selected as the baseline removal vessel category for the 2025 program. A vessel comparable to the DB Thor (Fig. 10-1) represents an appropriate reference case for cost and schedule modeling.

This class provides sufficient lift capacity for modular removal of topsides and sectioned jackets while maintaining compatibility with controlled material flow and downstream processing assumptions. It balances technical capability, offshore duration, and integration with the transportation and disposal framework described in the preceding sections.



Figure 10-1 – Heavy Lift Vessel DB Thor



10.6.1 Commercial Execution Basis

For this scope of work—encompassing modular topside removal, jacket sectioning, pile severance, and controlled recovery—a fully integrated operating spread consistent with current market deployment assumptions is applied for the DB Thor class vessel.

The assumed spread includes the derrick barge and crane operations, an air diving spread, a cutting crew with associated equipment, a dedicated material barge, a material barge tug, and a primary tug. The primary tug is assumed to deploy and recover the anchor spread, while the material barge tug provides operational redundancy and may assist with anchor handling as required.

This bundled execution model reflects realistic offshore removal conditions and ensures that vessel-day exposure, marine coordination requirements, and support asset utilization are accurately represented for POCSR operations.

10.6.1.1 Lift Capability in Context of POCSR Structures

The suitability of the selected heavy lift vessel must be evaluated against the actual structural inventory within the POCSR. Topside weights, jacket weights, and associated pile weights vary considerably across fields and campaigns, with structural scale increasing significantly in the deeper-water units. Accordingly, lift capability must be assessed not against total platform weight, but against the engineered section sizes anticipated under a piece-large removal methodology.

The table below summarizes the topside weights and combined jacket and pile weights by platform and campaign grouping. These values establish the governing structural envelope for lift planning and confirm the anticipated range of section weights for both modular topside removal and underwater jacket segmentation and are derived from previous studies, and construction drawings. Summarized tables of the platform data organized by each campaign is included in Appendix B – Platform Removal Weights

Table 10-2 – Total Platform Weight

Platform	Campaign	Topside Tons	Jacket & Pile Tons	Platform Total Tons
Hermosa	1	7,830	18,893	26,723
Hidalgo	1	8,100	12,300	20,400
Harvest	1	9,024	18,753	27,777
Gail	1	7,693	20,620	28,313
Grace	1	3,800	4,129	7,929
Habitat	1	3,514	3,399	6,913
Hogan	1	2,259	1,692	3,951
Houchin	1	2,591	1,893	4,484
Irene	1	2,500	3,860	6,360
A	2	1,357	2,084	3,441
B	2	1,357	2,090	3,447
C	2	1,357	2,097	3,454
Hillhouse	2	1,200	1,894	3,094
Gilda	2	3,792	3,988	7,780
Gina	2	447	612	1,059
Henry	2	1,371	1,594	2,965
Edith	3	4,134	4,057	8,191



Platform	Campaign	Topside Tons	Jacket & Pile Tons	Platform Total Tons
Elly	3	8,000	4,256	12,256
Ellen	3	5,300	4,032	9,332
Eureka	3	4,700	21,198	25,898
Heritage	3	9,826	36,485	46,311
Harmony	3	9,839	47,430	57,269
Hondo	3	8,450	13,944	22,394

When evaluated within this framework, the lift requirements for the POCSR inventory align with engineered sectional removals rather than single-piece lifts. The governing consideration is therefore whether the selected vessel provides sufficient revolving capacity within a controlled sectioning methodology.

DB Thor offers a 1,760 short ton revolving lift capacity on the main block and is well suited for modular topside removal consistent with historic installation weights. Anticipated jacket section lifts generally range from approximately 300 to 1,600 tons, which fall within Thor’s operational envelope. The vessel is also compatible with Panama Canal transit, supporting West Coast mobilization from Gulf-based fleets.

Under the assumed removal methodology, all structures are recovered through engineered sectioning rather than single-lift execution. Within this approach, Thor’s lift capacity is sufficient to manage expected topside modules and jacket sections across the POCSR inventory.

10.6.1.2 Diving and Cutting Support for Jacket Removal

The selected configuration also supports the required diving and cutting operations for jacket removal. This includes air diving for pile exposure, bracing cuts, and rigging installation; mechanical and/or abrasive cutting operations; controlled pile severance to fifteen feet below mudline; and rigging and recovery for sectional jacket removal. For deeper water structures or extended bottom-time requirements, Thor can accommodate installation of a modular saturation (SAT) diving system to support extended subsea operations.

10.6.1.3 Rigging Recovery and Section Transfer Capability

Jacket removal within the POCSR program requires staged high-rigging retrieval and controlled load transfer during sectional recovery, particularly for lower jacket sections where hook travel and block submergence constraints become governing considerations.

In prior evaluations, deepwater lowering winch systems were conceptually referenced to facilitate staged load transfer without submerging the primary block. For the 2025 evaluation, that conceptual approach is replaced with an existing and field-proven capability inherent to the DB Thor’s four-block rigging configuration.

The DB Thor is equipped with an auxiliary stroking block capable of traveling approximately 200 feet downward and 200 feet upward independent of the main block. This arrangement allows lower jacket sections to be engaged below the primary hook elevation, raised in a controlled stroke, transferred to the main block, and then lifted clear of the water column. The sequence can be repeated for subsequent sections without requiring submergence of the main block.

This integrated stroking capability enhances controlled sectional recovery of lower jacket components while minimizing the need for permanent structural modifications such as outriggers or supplemental lift



frames. It also improves rigging management and load transfer efficiency and reduces exposure of primary lifting equipment to seawater, thereby limiting wear and maintenance impacts.

The stroking block capacity is approximately 880 tons. Based on the engineered section sizing assumptions applied to the POCSR jacket inventory, this capacity does not constrain the sectional removal methodology adopted for this study.

By utilizing an existing vessel capability rather than a conceptual lowering system, the 2025 program assumptions reflect currently available equipment and reduce reliance on bespoke modifications to execute staged jacket recovery.

The following tables summarize the structural removal inventory by platform and campaign, including topside weights, total jacket and pile weights, engineered section counts, and corresponding average lift weights. These values reflect the assumed piece-large sectioning methodology adopted for this study and establish the governing lift envelope for jacket removal operations across the POCSR inventory.

Table 10-3 – Topside Section and Average Lift Weight

Platform	Campaign	Topside Tons	Topside Modules/Sections	Average Lift (Tons)
Hermosa	1	7,830	7	979
Hidalgo	1	8,100	7	900
Harvest	1	9,024	8	902
Gail	1	7,693	7	962
Grace	1	3,800	3	633
Habitat	1	3,514	3	586
Hogan	1	2,259	2	282
Houchin	1	2,591	3	288
Irene	1	2,500	2	500
A	2	1,357	2	339
B	2	1,357	2	339
C	2	1,357	2	339
Hillhouse	2	1,200	1	300
Gilda	2	3,792	3	632
Gina	2	447	1	224
Henry	2	1,371	2	343
Edith	3	4,134	4	517
Elly	3	8,000	7	800
Ellen	3	5,300	5	442
Eureka	3	4,700	4	470
Heritage	3	9,826	8	756
Harmony	3	9,839	8	757



Platform	Campaign	Topside Tons	Topside Modules/Sections	Average Lift (Tons)
Hondo	3	8,450	7	650

Table 10-3 summarizes topside weights and the corresponding modular or engineered sectioning approach assumed for removal. Consistent with historic installation methodology, topsides are assumed to be removed either in original modules or in engineered piece-large segments sized to remain within available revolving lift capacity.

Under this approach, individual topside lifts are maintained within the operational range of DB Thor’s 1,760 short ton main block capacity. Accordingly, modular removal of the POC SR topside inventory is compatible with Thor’s lift envelope.

Table 10-4 – Jacket Section and Average Lift Weight

Platform	Campaign	Jacket + Piles (Tons)	Jacket Sections	Average Lift (Tons)
Hermosa	1	18,893	20	945
Hidalgo	1	12,300	14	879
Harvest	1	18,753	20	938
Gail	1	20,620	22	937
Grace	1	4,129	5	826
Habitat	1	3,399	4	850
Hogan	1	1,692	4	423
Houchin	1	1,893	4	473
Irene	1	3,860	4	965
A	2	2,084	3	695
B	2	2,090	3	697
C	2	2,097	3	699
Hillhouse	2	1,894	3	631
Gilda	2	3,988	4	997
Gina	2	612	1	612
Henry	2	1,594	2	797
Edith	3	4,057	5	811
Elly	3	4,256	5	851
Ellen	3	4,032	5	806
Eureka	3	21,198	22	964
Heritage	3	36,485	38	960
Harmony	3	47,430	48	988
Hondo	3	13,944	15	930



Table 10-4 presents the total jacket and pile weights and the number of engineered sections assumed for removal. While total structural weights vary significantly—particularly in the deeper Campaign 3 inventory—the sectioning approach distributes these weights into manageable lift increments. This methodology avoids single-lift removal and aligns structural segmentation with available revolving lift capacity.

Taken together, the jacket and topside sectioning assumptions demonstrate that the full POCSR structural inventory—across all campaigns and water depths—can be executed within DB Thor’s revolving lift capacity under the engineered segmentation methodology adopted in this study.

10.6.1.4 Heavy Lift Vessel Mobilization and Demobilization

Mobilization and demobilization (Mob/Demob) of the selected heavy lift vessel (DB Thor) represent a material fixed cost component of the POCSR removal program. Because no comparable heavy lift barge is currently stationed on the U.S. West Coast, mobilization from the Gulf of America (GoA) is required.

Transit costs include tug hire and barge day rate during tow. In addition, a Panama Canal transit is required, with an assumed canal fee of approximately \$100,000 and a conservatively modeled 10-day canal delay exposure.

10.6.1.5 Allocation Across Campaigns

Because mobilization and demobilization are campaign-level costs rather than platform-specific costs, the total Mob/Demob expense is allocated proportionally across platforms within each campaign. Campaign 1 reflects a slightly lower per-platform allocation due to distribution across the immediate end-of-life inventory, while Campaigns 2 and 3 reflect adjusted allocation consistent with campaign grouping and platform count.

Table 10-5 summarizes the allocated Heavy Lift Vessel (HLV) Mob/Demob cost by platform and campaign.

Table 10-5 – Heavy Lift Vessel (HLV) Mob/Demob per Platform

Platform	Campaign	HLV Mob/Demob per Platform
Hermosa	1	\$1,583,600
Hidalgo	1	\$1,583,600
Harvest	1	\$1,583,600
Gail	1	\$1,583,600
Grace	1	\$1,583,600
Habitat	1	\$1,583,600
Hogan	1	\$1,583,600
Houchin	1	\$1,583,600
Irene	1	\$1,583,600
A	2	\$2,036,100
B	2	\$2,036,100
C	2	\$2,036,100



Platform	Campaign	HLV Mob/Demob per Platform
Hillhouse	2	\$2,036,100
Gilda	2	\$2,036,100
Gina	2	\$2,036,100
Henry	2	\$2,036,100
Edith	3	\$2,036,100
Elly	3	\$2,036,100
Ellen	3	\$2,036,100
Eureka	3	\$2,036,100
Heritage	3	\$2,036,100
Harmony	3	\$2,036,100
Hondo	3	\$2,036,100
Total		\$42,757,800

The total allocated Mob/Demob cost across all platforms equals \$42,757,800, reflecting the cumulative mobilization requirements across the three campaign waves.

The following Table 10-6 presents the estimated costs for platform topside and jacket removal by platform and campaign. These values reflect the engineered sectioning methodology validated against the POCSR structural inventory, the confirmed lift envelope of DB Thor, the allocated heavy lift vessel Mobilization/Demobilization costs, and the field-based campaign sequencing framework described in the preceding sections. Cost development incorporates marine spread duration, underwater cutting and pile severance operations, rigging complexity, and structural weight distribution under the assumed piece-large removal approach.

Topside and jacket removal costs are shown separately to illustrate the relative cost drivers, with jacket removal representing the dominant expenditure due to subsea cutting scope, section handling, and extended offshore execution time. The estimates presented herein represent offshore structural removal only; transportation and final disposal costs are addressed separately in the following section.

Table 10-6 – Topside and Jacket Removal Cost

Platform	Campaign	Topside Removal	Jacket Removal	Total
Hermosa	1	\$2,048,300	\$34,060,600	\$36,108,900
Hidalgo	1	\$2,067,300	\$21,991,700	\$24,059,000
Harvest	1	\$2,179,000	\$34,086,100	\$36,265,100
Gail	1	\$1,817,500	\$37,060,900	\$38,878,400
Grace	1	\$1,178,700	\$12,052,700	\$13,231,400
Habitat	1	\$1,194,500	\$8,210,300	\$9,404,800
Hogan	1	\$1,025,600	\$7,465,200	\$8,490,800
Houchin	1	\$1,194,500	\$6,414,000	\$7,608,500



Platform	Campaign	Topside Removal	Jacket Removal	Total
Irene	1	\$1,156,900	\$8,528,000	\$9,684,900
A	2	\$1,032,000	\$6,336,700	\$7,368,700
B	2	\$1,032,000	\$6,339,500	\$7,371,500
C	2	\$1,032,000	\$6,342,200	\$7,374,200
Hillhouse	2	\$895,300	\$5,157,300	\$6,052,600
Gilda	2	\$1,170,800	\$9,884,600	\$11,055,400
Gina	2	\$788,600	\$2,450,500	\$3,239,100
Henry	2	\$1,025,600	\$4,200,100	\$5,225,700
Edith	3	\$1,236,800	\$9,497,500	\$10,734,300
Elly	3	\$1,793,500	\$11,044,400	\$12,837,900
Ellen	3	\$1,455,900	\$9,317,900	\$10,773,800
Eureka	3	\$1,048,000	\$36,347,300	\$37,395,300
Heritage	3	\$2,116,100	\$69,695,200	\$71,811,300
Harmony	3	\$2,106,000	\$85,746,600	\$87,852,600
Hondo	3	\$1,838,000	\$27,499,800	\$29,337,800
Total		\$32,432,900	\$459,729,100	\$492,162,000

10.6.2 Additional Constraints: Platform Removal, Transportation, and Disposal Constraints

Once well plugging and abandonment activities are complete, the primary drivers of Pacific OCS decommissioning cost and schedule shift to platform removal, transportation, and final disposition. Unlike well operations, which can be sequenced and optimized through engineering and rig efficiency, structural removal is fundamentally constrained by heavy lift capacity, subsea cutting duration, marine logistics, and disposal throughput.

In the Pacific OCS context, there is no simple or high-throughput pathway for large-scale jacket removal and recycling. Previous studies modeled transportation either to Southern California ports or, in certain scenarios, to Gulf of America Coast recycling facilities via transit through the Panama Canal. Canal routing introduces extended cycle times, estimated at approximately multiple months per round trip when accounting for transit, queuing, and cargo operations. In addition, sustained reliance on long-haul transport requires a sufficient inventory of material barges and assist tugs to maintain reasonable campaign continuity, which may present logistical constraints.

More recently, regional recycling capacity has been identified on the West Coast, including facilities that, with appropriate upgrades, appear capable of handling the majority of anticipated platform recycling volumes under the campaign structures evaluated in this study. However, annual throughput limitations, including scenarios constrained to approximately tens of thousands of tons per year, effectively define the pacing variable for multi-platform campaigns. In practical terms, disposal capacity becomes the governing factor for campaign duration rather than heavy lift availability alone.

Under a full removal and recycling scenario, this dynamic results in multi-year heavy lift campaigns requiring sustained presence of a 1,500–2,000-ton class derrick barge on the West Coast. Extended



campaign duration is driven largely by substantial subsea cutting requirements associated with large-diameter jackets and pile systems in deep water. Cutting and severing these structures at depth represents one of the most time-intensive and exposure-sensitive phases of the removal process.

Such extended subsea operations introduce both operational and safety considerations. While technically feasible and routinely modeled in this study, prolonged subsea cutting exposure—particularly in deeper water environments—requires careful execution planning and risk management. The duration and intensity of these activities differ from certain other offshore regions where partial structure retention programs reduce the scope of full jacket severance.

In regions such as the Gulf of America, established reefing programs allow for partial removal to navigational clearance depth, significantly reducing subsea cutting scope, heavy lift time, transportation requirements, and recycling throughput. These programs have evolved within specific regulatory and environmental frameworks unique to those jurisdictions. The Pacific OCS currently operates under a different policy structure, and this study has therefore modeled full removal consistent with existing requirements.

However, it is important to recognize that alternative disposition frameworks—such as partial removal to a specified clearance depth, subject to environmental review and liability controls—would materially alter execution risk, schedule duration, and cost allocation. Reduced subsea cutting scope would shorten heavy lift campaigns, decrease diver and subsea exposure, and significantly reduce transportation and recycling demand. Such an approach could also reallocate a portion of cost currently associated with full structural removal and disposal.

From a policy perspective, where appropriate environmental and liability safeguards are established, alternative disposition models may present opportunities for value reallocation. Funds otherwise dedicated to extensive subsea cutting, transportation, and scrap processing could potentially be directed toward environmental mitigation, habitat enhancement, or other public-benefit objectives, subject to regulatory authorization.

This study does not advocate for any particular policy outcome. Rather, it documents that under a full removal and recycling framework, transportation logistics and disposal throughput constitute the primary pacing constraints for Pacific OCS structural decommissioning. The methodologies and cost estimates presented herein reflect reasonable and defensible execution assumptions within the current regulatory environment. At the same time, it is recognized that policy structure directly influences operational exposure, schedule duration, and cost allocation in large-scale offshore decommissioning programs.



SECTION ELEVEN – TRANSPORTATION AND DISPOSAL

Transportation and disposal represent the controlling logistical components of the 2025 POCSR Decommissioning evaluation. While offshore removal methodology determines how material is recovered, transportation and processing capacity ultimately determine how efficiently that material can be managed.

11.1 OVERVIEW

Unlike the Gulf of America, where multiple high-volume demolition facilities and barge fleets exist near offshore production areas, the Pacific Outer Continental Shelf Region operates within a constrained infrastructure environment. As a result, transportation and disposal planning must be treated as integral components of the removal strategy rather than downstream considerations.

The 2025 evaluation adopts a hybrid disposal model, with Infraestructura y Servicios Portuarios (ISP) in Ensenada, Baja California, Mexico (POEM) as the primary processing facility and GoA facilities as supplemental overflow destinations.

This framework balances geographic proximity with throughput capacity and transportation economics.

11.1.1 Primary Disposal Pathway: Port of Ensenada, Mexico (POEM)

The Port of Ensenada, Mexico (POEM) represents the only currently identified West Coast facility capable of handling large offshore platform demolition volumes at an industrial scale (Fig. 11-1).



Figure 11-1 – Platform Locations to POEM Transit Map

Alternative West Coast ports were evaluated during the course of this study, including the Ports of Los Angeles (POLA) and Long Beach (POLB). While both ports maintain substantial commercial



infrastructure, neither currently supports an established, high-throughput offshore structure demolition yard capable of processing the scale and sequencing considered in this program. In addition, large-scale structural dismantling within California port jurisdictions would involve heightened permitting complexity, particularly with respect to environmental compliance, biofouling management, and long-duration heavy industrial laydown requirements.

Marine growth management is a significant operational consideration in evaluating disposal pathways. Removal and handling of biomass from large offshore jackets introduce compliance and community exposure sensitivities that are comparatively more restrictive within California regulatory frameworks. These factors constrain practical scalability and increase permitting exposure for in-state demolition scenarios.

For these reasons, the Ports of Los Angeles and Long Beach are not assumed as primary disposal destinations in the 2025 baseline case. However, should the throughput, infrastructure, and operational considerations described above be resolved or confirmed at scale, POLA and POLB could become viable disposal options for future campaigns.

POEM, by contrast, provides industrial waterfront suitable for demolition staging, structural dismantling, and material segregation within a single operational envelope. Upon arrival at POEM, transported jacket and topside sections will first undergo marine growth removal at a temporary floating cleaning station moored away from primary dockside areas (Fig. 11-2). Conducting biomass removal at a segregated moored location allows cleaning to occur prior to yard intake and minimizes potential odor impacts to adjacent port facilities and nearby population areas. Cleaning will be performed while structures remain on their transport barges, with marine growth collected into sealed containment units for controlled transfer ashore. Marine growth removal activities are incorporated in the disposal cost framework for this study and are treated as part of the port-side processing sequence.

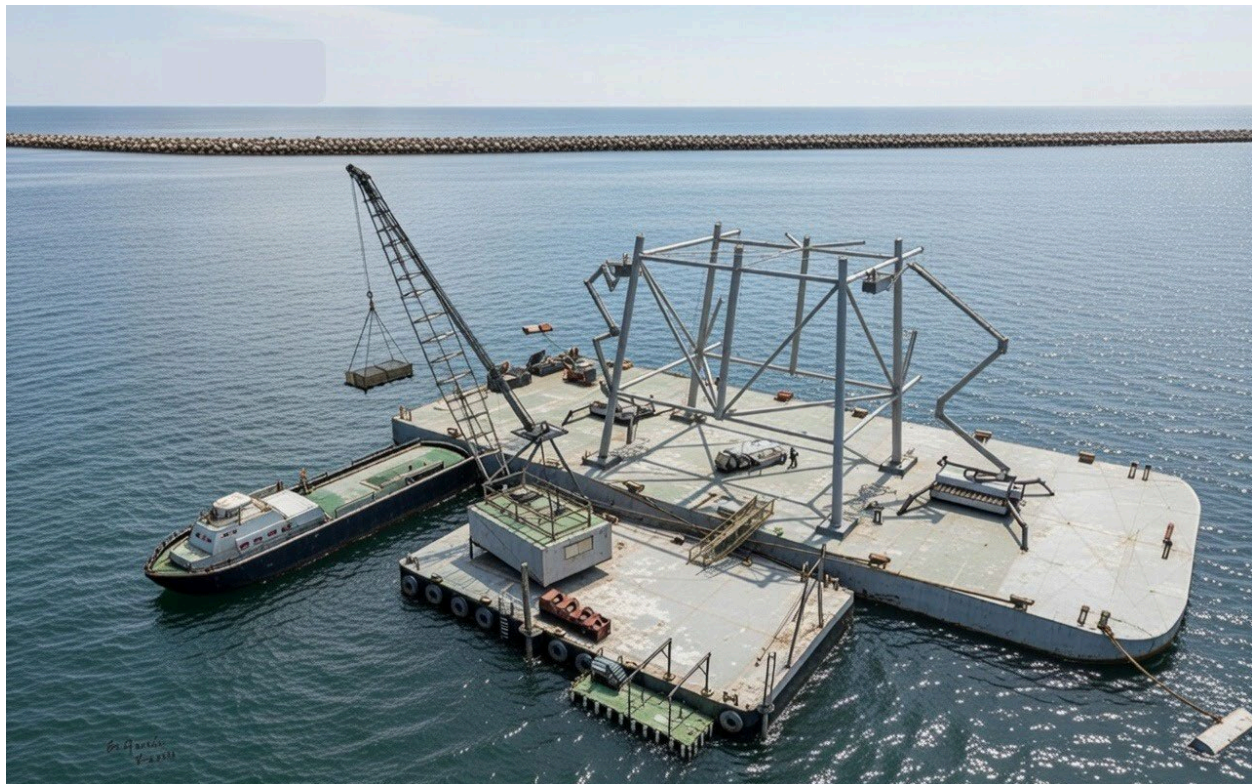


Figure 11-2 – Marine Growth Removal Station

Marine growth removal, structural dismantling, and material segregation occur within the same yard envelope. Accordingly, total annual delivery volumes must align with available processing capacity. Annual throughput is estimated at approximately 35,000 tons per year and is contingent upon completion of a planned facility upgrade. This capacity limit establishes the upper boundary for annual delivery volumes under the primary disposal pathway.

POEM therefore functions as the base-load processor within the model. Removal pacing assumptions are structured to maintain steady intake at or near annual throughput capacity without exceeding yard processing limits.

11.1.2 Supplemental Disposal Pathway: Gulf of America Facilities

For campaigns generating removal volumes that exceed POEM's annual processing capacity, incremental tonnage is assumed to be transported to established GoA demolition facilities. This supplemental pathway is incorporated as a planned element of the hybrid disposal model rather than as a contingency measure.



Figure 11-3 – POCSR Platform Locations to GoA Transit Map

The Gulf of America benefits from a mature offshore decommissioning infrastructure supported by multiple large-scale demolition yards and well-established offshore dismantling supply chains. The region’s waterfront facilities are equipped to accommodate heavy-lift operations, and the whole system operates with effectively unconstrained annual processing throughput relative to the volumes anticipated under this program. Marine growth removal is not a governing constraint within Gulf Coast disposal scenarios, as receiving facilities are configured to manage residual biomass within established dismantling workflows.

These characteristics allow GoA facilities to absorb large structural components — including deepwater jackets and integrated topsides — without the annual digestion limits assumed for West Coast processing.

The primary tradeoff associated with Gulf of America disposal is transportation exposure. Shipments originating in the POCSR must transit the Panama Canal, resulting in canal transit fees, extended voyage durations, and additional tug and barge day-rate accumulation. This routing also introduces potential schedule variability associated with canal passage and slot allocation. In addition, the extended interoceanic transit increases fuel consumption and associated air emissions, which must be considered in evaluating the program’s broader environmental footprint.

While these factors increase transportation cost relative to West Coast routing, Gulf Coast yards do not present throughput bottlenecks. As a result, overflow tonnage can be absorbed without creating downstream processing congestion or staging delays.



Within the 2025 study framework, the disposal system is structured to balance steady-state processing with surge capacity. POEM serves as the base-load processor, aligned with the anticipated campaign pacing and providing consistent throughput. Gulf Coast facilities operate as the balancing mechanism, absorbing incremental excess tonnage when campaign volumes exceed POEM’s capacity. Accordingly, overflow shipments during higher-volume campaigns are anticipated and have been incorporated into the baseline cost modeling assumptions.

This hybrid configuration preserves execution flexibility while maintaining alignment between offshore removal rates and confirmed processing capacity. The quantitative implications of overflow volumes, canal transit exposure, and associated cost differentials are presented in the following subsections.

11.2 CAMPAIGN-LEVEL VOLUME AND CAPACITY ALIGNMENT

The hybrid disposal framework is evaluated at the campaign level to confirm alignment between projected removal volumes and POEM’s assumed processing capacity. For modeling purposes, POEM throughput is conservatively capped at 35,000 tons per year, with campaign durations assessed on a 185-day working season basis consistent with offshore execution assumptions.

The analysis compares total campaign removal volumes—comprising combined topside and jacket tonnage removed to 15 feet below mudline—against available West Coast capacity over the projected execution period. The objective is to quantify any excess tonnage requiring diversion to Gulf Coast facilities and to determine whether removal pacing must be moderated to maintain steady-state intake.

The modeling indicates that Campaign 2 can be fully absorbed within POEM’s annual processing capacity over its projected execution duration. Campaigns 1 and 3, by contrast, exceed the West Coast threshold and therefore require partial diversion of tonnage to Gulf of America facilities. In each case, the overflow volumes remain proportionate to total campaign tonnage and do not necessitate restructuring of the campaign groupings.

These findings confirm that disposal throughput governs execution pacing rather than global feasibility. The hybrid model remains viable provided annual deliveries are aligned with the 35,000-ton threshold, overflow shipments are incorporated into baseline transport planning, and high-volume campaigns are sequenced to avoid compounding disposal demand.

The following tables summarize campaign-level removal tonnage, projected execution duration, corresponding West Coast POEM processing capacity over that duration, and resulting overflow volumes allocated to Gulf of America facilities.

Table 11-1 – Campaign Removal Volume Summary

Campaign	Topside Tons	Jacket Tons	Total Removal Volume Tons
1	47,311	85,539	132,850
2	10,881	14,358	25,239
3	50,249	131,403	181,652

The quantitative results of the campaign-level capacity alignment analysis are presented in Table 11-2. Using the 35,000-ton annual POEM throughput assumption and a 185-day working season basis, total campaign removal volumes are compared against cumulative seasonal intake capacity over the projected execution duration of each campaign. This establishes the maximum tonnage that can be processed at



POEM under steady-state delivery conditions and identifies any incremental overflow requiring diversion to Gulf of America (GoA) facilities.

Table 11-2 – POEM Processing Volume

Campaign	Total Duration (days)	Seasons (185-day basis)	Max POEM Capacity Tons	Total Volume Tons	Overflow to GoA Tons
1	616	4	116,547	132,850	16,304.00
2	180	1	34,073	25,239	-
3	855	5	161,721	181,652	19,931.00

For Campaign 1, total removal volume of 132,850 tons spans approximately three working seasons, allowing 116,547 tons to be processed at POEM and resulting in 16,304 tons diverted to the GoA. Campaign 2, with a total volume of 25,239 tons over a single season, is fully absorbed within West Coast capacity. Campaign 3 generates 181,652 tons over approximately five seasons, permitting 161,721 tons to be processed at POEM and requiring diversion of 19,931 tons to the GoA.

These overflow volumes are limited relative to total campaign tonnage and reflect the modeled constraint of annual intake capacity rather than a structural disposal limitation.

The following Table 11-3 converts the POEM-allocated tonnage into required barge movements and associated marine transportation cost. Total removal volumes are translated into barge count by campaign, consistent with heavy structural transport practices in the region.

Table 11-3 – Disposal Cost for Tonnage Processed in POEM

Campaign	Total Removal Volume Tons	Barge Count by Campaign	Max POEM Capacity Tons	Barge Trips to POEM	Total Cost
1	132,850	38	116,547	34	\$2,886,041
2	25,239	8	34,073	10	\$1,042,001
3	181,652	52	161,721	47	\$3,884,896

Transportation modeling incorporates deck barge day rates, tug support inclusive of fuel, barge preparation time, marine growth removal prior to shipment, and round-trip transit durations consistent with coastal routing to POEM. While intermediate assumptions are not shown in the summarized table, they are embedded within the calculated totals.

Modeled POEM transport costs are \$2.89 million for Campaign 1, \$1.04 million for Campaign 2, and \$3.88 million for Campaign 3. These values reflect short-haul coastal transit consistent with the primary disposal pathway.

The final Table 11-4 presents transportation requirements and cost for overflow tonnage diverted to Gulf of America facilities. Because POEM intake is seasonally constrained, the limited excess material in Campaigns 1 and 3 requires long-haul export.

Table 11-4 – Disposal Cost for Tonnage Processed in GoA



Campaign	Total Removal Volume Tons	Barge Count by Campaign	GOA Tons	Barges to GOA	Total Cost
1	132,850	38	16,304	5	\$10,906,000
2	25,239	8	0	0	-
3	181,652	52	19,931	6	\$13,087,200

Transport to the GoA is modeled using the same 3,500-ton average barge capacity and tug rate assumptions, but incorporates extended transit duration, Panama Canal transit fees per barge, equivalent empty return duration, and marine growth removal prior to departure.

