OCS Study
BOEM 2022-077

History of the Gulf of Mexico Offshore Oil and Gas Industry during the Deepwater Era

Volume 2: Shell Oil's Deepwater Mission to Mars

US Department of the Interior
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Volume 2: Shell Oil's Deepwater Mission to Mars

Authors

Tyler Priest
Joel Hewett
Diane E. Austin
Morgan Lundy

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COVER IMAGE

The Mars tension-leg platform (TLP) is pictured in 2012. Photo courtesy of Jason Theriot.

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Acknowledgements

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Volume 1	Joel Hewett University of Houston	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume I: the shape of these monsters: from fixed to floating offshore oil and gas production, 1976–2006.
Volume 2	Tyler Priest University of Houston	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume II: Shell Oil's deepwater mission to Mars
Volume 3	Joel Hewett University of Houston	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume III: the secret of the sea: offshore oil and gas revenue collection, valuation, and royalty relief, 1973–2010
Volume 4	Morgan Lundy University of Arizona Diane E. Austin University of Arizona Editors	History of the Gulf of Mexico offshore oil and gas industry during the deepwater era: Volume IV: a guide to the interviews

Overview of This Four-Volume Study (History III)

Offshore oil is the subject of one of the most important energy stories of the last 75 years, and the move into deepwater (usually defined as 1,300 feet or 400 meters) is its crowning achievement. From negligible production after World War II, offshore oil has grown to account for 30 percent of total global conventional oil production. Deepwater makes up only seven percent of the total, but this percentage is growing (US Energy Information Administration, 2016). By 2006, the industry had discovered 60 billion barrels (bbl) of oil in deepwater, production from which is still coming online (Williams, 2006). During 2007–2012, 50 percent of the 170 billion bbl of global conventional oil (and natural gas equivalent) discovered by the industry was in deepwater. Many of those discoveries are yet to be developed (Nelson et al., 2013). From 6 million barrels of oil per day (b/d) in 2017, oil analysts project deepwater output to grow as high as 14 million b/d by 2030 (Seeking Alpha, 2017). The International Energy Agency (IEA) estimates that nearly half of the 2.7 trillion bbl of remaining recoverable reserves are offshore, 25 percent of which—or 340 billion bbl—will be found in deepwater (IEA, 2013). Rather than merely stemming production declines, deepwater oil has provided a substantial addition to global supply, an increase that few other sources in recent years have matched (Miller, 2014).

At current (April 2017) oil prices ($50/barrel), the present value of deepwater oil discovered in 2007–2012 is worth more than $4 trillion. Despite the sobering upfront costs of projects extending into 10,000 feet of water, the prolific per-well flow rates of 10,000–20,000 b/d (compared to 1,000–2,000 b/d for wells onshore or on the continental shelf) in many reservoirs often make them the most profitable investments for a large oil company. Royal Dutch Shell's Mars field, one of the largest in the Gulf of Mexico (Gulf) , started producing in 1996 and will earn an estimated average annual net cash flow (gross revenues minus costs, royalties, and taxes) of $1.5 billion each year until 2027.

Such economic value was by no means assured when companies began exploring in unprecedented water depths. Why did they do so? Journalists and scholars often explain the deepwater push as a response to one or more of the following: "peak oil" supply constraints, the locking up of all the "easy" oil overseas by National Oil Companies, the Deep Water Royalty Relief Act signed by President Bill Clinton in 1995, rising oil prices in the 2000s, or the reckless charge of BP into unprecedented water depths beginning in the late 1990s (Bower 2009: 18-22; Jacobsen 2011: 38-40; Klare 2012: 44-49; Lustgarten 2012: 168-172).

These interpretations all miss the mark. Deepwater oil is the result of a longer process of historical development, going back at least to the early 1970s, when leading offshore companies began to peer beyond the edge of the continental shelf in search of new reserves. The industry's move off the shelf in the Gulf emerged from an even longer history of offshore oil exploration and development in that region that had its start in the 1930s. Although technological change and innovation in the offshore industry often took great leaps forward, it usually proceeded gradually. Each new phase built on the previous phase. In a constant search for new reserves to replace declining onshore production, explorationists and engineers adapted prevailing concepts and techniques to new demands and made incremental improvements that nudged offshore operations into deeper waters. Making sense of deepwater requires an understanding of the historical evolution of the industry.

Still, the "deepwater era" (1974–present) is different in several ways from what we might call the "formative era" (1938–1973) of the offshore sector. Leasing policies and exploration strategies evolved to meet new geologic, economic, and technological challenges. Fabrication and installation practices had to be modified to address new water depths, metocean conditions, and the increasing scale of deepwater projects. Over time, more of the infrastructure installed in the Gulf was built overseas, marking the internationalization of the Gulf offshore business. The nature of work changed with increasing automation on both platforms and drilling rigs, and with the geographic dispersal of workers. Finally, the oil price collapse of the mid-1980s forced the radical restructuring of the offshore business and uniquely affected communities all along the Gulf Coast and every in aspect of the industry. New deepwater discoveries beginning in the mid-1990s revived the business and set off a new rush for leasing and development, but in a way that differed markedly from earlier periods of expansion.

The Gulf remains the primary laboratory for offshore technological innovation and regulatory practices worldwide. As offshore oil assumes a high profile in national development strategies around the globe, any effort to analyze the political, social, and economic aspects of offshore exploration and development must recognize and use the Gulf as a historical precedent or basis of comparison. This study, History III, of the history of the deepwater era in the Gulf both builds on histories of the earlier period and provides the first in-depth historical investigation of important new trends over the last thirty years. It will be valuable to those who are responsible for planning and managing the development of offshore oil and gas reserves and for more broadly understanding the impacts of such development on the Gulf Coast region.

Background of History III

The cooperative agreement for this study was awarded on June 1, 2008. Researchers from the University of Houston C.T. Bauer College of Business (UH) and the University of Arizona Bureau of Applied Research in Anthropology (BARA) organized and carried out the study. Principal investigator Dr. Tyler Priest led the research and writing for the UH team. UH History Ph.D. student Jason Theriot (who earned his degree in 2011), assisted in managing the study, conducting oral histories, and drafting preliminary reports. Consultant Joel Hewett, who had served with Dr. Priest as an analyst on the President's National Oil Spill Commission (2010–2011), contributed intensive research, edited oral histories and volumes, and authored two of the three final technical reports. Other UH History graduate students, Juan Galván Rodríguez and Natalie Schuster, assisted with research and oral history edits. John Holt and Pedro Paulo Gedda provided research and insights on the North Sea and Brazil, respectively, that helped place the deepwater Gulf in global and comparative context. Anthropologists Dr. Diane E. Austin and Dr. Thomas McGuire led the BARA team in carrying out fieldwork and oral histories in Louisiana and Mississippi.

Two previous history studies, funded by the Minerals Management Service (now the Bureau of Ocean Energy Management), laid the foundation for this research study.

- History I: Assessment of historical, social, and economic impacts of OCS development on Gulf Coast communities (MMS 2001-026, MMS 2001-027)
- History II: History of the offshore oil and gas industry in Southern Louisiana (MMS 2004-049)

These studies produced substantial documents, and they generated more data than could be analyzed in the study period. History II, the second study, for example, produced audio recordings and transcripts of more than 450 oral history interviews by the time of its conclusion. History I, the first study, looked across the Gulf with comparisons among east Texas, south Louisiana, and south Alabama, but provided only a general overview of historical patterns and periods. History II provided a deeper look, but was focused on southern Louisiana and the period from the 1930s through the 1960s, although a significant amount of data was also collected on later decades, as well.

History III, the current four-volume study, broadens the inquiry both spatially and temporally by mining the rich oral histories and documents collected in the previous study and expanding the oral history interviews into Mississippi and to cover recent decades. It rounds out and deepens research on the 1970s–1990s, when exploration and development of oil and gas continually moved into deeper waters (now routinely exploring in 10,000 feet and producing in 5,000 feet) and into new offshore environments (from the Gulf and the North Sea to Brazil, West Africa, and elsewhere).

In 1974 in the Gulf, oil companies acquired the first leases in 1,000 feet of water, extending from the upper continental slope to the abyssal plain. Reaching the symbolic water depth of 1,000 feet marked the beginning of what we might call the "deepwater era." To operate in these depths and beyond, the industry had to develop fundamentally different development concepts and commercial strategies.

The ground for History II was also prepared by several other MMS and BOEM studies.

- MMS 2002-071, Effect of the oil and gas industry on commuting and migration patterns in Louisiana, 1960–1990, establishes some of the basic effects over time of the offshore petroleum industry on the communities and region within which it operates.
- MMS 2002-022, Social and economic impacts of OCS activities on individuals and families, Vol. I, highlights differences in offshore oil's effects on various Gulf of Mexico region subareas.
- Three study reports provide essential data and preliminary historical analysis of the deepwater era: Labor migration and the deepwater oil industry (MMS 2004-057), The economic impact in the US of deepwater projects: a survey of five projects (MMS 2004-041), and Deepwater Gulf of Mexico 2004: America's expanding frontier (MMS 2004-021).
- BOEM 2014-609 through BOEM 2014-612, The study report Gulf Coast communities and the fabrication and shipbuilding industry: a comparative community study, volumes I through IV, offer important information on demographic and labor market shifts in recent years relating to two key onshore support sectors.
- Two volumes–BOEM 2014-617, Offshore oil and Deepwater Horizon: social effects on Gulf Coast communities, vol. I: methodology, timeline, context, and communities, and BOEM 2014-618, volume II: key economic sectors, NGOs, and ethnic groups–were the culmination of emergency fieldwork carried out by anthropologists from BARA in the afternath of the 2010 *Deepwater Horizon* blowout and oil spill. The findings from this study are an important adjunct to History III.

Objectives and Methods

History III was launched with objectives similar to those of the previous history studies:

- to document the strategies and objectives of the companies involved
- to ascertain the cumulative effects of offshore development on the coastal landscape, and community and family relationships
- to describe how technology and managerial innovations enabled the development of reservoirs in deeper and deeper water depths
- to study how the policies and regulations of the government agencies with responsibilities in state and the federal jurisdictions were developed

- to explore how these aspects of the story were related and effected each other
- to make the data collected and the findings from the study widely available to the public and easily accessible to those who have worked in the industry and live in the region

There were three primary tasks for the History III project:

1) further process and analyze research data collected in the Histories I and II projects;

2) conduct, transcribe, process, and archive targeted interviews on the deepwater era to fill historical gaps; and

3) extend historical analysis from the formative era.

The emphasis of History II was on gathering and archiving the stories of the people, mostly from Louisiana during the formative era, who participated in the industry. The History III study aimed to continue gathering stories and information, but concentrated on industry-involved people who were from outside Louisiana, and on key individuals who could speak about the deepwater era. Greater emphasis was placed on providing historical analysis of the research data collected in Histories I and II and in other MMS-funded studies and on providing historical interpretations of the deepwater era.

The research for this study was wide-ranging. It first involved processing and analyzing abundant materials collected in the Histories I and II projects and consulting other government studies and scholarship on the deepwater offshore oil industry. Researchers undertook a comparative review of historical literature on other regions of offshore development around the world, especially the North Sea, Gulf of Guinea, and offshore Brazil. New research was collected in government archives, trade journals, technical papers, newspapers, periodicals, and videos. The study participants engaged in extensive informal discussions and correspondence with industry veterans and experts. They also conducted 253 formal oral history interviews; 48 by the UH team and 205 by the UA BARA team. This brings the total number of transcribed oral histories collected in History II and History III to 739. All are coded, compiled in a database, and include biographical and/or ethnographic prefaces. The audio and transcripts will be provided to BOEM and archived at UH, with copies deposited with six other archives and universities in Louisiana (see list below).

As they had done in History II, the UH team focused on the corporate and governmental side of the history, interviewing managers, entrepreneurs, engineers, scientists, and government officials. They targeted individuals involved in deepwater production (especially tension-leg platforms, floating platforms, and subsea wellhead systems), along with government officials active during changes in the federal leasing and regulatory regime. The BARA team gathered community-focused oral histories, concentrating on those in Alabama, Mississippi, and Lafayette, Louisiana, which had not been the subject of previous studies. They interviewed local entrepreneurs, workers, family members, community leaders, and others who can share information about how this industry developed and evolved. Locating this history within the context of the specific social, political, economic, and environmental changes occurring during the era, the BARA team focused its analysis on changes in the offshore petroleum workforce, the impacts of the evolving industry on local landscapes, and community-level responses to the industry.

Technical Reports

This study produced four technical reports, each published in a separate volume.

I) The shape of these monsters: from fixed to floating offshore oil and gas production, 1976–2006

II) Shell Oil's deepwater mission to Mars

III) The secret of the sea: offshore oil and gas revenue collection, valuation, and royalty relief, 1973–2010

IV) Guide to the interviews

Volume I, The shape of these monsters, traces how the semi-submersible platform design went from being the deepwater development concept of choice during the mid-1980s to being a pariah among Gulf operators during the boom years of the 1990s. The November 1988 start-up of the world's first floating offshore oil and gas production platform in deepwater, Placid Oil's *Green Canyon 29* semi-submersible, seemed to herald a "new era" in petroleum development in the US Gulf of Mexico. Instead, the project folded in just 18 months and was decommissioned over 1990 at a huge loss. Thirteen years would pass before a successful semi-submersible production facility would return to the deepwater Gulf. By resurrecting the all-but-forgotten story of the Green Canyon 29 debacle, and by re-assessing the hopes expressed by many industry soothsayers during the 1980s that the semi-submersible production vessel was the technological marvel of the future, Volume I comments on the ways in which non-technical, un-economic factors—like the specter of failure—can haunt the minds of firms and managers enough to influence technological outcomes. Specifically, the dominance across the 1990s of the tension-leg platform (TLP) in deepwater is shown to be as much a consequence of the dramatic failure of Placid's Green Canyon 29 semi-submersible as the natural result of the tension-leg platform's ostensibly "superior" technology.

Volume II, "Shell Oil's deepwater mission to Mars," is a case study of Shell Oil's greater Mars project in the 3,000-foot waters of the Mississippi Canyon. Mars was the second deepwater TLP installed in the Gulf. The volume provides a detailed, step-by-step historical reconstruction of the greater Mars project, from the acquisition of the original leases in 1985 to the installation of the Mars B, or *Olympus*, TLP in 2014. The report draws on oral history interviews, technical papers, and Shell publications, both internal and external, to provide a unique perspective on the unprecedented challenges to managing a frontier project of this magnitude and duration. The aim is an in-depth understanding of the interrelated investment, operational, and technical decision-making that went into the development of one of the largest and most valuable assets in the Gulf. A lifecycle narrative of a deepwater oil project like Mars demonstrates how a technically and commercially successful organization learns and innovates in one of the most challenging physical and commercial environments in the world. A close examination of such a project through time provides insight into the evolution of corporate exploration and production strategy and the development of technical competencies.

Volume III, The secret of the sea, lays out a comprehensive history of the federal offshore oil and gas program in the US since the late 1960s. Focusing on the ways in which the desire to boost federal revenue receipts resulted in major policy changes as the industry moved into the deepwater Gulf, the report details how disagreements over the seemingly mundane particulars of Outer Continental Shelf revenue policy served as a proxy for wider partisan wars over the wisdom of government administration of publicly-owned resources in the "fair" or open marketplace. The oil shocks of the 1970s, combined with the ever-improving ability of offshore firms to drill and produce petroleum deposits in water depths beyond 1,000 feet, only reaffirmed the program's importance to the country's security and well-being during the Nixon, Ford, and Carter administrations. However, the economic imperative to expand deepwater drilling soon collided with the desire of many coastal states in the 1980s to see their shores and coastal zones adequately protected from the threat of offshore oil spills and onshore industrial development alike. Part and parcel of achieving that aim was the demand from the coastal states that they receive an ample cut from the sale of the nation's offshore resources—funds that would ultimately tally in the many hundreds of billions of dollars.

Volume IV, Guide to the interviews, provides summaries of oral histories conducted between 2007 and 2015 with men and women who lived and/or worked in southern Louisiana, Texas, or Mississippi in the decades that mark the deepwater era of the offshore petroleum industry in the Gulf (from the 1970s to the end of the 20th century). These summaries have been combined with interviews conducted in 2001–2006 for the History II study, MMS 2004-049, History of the offshore oil and gas industry in Southern. The summaries are arranged in alphabetical order by last name of the interviewee. Section 4.1 of Volume IV lists the interviews conducted for History III, and section 4.5 lists the interviews conducted for both

History II and History III.

Study Depositories

The materials produced from History III, "History of the Gulf of Mexico Offshore Oil and Gas Industry during the Deepwater Era," are archived at the locations listed below. Each depository has the four volumes produced in the study, digital copies of all audio files and transcripts, and digital copies of all consent forms.

University of Houston Houston History Archives Repository Suite 261, Special Collections Department MD Anderson Library-2000 Houston, TX 77204-2000 http://archon.lib.uh.edu/index.php?p=collections/controlcard&id=231	Nicholls State University Allen J. Ellender Archives Ellender Memorial Library PO Box 2028 Thibodaux, LA 70310 http://www.nicholls.edu/library
University of Louisiana Lafayette Special Collections and Archives Edith Garland Dupré Library PO Box 40199 Lafayette, LA 70504 http://library.louisiana.edu/collections	Louisiana State University Center for Energy Studies Energy, Coast and Environment Building Nicholson Drive Extension Baton Rouge, Louisiana 70803 http://www.enrg.lsu.edu/
Morgan City Archives 501 Federal Ave. Morgan City, LA 70380	South Lafourche Library 16241 East Main St. Cut Off, LA 70345 www.lafourche.org
Terrebonne Parish Library 151 Library Drive Houma, LA 70360	

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List of Abbreviations and Acronyms

Short form	Long form
AAPG	American Association of Petroleum Geologists
AFE	Authorization for Expenditure
AGM	Aker Gulf Marine
ASCI	Argus Sour Crude Index
AWL	area wide leasing
BBL	barrel of oil
BBL/D	barrel of oil per day
BBSM	behavior-based safety management
BLM	Bureau of Land Management, US Department of the Interior
BOE	barrel of oil equivalent
BOEM	Bureau of Ocean Energy Management (formerly MMS), US Department of the Interior
CEO	Chief Executive Officer
DHI	direct hydrocarbon indicators
DOE	US Department of Energy
DOI	US Department of the Interior
DVA	direct vertical access
DWPR	deepwater pipeline repair
E&P	exploration and production
EIA	Energy Information Administration, US Department of Energy
EPA	US Environmental Protection Agency
FDP	final development plan
FID	final investment decision
FPS	floating production system
FPSO	floating production, storage, and offloading facility
IODP	Integrated Ocean Drilling Program
GOM, Gulf	Gulf of Mexico
GSI	Geophysical Services Incorporated
GUMBO	Greater Ursa-Mars Basin Opportunity Project
HMC	Heerema Marine Contractors
HSE	Health, Safety, and Environment
JSEA	Job Safety and Environmental Analysis
LOOP	Louisiana Offshore Oil Port
MC	Mississippi Canyon (US Gulf of Mexico)
MD	Millidarcies
MIFDT	Mars Integrated Facilities Design Team
MIPT	Mars Integrated Project Team
MMCF	million cubic feet
MMCF/D	million cubic feet per day
MMS	Minerals Management Service, US Department of the Interior
MPMT	Mars Project Management Team
NASA	National Aeronautics and Space Administration
NOIA	National Ocean Industries Association
NTL	Notice to Lessee
NYMEX	New York Mercantile Exchange
OBM	oil-based muds
OBS	ocean bottom seismic
OCS	Outer Continental Shelf
OSHA	Office of Safety and Health Administration,
OPEC	Organization of Petroleum Exporting Countries
OSV	offshore service vessel
OTC	Offshore Technology Conference
PDMS	plant design management system

Short form	Long form
PES	production engineering services
PLET	pipeline end termination
PNC	pulsed neutron capture
PPG	pounds per gallon
PSI	pounds per square inch
RFT	repeat formation tester
ROP	rate of penetration
ROV	remotely-operated vehicle
SAFE	Safety Award for Excellence
SBM	synthetic-based muds
SCF	standard cubic feet
SEPCO	Shell Exploration and Production Company
SIMOP	simultaneous operations
SWF	shallow water flows
SOI	Shell Offshore Incorporated
SSCV	semi-submersible crane vessel
TLP	tension leg platform
TLWJ	tension leg well jacket
USGS	US Geological Survey, US Department of the Interior
VIV	vortex-induced vibration
WAZ	wide azimuth
WTI	West Texas Intermediate

> And Mars has never ceased to be what it was to us from our very beginning – a great sign, a great symbol, a great power. And so we came here. It had been a power; now it became a place.
>
> —Kim Stanley Robinson, *Red Mars* (1993)

1. Introduction

On December 4, 1996, the United States National Aeronautics and Space Administration (NASA) launched its Pathfinder mission to the planet Mars. As the first spacecraft to visit Mars since the 1970s and the first to hatch a remote-controlled rover, the voyage and landing of the Mars Pathfinder riveted audiences around the world. Six months before the Mars Pathfinder left Earth, in July 1996, Shell Oil began producing oil and gas from its Mars tension-leg platform (TLP), located in 2,940 feet of water in the Gulf of Mexico's (Gulf) Mississippi Canyon (see Figure 1.1). Shell's Mars project attracted considerably less attention than NASA's. Outside of Houston and New Orleans, it went virtually unnoticed. One could make a case, however, that these namesake outer-space and inner-space adventures deserved at least equal billing. At a total cost of $1.2 billion, Shell's Mars was nearly four times as expensive as the Mars Pathfinder, and its remote technologies and engineering systems were arguably more sophisticated (Godfrey et al. 1997; Jet Propulsion Laboratory 2014).

Shell Oil's Mars is a monument in the exploration and development of oil and gas in deepwater.[1] It was not the company's first deepwater discovery. That was Powell, in the Viosca Knoll area south of Mobile, Alabama, which became a joint venture with Amoco and Exxon. Nor was it Shell's first TLP. That was Auger, which started producing two years earlier in the Garden Banks area 136 miles off the coast of Louisiana. But Mars was special in many ways. The Mars field was the largest discovered in the US since Alaska's Prudhoe Bay had been discovered in 1968. It was ultimately appraised to contain recoverable reserves of 1.13 billion barrels of crude oil and 1.26 trillion cubic feet of natural gas. Mars was the deepwater "basin opener," the project that confirmed a voluminous sand supply to deepwater and established the deepwater "tabular salt-minibasin province" (extra-salt, Upper Miocene-Pliocene) as a bona fide play for the industry (Diegel et al, 1995; Prather et al 1998; Yeilding 2013). At Mars, Shell integrated high-resolution three-dimensional (3D) seismic with well and outcrop data to develop a model for analysis of deepwater depositional patterns and classification of deepwater turbidite deposits. The platform had an initial production capacity double that of Auger. Production from Mars was so prolific that its oil became a benchmark for pricing medium sour crude on the US Gulf Coast. The large quantities of crude transported by the Mars pipeline to Fourchon, Louisiana also helped sustain the Louisiana Offshore Oil Port (LOOP) and its Clovelly storage terminal.

Mars unlocked the key to the economics of deepwater and became a showcase for how to develop billion dollar offshore projects in an era of low-priced oil and technological uncertainty. To offload some of the initial risk and cost, Shell brought in BP as a joint-venture partner at Mars, opening the door for BP as a major player in the deepwater Gulf. The Mars TLP broke the record for deepest offshore platform and had a number of design improvements over Auger that pared down development costs. Shell also introduced team-based project management schemes and an alternative risk-reward contracting strategy that reduced the time to completion and overall unit cost of the mammoth $1.2 billion project, which resulted in significant savings for Shell and J. Ray McDermott, Inc., the fabricator of the platform's deck and integrated topsides. Years after the TLP started up, Mars continued to be a leader in offshore innovation. The recovery and repair of the Mars TLP and export pipelines after extensive damages during Hurricane Katrina in 2005 were pioneering achievements both in a technical sense and in terms of health and safety management.

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[1] The most commonly-accepted definition of "deepwater" in the industry is 400 meters or approximately 1,500 feet.

Figure 1.1. The Mars TLP in 2012.
Source: Photo courtesy of Jason Theriot.

The significance of Shell Oil's Mars Mission extends beyond the Mars TLP and the oilfield beneath it. The first TLP to host a subsea tieback[2], Mars also became a regional hub for multiple fields. In 1999, Shell started producing from Ursa, a sister TLP, to Mars; Ursa was located two blocks and less than eight miles to the east. Mars and Ursa were eventually joined as part of the same development, the Greater Ursa-Mars Basin Operation, or GUMBO. This development received a new lease on life in 2014, when Shell installed its "Mars B" or Olympus TLP one mile away from the original Mars TLP. The first deepwater platform in the Gulf to be set in the same field and block as another, Olympus brought in new production from deeper reservoirs in the Mars-Ursa basin, tied in the West Boreas and South Deimos satellite fields, and facilitated an expanded enhanced recovery program that extended the life of Mars possibly another 50 years.

The story of the deepwater Gulf can be told through the story of Mars. It was one of the earliest prospects to be drilled and developed on some of the first federal deepwater leases offered in the early 1980s. In the 2010s, thirty years later, it remains one of the most productive basins in the Gulf, and at the cutting edge of technology. More than any other project in the Gulf, Mars documents the wide-ranging innovations that have propelled the industry into ever-deeper waters and new geological frontiers. It provides a window into the evolution of geophysical technology and interpretation, drilling and well completion, platform and facilities design, workforce organization and culture, process engineering, subsea engineering, reservoir engineering, pipelining, project management, disaster management, and safety management. Mars marks the transition from fixed to floating production platforms in deepwater, and from "conventional" deepwater to subsalt deepwater. It also had a starring role in the industry's recovery from two traumatic disasters: Hurricane Katrina in 2005 and the *Deepwater Horizon* blowout and spill in 2010. Finally, the 2014 installation of a second, state-of-the-art production facility in the same field once again placed Mars in the forefront of offshore development.

[2] A tieback is an engineering process that connects a new oil and gas discovery to an existing production center.

Few people will ever get the opportunity to take a helicopter ride to a deepwater platform. This volume of History III offers the next best way to witness one of these marvels of human ingenuity. It provides a detailed, step-by- step historical reconstruction of the greater Mars project, from the acquisition of the original leases in 1985 to the installation of the Mars B-Olympus TLP in 2014. The report draws on oral history interviews, technical papers, and Shell publications, both internal and external, to provide a unique perspective on the challenges to managing a frontier project of this magnitude and duration. The purpose is to achieve an in-depth understanding of the interrelated investment, operational, and technical decision-making that went into the development of one of the largest and most valuable assets in the Gulf. A lifecycle narrative of a deepwater oil project like Mars reveals how a technically and commercially successful organization learns and innovates in one of the most challenging environments in the world. Not merely a business venture, Mars was a massive, interdisciplinary, geoscience and engineering project carried out over a span of decades, much like the human quest to explore the planet Mars, only more successful. A close examination of such a project through time provides insight into the evolution of corporate exploration and production (E&P) strategy and the development of technical competencies. This volume also demonstrates the role of culture and contingency. The Mars prospect was technically controversial. There was at least an even chance that Shell never would have drilled it. Hunches, in addition to cold calculations of risk and return, and personalities, as well as organizational machinery, help explain why it eventually did.

2. The Deepwater Mission

The deepwater oil and gas business was born in the Gulf of Mexico (Gulf), largely as result of pioneering efforts by Shell Oil Company.[3] In the late 1940s, Shell Oil made many of the early moves offshore and continued to lead the way into deeper waters and new geologic trends. For decades, the company dominated the Gulf, discovering and producing more oil and gas than any other firm. In 1977–1979, Shell installed the Cognac steel jacket in 1,025 feet of water (300 meters), the first platform in deepwater by one of the modern definitions of the term. Other operators followed with platforms along the "Flex Trend," an area in the Gulf that reaches just beyond the edge of the continental shelf, where there is a flexure in the seafloor (Cossey 2004).

Many discoveries leading up to and along the Flex Trend were made using "direct hydrocarbon indicators" (DHIs) or, as Shell referred to them at the time, "bright spots." This method of interpreting seismic attributes emerged in the late 1960s from dramatic advances in digital capabilities. Binary-gain digital recording systems enabled geophysicists to measure and quantify the "relative wave amplitudes" between seismic traces for the first time. This measurement was sometimes referred to as "true amplitude recovery" (Forrest 1999; Forrest 2000a). Before then, seismic techniques were used mainly to map subsurface structures and identify possible oil traps. Operators still had to take the substantial risks of drilling to determine if oil and gas existed in those structures and traps. But the new digital seismic data offered the enticing possibility of "directly detecting" hydrocarbons on the seismic record by the identification of "amplitude anomalies" or "high amplitude reflections" produced by slight changes in the acoustic velocities of sound signals as they passed through oil or gas (Forrest 1999; Forrest 2000a). Shell Oil and Mobil Oil were the first companies to identify and quantify such anomalies, and to factor them into their bids for offshore leases in the early 1970s. Mobil referred to them as "hydrocarbon indicators." Shell called them bright spots, because they seemed to light up on the seismic record. Being able literally to "see" hydrocarbons on the seismic record before ever drilling a well could solve questions about whether hydrocarbons existed in a certain location or what the drilling targets were. The method was not foolproof. It did not work in all kinds of geology, and it sometimes produced false indicators of oil and gas. But, in general, bright spots became a valuable exploration tool in the Gulf (Offshore Energy Center 2006).

Although Shell Oil had pioneered bright spot seismic and made an important amplitude discovery at Cognac, it largely missed out on the Flex Trend. During 1975–1977, Shell had deemphasized this play in favor of exploration elsewhere, such as Alaska, and on geopressured natural gas prospects in the ultra-deep Texas Miocene. Although the company achieved success in discovering natural gas, it became clear, as a 1987 "lookback study" by Shell exploration and production (E&P) concluded, that Shell had "lost a good opportunity to add volumes mostly by Bright Spot discoveries," and "a lot of smaller companies did well on the 78 percent of the volumes SOI [Shell Offshore, Inc.] did not bid" (Holmes 1987). In the late 1970s, Shell exploration refocused on the Gulf frontier, looking beyond the Flex Trend into the deep waters off the edge of the continental shelf.

The industry in general shied away from going any further into deepwater, and development had stalled out in the late 1970s along the shelf edge. Discoveries in the Flex Trend were significant, but they were relatively small, with discontinuous sands and fairly low flow rates. Experts in many companies had looked at the field size distribution in the Gulf and the available and evolving production technologies and concluded that there would never be an economic development more than 60 miles from shore. Existing geological data also suggested the unlikelihood of major oil finds in deepwater. More than 100 wells had drilled into the bathyal zone and found very few commercial hydrocarbon-bearing sands. These were wells on the shelf drilled deeper than existing productive zones to test older sediments lying beneath

[3] For background on Shell Oil and its offshore history, see Priest 2007. Parts of this report are adapted and expanded from this study.

(Sears 2010a). The conventional wisdom was that deepwater contained “no sands, no source rock, no nothin’” (Yeilding 2013). Combining information from deepwater cores with a regional seismic survey acquired and processed by Petty-Ray Geophysical in 1977, scientists from industry and academia had begun to piece together a regional picture of deepwater geology in the Gulf. This picture showed that massive salt pillars, or diapirs, had squeezed up from the mother layer of salt called the Louann sheet.

The Mayan (Yucatan) continental block had been displaced from the Gulf Coast margin of the US by rifting beginning 165 million years ago (mya) during the Jurassic period (201–143 mya). Cycles of seawater rushed into and evaporated from a slowly forming Gulf, leaving behind layers of salt that grew as thick as 30,000 feet in some places. During the late-Jurassic period, several major river systems draining the continental interior of North America piled enormous quantities of coarse, clastic sediments on top of fine-grained, organic-rich carbonates and shales that had been deposited by marine sequences over the salt: Upper Jurassic limestone and marl, Lower Cretaceous marl, lower Upper Cretaceous marl and mudstone, and lower Tertiary mudstone (Galloway 2009). These carbonates and shales, subjected to just the right amount of heat and pressure, became excellent sources for hydrocarbon generation in the shallower parts of the Gulf continental shelf. One early concern about deepwater was the availability and maturity of source rocks off the edge of the continental shelf, but “modeling successfully demonstrated that probable source rocks, predominantly Cenomanian to Turonian [Cretaceous Period, 143–67 mya] in age, have entered the oil window throughout most of the deep and ultra-deep water province” (Whaley 2006: 20).

During the Paleogene period (66–23 mya), which followed the Cretaceous, siliciclastic sediment poured in from the ancestral Rocky Mountains, followed by Appalachian-derived sediment from the proto-Mississippi River during the Miocene and Pliocene epochs (23–3 mya). These formed the major reservoirs to which hydrocarbons from the source rocks migrated. Buried under mounting layers of sediment deposited over tens of millions of years, and so subjected to tremendous heat and pressure, the salt turned from brittle to ductile and began to pinch up (Voosen 2010). The tilting of the continental margin caused the salt to flow into broad canopies down the slope. Salt movement forced sandstones overlaying the salt in deepwater to subside slowly, forming cup–shaped minibasins featuring many different kinds of arrangements for trapping oil. These mini-basins also overflowed and allowed sand to be transported to unconfined areas downdip (Steffens and Braunsdorf 1997). Although minibasins contain loads of reworked sediment, they get progressively younger, from 6.2 to 4 million years old, as one moves southwest across the slope from the Mississippi Canyon to the Keathley Canyon (Yeilding 2013).

These sandstones were named “turbidites” because they had been deposited when ancient underwater rivers systems driven by turbidity currents channeled huge volumes of sediment off the edge of the continental margin (see Figure 2.2). In the 1940s and 1950s, pioneering geologic work to piece together the Gulf at the basin and regional levels had discovered that the Mississippi River had created a broad alluvial valley, repeatedly entrenched and filled since at least the Pleistocene epoch (3–1 mya), and that submarine troughs with bottom-hugging currents had transported denser-than-seawater sediment onto the continental slope and abyssal plain (Kolla and Perlmutter 1993). The structural anomalies in these basin settings suggested by the 1977 Petty-Ray regional seismic survey looked similar to productive features on the shelf. “These big structures popped up out there,” remembered John Bookout, president of Shell Oil at the time and a dedicated petroleum geologist himself. “Everybody was just astonished. ‘Look at all the different kinds of possible traps and variety of configurations.’” Still, the spotty seismic coverage made these anomalies speculative at best (Bookout 1998).

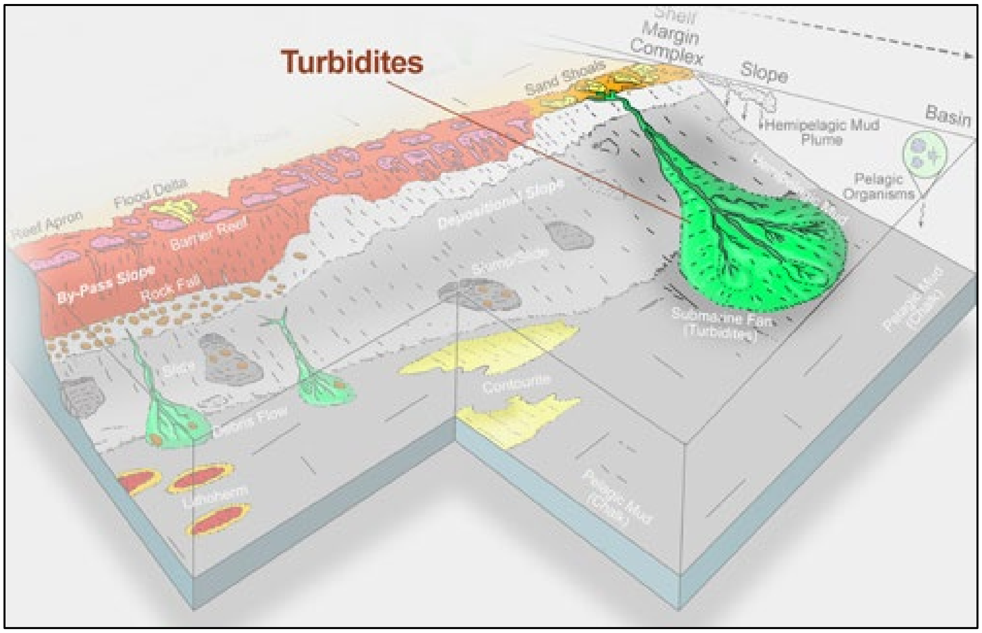

Figure 2.2. Diagram of sand transported down continental slope by turbidity currents.

Source: Reproduced with permission of the Bureau of Economic Geology, University of Texas at Austin.

Shell Oil, always the leader in frontier exploration in the Gulf, was willing to entertain the speculation. Top officials in the company believed that Shell Oil's future lay offshore. Over the years, they had placed larger and larger bets on offshore development. Now, John Bookout and other E&P leaders were prepared to stake the company on it. There was no alternative for an enterprise whose core business was in the US Exploration vice president, Bob Nanz, estimated that 60 percent of the oil yet to be found in the nation was located offshore, most of it on the federal outer continental shelf (OCS) (Nanz 1975). Shell was eager to lease and drill off the entire extent of the U.S. coastline, from the Atlantic to the Pacific to the Arctic. But all these frontier areas posed daunting environmental as well as political challenges. The Gulf of Mexico, by contrast, was familiar. It had established infrastructure and service industries. The population that lived there was accepting of the industry. The Gulf basin had been giving to the industry for decades, going all the way back to the Spindletop discovery of 1901. Could it give any more?

Peering into deepwater from the edge of the Gulf's continental shelf, Shell's geologists were itching to find out. The company had drilled a few oil discoveries, such as Cougar and Peccary, along the shelf margin in turbidite sands. But deltaic and turbidite reservoirs on the shelf were highly faulted and required many wells to develop. Turbidites in deepwater, by contrast, were potentially larger and less faulted, thus requiring fewer wells. Theory held that they could be unusually porous, due to the sifting of the sands carried by turbidity currents over long distances, and that they might be more tightly sealed and under higher pressure (Steffens and Braunsdorf 1997; Voosen 2010). Evidence also existed that oil had been generated in deepwater. During 1964–1967, Shell Oil's research lab had sent the drillship *Eureka*, equipped with the first automatic dynamic positioning system, on a core-drilling program in 600–4,000 feet of water in Gulf. Some of those cores, taken from the tops of shallow salt domes, had oil shows. How much might exist further down was still a big question (Steward 2004).

Hoping to test its theories about the Gulf's regional geology, during 1978–1980, Shell nominated deepwater tracts at federal auctions. But no other companies seconded their nominations, and the US Bureau of Land Management (BLM) did not select the tracts for lease (Flowers 1999; Otteman 2001). Even if the tracts had been offered, the price of lease bonuses had soared so high, in lockstep with oil price increases in the late 1970s, that the costs of exploring in deepwater would have been prohibitive

(Bookout 1998). Some of Shell's top exploration officials began lobbying the Department of Interior, the BLM, and the US Geological Survey (USGS) to open up the deepwater to leasing and to relax the terms of access (West 2002).

The lobbyists got their wish after the election of Ronald Reagan as the 40th US president and his appointment of the Colorado conservative, James Watt, as Secretary of the Interior. In 1981, Watt honored his pledge to lease a billion acres of the OCS by announcing a new system of "area-wide" leasing (AWL) offshore. This policy put into play entire planning areas (e.g., the central Gulf) up to 50 million acres, rather than rationed tracts through a restrictive nomination and selection process as in the past. Oil companies could bid on any tract they wanted in a lease sale for a given planning area, rather than having to choose from a limited number of carefully selected ones. This would reduce competition for leases and bring down bonus bids. AWL gave the industry access to far greater offshore acreage at much cheaper prices (Boué and Luyando 2002). At the time, there were compelling reasons to proceed this way in the Gulf. Oil companies had long operated in this region, there was established infrastructure, and there was abundant geological information that could be put to more flexible use under a more open system. The introduction of AWL also coincided in 1982 with the merging of the BLM OCS program and the USGS Conservation Division into a new agency, the Minerals Management Service (MMS).

After Watt's 1981 announcement, Shell geared up for the deepwater play. The first objective was to demonstrate the feasibility and safety of drilling in deepwater. The capabilities of floating drilling in ever-deeper waters had evolved steadily since Shell Oil's pioneering work in the early 1960s with *Bluewater 1*, the first semi-submersible drilling vessel. During the 1970s, a series of major technological achievements in exploratory drilling technology extended capabilities to a 6,000-foot design limitation for the latest deepwater rigs. In the early 1970s, Shell and the drilling contractor Sedco introduced computer-controlled dynamic positioning, guidelineless reentry, and electro-hydraulic blowout preventer (BOP) controls on *Sedco 445*, a new class of drillship designed to break the 2,000-foot water-depth barrier. But, in 1981, this was still frontier territory. No well had been drilled deeper than 1,500 feet of water in the Gulf; there had been only a handful of wells drilled deeper than 3,000 feet around the world, and none of them were in the US Concerns remained about the hydrodynamic response of very long marine risers and the reliability of dynamic positing systems (Wickizer 1988).

Shell's first opportunity to upgrade and demonstrate deepwater drilling technology happened not in the Gulf, but off the Atlantic Coast. In preparation for a December 1981 lease sale there, in which Shell obtained leases in water ranging out to 7,500-foot depths in the Baltimore and Wilmington Canyon areas, Shell's Head Office assigned Carl Wickizer, manager of Production Operations Research, to conduct a feasibility study of "ultra-deepwater" drilling and development beyond 6,000 feet, where many critics believed a technology barrier existed. In 1982, Shell contracted with Sonat Offshore Drilling to lease the drillship, *Discoverer Seven Seas*, one of the few vessels in the world rated for 6,000-foot depths (see Figure 2.6). Shell then spent more than $40 million to extend the vessel's depth capability with a larger marine riser, enhanced dynamic positioning, and a new remotely-operated vehicle (ROV) to enable sophisticated work where human divers could not venture. Shell also used a proprietary side-scan sonar technology to demonstrate the stability of seafloor topography. In late 1983, with the concerns of regulators allayed, *Seven Seas* drilled an exploratory well in a world record water depth of 6,448 feet in the Wilmington Canyon. Although the drilling program in the Atlantic, which included two other deepwater wells, did not discover oil, the successful demonstration of drilling at such extreme depths established the industry's capability to work safely beyond 6,000 feet and inspired confidence in Shell's management for moving forward into deepwater in the Gulf (Wickizer 1988).

Figure 2.6. *Discoverer Seven Seas* drillship that drilled the Mars discovery (2009 photo).
Source: Shipspotting.com.

The achievements in deepwater drilling came with a loud caveat: cost. “Simply extending the equipment and practices of our shallow water past,” warned Carl Wickizer in a May 1984 luncheon talk to the Offshore Technology Conference (OTC), “is not likely to be cost effective in deepwater. Inefficiencies and equipment failures can inflate the cost of a well so as to negate the impact of technological advances” (Wickizer 1984). In Shell’s deepwater feasibility program, *Discoverer Seven Seas* spent one day out of seven simply testing the BOP system. Lost time from equipment malfunctions was inordinately expensive. Day rates for leasing a deepwater vessel would be pricey. “If we are to achieve the cost effectiveness needed,” explained Wickizer, “we must reach new levels of reliability, quality assurance, preventative maintenance, and operational efficiency” (Wickizer 1984). Even then, he suggested, these things might not be enough. Two other conditions had to be met. Well productivity had to be high and the fields had to be giant. “In the face of such experience, we must ask ourselves about field development,” said Wickizer. “Is it feasible?” He answered the question in the affirmative, but with some hesitation. “We think so, and in a reasonable time frame–provided that the proverbial deepwater elephant has finally been discovered, and that we can achieve acceptable costs” (Wickizer 1984).

By this time, Shell’s exploration teams were actively hunting for deepwater elephants. Because of the tremendous costs of deepwater development, their guiding principle was “high rates and high ultimates.” In other words, they were looking for fields with high flow rates and high ultimate reserves. Nothing less would work. But Shell officials were buoyed by their advancing geophysical capabilities, their reinforced confidence in deepwater drilling, and the expectation of cheaper leases with area-wide sales. They bid aggressively at the first area-wide sale for the Gulf, held in New Orleans on May 25, 1983. It was a momentous occasion. “While rigs stood idle in the inshore shallows of the Gulf of Mexico,” reported Newsweek on the first sale under the new system, “more than 1,200 oilmen gathered last week in New Orleans’ Superdome to testify to their faith in the health of their industry” (Newsweek 1983: 77). The sale brought a record $3.47 billion in high bonus bids. But with so much acreage put up for sale, the average price per acre was only about $1,000, three to four times lower than the average in the 1979–1980 sales. Shell spent $270 million for sixty blocks (Oil and Gas Journal 1983: 48). Three of the prospects it bought–Bullwinkle, Tahoe, Popeye–were in 1,300–3,000-foot water depths. In October 1983, *Discoverer Seven Seas* made a major discovery at Shell’s Bullwinkle prospect on the shallow end of that depth range.

After this discovery, Shell briefly lost its deepwater nerve. Fixed platform technology could not be enlarged much beyond the depth of the monster steel jacket planned for Bullwinkle in 1,300 feet of water. The costs of alternative concepts, such as tension-leg platforms, compliant towers, and subsea completions, presented serious questions. Subsea wells were still expensive and not yet completely reliable. Conoco's Hutton TLP, installed in the North Sea in 1984, had experienced serious cost overruns. One of the leading methods Shell's production department considered for depths beyond 1,500 feet was subsea wellheads linked by pipeline back to a fixed platform in shallower water. But offshore pipelining faced distance limitations and economic constraints. Shell's production managers had an ironclad rule: the company could explore no farther than fifteen miles past 600 feet of water, the practical depth limit and distance for installing marine pipelines at the time. Due to this policy, Shell Offshore's exploration managers made only a few bids in the April 1984 sale, the second major area-wide sale in the Gulf. They were caught off guard, however, when other companies, notably Exxon and Placid Oil, acquired acreage in water deeper than Shell had been prepared to go (Forrest 1999; Oil and Gas Journal 1984: 36).

The results from the April sale prompted a flurry of meetings and discussions in Shell about what its deepwater strategy should be. Billy Flowers, then offshore vice president, met with Shell's top E&P officials Jack Threet, vice president for exploration, Charlie Blackburn, executive vice president for E&P, and John Bookout to make the case for pushing farther into the Gulf. All three appreciated the urgency, given the competition, and they resolved that Shell would drop the fifteen-mile rule and begin to gather seismic data from ultra-deepwater, using a $45 million, state-of-the-art seismic vessel, *Shell America,* which had just been launched and outfitted (see Figure 2.8). Time was short before the next Gulf area-wide lease sale in July 1984. On the auction block, the government placed large tracts in the western Gulf. *Shell America* immediately set out to gather as much proprietary seismic data as possible. Because of the time constraint, however, the vessel had to focus on specific locations. Tom Velleca, general manager of geophysics in Houston, urged the Offshore Division to organize a team to search quickly for prospects in the Garden Banks area. Located in waters ranging from 1,000 feet to 4,000 feet, the prospects they worked on were considered very speculative. The geophysicists did not have as much seismic coverage as they would have liked. *Shell America* had time to shoot only one seismic line across some of them. Shell bid on 10 prospects in the sale and won seven of them, including a potential field in the Garden Banks area called Auger, which would become Shell's first deepwater development (Abbott 1984; Flowers 1999).

Figure 2.8. The launching of the seismic vessel *Shell America* on the Mississippi River at New Orleans in 1984.

Source: Photo courtesy of Ed Picou.

As the next big area-wide sale for the central Gulf approached in May 1985, Shell managers wanted more assurances about the economics of deepwater field development. Billy Flowers and offshore exploration general manager, Mike Forrest, the father of bright spot seismic interpretation at Shell, pressed production department managers Carl Wickizer and Gene Voiland on what size oil fields in 3,000–6,000 water depths, using "to be designed" technology, would be needed to make deepwater production economical. Considering the known variables and running some quick simulations, Wickizer and Voiland finally stated that if the exploration group discovered fields of at least one hundred million barrels, the engineers would find a way to make the discoveries pay (Forrest 1999; Forrest 2000b).

While these discussions were taking place, Shell drilled an exploration test well in 3,000 feet of water on Prospect Powell, in the southeastern corner of the Viosca Knoll protraction area off the Main Pass of the Mississippi River, which had been leased in the 1983 area-wide sale. Drillers located the well to penetrate a very strong, shallow bright spot anomaly, plus a deeper, poor-quality bright spot. Drilling indicated that the shallow anomaly was not associated with oil or gas. However, Don Frederick, division exploration manager, excitedly reported the discovery of a 40-foot-thick oil pay at the deep level. Further drilling and seismic surveys showed that the trap was entirely stratigraphic, likely to contain huge amounts of oil, certainly enough to meet the economic criteria set by the production department (Forrest 2000b).

Armed with this bit of intelligence, Shell Oil dominated the May 1985 sale. With partners or alone, the company was the high bidder on 86 of 108 blocks for which it submitted a bid, in a variety of areas (Oil and Gas Journal 1985: 46–47).[4] Its share in the high bids totaled more than $200 million. While most other deepwater lessees did not show interest in acquiring additional deepwater acreage, Shell took a giant plunge, obtaining tracts ranging out to 7,500 feet of water. Combined with the tracts leased in the 1983 and 1984 area-wide sales, Shell now had huge areas of deepwater acreage in the Gulf, acquired at very low bonus prices. Although no one at the time knew the exact extent of what this acreage held, they would soon see Shell's deepwater play open the most spectacular new offshore frontier ever encountered.

[4] During 1983–1986, Shell Oil won 252 of the 327 (77 %) tracts awarded in Gulf lease sales (Holmes, 1987).

3. Exploration

3.1. Discovery

Four of the tracts purchased in the May 1985 lease sale covered a prospect code-named “Mars.” Months before the sale, while probing for oil in the deep waters of Mississippi Canyon, off the mouth of the Mississippi River, Shell geoscientists in New Orleans came across an intriguing basin. Entrenched by slope failure and sediment flows funneled in massive amounts from the ancient Mississippi River more than 30,000 years ago, Mississippi Canyon is the most prominent submarine trough in the northern Gulf of Mexico (Gulf). It has been one of the largest conveyor systems for marine sediment in the world. Beginning about 19,000 years ago, the canyon began rapidly filling in with deep-sea fan and turbidite sediments. It remains a massive submarine canyon, 127 kilometers long with an average width of eight kilometers and up to 300 meters (984 feet) of bathymetric relief Forresrt(Kolla and Perlmutter 1993).

The Mars basin in the Mississippi Canyon is chalk-floored and narrow, filled with turbidite deposits surrounded by shallow, allochthonous (originating at a distance from present position) salt bodies (see Figure 3.3). It underlies a portion of a larger structural trend, known as the tabular salt-minibasin province, which covers most of the Gulf continental slope (Diegel et al 1995). Deep depocenters in this province formed in various ways–by the evacuation of salt “pillows” as result of gravity spreading, the depletion of a deep source of salt, or by local or regional extension caused by the divergence of continental plate boundaries. Many of the oilfields discovered in the early deepwater play were in “minibasins” that had formed as a direct result of salt tectonics. The Mars prospect was in a somewhat different kind of geological setting than other minibasins. There, the salt canopy does not cover the primary basin. Patricia Santogrossi, team leader for the Mars appraisal during 1990–1991, first described such a basin as a “window” in the Sigsbee Salt Nappe (Bouroullec, Weimer, and Serrano 2004).

The clues to a possible oil find in this particular basin came from analyzing some proprietary two-dimensional seismic data and log records from two nearby wells. Getty Oil and Exxon had drilled one in 1984 on the southern margin of the basin, and Arco had drilled another in the northern part of the basin in 1985. A rumor from the time had it that someone high up in Shell, over drinks at a bar in Houston, caught wind that the Getty and Exxon well, called “Venus” (MC 852 #1), had encountered high-quality reservoir sands with shows of hydrocarbons. These were Pliocene-age sediments, and nobody at the time was sure there could be a good reservoir in such sediment that far off the shelf in Mississippi Canyon (Newman, 2014). Fluid pressures measured at the well also suggested “the possibility of a hydraulically blown trap” (Duey 1999, 6). The Arco well had drilled through lower Pliocene sediments to reach a sand-poor stratigraphic section of upper Miocene, with few indications of hydrocarbons on the mud logs. But a strong seismic reflection, or bright spot, had been observed on two seismic lines located on the south flanks of the shallow Antares (north) and Venus (south) salt bodies near the two wells (Duey 1999).

In search of plays in deepwater leading up to Federal OCS Lease Sale 98 to be held in 1985, Roger Baker, Offshore Louisiana District exploration manager for Shell Oil, had instructed his staff to search for prospects within a regional two-by-two mile seismic grid. Staff geologist and Delta Province leader, Dan Newman, laid out the proprietary regional grid in the vicinity of the Venus well and salt body. Influenced by the Venus name, Newman decided to use astronomical bodies as the codename theme for the Delta Province’s prospects in the upcoming sale. The seismic in this particular area revealed a very deep basin surrounded by salt, and amplitude reflections indicated the possibility of a salt flank prospect. Newman named the prospect “Mars,” the next planet besides Venus closest to Earth (Newman 2014). Mars and Venus were also the Roman names for the son and daughter of Jupiter, the king of the ancient gods.[5]

[5] Some news stories about Shell Oil’s Mars project referred to Mars as the “Greek god of war,” which is not correct (Musarra 2014). Greek and Roman mythology often have the same gods, but with different names. Roman gods were borrowed from Greek mythology and had similar as well as distinctive traits. Ares is the Greek

Mars was the god of war (and fertility), and Venus was the goddess of love. The adulterous affair between the two gave birth to Concordia, the goddess who embodies the allegorical unification of love and war, male and female, in mutual affection.

The Delta Province staff geared up to evaluate many prospects for the sale, including Mensa, Europa, Andromeda, Kepler, Ariel, Umbriel, and Uranus. Clay Fernandez and Henry Pettingill performed the regional seismic sequence stratigraphy for the Mars and surrounding prospects. "Seismic sequence stratigraphy" is generally regarded as a method for predicting the stratigraphic composition of individual layers of rock in a given area by correlating seismic data with distant well data. Exxon geologists pioneered the method, or at least they were at least the first to publish on it in 1977 (Vail and Mitchum 1977). Shell geologists in the Gulf had used seismic stratigraphy in a qualitative sense to predict sand and shale packages as early as the late 1960s, when Ward Abbott, a Shell geologist in Houston, developed seismic stratigraphy concepts in working the offshore Texas Pleistocene trend. The work by Abbott and others gave birth to "seismic facies" analysis, which correlated seismic reflection attributes to stratigraphic characteristics of identified sequences (Pettingill 2014; Forrest 2014).

Shell geologists employed this kind of analysis throughout the deepwater during this period, but in a different way from what Exxon geologists had published. The erosional unconformities along the coastal margin emphasized by Exxon became correlative conformities in deepwater. Shell geologists defined stratigraphic packages based on highly-correlative "flooding surfaces," which record major changes in ancient sea level where deeper-water strata overlay shallower-water strata. This is important because these major sea-level events can be correlated across basins and often with other areas around the globe. The geologists then mapped the stratigraphy between the packages by integrating seismic facies analysis with isopach maps (illustrating thickness variations within a unit), maps of the shelfal depocenters (areas of maximum deposition), and established eustacy (global sea level) curves (Pettingill 2014).

At Mars, correlations between the well data and the seismic showed a thickened stratigraphic section in the flattened part of the middle basin, holding out the possibility for better reservoir sands. Based on the hydrocarbon indications from the Getty well, the geologists deduced that hydrocarbons would have entered the basin along the salt-sediment interface associated with Venus. Hanh Nguyen, a staff geophysicist under Dan Newman, was the first to recognize Mars as an interesting prospect. Nguyen worked with Shell Oil seismic crew chief, Bob Peebles, to shoot the new lines across the Mars basin and performed the original mapping on the prospect, identifying the area between the Antares and Venus salt bodies as one of his favorites. In late 1984, with the lease sale fast approaching in the spring, Newman's team was working overtime evaluating all the prospects they had in the queue. They had not yet begun the detailed evaluation of Mars, so Roger Baker assigned Patrick Franklin from Byrd Larberg's Plio-Pleistocene Province team to carry forward the mapping and evaluation of the area along with Henry Pettingill as the regional geologist, and Gail Ingram as the prospect geologist. Bill Trojan, who had worked on the Powell and Tahoe prospects the year before, also assisted with the evaluation (Newman 2014; Pettingill 2014).

Byrd Larberg and his colleagues schooled their young geoscientists in fundamental geology, mapping, stratigraphic correlation, interpretation techniques. Franklin was a 24-year-old exploration geophysicist, and the only geophysicist of color working for Shell Offshore in New Orleans. "I had a burning desire to prove my worth and learn my trade as quickly as possible in a new, challenging environment," remembered Franklin. Oil prices were sinking and layoffs loomed for many young professionals in the industry. This only further motivated staff to achieve their ultimate goal, which was to have a bid placed on their work and acquire a lease to drill it. "As anxious as I was to apply my knowledge," added Franklin, "it was extremely difficult to receive meaningful assignments with value-added impact to the organization. Byrd's guidance gave me the leasing and direction I needed" (Franklin 2014).