Due to the substantially longer voyage cycle and canal exposure, transportation cost increases considerably relative to West Coast routing. Supplemental GoA transport totals \$10.91 million for Campaign 1 and \$13.09 million for Campaign 3, while Campaign 2 requires no diversion.

Taken together, these tables demonstrate the economic and logistical basis for the hybrid disposal model. POEM functions as the base-load processor aligned with controlled campaign pacing, while the GoA serves as the balancing mechanism for incremental excess tonnage. Disposal throughput governs pacing rather than feasibility, and limited overflow shipments are incorporated into baseline cost modeling assumptions.

11.2.1 Interpretation of Results

The capacity alignment analysis confirms that POEM can serve as the primary disposal destination across all campaigns, if removal pacing is properly controlled. For higher-volume campaigns, overflow tonnage is limited and can be accommodated within conventional marine transport logistics. These overflow volumes do not indicate a disposal constraint; rather, they reflect the intended balancing role of Gulf Coast facilities within the hybrid framework.

This alignment analysis establishes the basis for subsequent transportation modeling, including determination of required barge counts, transit cycle times, Panama Canal exposure, transportation cost per ton, and total integrated transport and disposal cost by campaign.

Those calculations are presented in the following subsection 11.3.

11.3 CONTEXT: FULL REMOVAL SCOPE AND RIGS-TO-REEFS CONSIDERATIONS

The full removal scenario modeled in this study is extensive in scope. It requires complete topside removal, sectional jacket cutting to 15 feet below mudline, recovery of piles and conductors, marine transport of all material, and downstream dismantling of more than 450,000 tons of steel across the evaluated campaigns. For deeper structures, this involves prolonged subsea cutting and staged recovery operations conducted over extended offshore durations.

From a programmatic perspective, it is reasonable to ask whether such a large-scale subsea cutting and transportation effort represents the only practical pathway. In regions such as the Gulf of America, partial removal and Rigs-to-Reefs conversions have reduced both subsea cutting scope and downstream disposal demand under established statutory and regulatory frameworks.

In the Pacific Outer Continental Shelf Region, however, no implemented federal offshore reefing program currently exists. Although California has enacted enabling legislation allowing reefing to be considered under defined conditions, federal–state alignment, title transfer mechanisms, long-term stewardship



funding, and demonstration of net environmental benefit remain unresolved. As a result, reefing cannot presently be relied upon for planning, schedule, or cost reduction in the POCSR.

This distinction is essential because the principal constraints identified in this study arise directly from the requirement for full removal. Jacket structures represent the dominant tonnage component of the inventory and drive transportation demand, scrap processing throughput, and campaign pacing. Full removal also requires substantial subsea severance work, which extends offshore duration and increases cumulative operational exposure.

If reefing were implemented for a meaningful portion of the inventory, both downstream processing demand and subsea cutting scope would be substantially reduced. However, until an operational, regulatory and legally secure framework is in place, those reductions remain hypothetical.

Accordingly, the 2025 evaluation retains complete removal as the bounding and defensible case for liability and bonding analysis. The magnitude of the modeled effort reflects regulatory requirements as they presently exist, not a preference for operational complexity.



SECTION TWELVE – SITE CLEARANCE

Site clearance represents the final offshore activity in the decommissioning sequence. Its purpose is to ensure that the lease area is returned, to the extent practical, to the condition that existed prior to installation of the structure. The governing requirements are established under 30 CFR 250.1740 and 30 CFR 250.1743, with implementing guidance provided in BSEE NTL No. 2010-G05, "Decommissioning Guidance for Wells and Platforms." Collectively, these authorities require the lessee to confirm that the seafloor within a one-quarter mile (1,320-foot) radius of the former platform location is free of debris, structural remnants, and other obstructions, and that the cleared area does not present a hazard to navigation, commercial fishing, or other lawful uses of the seabed. Verification is accomplished through approved survey methods—typically side-scan sonar, trawling, or a combination thereof—and the results must be documented and submitted to BSEE as part of the final decommissioning report.

12.1 INTRODUCTION

Following jacket and conductor removal to the required depth below mudline, a comprehensive debris survey will be conducted across the full 1,320-foot clearance radius. High-resolution multibeam bathymetry and side scan sonar will be used to achieve full geophysical coverage of the area. Data acquisition parameters will be selected to ensure complete seabed coverage without gaps and with sufficient resolution to identify objects exceeding applicable regulatory size thresholds. All anomalous contacts identified within the clearance zone will be investigated using a work-class ROV deployed from a dynamically positioned support vessel. Debris attributable to platform removal or historical lease operations that exceeds applicable size criteria will be recovered using the ROV in conjunction with the vessel's crane or a hydraulic grapple. Recovered debris will be placed onto a material barge and transported to local Port of Los Angeles (POLA) or Port of Long Beach (POLB) recycling facilities, or other appropriate disposal facilities, consistent with the project's materials management plan.

Historically, verification trawling has been used in some regions as a method of demonstrating site clearance. Under that approach, a trawl board and net are towed across the clearance radius to confirm that no obstructions remain that would foul commercial fishing gear. In the Gulf of America, reinforced trawl nets are commonly employed not only as a verification tool but also as a debris recovery device, effectively snagging and retrieving debris encountered during towing. While this method has been workable in soft sediment environments, it involves mechanical disturbance of the seabed across the entire clearance area.

The 2023 Pacific Region Programmatic Environmental Impact Statement (PEIS) prepared for the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM) evaluated potential environmental impacts associated with decommissioning activities, including seabed disturbance from clearance methods. The PEIS recognized that mechanical seabed disturbance may result in benthic habitat disruption, sediment resuspension, and localized ecological impacts, particularly in areas characterized by hard substrate, mixed sediments, or biologically sensitive communities. Offshore California presents materially different seabed conditions than many Gulf locations, including areas of harder bottom, variable sediment types, and developed benthic communities. Full-area mechanical trawling across the clearance radius has the potential to disturb these resources in a manner that may not align with the environmental impact considerations identified in the PEIS.

Moreover, this study addresses the potential removal of shell mounds, which are generally understood as accumulations of shell material and associated deposits, potentially including biologically harmful elements, that have formed on the seafloor adjacent to offshore facilities. These features represent a



sensitive seabed irregularity from both environmental and regulatory perspectives. While the PEIS broadly addresses seabed obstructions, it does not explicitly define shell mound removal as a standard requirement or prescribe specific methodologies. Accordingly, there are no well-established industry precedents or accepted technical standards governing shell mound removal, and applicable regulatory requirements remain uncertain and project-specific. A proposed methodology, technical approach, and order-of-magnitude cost range have been developed based on publicly available information and a range of conservative assumptions. These are presented in Appendix G.

12.2 ANALYTICAL APPROACH

This study assumes that site clearance will be demonstrated through full-coverage, high-resolution geophysical survey combined with documented ROV inspection and targeted debris removal, rather than full-area trawl sweeping. This approach achieves the same regulatory objective, confirmation that the area does not present a hazard, while minimizing unnecessary benthic disturbance.

Under this methodology, clearance is achieved when:

1. The entire 1,320-foot radius has been surveyed with complete geophysical coverage;
2. All identified debris exceeding regulatory thresholds has been investigated and removed;
3. Required cut elevations below mudline have been verified; and
4. ROV video documentation confirms that no remaining obstructions are present that would interfere with normal seabed use.

Final acceptance would be subject to regulatory review and concurrence based on the submitted Site Clearance Report, which will document survey coverage, contact lists, debris disposition, cut verification, and final seabed condition.

The duration of site clearance activities is driven primarily by water depth, seabed soil conditions, and the volume of debris generated during removal operations. Increased water depth affects survey and ROV cycle times, while seabed composition influences debris detectability and recovery efficiency.

12.3 COST MODEL AND METHODOLOGY

The site clearance costs model is based on a calculation driven by the factors described above. Time has been allocated in the model to account for targeted debris removal that is driven by a fraction of the estimated removal weight. The estimated removal weight is defined by the weight of the topside and jacket structures. The fractional figure used to estimate the weight of the debris to be removed during the site clearance operations is 0.05%. Additionally, at BSEE's request, estimates for the removal of shell mounds at the base of the POCSR platforms are included in Appendix G. These estimates are built upon the most recent publicly available information and are subject to change as additional survey, study, and removal methodology refinement work is completed. Table 12-1 below shows the total estimated cost for site clearance debris removal.

Table 12-1 – Site Clearance Cost

Platform Name	Water Depth	Campaign Sequence	Total Cost
A	188	2	\$552,000
B	190	2	\$554,600
C	192	2	\$557,100



Platform Name	Water Depth	Campaign Sequence	Total Cost
Edith	161	3	\$518,400
Ellen	265	3	\$650,000
Elly	255	3	\$637,600
Eureka	700	3	\$1,201,300
Gail	739	1	\$1,249,400
Gilda	205	2	\$574,000
Gina	95	2	\$503,800
Grace	318	1	\$715,200
Habitat	290	1	\$679,800
Harmony	1198	3	\$1,834,600
Harvest	675	1	\$1,168,500
Henry	173	2	\$533,000
Heritage	1075	3	\$1,678,200
Hermosa	603	1	\$1,077,300
Hidalgo	430	1	\$858,000
Hillhouse	190	2	\$554,500
Hogan	154	1	\$507,400
Hondo	842	3	\$1,380,500
Houchin	163	1	\$518,900
Irene	242	1	\$619,100
Total Site Clearance Cost			\$19,123,200



SECTION THIRTEEN – INFLATION, MARKET DYNAMICS, AND ESCALATION ASSESSMENT

Since publication of the 2020 POCSR decommissioning cost study, general economic conditions have changed materially. Cumulative Consumer Price Index (CPI) growth has approached approximately 25 percent over the intervening period, reflecting broad increases in labor, materials, transportation, and energy across the U.S. economy. While this macroeconomic context provides useful background, offshore decommissioning execution does not move in lockstep with CPI. The cost structure of a Pacific OCS removal campaign is driven primarily by marine asset utilization, workforce specialization, and campaign structuring rather than consumer price movements alone.

Within that cost structure, the dominant component is marine execution, centered on the derrick barge and associated support services. For typical structure removals, the 1,000–1,600-ton anchored derrick barge class has historically served as the principal lift asset. Accordingly, any assessment of escalation relative to the 2020 study must begin with conditions in the heavy lift market.

Historical OCS platform removal data demonstrate that demand for conventional 1,000–1,600-ton class heavy lift vessels peaked during the 2011–2014 period when annual removals approached 300 platforms and the five-year rolling average exceeded 240 removals per year, as shown in Figure 13-1. Since that time, removal activity has moderated significantly, with the rolling average declining to roughly one-third of its peak level. This reflects a structural reduction in remaining inventory rather than a temporary contraction.

Count of OCS Platform Removals by Year and 5yr Rolling Average

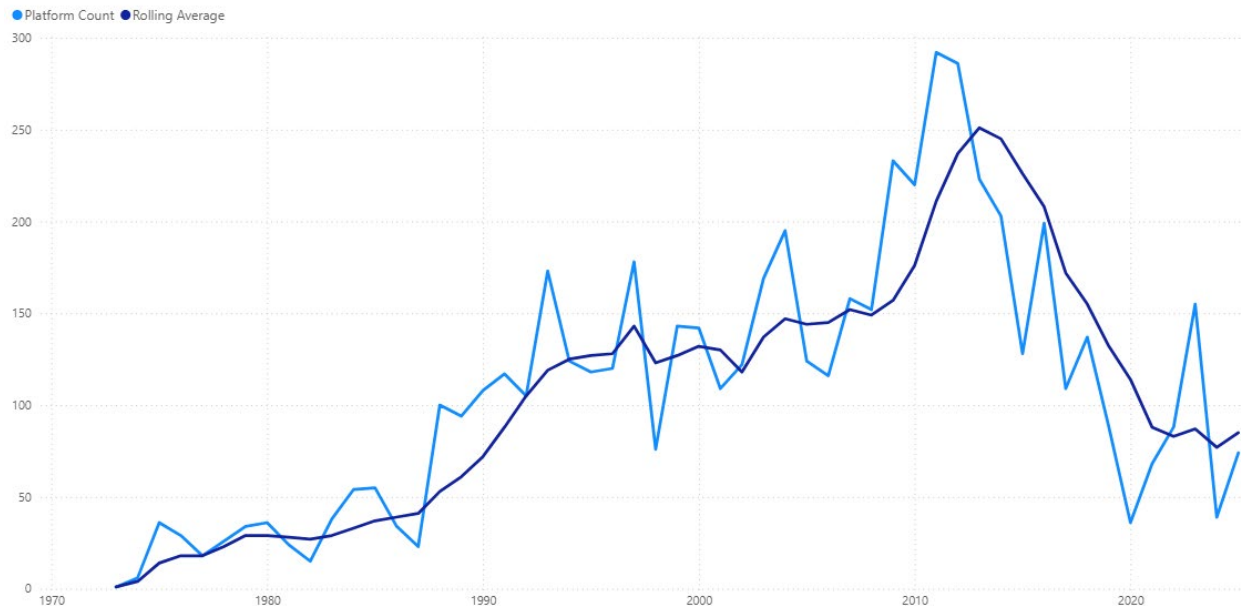


Figure 13-1 – Gulf of America Decommissioning History and 5 Year Rolling Average

Fleet capacity within the 1,000–1,600-ton derrick barge class has remained relatively stable over this period. There has been no meaningful expansion in lift capacity. The principal structural change has been consolidation among marine contractors, resulting in fewer owners controlling a similar number of heavy



lift assets. Under traditional supply-demand dynamics, declining removal volumes combined with stable fleet capacity would typically exert downward pressure on market-based day rates. However, consolidation has introduced greater pricing discipline. Asset owners are better positioned to manage utilization strategically and avoid aggressive rate competition during softer demand periods.

As a result, effective derrick barge spread pricing has increased moderately since 2020, generally in the range of approximately 10 to 15 percent on a fully burdened operational basis. This escalation does not reflect CPI-level inflation or structural tightening of fleet supply. Rather, it reflects contractor consolidation, moderate cost pressure in fuel and crewing, and intermittent clustering of decommissioning campaigns.

Broader heavy lift conditions further influence market behavior. Higher-capacity crane vessels and dynamically positioned subsea construction assets are increasingly deployed in offshore wind installation, subsea infrastructure, and large marine construction projects. Demand growth in these adjacent sectors has resulted in percentage increases in the mid-teens range for larger and higher-specification assets. While Pacific OCS removals do not universally require ultra-heavy lift vessels, global demand for high-capacity marine equipment influences availability and pricing expectations across the heavy lift spectrum.

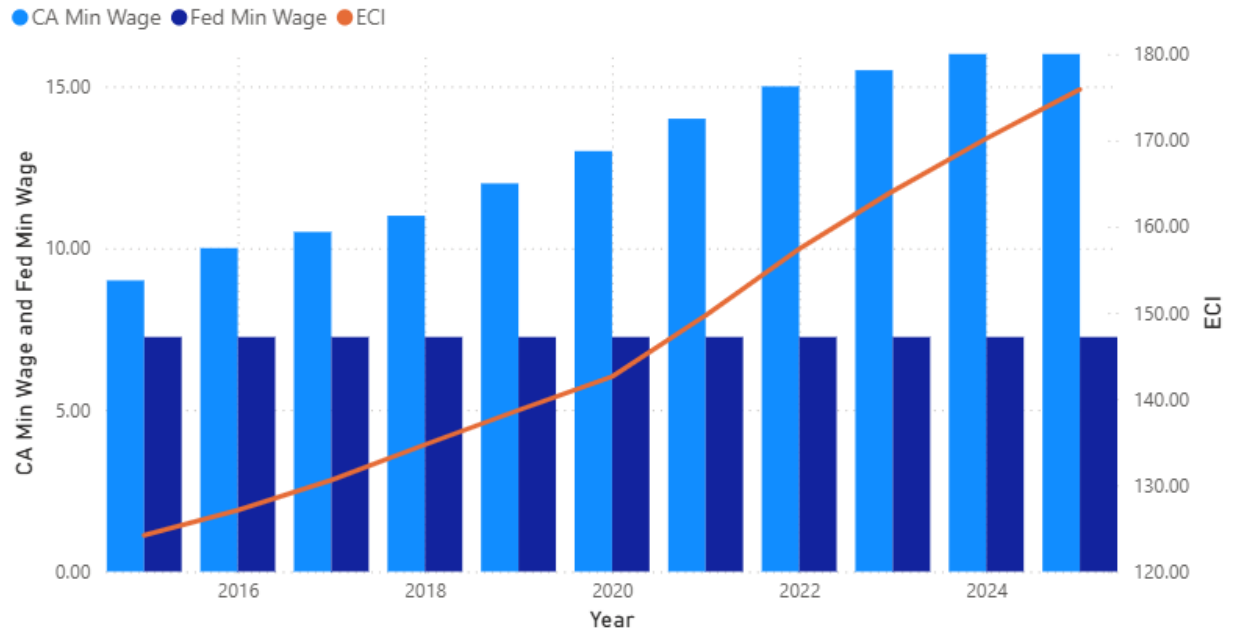
Diving strategy also contributes to the escalation profile. The prior study incorporated saturation diving mobilized onto a dedicated dynamically positioned vessel. In reassessing execution efficiency, multiple configurations were evaluated, including portable saturation systems deployed from a derrick barge. When normalized for mobilization exposure, decompression allowances, and anticipated task durations, saturation deployment did not produce material cost advantages for the majority of anticipated scopes. Accordingly, the current execution model reflects an integrated marine spread assumption rather than reliance on a separate high-specification saturation vessel. This refinement represents execution optimization rather than structural escalation.

Labor escalation presents a differentiated pattern. Compensation for engineering, project management, environmental compliance, and technical oversight roles has increased materially since 2020, generally in the range of approximately 18 to 25 percent. This pressure is particularly evident in California where competition for experienced technical personnel remains strong. These increases directly affect planning, permitting, and management components of decommissioning programs.

Figure 13-2 below shows that the federal minimum wage has remained stagnant while minimum wage in California has increased by nearly 78 percent in the same 10-year period. This demonstrates a driver for the increase in labor rates for engineering, project management, planning, and regulatory compliance.



CA Min Wage, Fed Min Wage and ECI by Year



Year	ECI	Fed Min Wage	CA Min Wage (26+emp)
2015	124.20	7.25	9.00
2016	127.10	7.25	10.00
2017	130.60	7.25	10.50
2018	134.70	7.25	11.00
2019	138.70	7.25	12.00
2020	142.60	7.25	13.00
2021	149.70	7.25	14.00
2022	157.40	7.25	15.00
2023	164.10	7.25	15.50
2024	170.20	7.25	16.00
2025	175.89	7.25	16.00

Figure 13-2 – Employment Cost Index (ECI) & Minimum Wage References

Offshore marine crews, subsea technicians, and fabrication yard personnel have experienced more moderate escalation, generally in the range of approximately 8 to 12 percent. Compensation within these sectors remains influenced primarily by marine utilization cycles and established labor structures. While upward pressure exists, escalation has not mirrored the increases observed in professional services.

Certain consumable materials introduce additional nuance. Cement, steel, and related inputs used in well abandonment operations, including casing bridge plugs and related applications, have increased at rates exceeding general CPI in recent years. However, these materials represent a smaller share of total campaign cost relative to marine spreads and labor. Their escalation contributes to cost movement but does not dominate normalization.

It is also important to consider the commercial behavior of operators and liability holders. Decommissioning obligations represent significant financial liabilities, and operators have historically



structured campaigns to manage cost exposure carefully. Work scopes are frequently aggregated to achieve scale efficiencies. Campaign timing may be aligned to take advantage of softer marine markets. Well plugging programs are sequenced to optimize rig utilization and minimize nonproductive time. These strategies introduce countervailing pressure against broad-based escalation and help moderate cost growth.

When these factors are evaluated collectively, cumulative CPI growth does not accurately represent the escalation profile of Pacific OCS decommissioning execution. The largest cost component, heavy lift marine spreads, has increased moderately in the approximate 10 to 15 percent range. Professional services have escalated more significantly. Offshore labor and subsea services have risen at intermediate levels. Certain consumables have exceeded CPI, though their proportional impact is limited. Operator campaign structuring has partially offset upward pressure.

After weighing these components according to their relative contribution within a typical removal campaign, a blended normalization of approximately 13 percent relative to the 2020 study values is applied in this update. This adjustment reflects observed marine market behavior, contractor consolidation effects, differentiated labor escalation, elevated material inputs, and commercially optimized execution strategies. It avoids mechanical CPI escalation while recognizing documented movement across key cost drivers.

The resulting 13 percent normalization is considered reasonable, defensible, and consistent with current heavy lift utilization patterns and workforce market conditions.

13.1 REGIONAL ASSET AVAILABILITY AND WEST COAST CAPACITY

It is also important to note that regional marine capacity on the West Coast has evolved since publication of the 2020 study. While historically much of the heavy lift and subsea capability supporting Pacific OCS activity was mobilized from the Gulf of America, the current market reflects increased regional availability of marine assets.

This includes the presence or anticipated availability of dynamically positioned construction vessels capable of supporting ROV and subsea operations, additional material barges operating in California waters, two smaller derrick barges in the approximate 500- and 800-ton lift class, and a 2,000-ton shear leg heavy lift vessel operating regionally.

While the smaller lift-class barges are not substitutes for the 1,000–1,600-ton Shelf-class derrick barges required for primary jacket removal, they provide flexibility for preparatory lifts, conductor removals, module handling, and certain structural segmentation activities. Similarly, the availability of a regional shear leg vessel introduces discretion for larger lift scopes without full reliance on Gulf-based mobilization.

The presence of these assets does not eliminate the need for Gulf-based heavy lift capability in all cases. However, increased regional alternatives moderates mobilization exposure, improves competitive positioning, and reduces the risk of structural rate escalation driven solely by geographic scarcity.

Accordingly, while moderate increases in marine spread pricing have occurred since 2020, the expanded regional asset base provides a counterbalancing influence and supports the reasonableness of the blended normalization applied in this update.



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APPENDIX A – DECOMMISSIONING COST ESTIMATES

This Appendix describing the total costs by decommissioning phase by platform shown in Table A-1.

Table A-1 – Decommissioning Cost Estimates in \$ USD by Platform

Platform	Permitting & Regulatory	Platform Prep	Pres. & Maint.	Well P&A Costs	HLV Mob/Demob	Platform Removal	Transp. & Disp.	Pipeline Decom	Power Cable Decom	Site Clearance	PMEP	Work Contingency	Weather Contingency	Total
A	1,066,700	394,100	18,856,000	32,656,600	2,036,100	7,368,700	1,098,900	1,985,100	248,300	552,000	5,215,700	9,939,400	3,206,500	84,624,100
B	1,066,700	401,200	17,974,000	24,532,600	2,036,100	7,371,500	1,119,700	2,074,300		554,600	4,485,100	8,569,600	2,749,900	72,935,300
C	1,066,700	355,200	15,916,000	22,506,400	2,036,100	7,374,200	1,104,100	1,229,000	280,300	557,100	4,108,700	7,863,800	2,514,600	66,912,200
Edith	1,066,700	801,500	7,678,800	9,729,400	2,036,100	10,734,300	2,191,600	490,500	230,700	518,400	2,752,900	5,321,700	1,667,200	45,219,800
Ellen	1,066,700	1,101,000	20,092,700	29,021,500	2,036,100	10,773,800	3,669,800			650,000	5,387,600	10,261,700	3,313,900	87,374,800
Ely	1,066,700	854,000	2,702,700		2,036,100	12,837,900	3,165,100	656,900		637,600	1,831,200	3,593,600	1,091,200	30,473,000
Eureka	1,066,700	1,539,200	18,464,200	24,643,500	2,036,100	37,395,300	9,125,200	2,701,400	556,200	1,201,300	7,813,000	14,809,400	4,829,800	126,181,300
Gail	1,113,300	1,585,100	4,848,300		1,583,600	38,878,400	8,970,800	1,660,800		1,249,400	4,702,100	8,983,500	5,766,300	79,341,600
Gilda	1,066,700	932,700	19,752,600	28,889,100	2,036,100	11,055,400	2,515,300	1,327,000	233,400	574,000	5,385,200	10,257,300	6,624,900	90,649,700
Gina	1,066,700	145,000	5,766,200	5,174,100	2,036,100	3,239,100	330,200	811,700	248,800	503,800	1,460,400	2,898,300	859,400	24,539,800
Grace	1,113,300	843,600	2,698,800		1,583,600	13,231,400	2,091,100	1,216,900		715,200	1,790,400	3,524,100	2,126,700	30,935,100
Habitat	1,113,300	687,700	4,170,600	7,123,500	1,583,600	9,404,800	2,235,700	627,900	262,000	679,800	2,142,000	4,183,300	1,283,100	35,497,300
Harmony	1,066,700	2,013,100	15,546,100	26,747,300	2,036,100	87,852,600	17,846,000	4,206,700	499,300	1,834,600	12,686,500	23,947,300	15,751,500	212,033,800
Harvest	1,113,300	1,816,100	5,248,300		1,583,600	36,265,100	8,335,700	1,254,900		1,168,500	4,453,800	8,517,800	8,183,800	77,940,900
Henry	1,066,700	324,300	9,448,000	11,731,400	2,036,100	5,225,700	884,400	1,012,000	701,800	533,000	2,551,700	4,944,500	1,541,500	42,001,100
Heritage	1,066,700	2,047,100	19,662,100	38,962,500	2,036,100	71,811,300	14,539,900	2,517,000	934,600	1,678,200	12,335,100	23,288,300	22,968,300	213,847,200
Hermosa	1,113,300	1,570,600	5,248,300		1,583,600	36,108,900	7,047,700	1,817,400		1,077,300	4,356,300	8,335,100	8,001,100	76,259,600
Hidalgo	1,113,300	1,624,700	5,248,300		1,583,600	24,059,000	5,380,100	1,403,800		858,000	3,212,600	6,190,600	5,856,600	56,530,600
Hillhouse	1,066,700	359,800	16,798,000	23,494,800	2,036,100	6,052,600	1,125,100	1,247,800	747,900	554,500	4,193,300	8,022,500	2,567,500	68,266,600
Hogan	1,113,300	525,700	7,688,900	10,751,800	1,583,600	8,490,800	1,324,100	1,458,900	255,500	507,400	2,606,900	5,055,000	1,573,700	42,935,600
Hondo	1,066,700	1,732,900	13,488,100	18,200,600	2,036,100	29,337,800	6,960,100	691,700	676,400	1,380,500	5,960,300	11,335,600	7,343,800	100,210,600
Houchin	1,113,300	569,500	8,570,900	10,357,700	1,583,600	7,608,500	1,456,700	1,227,300	238,200	518,900	2,570,500	4,986,700	1,550,900	42,352,700
Irene	1,113,300	583,600	8,584,800	10,795,000	1,583,600	9,684,900	2,037,400	1,752,000	255,200	619,100	2,871,600	5,551,300	5,217,300	50,649,100
Total	24,953,500	22,807,700	254,452,700	335,317,800	42,757,800	492,162,000	104,554,700	33,371,000	6,368,600	19,123,200	104,872,900	\$200,380,400	\$116,589,500	\$1,757,711,800



APPENDIX B – PLATFORM REMOVAL WEIGHTS

This Appendix shows the estimated removal weights of each platform by component in Table B-1 below.

Table B-1 – Removal Weights by Platform

Platform	Water Depth (feet)	Jacket and Pile Weight (tons)	Conductors (tons)	Topside (tons)	Total Weight (tons)
A	188	2,084	1,343	1,357	4,784
B	190	2,090	1,439	1,357	4,887
C	192	2,097	1,354	1,357	4,808
Edith	161	4,057	381	4,134	8,572
Ellen	265	4,032	6,299	5,300	15,631
Elly	255	4,256	0	8,000	12,256
Eureka	700	21,198	12,185	4,700	38,083
Gail	739	20,620	7,519	7,693	35,833
Gilda	205	3,988	3,190	3,792	10,970
Gina	95	612	373	447	1,432
Grace	318	4,129	0	3,800	7,929
Habitat	290	3,399	2,063	3,514	8,976
Harmony	1,198	47,430	15,281	9,839	72,550
Harvest	675	18,753	5,052	9,024	32,828
Henry	173	1,594	845	1,371	3,810
Heritage	1,075	36,485	12,901	9,826	59,212
Hermosa	603	18,893	0	7,830	26,723
Hidalgo	430	12,300	0	8,100	20,400
Hillhouse	190	1,894	1,893	1,200	4,987
Hogan	154	1,692	1,411	2,259	5,362
Hondo	842	13,944	5,885	8,450	28,279
Houchin	163	1,893	1,370	2,591	5,854
Irene	242	3,860	1,801	2,500	8,161



APPENDIX C – PLATFORM, DECK, AND JACKET REMOVAL DETAILS

This Appendix shows the details of each platform

Table C-1 – Platform, Deck, and Jacket Removal Details for Campaign 1

Platform Name	Hogan	Houchin	Habitat	Irene	Grace	Gail	Harvest	Hermosa	Hidalgo
Water Depth, feet	154	163	290	242	318	739	675	603	430
Deck Weight, tons	2,259	2,591	3,514	2,500	3,800	7,693	9,024	7,830	8,100
Number of Modules/Lifts	2	3	3	2	3	7	8	7	7
Max Weight per Module, tons	1,130	864	1,171	1,250	1,267	1,099	1,128	1,119	1,157
Jacket and Pile Weight, tons	1,692	1,893	3,399	3,860	4,129	20,620	18,753	18,893	12,300
Jacket Sections	4	4	4	4	5	22	20	20	14
Max Weight per Section, tons	423	473	850	965	826	937	938	945	879
Number of Main Piles	12	8	8	8	12	8	8	8	8
Number of Skirt Piles	-	-	-	-	8	12	20	12	8

Table C-2 – Platform, Deck, and Jacket Removal Details for Campaign 2

Platform Name	A	B	C	Henry	Hillhouse	Gina	Gilda
Water Depth, feet	188	190	192	173	190	95	205
Deck Weight, tons	1,357	1,357	1,357	1,371	1,200	447	3,792
Number of Modules	2	2	2	2	1	1	3
Max Weight per Module, tons	679	679	679	686	1,200	447	1,264
Jacket Weight, tons	2,084	2,090	2,097	1,594	1,894	612	3,988
Jacket Sections	3	3	3	2	3	1	4
Max Weight per Section, tons	695	697	699	797	631	612	997
Number of Piles	12	12	12	6	8	6	12
Number of Skirt Piles	-	-	-	-	-	-	-

Table C-3 – Platform, Deck, and Jacket Removal Details for Campaign 3

Platform Name	Hondo	Heritage	Harmony	Edith	Elly	Eureka	Ellen
Water Depth, feet	842	1,075	1,198	161	255	700	265
Deck Weight, tons	8,450	9,826	9,839	4,134	8,000	4,700	5,300
Number of Modules	7	8	8	4	7	4	5
Max Weight per Module, tons	1,207	1,228	1,230	1,034	1,143	1,175	1,060
Jacket Weight, tons	13,944	36,485	47,430	4,057	4,256	21,198	4,032
Jacket Sections	13	33	43	4	4	20	4
Max Weight per Section, tons	1,073	1,106	1,103	1,014	1,064	1,060	1,008
Number of Piles	8	8	8	12	12	-	8
Number of Skirt Piles	12	26	20	-	-	24	-



APPENDIX D – WELL RISK CATEGORIZATION

This Appendix shows the Well Categorization by platform in Table D-1

Table D-1 – Well Categorization by Platform

Platform	Average Well Depth(feet)	High	Med	Med-Low	Low	TA-To Surface	Conductor Only	Total Count
A	3,714	12	35	0	8	0	2	57
B	3,123	1	36	4	11	1	3	56
C	3,337	4	28	0	13	0	3	48
Edith	5,371	0	15	3	0	2	9	29
Ellen	7,127	0	43	18	0	2	1	64
Eureka	6,639	0	34	12	3	1	10	60
Gilda	7,855	1	41	16	1	4	0	63
Gina	6,474	0	6	6	0	0	0	12
Habitat	11,609	2	3	1	0	14	0	20
Harmony	12,908	7	28	0	0	0	5	40
Henry	4,142	0	22	1	0	1	0	24
Heritage	15,098	16	33	0	0	0	0	49
Hillhouse	3,421	1	38	4	5	1	0	49
Hogan	5,346	1	11	4	1	6	17	40
Hondo	13,064	3	25	0	0	0	0	28
Houchin	3,664	1	2	14	3	7	9	36
Irene	11,208	3	12	4	0	0	0	19
Total		52	412	87	45	39	59	694

There are 113 wells reported as permanently abandoned in the data provided by BSEE dated March 23, 2026. There is a subsea well near Platform B that has not been included in this analysis; the API number of this well is 043112000900. The well counts shown in Table D-1 do not include wild cat/exploratory wells.