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counterpart to the Roman Mars, and Aphrodite is the Greek counterpart to the Roman Venus.

Mars was considered very speculative, a "lead" rather than an actual prospect. Shell had limited proprietary seismic data in the area and a mixture of contracted data. Most of the contract data came from long regional lines, which provided a regional picture of the area. But these lines were on a one-mile grid and terminated in the middle of the prospect due to water depths in excess of 3,000 feet and the lack of well control. This impeded the ability to make specific stratigraphic projections. With each review session, Franklin and Ingram intensified their research and quest for additional information through new seismic lines and well correlations. They discovered that Mars is a faulted anticline overlying salt in an area heavily populated with salt domes connected by faults in some features that created closures and traps. They mapped three subsurface horizons for the prospect: 1) P1.6 at 9,000 feet; 2) Pink (PM4) at 12,000 feet; and 3) Deep Orange at 13,500 feet. After the final division review, they mapped an additional shallow Red level, 1,200 feet above Pink (Franklin 2014).

Franklin and Ingram located several major bright spots, or amplitude anomalies, on the seismic lines that tied in well with the limited seismic data they had at the time. Henry Pettingill worked with Franklin on regional correlations to confirm the bright spot interpretations. The P1.6 level showed no anomalous amplitudes associated with mapped enclosures, but the Pink event indicated two bright spots and the Red level revealed several (see Figure 3.4). Still, Prospect Mars looked unfamiliar compared to something like Auger, one of Shell's other major prospects at the time, which had recognizable amplitude anomalies propped up against salt. The amplitude anomalies at Mars appeared to be outside the areas of structural closure, and the stratigraphic window along the northern salt flank at the P1.6 level was narrow. Finally, the Mars prospect was way down the flank of a shallow salt body, in the middle of a "ponded basin," where sands had been deposited between two salt domes. There was still great uncertainty about the amount of hydrocarbons or the thickness of the pay sands in the middle of the basin. Some other companies referred to these basin-centered amplitudes as "synclitudes." As Shell Oil, BP, and other companies would later learn, basin-centered bright events could also be associated with regional marl (lime-rich mudstone), containing wet sands but no oil (Forrest 2000b; Franklin 2014, Santagrossi 2014).

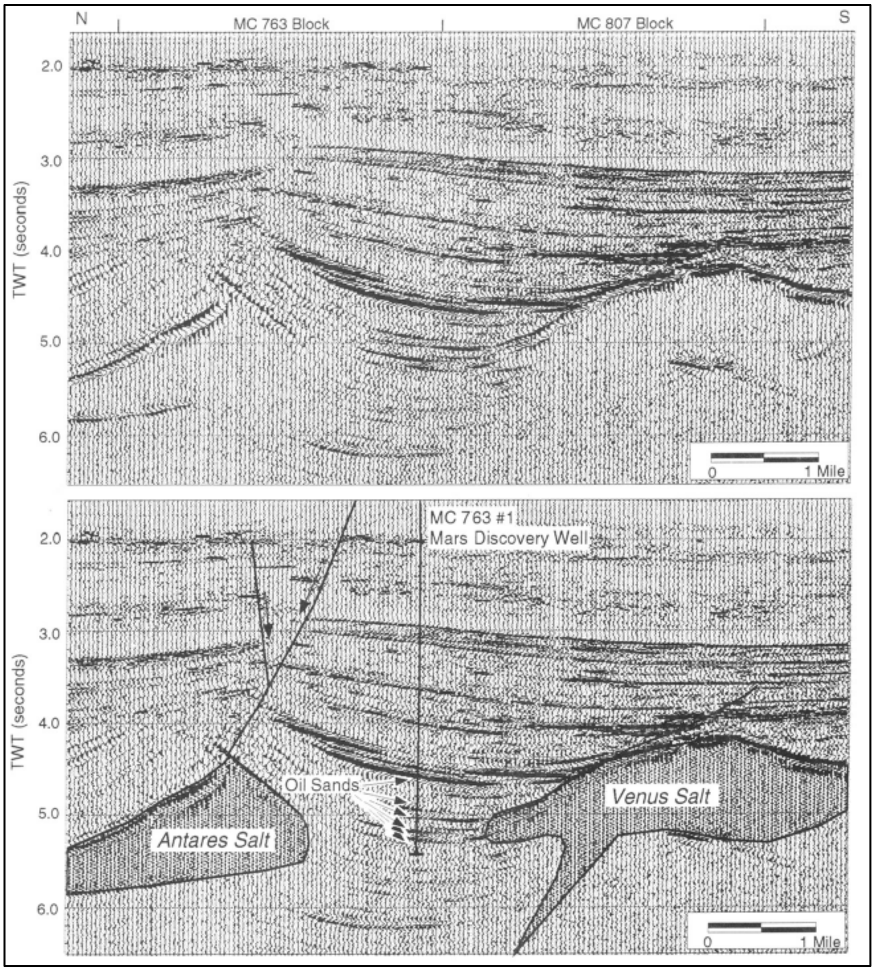

Figure 3.4. An uninterpreted (top) and interpreted (bottom) seismic profile of the Mars basin through the Mississippi Canyon (MC) 763 #1 discovery well.

The bright spot seismic amplitude anomalies located between the Antares and Venus salt bodies indicated the major hydrocarbon-bearing sands at the discovery.

Source: Mahaffie 1994. Reproduced with permission of the Gulf Coast Section of the Society for Sedimentary Geology.

Despite the large uncertainties, Franklin and Ingram successfully shepherded Mars through each review leading up to, and concluding with, Lease Sale 98. Dan Newman, Delta Province leader, distinctly remembered Franklin's presentation to top exploration officials in Shell Offshore in late February or early March, shortly before the auction in May. Mike Forrest, general manager for exploration in Shell Offshore, was at the meeting. Newman recalled one line in particular with numerous seismic events that were unusual for their amplitude strength and location flanking the salt wall. "Mike looked directly at me and said, 'What do you think this is!?' Of course it was a rhetorical question. He knew and so did I that it was hydrocarbons, and that's how I answered his question. It was one of those emotional moments we've all felt when we believe we just discovered something exceptional" (Newman 2014).

Not everyone was so sure. Louisiana Offshore district exploration manager, Roger Baker, playfully called the amplitude anomalies on the prospect map "winky blinkies." He suspected oil, but "we were dealing with so many unknowns" (Solomon and Fritsch 1996). "We didn't see enough potential there based on early two-dimensional seismic sections," remembered Jim Funk, division exploration manager at the time. "We saw some hydrocarbons there, but we didn't have a good enough picture yet" (Davis 1997).

The evaluation team estimated the chance of commercial success at only 10 percent. At the final presentation to earn a bid in the lease sale, there was some debate over whether Patrick Franklin should present his work or have a higher-level manager do it for him, based on his inexperience in interacting with the company's top decision-makers. Ultimately, he received the go-ahead to sell the story of a potential discovery (Franklin 2014).

Mars made the cut, but barely, as part of a group of low-ranked "spec" prospects. Exploration managers added Mars at the last minute in the meeting to decide the bidding strategy. A dozen geoscientists and managers gathered in a conference room a few days before the lease sale to prepare bids for 107 blocks. "Are we done?" one of the managers asked. "Yes," the team agreed, until someone asked, "Hey, what about Roger's blocks?" Recalling his winky blinkies, they decided to include four of the blocks covering Prospect Mars and attached bids to them that were at or just slightly above the federally required minimum of $900,000 (Solomon and Fritsch 1996). In Lease Sale 98, held in May 1985, Shell won a 100 percent stake in blocks Mississippi Canyon (MC) 762, MC 763, MC 806, and MC 807 (as leases G07957, G07958, G07962, and G07963) for trifling bonuses of $1.3 million, $1.2 million, $900,000 and $1.2 million, respectively. The company, it turned out, had no competition at all. Effective July 1, 1985, each lease had a primary term of 10 years (US Department of the Interior 2014).

After the leases were acquired, Roger Baker passed the prospect on to staff geologist Susan Waters and her partner, geophysicist Mark Stockwell. Their task was "to mature the prospect." In other words, they were to determine if Shell should spend millions of dollars to drill a wildcat well, and if so, where to place it. The first round of new two-dimensional seismic sections, shot in 1986 after the acreage was acquired, revealed at least a dozen potential hydrocarbon-bearing layers. In mapping the seismic horizons, Stockwell assigned each a color. The two most promising bright spot anomalies remained the Orange level event, at 14,000 feet subsurface depth, and the "Pink," at 11,000 feet (Judice 1996b; Solomon and Fritsch 1996). But Stockwell penciled in other attractive seismic horizons, such as Scarlet, Lavender, and Magenta. "We ran into so many layers of interest that I ran out of colors," he remembered (Solomon and Fritsch, 1996). Following this preliminary geophysical work, Shell purchased two adjoining leases, MC 850 and MC 851 (as G09881 and G09882), for $500,000 and $200,000, respectively, in Lease Sale 113, held in March 1988 (US Department of the Interior 2014). In 1987, the Minerals Management Service (MMS) had dropped the minimum bid requirement for deepwater tracts from $900,000 to $150,000, enabling companies to solidify lease positions very cheaply, like Shell did at this sale (Steffens and Braunsdorf 1997). Still, as Bill Broman, general manager for exploration at the time, remembered, "we were very concerned that we would have enough pay to make the field economic" (Broman 1999).

The exploration team believed that there were hydrocarbons down there, but to drill a well to find out was a major risk. First, the general economic climate in the oil industry discouraged investments in large-scale projects. In 1985–1986, oil prices collapsed down to $10 per barrel, as both Organization of Petroleum Exporting Countries (OPEC) and non-OPEC producers ramped up production. Shell had just spent $300 million to drill a succession of dry holes offshore Alaska, and its net income was sinking. Combined with the rising price of lease bonuses (before area-wide leasing) and some disappointing finds along the Flex Trend, the downturn had sucked the wind out of drilling in the Gulf. Shell Oil's Bullwinkle development in 1,000 feet of water was encouraging, as were the deepwater discoveries at Tahoe (1984), Powell (1985), Auger (1987), and Mensa (1987). But the bright spot game Shell was playing with seismic interpretation also had thrown the company some curves, leading to some expensive dry holes in excess of $10 million. Reservoirs with small amounts of natural gas could sometimes give the same amplitude effect on the seismic section as those with large amounts of gas. By the spring of 1988, the Mars team still could not determine from the data they had whether Mars contained massive amounts of oil, or mostly water. "We had trouble understanding it," admitted Stockwell (Solomon and Fritsch 1996). Even if they had oil, many economic and technical questions remained about how to produce deepwater discoveries. The anticipated reservoir model, comprised of thick, continuous sands and high-flow rates, had yet to be confirmed. The projected cost of developing Auger exceeded $1 billion. Moreover, because the Orange and Pink anomalies at Mars were not stacked vertically, the company could not test them with a single well, which would cost in the $15–20 million range. They had to be drilled separately (Duey 1999).

Objections from several exploration managers almost kept any drilling from happening at Mars. There was too much geological and economic risk. A last minute intervention by the exploration operations manager, however, tipped the scales. He informed top exploration and production (E&P) officials that Mars would be the only prospect ready to drill in late 1988 for *Discoverer Seven Seas*, the drillship that Shell Offshore had under contract from Sonat . This was apparently enough to persuade Bob Howard, president of Shell Offshore, who made an effective presentation to Shell Oil's board of directors, some of whom were skeptical about deepwater, to gain their support. Once again, Mars barely survived another cross-examination. Right after New Year's in 1989, *Discoverer Seven Seas* set off to drill the first exploratory well. On January 13, 1989, the drillship spudded the MC 763 #1 well in 3,170 feet of water, aiming to drill down to the Orange event (Davis 1997, 1E) (see Figure 3.5). The decision to drill at Mars, however, still made some Shell officials nervous, particularly Frank Richardson, who had replaced the retiring John Bookout as president of Shell Oil, and Jack Little, president and chief executive officer (CEO) of Shell Exploration and Production Company. Assuming this leadership in the late 1980s, when oil prices and net income were plummeting, and the crude oil windfall profits tax, which penalized new domestic oil production, was in place, Richardson and Little had to make difficult, costing-cutting decisions. If the company were to invest in new wells, Little preferred that they be drilled to develop existing fields, like those in West Texas, not as expensive wildcats in deepwater.

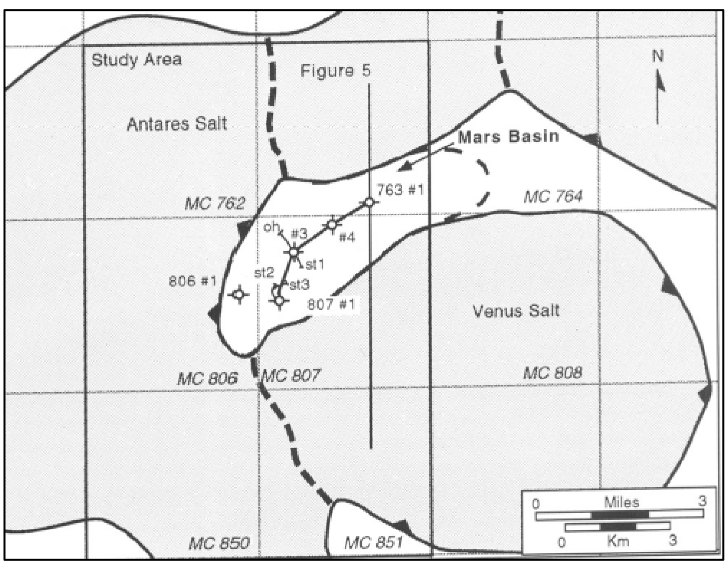

Figure 3.5. Base map of the Mars Basin.

The solid black box highlights the six-block study area for the Mars Prospect. The black dashed lines indicate the location of the major boundaries within the Antares and Venus salt bodies. The location of the regional correlation section and seismic profile depicted in Figure 2.4 is drawn between the discovery well 763 #1, completed in April 1989, and the first appraisal well, 807 #1, completed in November 1989.

Source: Mahaffie 1994. Reproduced with permission of the Gulf Coast Section of the Society for Sedimentary Geology.

In late 1988, facing strains on the company's bottom line, Richardson had Little order deepwater exploration manager, Jim McClimans, to slash his budget. With two deepwater drilling vessels under contract, McClimans sought a partner on Mars to help spread risks and costs. It was a never-ending struggle at that time to keep the rigs operating. As the Mars well was being drilled, BP agreed to take a 28.5 percent working interest in the project, along with working interests in other Shell deepwater prospects, including a 33.33 percent interest in the Mississippi Canyon 810 and 854 leases that covered nearby Ursa. The partnership with BP seemed like a good way to hedge the large expenditure to drill Mars, which still had a low probability for a major discovery. Furthermore, BP posed seemingly little competitive threat. Iran and Nigeria had nationalized the company's operations in 1979, and it was struggling along with a top-heavy management structure, underperforming global assets, and lackluster leadership. Shell viewed BP's role in Mars as merely a banker. For BP, however, Mars presented an enticing opportunity. BP land manager Karl Rugaard remembers first hearing about Mars after being stopped in the hallway at the company's Houston office by Bill Sears, head of BP's production business unit and a 20-year veteran of the Gulf Coast oil patch. "He pulled me aside and said, 'This is a good prospect and we ought to get involved,'" recalled Rugaard. "When you get someone like Bill Sears saying something like that about a prospect, you know you've got a hot one" (Davis 1997, 1E).

The Shell and BP exploration teams waited anxiously through the winter for word about the well. The initial reports that arrived via encrypted fax messages and coded phone calls were not reassuring. In April, drilling to 10,400 feet–the Scarlet layer–*Discoverer Seven Seas* encountered only wet sand. The same went for the Lavender layer further down at 11,900 feet. Then, a few days later, Susan Waters received a 2:00 a.m. phone call at home reporting that the drill had entered the Orange horizon at 13,500 feet subsurface depth and continued on through 127 feet of hydrocarbons–a major strike. Keeping the news secret even from her husband, Waters rushed to work the next morning. "Entering her office with Mr. Stockwell, she calmly closed the door behind them," the Wall Street Journal later reported. "The two began to laugh uncontrollably" (Solomon and Fritsch 1996). Spirits soared on the rig and for those privileged to the information about the discovery at One Shell Square in downtown New Orleans. "We started to get really excited," said Jim Funk, division exploration manager. "It sits out in a basin and for it to be hydrocarbons meant that it had to be huge" (Davis 1997, 2E). Drilling continued deeper to test weaker amplitude events between 15,000 and 18,000 feet, the Miocene interval Yellow and Green layers, which were eventually determined to be the heart of the field (see Figure 3.6). In April, the well was eventually plugged and abandoned after reaching a total measured depth of 18,420 feet and penetrating more than 440 net feet of oil in seven different layers of Miocene-Pliocene age sediments. Mars was a significant discovery. Whether it was significant enough, however, to turn a profit in the deepwater frontier remained to be seen (Duey 1999).

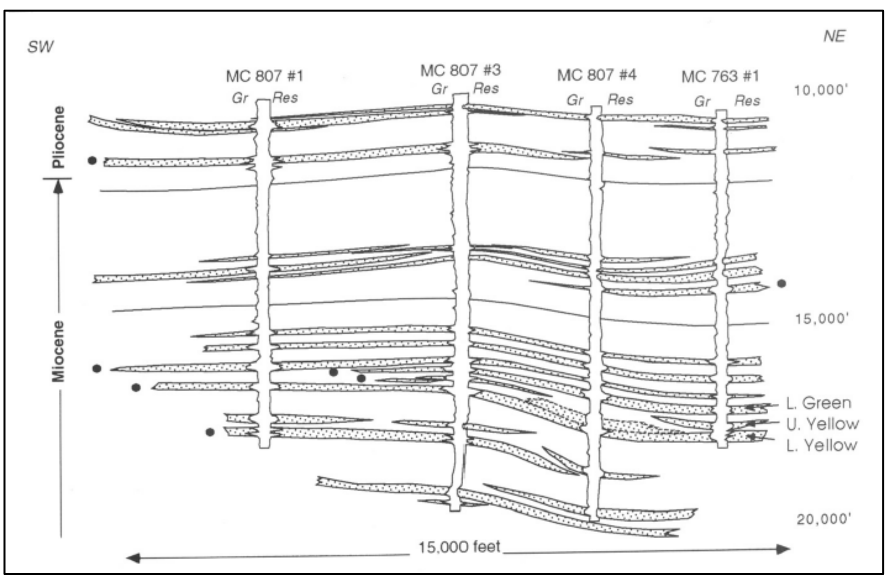

Figure 3.6. Image displaying the correlation section through the Mars basin and the distribution of turbidite sands.

The solid circles represent the seven major reservoir intervals at the discovery, as interpreted in 1994, which were estimated to contain approximately 60 percent of the recoverable hydrocarbons.

Source: Mahaffie 1994. Reproduced with permission of the Gulf Coast Section of the Society for Sedimentary Geology.

3.2. Field Appraisal

In January 1988, a year before *Discoverer Seven Seas* began drilling Mars but after the discovery at Auger, Shell Offshore, Inc. formed a task force to address pressing questions about deepwater turbidite reservoirs. This "Turbidite Task Force" formed the nucleus of an emerging deepwater organization within Shell. Deepwater had been simply part of Shell's Gulf exploration and production organization and fully contained within operations on the shelf. There were three different streams of effort going on in the deepwater. The first was the evaluation of the Powell, Tahoe, and Popeye discoveries. The second involved advancing deepwater exploratory drilling. The third had to do with the general geophysical and geological exploration approach to this new frontier. As the company struggled to manage the deepwater challenge in the mid-1980s, people working in these effort streams endured constant organizational change. Carl Wickizer, who led the deepwater drilling feasibility tests in the Atlantic, was a constant overseeing presence, continually responsible for the technical management of deepwater activity until he retired in 1993. Wickizer and other managers assembled the Turbidite Task Force in early 1989 and charged it with integrating these efforts to study how turbidite reservoirs might behave and determine how Shell could reach its objective of achieving "high-rate, high-ultimate" wells (Wickizer 2001).

The first exchange at the inaugural meeting of the group, which included about a dozen people, captured the problem. Representatives from exploration, Gary Steffens and John Howell, walked into the room and put the production engineers on the spot: "Why won't production mature our prospects?" Production leader, Mark Shannon, who came from petrophysical research, met the question with his own rejoinder: "Why can't you find something that's clearly commercial?" (Montague and Shannon 2009). The difference in opinion was friendly, for the most part, and a meeting of the minds was the whole point of the group, which included geophysicists, petrophysicists, reservoir engineers, specialists in aquifer modeling, and different kinds of geologists. This "brain trust" did not focus on discrete projects or prospects. Rather, as co-leader Dave Montague put it, they had free reign "to systematically go through the available data, to gather new data, to look at interpretations of existing fields, to come up with out-of-the-box ways to answer the questions we had" (Montague and Shannon 2009).

There were few direct analogs on which to draw to answer those questions. Bullwinkle's wells were producing at a high rate, more than 3,500 barrels per day. Deepwater economics, however, required much higher rates than that. Only a few wells in the history of the Gulf could match Bullwinkle's. The same could be said for per-well ultimate reserves. The average Gulf well produced one or two million barrels at the most. Shell was banking on ten times that amount. "But we did have some knowledge and encouragement from some of the fields we had worked on and also some of the foundation work that had gone into the lease sales themselves," said Shannon (Montague and Shannon 2009).

They needed more than encouragement. The Turbidite Task Force collected data from everywhere they could find. They scoured the world for turbidite outcrops, from Spain, to Norway, to Newfoundland, to California. They studied the academic literature on turbidites. They mined MMS data for production on every well in the Gulf, how the wells were arrayed, and what this information said about drainage areas. They studied competitor's fields, paying special attention to Conoco's Jolliet development in Green Canyon as it had pays in multiple depositional sequences. They traded data with companies, such as Exxon and Mobil. They carried out studies of their own fields on the continental shelf that might serve as analogs for Shell's deepwater finds. Peccary, a small gas field located 25 miles northeast of Popeye and 50 miles from Bullwinkle in the Green Canyon, had pay zones and geological characteristics similar to some of the fields they were considering in deeper water. "We did a lot of work on Peccary to unravel it and then put it back together," said Mark Shannon. "Sort of upscale it and see what it might do had it been a deepwater field developed in the way we were thinking about doing at places like Auger" (Montague and Shannon 2009).

In its studies, the Turbidite Task Force attacked a long list of problems. They needed to understand how to interpret the “seismic facies.” In other words, how could they get more than structural information from seismic data? How could they find out the geological causes responsible for the seismic signature of the particular rocks, which was the driving force behind the development of seismic facies analysis? What did this say about the reservoir properties and the production systems? What was the reflection coefficient of deepwater sands if they were, in fact, over-pressured and compactable? How could you distinguish between “amalgamated channels” of sands and sand “sheets”? This was very important, because amalgamated channels were likely to be more compartmentalized than sheets, and thus would make a difference in decisions about where to drill. None of these kinds of analyses had really been performed before with turbidites. “We were basically trying to link from seismic to the storage tank to understand how things worked, how the plumbing worked,” said Dave Montague. The task force also looked at potential disaster scenarios with these young reservoirs that had been buried extremely rapidly and were therefore highly compactable. With the drawdown in reservoir pressure from production, they would compact and possibly damage the well tubulars. “In fact, they were highly compressible,” explained Mark Shannon. “But we got more support from aquifers than we had expected. The reservoirs, in fact, stood up better over time than had been predicted” (Montague and Shannon 2009).

The primary conclusions of the task force, which ran through 1992, were very encouraging. The first and most important one was that, barring structural complications, turbidites could be amazingly continuous over a distance of miles. To think that these very thin beds would be that continuous was a surprising and counterintuitive conclusion for some geologists. Second, turbidites did have the capacity for high-rate production with the proper completion systems. Deepwater turbidites were more tightly sealed below layers of dense mud and therefore highly pressurized. “It’s like putting a brick on a balloon full of water,” explained Shell exploration geologist Alan Kornacki. “The water wants to burst upwards. If you put a straw into that balloon, the weight of brick will push the water out at a tremendous rate” (Thorpe 1996, 144). Third, they found some confirmation, as indicated at Mars, that sands deposited in the middle of the basins, down off the structural highs, would be more prospective than sediments at the top of salt relief. This was due to the nature of structural deposition when the salt had preceded sedimentation of the source rock or reservoir, but also as a result of structural complications near the top of salt features. The time-honored tactic in the Gulf Coast region was to drill the bumps at the top of salt domes. But the task force compiled a lot of evidence to show that this might not be the best place to target drilling. “We had a geologist in the team who used to sarcastically refer to the ‘bump drillers,’” remembered Shannon (Montague and Shannon 2009).

Alongside the work of Shell’s Turbidite Task Force, the initial exuberance over the Mars discovery quickly turned to sober determination to understand the character and extent of the reservoirs. In July 1989, Shell began drilling its first appraisal well in block MC 807. On August 9, as the drill bit was penetrating the shallow layers of the seabed, 20th Century Fox released *The Abyss*, a film directed by James Cameron, in which an experimental oil drilling vessel, *Deep Core*, owned by a company called Benthic Petroleum, discovers an alien race inhabiting a spacecraft sitting eight kilometers deep in the Cayman Trench. No telling what crossed the imaginations of those in charge of the drilling operation as they approached the targets at Mars. No doubt some of them had seen the blockbuster film and felt at least a small sense of other-worldliness in the work they were doing. The appraisal drilling lasted until August 1991, totaling six wells, including one sidetrack. Five were drilled in MC 807, one block south of MC 763, and all penetrated pay sands in numerous Pliocene and Miocene intervals (see Figure 3.7). A sixth drilled in MC 806 was a dry hole, delimiting the southwest extent of the field. All were successfully plugged and abandoned, except for MC 807 #4, which was suspended and completed later as a subsea producer. Together the appraisal wells established the presence of 24 individual pay sands within 14 significant hydrocarbon-bearing turbidite reservoir layers ranging from 10,000 feet to 19,000 feet below seafloor level. The heart of the field lay in MC 807, which became its official marker (Mahaffie 1994: 234; US Department of the Interior 2014).

The drilling appraisal produced exhilarating results. However, there was still a lot of work left to do for the geologists to comprehend the character of the field they had discovered. “It’s a big field, so to get your mind around the reservoir and its extent necessitated a rather lengthy appraisal program,” said Bill Henry, Mars development engineering team leader (Duey 1999). Mars was in a new geological frontier beneath unprecedented water depths. The configurations for oil traps had been profoundly influenced by the interaction between sedimentary processes and salt movements. Early interpretations of “repeat formation tester” (RFT) pressure measurements and geochemical samples indicated that the reservoirs were compartmentalized in complex ways. The problem, as Shell Offshore geologist, Mike Mahaffie, explained, was that “details regarding the spatial arrangements of individual sands within the reservoir interval is often lacking, due to the inability to accurately predict internal reservoir architecture between existing well control or within the seismic loop itself” (Mahaffie 1994, 233).

Not just Shell, but the industry as a whole was inexperienced with deepwater turbidites. In April 1990, Placid Oil pulled the plug on a small floating platform in the Green Canyon (GC) 29 area because of poor results from wells in turbidite sands (see Volume I of this study). Before any decisions could be made about developing Mars, which would require giant capital outlays, geologists needed to understand the depositional history, shape, and behavior of the reservoirs. This meant constructing a new and reliable model to provide certainty about the characteristics of the reservoir sands. This was essential to informing a billion-dollar investment. By 1990, such understanding was ever more vital. Oil prices had continued to slide, while Shell’s costs had soared. Shell E&P’s long-range plan forecast persistently low prices. Thus, the Mars field appraisal took place during a period when management was not keen to move forward aggressively on costly projects. “It was a big investment at a time when there wasn’t a lot of money available, and we were really stepping out in terms of the rock,” noted Bob Markway, the Mars asset leader. “That probably led to a little more caution than usual” (Duey 1999, 8).

Nevertheless, the work continued. Mars was too promising to postpone. In August 1989, immediately after the drilling began, Jim Funk, division exploration manager, assigned Patricia Santogrossi to be the team lead for the Mars appraisal. Santogrossi was one of the few women to have established herself as a senior professional in the male world of exploration. She had joined Shell in 1975, one of seven women in a class of 43 geoscientists. Seven years later, she was the only woman left. She survived layoffs in the mid-1980s, when a disproportionate number of women and people of color who had newly joined the industry lost their jobs. Santogrossi spent ten years in the 1980s gaining valuable experience working in the Santos Basin for Shell Pecten in Brazil learning how to interpret turbidite sandstones with seismic data. In 1979, Pecten Brazil had made the first discovery under Brazil’s risk-contract drilling system, a gas field called Merluza (Santogrossi 2014).

As data from the wells came in, Santogrossi’s appraisal team undertook a stratigraphic study to model the architecture of the reservoirs. The key to this was the use of high-resolution 3D seismic data acquired over the area by the seismic vessel *Shell America* after the discovery well had been drilled. The 1970s revolution in digital, 3D seismic imaging, pioneered by Geophysical Services, Inc. (GSI), had dramatically enhanced the resolution of subsurface data. In the 1980s, the move to computer workstations enabled much faster processing, giving geophysicists the ability to handle the massive amount of data generated in a 3D survey from increasingly tighter grid spacing. By the late 1980s, 3D seismic could bring into focus subtle details about fault geometries, depositional features, petroleum traps, and reservoir continuities. A 3D survey, at that point in time, was very expensive. It cost approximately $3 million to acquire a 3D data set covering a 20-by-20-kilometer area and another $1 million for the hardware to process it (Boreham et al 1991, 41). The total exploration and well appraisal costs for the Mars field are estimated to have totaled $110 million. The 3D survey was a significant item, but clearly justifiable for Shell’s exploration leaders. The general attitude at Mars, according to Bill Henry, was “let’s make sure we optimize the heck out of it before we move forward” (Duey 1999, 8).

Like other deepwater decisions at Shell Oil in the late 1980s, it took a hard sales pitch to upper management to get approval. In 1989, Jack Little, president of Shell Exploration & Production Company, wanted to save money by parking *Shell America* in port. To preserve the deepwater opportunity, Shell Offshore exploration general manager, Bill Broman, traveled from New Orleans to Shell's Houston headquarters to make a presentation to Little. Broman showed quite clearly it would cost more to keep *Shell America* in the Port of Galveston, Texas, doing nothing than to have it working in the Gulf acquiring seismic data. Little had to concede the case. He wanted to cut costs, so *Shell America* continued to shoot seismic. Shell Oil exploration vice president, Tom Hart, who often forcefully expressed his views about exploration to Little, was deeply impressed with this masterful presentation by Broman. "I wouldn't have had the nerve to make that claim to Little," he said. From then on, Hart referred to *Shell America* as *Flying Dutchman*, the mythic ghost ship unable to make port and destined to sail the oceans forever (Sears 2010b)

In May 1990, *Shell America* finally did return to port in Galveston to receive major equipment upgrades. The vessel previously had acquired 3D seismic surveys, but with only one digital streamer cable–the device equipped with hydrophones that recorded acoustic echoes bounced off the subsurface layers. It often had to work in conjunction with other seismic vessels to gather enough data, making many passes over the target area to acquire the needed information. This is what made a 3D survey so expensive. To help bring down costs and allow for single-ship data acquisition, crews added new digital streamer cables and rebuilt floats–the sound sources arrayed on both sides of the boat that released compressed air into the water and acoustic vibrations into the earth. Before the upgrade, the ship had a single reel that stored a maximum of 18,000 feet of streamer cable. The refurbished ship had a total of 48,000 feet of cable, 24,000 feet on each of two massive storage reels, 18-feet in diameter. The upgrades also included a remodeled main deck to accommodate the weight and bulk of the new cables and reels and a more powerful computer system that allowed for onboard seismic data processing. The upgrades enabled *Shell America* to tow two or even three streamers at a time, instead of just one, and thus collect two to three times as much data for each survey-pass. "As you move into the world of 3D, you can speed up the acquisition of data by getting as many subsurface lines as possible each time the vessel makes a pass," explained Yoram Shoham, manager of Applied Geophysics Research at Shell's Bellaire Research Center. "The main difference between a two-dimensional line and three-dimensional areal coverage is in aperture; if you close one eye you lose depth perception. You see things better with both eyes open, and you could see even better if you had an array of 20 or 200 eyes. With 3D surveys, we're looking at the same object, but from many directions, and that gives us a much better view of it" (Abbott 1991, 29).

After crews worked around the clock to complete the upgrades, *Shell America* departed in late 1990. It increased the speed and extent of proprietary 3D surveying not only for Mars, one of its first major targets, but also for much of the company's deepwater leasehold and prospects for upcoming sales. The ambitious 3D data collection taken at Mars was a turning point in the history of exploration in the Gulf. Because of the extraordinary expenditure, 3D surveys before Mars were small, "postage stamp" in size (Yielding 2013). At Mars, Shell began gathering blanket coverage of complex structural areas, shooting up to 500 parallel lines across a target area, spaced between 50 and 200 feet from each other. In 1989, only 5 percent of the wells drilled in the Gulf relied on 3D seismic; in 1996, nearly 80 percent did. Companies acquired the majority of that data between 1990 and 1993 (Oil & Gas Journal 1997). During this time, operators began to rely on 3D seismic not only for field development, but for wildcat exploration as well. Wider swaths of equipment, including multiple vessels and streamers, and the advent of onboard processing significantly reduced the unit costs of 3D acquisition. Group shoots and large speculative surveys by geophysical contractors brought forth a torrent of high-quality 3D seismic data in the Gulf. By many accounts, 3D seismic boosted wildcat finding success from less than 30 percent to 60 or 70 percent. In 1992, Woody Nestvold, chief geophysicist for the Royal Dutch Shell Group in The Hague, announced that the Group would no longer acquire 2D data. It would use 3-D exclusively for both exploration and production (Nestvold 1996). In the Gulf, Mars was the field that marked the dramatic transition from 2D to 3D seismic acquisition.

The Mars geologists integrated the outcrop studies from the Turbidite Task Force and data from wireline well logs with the 3D seismic package. Using “seismic inversion,” a method of correlating seismic profiles with values measured in the borehole, they were able to extend well information throughout the 3D seismic architecture and produce a “reservoir rock property distribution that incorporated all available data” (Chapin, Tiller, and Mahaffie 1996, 178). This gave them a framework with which to develop depositional models for the 14 pay-bearing sands. They then used these models to predict the aerial distribution of “lithofacies,” or stratigraphic units, and to aid in the extrapolation of reservoir attributes needed to guide the placement of development wells. The outcrop studies helped the geological evaluators develop a classification scheme that subdivided the stratigraphic units into “three major categories: 1) thin-bedded channel levee and overbank sediments, 2) channel-fill complexes, and 3) sheet sands” (Mahaffie 1994, 233). In short, the depositional models and classification schemes gave Shell a much better idea of where the big pay sands would be. The few wells that had been drilled out in deepwater, such as those by Getty and Arco, had been drilled on the tops of structural crests, where the sands were poor. Explorationists raised on the wisdom of “bump drilling” had difficulty accepting that reservoirs would be out in the flats in the middle of the basin. But Shell reservoir analysis, combined with the work of the task force, showed that the best pays would be down off the crests in the basin. “It was initially hard to grasp that this was as big as the seismic (data) suggest,” recalled Jim Funk. “It looked like it could be a one-of-a-kind field” (Davis 1997, 2E).

By the spring of 1991, with the appraisal drilling nearly completed and the geological analysis progressing, Shell E&P had grown confident enough to go public with Mars. On May 4, after two years of secrecy, Shell Oil and its partner, BP, announced the discovery with initial reserve estimates that suggested it was the largest and most important US oil find of the late 20th century. The final resource appraisal for Mars placed the oil reserves at 1 billion barrels, nearly four times the size of Auger. This is the amount of oil Shell internally booked when exploration transferred the asset to production (Santogrossi 2014). In an early statement to the press, however, BP had mistakenly estimated the reserves at 700 million barrels, which is what was widely reported and never corrected at the time. Even the smaller field-size estimate was major news. Shell’s string of previously announced deepwater discoveries had caught the industry’s attention, but Mars made people sit up and listen. The announcement suggested that the potential of the deepwater Gulf was far greater than anyone outside of Shell had suspected. Oil analyst Daniel Yergin called Mars “the most significant discovery since the North Slope” of Alaska in 1968 (Lee 1991).

Although the oil industry took notice of the Mars discovery, the general public and most journalists did not. The Los Angeles Times and the Christian Science Monitor were the lone US newspapers to carry the story. The only reporting that the New York Times did on Shell Oil during mid-1991 was on the company’s July announcement of a 15 percent reduction in its US workforce of 31,000 (Hayes 1991). The biggest stories on “Mars” in 1991 were the suggestion by astronomers that the planet had once contained oceans, the National Aeronautics and Space Administration (NASA)’s announcement of a plan to send a single-spacecraft mission to the planet, and the call by a US National Space Council study for a manned mission to Mars by 2014 (Hayes 1991; McKay, Toon, and Kasting 1991). This would be only the first instance in which Shell’s Mars project would be overshadowed by public and official fascination with the planet Mars.

One person at Shell Oil was certainly not distracted by news about the celestial Mars: Rich Pattarozzi. Promoted to general manager of E&P for deepwater in 1991, Pattarozzi faced a troubling problem. Oil prices had crashed again after a brief rise during the Iraq crisis and war. At the same time, E&P managers learned that Shell had the highest cost per barrel of oil and gas produced among its competitors, and the company had just registered its first quarterly loss since the Great Depression, which led to the voluntary layoffs announced in July. By the end of the year, Shell Oil would register a miniscule net income of $20 million on more than $20 billion in revenue and assets, a $1 billion decrease in net income from the previous year. With construction beginning on the Auger TLP, Pattarozzi was deeply worried about the profitability of this and other deepwater projects. Auger's wells were planned to produce around 4,000 barrels per day, similar to what Bullwinkle's were then producing. "This isn't going to work," Pattarozzi told his staff. "The economics aren't there. We've got to do better than that." It was conceivable that Auger might be Shell's first and last deepwater project (Pattarozzi 2000).

By this time, however, Shell's reservoir engineers and geologists, supported by the Turbidite Task Force studies, grew increasingly optimistic about the quality of turbidite reservoirs and the potential for high-rate, high-ultimate wells in deepwater. In the spring 1991, based on the recommendation of the task force, the deepwater division began a production test at Tahoe (Viosca Knoll Block 783), one of the company's early deepwater discoveries (see Figure 3.7). It was a relatively small gas field that did not merit a production facility, but was on the drawing board as a subsea tieback. "We didn't want a production test in the Gulf of Mexico," recalled Dave Montague. "That was the last thing Shell wanted to do. But we made a very strong case that a large part of our reservoirs were thin-bedded, Tahoe-like reservoirs, and we just really needed to know about the productivity and lateral extent of those reservoirs" (Montague and Shannon 2009). The test was carried out safely and successfully. Flow rates from beds at Tahoe as thin as a centimeter were encouraging, achieving 29 million cubic feet per day (MMcfd) of natural gas and 974 barrels per day (bbl/d) of condensate (Abbott 1994a; Lawrence and Anderson 1993).

Figure 3.7. Prospect Tahoe production test uniform patch, 1991.

This was very good analog data, but not enough reassurance for Pattarozzi at Auger.

Based on the information coming in, his engineers believed that deepwater wells should behave differently than other wells, and that they could produce at higher rates than initially thought. Auger's wells could possibly produce something close to 8,000 barrels per day, twice the rate planned for the facility and twice as good as any well ever produced in the Gulf. "But we had no way of knowing whether that was really true or not," said Pattarozzi. In the spring of 1992, after extended deliberation, he and his engineers approached the production superintendent at Bullwinkle, on the outer-continental slope, just off the shelf edge, to see if he would test a producing well at higher rates. Bullwinkle had Pliocene turbidite reservoirs similar to those examined in deepwater. Its wells were producing at about 3,500 barrels per day, which was considered highly productive. On the shelf, a good well produced 1,000 bbl/d and an excellent well flowed at 2,000 bbl/d. Understandably, the Bullwinkle superintendent was not thrilled about increasing the choke on one of his wells and possibly damaging it. But Pattarozzi's engineers, with upper management support, convinced him that the draw-down pressure in the well would not increase enough to do any damage. Fortunately, Bullwinkle's wells had been installed with downhole pressure gauges, so that pressure changes in reservoirs at 12,000 to 15,000 feet subsurface depths could be observed and measured (Patarozzi 2000).

The engineers were right. The first well they tested at Bullwinkle increased its production from 3,500 bbl/d to 7,000 bbl/d with hardly any change in bottom-hole, draw-down pressure (Pattarozzi 2000). The test was a divine breakthrough. If this was any indication of the general productivity of the wells at Auger and other prospects Shell had under lease, it not only radically changed the cost structure of Auger but gave the company a whole new economic model with which to approach deepwater projects. "We went from believing wells could only produce 3,500 barrels a day to saying wells could produce 20,000 barrels a day," remembered Pattarozzi. By increasing the productivity of the wells, deepwater platforms could be designed with fewer of them, thus reducing overall costs significantly. The results were so encouraging that Shell Offshore mangers, in August 1993, were able to obtain relatively swift approval from Shell Oil's board of directors to move ahead with development of another tension-leg platform (TLP) at Mars, even though Auger had not yet been installed. After the production test at Bullwinkle, said Bob Howard, president of Shell Offshore, Mars was a "pretty easy sell" (Howard 2000).Shell took four years, 1989–1993, between the discovery of Mars and the "authorization for expenditure" (AFE) to go ahead with development. By 1993, the pieces seemed to be in place. Shell E&P had a new reservoir model for the deepwater basin province, backed by high resolution 3D seismic, borehole data, and outcrop analog studies. And it had a new economic model, supported by analog field production tests. The annual convention of the American Association of Petroleum Geologists (AAPG) in New Orleans that year was a coming out party for deepwater petroleum geology. Papers presented by representatives from oil companies, academic institutions, and government organizations studying the Gulf amounted to nothing less than a "paradigm shift" in the integrated understanding of the "geology, geophysics, biostratigraphy, and hydrocarbon habitat of the deepwater gulf of Mexico [sic]," according to Dave Lawrence of Shell Offshore and Roger Anderson of the Lamont-Doherty Earth Observatory. Speakers commonly cited the high porosities and permeabilities of deepwater reservoirs, excellent connectivity in the sands, and high recovery efficiencies. Lawrence and Anderson said, "Well data from 160 rank wildcat wells, more than 110 appraisal and field wells, and seismic data acquired through more than 1,000 proprietary seismic crew months portray the deepwater as a diamond in the rough" (Lawrence and Anderson 1993).

3.3. Drilling

In early 1990, after the Mars discovery, Shell engineers formulated a two-phase plan for development. Phase 1 called for drilling 24 wells through the TLP, plus two nearby subsea wells. Depending on the results of Phase 1, Phase 2 would drill another 15 wells from either a second TLP or some other facility. Even with the expert geological and geophysical work Shell was doing at Mars, there were still many unknowns about the field's multiple reservoir horizons. The overriding imperative was keeping the number of expensive wells drilled to a minimum. In order to do that, engineers needed as much reservoir information as possible. Given the enormous investment required to develop the field, managers wanted to gather samples about early production performance and pre-drill a number of wells before the TLP arrived on site (Kunkel 1999).

Shell took an unconventional and untried approach to the pre-drilling program. The drilling team, led by development engineering head Bill Henry and drilling superintendent Joe Leimkuhler, set out to drill ten wells. But instead of drilling down to the deepest reservoirs in a traditional "bottoms-up" approach, Shell decided to drill to intersect as many of the stacked and offset reservoirs as possible. "There was some risk associated with the sampling approach, but it was offset by tremendous reservoir performance knowledge in all of these major reservoirs that we could then take advantage of in the subsequent drilling development program," said Henry. "It helped us define how we could optimize the development as we went down the road" (Duey 1999, 8).

One of the biggest risks was dealing with the presence of "shallow water flows" (SWF) at the targeted drilling locations. A confusing name for a problem encountered in deep water, SWF are geohazards that occur not in shallow water, but at shallow formation depths usually less than 5,000 feet below the mudline. The Mississippi River has long dumped massive sediments into Mississippi Canyon at a rate too rapid for them to consolidate. As more sediment piled up, water and pressure became trapped. Here, in what are known as shallow water zones, sands are highly pressured and unconsolidated. When a well drills through one of these zones, overpressured water and sand escape. In extreme cases, a cavern is excavated around the well. With no support for the casing string, the well buckles. Overpressures can even "communicate through the fractures to shallower zones, adjacent wells, or the seafloor," causing "large craters, mounds, or cracks and potentially the loss of the well and the site" (Sparkman 2002, 661).

At the very least, SWF zones cause circulation problems because of the narrow window between pore pressures and fracture gradients. In other words, if the weight of the drilling mud is not heavy enough, the pore pressure of the formation will push sand and water into the well and cause it to fail. If the mud is too heavy, or "overbalanced," the sands may fracture, resulting in the loss of drilling mud, or "lost returns," and thus the loss of well control. In a SWF zone the difference between a mud weight that is too high and one that is too low is precariously small, less than 100 pounds per square inch (psi), or a mud weight of 0.3 pounds per gallon (ppg).[6] "A more technically appropriate term might be 'deepwater, near-surface, narrow-margin drilling," writes Greg Myers, manager of engineering and operations for the Integrated Ocean Drilling Program (IODP) (Myers et al 2007, 88).

Mississippi Canyon was an area prone to shallow water flows. Paleontological age determinations found that SWF risks are associated with regions that had high rates of sediment accumulation during the past 70,000 years, especially near the center of deltaic deposition by the Mississippi River (Ostermeier et al 2002). Before development drilling at the Mars, Shell had lost three wells in the area. One had been a Mars appraisal well, which suffered serious flow back to the seabed. In 1990–1991, two other exploration wells at the Ursa prospect, seven and one-half miles east of Mars, had experienced buckled and worn casing due to SWF and had to be abandoned (see below). "I was worried about that flow based on some of things we had seen at Ursa," admitted Joe Leimkuhler. "One of the flows seen at Ursa was severe enough to ruin a potential TLP tendon pattern" (Silverman 1999, 32).

Exploration drilling at Mars also had experienced the problem of poor penetration rates at deeper depths– a snail's pace of 18 feet-per-hour below 12,000 feet. This was approximately the same drilling rate as for the Auger development wells. With the high rig cost of the Sonat semi-submersible, *George Richardson*, hired to perform the pre-drilling, this rate of penetration (ROP) threatened to inflate drilling costs intolerably. One way to increase the ROP in taking the pre-drilled wells to depth was to use synthetic drilling muds, as opposed to water-based muds, which were just being introduced into the Gulf. Synthetic-based muds (SBM) formulated with linear alphaolefins and isomerized olefins had lower kinematic viscosities, which is measured as the time it takes oil to travel through the orifice of a capillary under the force of gravity, than water-based fluids. Their use provided for faster penetration, less mud-related nonproductive time, and they were more environmentally friendly than oil-based muds (OBM), which were another alternative for achieving faster penetration. In 1993, the US Environmental Protection Agency (EPA) prohibited the on-site discharge of drill cuttings from OBMs, which had to be hauled onshore for disposal. At the time, the EPA allowed the discharge of SBM cuttings on the basis that they met the discharge limitations for water-based muds. Synthetic fluids were expensive, priced at around $300 per barrel, but the higher cost was offset by not having to ship the cuttings to shore. Still, with the potential for lost returns in the SWF zones, the gain from increased ROP came at the risk of losing precious drilling fluids (Silverman 1999; Friedheim and Candler 2008).

Weighing the benefits of a smoother ride for the drillbit versus the costly chance of lost circulation in the three deeper wells, the drilling team chose to use conventional muds to drill through the SWF zone and try SBMs in the 9 7/8-inch hole section further down below it. Positive results led to continued improvement. "When we started using the SBM at Mars, we averaged only 32 ft/hr, and used it on 26 percent of the well," said Leimkuhler. "We worked our way up to 60 ft/hr in 80 percent of the well depth. We elected not to use SBM in the first interval below the SWF, because if you lost the returns in the flow zone, you would have a paved interstate highway to the mud line and we did not want that to happen." Returns lost with water-based muds tended to swell and heal the fractured rock, whereas the SBM coated and sealed the shales, keeping them from healing as fast (Silverman 1999, 34).

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[6] The Macondo well, drilled by the *Deepwater Horizon* in 2010, encountered narrow pore pressure/fracture gradient differentials throughout the well, one of the complications that led to the catastrophic blowout.

Mars appraisal leader Patricia Santogrossi helped the drillers precisely identify and account for the SWF zones at the drilling site. She demonstrated to them and her management that the subsurface contained a feature that “soled” at approximately 5,100 feet. Swift currents during sediment deposition often caused a “sole marking,” such a flute or groove on the bottom or sole of a sandstone bed. Soles are common in turbidites. The particular sole in question consisted of a large concentric region of extensional fault blocks that had detached at that level. At least one Shell geoscientist at the research lab believed the feature to be a channel. But its true nature was revealed by a “complex tracing analysis” display of instantaneous phase, or a different kind of seismic representation. According to Santogrossi, her management suggested that she not confuse the drillers with alternate seismic displays they might not understand. However, it was too late. Her production colleagues already had taken the seismic section and proceeded to change the casing-riser design to address the problem (Santogrossi 2014).

The key to conquering the SWF zones was the use of a “two riser system,” first developed at Auger. A drilling riser is a low-pressure tube that provides a conduit for the drill stem and drilling fluids from the vessel to the blowout preventer at the seafloor. For conventional subsea drilling systems, the dimensions of the wellhead and subsea blowout preventer restricted the size of casings, the metal pipes inserted into a recently drilled section of a borehole and held in place with cement. At Auger and Mars, five to six casing strings were required to get down to depth, each getting smaller as they were sleeved through the larger diameter casings on the way down the well hole, like an old-fashioned maritime telescope from the end lens to the eyeglass. The production casing in the pay zones at Mars was designed to be 7 inches in diameter, in order to handle the anticipated higher-than-normal flow rates. A conventional system could not support production casing of this weight. The two-riser system allowed for larger casing as it employed a 26-inch marine riser and subsea diverter, a device that diverts gas or other fluids from shallow zones away from the rig, in combination with a conventional 21-inch riser and subsea blowout preventer (Gonzalez et al 1992). A less costly and complicated alternative was “riserless drilling,” which uses seawater pumped down the drill pipe as the primary drilling fluid. This avoids the challenge of filling the marine riser with fluid to offset the well pressure, thus making it easier to balance subsea well pressures and re-enter the drilling hole. But riserless drilling often required a shallower placement of the casing shoe and shorter casing intervals, leading to slimmer-than-desired production casing. “We elected to set 26-inch casing above the SWF, grout it in place for pile integrity, then drill through the SWF zone with the 26-inch riser and subsea diverter employed,” explained Leimkuhler. In order to gather as much information about the SWF zone, *George Richardson* drilled four wells to total depth near the corners of the well pattern. Data from these wells helped define casing points, drilling procedures, and cementing strategies such as casing running speeds, cement slurry density, and cement volumes that eventually guided the success in isolating the SWF on all of Mars 24 wells (Silverman 1999, 33).

Cementing wells in the SWF zone posed another set of hurdles. The drilling team could tell what the pressures in the sands were while drilling through them, but they could not tell what the pressures were on the backside while cementing. The industry later employed devices to monitor pressure on the annulus, which is the void between the drill string and the formation, but this was not available at Mars. “It turned out that on the initial wells we did a lot of damage to the zones from that mud that was forced in during drilling and cementing operations,” Leimkuhler said. They began drilling under the impression that the formation was stronger than it really was, using mud and cement that were too heavy, and found that not enough cement was returning up the annulus between the casing and the formation. “As we drilled and cemented each subsequent well, we did increasing damage to the surrounding area. We had flowback to the seafloor after a lot of the cementing jobs at Mars” (Silverman 1999, 34-35). In hindsight, it turned out to be a normal flowback of well fluids, not shallow water flows, a result of drilling too fast and generating too much pressure behind the drill from the flow and cuttings.

The pre-drilling program lasted three years, October 1993 to January 1996. The team and *George Richardson* successfully drilled and cased a total of 10 wells to reservoir depth prior to the installation of the TLP and also completed a subsea well to be tied back to the facility. Difficulties notwithstanding, they completed the casing and cementing of the 10 wells with success. Still other struggles had to be overcome in the process. Mars drilling locations exposed Shell to deepwater Loop Currents for the first time at a permanent site in the Gulf. These currents, traveling as deep as 2,500 feet below the water surface, arrive through the straits of Yucatan, loop around into the northern Gulf, and then exit through the Florida Keys. They placed substantial stress and created vortex-induced vibrations (VIV) on the risers and the auxiliary choke and kill lines used for circulating fluids to the subsea blow-out preventer (BOP) at Mars. In 1994 and 1995, *George Richardson* lost a total of 60 days of rig time due to two separate Loop Current events. A workable solution was found to attach a system of fin-like fairings to the risers and auxiliary lines to streamline the current flow, similar to an airplane wing, to reduce VIV. The first system of fairings worked well until Hurricane Opal passed over the Mississippi Canyon area in September 1995. Afterward, engineers built a second set that was easier to run and pull and used it to finish the pre-drilling program at Mars and also at Ursa (Silverman 1999).

Another dilemma for the Mars pre-drilling program involved the selection a desirable well completion system. Reservoirs consisting of relatively young sediments, like Mars's, tended to be so poorly consolidated that sand was often produced along with the hydrocarbons. Sand intrusion created numerous complications. It could fill up the well bore, clog surface processing equipment, and erode well tubulars, valves, fittings, and flowlines. Conventional techniques for controlling sand production typically employed a "gravel pack," which involved placing a steel screen in the wellbore along the production zone, and then packing surrounding annulus with gravel to prevent the passage of formation sand into the well (Van Domelen et al 2000; Economides et al 2013). Some of Mars' deepwater turbidites presented a further complication. Their sands were very large-grained, and thus characterized by high porosity. They had significant space between sand grains. The ratio of void space to total rock was in excess of 25 percent, very high. They also had high permeability. The connectivity or ease of movement of fluids through pore spaces ranged from 500 mD (millidarcies) to 4 darcies, again very high.[7] The Mars field had an average porosity of 24–32 percent and permeability averaging 190 mD, but which ranged up to 2 darcies (*Oil and Gas Journal* 1993). In such reservoirs the gravel often had to be injected at pressures at or near the formation fracture pressure to pack it into all the well perforations. Shell used this approach, called a "high rate water pack," to complete the wells at Auger. Mars, however, was a good candidate for a relatively new type of completion called a "frac pack" (Silverman 1999).

A frac pack is a method of hydraulically fracturing a high permeability well. A propping agent, such as silica sand, resin-coated sand, or high-strength ceramic materials like sintered bauxite, is injected into the formation to create and prop open fractures. Frac packs were initially used in the early 1990s to bypass near-wellbore damage inflicted during drilling or well perforation to generate higher flow rates from the well than what was generally seen in gravel packed wells (Ellis 1998). For various reasons, not all reservoirs or wells at the time were considered for frac packing. But the Mars wells were. Working with Halliburton Production Enhancement services, the drilling team applied frac packs to six of the first 10 pre-drilled wells. Not only did this completion method give the wells additional flow capacity, it also provided for greater sand control reliability. The average per-well production rate with frac pack completion was 13,000 bbl/d, ranging from 8,000 bbl/d to 20,000 bbl/d (Silverman 1999). Based on the success of fracpacking, Shell obtained approval of the MMS to comingle production from some of the smaller, stacked reservoirs in the same well. That way, both could be produced at a lower rate for greater ultimate recovery than if completed separately in different wells, thereby increasing reserves and reducing the number of wells needed (Kunkel 1999).

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[7] A darcy and millidarcy are units of permeability, named after Henry Darcy. The unit is a coefficient calculated by factoring together viscosity, pressure, and thickness of the medium.

Optimized well design from the reservoir sampling, the plan for multiple completions, and the higher-than-expected flow rates from the pre-drilled wells (13,000 bbl/d compared to 11,000 bbl/d) forced a redesign of the Mars TLP as it was under construction. The Mars project was initially approved to include a second TLP or facility to drill additional wells. But managers determined that the reserves for both phases could be developed by the single TLP if its capacity was expanded from 100,000 bbl/d of oil and 110 MMcfd of gas to 140,000 bbl/d of oil and 170 MMcfd of gas. The Mars team scrambled to perform a debottlenecking study and introduced several innovative technologies to increase design production rates. The flexibility of a new contracting alliance system helped pull off this crucial modification with little delay (see below).

The pre-drilling program at Mars was a technical success and readied the site for the installation of the TLP in 1996. The average drilling performance of spudding each well and reaching total depth was 2.4 days per 1,000 feet, compared to 3.8 days per 1,000 feet at Auger.