APPENDIX E – PIPELINE REMOVAL

At the request of BSEE, this study includes a generalized cost estimate for the full removal of all pipelines currently included in the updated inventory. The pipeline inventory utilized in this analysis reflects updates provided through Clarification Request CR 2 (POCSR Pipeline Inventory List dated March 17, 2026). These updates resulted in the addition of three pipelines that were not included in the draft submission, as well as revisions to previously identified segments. The updated inventory has been incorporated into the removal methodology and cost model accordingly.

E.1 PIPELINE REMOVAL METHODOLOGY

The pipeline removal approach follows a conventional offshore “slice and dice” methodology, which has been selected based on constructability, safety considerations, and consistency with observed performance on comparable projects. This methodology consists of uncovering the pipeline using mass flow excavation techniques, segmenting the pipe into manageable lengths, and recovering the material to the surface for transport and disposal.

The offshore removal spread consists of either an anchored derrick barge or a dynamically positioned (DP) vessel in deeper water, supported by a material barge and tug configuration. Two material barges and associated tugs are included in the spread to maintain continuous operations, with one barge actively supporting the removal spread while the second is in transit or offloading. An accommodation barge is also included to support 24-hour operations and maintain workforce efficiency.

Pipeline segmentation is performed using a hydraulic shear, with typical cut lengths ranging from approximately 30 to 40 feet. A hydraulic grapple system, guided by onboard survey systems, is used to recover the cut sections to the surface. The methodology does not require diver intervention, as all operations are conducted using surface-controlled equipment and real-time positioning.

The selected approach represents a departure from previously considered reverse lay methodologies. While reverse lay can offer advantages under certain controlled conditions, it introduces increased risk in environments where pipeline condition, burial variability, and structural integrity are uncertain. Based on experience from comparable projects, these risks were determined to outweigh potential efficiency gains, particularly given the age and unknown condition of many POCSR pipelines. The slice and dice methodology provides a more controlled and predictable removal process.

Production rates for pipeline removal are based on observed performance from a comparable offshore project utilizing a similar spread configuration. The baseline production rate was established for 16-inch pipeline and subsequently adjusted to account for variations in pipeline diameter and operational efficiency. These rates are further adjusted based on water depth and pipeline characteristics, recognizing that larger diameter pipelines and deeper water conditions generally reduce production efficiency.

Recovered pipeline material is transported to shore for disposal at regional recycling facilities, including the Port of Los Angeles (POLA) and Port of Long Beach (POLB). Disposal costs are estimated at \$200 per ton, consistent with current market conditions for steel recycling and handling.

Pipeline weights used in the analysis are based on Schedule 40 steel pipe assumptions, with additional weight applied for concrete weight coating (CWC) on pipelines 16 inches in diameter and larger. A coating thickness of 1.5 inches and a density of 140 pounds per cubic foot were applied to represent typical historical coating practices.



In general, the selected methodology reflects a balanced approach that prioritizes operational reliability, safety, and realistic production performance, while providing a consistent basis for estimating full pipeline removal costs across the POCSSR inventory.

Cost estimates based on this methodology for the complete removal of the pipelines are shown in Table E-1.

Table E-1 – Pipeline Removal Cost

Platform	Segment 1	Segment 2	Segment 3	Segment 4	Segment 5	Total Cost
A	\$5,765,700	\$5,765,700	\$418,100	\$495,900	\$495,900	\$12,941,300
B	\$386,900	\$386,900	\$2,950,000	\$5,747,500	\$5,747,500	\$15,218,800
C	\$332,900	\$332,900	\$332,900	\$562,100		\$1,560,800
Edith	\$3,284,600					\$3,284,600
Elly	\$11,571,000					\$11,571,000
Eureka	\$1,438,200	\$952,200	\$1,445,900	\$1,694,400	\$1,445,900	\$6,976,600
Gail	\$4,340,500	\$4,432,100	\$4,276,400			\$13,049,000
Gilda	\$4,885,200	\$4,094,100	\$2,512,200			\$11,491,500
Gina	\$1,850,900	\$1,224,400				\$3,075,300
Grace	\$9,263,500	\$7,761,100				\$17,024,600
Habitat	\$4,153,400					\$4,153,400
Harmony	\$12,819,700	\$7,815,000	\$4,428,700	\$4,859,100		\$29,922,500
Harvest	\$3,438,000	\$2,302,100				\$5,740,100
Henry	\$1,283,600	\$1,301,900	\$1,044,700			\$3,630,200
Heritage	\$16,376,600	\$9,999,500				\$26,376,100
Hermosa	\$12,767,800	\$11,061,100				\$23,828,900
Hidalgo	\$6,557,600	\$4,157,400				\$10,715,000
Hillhouse	\$383,400	\$329,700	\$329,700	\$383,400		\$1,426,200
Hogan	\$1,647,800	\$1,961,200	\$1,647,800	\$717,800		\$5,974,600
Hondo	\$3,986,100					\$3,986,100
Houchin	\$320,600	\$558,900	\$558,900	\$637,700		\$2,076,100
Irene	\$8,718,800	\$3,438,700	\$3,438,700			\$15,596,200
Total						\$229,618,900

Pipeline Removal Assumptions

- ROV mobilization and transit preparations are included in vessel mobilization costs.
- Pipeline weights are based on:
 - Schedule 40 steel pipe
 - Concrete weight coating applied to 16-inch through 24-inch pipelines, assuming:
 - 1.5-inch coating thickness
 - 140 lb/ft³ density
- Disposal costs are assumed at \$200 per ton, based on delivery to recycling facilities at POLA or POLB.



- Production rates and costs are intended to represent average expected performance and do not account for localized anomalies such as excessive burial, damage, or obstructions



APPENDIX F – POWER CABLE REMOVAL

At the request of BSEE, this study includes a generalized cost estimate for the full removal of all power cables.

F.1 POWER CABLE REMOVAL METHODOLOGY

Power cable removal is assumed to be executed concurrently with pipeline removal activities, utilizing the same offshore spread, vessels, and operational sequencing. Under this approach, a DP2 vessel equipped with work-class ROVs, supported by material barges and tugs, performs cable recovery in parallel with pipeline “slice and dice” operations, allowing for shared resources and continuous 24-hour execution. Power cables are located, exposed, and severed into manageable sections using subsea cutting tools, with recovery conducted via crane or winch systems and transferred to material barges for transport to shore. Nearshore and platform interface segments are disconnected, with burial or stabilization performed in accordance with regulatory requirements. Consistent with the integrated removal strategy, two material barges are assumed to maintain efficiency, enabling simultaneous offshore operations and transport logistics. This concurrent execution approach is consistent with prior Pacific OCS studies, which evaluate pipelines and power cables within a unified operational and cost framework.

Recovered power cable material is transported to shore for disposal at regional recycling facilities. No net material value is included in the cost estimates shown in Table F-1.

Table F-1 – Power Cable Removal Cost

Cable Origin	Cable Terminus	Length (ft)	Depth (ft)	Campaign	Survey Cost	Removal	Total Cost
Habitat	A	19,536	292-188	1	\$39,000	\$1,383,800	\$1,422,800
Hogan	Shore	4,752	150-0	1	\$39,000	\$209,400	\$248,400
Houchin	Hogan	3,800	176-150	1	\$39,000	\$157,900	\$196,900
A	B	2,640	188-200	2	\$46,000	\$109,700	\$155,700
Ellen**							
Elly							
Eureka*	Ellen x 2 cables	2,640	200-193	3	\$46,700	\$220,000	\$266,700
Gail							
Irene	Shore	14,784	242-0	1	\$39,000	\$614,300	\$653,300
Gilda	Shore	36,960	205-0	2	\$38,900	\$1,535,800	\$1,574,700
Grace							
C	Shore	26,400	193-0	2	\$38,900	\$1,225,500	\$1,264,400
Henry	Shore x 2 cables	13,200	170-189	2	\$46,600	\$1,292,600	\$1,339,200
Harvest							
Gina	Shore	1,584	90-0	2	\$38,900	\$68,300	\$107,200
Hillhouse	Shore	17,952	189-0	2	\$38,900	\$1,704,700	\$1,743,600
Heritage	Shore	104,544	1075-0	3	\$39,600	\$4,344,100	\$4,383,700
Hermosa							
Hidalgo							
Heritage	Harmony	39,072	1075-1200	3	\$39,600	\$1,623,600	\$1,663,200
Edith	Shore	36,960	150-0	3	\$39,600	\$1,535,800	\$1,575,400
Hondo	Harmony	47,520	842-1200	3	\$39,600	\$4,212,900	\$4,252,500
Eureka	Ellen	15,297	700-265	3	\$39,600	\$646,400	\$686,000
Harmony	Shore	59,664	1200-0	3	\$39,600	\$2,479,200	\$2,518,800
Total							\$24,052,500



*Data indicates two cables, total length is for each cable, costs reflect both cables.

** Ellen connects to Elly by topside bridge, costs for abandonment are reflected in Platform Preparation.

Power Cable Removal Assumptions

- ROV mobilization and transit preparations are included in vessel mobilization costs.
- Disposal costs are assumed at \$200 per ton, based on delivery to recycling facilities at POLA or POLB.
- For cost estimating purposes, recovered power cables are assigned a unit weight of 55 pounds per linear foot to account for armoring and associated materials, forming the basis for transportation and disposal cost calculations.
- Production rates and costs are intended to represent average expected performance and do not account for localized anomalies such as excessive burial, damage, or obstructions



APPENDIX G – SHELL MOUND REMOVAL

At the request of BSEE, a removal cost estimate for shell mounds that are believed to be present at all the POCSR platforms has been prepared as follows. This cost estimate is based on varied assumptions, incomplete data, and without industry standard removal methodology. This estimate is also limited by unclear regulatory requirements for shell mound removal. As discussed in this section, the 2023 PEIS Record of Decision (ROD) is not explicit in determination if shell mound removal is mandated.

Shell mounds are accumulations of biofouling organisms (primarily mussel shells and barnacles), natural sediment, and, in many cases, historic drill cuttings and drilling mud that have settled on the seafloor beneath and immediately surrounding offshore oil and gas platforms over decades of operation. The following is a characterization of shell mounds at all 23 POCSR platforms, evaluation available dimensional and volumetric data, and proposed removal methodology based on the most current technical planning documents.

G.1 INTRODUCTION

Shell mounds have been confirmed at 17 of the 23 POCSR platforms through direct survey or sampling, including submersible video transects conducted by Goddard & Love (MMS 2007-007; Bull. Marine Sci. 86(3), 2010), multibeam hydrographic surveys by MEC Analytical Systems/Sea Surveyor, Inc. (2003), and biological sampling reported by Page & Dugan (OCS Study MMS 2005-001, February 2005). For the remaining 6 platforms (A, B, Habitat, Henry, Heritage, and Hillhouse), shell mound formation is anticipated on the basis of operational history, but specific survey data has not been identified in the reviewed literature.

Mound dimensions and volumes vary considerably across the inventory, reflecting differences in water depth, platform age, organism productivity, and historical drilling activity. Shallow-water platforms tend to have larger, better-defined mounds: Platform Gina at 95 ft water depth has a measured volume of approximately 4,200 cubic yards, while Platforms Hogan and Houchin at 154 and 163 ft water depth are estimated at 8,000 to 16,000 cubic yards each based on published footprint and height measurements. In deeper federal waters, mound volumes generally decrease, with some platforms exhibiting multiple small, poorly defined features rather than a single cone-shaped mound.

Among the site clearance obligations that arise upon platform removal, the presence of shell mounds beneath and around each platform structure is an increasingly prominent regulatory and engineering consideration. Shell mounds are not uniformly addressed under federal decommissioning regulations. Nevertheless, understanding the nature, extent, and potential removal methodology for these features is essential to complete decommissioning planning, particularly given the 2023 Pacific Region Programmatic Environmental Impact Statement (PEIS) Alternative 1 call for complete removal of obstructions.

The removal approach is informed by publicly available shell mound data, and concurrent removal methodology proposals for the 23 POCSR platforms. At the time of writing, significant assessment and evaluation has been conducted for a platform in state-waters with a potential requirement for the removal of a shell mound at its base. This assessment and evaluation represents the most technically developed precedent for POCSR-comparable conditions.

Platform decommissioning in the POCSR is governed principally by 30 CFR Part 250, Subpart Q (Decommissioning Activities), which requires the removal of platforms, equipment, and subsea obstructions that would interfere with commercial navigation or fishing. The 2023 PEIS Record of Decision (ROD) selected Alternative 1 – Proposed Action as the preferred approach, calling for the complete removal of platforms, conductors, pipelines, and subsea infrastructure. However, the ROD



explicitly states that it “does not by itself authorize or impose requirements on decommissioning activities on the POCS,” and site-specific requirements are to be determined through individual future NEPA reviews.

Shell mounds are not explicitly enumerated as a mandatory removal item under Alternative 1, and their regulatory status remains subject to site-specific NEPA review and coordination with state agencies (including the California State Lands Commission and California Coastal Commission where applicable). The ROD’s discussion of shell mounds in the context of alternatives involving infrastructure left in place underscores the importance of mound characterization when making final disposition decisions.

G.2 SHELL MOUND DESCRIPTION AND CHARACTERISTICS

Shell mounds at offshore oil and gas platforms are the product of two distinct but interrelated processes that have occurred concurrently over the operational lifetimes of the platforms. The first is the accumulation of drill cuttings and drilling muds discharged to the seafloor during well drilling operations. From the late 1950s through the early 1970s, regulatory practice permitted the direct seafloor discharge of cleaned drill cuttings and water-based drilling muds from platforms on both state and federal leases. During this period, the drilling muds used commonly contained polychlorinated biphenyls (PCBs), metals, polycyclic aromatic hydrocarbons (PAHs), and hydrocarbons, which settled beneath each platform to form an initial mounded deposit of contaminated material.

The second process is the biological colonization of the platform substructure and the subsequent fall of encrusting organisms to the seafloor. California offshore platforms support exceptionally dense populations of blue mussels, barnacles, and other fouling invertebrates on their submerged structural members. Over decades of platform operation, these organisms grow, die, detach, or are cleaned from the jacket member surfaces, and fall to the seafloor beneath the platform, accumulating as a shell hash layer on top of and surrounding the underlying drill-mud-and-cuttings core. This outer biogenic layer is composed primarily of empty mussel shells intermixed with natural marine sediment and is typically 1 to 7 feet thick at its deepest points at the mound crest. The result is a two-layer structure: an inner core of contaminated drill waste overlaid and partially encapsulated by an outer layer of biogenic shell material.

Over time, natural sedimentation further modifies the mound profile, progressively burying the lower portions of the mound and contributing to the apparent stability observed in long-term bathymetric monitoring of the former 4H platform sites (Hazel, Hilda, Heidi, and Hope), where geophysical surveys conducted between 1996 and 2021 showed no evidence of slope failure and a consistent mound topography despite multiple physical disturbances.

Shell mounds in the POCSR generally take one of two forms depending primarily on water depth and the magnitude of associated biofouling productivity:

Single, well-defined mound – Characteristic of platforms in shallow to moderate water depths (approximately 95 to 320 ft). These mounds rise as a broadly conical or flat-topped feature directly beneath the platform structure, with a discernible crest, sloping flanks, and a relatively well-defined base perimeter at the surrounding seafloor. The apex of the mound is typically located within the platform footprint, often beneath the center of the conductor bay.

Multiple small, poorly defined mounds – Characteristic of deeper-water platforms (generally greater than 500 ft water depth) or platforms with lower biofouling productivity. These platforms exhibit several discrete small mounds rather than a single large feature, often described as having no clear apex or perimeter. Platforms Gail (739 ft), Harmony (1,198 ft), Hondo (842 ft), and Hermosa (603 ft) all display this multi-mound character.



Across the full POCSR inventory surveyed by MEC/Sea Surveyor (2003) using multibeam hydrographic methods, mound heights ranged up to approximately 28 feet, and mound footprints extended up to approximately 85,700 square feet. Volumes ranged from less than 500 to approximately 12,500 cubic yards across the federal OCS platform inventory.

Shell mounds support distinct and productive benthic communities that differ significantly from the surrounding soft-sediment seafloor. Goddard & Love (2010) documented diverse assemblages of mobile macroinvertebrates at all 15 platforms surveyed, including sea stars, sea urchins, sea cucumbers, rock crabs, spiny lobsters, and octopus. The hard substrate provided by shell hash layers supports both encrusting and mobile species, effectively creating an artificial reef complex on the seafloor.

The contaminated drill-mud core within each shell mound presents a latent environmental concern. Studies of the 4H platform mounds conducted through 2023 have found trace concentrations of PCBs, PAHs, metals, and barium in mound sediment cores. However, 2006 site studies concluded that chemical contaminants in the 4H mounds are not presently being remobilized into the overlying water column, and that without large physical disturbance, the contaminants will likely remain sequestered by the overlying shell-hash layer and accumulating natural sediments.

The primary environmental risk associated with shell mound removal is the disruption of contaminated sediments during excavation. Both the U.S. Army Corps of Engineers and the Central Coast Regional Water Quality Control Board raised concerns during the 2003 EIR/EA process for the 4H platform mounds, specifically regarding the risk of introducing PCBs and other contaminants into the water column through clamshell dredging. Removal operations must therefore employ sediment containment measures, use sealed hopper barges, and develop turbidity monitoring and contingency plans in coordination with applicable regulatory agencies.

G.3 DATA SOURCES AND SURVEY METHODS

Shell mound presence and physical characteristics for some of the 23 POCSR platforms have been established through several independent survey programs conducted between 1997 and 2023:

- Multibeam Hydrographic Survey (MEC/Sea Surveyor, 2003): The primary source for platform-specific mound dimensions across the POCSR platform inventory. This survey used multibeam sonar to generate bathymetric contour maps and cross-sectional profiles of mound features at 16 platforms, covering the Santa Barbara Channel and Santa Maria Basin.
- Submersible Video Transects (Goddard & Love, 1997–2005): Delta-class submersible video documentation of shell mound features at 15 POCSR platforms, providing confirmation of mound presence and qualitative description of benthic communities. That survey did not systematically report dimensional data.
- Biological Sampling (Page & Dugan, 2000–2001): SCUBA and trap-based transect sampling at active state-water platforms Gina, Hogan, and Houchin, providing footprint dimensions and mound heights measured from de Wit (2001) and MEC (2003).
- Platform Gina Characterization (BOEM, 2007): Detailed physical and chemical characterization of the Platform Gina shell mound, providing the only published measured volume in the POCSR inventory (~4,200 cubic yards).

Six platforms (A, B, Habitat, Henry, Heritage, and Hillhouse) have not been covered by published shell mound surveys in the reviewed literature. Shell mound formation is anticipated at these platforms based on their operational history and the universal presence of biofouling on all California offshore platform structures.



G.4 AVAILABLE SHELL MOUND DATA

The following subsections present the available shell mound data for each of the 23 POCSR platforms, A consolidated summary table follows on Table G-1.

Platforms A, B, and C are platforms in the Santa Barbara Channel standing at water depths of 188, 190, and 192 feet respectively. Platform C was confirmed to have a shell mound through Goddard & Love (2010) submersible transects conducted in 2000. Platforms A and B fall within the same water depth range and are anticipated to have similar mound characteristics; however, no published dimensional data was identified for any of these three platforms individually.

Gilda (205 ft) has a single, clearly defined shell mound approximately 22 feet in elevation at its apex, centered along the western edge of the platform. This is the tallest mound reported for the shallow-water Santa Barbara Channel platforms and is notable for its offset position relative to the platform centerline, which may reflect asymmetric biofouling or the lateral position of drilling activities. Full footprint dimensions were not individually reported in the MEC/Sea Surveyor (2003) survey, and the total volume is not calculable from available data.

Grace (318 ft) has a shell mound centered on the northwest corner of the platform, with portions of the mound extending laterally beyond the platform footprint. This lateral extent indicates a substantial mound that may pose access constraints for jacket removal. Specific height and volume data are not published in the reviewed literature.

Gail (739 ft) is the best-characterized deep-water platform with respect to individual mound dimensions. The MEC/Sea Surveyor (2003) survey documented four discrete small mounds beneath and adjacent to Platform Gail: two approximately 3 feet in height (one with a base of approximately 40 by 60 feet) and two approximately 2 feet in height (with bases of approximately 20 by 70 feet and 25 by 50 feet). Using an elliptical cone approximation described in Section 12.4.4.1, the total volume of all four mounds is estimated at approximately 190 cubic yards – consistent with the lower end of the MEC (2003) reported range and characteristic of small, dispersed features at greater depths.

Platforms Harmony (1,198 ft) and Hondo (842 ft) exhibit multiple small, poorly defined mounds as confirmed by Goddard & Love (2010). At these depths, biofouling organism productivity is substantially reduced compared to shallower platforms, and the resulting mound features are less coherent. The volumes at these depths are expected to fall in the lower portion of the published range.

Platform Heritage (1,075 ft) has not been covered by published shell mound surveys. At its depth, mound features similar to those observed at Harmony and Hondo are anticipated.

Platforms Edith (161 ft), Ellen (265 ft), Elly (255 ft), and Eureka (700 ft) were all confirmed to have shell mounds through Goddard & Love (2010) submersible transects. Edith was surveyed in 1998, while Ellen, Elly, and Eureka were surveyed in 2005. Individual mound dimensions were not systematically reported for any of these platforms in the available literature. Edith, at 161 ft, is the shallowest of the four and is likely to have a more substantial, well-defined mound compared to the deeper platforms. Eureka, at 700 ft, falls in the depth range associated with smaller, less coherent mound features.

Gina (95 ft) has the most detailed characterization of any POCSR platform, documented in the BOEM (2007) study. The mound footprint is approximately 148 by 207 feet with a height of 12.8 feet, and the total volume is measured at approximately 4,200 cubic yards. Mound composition includes shell hash, sediment, and drill cuttings. Despite its comparatively shallow relief, Gina's mound represents a substantial volume of material for a single platform.

Hogan (154 ft) has a well-defined shell mound with a footprint of approximately 78 by 78 meters (256 by 256 feet) and a height of 7.8 meters (25.6 feet), measured by trap and transect sampling during 2000–



2001 (Page & Dugan, OCS Study 2005-001). Using the elliptical cone volume model described in section G.5, the estimated volume is approximately 8,000 to 16,000 cubic yards – among the largest in the POCSR inventory. The wide estimated volume range reflects the sensitivity of cone-based estimates to assumed base shape.

Houchin (163 ft) has a similarly substantial mound: footprint 276 by 276 feet, height 20.7 feet. Estimated volume using the same cone model is approximately 8,000 to 15,000 cubic yards. Together, Hogan and Houchin represent the largest anticipated shell mound removal volumes in the POCSR inventory.

Platforms Habitat (290 ft), Henry (173 ft), and Hillhouse (190 ft) have not been covered by published shell mound surveys. All three are platforms with documented biofouling communities. Shell mounds are anticipated at each location, but no defined dimensional data appears in the reviewed literature.

Hidalgo (430 ft) was surveyed multiple times (1997–2001, 2004–2005), as were Harvest (675 ft, 1997–2000 and 2004), Hermosa (603 ft, 1997–2000 and 2004), and Irene (242 ft, 1997–2001 and 2004–2005). All four were confirmed to have shell mounds through Goddard & Love (2010) surveys. Hermosa exhibits multiple small, poorly defined mounds consistent with its intermediate depth, while Harvest, Hidalgo, and Irene likely have more discrete mound features. Individual dimensional data are not published in the available literature for any of these platforms, and volumes fall within the MEC (2003) range of less than 500 to 12,500 cubic yards.

Table G-1 shows the consolidated available shell mound data for all 23 POCSR platforms.

Table G-1 – POCSR Shell Mound Inventory

Platform	Water Depth (ft)	Shell Mound	Height (ft)	Footprint	Est. Volume (cu yds)	Primary Source
A	188	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
B	190	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
C	192	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Edith	161	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Ellen	265	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Elly	255	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Eureka	700	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Gail	739	Confirmed	2-3	Four discrete mounds; bases 20–70 ft	~190	MEC/Sea Surveyor (2003)



Platform	Water Depth (ft)	Shell Mound	Height (ft)	Footprint	Est. Volume (cu yds)	Primary Source
Gilda	205	Confirmed	~22	Centered on west edge of platform	N/D	MEC/Sea Surveyor (2003)
Gina	95	Confirmed	12.8	148 × 207 ft	~4,200	BOEM (2007)
Grace	318	Confirmed	N/D	NW corner; portions extending outside platform footprint	N/D	MEC/Sea Surveyor (2003)
Habitat	290	Anticipated	N/D	N/D	N/D	Not yet surveyed
Harmony	1,198	Confirmed	N/D	Multiple small, poorly defined	N/D	Goddard & Love (2010)
Harvest	675	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Henry	173	Anticipated	N/D	N/D	N/D	Not yet surveyed
Heritage	1,075	Anticipated	N/D	N/D	N/D	Not yet surveyed
Hermosa	603	Confirmed	N/D	Multiple small, poorly defined	N/D	Goddard & Love (2010)
Hidalgo	430	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)
Hillhouse	190	Anticipated	N/D	N/D	N/D	Not yet surveyed
Hogan	154	Confirmed	25.6	256 × 256 ft (78 × 78 m)	~8,000–16,000	Page & Dugan (OCS 2005-001)
Hondo	842	Confirmed	N/D	Multiple small, poorly defined	N/D	Goddard & Love (2010)
Houchin	163	Confirmed	20.7	276 × 276 ft	~8,000–15,000	Page & Dugan (OCS 2005-001)
Irene	242	Confirmed	N/D	N/D	N/D	Goddard & Love (2010)

Notes:

- N/D = Not determined; no dimensional data available in reviewed literature.



- “Anticipated” indicates mound formation expected based on operational history but not confirmed by published survey.
- Volume estimates for Hogan and Houchin based on elliptical cone model applied to published footprint and height data (Page & Dugan, 2005); actual volumes may differ.
- Platform Gina volume is measured (BOEM, 2007).
- Platform Gail volume calculated from MEC (2003) dimensions.

G.5 VOLUME ESTIMATION METHOD

Shell mound volumes in the POCSR inventory have been established through three methods: (1) direct measurement from multibeam bathymetric surveys with volumetric integration, (2) calculation from published physical dimensions using geometric models, and (3) estimation from published literature ranges for platforms with no individual data.

For platforms where only height and footprint dimensions are available (Hogan and Houchin), an elliptical cone volume model is applied:

$$V = (\pi/3) \times a \times b \times h$$

where a and b are the semi-axes of the elliptical footprint (half of the reported width and length dimensions) and h is the measured mound height. This formula estimates the volume of a perfect cone with an elliptical base and represents an upper bound since actual mounds do not extend to a perfect apex. A range is provided to reflect the uncertainty in mound geometry.

For Platform Gail, individual mound volumes are calculated using the same cone formula applied to the four discrete mounds documented by MEC/Sea Surveyor (2003), with each mound modeled as an elliptical cone. The total for all four mounds is approximately 190 cubic yards.

For platforms where neither measurements nor dimensions are available, the MEC/Sea Surveyor (2003) range of less than 500 to 12,500 cubic yards is cited as the applicable envelope. The lower end of this range is most likely for deep-water platforms (greater than 600 ft) with multiple small mounds; the upper end applies to shallow-water platforms with significant biofouling.

G.6 PROPOSED SHELL MOUND REMOVAL METHODOLOGY

The proposed removal methodology for shell mounds is adapted from similar analysis and evaluations of a platform located in state-waters. While the subject platform is not a POCSR study platform, the project is the most technically current and thoroughly planned shell mound removal effort for a California offshore platform, and its methodology is directly applicable to POCSR platform conditions.

Two primary excavation methods are proposed, both deployed from a light derrick barge positioned over the platform site. Both methods discharge excavated material to a sealed hopper barge, which transports the material to an approved port facility for onshore processing and final disposition. The two methods may be used in combination, depending on mound consistency, material composition, and operational efficiency.

The first removal method employs a high-capacity submersible dredge pump system (such as the Toyo submersible pump or equivalent) deployed from the light derrick barge by crane to the seafloor surface of the shell mound. The pump system uses a combination of hydraulic agitation and suction to excavate shell material, drill cuttings, and natural sediment from the mound and discharge it as a slurry upward through a flexible hose to the surface, where it is discharged directly into the sealed cargo hold of the hopper barge moored alongside.



The submersible dredge pump is lowered to the mound surface and moved systematically across the mound footprint, working from the mound perimeter inward toward the apex. The excavation pattern is directed to expose the underlying seafloor progressively, with the operator monitoring the operation via ROV video feed to confirm clearance and avoid interference with the remaining jacket structure. The pump system is capable of high production rates in unconsolidated shell hash and soft sediment and is particularly well-suited to the biogenic outer layer of the mound.

Advantages of the submersible dredge pump approach include:

- High volumetric production rate, particularly in the shell hash and soft sediment outer layer.
- Continuous discharge stream, minimizing crane cycle time and hopper barge turnaround.
- Effective penetration of loose, unconsolidated shell material.
- Reduced physical disturbance of the mound perimeter compared to bucket operations, which may reduce turbidity.