The quality of the crude oil assayed through the drilling program was average, with the better quality crude found in the deeper, Lower Miocene intervals. The reservoirs had low gas-to-oil ratios of 1,100–1,200 standard cubic feet per barrel (scf/bbl). The API gravity rating for the younger Pliocene (Pink and Orange) sands was 22–26, and 31–34 for the Miocene sands, which classified Mars crude as medium grade.[8] The crude was also high sulfur, or "sour," 2.3–2.6 percent for the Pliocene and 1.8–2.2 percent for the Miocene.[9] It also tended to have high metals content and wax and hydrate potential. All this meant that Mars crude would have to be discounted due to extra processing required. But this only slightly tempered the enthusiasm over the size and productivity of the field that Shell was about to put into production.

[8] The API gravity rating measures how heavy or light a petroleum liquid is compared to water. The higher the number, the lighter the crude. A gravity of greater than 10 means the oil is lighter and floats on water. If less than 10, the oil is heavier and sinks. Medium oil is defined as having an API gravity between 22.3 and 31.1, and light crude has a gravity above 31.1.

[9] Oil containing more than 0.5% sulfur is classified as high sulfur, or sour.

4. The Tension Leg Platform (TLP)

4.1. Concept

Before gaining formal approval for the Mars tension-leg platform (TLP), Shell managers studied several alternative development systems. The options for full field development were either a massive compliant tower or a tension-leg platform. For a phased-in development, Shell considered several alternatives to the TLP: a complete subsea well system, with wet-tree production wells completed on the sea floor and connected by flow lines and controls back to a back to a host platform 70 miles closer to shore; a floating production system (FPS) or floating production, storage, and offloading system (FPSO); and tension-leg well jackets (TLWJ), similar to Conoco's Jolliet platform installed in the deepwater Gulf of Mexico (Gulf) in the late 1980s (see Volume I of this study). Gordon Sterling, manager of Shell's deepwater operations, had a number of individual teams each working on different proposals for development options to assess cost, scheduling, and risk (Sterling 2009).

The TLP emerged as the winning concept (see Figure 4.11). Compared to a full-scale TLP, the TLWJ had limited drilling and production capabilities. As information about the field came in, the right number of wells looked to be 24, which a TLWJ could not support. The huge initial investment of a compliant tower ruled out that concept. Although a giant fixed platform more than twice the size of Bullwinkle was technically feasible, the preliminary designs indicated prohibitive costs. At the time, Shell's engineers were less confident about subsea well technology, especially with the "waxy" crude oil in the Mars field. Moreover, a complete subsea system might impose limitations on future waterflooding. Floating systems also would require subsea wells and high capital and operating costs, thus eliminating their consideration (Godfrey 1992a). Finally, the choice of going with a TLP at Mars was also based on the fact that Shell was already building one for Auger. Shell managers recognized that Mars and subsequent projects would benefit from the learning curve experienced on this initial project. "Since we had done one, we know what we were doing," said Sterling. "These others were starting brand-new again, and then finally we have a lot people or will have a lot people who will be trained to operate on this type of facility. So that's why we went with the tension-leg platform" (Sterling 2009).

Figure 4.11. Mars TLP hard hat sticker.

As far back as the late 1960s and 1970s, engineers first contemplated future technological possibilities for exploration and production (E&P) in deeper water. Subsea production systems had potential, but still required a platform on the surface to support the production and export operations. Some companies, including Shell, experimented with manned subsea one-atmospheric systems with dry chambers for workers, but the risk to human life in the subsea world proved too great. This was especially true for deepwater. In the early 1970s, operators began to investigate production options in water depths way beyond five hundred feet. Many recognized that the next phase of technology for developing deepwater prospects would have to incorporate a conventional platform deck for the air-water interface at the surface for power, routine repairs, maintenance, and inspections. But holding the platforms and production risers in place over a field while withstanding high tension, pressure, and sea states in deepwater proved to be a major engineering challenge. It was during this time that the first discussions about a TLP scale-model test began to take shape.

The TLP concept combined the technologies of the semi-submersible vessel and the modular deck design. The TLP was tethered to the ocean floor by a series of tubular steel tethers. These tethers kept the platform in tension vertically at the surface above the producing wells and allowed the facility and the dozens of well risers to move a small degree horizontally in response to wave forces. In 1975, Deep Oil Technology, a technology development subsidiary of Fluor, conducted the first test of a TLP model. It was a one-third-scale triangular-shaped model held by steel cables to the seafloor off the US Pacific Coast near Catalina Island in 200 feet of water. Several oil companies participated as sponsors, including Conoco and Shell, the two companies that later pioneered scaled-up TLPs. The industry gained considerable insight from the model test but recognized that the data was limited. Certain aspects of the application needed to be improved, such as replacing the cables with tubular steel for longevity and to reduce costs. Engineers at Conoco closely studied the performance data and decided that a real commercial test case would be required in order to prove the concept (Curtis 1984).

Conoco subsequently turned its attention to the treacherous North Sea and the newly discovered Hutton field (1973) in 485 foot of water, ninety miles northeast of the Shetland Islands. With marginal recoverable reserves (less than 250 million barrels), Conoco needed to figure out a way to develop it economically. A production platform for that area had to be much stiffer and stronger than conventional platforms installed in the Gulf, where the average sea conditions were not as violent. The record-setting fixed platforms in the Gulf proved that brute strength and enough steel could withstand the forces of nature. Bottom-supported fixed platforms had been successfully used before in the North Sea, but Conoco ventured for something different, something innovative that would prove the economics of developing hydrocarbons in deeper waters. The environment in the North Sea, with frequent storms, one hundred-foot-high waves, and one hundred mile-an-hour winds, offered an excellent test case for the TLP prototype. Lawrence "Buck" Curtis spearheaded the development of the new platform. His Production Engineering Services (PES) team, created in the early 1970s to solve technical problems confronting the industry, conducted years of physical model testing and research to develop calculations and analytical procedures that would accurately predict the performance of the TLP structure in strong sea states. PES decided to test their research at Hutton. "We reasoned that if we could develop a system that would be adequate for this field," wrote Curtis, "the TLP could be designed for virtually any part of the world" (Curtis 1984, 36).

A key factor in making a TLP in the North Sea successful was controlling the movement of a giant facility. The platform and its mooring system had to be stable enough to allow workers to live aboard the TLP during severe weather conditions. Unlike in the Gulf, where platforms were routinely evacuated due to approaching tropical systems, offshore crews in the North Sea typically remained on the platform through the storm events. Therefore, the technology of the TLP had to be robust enough to assure that human life would be sustained during these severe storms, and that catastrophic events offshore, such as the 1965 *Sea Gem* disaster, would be avoided. The revolutionary development of flex joints or elastomeric joints installed on the seafloor and the top of the columns that accommodated the sixteen tubular steel mooring tethers or tendons, together with the buoyancy of the massive hull and deck, provided the tension necessary to hold the platform stationary over the wells systems, even in rough sea conditions (Curtis 1984).

Construction of the Hutton TLP began in the early 1980s at a shipyard in Scotland. In July 1984, it was installed and commissioned at sea. Compared to conventional platforms, such as Cognac, which took several years from fabrication to first production, the Hutton TLP began producing oil just three months after it was built. This short lag time between completion of the fabrication and first oil proved another economic benefit of the TLP over other systems. The potential reusability of the TLP and/or the low cost of decommissioning the facility at the end of the life of the field represented another economic advantage. Most importantly, the Hutton TLP provided the first application of an idea that could meet the technical challenges of deepwater petroleum production. The cost of this prototype TLP was higher than a conventional platform, but not by a large amount. By the time Conoco's TLP began production in the North Sea, Buck Curtis's Production Engineering Services organization was already looking at converting its North Sea technology into an affordable system for the deepwater frontier in the Gulf (Taylor 1984).

For Shell Oil, the company with the largest deepwater portfolio, consisting of multiple fields in several thousand feet of water, the TLP seemed to offer the best technology for successfully developing these fields. The Auger field, discovered in 1987 in the Garden Banks Block 426, was Shell's first commercial application of the TLP concept. The 100 percent Shell-owned prospect was located in 2,860 feet of water, about 136 miles off the coast of Louisiana. TLP technology had advanced since Hutton, and Shell's engineers had seriously studied the concept at least since 1977, when head office formed a special Marine Systems Engineering Group led by Carl Wickizer. This group had initiated ongoing development work on floating production and subsea systems, all with a design depth of at least 3,000 feet. With help from the civil engineering group and Shell Development, they had looked at various alternatives, including the TLP, and actually did the first conceptual design of a TLP at the time. In mid-1988, Placid Oil installed a floating system in 1,540 feet of water in the Gulf. And in 1989, Conoco placed its Jolliet tension-leg well-platform (not a full-blown TLP) in 1,760 feet of water in the Gulf (see Hewett, Volume I of this study). These pathbreaking projects and the design-work of Wickizer's group could be applied to developing Auger. But this was still a serious undertaking. At 2,800 feet, Auger was extending TLP technology over a thousand feet deeper than Conoco's Jolliet. Its design and construction were by far the most sophisticated yet attempted. With the largest design-to-capacity ratio of any of the company's production facilities, the Auger TLP would be an equipment-heavy platform supporting full drilling and production with thirty-two wells (Shell Oil 1990).

Shell's strategy was to design Auger conservatively and build up engineering capacity during the learning curve process to improve subsequent TLP projects. The Auger TLP was designed to support full drilling and production capabilities to develop a deepwater field with an estimated 220 million barrels of oil equivalent. The floating platform consisted of a fixed drilling rig, processing modules, living quarters, and a well bay on the deck that supported fourteen free standing individual well risers. A double mooring system, combining lateral mooring lines and twelve steel tubular tendons that tethered the bottom of the hull to foundation templates on the seafloor, held the facility on location (Enzie 1994). Shell's engineers used existing technology, but in some cases had to work closely with other contractors and vendors to develop new equipment and design new machines to manufacture some of the specialized components (Patterson 2009).

The unique tensioner system and well bay ultimately drove Auger's main design features. One uncertainty was predicting the longevity and fatigue performance of the tendons, especially during extreme weather loads. Engineers conducted a series of tests at different wave tanks across the country, including a test on a full-scale segment of the tensioning system (Brasted 1997). The elastomeric tensioning system used synthetic rubber and air to support the twelve individual strings of tendons and allowed for angular movement. Because there were no fixed jacket from which to attach the risers, engineers were concerned about long-term motions that would cause oscillating stresses on the wells. Engineers designed the center of Auger with an elliptical-shaped well bay, or a "moon pool," to allow enough spacing for the well-risers to move freely without bumping into one another (Patterson 2009).

To achieve this performance in design and construction, Shell instituted a team-based system for the overall project development and delivery. The team concept involved merging research capabilities and technology experts at Shell to actually design and support fabrication on the ground. One of the more notable changes with the Auger team concept was that the supervisor served in a supporting role, rather than a dictatorial position, as had been typical in the offshore industry. "The new organization has changed things," said one worker at the time. "We're expected to speak up if we see something we think we should be doing differently. Let me tell you, that's a big, big change for the oil patch" (Abbott 1994b). In some cases, workers had a chance to write operational procedures were none existed. Depp Cheramie, who spent many years working for Texaco before going to work for Shell on the Auger project as a production technician, recalled that the team setting was something new and exciting for the industry. "The team concept was awesome," he said. "They wanted to hear what you had to say, it was important what you had to say, and the team made the decision on what was going to happen, not the supervisor. The crews were not just involved doing the work, but also planning of the work" (Cheramie 2009).

The fabrication of the Auger TLP took more than three years to complete. In August 1990, Shell awarded the topsides fabrication contract to McDermott International in Morgan City, Louisiana and the hull construction to Belleli S.p.A. in Taranto, Italy. As construction of the Auger TLP was just getting underway, problems arose. These included cost overruns, delays, and strained relationships with contractors. Fabrication of the topsides, in particular, fell behind schedule. Auger was the first platform of its kind in the deepwater Gulf. Design and fabrication involved a great deal of trial and error. Shell engineers designed the entire project and worked closely on every detail of fabrication, installation, and drilling, but contractors came from far and wide. Using a complicated contracting strategy that relied on multiphased bidding, Shell contracted with nine hundred companies in the United States and thirty-three foreign companies on the project. Two site teams, one from Shell and one from McDermott, managed the deck and topsides construction separately.

In the fall 1993, the various components of the Auger TLP finally came together. But it was a trying ordeal for the managers of the project. McDermott finished fabricating the deck just in time for it to be trapped in Amelia, Louisiana, when the great Mississippi River flood silted up the Atchafalaya River. Six weeks of dredging the Atchafalaya by the US Army Corps of Engineers finally removed enough silt to allow the deck to be towed through the channel to the Gulf. The delay, however, forced Shell to gamble on the weather and schedule the mating of the hull and deck during hurricane season. In October, McDermott performed the tricky mating operation, which involved submerging the hull, bringing the barge carrying the giant deck in between the four legs, and then gently deballasting the hull up to the deck. "When the process was explained to me," remembered Pattarozzi, "I was so scared I could hardly stand it. The things that could go wrong in that whole mating process were just phenomenal." His sense of relief was just as palpable when he received the phone call informing him that it had been successfully accomplished (Pattarozzi 2000).

In mid-1994, Shell brought in production at Auger. Following initial well-flow problems, the wells began producing at 10,000 barrels of oil a day (bbl/d) (about 100,000 bbl/d total) and 300 million cubic feet (MMcfd) of gas, larger than any previous field in the Gulf. This was resounding confirmation of the reservoir studies of Shell's Turbidite Task Force. News soon trickled out about the productivity of the Auger wells, setting the industry abuzz about deepwater. Derided by oilmen as the "dead sea" after a twenty-year decline in overall production, the Gulf became one of the hottest areas in the world.

In more ways than one, Auger laid the groundwork for what followed in deepwater Gulf. An early recognition of this was the American Society for Civil Engineering's decision to give Auger the 1995 award for Outstanding Civil Engineering Achievement, honoring a Shell Oil offshore platform for an unprecedented third time (the first two were Cognac and Bullwinkle). "What Shell has done out there is truly extraordinary," said John Kingston, editor-in-chief of Platt's Oilgram News. "They basically opened up a new vista" (Thorpe 1996, 144).

Shell E&P recognized early on that Auger would be a steppingstone into deepwater. It was a trial-and-error project that suffered cost overruns, change orders, and a six-month delay to reach first oil. Spending $1.3 billion to develop a field with an estimated 220 million barrels of recoverable reserves was not something that could be repeated. "They didn't make the scheduled completion date, and, frankly, pretty much blew the budget," recalled Dwight Johnson, a Shell engineer who worked on the project. "McDermott was locked into a fixed price, but the project did not go well and they ended up spending a lot more money than the contract was set up for" (Johnson 2009). As Denis Webre, Jr., McDermott's senior project engineer at the time, put it: "Auger was a technical success but a financial failure for us"

(Webre 2009). To unlock the economic potential of the new expensive frontier in deepwater, Shell needed to improve its TLP model, cut costs, and change the way it did business with contractors.

Difficulties at Auger did not deter Shell's commitment to the play. The company's strategy was premised on first establishing the reservoir model and technological viability of deepwater production and then moving up the learning curve to make it all profitable. Having achieved such abundant exploration success, Shell did not have adequate resources (personnel, money, risk capacity) to undertake development of all its discoveries at once. Instead, managers devised a strategy to space out major platforms by about two years, allowing time to apply lessons and make improvements from one project to the next, spread out manpower and cash requirements, and mitigate against investment risk. Simultaneously, they laid out a similar strategy for subsea developments, in anticipation that subsea satellite wells would be widely used to develop smaller discoveries.

As Auger moved forward, Mars was the next project in line. Ram Powell was another leading candidate, but protracted negotiations with partners, Amoco and Exxon, delayed that project and focused Shell's efforts on Mars. Auger taught Shell Oil's production managers that they had to find a way to work more effectively with contractors to reduce cost and deliver the Mars project on time and within budget. The implication was not that Auger was a failure–far from it. Auger was the project that demonstrated the viability of deepwater, and it would become a very profitable asset for Shell. But in the difficult economic environment of the early 1990s, Shell recognized that applying a "business as usual" model on the Mars project imposed intolerable financial risks. A new approach was mandatory.

4.2. Project Management and Contracting

In mid-1991, Rich Pattarozzi, recently named E&P general manager for deepwater, called Dan Godfrey, Mars project manager, into his office. The company's net income was in free fall and layoffs were impending. "Dan, you're going to have to find a way to improve the earning power by about 3 percent if you want us to carry this forward to the board," Pattarozzi told him. "We will have to find ways of doing it differently (from Auger)" (Davis 1997). Earning power is a measurement of rate of return. It is a tall order to find a 3 percent improvement on earnings for a $1.2 billion project. If this were to be achieved solely by speeding up the project to increase the time value of money, the project would have to be finished in virtually no time at all. Impossible. To realize this simply by reducing costs would have required a $400 million savings, which appeared inconceivable.

What was to be done? The answer had to be some combination of cost and schedule reductions. In order to improve earning power, compressing the "cycle time"–the period covering design, bidding, and contracting–was just as important as cutting cuts. Time, after all, is money. In a deepwater development, where the time from discovery to first production averaged about ten years, reducing any amount of time was invaluable. On a platform producing 50,000 to 100,000 bbl/d, the time-value of the money made at the beginning rather than at the end of the platform's life was quite significant. To meet the economic requirements of improved return on investment, the Mars project organization set a goal, based on the Auger experience, to reduce the project duration by nine months and total costs, including fabrication, by $150 million (Godfrey et al 1997).

Godfrey started by putting the project on hold for three months to reconsider costs. He asked his team: "What do we have to have? What fits the purpose? What do we really need here?" (Godfrey 2009). This team, headed by construction superintendent John Haney, systems technical manager Dwight Johnston, and facilities technical manager Aubrey Pippin, looked for ways to squeeze down costs by redesigning aspects of the anticipated TLP concept. They realized that a lateral mooring system like that on Auger, which allowed the TLP to swing 200 feet in any direction, was not necessary. Instead of moving the platform over new well locations, the rig could be moved on skids around the deck to complete the 14 planned wells. Eliminating the lateral mooring system would provide $25–30 million in savings. Employing a removable leased drilling rig verses installing a permanent rig on the TLP would save the project an additional $50 million. The use of a direct tendon-pile connection to the seafloor compared to the use of more robust foundation templates reduced costs by another $20 million or more. Godfrey's group came up with a way to integrate topsides modules that required much less steel, 7,200 tons on the top deck compared to Auger's 10,000 tons. They could also decrease steel elsewhere on the platform, reducing the overall amount by 6.4 percent. Considering the cost of floating a pound of steel at $5–15 dollars, the savings amounted to another $20 million. Project managers performed a risk analysis and discovered that they did not need to have giant nets between the hull columns to prevent a wayward boat from hitting the well risers. They did not need to house pumps, elevators, and other ballast-related equipment in all four hulls if they could be contained in only two. This provided another $5–10 million in savings (Godfrey 1993a; Judice 1996a; Godfrey 2009).

In July 1992, Shell Oil's Mars project organization decided on the TLP and formed a team with BP, called the Mars Integrated Project Team (MIPT), to prepare a final development plan (FDP). In the early stages, both companies found they were doing a lot of the same work independently. Eliminating duplication would reduce costs. The alliance also broke new ground in the industry by establishing an arrangement for sharing technology and patents created on the project, although Shell Oil ended up giving away a lot more than BP, which had no experience in deepwater. Indeed, this was an unprecedented move for Shell Oil, which for the most part had always gone at it alone offshore. But the costs of deepwater were too staggering to continue this way. Both Shell Oil and BP assigned staff to the MIPT, which totaled 72 people at its peak. Most came from Shell; BP's staff totaled seven. Godfrey and the people who reported directly to him within Shell constituted a group called the Mars Project Management Team (MPMT) (see Figure 4.12). Although wary of each other at first, Shell Oil and BP personnel bought into the team concept. Team leaders collectively put together and signed a mission statement that guided the vision for the alliance, which focused on fostering a "Mars Culture" based on best practices, integrity in decision-making, and teamwork that extended beyond the project. Facilities manager Judy Wagner was Godfrey's counterpart at BP. "Judy was excellent to work with," remembered Godfrey. "In many cases, BP helped us move the project along because they actually approved things before we did. It is quite unusual for your partner to approve first" (Godfrey 2009). Said Shell construction superintendent John Haney: "We've taken the best of their practices and the best of our practices and molded them into a winning combination." Team members from the two companies were even encouraged to socialize, spending Christmas together in 1992 (Davis 1997).

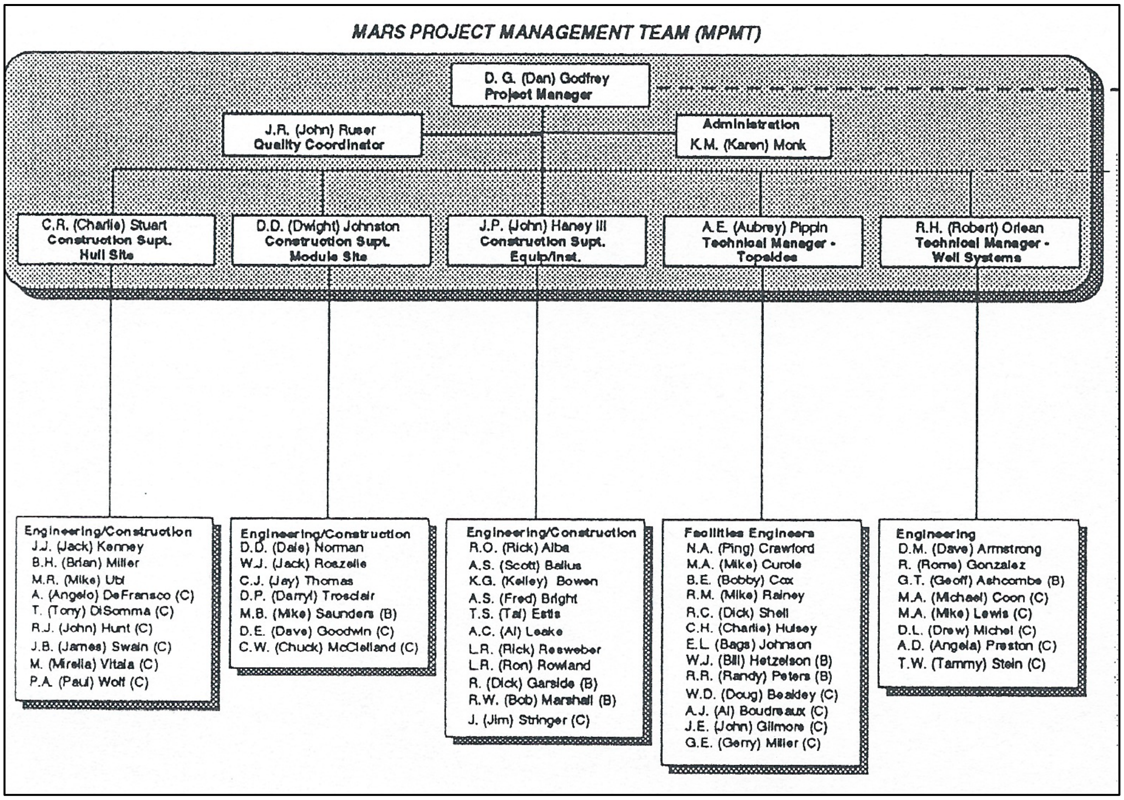

Figure 4.12. Mars Project Management Team (MPMT), January 1994.

BP staff indicated by (B). Consultants indicated by (C). Source: Godfrey 1996a.

Shell and BP carried over the alliance concept to their relationship with contractors. To reduce the project duration by nine months, using the Auger baseline, the alliance proposed a fast-track, overlapping design-build plan. By eliminating a prolonged bid-negotiation period with the selected contractors and starting the fabrication before completing the design work, Shell could realize significant time savings. Rather than drawing up all the specifications for various parts of the TLP and then asking for lump sum bids, contractors would participate in critical decisions and share the risks and benefits. "This overlapping design/build approach enabled reduction of schedule time," Dan Godfrey explained, "but led to increased cost uncertainty compared to conventional lump sum, fixed price contracting approach. Therefore, an alternative contracting approach was necessary" (Godfrey et al. 1997).

The alternative arose from something Godfrey had observed during a recent assignment in Brazil. There, he had witnessed a Royal Dutch Shell affiliate use a different contracting method to build an aluminum plant in the northeast part of the country. In the late 1980s, Brazil was experiencing massive currency inflation, and businesses had to contend with complex rules taxing imported goods. The Shell affiliate in Brazil had coped with these constraints by avoiding lump-sum contracts, instead working closely with contractors in the design phase and allowing for flexibility in contracting. This upended the traditional adversarial relationship of client and contractor with a new spirit of collaboration. Godfrey proposed something similar for Mars. "I learned a lot in Brazil about doing things under 94-percent-a-month inflation," he recalled (Godfrey 2009). Under the new model, if construction drawings differed from preliminary designs or if contractors encountered unexpected cost increases on their end, then the contract could be adjusted. With this mechanism in place and work-hour targets established, Shell and the contractors would agree to share cost overruns or savings. For every dollar a contractor went over budget, in other words, he or she would split the cost with Shell. For every dollar saved, the contractor received half the benefit. The success of this risky commercial experiment meant changing the business culture at

Shell and at the major contractors, such as McDermott, forcing them, essentially, to open their books and agree to greater transparency, particularly with respect to estimating unit costs and personnel.

The alliance concept was not only about costs and savings; it was about giving contractors a greater voice in the project. This was the truly revolutionary idea behind the concept and the reason why contractors were shocked by it. One lesson learned on Auger was that Shell engineers may be very good at designing something, but not necessarily expert at building it. Such an admission from a major oil company was rare. The alliance concept would bring the contractors in on the process as early as possible, allowing them to help make design and fabrication more complementary. Dwight Johnston, Shell's construction superintendent on Mars, recalled: "We went from a mindset of 'you set up a firm price and you hold the contractor's feet to the fire and he delivers on schedule and on that price and there's no extras, there's no changes, you deliver on that,' to one where instead of the contractor being an adversary, the contractor is a partner" (Johnston 2009). Nobody, initially, thought Shell was serious about changing the mindset. "When we had our first workshop with contractors, the facilitator kind of paused and asked for participation—you could hear a pin drop in the room," remembered Godfrey (Davis 1997).

Godfrey realized that shifting the paradigm was risky, but potentially game-changing. The contractor selection process went forward through three stages – prequalification, short-listing, and evaluation of competitive proposals. In January 1993, the MIPT reviewed 20 qualified companies identified in a contractor survey conducted for the Auger TLP fabrication. In April, after meetings with contractors by multi-disciplinary teams to discuss the new overlapping design/build risk-sharing approach and assess contractor receptiveness and commitment, the MIPT short-listed the top candidates, three for hull fabrication (Belleli, Aker-Gulf Marine, and Avondale) and four for deck module fabrication (Aker-Gulf Marine, McDermott, Brown & Root, and Gulf Island). In June, Shell provided the short-listed companies very preliminary drawings and job scope documents, and final proposals were collected in July, following numerous meetings to "discuss risk sharing, develop change mechanisms, and align objectives" (Godfrey 1996b). Godfrey told the contractors: "Well, here's your chance. You always said that if we did things differently, it wouldn't cost as much. Come make a proposal on how to do it differently" (Godfrey 2009).

Some contractors were not interested in the alternative approach, and some struggled with how they would achieve the behavioral and work process changes required to meet the contracting goals. The new approach was particularly challenging for McDermott, whose relationship with Shell was already being tested over Auger. McDermott had pioneered and perfected the conventional jacket-type platform over many decades, and it was looking take the lead in the new deepwater market. The size of its Amelia yard and experienced workforce allowed the company to retrofit its capabilities for building TLP topsides modules. Adapting existing infrastructure to meet changing technology was one thing, but altering the way McDermott negotiated large fixed contracts and managed tens of thousands of man-hours was another. Godfrey remembered Bobby Rawle from McDermott coming to see him several times to ask, "What is it you really want?" To which he replied, "I want you to make a proposal that leverages the way you work, your facilities, your stuff" (Godfrey 2009).

Contractors soon warmed to the new and innovative method of contracting, which proved to be advantageous to all parties. What Godfrey proposed was unorthodox, but if the plan worked, the Mars project and subsequent TLP projects would be financially rewarding for the respective companies. "Shell realized they had a series of structures coming out, and they knew the infrastructure here, that McDermott would be a prime candidate to fabricate them one after another," recalled McDermott's Denis Webre, Jr., the co-project manager on Mars. "I'll never forget Dan Godfrey saying what he wanted the contractor to do, and he said he wanted the contractor to make a profit. I'll never forget that" (Weber 2010). In August 1993, Shell Oil's board sanctioned the project, and on September 30, Shell management formally approved the authorization for expenditures (AFE). One day later, MIPT awarded the hull fabrication to Belleli, S.p.A. and the deck module fabrication to J. Ray McDermott. Both companies were also fabricating the same structures for the Auger TLP. Hull construction commenced in December 1993, and module fabrication began in May 1994 (Godfrey 1996b).