Limitations include reduced effectiveness in dense, consolidated drill mud or hardened cuttings layers in the mound interior, and the requirement for careful pump positioning relative to the remaining jacket structure to avoid hose entanglement or equipment damage. The effectiveness of this type of excavation is reduced as water depth increases. This method is not recommended for shell mound removals in greater than 300FSW.

The second removal method uses an environmental clamshell bucket (also known as an environmental clam bucket) suspended from the crane on the light derrick barge to mechanically excavate shell mound material. Environmental clamshell buckets are specially designed for dredging in sensitive environments: they feature closed, watertight jaws that seal tightly upon closure, preventing release of the captured material and minimizing turbidity by containing the excavated material within the bucket during the full lift cycle.

The bucket is lowered to the mound surface, closed to capture a quantity of shell, sediment, and drill-mud material, raised to the surface, swung over the cargo hold of the hopper barge, and then opened to discharge the material. Environmental clamshell buckets are available in a range of capacities, and the appropriate size is selected based on the mound material consistency, the hopper barge and deck barge configuration.

Advantages of the environmental clamshell bucket approach include:

- Effective at penetrating denser or more consolidated material in the drill-mud core layer.
- Lower turbidity generation compared to open-jaw dredge operations.
- Better-defined excavation boundaries, allowing precise removal of targeted mound areas.
- Suitable for work in confined areas near remaining jacket structure.

Limitations include lower production rates compared to the pump system, greater sensitivity to sea state, and potential for incomplete capture in very coarse, loose shell material.

Both removal methods require a light derrick barge as the primary work platform, anchored in four-point mooring depending on water depth and vessels selected. The light derrick barge provides the crane capacity needed to deploy the dredge pump system or clamshell bucket and to reposition equipment across the mound footprint. A sealed hopper barge is moored alongside the derrick barge to receive the excavated material and accompanying seawater.

The typical marine spread for a shell mound removal operation would include:

- One light derrick barge (crane capacity 150–300 tons) with either a submersible pump system or environmental clamshell bucket (or both, for sequential use).



- One or two sealed hopper barge(s) for material transport to port.
- One tugboat for barge towing and positioning.
- One ROV support spread for real-time mound visualization and clearance verification.
- One crew boat for personnel transfer and logistics support.

Once the hopper barge cargo hold is filled with excavated shell mound material and accompanying seawater, the barge is sealed and towed by tugboat to the designated port facility. Natural separation of the shell and sediment material from the captured seawater begins during transit: the denser solids settle to the bottom of the cargo hold, and a layer of relatively clear seawater overlies the settled material upon arrival at the port.

At the receiving port facility, the following processing sequence is executed:

- **Seawater Decanting:** Upon docking, seawater overlying the settled solids in the cargo hold is suctioned off through a portable filter system. The filtered water is polished to meet the quality requirements for disposal at a local wastewater treatment plant. The treated water may be trucked to an approved offsite wastewater processor for licensed treatment, or pumped directly into an approved sewer pipe for treatment by the local wastewater utility, subject to pre-approval and permitting from the utility and regulators
- **Solid Material Offloading:** Following water decanting, equipment operating from the dock (one or more excavators, or cranes with clam buckets) will offload the remaining shell, sediment, and drill-cutting material from the hopper barge hold. Equipment is selected based on the material consistency and the dock layout.
- **Material Containerization:** The recovered biomass (shell hash and marine growth debris) and sediments are placed in sealed roll-off containers or similar certified containment for transport to an approved disposal facility. Material that can be confirmed as free of regulated hazardous waste constituents above applicable thresholds may be disposed of at a permitted landfill or composting facility.
- **Water Quality Verification:** Prior to discharge, the filtered and treated seawater is tested to confirm that concentrations of PCBs, metals, PAHs, and other regulated constituents are below applicable limits. The final disposition approach for the water stream (local sewer, permitted treatment facility, or NPDES-permitted direct discharge) depends on the constituent concentrations and the regulatory framework at the receiving facility.
- Detailed methodologies and procedures for underwater excavation, the transportation of spoils, the processing of solids and water, the layout of receiving-site infrastructure, turbidity monitoring protocols, and contaminant management will be developed and documented in the Project Work and Safety Plan (PWSP) for each individual platform decommissioning project. The final disposition approach for recovered seawater will depend on constituent concentrations measured in representative samples, the treatment capacity of the local wastewater utility, and the terms of any applicable discharge permit.

The most significant environmental risk associated with shell mound removal is the disruption of contaminated sediments from the drill-mud-and-cuttings core into the water column during excavation. Both the U.S. Army Corps of Engineers and the Central Coast Regional Water Quality Control Board raised formal concerns about this risk during the 2003 EIR/EA review process for the 4H platform mounds, noting that clamshell dredging can generate turbidity plumes and suspend PCBs, metals, and PAHs that have otherwise remained sequestered in the mound for decades.

The use of environmental clamshell buckets, which close tightly prior to lifting, substantially reduces the turbidity generation compared to open-jaw dredge operations. The submersible dredge pump method,



while more efficient volumetrically, may generate a more continuous turbidity plume at the excavation face.

G.7 COST ESTIMATE

The cost model is derived from similar shell mound removal work being assessed and evaluated for a platform in 211FSW and with 7,888 cubic yards of a biomass to be removed. Table G-3 below provides a range of volumes; high, medium, low for each shell mound. This volume is the basis for removal cost estimates. The estimated durations and cost ranges are shown in Table G-2.

Table G-2 – Shell Mound Removal Volume

Platform Name	Water Depth (ft)	Shell Mound Present	Est. Volume Low (cubic yards)	Est. Volume Med. (cubic yards)	Est. Volume High (cubic yards)
A	188	Confirmed – MEC	3,000	6,000	12,500
B	190	Confirmed – MEC	3,000	6,000	12,500
C	192	Confirmed – MEC	3,000	6,000	12,500
Edith	161	Confirmed – MEC	4,000	8,000	12,500
Ellen	265	Confirmed – MEC	1,500	3,000	6,000
Elly	255	Confirmed – MEC	1,500	3,000	6,000
Eureka	700	Confirmed – MEC	300	750	2,000
Gail	739	Confirmed – Measured	150	190	250
Gilda	205	Confirmed – Partial Dims	2,500	5,000	8,000
Gina	95	Confirmed – Measured	4,200	4,200	4,200
Grace	318	Confirmed – Partial Dims	1,500	3,000	6,000
Habitat	290	Anticipated – No Survey	1,500	3,500	6,000
Harmony	1,198	Confirmed – Small Mounds	100	300	750
Harvest	675	Confirmed – MEC	300	1,000	2,500
Henry	173	Anticipated – No Survey	4,000	8,000	12,500
Heritage	1,075	Anticipated – No Survey	100	300	750
Hermosa	603	Confirmed – Small Mounds	300	750	1,500
Hidalgo	430	Confirmed – MEC	750	1,500	3,000
Hillhouse	190	Anticipated – No Survey	3,000	6,000	12,500
Hogan	154	Confirmed – Measured	8,000	12,000	16,000
Hondo	842	Confirmed – Small Mounds	200	500	1,000
Houchin	163	Confirmed – Partial Dims	8,000	11,500	15,000
Irene	242	Confirmed – MEC	1,500	3,000	6,000

Table G-3 – Shell Mound Removal Duration and Cost Estimate Range

Platform Name	Removal Duration Low (in Days)	Removal Duration Med. (in Days)	Removal Duration High (in Days)	Removal Cost Low	Removal Cost Med.	Removal Cost High
A	8	16	32	\$1,811,300	\$3,387,500	\$6,590,700
B	8	16	32	\$1,811,300	\$3,387,500	\$6,590,700



Platform Name	Removal Duration Low (in Days)	Removal Duration Med. (in Days)	Removal Duration High (in Days)	Removal Cost Low	Removal Cost Med.	Removal Cost High
C	8	16	32	\$1,811,300	\$3,387,500	\$6,590,700
Edith	11	21	32	\$2,389,700	\$4,385,400	\$6,590,700
Ellen	5	8	16	\$1,182,100	\$1,811,300	\$3,387,500
Ely	5	8	16	\$1,182,100	\$1,811,300	\$3,387,500
Eureka	5	5	6	\$1,060,400	\$1,106,100	\$1,391,800
Gail	5	5	5	\$1,045,200	\$1,049,300	\$1,055,400
Gilda	7	13	21	\$1,601,500	\$2,809,100	\$4,385,400
Gina	11	11	11	\$2,410,000	\$2,410,000	\$2,410,000
Grace	5	8	16	\$1,182,100	\$1,811,300	\$3,387,500
Habitat	5	9	16	\$1,182,100	\$2,021,000	\$3,387,500
Harmony	5	5	5	\$1,040,100	\$1,060,400	\$1,106,100
Harvest	5	5	7	\$1,060,400	\$1,131,400	\$1,601,500
Henry	11	21	32	\$2,389,700	\$4,385,400	\$6,590,700
Heritage	5	5	5	\$1,040,100	\$1,060,400	\$1,106,100
Hermosa	5	5	5	\$1,060,400	\$1,106,100	\$1,182,100
Hidalgo	5	5	8	\$1,106,100	\$1,182,100	\$1,811,300
Hillhouse	8	16	32	\$1,811,300	\$3,387,500	\$6,590,700
Hogan	21	31	41	\$4,385,400	\$6,381,000	\$8,376,700
Hondo	5	5	5	\$1,050,300	\$1,080,700	\$1,131,400
Houchin	21	30	39	\$4,385,400	\$6,171,300	\$7,957,300
Irene	5	8	16	\$1,182,100	\$1,811,300	\$3,387,500
Totals	179	272	430	\$39,180,40	\$58,134,900	\$89,996,800

Due to the various assumptions, limited data, technical, and methodological precedents related to shell mound removal, a confidence range has been established. The basis for volumetric estimate is used to determine the confidence level.

Confidence Intervals:

- High – Full measurements of dimensions
- Medium – Partial measurement of dimensions
- Low-Medium – Platform criteria (age, water depth, geographic region, etc.) aligns with quoted range of shell mound volumes and is analogous to other platforms
- Low – No survey data and limited analogous data

Table G-4 below describes the shell mound volume confidence interval for volume estimates.

Table G-4 – Shell Mound Volume Calculation Confidence

Platform	Water Depth (ft)	Volume Estimate Basis	Confidence
A	188	MEC (2003) range; Goddard & Love (2010); depth-analogous to Platforms B & C	Low-Medium – MEC range only





Platform	Water Depth (ft)	Volume Estimate Basis	Confidence
B	190	MEC (2003) range; Goddard & Love (2010); depth-analogous to Platforms A & C	Low-Medium – MEC range only
C	192	MEC (2003) range; Goddard & Love (2010)	Low-Medium – MEC range only
Edith	161	MEC (2003) range; Goddard & Love (2010); depth-analogous to Houchin (163 ft)	Low-Medium – MEC range only
Ellen	265	MEC (2003) range; Goddard & Love (2010); moderate depth	Low-Medium – MEC range only
Elly	255	MEC (2003) range; Goddard & Love (2010); depth-analogous to Ellen (265 ft)	Low-Medium – MEC range only
Eureka	700	MEC (2003) range; Goddard & Love (2010); deep – smaller mounds expected	Low-Medium – MEC range only
Gail	739	MEC/Sea Surveyor (2003): four small discrete mounds; volume calculated ~190 cu yds	High – measured dimensions
Gilda	205	MEC (2003): ~22 ft mound height confirmed; footprint inferred; Goddard & Love (2010)	Medium – partial survey data
Gina	95	BOEM (2007): measured volume 4,200 cu yds; Page & Dugan, OCS Study MMS 2005-001	High – measured dimensions
Grace	318	MEC (2003): NW-corner mound noted; extends beyond platform footprint; MEC range	Medium – partial survey data
Habitat	290	No survey; inferred from depth; gas-only platform (minimal drill cuttings expected)	Low – no survey data; analogy only
Harmony	1,198	MEC (2003): multiple small poorly defined mounds; very deep – minimal biofouling	Low-Medium – deep, small mounds
Harvest	675	MEC (2003) range; Goddard & Love (2010); deep platform	Low-Medium – MEC range only
Henry	173	No survey; inferred from depth; comparable to Edith (161 ft) and Houchin (163 ft)	Low – no survey data; analogy only
Heritage	1,075	No survey; very deep; inferred analogous to Harmony (1,198 ft)	Low – no survey data; analogy only
Hermosa	603	MEC (2003): multiple small poorly defined mounds; deep platform	Low-Medium – deep, small mounds
Hidalgo	430	MEC (2003) range; Goddard & Love (2010); moderate-deep	Low-Medium – MEC range only
Hillhouse	190	No survey; inferred from depth; depth-analogous to Platform C (192 ft)	Low – no survey data; analogy only
Hogan	154	Page & Dugan, OCS Study MMS 2005-001; measured dimensions 256×256 ft footprint	High – measured dimensions
Hondo	842	MEC (2003): multiple small poorly defined mounds; very deep platform	Low-Medium – deep, small mounds
Houchin	163	Page & Dugan, OCS Study MMS 2005-001; measured dimensions 276×276 ft footprint	Medium – partial survey data
Irene	242	MEC (2003) range; Goddard & Love (2010); moderate depth	Low-Medium – MEC range only



G.8 COST MODEL ASSUMPTIONS:

- For the purposes of this study, the applied removal rate of shell mound biomass and water is 394.4 cubic yards per day. This removal rate is impacted by water depth, total removal volumes and removal method used: jet pump or clamshell bucket.
- There is clear vertical access to the shell mound for removal
- The data shows shell mounds in deep water (>400ft) are mostly in a multiple mound formation with very poor dome shaped geometry. Volume estimates for these platforms are most likely widely varied.
- The cost estimates do not include pre-removal surveys
- The full extent of regulatory permitting is unknown and permitting costs are not included in the estimates.
- The volume estimate basis and confidence are derived from the existence and quality of publicly available data and reviewed literature. For instances where no historical survey information is available, analogues were used. These analogues are based on water depth and platform age.
- Actual volumes for each platform must be established through pre-removal multibeam hydrographic surveys. The wide uncertainty range reflects the limited dimensional data available for most of the platform inventory.
- Seawater recovered during dredging operations would add an estimated 1.6 times the solids volume (60/40) seawater-to-solids ratio.



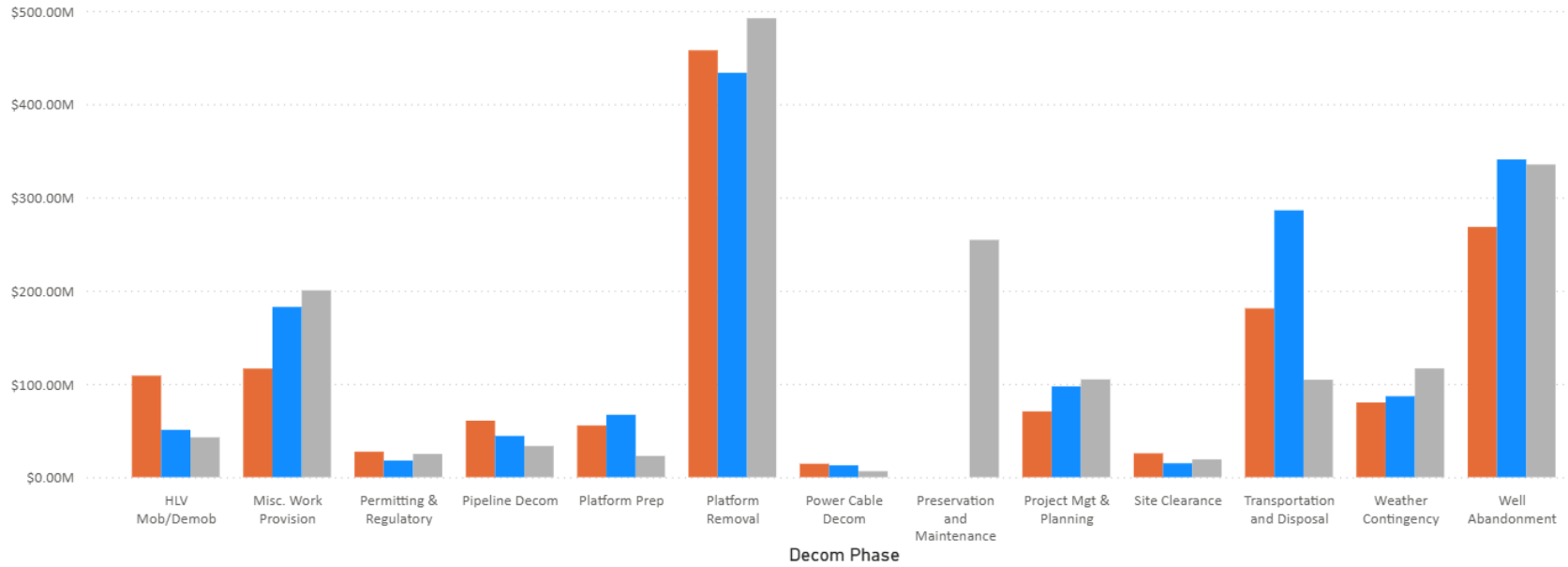
APPENDIX H – COMPARISON OF DECOMMISSIONING COSTS BY STUDY YEAR

The figures in this appendix show a comparison in total costs by study year, campaign summaries, and phase specific cost visualizations.

Cost of Decommissioning by Phase by Study Year

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$42,757,800	\$200,380,400	\$24,953,500	\$33,371,000	\$22,807,700	\$492,162,000	\$6,368,600	\$254,452,700	\$104,872,900	\$19,123,200	\$104,554,700	\$116,589,500	\$335,317,800
2020	\$50,712,500	\$182,572,100	\$17,856,000	\$44,190,000	\$66,899,000	\$433,607,600	\$12,752,100		\$97,371,600	\$14,924,600	\$286,128,000	\$86,856,500	\$340,787,800
2016	\$108,900,000	\$116,472,620	\$27,300,000	\$60,589,002	\$55,393,271	\$457,815,614	\$14,444,841		\$70,578,081	\$25,624,000	\$181,064,473	\$80,132,629	\$268,359,297

Figure H-1 – Cost of Decommissioning by Phase by Study Year



Cost of Decommissioning Tasks by Study Year for Platform A

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

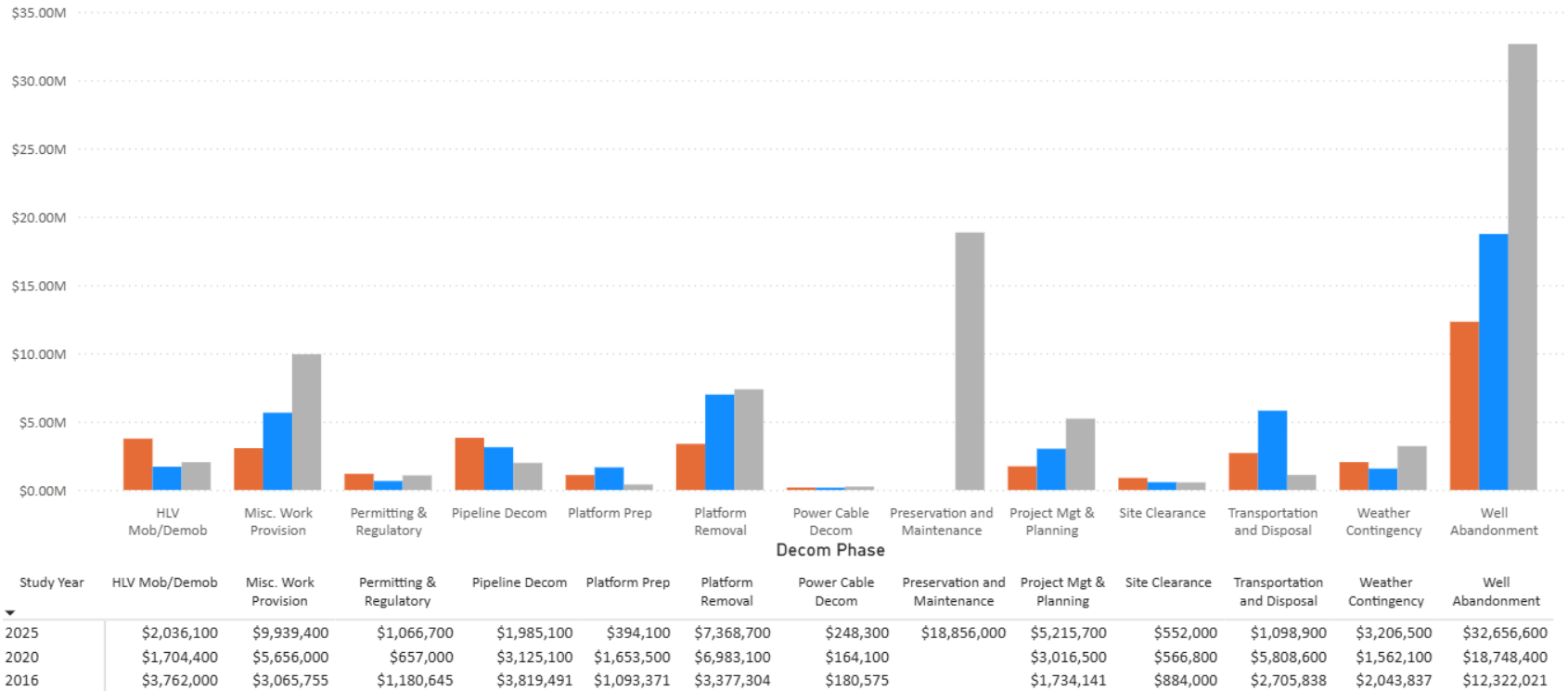


Figure H-2 – Cost of Decommissioning Tasks by Study Year – Platform A



Cost of Decommissioning Tasks by Study Year for Platform B

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

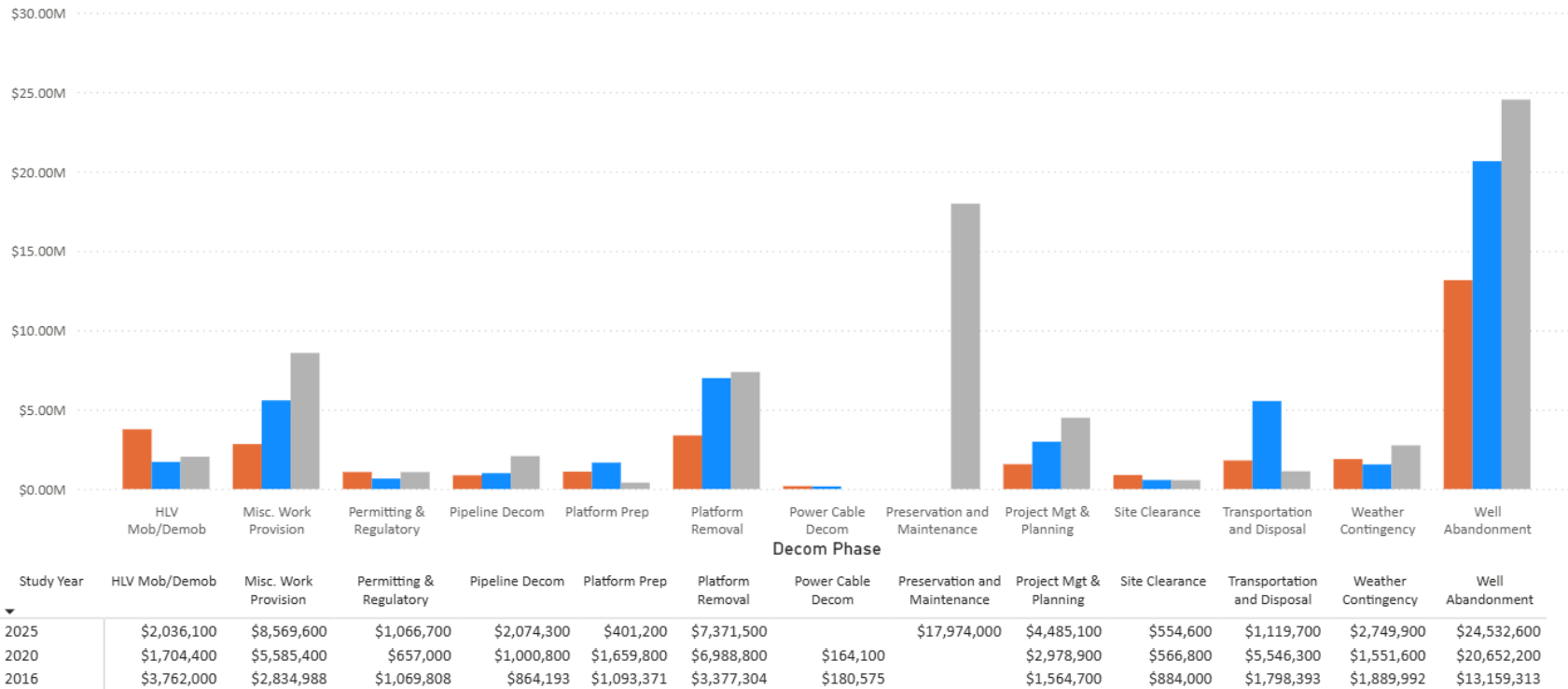


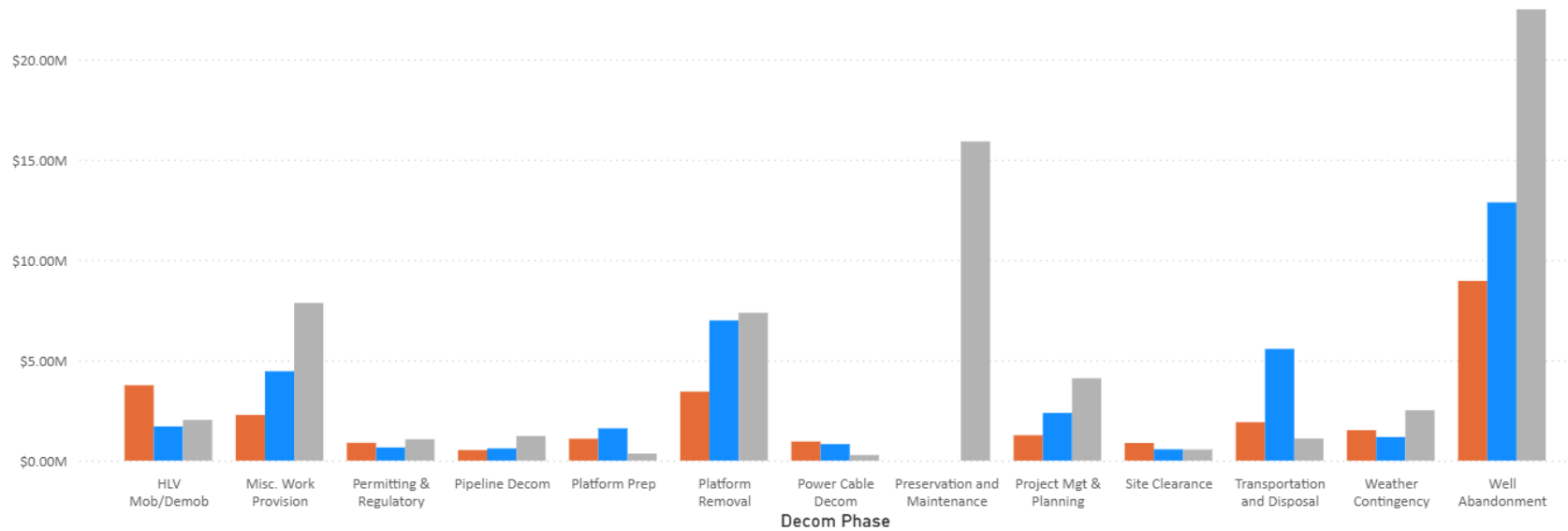
Figure H-3 – Cost of Decommissioning Tasks by Study Year - Platform B



Cost of Decommissioning Tasks by Study Year for Platform C

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$7,863,800	\$1,066,700	\$1,229,000	\$355,200	\$7,374,200	\$280,300	\$15,916,000	\$4,108,700	\$557,100	\$1,104,100	\$2,514,600	\$22,506,400
2020	\$1,704,400	\$4,457,900	\$657,000	\$611,200	\$1,610,200	\$6,994,400	\$829,400		\$2,377,600	\$566,800	\$5,572,700	\$1,174,500	\$12,877,700
2016	\$3,762,000	\$2,284,036	\$891,505	\$528,022	\$1,093,371	\$3,446,640	\$953,587		\$1,269,759	\$884,000	\$1,916,888	\$1,522,691	\$8,966,362

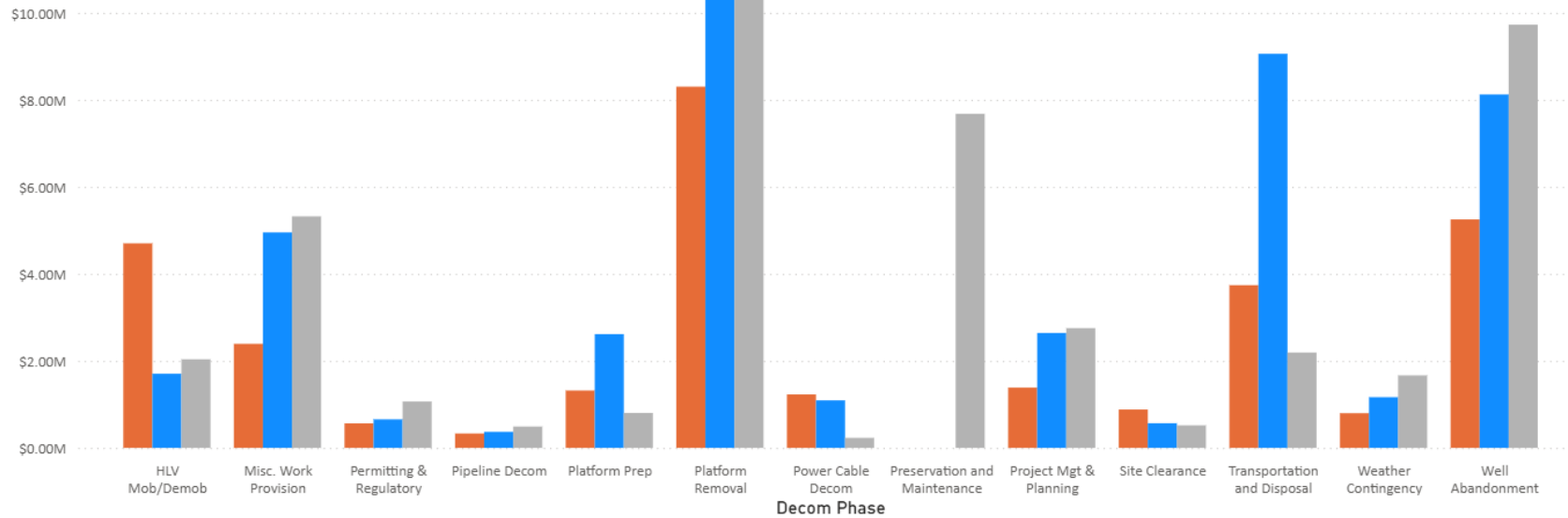
Figure H-4 – Cost of Decommissioning Tasks by Study Year - Platform C



Cost of Decommissioning Tasks by Study Year for Platform Edith

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$5,321,700	\$1,066,700	\$490,500	\$801,500	\$10,734,300	\$230,700	\$7,678,800	\$2,752,900	\$518,400	\$2,191,600	\$1,667,200	\$9,729,400
2020	\$1,704,400	\$4,952,100	\$657,000	\$368,400	\$2,613,500	\$10,532,400	\$1,093,500		\$2,641,100	\$566,800	\$9,058,900	\$1,164,900	\$8,123,300
2016	\$4,702,500	\$2,391,226	\$564,723	\$331,960	\$1,319,700	\$8,302,845	\$1,230,590		\$1,385,785	\$884,000	\$3,739,794	\$797,075	\$5,253,219

Figure H-5 – Cost of Decommissioning Tasks by Study Year - Platform Edith



Cost of Decommissioning Tasks by Study Year for Platform Ellen

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

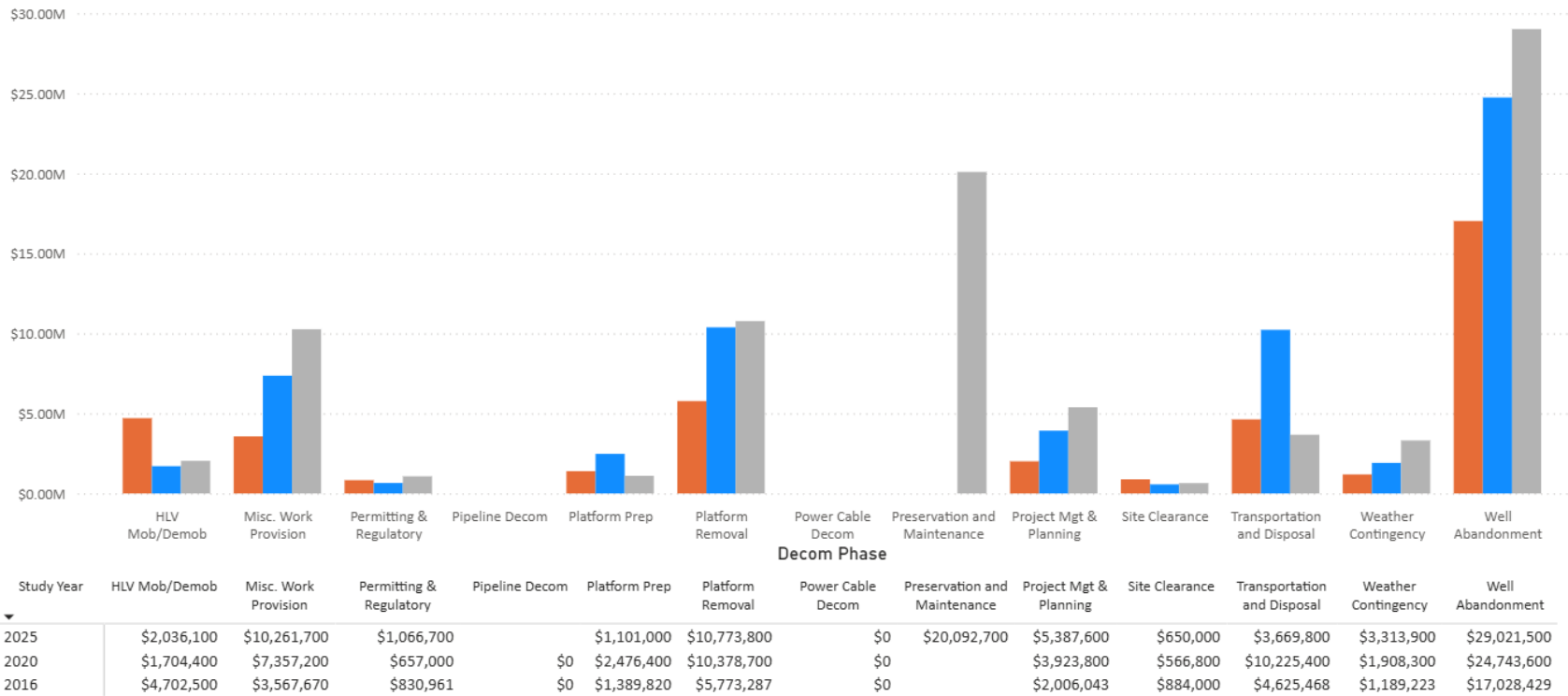


Figure H-6 – Cost of Decommissioning Tasks by Study Year - Platform Ellen



Cost of Decommissioning Tasks by Study Year for Platform Elly

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

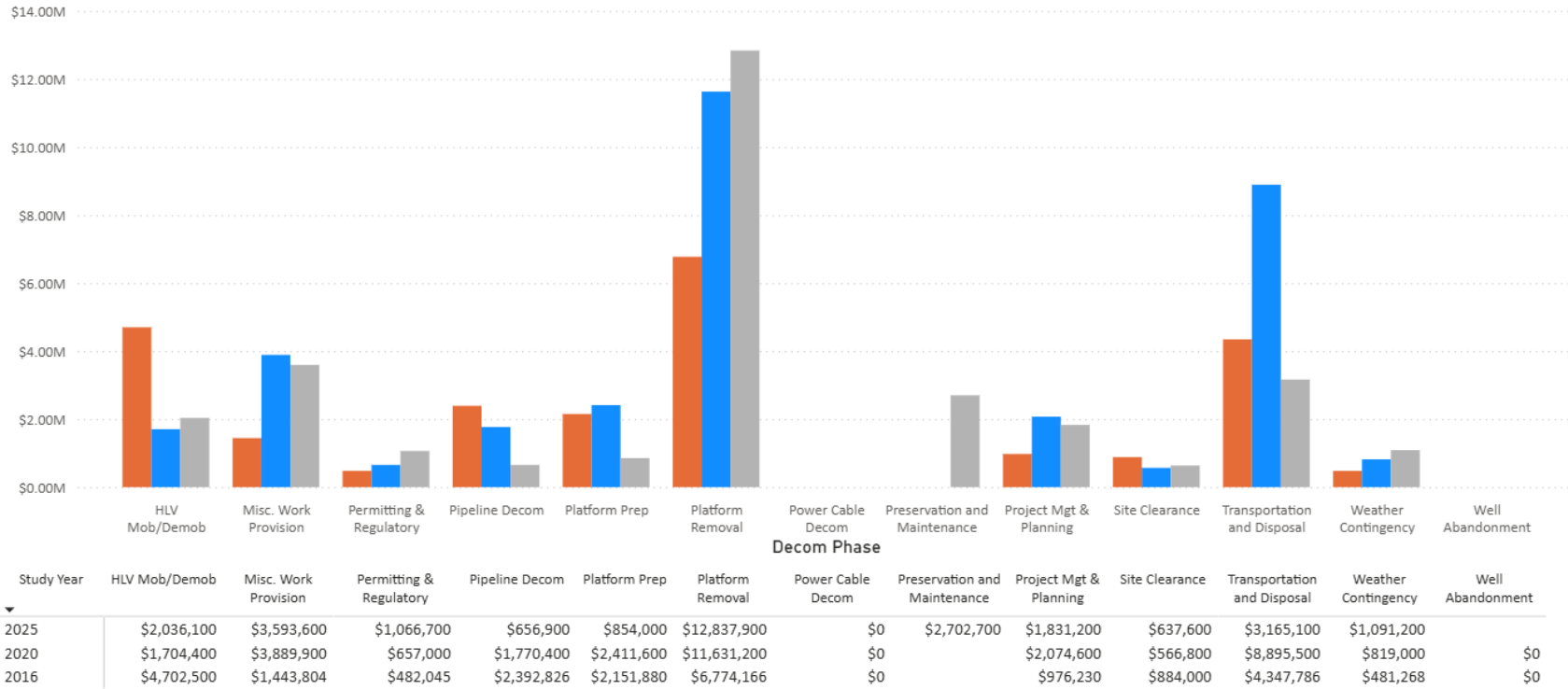


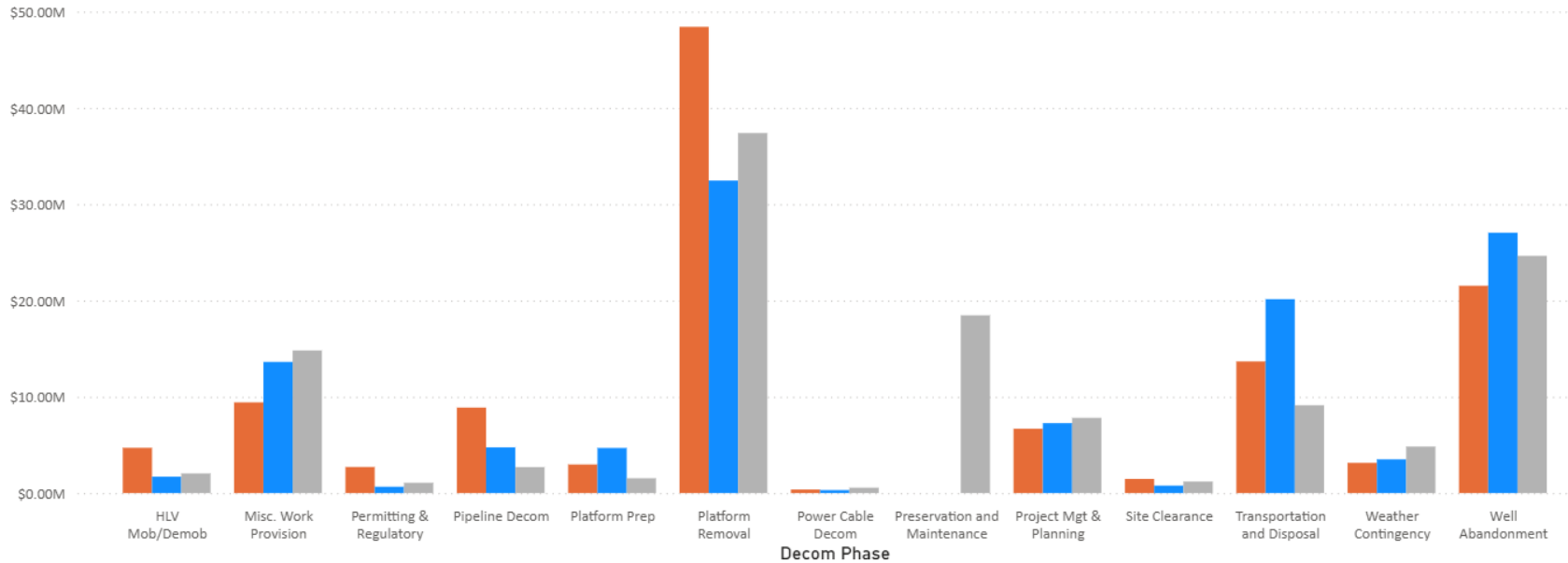
Figure H-7 – Cost of Decommissioning Tasks by Study Year - Platform Elly



Cost of Decommissioning Tasks by Study Year for Platform Eureka

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$14,809,400	\$1,066,700	\$2,701,400	\$1,539,200	\$37,395,300	\$556,200	\$18,464,200	\$7,813,000	\$1,201,300	\$9,125,200	\$4,829,800	\$24,643,500
2020	\$1,704,400	\$13,623,800	\$657,000	\$4,753,000	\$4,685,600	\$32,457,600	\$313,100		\$7,266,000	\$776,600	\$20,140,100	\$3,501,400	\$27,042,400
2016	\$4,702,500	\$9,417,994	\$2,713,271	\$8,876,961	\$2,969,203	\$48,420,784	\$373,589		\$6,691,365	\$1,472,000	\$13,668,746	\$3,139,331	\$21,529,521

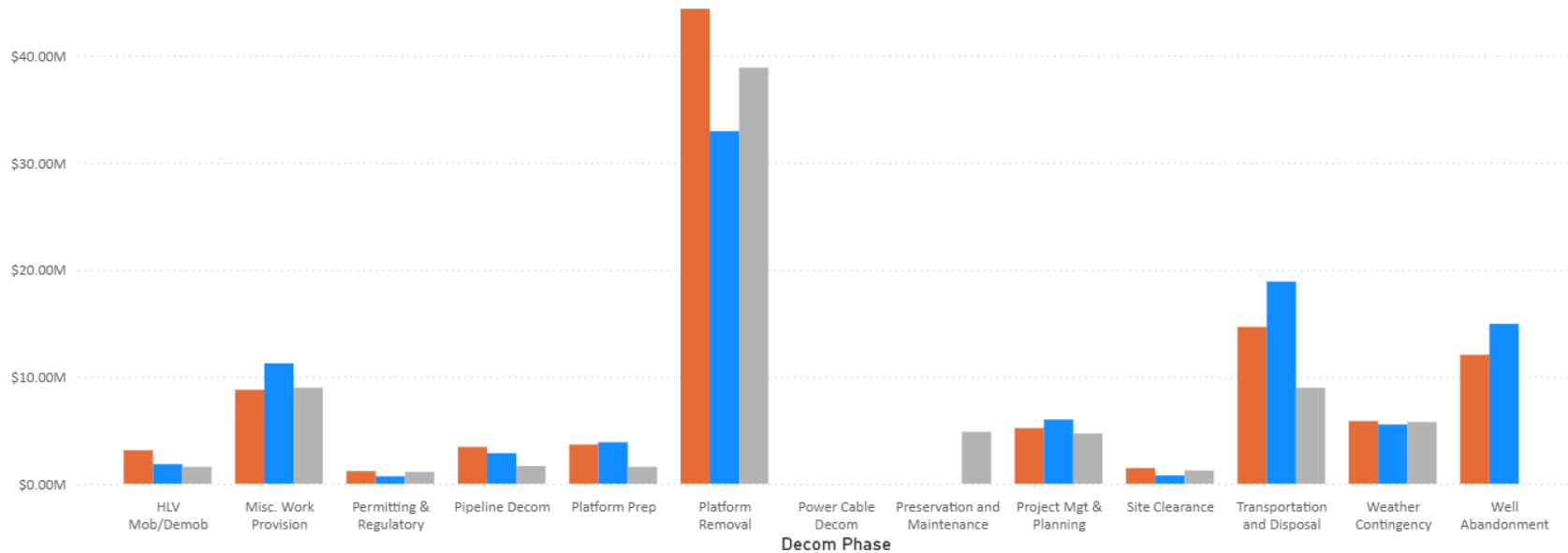
Figure H-8 – Cost of Decommissioning Tasks by Study Year – Platform Eureka



Cost of Decommissioning Tasks by Study Year for Platform Gail

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$1,583,600	\$8,983,500	\$1,113,300	\$1,660,800	\$1,585,100	\$38,878,400	\$0	\$4,848,300	\$4,702,100	\$1,249,400	\$8,970,800	\$5,766,300	
2020	\$1,833,700	\$11,250,800	\$702,000	\$2,858,800	\$3,885,900	\$32,941,700	\$0		\$6,000,400	\$776,600	\$18,898,800	\$5,540,400	\$14,941,400
2016	\$3,135,000	\$8,786,319	\$1,190,846	\$3,440,911	\$3,669,809	\$44,376,544	\$0		\$5,201,063	\$1,472,000	\$14,650,776	\$5,857,546	\$12,054,028

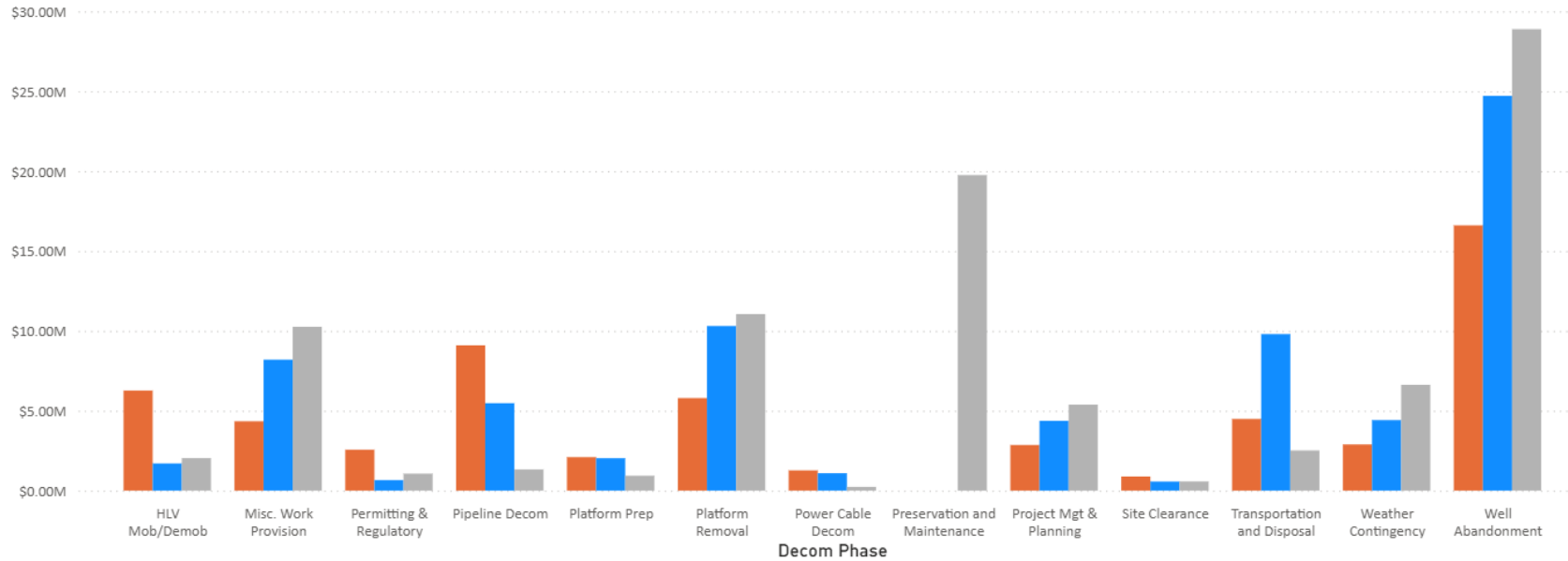
Figure H-9 – Cost of Decommissioning Tasks by Study Year - Platform Gail



Cost of Decommissioning Tasks by Study Year for Platform Gilda

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$10,257,300	\$1,066,700	\$1,327,000	\$932,700	\$11,055,400	\$233,400	\$19,752,600	\$5,385,200	\$574,000	\$2,515,300	\$6,624,900	\$28,889,100
2020	\$1,704,400	\$8,196,900	\$657,000	\$5,474,400	\$2,030,900	\$10,305,500	\$1,093,500	\$0	\$4,371,700	\$566,800	\$9,800,900	\$4,418,800	\$24,717,000
2016	\$6,270,000	\$4,343,460	\$2,565,674	\$9,094,834	\$2,096,094	\$5,793,544	\$1,267,549	\$0	\$2,859,588	\$884,000	\$4,489,009	\$2,895,640	\$16,608,830

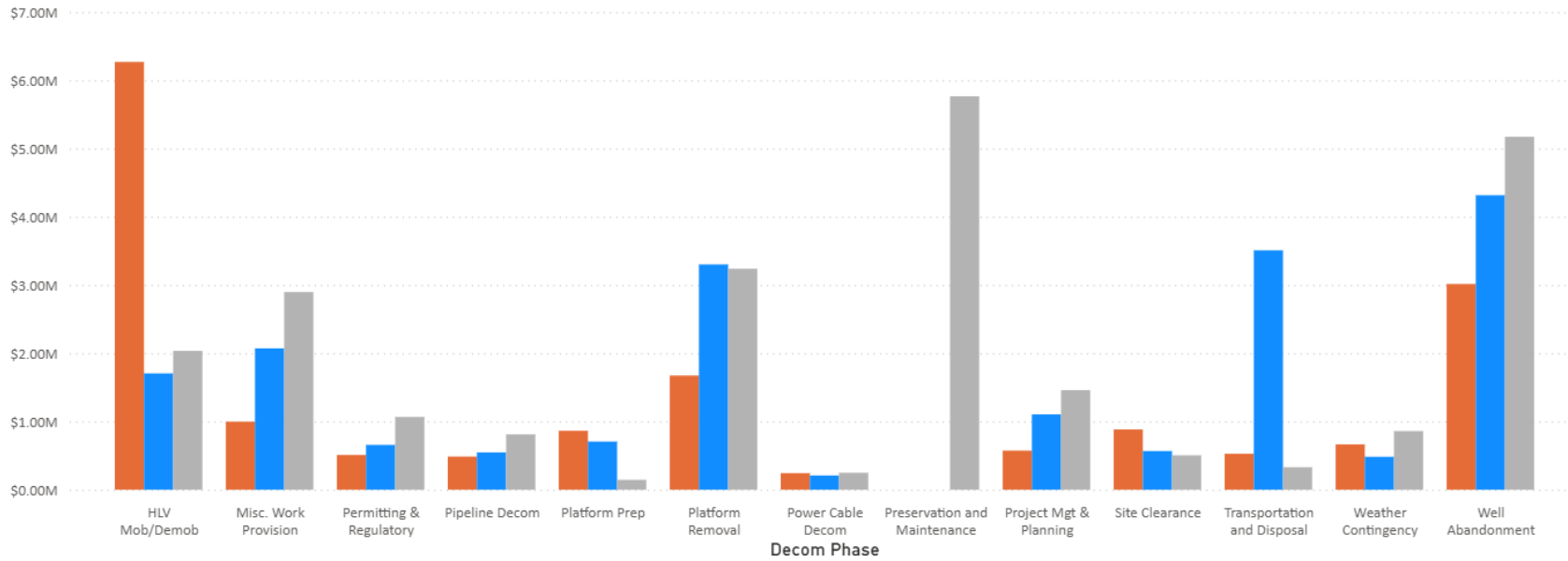
Figure H-10 – Cost of Decommissioning Tasks by Study Year - Platform Gilda



Cost of Decommissioning Tasks by Study Year for Platform Gina

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$2,898,300	\$1,066,700	\$811,700	\$145,000	\$3,239,100	\$248,800	\$5,766,200	\$1,460,400	\$503,800	\$330,200	\$859,400	\$5,174,100
2020	\$1,704,400	\$2,071,900	\$657,000	\$547,100	\$705,100	\$3,302,000	\$208,600		\$1,105,000	\$566,800	\$3,508,800	\$482,300	\$4,317,000
2016	\$6,270,000	\$997,585	\$509,672	\$485,330	\$864,100	\$1,674,634	\$243,574		\$573,387	\$884,000	\$527,913	\$665,057	\$3,015,698

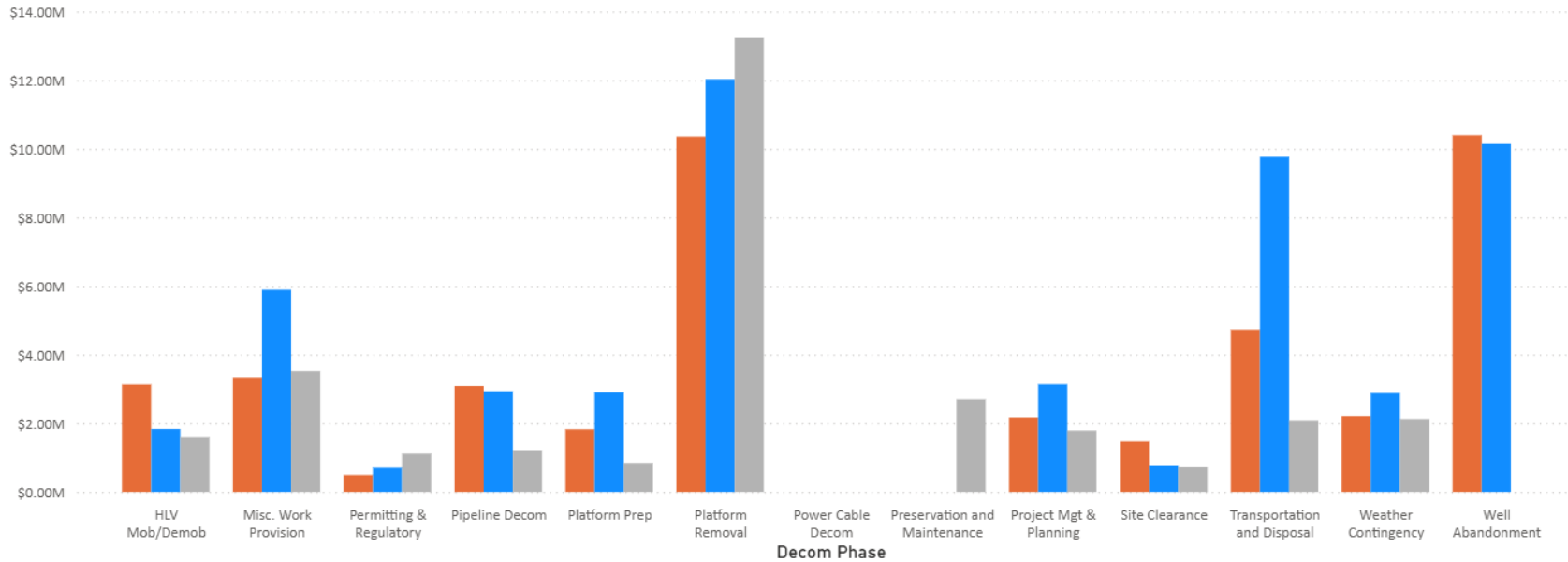
Figure H-11 –Cost of Decommissioning Tasks by Study Year - Platform Gina



Cost of Decommissioning Tasks by Study Year for Platform Grace

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$1,583,600	\$3,524,100	\$1,113,300	\$1,216,900	\$843,600	\$13,231,400	\$0	\$2,698,800	\$1,790,400	\$715,200	\$2,091,100	\$2,126,700	\$10,145,800
2020	\$1,833,700	\$5,889,700	\$702,000	\$2,935,000	\$2,909,900	\$12,030,900	\$0	\$0	\$3,141,200	\$776,600	\$9,764,700	\$2,879,800	\$10,145,800
2016	\$3,135,000	\$3,318,381	\$494,498	\$3,090,490	\$1,826,637	\$10,362,874	\$0	\$0	\$2,172,220	\$1,472,000	\$4,734,088	\$2,212,254	\$10,400,751

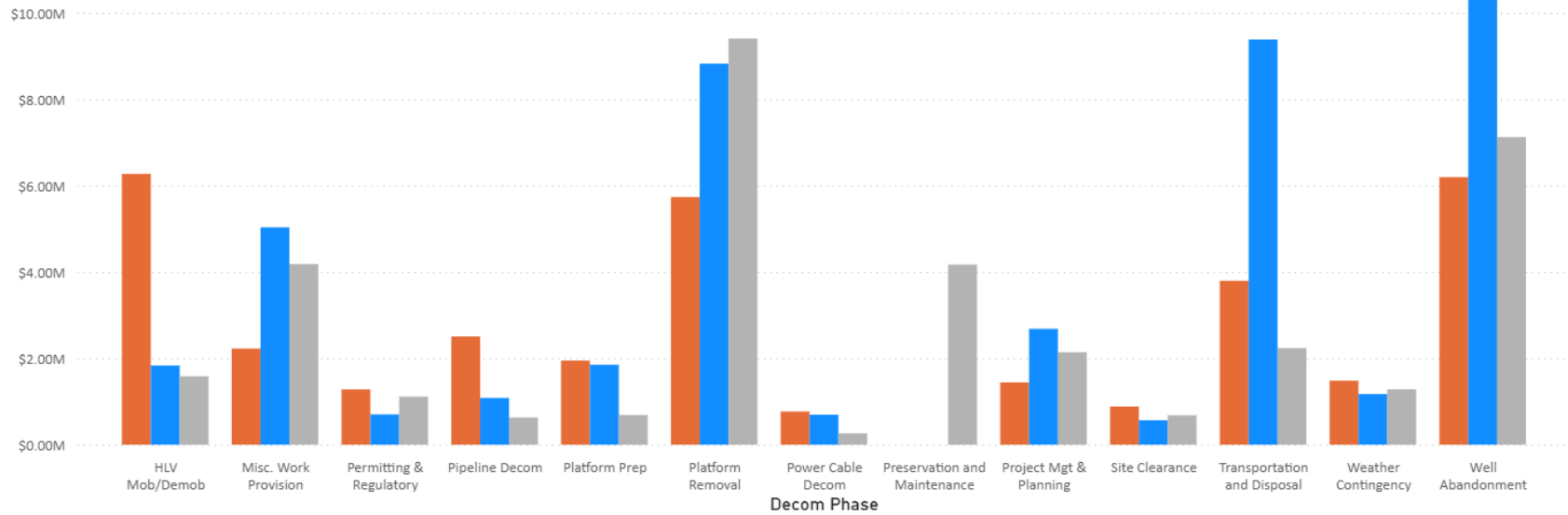
Figure H-12 – Cost of Decommissioning Tasks by Study Year - Platform Grace



Cost of Decommissioning Tasks by Study Year for Platform Habitat

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$1,583,600	\$4,183,300	\$1,113,300	\$627,900	\$687,700	\$9,404,800	\$262,000	\$4,170,600	\$2,142,000	\$679,800	\$2,235,700	\$1,283,100	\$7,123,500
2020	\$1,833,700	\$5,030,100	\$702,000	\$1,082,400	\$1,851,200	\$8,823,500	\$695,700		\$2,682,700	\$566,800	\$9,381,000	\$1,172,500	\$10,431,300
2016	\$6,270,000	\$2,225,328	\$1,280,654	\$2,506,038	\$1,949,544	\$5,733,854	\$769,029		\$1,443,015	\$884,000	\$3,793,458	\$1,483,552	\$6,195,224