Having some of the same major contractors from Auger on the Mars project allowed all parties to draw on past experience, good and bad, to make improvements on the design and construction of the TLP. One improvement was that the deck modules would be lifted individually by crane onto the hull rather than mated as one piece to the hull in the water. “We never did that mating again,” sighed Rich Pattarozzi in relief (Pattarozzi 2000). Major contracts were awarded to two other companies for deck integration and facility installation. On October 1, 1993, Shell awarded an integration contract to Aker-Gulf Marine to fabricate the piles and tendons and integrate the hull and modules. HeereMac was chosen to perform the installation, but the contract was delayed until after the Auger installation in August 1994 to take advantage of lessons learned, avoid undue contingency, get a better idea of the costs, and to evaluate TLP and pipeline installation conflicts or synergies (Godfrey 1996b).

The contracting strategy demanded a close relationship between Shell and the contractors, which was established through Management Steering Teams and Shell-Contractor Integrated Site Teams. The Management Steering Teams, established with each contractor, selected the guiding principles for the integrated teams to follow. To add a trust-building and personal relationship component to the development of the team-based management approach, Shell and McDermott conducted a series of team-building workshops, facilitated by a third-party consultant, Mike Cushman, who had many years of experience working on spacecraft and defense systems. He understood that different corporate structures and cultures could erect barriers to personal relationships. With Cushman to guide the process, the team leaders strove to dismantle those barriers. He helped cultivate business and personal relationships between the members on the Mars steering committee and the MIPT, building trust among team members and a system for conflict resolution. As the project took off, a series of “barrier elimination” meetings were held offsite that were designed to address various issues likely to arise. Cushman also documented the work sessions and planned social gatherings, such as crawfish boils and quarterly socials with families of the team members, which occurred throughout the course of the project (Webre 2010).

The Steering Teams developed the protocols for building and nurturing the professional and personal relationships of the Integrated Site Teams (see Figure 4.13). Committee members were influenced by the Construction Industry Institute studies on the relationship between cost containment and trust. The uncontrolled scope changes and change orders on the Auger project were a nightmare for Shell and McDermott. The Mars teams consequently drafted a change management plan to avoid that costly problem. This plan established a systematic process for managing change that fully assessed the impact of a proposed change before it was made, and communicated those proposed changes to all members of the project. It played a key role in maintaining the “fit for purpose” philosophy, which emphasized the need to build only what was absolutely necessary and avoid costly experimentation (Webre 2010). Mars needed to be built like a durable Ford truck, not like a Rolls-Royce. This system essentially pushed decision-making down at the lower levels, which gave the co-project managers and their superintendents more responsibility and autonomy to make timely resource allocation decisions. The principal subcontractors were also brought into the process, made members of the teams, and took ownership of their share of the risk. “I’ll tell you that first six to twelve months was pretty challenging because we had to change a culture, we had to change a mindset,” said Dwight Johnston. “It was a very different concept and it took a while for people to catch on, but once they caught on, everybody saw the wisdom and the benefit of it” (Johnston 2009).

Figure 4.13. Mars Integrated site team hard hat sticker.

The Steering Teams picked the team members to manage the fabrication of the five topsides modules and to oversee the construction of the hull. They established an organization chart and a uniform scheduling system to keep the project on time. The Integrated Site Teams coordinated the "planning and scheduling of drawing deliverables, sequencing the work of different crafts/subcontractors to improve productivity, development a common view of schedule status and resource needs, and joint decision making to the needs of all parties" (Godfrey 1996b). They even integrated the office space—an industry first—where Shell and McDermott counterparts, for example, sat side-by-side at work each day (Haney 1997; Johnston 2009; Webre 2010). They held weekly production and safety meetings with clear-cut agendas, and incorporated sophisticated computer programs to evaluate the project schedule. A new approach to managing worker safety on the job was another key component of the alliance structure. Team integration also improved the ability to identify potential major safety hazards and mitigate those hazards early on in the development phase. The whole approach to managing risk was another key component of the alliance structure. Shell developed a robust Risk Management Plan, "the most comprehensive program ever undertaken by Shell Deepwater Development Inc.," that all contractors followed (Curole 1997).

The overlapping design-build strategy closely aligned the processes of design and fabrication. The site teams collaborated with the design engineers on the construction documents to identify obstacles, ensure ease of fabrication, and eliminate duplication of work. Engineering consultants, Waldemar S. Nelson (electrical design) and W. H. Linder & Associates (topside facilities design), formed a working partnership called the Mars Integrated Facilities Design Team (MIFDT). The purpose of the MIFDT was to jointly develop, alongside core members of the Mars project team, the TLP design schemes based on "constructability" (Godfrey 1993b). "Typically operations doesn't get involved until after the designers are done; then they work with the designers to make the platform more friendly to operate," said Dan Godfrey. "But in this case we spent time in the beginning determining what the equipment would be, how to handle change, and how to balance what our preferences were versus what our necessities were" (Abbott 1995). Engineers used Cadcentre's sophisticated Plant Design Management System (PDMS) that allowed them to plot coordinates of a structure in three dimensions. "Our operations people have used the system to check for things like access to valves and equipment for maintenance," noted Aubrey Pippin. "We also hired a human factors consultant who used PDMS to review all the ergonomic factors on the platform, such as stairway angles. Our maintenance consultant also used it to check on access to motors, fans, and other equipment and some of our contractors planned their fabrication process with the information they gained from it" (Abbott 1995).

Also contributing to the radical new design of Mars was the involvement of the people who would actually be operating the TLP. While Auger was under construction, Rich Pattarozzi added an Operations Group, headed by Bob Markway, to the Deepwater Project Design Team under the direction of Gordon Sterling. Markway's staff of senior operations people worked with design engineers to ensure the human operability, safety, and efficiency of the TLP. An important part of their work focused on the design for fireproofing structural members, deluge systems, and related firefighting equipment, which were far more extensive than on previous bottom-founded platforms. The Operations Group also worked the Shell Oil Governmental Affairs to achieve US Coast Guard licenses for new design features and for new operating positions required for TLPs. Finally, Markway's staff spent a year revamping the organization design, work processes, workspace arrangements, and incentive systems for the newly created Shell Deepwater E&P organization. This included a performance-based pay scheme that, as Markway noted, "encouraged multiskilling to allow us to meet all of the new and old skill requirements on these complex systems," as well as "a highly developed safety culture by giving operation personnel 'second hats' in various areas such as HSE," instead of relying strictly on 'non-line' safety technicians. Integrating operations into the design of Mars in these ways was a significant departure from Shell Oil's previous experience in building platforms (Markway, 2017).

Although smaller and lighter than Auger, Mars carried twice the production capacity, originally designed for 100,000 bbl/d of oil and 110 mmcf/d of gas. Saving weight was important to the builders—each extra pound added another five dollars to the cost of the structure. Weight reduction and control became an essential aspect of the design. To test how the lighter weight platform would perform in rough seas, Shell engineers built a plastic Mars model, 1/55th the size of the actual structure at Texas A&M University's Offshore Technology Research Center. They tethered the five-foot square model 55 feet to the bottom of the center's pool, one of the deepest in the world. Then, a mini-indoor hurricane was created. Fans simulated steady, 100 mph winds. As the Wall Street Journal reported: "Wind gusts with 50% more force combined with 16-inch-high whitecaps–the real-life equivalent of six-story waves–to rock the hull. But the columns basically held and the toy Mars survived its hurricane test" (Solomon and Fritsch 1996).

The fit-for-purpose strategy meant that little extra capacity could be factored into the design. Every square inch of space was maximized. The deck provided room for twenty-four well slots, separation and treatment facilities, and accommodations for 106 people. "We designed it about as tight as we can," said Godfrey at the time. "We don't have much room for growth. But that was a conscious decision we made in order to keep the cost of the project acceptable. If the production rates go higher, we'll have to find a way to debottleneck it" (Abbott 1995). They had to, indeed. As fabrication was proceeding in 1995, the pre-installation drilling by Sonat's *George Richardson* discovered that Mars wells were much more prolific than the expected 11,000 bbl/d, thanks to better well completion technology. Pleased with these results, the Mars team nevertheless scrambled to do a debottlenecking study while the TLP was already under construction and introduced several innovative technologies to increase design production rates to 140,000 bbl/d of oil and 170 mmcf/d of gas. Further tweaking after start-up boosted those numbers even higher, to 160,000 bbl/d of oil and 185 mmcf/d of gas. The flexibility of the alliance system helped complete these crucial modifications with little delay.

The biggest difference between Mars and Auger was beneath the surface of the water. Shell spaced the twenty-four wells on Mars in a close, rectangular pattern, rather than the widely spaced oval pattern on Auger (see Figure 4.14). On the first project, the engineers were not sure how close wells could be spaced working in 2,850 feet of water. So they opted for a conservative design, providing ample room to work between wells. Drilling experience at Auger, however, proved that spacing could be done more conventionally. Closer well spacing at Mars allowed Shell to use conventional guidelines instead of an expensive lateral mooring system like the one used at Auger, which was needed to move the TLP over the wells. With closer wells, moreover, engineers were able to design the structure without Auger's huge, expensive moon pool. "Mars knocked down so many myths about deep water," said Steve Peacock, exploration manager for BP. "It's amazing how the industry gets caught, not so much by what it doesn't know, but by what it thinks it knows that just ain't so" (Davis 1997).

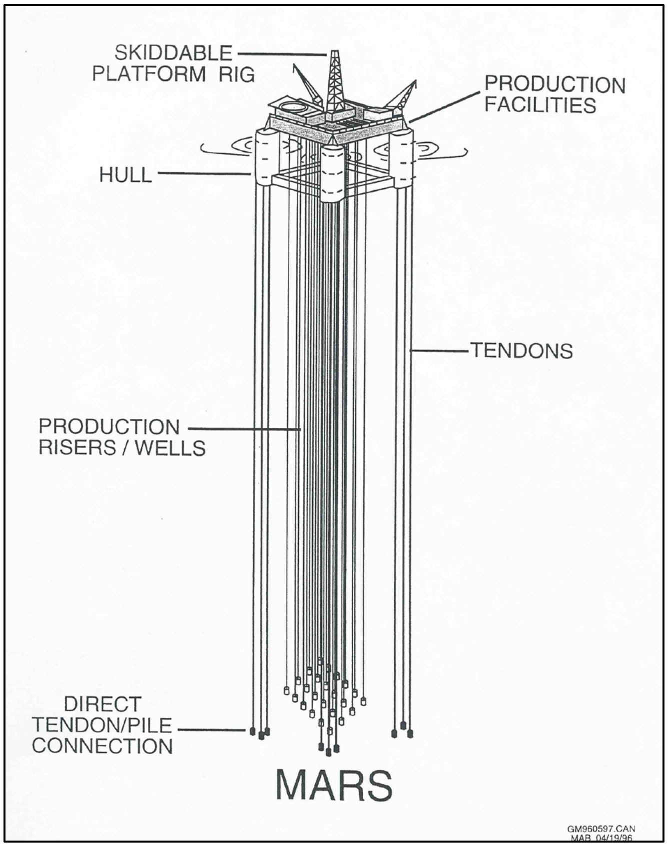

Figure 4.14. Mars TLP schematic drawing, April 1996.
Source: Godfrey 1996a.

Focusing on upfront "constructability," Shell-McDermott site teams made sure engineering specifications matched the logical construction sequences planned by the fabricator, which became all the more critical in building the five topsides modules separately, then later integrating each unit onto the hull anchored at Ingleside, Texas. This process represented a cost savings compared to building one, massive topsides deck and mating the deck to the hull offshore, as with Auger. The five modules included: (1) the process module (see Figure 4.15), used to separate and treat 100,000 barrels of oil a day and 110 million cubic feet of natural gas a day, plus produced water; (2) the power module, which contained three turbine generators (five megawatt each) capable of generating enough power for a small town; (3) the drilling module that supported a leased drilling rig; (4) the quarters module for housing 106 workers; and (5) the well bay module, which supported the 24 oil and gas wells (Godfrey 1996; Edwards et al 1997). According to Shell and McDermott engineers: "Simplification of joint details, the use of open section structural forms, widespread use of stiffened plate, adoption of a two way floor system, and the use of 60 ksi [kilograms per square inch] yield steel were major components of the design of the Deck–with resulting reductions in cost and weight while retaining structural integrity" (Edwards et al 1997). Although built in five modules, the deck was designed as a single piece in order to conserve steel in the fabrication process and keep down the weight of the deck. "In the past we had the primary steel built in one place and the individual modules built at smaller fabricators," explained Dwight Johnston. "Then we'd bring them in and set them in place in the construction yard. With Mars we decided to build an integrated deck all in one piece" (Abbott 1995).

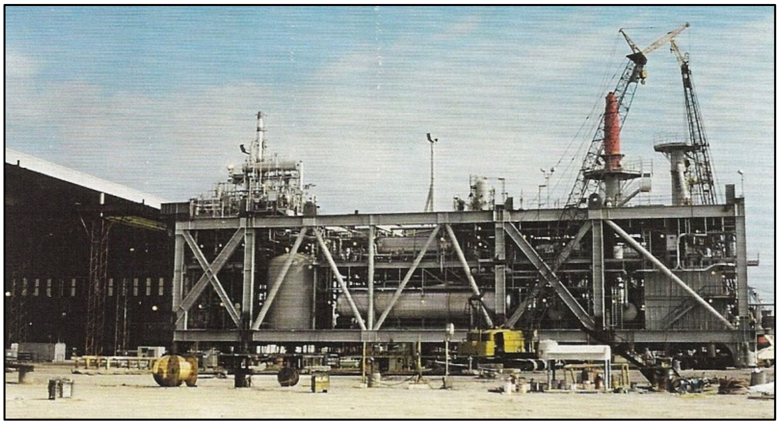

Figure 4.15. Mars TLP process module fabricated at McDermott's Amelia, Louisiana yard.
Source: Godfrey 1996a.

Cost control and sharing was an overriding factor in the design and construction of the TLP deck. Shell and McDermott spent several months coming up with unit costs and tied those cost to the initial fixed price, then negotiated target prices for the remainder of project that became the risk-reward figures. The cost expectations centered on the following: (1) a mix of fixed, reimbursable, and targeted costs based on target man hours and labor rates; (2) a mutually agreed pre-set mechanism to determine cost changes based on historical data; and (3) a 50/50 productivity risk-sharing both above and below target work-hours (Godfrey 1993b; Haney 1997). The concept worked like this: if they estimated a million work hours to complete the project, and, by working more efficiently as a team, the project used only 800,000 personnel hours, then the two companies would share the rewards of the additional 200,000 work hours not used. Essentially, McDermott would get paid for the extra 100,000 work hours and Shell would benefit by having the TLP ready ahead of schedule to reach first oil faster and on budget (Sterling 2009). Shell had an incentive to keep the targeted work hours low; McDermott had an incentive to be productive (Webre 2010).

Project control systems were an integral part of the team-based management plan. Denis Webre, Jr., a twenty-year veteran at McDermott, took charge of project scheduling for the Mars topsides. He used an innovative software system called Primavera P3© that produced the schedules used by the site teams. The system generated data on "histograms" that illustrated when, where, and how a section of the topsides was lagging behind, which allowed project managers to react appropriately to keep the scheduling on track. These histograms analyzed man-hours needed versus actual man-hours used for a given period. This gave the managers the ability to make decisions quickly, and, if behind on any schedule, to "catch up" with overtime or additional workers, or to slow down the man-hours in certain areas, if required. Although McDermott had used this system on previous projects, the big change occurred when Webre shared the scheduling tool with other Shell team members, and the teams agreed to operate under that one schedule to manage weekly activities. Webre, who also had been a senior project engineer on the Auger topsides, recognized the importance of this change. "We needed to become more sophisticated in our scheduling, because in the old days you got a set of blueprints, you gave it to one of our superintendents, he flipped through it, and he knew how to build it in his head." But the equipment and complex engineering on the TLP was something new. "So you needed sophisticated scheduling in order to get a grip on where you were with respect in the schedule," he said (Webre 2010). Computer systems produced the drawings and man-hour data needed to estimate unit cost and to hit the targets for the final risk-reward figures. It was a process culture change for some of the veteran engineers who had to transition from working solely on blue print drawings to high-performance computer screens (Crawford 1997).

The risk-reward approach required that McDermott share with Shell detailed information on cost accounting to build the deck and modules. For instance, installing plate girders on the deck cost so many dollars per ton. McDermott agreed to reveal the price per ton it took to buy the steel, do the welding, and fabricate the plate girders. The teams shared the same cost information for all the major components. "You had a unit cost that was McDermott's base cost, what it cost them to build those things," Dwight Johnston explained. "We then took those, added a profit margin, and agreed that every time we built a stairway, every time we built a plate girder, every time we put in deck steel, we would use that unit cost with that guaranteed profit, and all we had to do is estimate the tonnage because you had a dollars per ton or dollars per pound figure." By calculating the tonnage and applying the unit cost, the companies determined and agreed to a contract price. "The great thing is that once the drawings were finished," noted Johnston, "we did that weight take off, we applied those unit costs, we came up with what turned out to be the lump-sum price that locked in the price right then and there. If we did it for less than that, McDermott shared 50 percent of the savings. If it cost more than that, Shell paid for 50 percent of the increase. So that very thing right there created what is unique in our industry, a win-win scenario. What was best for Shell was best for McDermott" (Johnston 2009). By proposing and implementing a concept that the two companies enter into a "partnership" for "best for project" purposes on the Mars TLP, Shell essentially tied its future in deepwater to McDermott and a new integrated project team-based management approach.

Shell's other principal contractors also participated in the alliance. These included: Petro Marine (drilling rig), Broadmoor (quarters), Belleli (hull), Allseas (pipelines), HeereMac (TLP and riser installation), Aker Gulf Marine (integration and hook up), Bay Offshore (piping), SECO (electrical and instruments), and SIPCO (fireproofing) (Crawford et al 1997). Shell also extended the team-based management system to its scores of service contractors. Team building and project goals were discussed at workshops run by Shell personnel. These communication meetings helped the multitude of service companies develop an organizational scheme and work schedules. "The merging of the operators and contractor operations is so thorough that Shell has to put any new primary contractor representatives through a period of training and orientation to familiarize them with the program," a trade journal reported (Oil and Gas Investor 1999, 57). Many of Shell's contractors devised new processes and new equipment that were used on the Mars project, some for the first time. For example, Dril-Quip's wellhead and connector tieback systems, Frank's Casing Crew's production risers, and Delta Catering's offshore food and laundry service all developed novel solutions to meet the demands of the project. Edison Chouest Offshore, the leading offshore marine transportation company, designed and built a series of Offshore Service Vessels (OSVs) specifically to support Shell's Mars platform and subsequent deepwater facilities. According to Dr. Laney Chouest, the operator-contractor arrangement with Shell was unique. "We're not just a vendor," he said. "It's not an alliance in the sense of volume discounts. The arrangement is a prototype for any company pioneering in deep water" (Oil and Gas Investo*r* 1999, 59).

Dan Godfrey referred to Mars as the "burning platform." Not that it ever actually burned. Rather, this was a metaphor to describe an ongoing emergency condition that forces a change in the way of doing things. "The burning platform is usually the analogy that's used, when the platform's burning behind you, you'll change your preconceived notions about what you'll do to get away from it" (Godfrey 2009). For Shell, the risks of continuing to use a normal business approach to invest in deepwater far outweighed the uncertainty associated with instituting a radically different method to designing and building TLPs. The alliance concept produced dramatic and timely results. It effectively eliminated the need for change orders on major construction items. The total construction cost for the TLP was $450 million, some $50 million under budget and $200 million cheaper than the Auger TLP (Godfrey 1996b).

In addition to meeting the goals of improved relationships with contractors and cost containment, Mars also exceeded the desired reduction in schedule. Project cycle time was reduced by 12 months, an additional three months on top of the targeted nine-month schedule saving as a result of the overlapping design/construction plan. Two changes in the planned construction approach helped achieve the improvement. Two months were saved by transporting the Mars hull from Taranto, Italy to Corpus Christi, Texas on the Dockwise Heavy Lift Transport Vessel, *Mighty Servant 2*, instead of towing it with tugs. Another month was gained by attaching the drilling rig at the Integration Site rather than offshore (see below). After completion of the Mars construction work, the contracting alliance held "lookback" and "feed forward" sessions to document and incorporate lessons learned into the fabrication of subsequent Shell TLPs in the deepwater Gulf (Godfrey 1996b; Godfrey 1997).

Just before the barge load out of the completed topside modules from the fabrication site in Amelia, Shell and McDermott threw an open house celebration, complete with BBQ, balloons, and memorabilia (see Figure 4.16). This was a special occasion, something that McDermott had never done before. The companies invited all the designers and service contractors and their families to the yard to do a walking tour of the modules and to show off the project they all worked on for more than two years. John Sevin, a project engineer for McDermott on one of the modules, described the special significance of the celebration: "Once you look back on it, getting into the day-in and day-out details, you really don't have an opportunity to stand back and really think about what you've accomplished, and I think that putting on the open house really gave everybody appreciation of what we came together to do" (Sevin 2010).

Figure 4.16. Shell and McDermott "Open House" for completion of the Mars topsides modules.
Source: Photos courtesy of John Sevin.

4.3. Integration, Installation, and Operation

In late summer and fall 1995, Belleli and McDermott finished and delivered the Mars hull and deck topsides to the Aker Gulf Marine (AGM) fabrication yard in Ingleside, Texas, near Corpus Christi. The hull, fabricated in Belleli's Taranto yard, weighed in at 15,650 tons, equivalent to a small skyscraper. The four, massive circular steel columns each were 20 meters (66.5 feet) in diameter and 49 meters (162 feet) or 16 stories high. The columns were connected at the bottom by four pontoons, eight meters (27 feet) wide and seven meters (24 feet) high. Completed in early August 1995, the hull was loaded on *Mighty Servant 2* and made the 6,465-mile dry-tow journey through the Straits of Gibraltar and across the Atlantic Ocean to Ingleside in 22 days, arriving on August 31. The deck, consisting of the five integrated modules, was an open-truss frame design, 75x75x12 meters (245x245x45 feet) in dimension, or 1.5 acres, and weighed 36,500 tons. McDermott shipped the first module from Amelia, Louisiana on September 13, and the last of the five arrived on November 13. During winter 1995–1996, AGM used a newly built, massive shore-based Specialized Lifting Device to lift and assemble the modules onto the hull (see Figure 4.17). Once assembly was complete, AGM interconnected the structural steel, piping, electrical and instrumentation (Regg et al 2000).

Figure 4.17. Mars TLP integration at Aker Marine, Ingleside, Texas.
Source: Godfrey 1996a.

The assembled TLP left Ingleside on April 24, 1996, pulled by four-ocean going tugboats. Spectators gathered at the tip of I.B. Magee Beach Park to gawk in awe as the colossal structure floated through Aransas Pass into the open Gulf (see Figure 4.18). Five days later, after another several hundred-mile trip, the Mars TLP arrived on location at Mississippi Canyon Block 807 (Regg et al 2000). Sound waves, satellites, and transponders on the seafloor helped pinpoint the desired location. HeereMac's semi-submersible crane vessel (SSCV), *Balder* (the Norse god of light and purity), attached the platform to the ocean bottom via twelve sets of tendons, three per corner, each with a diameter of 28 inches, a length of 869 meters (2,852 feet), and a weight of 512 tons. The tendons were directly attached by ROVs to independently driven pipe piles. An underwater hydraulic pile hammer, the Menck MHU-500T, drove the 84-inch diameter, 398-feet-long pilings four hundred feet below the mud line. It took a major engineering effort–designing, planning, and modeling–to develop procedures to install the pipes without a template, assemble and hang the tendons from the SSCV, transfer tendons from the SSCV to the TLP while keeping the TLP stationary less than 10 meters away, and position the TLP with enough accuracy to insert the tendons into the piles and place them under tension (Garside et al 1997). The Mars hull with topside facilities was moved into position, ballasted to the desired draft that enabled the tendon assembly to attach to the base of the columns, then re-ballasted to generate the necessary tension, thus completing the TLP (Garside et al 1997).

Figure 4.18. Mars TLP tow-out from Ingleside.

Source: Photo reproduced with permission from the Associated Press. All rights reserved.

In July 1996, with the well risers brought up and connected to the platform from the seafloor, commissioning began from what was heralded as the deepest producing platform in the world. The final price tag for design, fabrication, and installation of the Mars TLP was $1.2 billion, 15 percent ($75 million) below the original cost estimate at the time of project approval. The time from the purchase of the first leases in May 1985 to first production in July 1996 was eleven years, two months. Production started from two pre-drilled wells from the Lower Miocene intervals. The first completed well reached a rate of 16,500 bbl/d, the highest daily, sustained flow rate ever reported in the Gulf up to that point. The second was a subsea well that initially produced 1,500 barrels/day. During the next year, production steadily increased as additional predrilled wells were completed, brought on stream, and opened up. In 1997, Shell commenced additional development drilling from the Helmerich & Payne platform rig, completing three wells in each of the next three years, 1998–2000, which brought the total number of producing wells on the platform to 19. By January 1999, production had reached 138,000 bbl/d of oil and 141 mmcf/d of gas (US Department of the Interior 2014).

The single oil subsea well tie-back to the Mars platform was the first of its kind in deepwater. The TLP facility supplied all the power, hydraulics, and chemicals through an umbilical cord to support the wet-tree well system, which produced from the seafloor and redirected the production up to the host facility through flowlines. The company's first subsea projects at the Tahoe and Popeye fields, tied back to shelf platforms, demonstrated the technical application of subsea natural gas production in just over a thousand feet of water (see below). By the time Mars came on line, Shell was in the midst of developing the Mensa dry-gas subsea field in 5,400 feet of water, the deepest subsea operation at the time. Doug Peart, one of Shell's leading subsea engineers, noted that the technical challenges of subsea systems in deepwater were only beginning to emerge at that time. "The piece that was the big stretch was that we've now gone passed diver depth," Peart said. "And you were in remote operations depth, and that was a big challenge. So, how did you operate the system? What were the flow assurance issues with producing in deep water, colder temperatures?" (Peart 2009). The first subsea oil producer at Mars was a very short tie-back, not extremely complicated. But it helped shore up many of the technical issues concerning oil subsea production operations and provided Shell's subsea group with the opportunity to learn as the technology pushed into deeper, more challenging water depths. Mars eventually evolved into a major regional host for subsea wells (see below), one of the largest and most productive hubs in the deepwater Gulf.

Production from Mars was transported back to shore through the deepest pipelines heretofore installed by the industry. McDermott laid a $135 million dedicated 18-inch pipeline to transport Mars crude 43 miles to Shell's West Delta 143 hub platform on the shelf. Natural gas traveled through a 14-inch pipeline to West Delta 143. From there, beginning in October 1996, the gas flowed through a new $62 million Mississippi Canyon Gathering system, a 30-inch diameter main line that gathered gas from Mars, Mensa, and Ursa and delivered it to Shell's Venice gas plant and two interstate pipelines onshore. Crude oil at West Delta 143 was routed into a 24-inch diameter oil line that ran 45 miles to the coast in lower Lafourche Parish near Port Fourchon and onward 26 miles to the Louisiana Offshore Oil Port (LOOP) onshore storage facility at Clovelly, Louisiana (see Figure 4.19). LOOP had originally been commissioned to support the offloading, transportation, and storage of foreign crude imports delivered by super tankers stationed just offshore. In 1996, federal and state authorities amended LOOP's statutory charter to allow the port to accommodate domestic production from the deepwater GOM. The need for a reliable, environmentally sound storage facility to handle the Mars production created an opportunity for LOOP to diversify. LOOP hollowed out a dedicated three million barrel capacity storage cavern (since expanded to eight million barrels) at the onshore Clovelly underground salt dome storage unit to hold Mars crude. This provided Shell with convenient and flexible access to 37 percent of the nation's refining network via four major inland pipelines (Theriot 2012). Moreover, Shell and its onshore pipeline contractors introduced innovative installation methods that limited the footprint of the pipeline canal through the fragile and eroding coastal wetlands. Shell's choice of marsh buggy-mounted dredges to dig the Mars pipeline ditch and backfill the ditch after construction represented the new preferred technique for laying pipelines in the marsh and a departure from the previous era of building massive, environmentally damaging flotation canals (Theriot 2014).