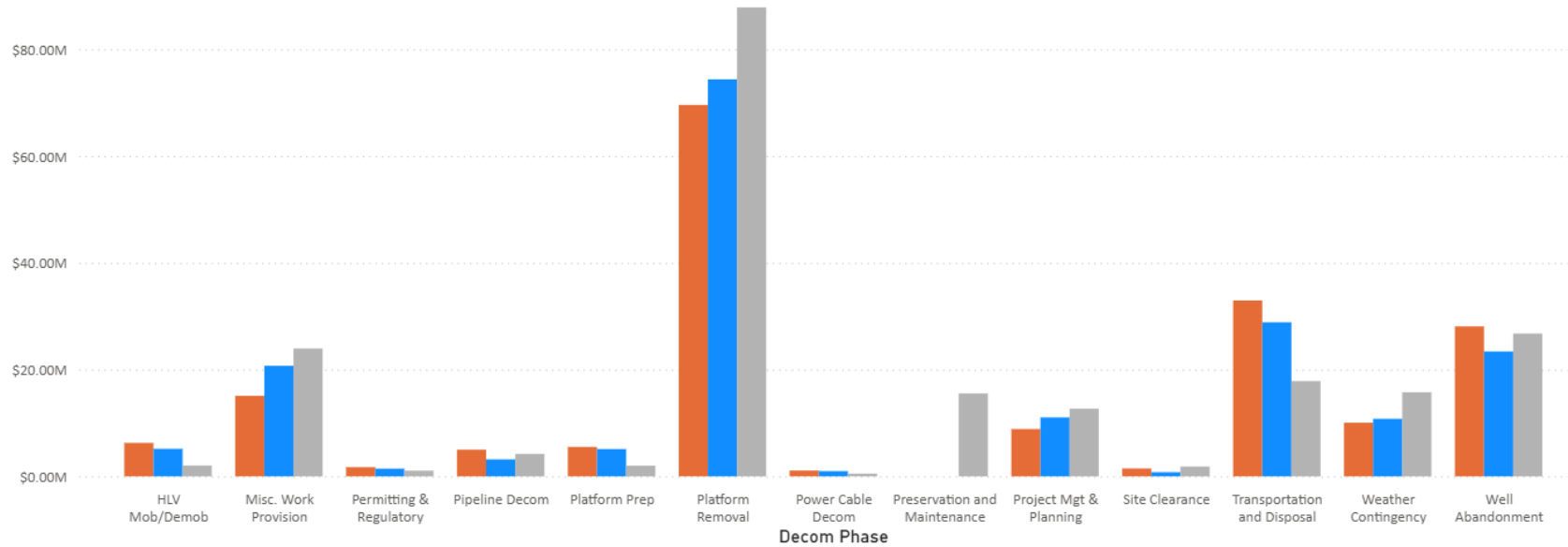
Figure H-13 – Cost of Decommissioning Tasks by Study Year - Platform Habitat



Cost of Decommissioning Tasks by Study Year for Platform Harmony

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$23,947,300	\$1,066,700	\$4,206,700	\$2,013,100	\$87,852,600	\$499,300	\$15,546,100	\$12,686,500	\$1,834,600	\$17,846,000	\$15,751,500	\$26,747,300
2020	\$5,153,600	\$20,719,400	\$1,437,000	\$3,183,100	\$5,108,700	\$74,382,900	\$980,000		\$11,050,300	\$776,600	\$28,865,700	\$10,782,600	\$23,395,100
2016	\$6,270,000	\$15,089,390	\$1,720,616	\$4,993,843	\$5,517,050	\$69,600,097	\$1,096,054		\$8,863,062	\$1,472,000	\$32,949,946	\$10,059,593	\$28,109,231

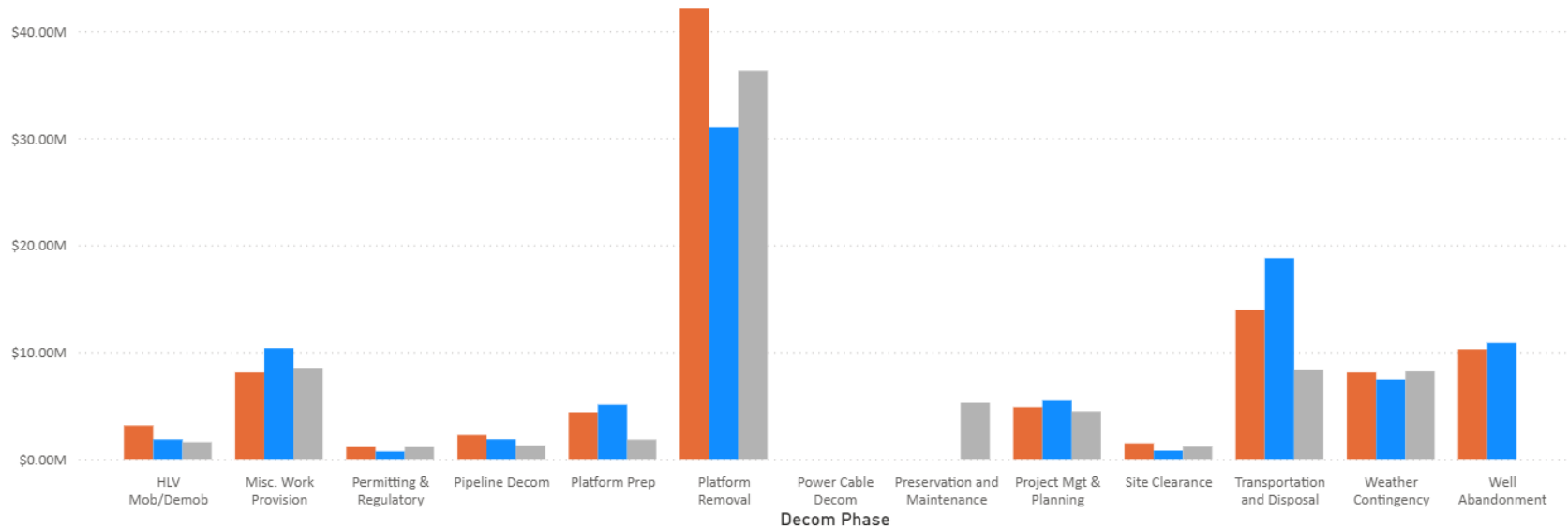
Figure H-14 – Cost of Decommissioning Tasks by Study Year - Platform Harmony



Cost of Decommissioning Tasks by Study Year for Platform Harvest

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$1,583,600	\$8,517,800	\$1,113,300	\$1,254,900	\$1,816,100	\$36,265,100	\$0	\$5,248,300	\$4,453,800	\$1,168,500	\$8,335,700	\$8,183,800	\$10,838,100
2020	\$1,833,700	\$10,356,000	\$702,000	\$1,847,300	\$5,066,400	\$31,034,400	\$0	\$5,523,200	\$5,523,200	\$776,600	\$18,774,900	\$7,434,400	\$10,838,100
2016	\$3,135,000	\$8,090,763	\$1,115,156	\$2,240,868	\$4,373,249	\$42,101,220	\$0	\$0	\$4,835,181	\$1,472,000	\$13,968,013	\$8,090,763	\$10,252,430

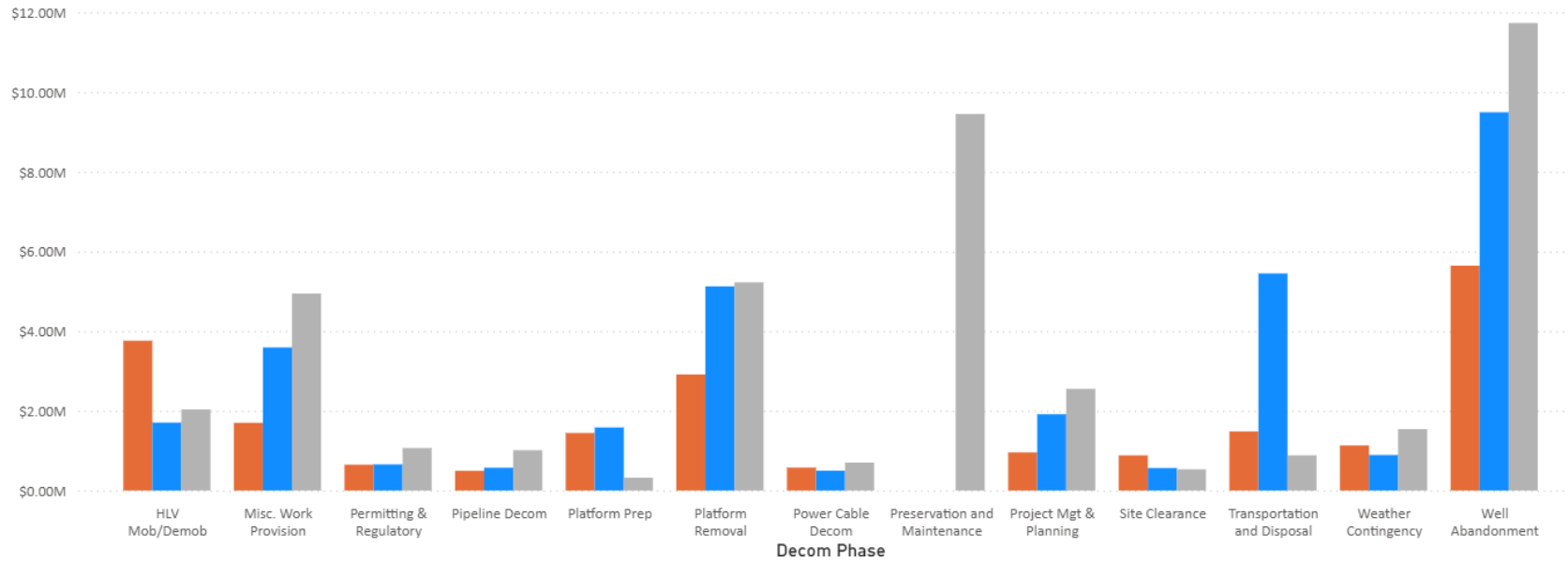
Figure H-15 – Cost of Decommissioning Tasks by Study Year - Platform Harvest



Cost of Decommissioning Tasks by Study Year for Platform Henry

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$2,036,100	\$4,944,500	\$1,066,700	\$1,012,000	\$324,300	\$5,225,700	\$701,800	\$9,448,000	\$2,551,700	\$533,000	\$884,400	\$1,541,500	\$11,731,400
2020	\$1,704,400	\$3,591,800	\$657,000	\$573,400	\$1,583,000	\$5,123,400	\$499,200		\$1,915,600	\$566,800	\$5,449,500	\$891,900	\$9,492,800
2016	\$3,762,000	\$1,699,207	\$650,555	\$495,927	\$1,445,091	\$2,913,049	\$575,920		\$956,536	\$884,000	\$1,483,738	\$1,132,804	\$5,642,716

Figure H-16 – Cost of Decommissioning Tasks by Study Year - Platform Henry



Cost of Decommissioning Tasks by Study Year for Platform Heritage

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

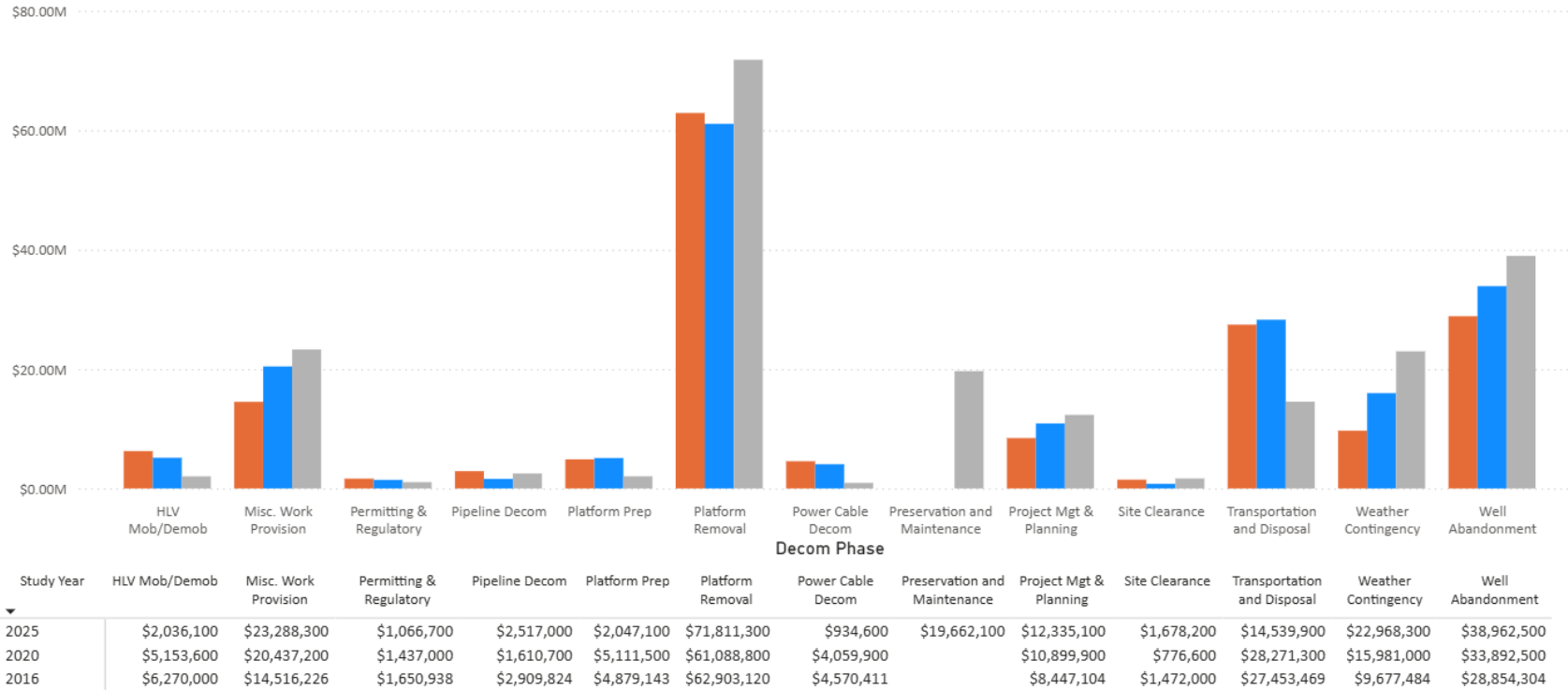


Figure H-17 – Cost of Decommissioning Tasks by Study Year - Platform Heritage



Cost of Decommissioning Tasks by Study Year for Platform Hermosa

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

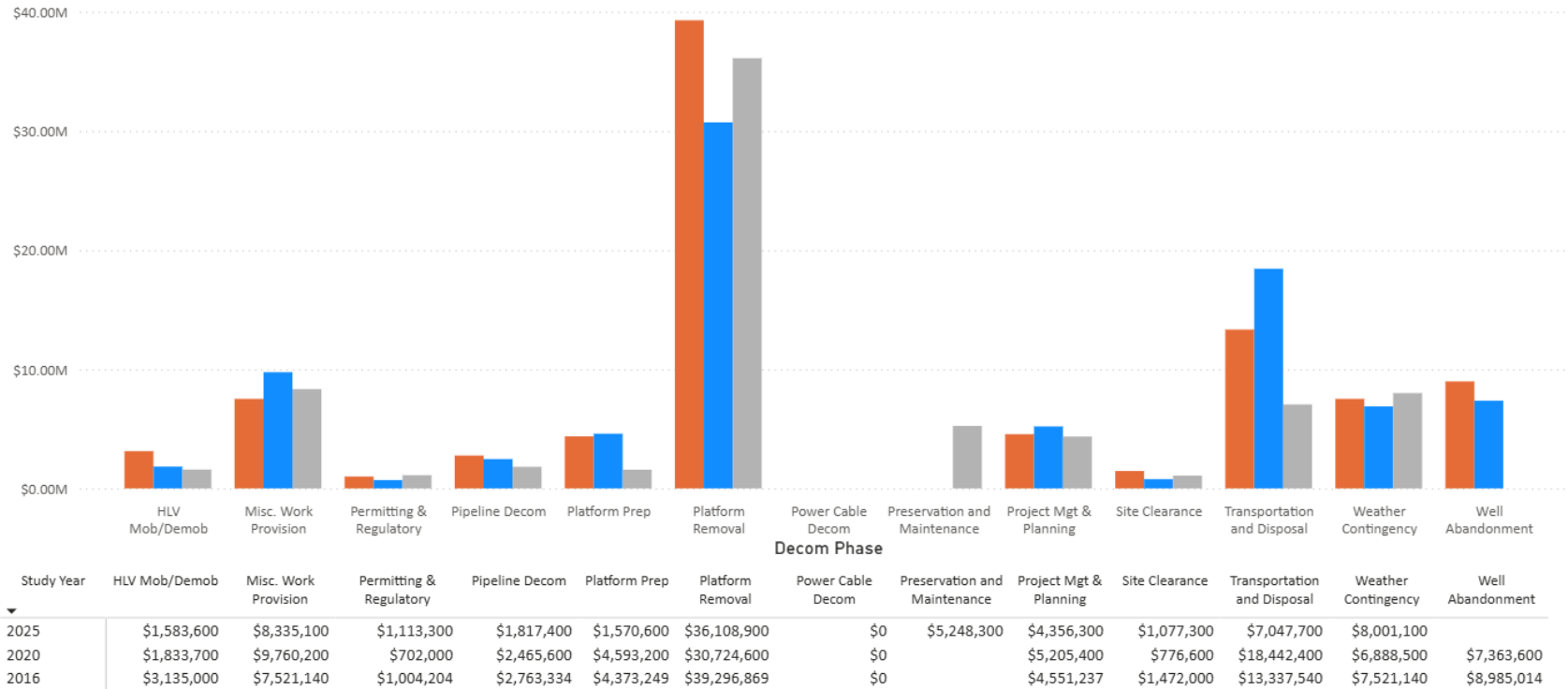


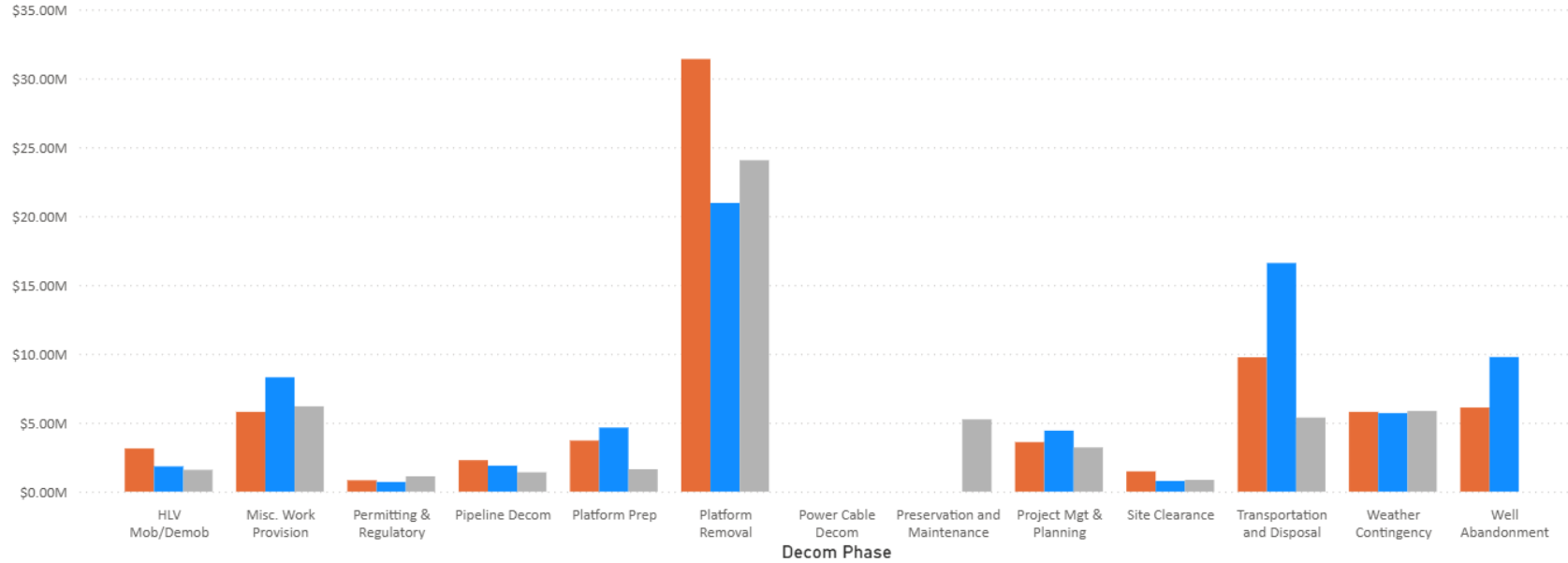
Figure H-18 – Cost of Decommissioning Tasks by Study Year - Platform Hermosa



Cost of Decommissioning Tasks by Study Year for Platform Hidalgo

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Study Year	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
2025	\$1,583,600	\$6,190,600	\$1,113,300	\$1,403,800	\$1,624,700	\$24,059,000	\$0	\$5,248,300	\$3,212,600	\$858,000	\$5,380,100	\$5,856,600	
2020	\$1,833,700	\$8,302,100	\$702,000	\$1,889,000	\$4,650,000	\$20,957,200	\$0		\$4,427,800	\$776,600	\$16,597,500	\$5,707,200	\$9,775,100
2016	\$3,135,000	\$5,789,512	\$827,534	\$2,286,225	\$3,707,793	\$31,410,271	\$0		\$3,598,559	\$1,472,000	\$9,756,575	\$5,789,512	\$6,105,698

Figure H-19 – Cost of Decommissioning Tasks by Study Year - Platform Hidalgo



Cost of Decommissioning Tasks by Study Year for Platform Hillhouse

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025



Figure H-20 – Cost of Decommissioning Tasks by Study Year – Platform Hillhouse



Cost of Decommissioning Tasks by Study Year for Platform Hogan

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

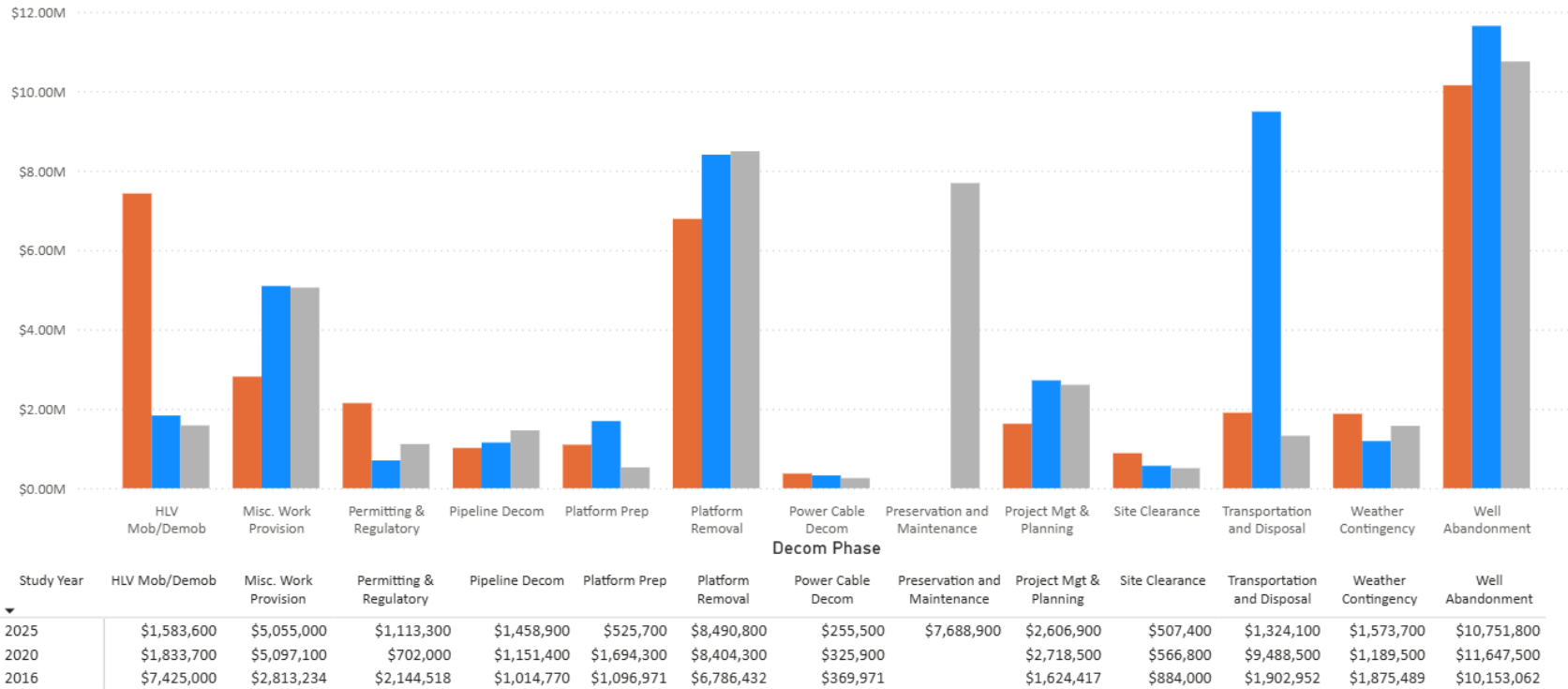


Figure H-21 – Cost of Decommissioning Tasks by Study Year - Platform Hogan



Cost of Decommissioning Tasks by Study Year for Platform Hondo

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

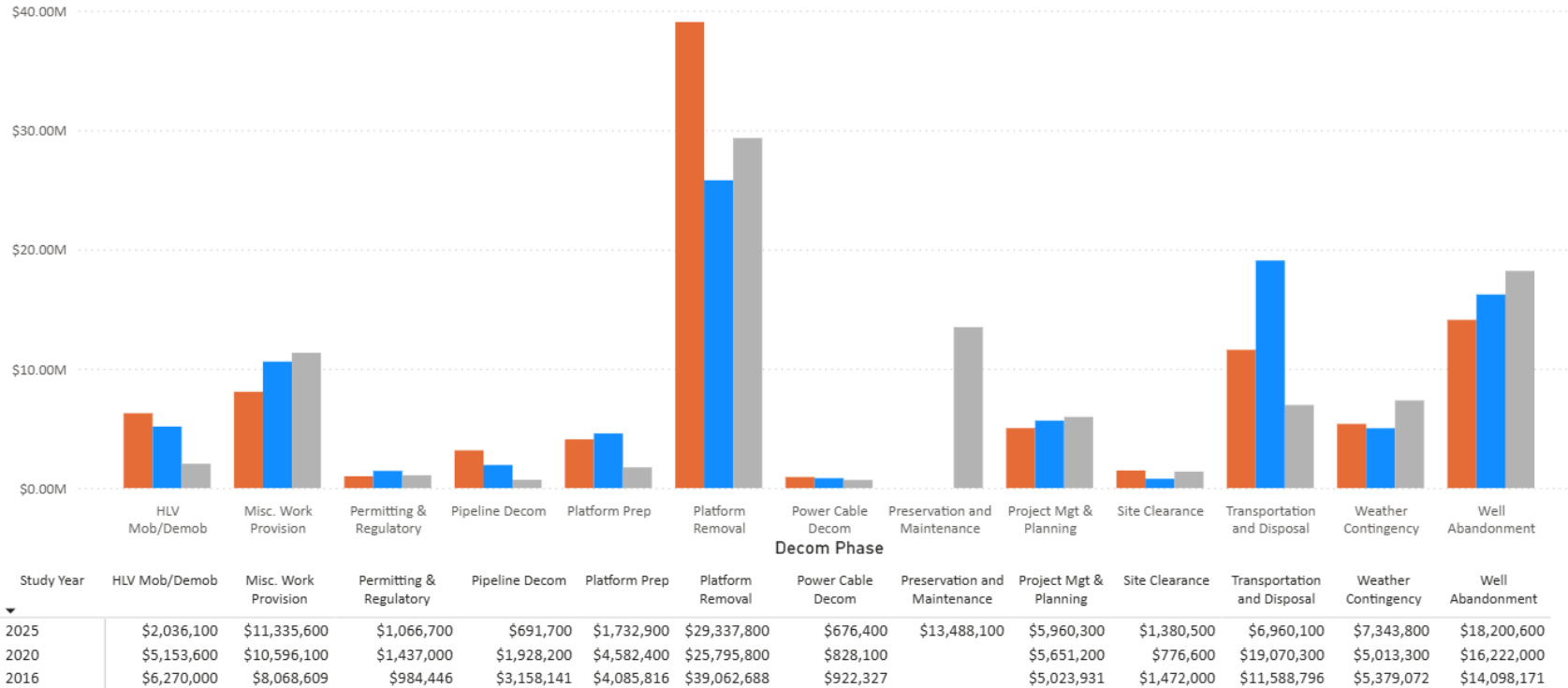


Figure H-22 – Cost of Decommissioning Tasks by Study Year - Platform Hondo



Cost of Decommissioning Tasks by Study Year for Platform Houchin

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

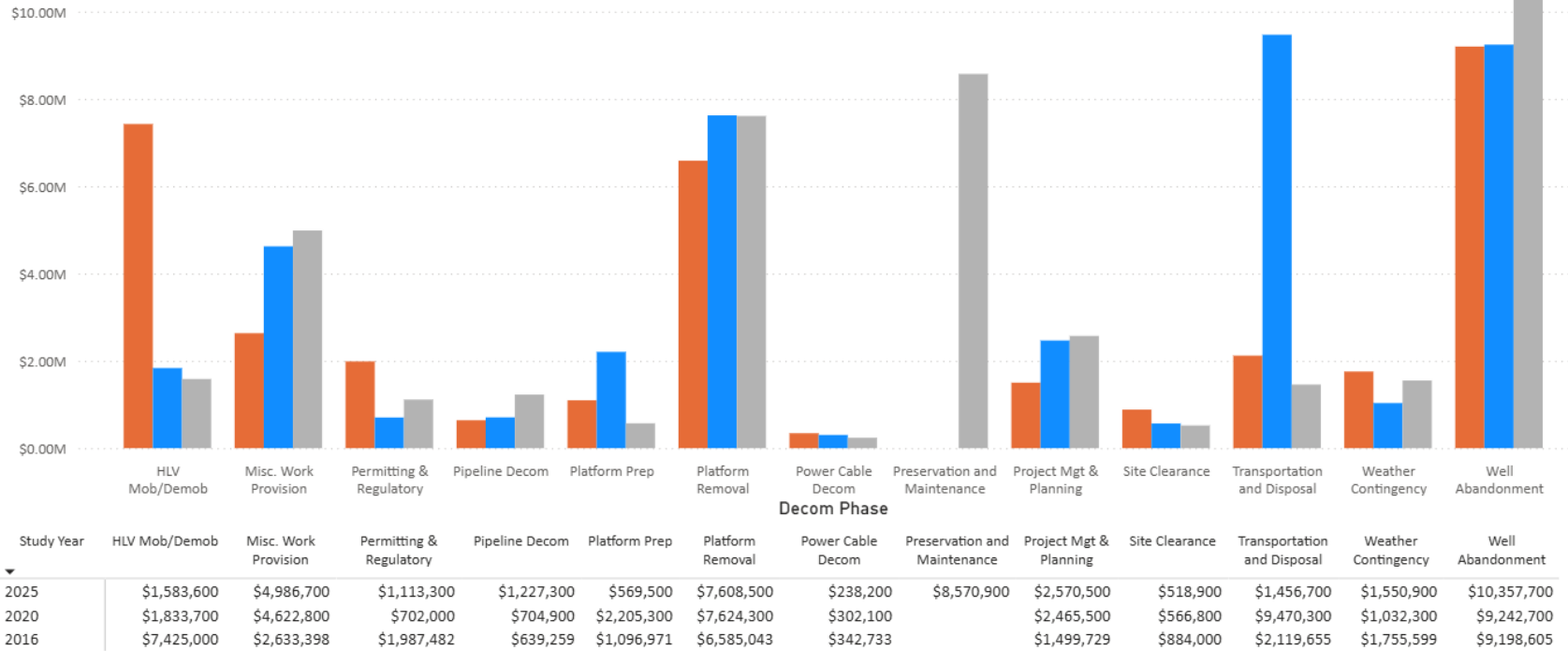


Figure H-23 – Cost of Decommissioning Tasks by Study Year - Platform Houchin



Cost of Decommissioning Tasks by Study Year for Platform Irene

(in \$ USD)

Study Year ● 2016 ● 2020 ● 2025

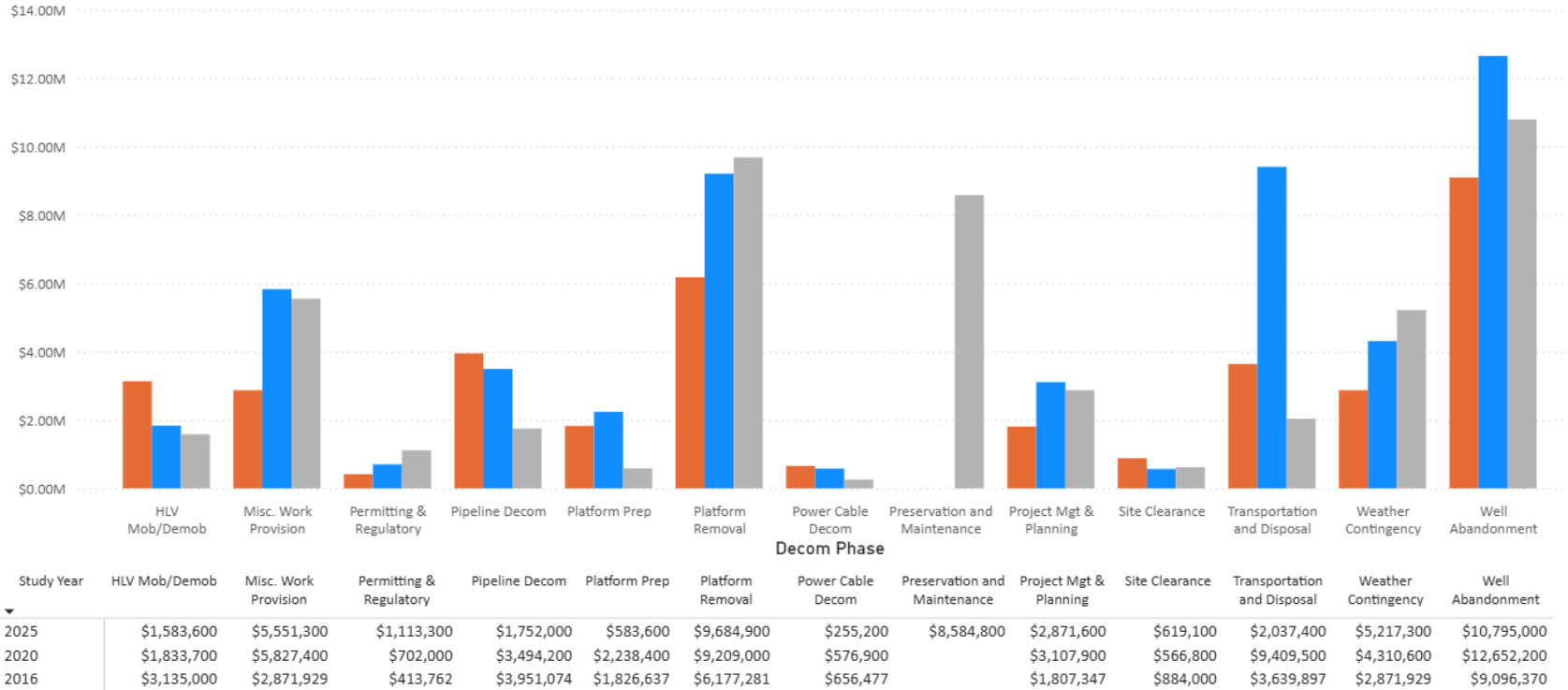


Figure H-24 – Cost of Decommissioning Tasks by Study Year – Platform Irene



Campaign 1
 (in \$ USD)

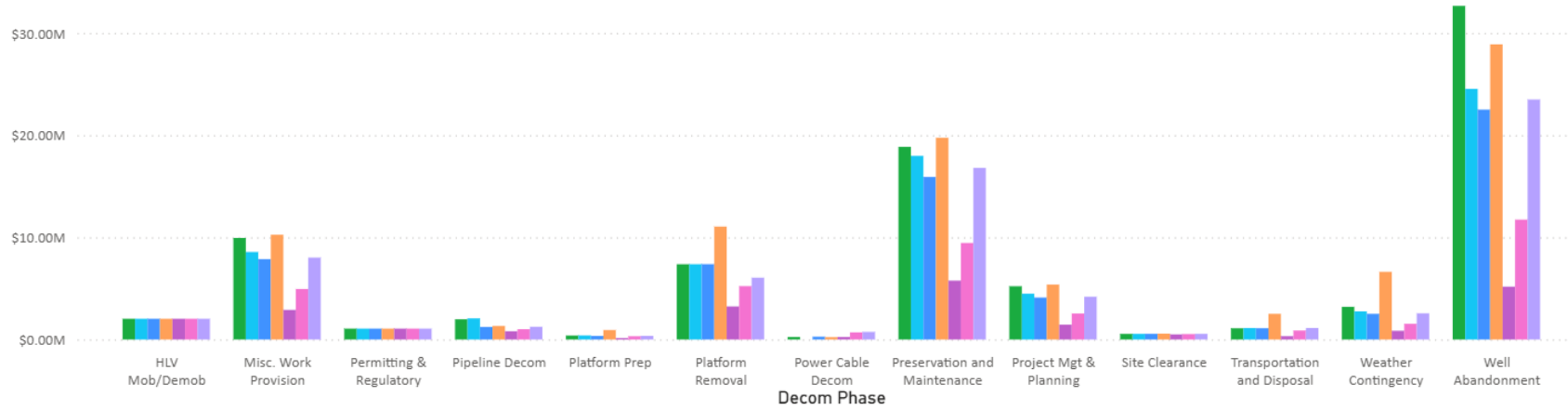


Figure H-25 – Campaign 1 Estimated Costs



Campaign 2
 (in \$ USD)

Platform ● A ● B ● C ● Gilda ● Gina ● Henry ● Hillhouse



Platform	HLV Mob/Demob	Misc. Work Provision	Permitting & Regulatory	Pipeline Decom	Platform Prep	Platform Removal	Power Cable Decom	Preservation and Maintenance	Project Mgt & Planning	Site Clearance	Transportation and Disposal	Weather Contingency	Well Abandonment
A	\$2,036,100	\$9,939,400	\$1,066,700	\$1,985,100	\$394,100	\$7,368,700	\$248,300	\$18,856,000	\$5,215,700	\$552,000	\$1,098,900	\$3,206,500	\$32,656,600
B	\$2,036,100	\$8,569,600	\$1,066,700	\$2,074,300	\$401,200	\$7,371,500		\$17,974,000	\$4,485,100	\$554,600	\$1,119,700	\$2,749,900	\$24,532,600
C	\$2,036,100	\$7,863,800	\$1,066,700	\$1,229,000	\$355,200	\$7,374,200	\$280,300	\$15,916,000	\$4,108,700	\$557,100	\$1,104,100	\$2,514,600	\$22,506,400
Gilda	\$2,036,100	\$10,257,300	\$1,066,700	\$1,327,000	\$932,700	\$11,055,400	\$233,400	\$19,752,600	\$5,385,200	\$574,000	\$2,515,300	\$6,624,900	\$28,889,100
Gina	\$2,036,100	\$2,898,300	\$1,066,700	\$811,700	\$145,000	\$3,239,100	\$248,800	\$5,766,200	\$1,460,400	\$503,800	\$330,200	\$859,400	\$5,174,100
Henry	\$2,036,100	\$4,944,500	\$1,066,700	\$1,012,000	\$324,300	\$5,225,700	\$701,800	\$9,448,000	\$2,551,700	\$533,000	\$884,400	\$1,541,500	\$11,731,400
Hillhouse	\$2,036,100	\$8,022,500	\$1,066,700	\$1,247,800	\$359,800	\$6,052,600	\$747,900	\$16,798,000	\$4,193,300	\$554,500	\$1,125,100	\$2,567,500	\$23,494,800

Figure H-26 – Campaign 2 Estimated Costs

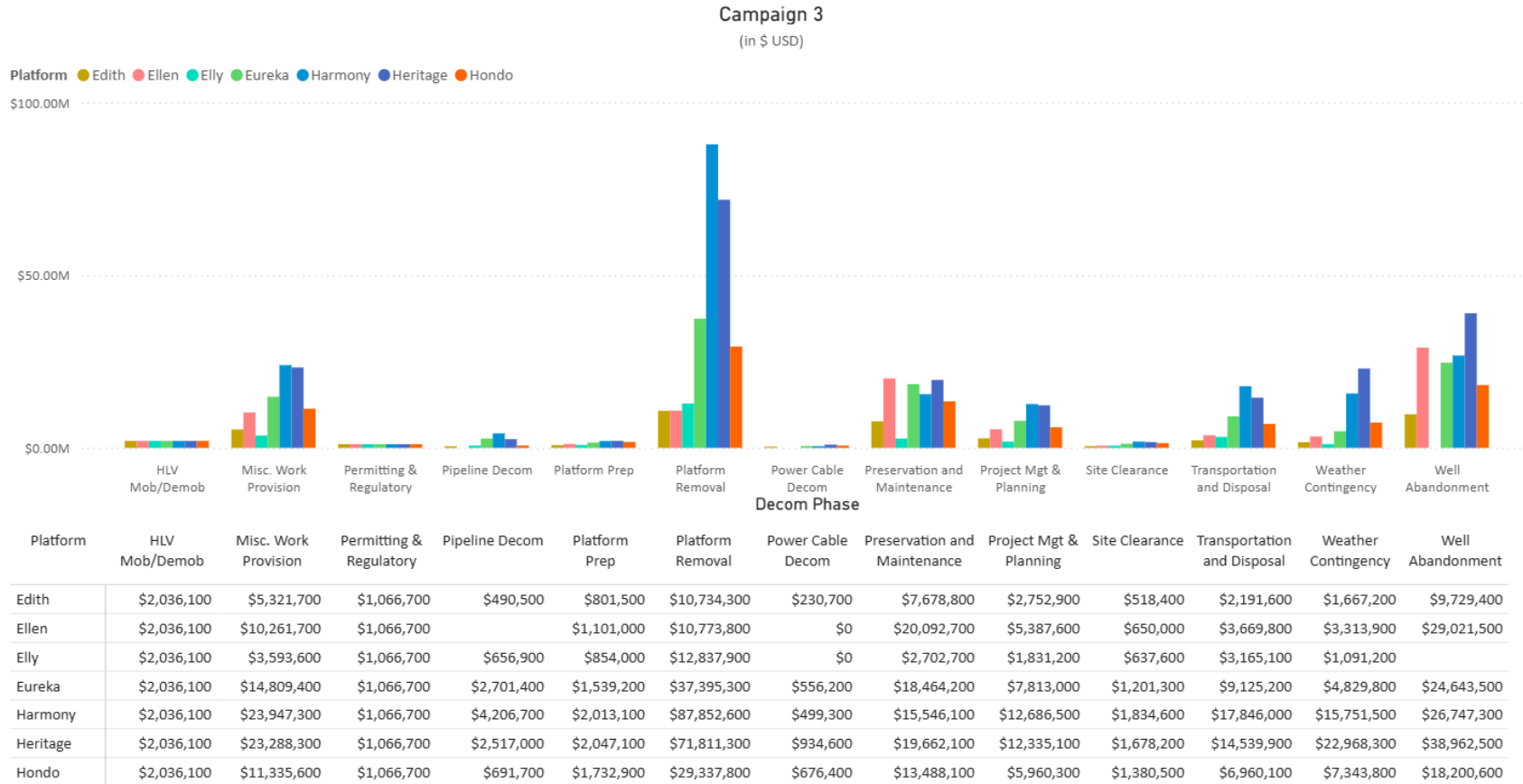


Figure H-27 – Campaign 3 Estimated Costs



Cost of Permitting & Regulatory By Platform

(in \$ USD)

Study Year ● 2025

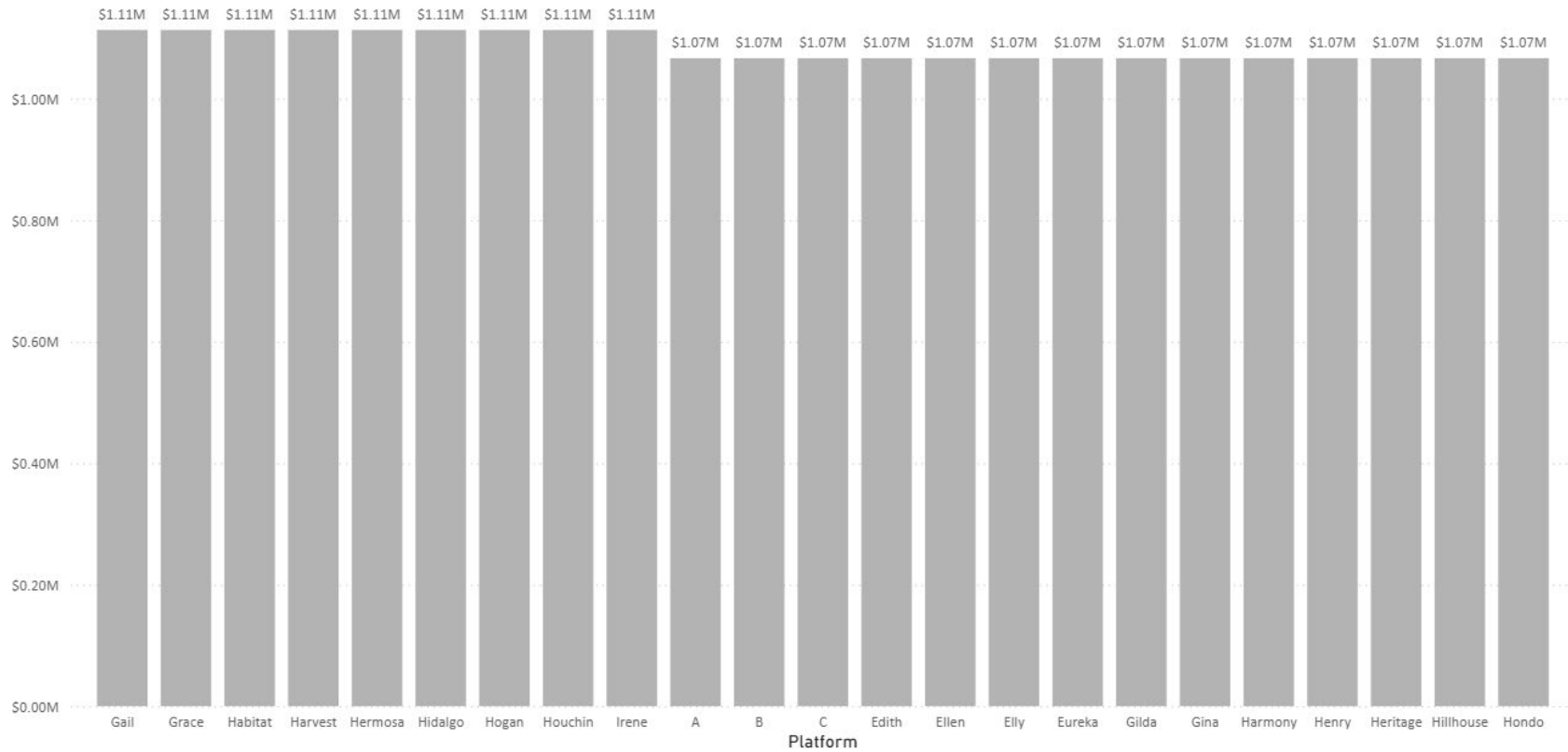


Figure H-28 - Regulatory & Permitting Costs by Platform



Cost of Project Mgt & Planning By Platform

(in \$ USD)

Study Year ● 2025

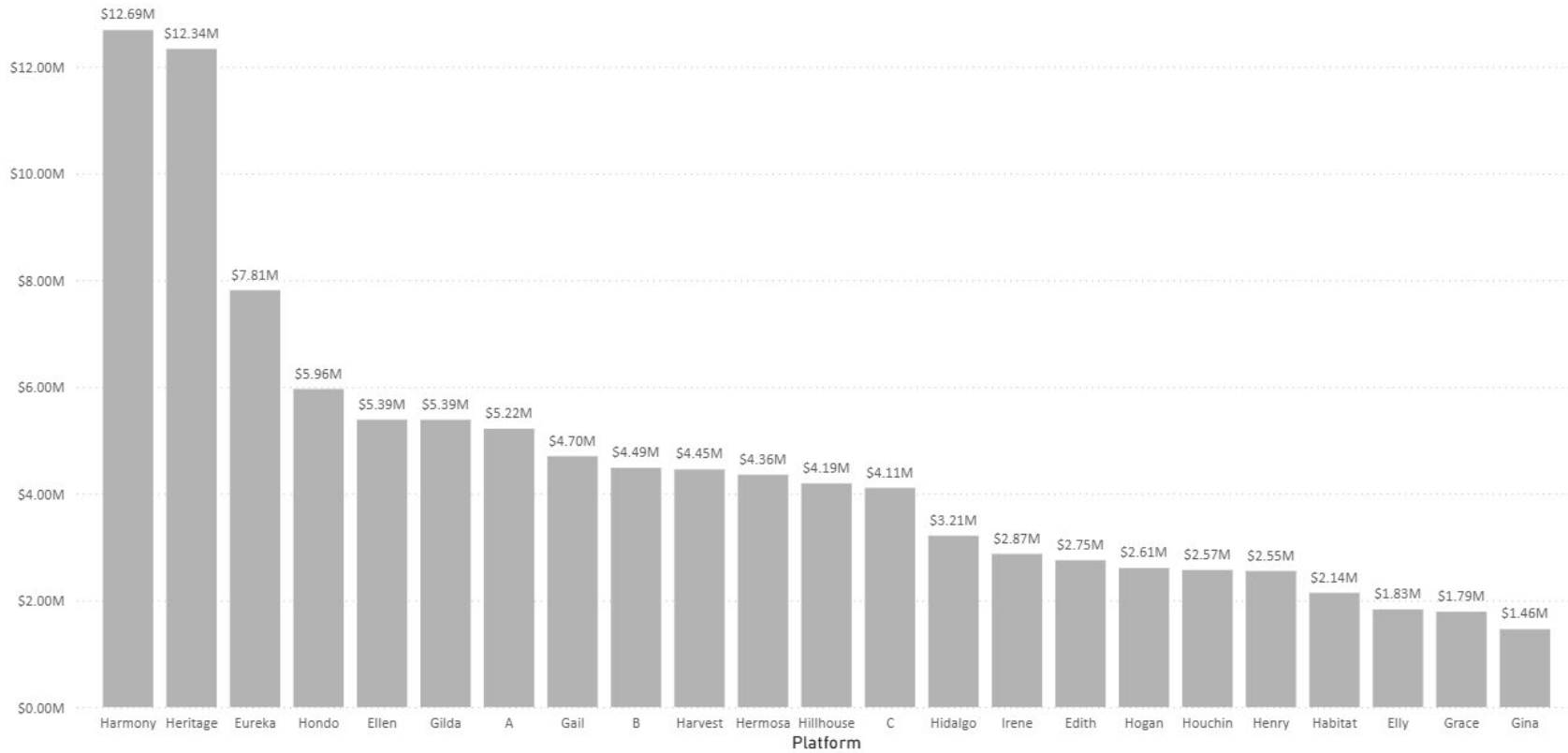


Figure H-29– Project Management, Engineering, and Planning Costs by Platform



Cost of Misc. Work Provision By Platform

(in \$ USD)

Study Year ● 2025

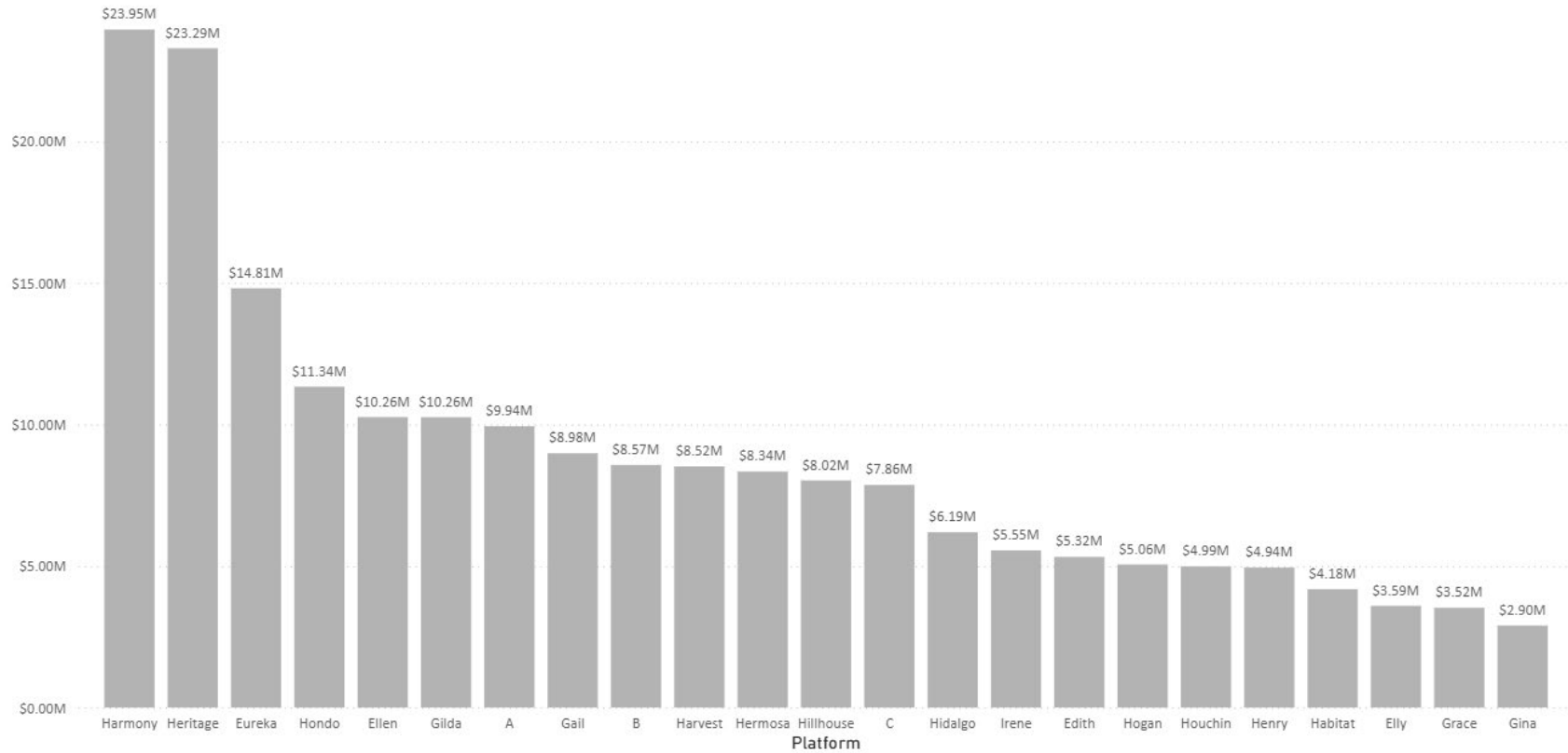


Figure H-30 – Misc. Work Provision Costs by Platform



Cost of Weather Contingency By Platform

(in \$ USD)

Study Year ● 2025

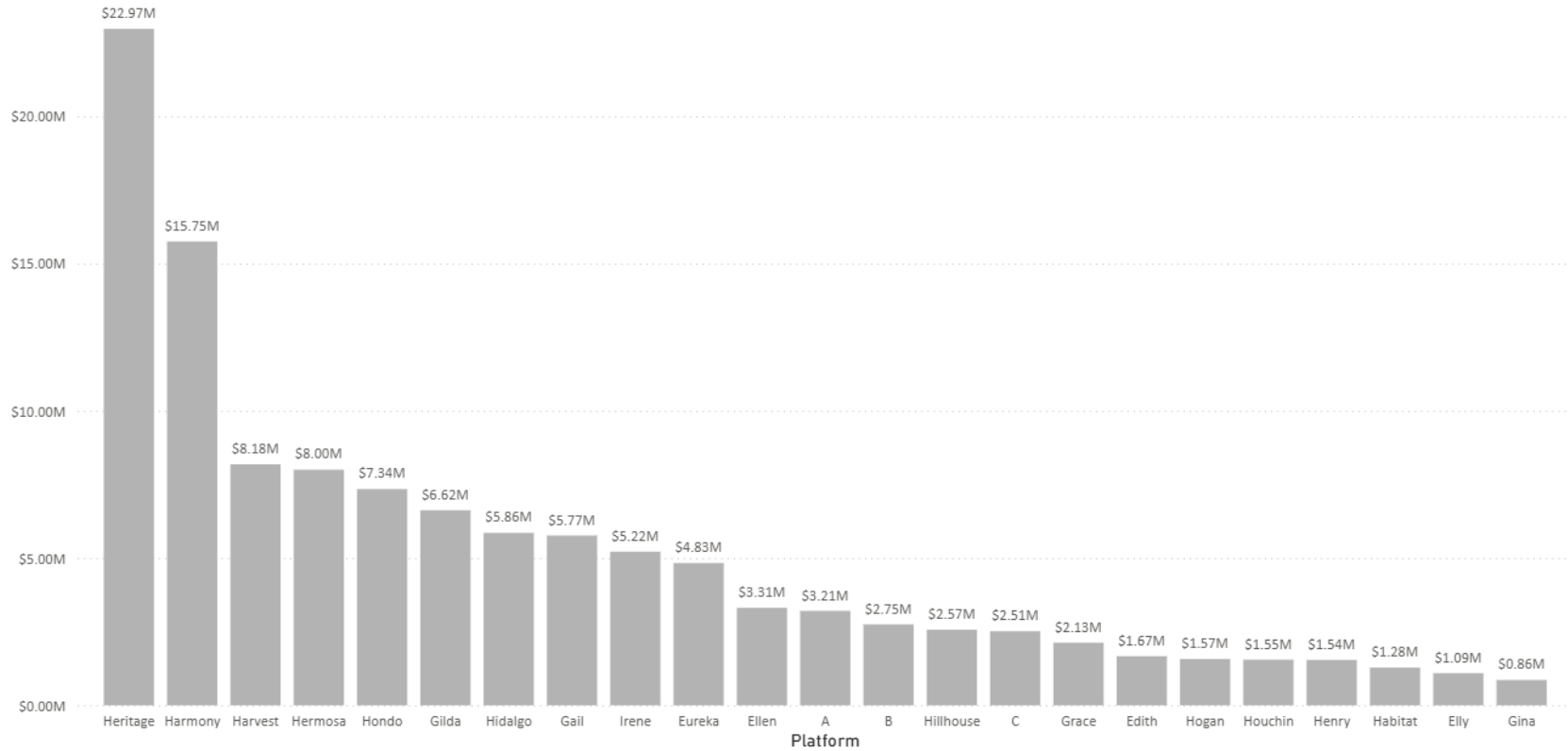


Figure H-31 – Weather Contingency Costs by Platform



Cost of Platform Prep By Platform

(in \$ USD)

Study Year ● 2025

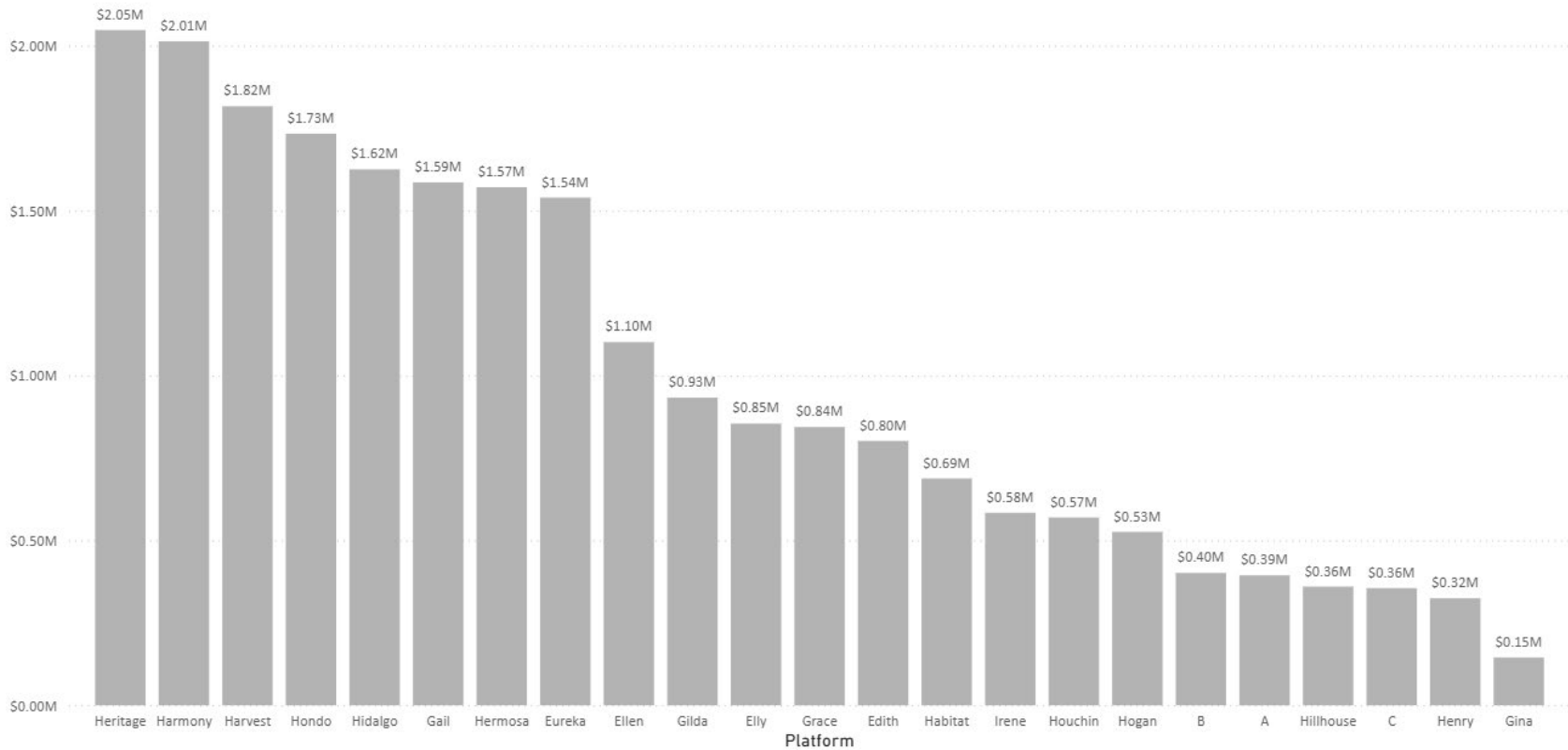


Figure H-32 – Costs of Platform Preparation by Platform



Cost of Preservation and Maintenance By Platform

(in \$ USD)