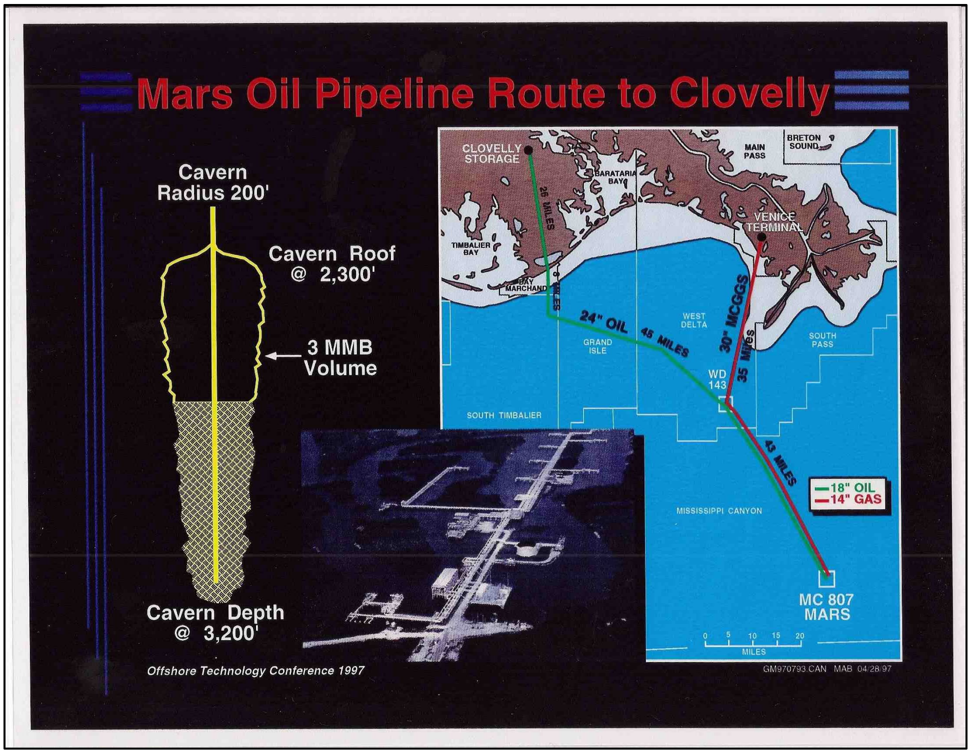

Figure 4.19. Mars oil and gas pipeline map.

Source: Godfrey et al 1997. Image courtesy of Dan Godfrey.

Even at two hundred miles away in several thousand feet of water, the offshore industry still depended on the coastal infrastructure to support oil and gas production in deepwater. Yet the coastal wetland system had been greatly diminished since the industry first ventured offshore in the 1950s. Four decades later, coastal advocates pointed to the potential economic risks to oil and gas infrastructure, as a result of continued coastal degradation. “No matter how abundant the offshore reserves might be, they are worthless unless they can be processed on shore,” noted a 1998 report from the Coalition to Restore Coastal Louisiana, a leading wetland advocacy group in the Gulf (Coalition to Restore Coastal Louisiana 1998). Nevertheless, the coastal infrastructure continued to serve as an enabler for the offshore oil and gas even during the deepwater era. “I think it’s one of the reasons why the Gulf of Mexico became such a prolific deepwater province,” echoed Robert Patterson, former Vice President Deepwater Projects at Shell, “because there was infrastructure to tie into. If you look at other deepwater areas where there’s not infrastructure, you end up with different development solutions. The geology is also a bit different in the Gulf of Mexico, which drives what development solutions are in the Gulf of Mexico versus other areas. That pipeline infrastructure provided access to market, it provided, I think, cost advantages, and it provided some flexibility as to where the hydrocarbons could go. I think all of those are real advantages enjoyed by operating companies, and customers, really, in the Gulf of Mexico area” (Patterson 2010).

In the summer of 1996, Mars sprang to life. The facility became a small factory town floating in 3,000 feet of water. It housed 130 people who worked 14 days straight before flying home for 14 days off. Typically, Shell worked a total of four crews with staggered schedules. Every seven days, one-quarter of the crew would return home to be replaced by another coming off shore leave. Petroleum Helicopters made 85 trips per month to Mars to cycle out the crew and bring in supplies. Most workers commuted from Gulf Coast communities, but many came from further away. “We have them from Georgia, Oklahoma, Texas, Michigan, Montana, and a few other places too,” Floyd Landry, Mars assistant manager, told a reporter in 2001. “They fly in, come to work, then fly back home” (Ballingrud 2001). Each day, they worked a twelve-hour shift. The accommodations and facilities on the new TLP were relatively deluxe compared to other platforms offshore, though they were smaller than Auger's, 175 versus 240 square feet per person, because of the need to economize on space (Godfrey 1993b). Most rooms slept two people, and everyone received his or her own television set and satellite control box. "No need to have fights over who watches what football game way out here," production foreman Vicki Settle Grimes commented (Ballingrud 2001). There was an exercise room, conference rooms, TV rooms, and a galley where Delta Catering of Harahan, Louisiana served delicious meals. "Hungry workers considered their options at a recent lunch," reported the *St. Petersburg Times*, "The seafood pasta? Maybe the garlic shrimp? The beef tenderloin tips in burgundy sauce was a 'superb' choice, one man pronounced." Said Landry: "The food's so good it can be a problem keeping your weight down. Our exercise room gets a lot of use" (Ballingrud 2001).

The teamwork process introduced in the fabrication of the TLP carried over into operating it. Mars asset leader, Bob Markway, supervised three teams on the TLP–Logistics, Process, and Utilities–plus an onshore Engineering team. Employees from both Shell and contractors made up the teams. The Logistics team handled drilling, completions, and transportation. The Process team covered producing and process operations as well as reliability engineering. The Utilities team managed air, power, water and food, along with maintenance, ballasting, communications, and information technology. Other key positions in the organization design included an offshore installation manager (OIM), who was the ultimate authority for risk management on the TLP and who reportedly directly to the asset leader, and a reliability engineer who reported to the Process team. The three members of the offshore leadership team, the OIM, the reliability engineer, the surface engineering staff, and Markway, communicating from onshore, met at 5 pm daily in a videoconference to discuss plans and operations for the next 72 hours. Performance data from the platform and wells was continuously transmitted into the onshore office so the staff there had already digested it before the meeting. This data included new sand detection sensors for the wells, which enabled engineers to establish safely the productive limits of the wells. The meeting also included discussions about operational plans among the leadership team, contractors, and important personnel who had a singular focus on simultaneous operations (SIMOPS) permitting. Dawn meetings on the TLP also took place with the entire facility population to discuss activities, safety trends, and operational performance. Monthly business reviews were held to examine all aspects of TLP performance and planning that involved both onshore and offshore leadership. "The feeling of asset ownership was quite pronounced," noted Markway, "particularly as much of the team had been together from the start of design" (Markway, 2017).

Safety was a central part of all discussions across all Shell TLPs. Within the newly-created TLP Operations Organization, Shell housed a health, safety, and environment (HSE) network called "Star Point Committees" that shared understanding about the risks posed by deepwater operations across all the company's TLPs (Markway 2017). From the beginning, Shell set a goal to keep incidents for both employees and contractors, reportable under the Offshore of Safety and Health Administration (OSHA) rules, to under one per 200,000 man-hours of work. This was easily achieved in the first several years of operation. In fact, in 1997, Mars earned the Minerals Management Service's (MMS) "Safety Award for Excellence" (SAFE), which recognized companies that "expend extra effort to enhance safety, conduct their operations in a manner that adheres to all regulatory requirements, and employ trained and motivated personnel." Mars was the first facility to earn the award for both drilling and production operations (Lyle 1999).

Regardless of Shell's attention to safety, the Mars crew was soon reminded of the ever-present risks of living and working on an offshore platform in a busy area of the Gulf. On October 14, 1997, managers on the TLP learned of potentially catastrophic news. An 810-foot-long Norwegian oil tanker, T/S *Stavanger Prince*, heading out of the mouth of the Mississippi River, had lost power as it drifted into the Gulf. Heavy winds put the tanker on a collision course with Mars. At the time, the tanker was approaching the TLP less than seven nautical miles from the north. Platform managers immediately ordered production on the TLP stopped and 116 workers evacuated by helicopter to the Transocean semi-submersible, *Rather*, stationed at the Ursa field eight miles to the east. The platform issued an emergency call to four Edison Chouest offshore service vessels–*Ross Chouest, Joan Chouest, Damon Chouest,* and *Mr. Jessie*–which turned and proceeded at top speed toward Mars. Upon arrival, *Damon* and *Mr. Jessie* stood by the TLP to assist evacuation. Meanwhile, *Ross Chouest*, an anchor-handling vessel, bore down on the renegade tanker and connected a towline to the ship's stern. With *Joan* and *Ross* assisting, *Ross Chouest* eased *Stavanger Prince* away from an impending collision with Mars. At the time of the rescue, the tanker was only about one mile or 32 minutes from smashing into the TLP. Personnel were then flown back to the site and production on Mars resumed five hours after the evacuation. Shell and the US Coast Guard quietly recognized the four Chouest service vessels and their crew for preventing a major maritime disaster in the Gulf. The story never reached any media outlet. Only personal recollections and a brief write-up in a Chouest newsletter testify to the details (Edison Chouest Offshore 1997).[10]

Other surprises visited the Mars inhabitants. Soon after the first several wells had come on line, the Gulf "Loop Current" shifted north to the Mars basin, bringing with it 3.5-knot current speeds. Operators noticed that the wellheads had begun vibrating, about three inches every 15 seconds. Marine engineers in Shell research determined that the current was creating a "harmonic sympathetic resonance" on the marine risers. Because the TLP hull was not yet supporting the weight of all 24 wells, there was enough excess buoyant capacity to allow the crew to increase tension on the existing wells to "tune out" the vibration. But this was only a temporary fix. A permanent design solution had to be found for the full complement of wells. The vibrations witnessed on the risers would reduce their fatigue life to a matter of months. The marine experts concluded that the problem had to do with the limited number of "vortex shedding stakes" on the risers that streamlined the oscillations caused by the passing current. Such stakes had been installed down to 500 feet below the water surface, as that was the maximum depth the currents were believed to exist. Newly-installed instrumentation, however, revealed that the current profile extended all the way down to the sea bottom. ROVs then fitted the risers with deeper stakes before the full amount of buoyancy was needed for the remaining wells (Markway, 2017).

During the late 1990s, Mars continued to be the site of bustling activity. Almost from the beginning of start-up through the year 2000, Shell enlarged the TLP's production capacity. "Tweaking" and "revamping" of topsides equipment boosted crude oil processing capacity after startup from 140,000 bbl/d to 160,000 bbl/d, and natural gas processing from 140 mmcf/d to 170 mmcf/d. Facility expansions required potentially dangerous SIMOPS, meaning that drilling, production, processing, and "hot work" construction were undertaken at the same time. "This was a monumentally complex effort to achieve safely," remembered Bob Markway. Careful planning, monitoring, and management were essential. The Star Point Committee approach and safety culture that it fostered, along with the risk management focus of the OIM, ensured that the expansion was completed successfully (Markway, 2017).

Another expansion was contemplated beginning in March 1998, when Shell Oil (34 percent operator) and partners BP Amoco (33 percent), Agip (32 percent), and Conoco (1 percent) announced plans to develop the Europa field, located 18 miles southwest of Mars in 3,900 feet of water, with a subsea production system tied back to Mars (see Figure 4.20). Months later, in July, Shell engineers initiated an 18-month operation to take the facility's processing capacity to 200,000 bbl/d of oil and 185 mmcf/d of natural gas in preparation for the arrival of Europa's production. Due to the size of the Mars reservoir and the opportunity to expand the basin over time, engineers had built in flexibility on the TLP to accommodate future production from a wider development area. They had installed a number of "porches" along the perimeter of the pontoons of the hull in anticipation of bringing in future subsea production lines, such as Europa's (Perdue 1999; Shell Oil 2000).

[10] The US Coast Guard may have an investigation report on this incident, but the online information center has posted only incidents investigated since 2002.

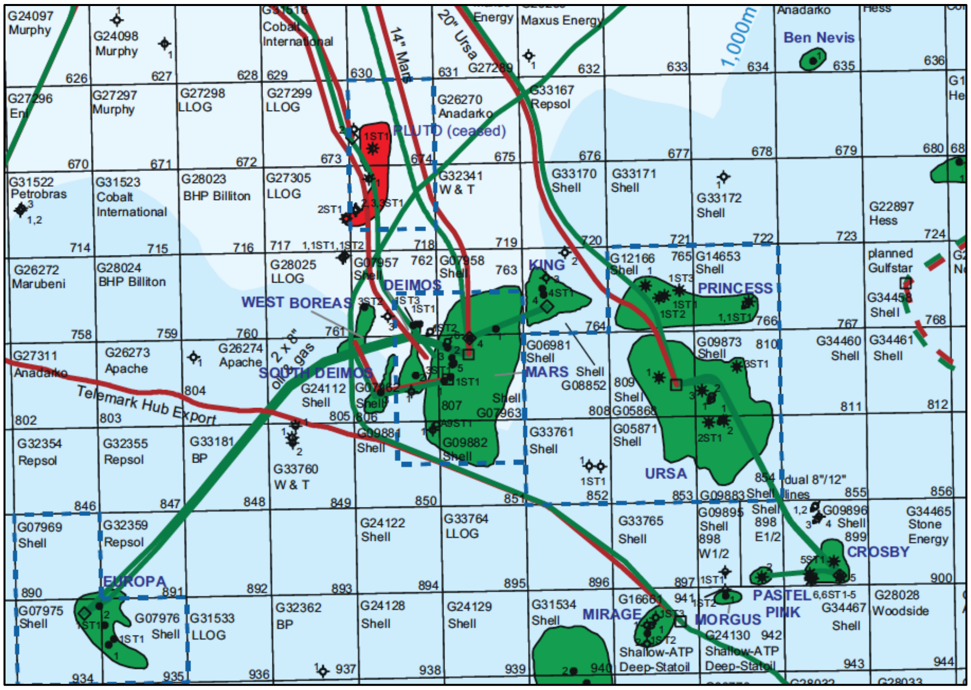

Figure 4.20. Oil fields in Greater Mars-Ursa Basin.
Source: Offshore magazine, The Gulf of Mexico Map (2012)

Shell was an early leader in subsea production in the deepwater Gulf. The company's first deepwater subsea project took place at prospect Tahoe, a gas field in 1,500 feet of water in the Viosca Knoll area, which provided the early production test that helped confirm the company's deepwater reservoir model. First drilled in 1989, the Tahoe project officially went forward in the fall of 1992. In January 1994, using a refurbished subsea tree and a control system that had been proven in the North Sea, Shell crews successfully brought Tahoe on-stream producing roughly 30 mmcf/d of gas. The importance of Tahoe was not in the gas recovered but in getting Shell established in deepwater subsea operations. Said Project Engineer Ken Orr, "we looked at Tahoe as a stepping stone to bigger and better projects" (Abbott 1994a).

Indeed, it was an important first step toward installing a larger and deeper system in the Popeye gas field in 2,000 feet of water in the Green Canyon area. In early 1996, two subsea wells at Popeye began flowing, ultimately reaching a production rate of 120 mmcf/d of gas. With Popeye, Shell achieved a number of technological firsts, including the Gulf's first diverless, cluster production system, the first guideline-less, 10,000 psi subsea trees, and the Gulf's first concentric completion-workover riser, a design that extended riser water-depth capabilities beyond 3,500 feet. Using a sleeve that pivoted pipe into place without divers or ROVs, Shell eventually connected the two wells to a central manifold, from which production was pipelined 24 miles to the Cougar platform (Oil and Gas Journal 1995a).

This was the longest tieback from a subsea well in the Gulf. By the mid-1990s, a host of newly developed technologies—new riser technology, horizontal trees, new methods for preventing oil from cooling and clogging in deepwater pipelines, and more capable umbilicals for hydraulic and electronic control systems—offered improved abilities for installing production equipment from the surface and for making long tiebacks between subsea wells and production platforms. In 1996, Shell pushed the boundaries of subsea technology by installing a cluster system modeled on Popeye at the Mensa gas field in a record-setting depth of 5,400 feet of water. The sixty-eight-mile tieback from the manifold to the West Delta Block 143 platform also set a world record. In 1998, the Mensa system, consisting of three wells linked to the manifold five miles away, reached a production rate of 280 mmcf/d of gas, boosting by almost 25 percent the company's overall natural gas production in the Gulf. Mensa served notice that subsea technology would be integral to future deepwater Gulf projects (*Oil and Gas Journal* 1995b).

After Mensa, the ratio of subsea to surface projects in the Gulf would grow, bringing in oil as well as gas. In 1997, Shell Oil, in equal partnership with Marathon Oil and BP (operator), started production of oil and gas from subsea facilities in the Troika field, located in 2,700 feet of water in Green Canyon, and began pipelining both back to the Bullwinkle platform. In preparation for Troika production, Shell increased the processing capacity of Bullwinkle from 55,000 bbl/d to 200,000 bbl/d. The development of satellite subsea wells around platform “hubs,” such as Bullwinkle, extended the life of existing infrastructure and increased the cost-effectiveness and flexibility of deepwater production (Oil and Gas Journal 1997b).

The hub concept came to play an integral role in Shell’s development strategy for deepwater TLPs. Discoveries at Tahoe, Popeye, Mensa, and Troika led Shell to marry subsea technology to the TLP concept at Auger. In the late 1990s, the company developed two fields adjacent to Auger—Macaroni and Cardamom—with subsea wells and tied them back to the TLP. Much of the new capacity at Auger was added to take production from these fields, which would not have been commercial on their own. The hub strategy further emboldened Shell’s approach to its deepwater play. “It’s meant that we continued our forward-looking exploratory tactics, explained Dave Lawrence, vice president of exploration and development for Shell Exploration & Production Co. (SEPCo), the Royal Dutch-Shell Group’s worldwide E&P organization. “It’s meant that we built our acreage position . . . and have continued to look for satellite opportunities around the Augers of the deepwater Gulf of Mexico” (Duey 2001, 46).

Like Auger, Mars served as a major hub facility for tiebacks from adjacent fields. Europa was the first. Shell and BP had purchased the leases for $4,615,000 in the same Outer Continental Shelf (OCS) Lease Sales it had acquired Mars–Sale 98 in May 1985 and Sale 113 in March 1988. In 1994, BP drilled a discovery well using the *Ocean America* semisubmersible, which was followed up with two sidetracks and one appraisal well. The field was estimated to contain 160 million barrels of oil equivalent, not large enough to receive its own production facility in nearly 4,000 feet of water. But, as Shell and its partners climbed up the subsea learning curve, Europa became an excellent candidate for a subsea tie-in. The $500 million project consisted of a subsea system with three initial wells and the capability of accommodating eight wells total. The chief contractors in the project included FMC technologies (trees, manifolds, and jumpers), Kongsberg Offshore Systems (controls), J. Ray McDermott (flowline installation), Intec (engineering services), and Stold Comex Seaway, Alcatel and Duco (umbilicals). In April 2000, the three wells came on line producing 40,000 bbl/d of crude and 30 mmcf/day of natural gas, with peak production for the system projected to be 60,000 bbl/d oil and 45 mmcf/d gas (Shell Oil 2000).

Rather than shutting down production during the expansion of processing to accommodate hydrocarbons from Europa, Shell elected to continuing drilling and producing at Mars. There were issues, such as using the platform’s cranes for construction compared to operation, coping with extra crew changes, and coordinating surveillance work. Based on similar SIMOP projects at Auger, the expansion installation team estimated that the job would take 30–40% more personnel hours to complete the work because of the additional safety precautions and planning necessary. “We had to figure out what operations we could do simultaneously without stumbling over one another or compromising safety,” said Jerry Jackson, expansion installation leader. “We decided that we could drill, produce, and construct at the same time with appropriate planning and communications. If there were additional activity, such as running wireline, we would need to decide what other activity should be shut down” (Perdue 1999, 46).

Besides maintaining a safe SIMOP, the most difficult challenge of the debottlenecking for Europa was that the TLP did not have much obvious room for expansion. Mars had been designed “tight,” as Dan Godfrey described it, with every square foot maximized. Deck space was limited. There was certainly not enough for a typical 15,000-hp compressor. Engineers thus opted for a Sulzer compression, 30–40% lighter than others, with a “works-in-a-drawer” design that allowed repair and maintenance in a small space. Most problematic, the platform was already at weight capacity. How could new equipment be added without overloading the facility? One place to obtain extra weight capacity was by adjusting the tension on the tendons, which differed in providing hurricane resistance during the summer season and fatigue resistance during winter. “We did a considerable amount of civil engineering work and came up with a program where we adjusted the tendon loads between the summer hurricane season and the winter storms which gave us more weight capacity,” said Mike Curole, expansion design leader. “Then we had value engineering sessions to figure out how to add the lightest equipment to perform the necessary functions.” Many other small solutions were found for conserving space and weight, one of which was staying within US Coast Guard regulations for the maximum number of people on board the TLP. Extra survival craft and bunks had to be added to increasing the onboard occupancy limit (Perdue 1999).

Auger opened a whole new vista for deepwater Gulf; the Mars TLP established a new paradigm for working in those depths and demonstrated Shell’s signature facility for technological and organizational innovation. It represented a culmination of nearly a half-century of effort by Shell Oil’s offshore pioneers to extend oil exploration and production into a frontier that was often viewed as unconquerable. The discovery and analysis of the field resulted from cutting-edge geophysics and geology. The TLP was an engineering marvel. And the organization of the project changed the industry’s thinking about how to manage deepwater projects.

This great advance, however, came at a price for Shell Oil. To cut costs and risk, the company had sacrificed some of its hard-earned competitive advantage in deepwater exploration and production technology by forming a partnership with BP, a longtime and bitter rival of Royal Dutch Shell around the world. The deal let BP in on the deepwater Gulf business, giving its managers and engineers a close-up view of all aspects of Shell Oil’s operations, from its exploration and reservoir evaluation models to its drilling and production techniques. With nothing in deepwater, BP geoscientists and engineers went to school and subsequently staked out a big position for their company in the deepwater Gulf. By 2004, the British oil giant was the largest leaseholder and, after the Shell E&P Company, the second-largest producer in deepwater. The partnership with BP was understandable given the financial constraints on management in 1988, and Shell had cut a good financial deal at the time. But it also provided an opening for a major competitor in this increasingly vital frontier.

Mars unlocked the keys to deepwater economics and increased the value of deepwater prospects and assets to majors and independents, and to the service contractors that fabricated and installed offshore facilities. The unique contracting risk management approach—a paradigm shift for the offshore industry—became a key component to the successful development of early deepwater in the 1990s. “It was a wonderful incentive,” said Dwight Johnson. “If you had a 600-million-barrel field and you couldn’t figure out how to develop it, well, it was just a matter of time before the deepwater may never take off. Frankly, we may be out of work… If we couldn’t figure out how to develop Mars with all of this reserves, Shell probably would not be what it is in the Gulf of Mexico today, if it were there at all” (Johnson 2009). Shell Mars was a triumph of ingenuity and a foundational deepwater project for the Gulf that combined technological advances with innovative business and contracting solutions to open up a critical frontier for US oil and gas production.

By 2012, the field had produced 610 million barrels of crude and 1 trillion cubic feet of gas, with an estimated 368 million barrels and 397 billion cubic feet of commercial reserves remaining (not counting the satellite fields discovered in the 2000s; see Section 2.7) (US Department of the Interior 2014). For Shell, at the time, Mars promised a big payoff for large bets on deepwater leases and gave the company a workable model for analyzing deepwater depositional patterns and classifying turbidite sands. This was a significant breakthrough, not only for the deepwater Gulf but also for other offshore areas of the world with similar geology. “It doesn’t take a mental giant to go from that point to thinking through several spots in the world where other situations ought to be there,” said Bill Broman, exploration general manager (Broman 1999). For the industry, Mars confirmed that the deepwater mini-basin trend in the Gulf was for real and reestablished the Gulf as the laboratory for developing the most advanced technologies in the offshore oil industry. For BP, Mars allowed the company’s managers, engineers, and scientists to learn from Shell's deepwater technology. Perhaps just as importantly, according to BP's chief in the U.S., Bob Horton, "Mars saved BP from bankruptcy" (Bower 2009, 19).

5. Subsequent Tension-leg Platforms: Ram Powell, Ursa, and Brutus

The alternative contracting strategy that became so successful on Mars demonstrated an economic pathway to developing the remaining tension-leg platforms (TLPs) in Shell's deepwater portfolio: Ram Powell (1997), Ursa (1999), and Brutus (2001). Shell and McDermott adopted the same risk-reward contracting and integrated team-based management approach for developing these prospects, each time carrying forward most of the original Mars team. At the end of the Mars project, the two partners developed the Topsides Alliance Construction Team, which continued the same team-based and alliance process for subsequent TLPs. Capturing the lessons learned at Auger and Mars and applying those lessons to future projects became the hallmark of Shell's development strategy into the deepwater. As Lou Wilkerson, Shell Oil's project manager on Ram Powell, stated, "The real effort was a matter of trying to capture lessons for each project that could be applied to the other project and sharing those lessons, and we did that through a management team and then coordinating the different project teams below the manager level to make sure that we considered each thing that was identified as a lesson learned, and if it was applicable, make use of it, if it was not, we'd know why we didn't, and then ultimately come up with the best design and the best approach to the development as a result of that" (Wilkerson 2009). For each project, Shell cut additional cost while expanding capacity and adding new innovations.

As the Mars TLP entered its later stages of construction, Shell and McDermott began developing a TLP for Ram Powell. This 270-million-barrel oil and gas field (predominantly gas) was located in the Viosca Knoll region, 80 miles due south of Mobile, Alabama, in 3,234 feet of water. Shell Oil discovered the field in May 1985 at a prospect codenamed "Powell" when *Discoverer Seven Seas* encountered multiple oil and gas pay zones in Miocene-age sands at Viosca Knoll Block 912. A 50-50 joint venture between Exxon and Amoco subsequently drilled appraisal wells on an adjoining block; this was the "Ram" prospect. In June 1989, the US Department of the Interior Minerals Management Service (MMS) approved a federal unitization agreement between the Shell Oil and Exxon and Amoco to develop the field, with Shell as the designated unit operator owning a 38% interest and Amoco and Exxon each retaining a 31% interest. Shell brought its partners into the alternative contracting arrangement and selected an Exxon construction superintendent to represent the Ram Powell co-owners. Shell integrated engineers from these other companies into the team-based system and improved the process for an overlapping design/build approach that accelerated the original schedule by an entire year. "We benefitted a great deal from the design work on Mars," said Topsides Team Leader John Tarbell, who managed the design of Ram Powell's deck modules. "Some of the things we're doing are the same, and some aren't, such as using larger-bore tubulars to increase our well production rates. But in most cases, we're following the philosophy behind Mars" (Abbott 1996, 9).

Shell Oil managers often referred to Ram Powell as a Mars "clone." The water depth at Ram-Powell was only about 300 feet deeper than Mars, requiring little change in design of the structure. Integration and installation were quite similar. "This is the first project I've ever been involved with in which we've tried to duplicate to the work we've done before as much as possible," observed Structural Design Team Leader Bill Luyties. "At the same time, we're trying to make the design changes necessary to operate in deeper water" (Abbott 1996, 10). Some of the main differences at Ram Powell included the installation of top-tensioned export risers, which had some advantage over catenary risers for the natural gas-dominated production, and the use of both conventional and horizontal wells. The horizontal drilling extended out more than one-half mile and opened up a larger section of the reservoir to the wellbore, thus increasing the TLP's production rate and allowing the facility to produce with fewer wells. The engineers also increased production by using four-and-a-half-inch tubing, which was bigger than the other Shell Oil TLPs. Based on the experience at Auger, where 13,000 barrels per day (bbl/d) ran through three-and-a-half-inch tubing, they upgraded their design from 8,000 bbl/d to 15,000. The Ram Powell TLP began production operations in 1997 and, like Mars, came in ahead of schedule and under budget. By late 1998, the facility reached a high of production of around 300 mmcfd of gas and 45,000 bbl/d of oil. Further gas debottlenecking resulted in addition hikes in natural gas output.