Study Year ● 2025

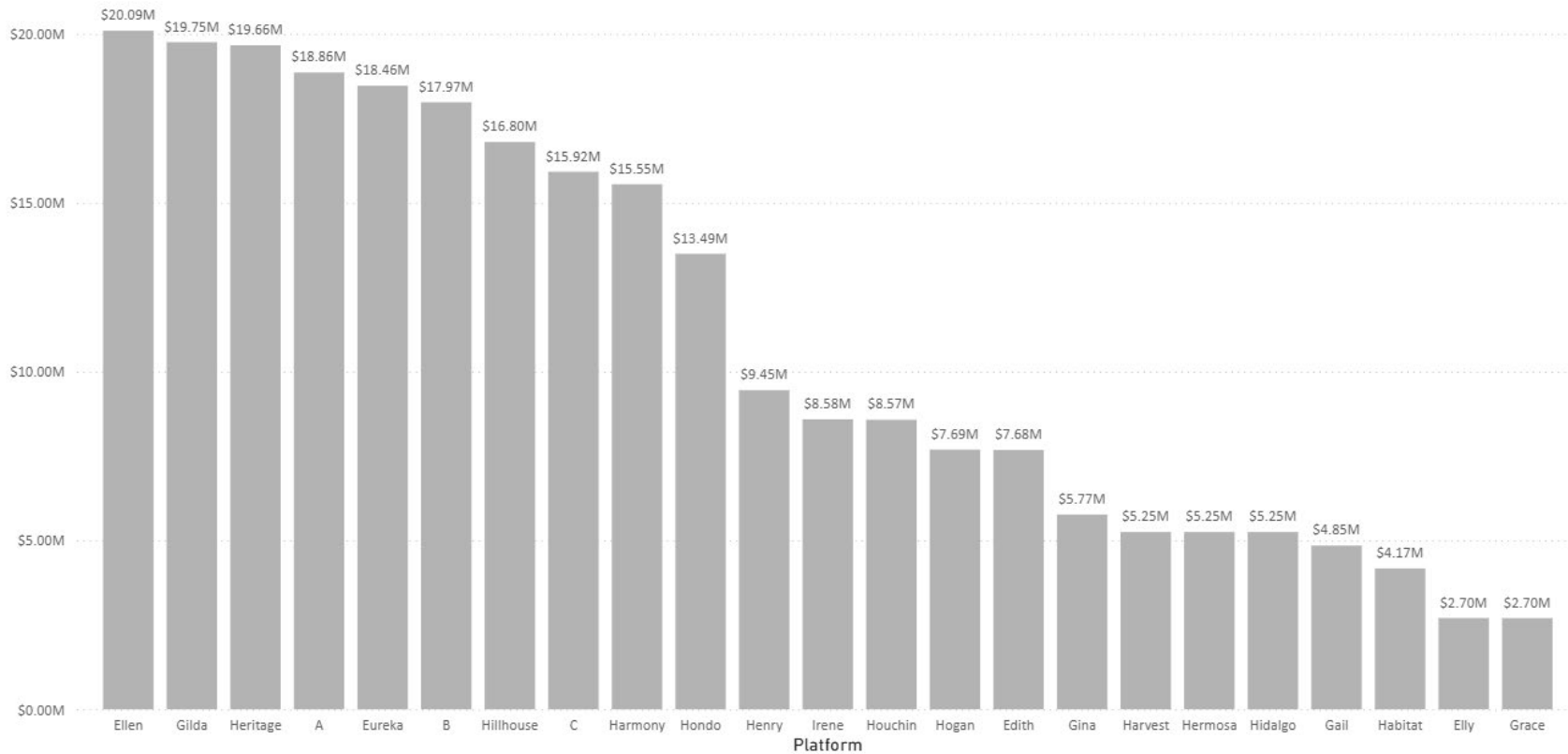


Figure H-33– Costs of Preservation and Maintenance by Platform



Cost of Well Abandonment By Platform

(in \$ USD)

Study Year ● 2025

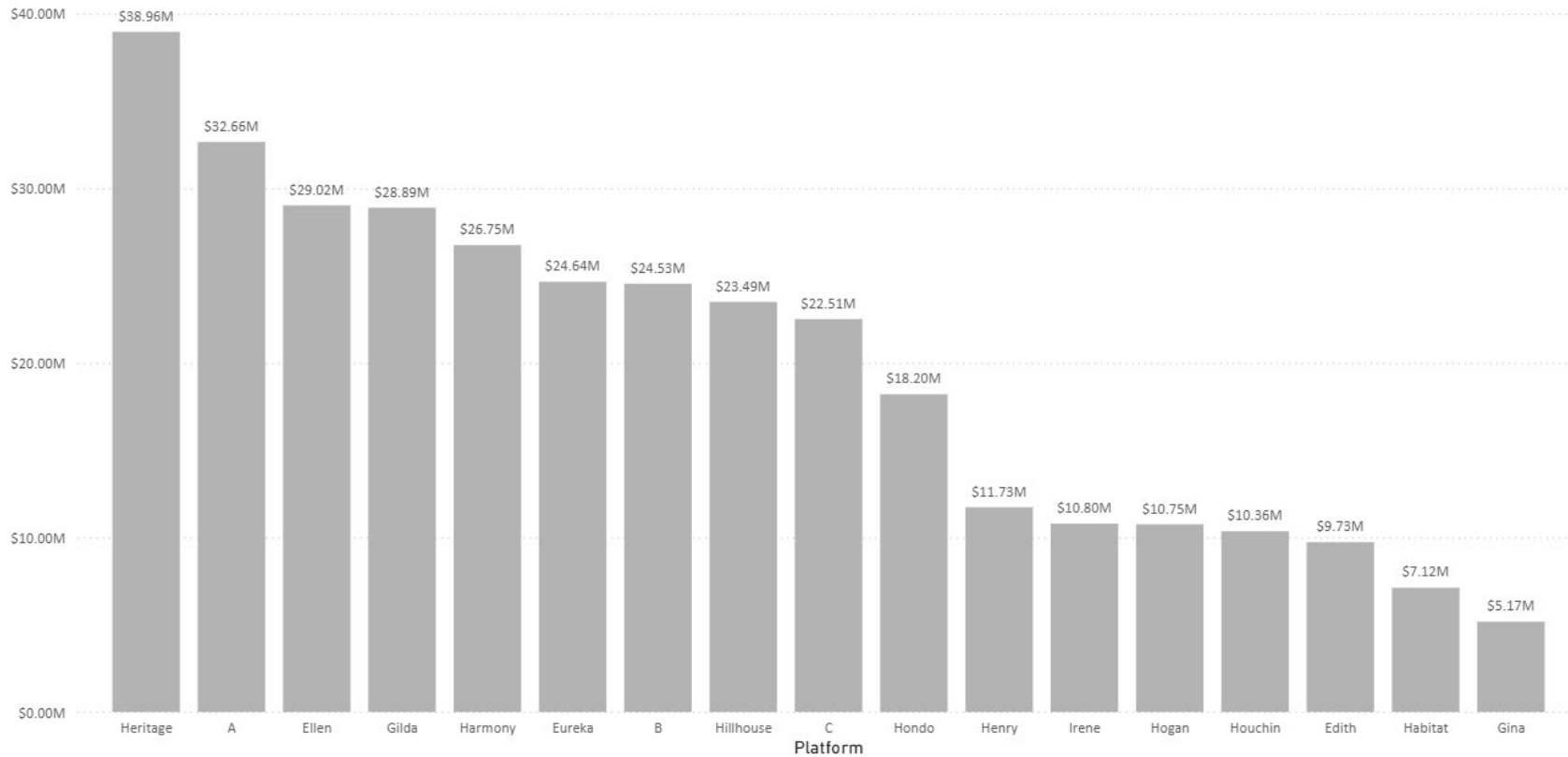


Figure H-34 – Costs of Well Abandonment by Platform



Cost of Pipeline Decom By Platform

(in \$ USD)

Study Year ● 2025

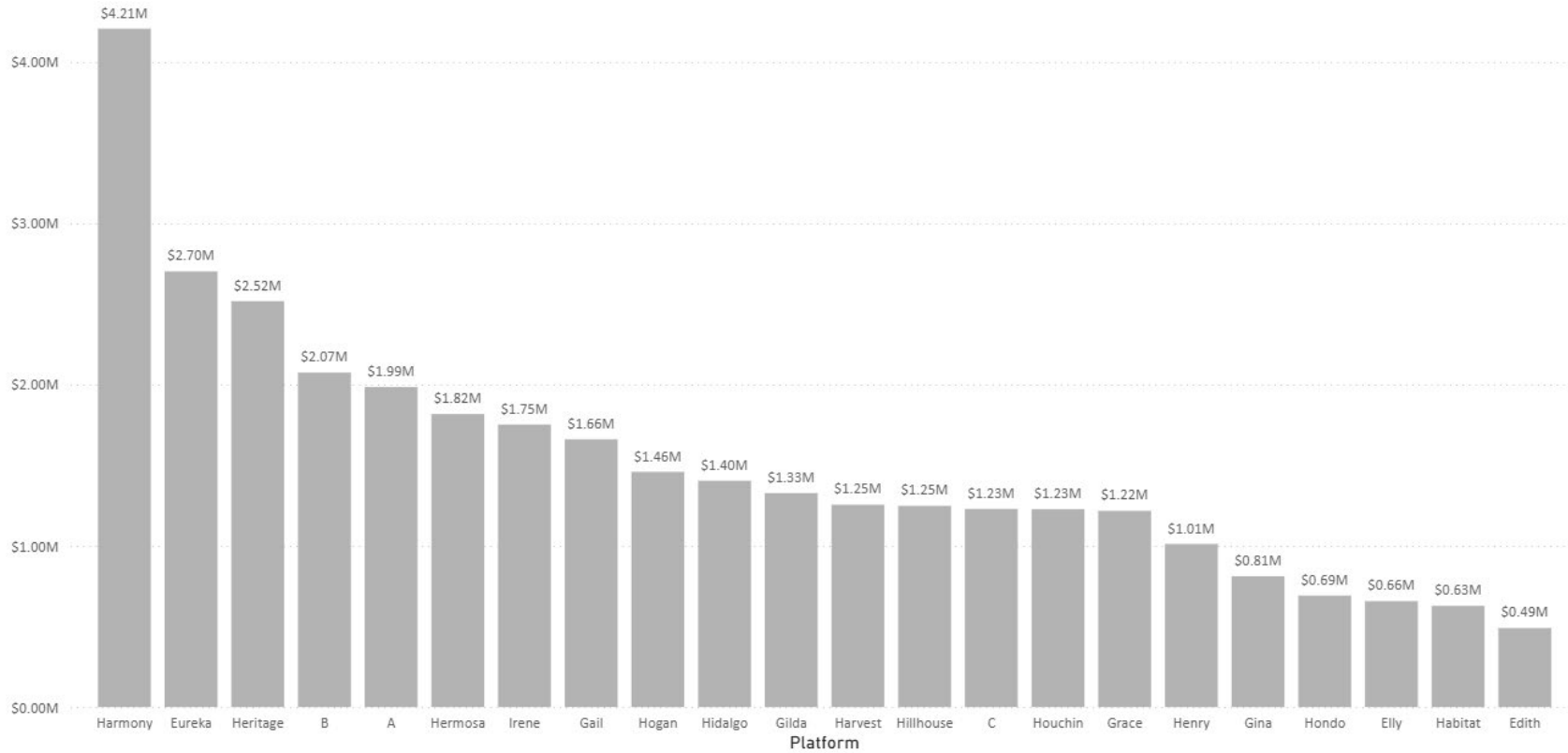


Figure H-35 – Costs of Pipeline Decommissioning by Platform



Cost of Power Cable Decom By Platform

(in \$ USD)

Study Year ● 2025

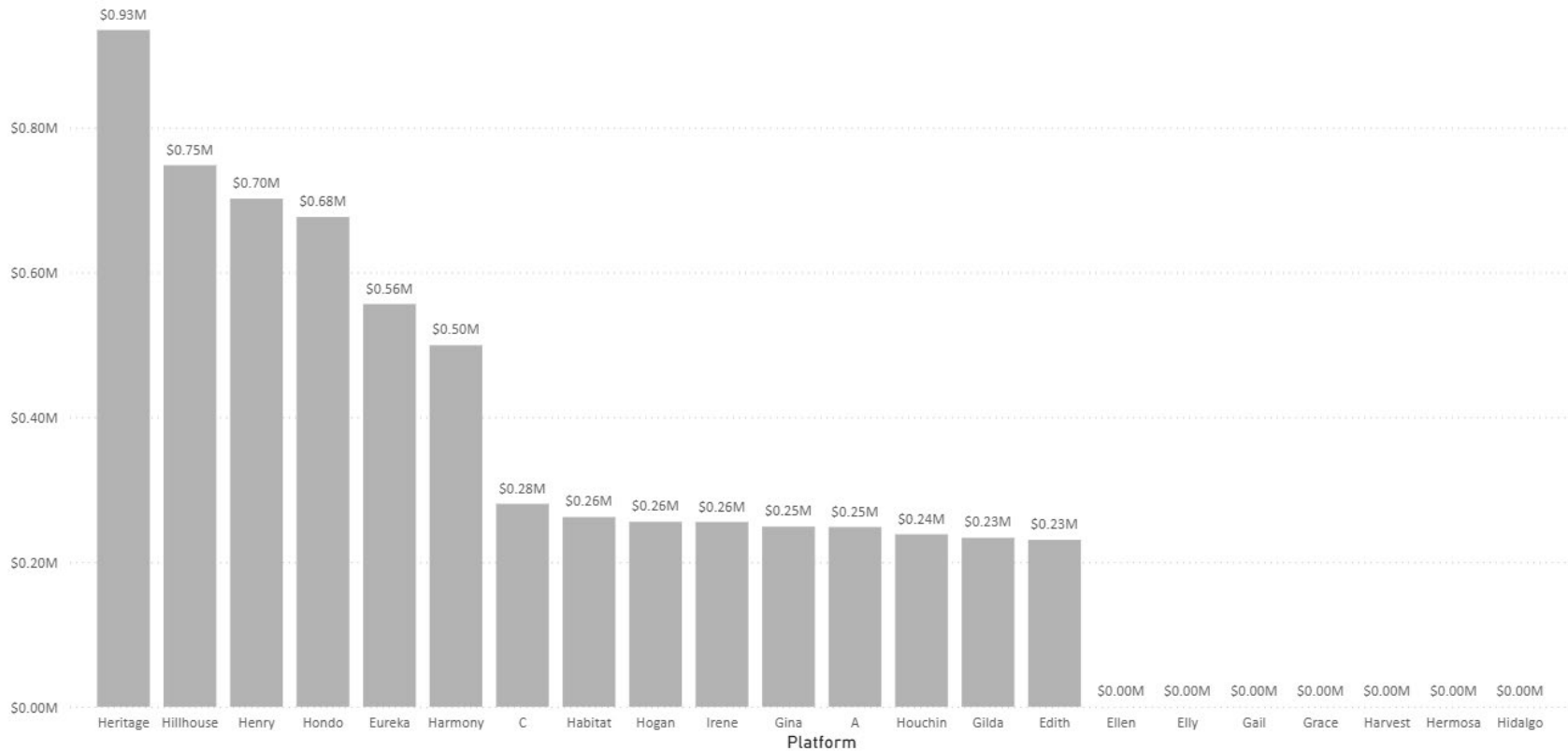


Figure H-36 – Costs of Power Cable Decommissioning by Platform



Cost of Platform Removal By Platform

(in \$ USD)

Study Year ● 2025

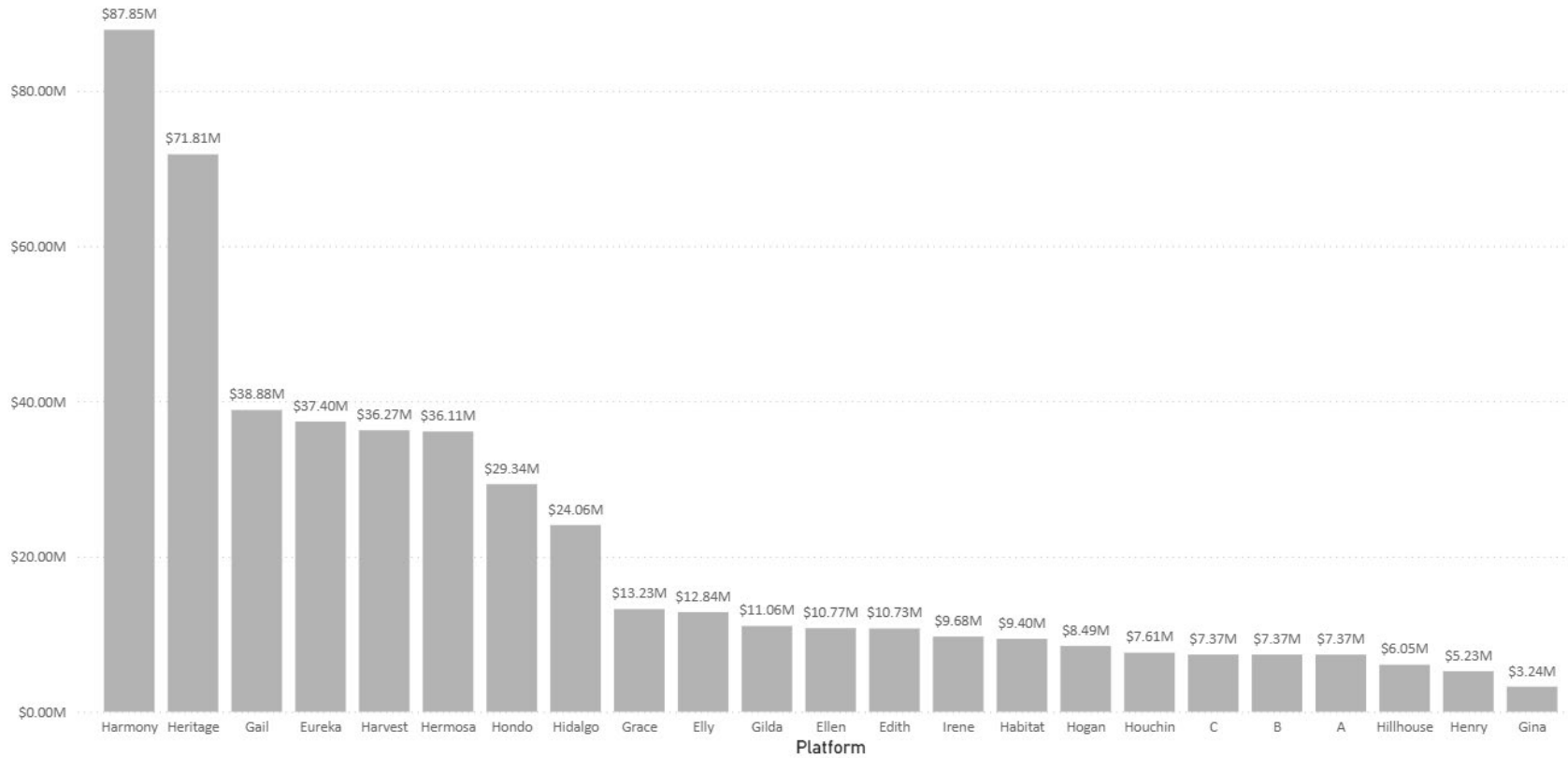


Figure H-37 – Cost of Platform Removal by Platform



Cost of Transportation and Disposal By Platform

(in \$ USD)

Study Year ● 2025

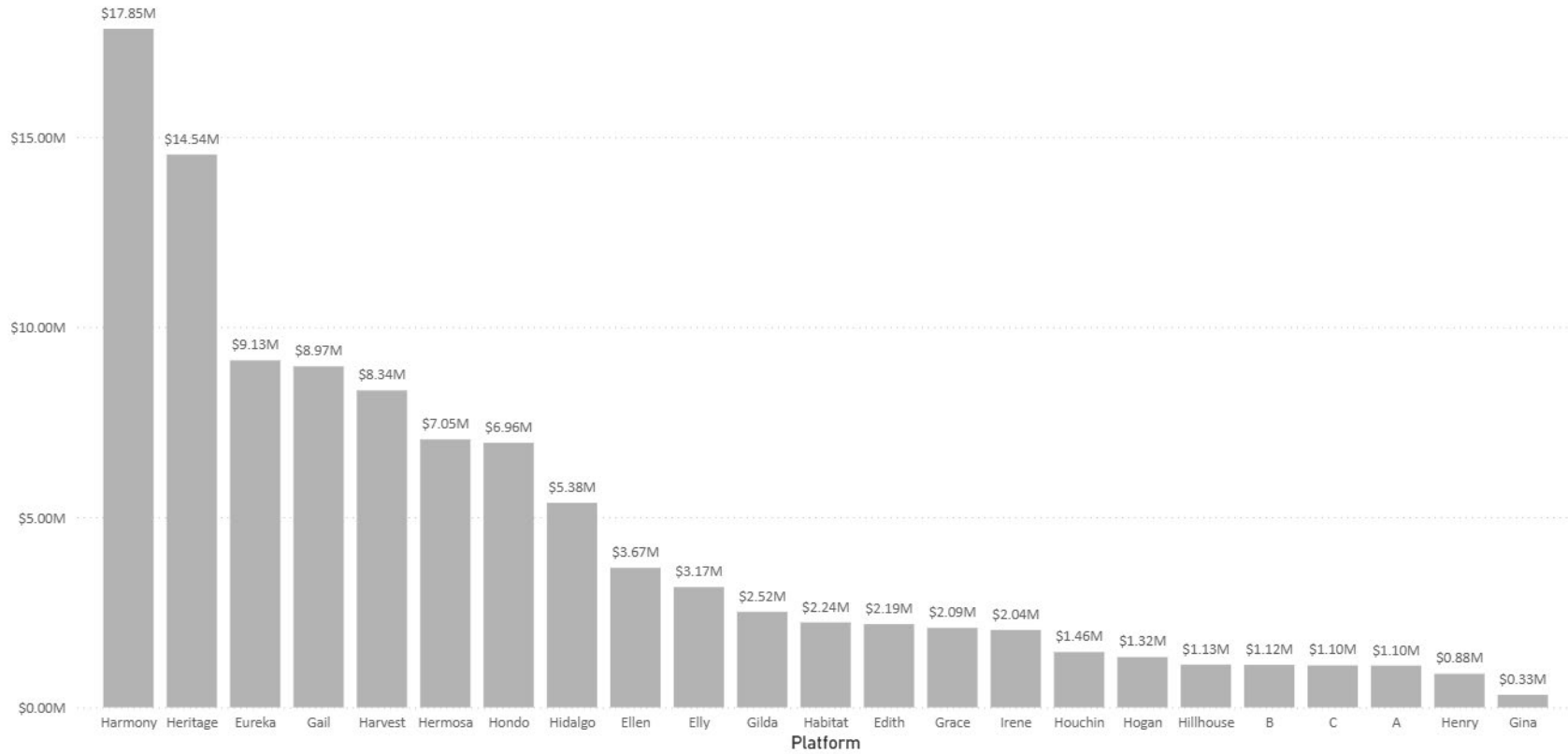


Figure H-38 – Cost of Transportation and Disposal by Platform



Cost of Site Clearance By Platform

(in \$ USD)

Study Year ● 2025

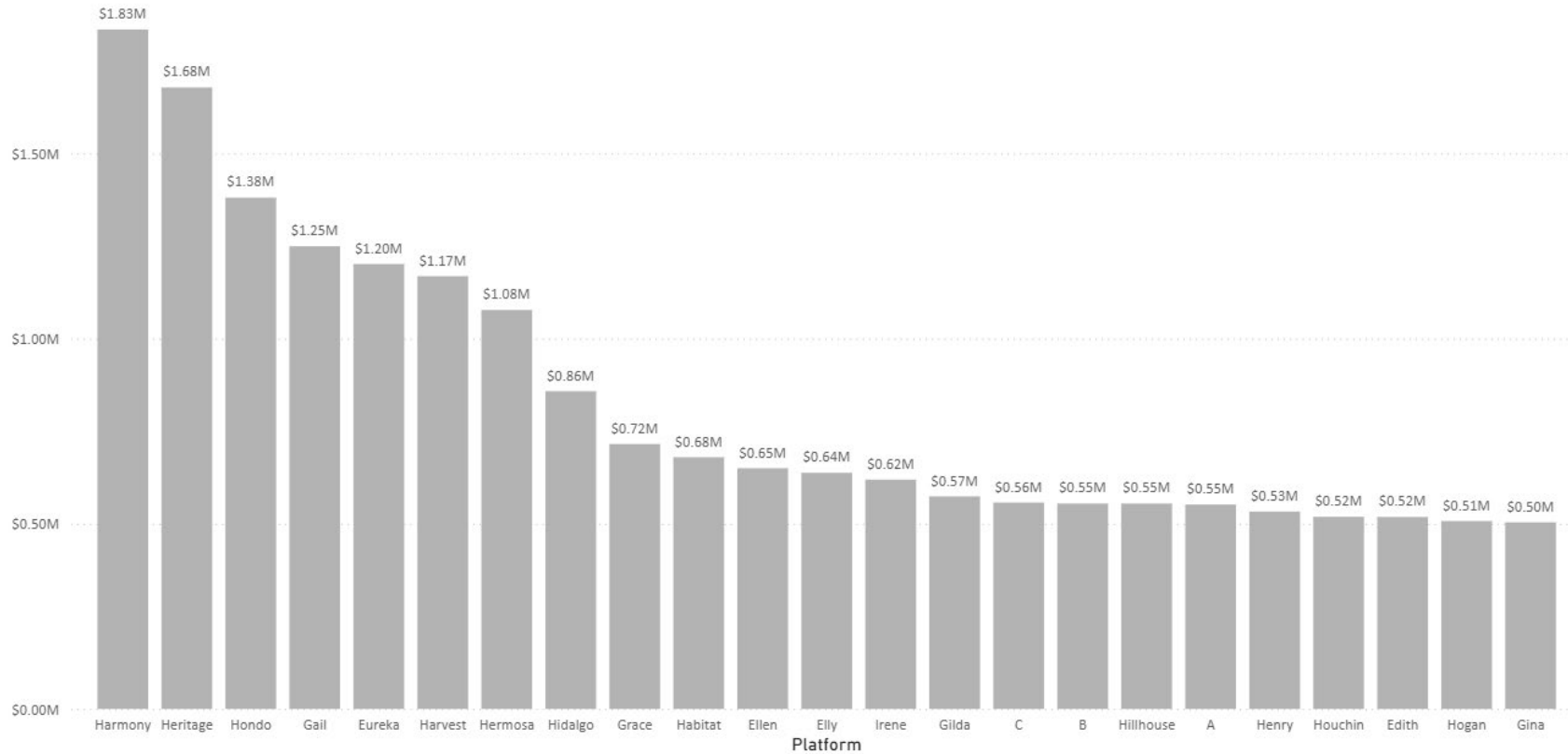


Figure H-39 – Cost of Site Clearance by Platform



Cost of HLV Mob/Demob By Platform

(in \$ USD)

Study Year ● 2025

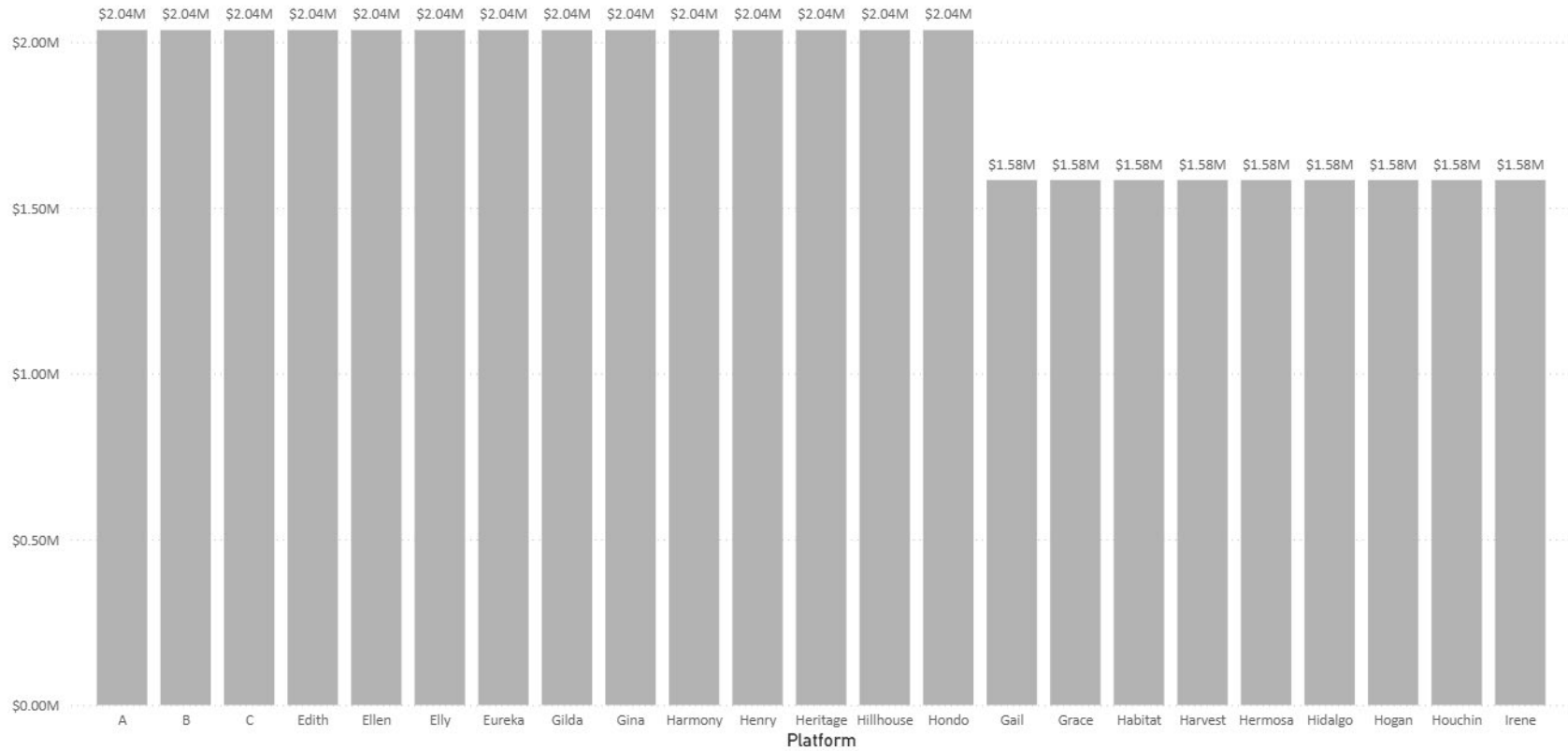


Figure H-40 – Cost of HLV Mob/Demob