The next major TLPs were Ursa and Brutus. Mars' sister field, Ursa, had estimated recoverable reserves of 500 million barrels of oil. Located within the Mars basin, the Ursa TLP was installed in March 1999 in Mississippi Canyon Block 809 (see Figure 4.20). At 3,950 feet of water, Ursa set a new record for the deepest producing TLP in the Gulf of Mexico (Gulf) (see Section 2.5). Brutus, Shell's fifth TLP installed in the Gulf, began operations in mid-2001. Shell Oil acquired the leases to Brutus, Green Canyon 158 and 202, in Lease Sale 98 for $12.2 million and $3.3 million, respectively. In March 1989, Shell Oil drilled a discovery in Block 158. Three months later, Shell entered into a "farmed out" agreement assigning a 47.5 percent stake in both blocks to Exxon, retaining a 52.5 percent interest and operatorship. The Brutus TLP was designed to develop a 250 million barrel oil field in 2,985 feet of water in Green Canyon Block 158. With Brutus, Shell built on proven designs and fabricator experience to dramatically improve the overall economics and performance of the TLP technology. The project cost of $760 million, including pipelines, was 17 percent less than Mars. The construction schedule from approval to first oil was seven months shorter than previous TLPs. Brutus was Shell's first major deepwater platform designed to serve as a hub for five additional subsea developments (Rainey 2002).

Brutus was also the one major Shell TLP that performed well below expectations. Starting up in 2001, the project ran into a series of problems. In February 2002, a series of valve failures in the oil and gas processing system forced production to be shut in. This action was not taken lightly, but with full support of Shell management, which testified to a rigorous safety culture that would go so far as to shut down the company's newest, most highly visible project for an undetermined period in order to solve the problem. All the valves were disassembled to discover the root cause of the failures, which turned out to be inclusions in the elastomers of the "O" rings in the intermediate and high-pressure valves (Markway, 2017). After repairs and upgrades to the TLP's processing capacity, production from eight wells came in at rates much lower than anticipated, at 55,000 bbl/d of oil and 73 million cubic feet per day (MMcf/d of gas. Output declined sharply over the next several years, despite work on recompleting the wells that began in 2002, down to 4,000 bbl/d of liquids and 8 mmcfd of gas in 2011. Engineers determined that compartmentalization of the reservoir was the major factor in the low flow rates from the individual wells. Several sidetrack wells at Brutus and the hosting of production from subsea tie-backs to the nearby Glider and J. Bellis fields have allowed the TLP to continue producing a relatively low rates. But Brutus maintains a large amount of excess processing capacity and is expected to cease producing by the end of the decade (US Department of the Interior 2014).

Mars's close neighbor, Ursa, was a more fulfilling project and greatly enhanced the value of the Mars basin to Shell, whose minority partners on the project were BP, ConocoPhillips, and ExxonMobil. However, this was by no means apparent in the early stages. "From the start of drilling at the site," reported Offshore magazine, "Ursa would not give up secrets without a fight" (Furlow 1999). Severe shallow water flows vexed the drilling engineers and plagued the development of the field. At the time, drillers relied on two basic methods for drilling the near-surface section in deepwater. One was called "overbalanced drilling," in which a riser with weighted mud was used to prevent reservoir fluids from entering the wellbore. If too large an interval was drilled, however, the mud weight required to control the pressure of the deepest sand encountered would exceed the fracture gradient of the formation or the fracture strength of the "casing shoe," the bull-nose device attached to the bottom of a casing string. In shallow water flow zones, or "near-surface, narrow-margin sections," the acceptable intervals are very small. The alternative was to drill the near-surface section "underbalanced," with lighter seawater and no riser. The drawback to this method was the potential for washouts in overpressured sands that were uncontrolled. This would lead to lost returns of mud and drill cuttings. Drilling engineers faced a difficult decision about whether to drill the shallow sands overbalanced or underbalanced (Winker and Stancliffe 2007b).

The first two wells drilled at Ursa caused major headaches. The first well (MC [Mississippi Canyon] 854 #1), drilled underbalanced in the summer of 1990 on Mississippi Canyon Block 854 (obtained in Lease Sale 113 in March 1988 for $200,000) by *Discoverer Seven Seas*, had to be prematurely abandoned at

6,357 feet due to buckled casing and shallow water flows (SWF). A second well (MC 854 #2), located 140 feet from the first, using a 20-inch riser, successfully drilled to nearly 19,500 feet. In August 1990, this well encountered oil and gas deposits in multiple Lower Pliocene to Upper Miocene turbidite intervals, another big-time deepwater find for the company. The elation over the Ursa discovery, however, gave way to growing concern. In January 1991, shallow water flows inflicted severe wear and buckling of the casing, which forced the abandonment of the well (Eaton 1999: 1; Winker and Stancliffe 2007b: 3–4).

Appraisal drilling commenced two years later, after the acquisition and interpretation of new 3D seismic data and the award of a six-block federal unit that included BP, Exxon, and Conoco. But the first appraisal well (MC 809 #1), on the adjacent Mississippi Canyon 809 lease, also suffered SWF issues. "A water flow to the seafloor and subsequent kill operations caused a massive disturbance to the seafloor which made the surface location unusable for future wells," explained Luke Eaton, in a presentation to the Society of Petroleum Engineers/International Association of Drilling Contractors (Eaton 1999, 1).

Before drilling the second appraisal well, Shell assembled a multidisciplinary Shallow Water Flow Team at the company's Bellaire Technology Center in Houston to study the problems at Ursa. The chief dilemma was the uncertainty in predicting pore pressures and fracture gradients. To gather more information about soils and lithology in the area, Shell drilled a geotechnical well just below the first flowing sand. The company also undertook a study with Halliburton to develop a low-density, foamed slurry cement that would more quickly develop higher compressive strengths than regular cement in the cold temperatures (40 degrees F) of deepwater. To address the problem of casing buckling and wear, the team designed a 36-inch structural casing, driven to 350 feet below the mud line, to support the axial loads of the entire well. The structural casing would prevent buckling of subsequent strings as long as there was not flow up the outside of the 36-inch pipe (Eaton 1999).

In February 1996, Shell began the final round of appraisal drilling at a location intended to be the future site of the TLP. But, again, several problems related to shallow-water flows arose with the appraisal well (MC 810 #3). A new casing program was employed, which added a shallow casing string with the 20-inch interval to be drilled overbalanced using Shell's 26-inch riser and subsea diverter to take returns to the drill floor while drilling the third section of the well. This was the same system used to drill the shallower sections of Auger and the Mars pre-drill program. But while drilling the SWF zone, the pore pressure rose to a point where an increase in mud weight approached the fracture gradient at the 26-inch shoe. At that point, the riser was pulled and the remaining sections were drilled riserless using seawater as the counterweight. The well was drilled to total depth with two geologic sidetracks, with no indication of buckling, casing wear, or flow outside the casing to the seafloor. By these criteria, the well represented a step forward from the previous wells. But engineers did not consider it a complete success, as "there were still serious doubts about the cement job on the 20" casing, and it was recognized that the three main sand intervals were on different pressure gradients" (Winker and Stancliffe 2007b: 5). They were concerned that pressure from the deepest sands could communicate up to the shallowest sands, thus compromising the integrity of the TLP foundation. While the well confirmed the commercial viability of the Ursa field, it also warned of the difficult drilling conditions to develop it (Eaton 1999; Winker and Stancliffe 2007b).

The drillers relocated again to drill a test well (MC 810 #4) "to prove the ability to successfully drill the shallow sections prior to major expenditures in building the Ursa TLP" (Eaton 1999, 4). Drilled to 5,780 feet, this well (MC 810 #4) succeeded in isolating the production zones and experienced no flows to the mud line outside of the casing. Encouraged by the success of drilling below the shallow flow interval, Shell selected this site as the location for the TLP and planned to "batch set" 23 wells. Batch setting entails arraying a group of wells with a subsea template and then drilling and casing them all through the SWF zone before deepening any of them to total depth. This allows wells to be "assembly lined," saving time. The drilling rig moves over and drills each well with the same drilling mud, rather than changing out to the next formula for the middle sections. In the 30-inch casing interval, which contained no sands, the first four corner wells were drilled and cased without encountering flows. However, in the 24-inch sand interval, which was drilled riserless through shallow flowing sands, problems arose on the fourth well and on three subsequent wells. Flows blew the drill string far enough up the hole to buckle and damage the drill pipe above the mud line. Investigations revealed buckling damage in other wells across the shallowest sands (Winker and Stancliffe 2007b).

It became clear that several factors contributed to the failure. Shallow sands experienced major washouts during drilling riserless with seawater. Cement failed to displace mud out of the large cavities created by the washouts. The close well spacing allowed for the large washouts to interact, leading to subsidence of the overburden and increased axial loads on the casing strings. By batch setting the wells, those drilled first had only a single casing string across the washed-out sands for a longer time than in a conventionally drilled well. The early wells drilled in the batch did not benefit from added buckling resistance provided by subsequent casing strings and cement. And excessive loss of fluids may have fractured already overpressured formation zones. The batch-set site for the installation of the Ursa TLP had to be abandoned and moved to an area with smaller but still significant shallow flow risk in Mississippi Canyon Block 809 (Winker and Stancliffe 2007b; Jefferis et al 1999).

Having learned lessons from two previous attempts at selecting a TLP site and one failed try at batch-setting wells, Shell engineers approached the new site with a different concept. To ensure against the possibility of interacting washouts, engineers reduced the well count in the batch template from 24 to 12 and increased the minimum well spacing from 20 feet to 32 feet. This meant that half of the development wells would have to be satellite wells with subsea completions. But this also gave engineers more latitude in picking a site for the TLP. The platform was even equipped with extra subsea tieback hangers to maintain the option of developing the field completely with subsea wells in case this was needed to manage the shallow flow risk (Huete, 2017). In either case, the TLP no longer needed to be situated in the center of the field in order to reach all reservoirs, making it easier to choose a location with the most favorable geological conditions. The drilling team selected a place with a thicker overburden above a thinner section of targeted sand. The first test well (MC 809 #2) encountered some shallow water flow problems, but with only minor washouts and no buckled casing. Two more wells proved the integrity of the site and well design, and the team proceeded with batch setting the remaining nine wells. "The last of the batch set wells was drilled and cased through the SWF zone in June 1998, eight years after the Ursa discovery," wrote C.D. Winker and R.J. Stancliffe. "The seafloor remained quiet without additional flows or damage. The green light was given to installation of the TLP, from which the development wells would be drilled to depth" (Winker and Stancliffe 2007b: 7).

The change in permanent site location for the Ursa TLP created a crisis for the project. Moving the planned installation commencement from June to October 1998 threatened to delay project delivery and production of first oil (Jefferis et al 1999). In late March 1998, in order to mitigate the increased risk and cost with installation, the Ursa Project Team abruptly shifted the project schedule. To meet the April 1999 target date for first oil production, Shell and Heerema devised an alternative plan to set the modules and perform a partial integration at a near shore location in Caracas Bay, Curacao, off the coast of Venezuela. Heerema's semi-submersible crane vessel (SSCV) *Balder* had recently been in Curacao for routine maintenance, plus the sheltered location offered protection for marine operations in September. The hull, built by Belleli, S.p.A., which had entered bankruptcy proceedings in Italy, and the SSCV *Balder* were quickly rerouted to Curacao. The modules and drilling rig package were towed on ten separate barges 1,700 nautical miles across the Gulf and Caribbean to join up with the hull and installation crew (Gottung et al 1999).

The partial integration strategy involved a host of design and operational challenges. Shell had originally planned to perform the deck module installation on a fully tensioned hull with the SSCV *Balder* rotating around the fixed hull for each module set. The new plan and location required new mooring systems for *Balder* and the hull. Special arrangements had to be made for labor and materials provision, as well as logistics. Environmental permits had to be obtained for the disposal of sand-blast sand and treated sewage from the vessels and TLP. The hull-deck-rig integration was completed in October 1998 and the facility embarked on a 25-day manned tow to the Gulf for tendon installation, facilities hook-up and commissioning (Gottung et al 1999). The two-month installation operation and commissioning was performed without a hitch and target dates to first oil were ultimately met in March 1999, four months ahead of the original schedule (Jefferis et al 1999). The standardized team-based concept for problem-solving and decision making on TLP projects that Shell first adopted on Mars proved to be especially valuable in adapting to the unexpected changes with the Ursa TLP.

Ursa had an initial estimated recoverable reserves of 500 million barrels of oil. Set in 3,950 feet of water, the Ursa TLP established a new record for the deepest producing platform in the Gulf . It was also the largest TLP, weighing 63,300 tons, nearly twice that of Mars. With capacity for 150,000 bbl/d and 400mmcfd, Ursa was designed to accommodate higher production rates. On September 8, 1999, the platform's A-7 well broke previous Gulf records by producing 39,317 barrels of oil and 60.67 million cubic feet of gas, or a total of approximately 50,000 barrels of crude oil equivalent (boe) (Priest 2007, 262). It also had built-in flexibility with 2,840 tons of spare load capacity to support additional well risers and production from new wells and/or subsea wells (Jefferis et al 1999). Shell designed Ursa for future use as a regional hub for the tie-back of satellite fields, such as Princess (discovered in 2000) and Crosby (discovered in 1999, see Figure 4.20). As such, nearly everything on Ursa was made bigger than previous TLPs. For example, the size of the facility and the depth of operations required larger and longer tendons, sixteen in all, and a process module split into two separate units (Zimmer et al 1999).

6. The Mars Recovery

In late August 2005, Hurricane Katrina swept into the central Gulf of Mexico (Gulf), pummeling the Louisiana and Mississippi coasts and generating a storm surge that breached levees and flooded large parts of New Orleans and other communities. The nation was transfixed and horrified by the social and environmental catastrophe. It was the costliest natural disaster (an estimated $75 billion in damage) and one of the five deadliest hurricanes to ever hit the United States. More than 1,800 people died from the storm and subsequent floods. Many people never learned that Katrina also inflicted serious damage on one of the most important oil-producing facilities in the Gulf: the Mars TLP and its pipelines. Alongside the human and environmental tragedy unfolding onshore, Shell officials faced a different kind of problem resulting from the hurricane–a very serious and urgent one–located 130 miles south of New Orleans in 3,000 feet of water.

Well ahead of Hurricane Katrina, Shell and other industry personnel had been safely evacuated from Mars and other platforms. But the day after the hurricane passed, a Shell crew traveling by helicopter to perform an aerial inspection of the company's substantial production assets in the Mississippi Canyon area came upon a frightening sight as they approached Mars (Fletcher 2005). As later determined, Katrina's eye had traveled directly over the TLP, which had absorbed four hours of sustained 170 mph winds, gusts that exceeded 200 mph, and 80-foot waves. The 670-ton drilling rig substructure had collapsed and crushed the gas-processing facilities beneath it (see Figure 2.21). Damaged facilities included the glycol gas dehydration regeneration system, a vapor recovery unit, two field gas compressors, and the piping and cabling that connected these systems. The drilling derrick was gone, apparently toppled into the ocean. Waves had run up the hull columns, bending steel beams, smashing the lower deck, and blowing out the tops of the escape capsules. Dead fish were found 125 feet above the normal water level. Fortunately, however, the TLP hull structure and wells survived undamaged (Duplantis and Knoll 2006; Williams 2010).

Figure 6.21. Damage to Mars TLP by Hurricane Katrina.

Source: US Department of the Interior 2015, Photograph ID number 338.

Shell's engineers had expected some damage, but the rig collapse shocked everyone. Mars had been designed to withstand 140 mph winds and waves cresting up to 70 feet. The fury unleashed by Katrina, however, had sheared the three-inch-diameter steel bolts that fastened clamps holding the drilling rig to a concrete slab on the deck. Such clamps had survived many hurricanes on numerous platforms. In fact, they held on at Mars's sister TLP Ursa, located only 7.5 miles to the east, which emerged virtually unharmed by the hurricane (Mufson 2006; Hays 2007). Mars had been in the wrong place at the wrong time. As the Gulf's single highest volume oil installation, handling 150,000 barrels/day (bbl/d) of crude oil and 155 million cubic feet per day (MMcf/day) of natural gas, it was also the wrong platform to be visited by a misfortune such as this. "The intensity we saw here was unprecedented," marveled Charlie Williams, Shell's chief scientist of well engineering and production technology, who would lead the effort to repair the TLP (Hays 2007).

Mars sustained some of the most dramatic destruction meted out by the double-whammy of hurricanes Katrina and Rita, another monster storm that followed about three weeks later, passing to the west of Katrina's path, yet worsening the effects of its predecessor. Together, the two hurricanes completely destroyed 115 oil and gas platforms and damaged 52 others. They also flooded electrical facilities and wreaked havoc on pipelines and pump stations. The US Department of the Interior Minerals Management Service (MMS) estimated that roughly 3,050 of the 4,000 platforms and about 22,000 of the 33,000 miles of offshore platforms had lain in the path of the two hurricanes. The storms caused 124 reported spills, totaling 17,700 barrels of petroleum products. Of this total, 13,200 barrels were crude and condensate from platforms, rigs, and pipelines (Det Norske Veritas 2007, 13, 27).

Damage to pipelines was as worrisome as damage to platforms. Pipelines accounted for 72 of the 124 spills, totaling 7,300 barrels of crude and condensate (Det Norske Veritas 2007, 27). Three older Shell platforms were knocked over, damaging riser-pipeline connections. Pump stations at Southwest Pass 24, Main Pass 69, and Nairn were inundated, filling their engines with sand, destroying controls, and washing buildings off their foundations. Because of the severity of Katrina and Rita, dozens of anchored mobile drilling vessels were displaced, dragging their wire, chain, or anchor mooring components across the seafloor. As a result, numerous pipelines were dented, cracked, or separated. Shell's Mars and Ursa export pipelines suffered injury from a 12-ton anchor yanked by a renegade semi-submersible buffeted by the storm. A remotely operated vehicle (ROV) was sent to excavate the lines, which had been pushed five feet down into the mud and displaced 15–30 feet to the east of where they had originally lain. The Ursa oil and gas pipelines had significant dents, and the Mars lines were cracked, with seawater leaking in to the gas line. Furthermore, Shell's West Delta 143 platform, which was a booster and transfer station for all of Shell's Mississippi Canyon production from the Mars, Ursa, Crosby, and Princess facilities, suffered serious damage when a flare tower fell over onto a crane boom. Shell's Venice gas plant and liquids handling facilities also sustained damage. The oil production that passed through West Delta 143 represented 17 percent of the output from the entire Gulf (Coyne, Dollar, and Hardie 2006, 1; Severns 2005).

Repairing and restarting Mars and its pipeline system immediately became a strategic priority for Shell. As the source of such a large portion of domestic oil production, it was also critical for the industry and the nation itself. Oil traders and analysts worried about the impact on oil prices from the loss of production and possible delays in restoring it. Shell and other operators in the Gulf faced massive challenges in repairing facilities and getting the oil moving again. First, simply mobilizing people, equipment, materials, and resources was a complex undertaking. Everything was in short supply. Employees at Shell and throughout the industry had suffered tragic personal losses of family or property, and many had been evacuated or disbursed from the region. Logistical problems were immense, due to the near-total devastation of the lower Mississippi Delta infrastructure, including roads. The costs of recovering from the disaster would be dear. A year after the storms, the Congressional Budget Office estimated the total cost of repairs for the industry would range from $18 billion to $35 billion (Mufson 2006).

Shell managers spent three months planning what came to be known as “The Mars Recovery.” In addition to the logistical issues, they faced three other interrelated challenges. First was the technical challenge of removing and replacing the damaged rig and other facilities, as well as repairing the deepwater pipelines. Many of the tasks required technical “firsts” in the industry. Second was the HSE (health, safety and environment) challenge of doing this without injuries, fatalities, or environmental impacts. The platform was in a treacherous and uninhabitable state. There was no electricity; initial crews could only work in daylight hours. The microwave antenna on the derrick was gone, which limited communication (Williams 2010). Operating a platform in 3,000 feet of water already required heightened attention to safety. Repairing and restarting one magnified the imperative. Finally, these challenges together created an overall project management challenge to organize the work, choose the right people, and give them the tools and training to complete the job safely. This is why Shell spent three months planning the project, almost like a military campaign.

The first phase of the recovery involved removing the collapsed drilling rig from the platform. Lifting the 670-ton substructure from a tangled mess of facilities and processing equipment was an unprecedented feat. It had to be raised vertically so as not to irreparably damage the glycol separator. At the time, there was at least a yearlong wait to purchase and receive a new one. The lift demanded the services of a massive crane vessel. Fortunately, the Dutch company, Heerema Marine Contractors (HMC), had its giant *Hermod* (named after the son of the Norse god, Odin) semi-submersible crane vessel available. It was the first SSCV ever built (1979) and the holder of several offshore lift records. *Hermod* was an anchored vessel, as opposed to a dynamically positioned one. So it had to be located and anchored alongside the TLP very carefully so as not to damage the wells or pipelines. Operated by a largely Malaysian crew, *Hermod* successfully used its two derrick cranes to disentangle, lift, and remove the rig substructure (Williams 2010).

The second phase of the recovery required deconstructing and reconstructing the damaged facilities. Deconstructing debris was a major part of the operation and required the mobilization of a large offshore workforce. That workforce would need proper offshore accommodation. Workers could not live on the TLP, and they could not be ferried 100 miles from shore each day to get to it. Shell approached Prosafe, a Norwegian provider of accommodation vessels for offshore construction, for a way to house the workforce on site. Prosafe had one vessel available, *Safe Scandinavia*, a “flotel,” which was just completing a job for Conoco-Phillips in the North Sea. However, *Safe Scandinavia* had a twelve-point mooring system with no self-propulsion, which posed problems for situating it next to the TLP. Moreover, no accommodation vessel had ever been moored in 3,000-feet water depth, and never alongside a facility in such an environment for an extended period (Prosafe 2006, 4).

Shell and Prosafe devised changes to *Safe Scandinavia*’s mooring system and found an innovative solution to the problem of coupling the vessel to the TLP. To maximize the stability of the accommodation vessel in deep water, the technical team designed new taut-leg mooring pattern as a more effective alternative to the conventional catenary pattern. The system was reduced from 12 points to 10 to allow for close positioning of the accommodation platform to the TLP. Suction-pile anchors were pre-laid in carefully determined locations. *Safe Scandinavia* arrived in the Gulf in late November 2005 but had to wait a month at an offshore holding area at Grand Isle 118 for the completion of the mooring installation and the acquisition of enough vessels to take it into the field (Prosafe 2006, 5).

Once there, another problem had to be solved. To ensure constant access to the TLP via a gangway, Shell officials decided that the two units would have to be coupled. But Mars tended to move up to 20 meters from its center point in any direction. To eliminate some of the low frequency movements of the TLP, the units were tethered together using *Safe Scandinavia*’s two forward winches. The TLP was pulled off its natural center by 12 meters, thus synchronizing the two units’ natural frequencies so that the gangway remained safe and stable around the clock. The vessel and the TLP were successfully mated the day after Christmas, 2005 (Prosafe 2006, 5).

With six stories of accommodations, *Safe Scandinavia* "flotel" housed 500 workers. A labor shortage along the Gulf Coast following the hurricanes forced Shell to import guest workers from Europe, Mexico, and the Philippines. The company obtained special permission from US government authorities to turn *Safe Scandinavia*'s heliport into a customs and immigration point for bringing in foreign workers on six-month shifts. These men were divided into twenty person groups with translators. All those participating in the deconstruction operation were skilled welders, fitters, and scaffolders. A great deal of effort involved erecting scaffolding under the deck to provide space and footing to work. Shell stationed 75 people offshore, working in close communication with an onshore command center that functioned around-the-clock, seven days a week. The onshore team consisted of 15 managers backed by an engineering staff of 25. Supervisors from other undamaged and low-producing Shell platforms were pulled off to work on the recovery operations (Williams 2010).

Managing safety was an overriding element of the project. More than 1,300 people–within Shell and from various contractors–attended orientations on HSE expectations, roles, and responsibilities. Nearly 900 received training on "fatigue awareness" and how to take measures to prevent it. And at least 300 people attended training on fall protection and prevention. Each day, the command center would plan work around small groups, which promoted initiative and enforced continuous, real-time decision-making. All workers were empowered with "stop work authority"–the right and indeed the responsibility to call a halt to a task if someone saw an unsafe situation or behavior. Supervisors carried out "Behavior Based Safety Management" (BBSM) observations, tracking actions and communicating information about risky behaviors and areas for improvement. These observations identified 365 unsafe conditions that were subsequently corrected. Shell Exploration and Production Company's "permit to work" system was employed on all aspects of the project. This system made workers plan their tasks before receiving a permit to carry them out, ensuring compliance with Shell guidelines for procedures involving "management of change" and "simultaneous operations" (Duplantis and Knoll 2006; Williams 2010).

A process of "continuing education" reinforced HSE vigilance. Each group held safety meetings twice a day to review past HSE issues, discuss best practices, and forecast hazards associated with upcoming jobs. Formal safety meetings were conducted weekly to discuss "HSE trends, HSE milestones and targets, recent incidents, workplace audit results and work scope." During the recovery operation, management conducted 75 walkthrough audits. Charlie Williams, Shell's head of the Mars recovery, visited the site every two weeks. Marvin Odum, president of Shell Oil Company and Royal Dutch Shell director of Upstream Americas, made five visits to the platform, underscoring the strategic importance of the operation and management's commitment to the HSE effort. Furthermore, Shell conducted nearly 550 "job safety and environmental analysis" (JSEA) and job site audits to identify and rectify gaps in the hazard determination process (Duplantis and Knoll 2006; Williams 2010).

As the deconstruction and reconstruction of the Mars TLP proceeded over the winter of 2005–2006, Shell had already shifted into high gear to repair the damaged pipelines serving the Mississippi Canyon and Delta area production. The first task was reconfiguring the pipeline network in the Delta region to move crude to the Clovelly Dome Storage Terminal in South Louisiana. This complex operation entailed repiping and reversing the flows in certain pipelines and constructing temporary interconnections between Shell, BP, and Chevron pipeline facilities while repairs were made to damaged lines such as the Delta 20-inch pipeline from Nairn to Norco. As the piping work was being done, Shell arranged for barges to carry crude temporarily from the company's Bud and Ram-Powell platforms. Executed on an emergency schedule, the reconfiguration allowed oil and gas production from the eastern Gulf to resume by mid-October. Meanwhile, elevated concrete platforms were installed at pumping stations to house new electrical equipment. The reconfiguration of the pipeline system and its eventual transition back to normal operation was achieved, according to a Shell Offshore Technology Conference presentation, "without safety or environmental incident" (Coyne, Dollar, and Hardie 2006, 2).

Repairing the Mars Export Lines (18" oil and 14" gas) was an altogether different challenge. Sections of the lines in 2,750 feet of water had cracks and had to be replaced.[11] On-bottom repairs to a deepwater platform had never before been attempted. Shell was prepared for the possibility. It had a Deep-Water Pipeline Repair (DWPR) system, designed as a precaution years earlier, at the ready. Components from the original system were taken out of storage in Morgan City, Louisiana and shipped to Houston, Texas for pre-deployment preparations. All work had to be accomplished using ROVs. With construction vessels in short supply, Shell searched for an appropriate base before hiring the *Botanica*, a North Sea icebreaker with two ROV spreads and enough deck space for the repair equipment, which arrived in the Gulf in late November (Povloski 2008).

First, hydrocarbons had to be flushed from the pipelines. A hydraulically controlled "pipe-line frame" lowered from the *Botanica* lifted the pipeline off the seafloor to give the ROVs access. The initial ROV mission was to attach to the cracked sections of the lines a temporary clamp assembly with a 650-barrel capacity "pollution dome" and pumping system. As water was flushed through the pipe to evacuate the hydrocarbons, the dome collected the oil and gas that was squeezed out the cracks. About 3,200 barrels of oil were recovered and pumped to an oil spill response vessel; the excess gas was first vented off the riser to a temporary spread installed on the TLP and then pushed to the West Delta 143 platform to be flared (Coyne, Dollar, and Hardie 2006, 3-4).

The ROVs then went to work replacing the damaged sections. The two ends of the pipelines were lifted and relocated close to their original position before the storm. The ROVs cut and removed the damaged sections with diamond wire saws. Next, "pipeline end termination" (PLET) sleds were deployed from the surface and set in position. The ROVs then prepared the ends of the severed pipeline with "Grip and Seal Hydraulic Connectors" lowered on gantry frames. These were attached to each end of the pipeline and secured to the sled. Finally, u-shaped "jumpers" or "spoolpieces" of pipe were lowered from a supply vessel to reconnect the ends. The jumpers were equipped with wyes and future tie-in hubs. Winter weather delayed the final installation of all the connectors and spoolpieces, but both pipelines were ready for operation by April 2006 (Povloski, 2008; Coyne, Dollar, and Hardie 2006, 4).

The repairs of the Mars Export Lines were an industry first in deepwater, pioneering the use of special oil containment devices, on-bottom procedures involving ROVs, and a specially engineered pipeline repair kit. Specialized contractors have since improved upon all these, making deepwater pipeline repair increasingly routine and reliable, although still a highly undesirable scenario.

On May 22, 2006, only nine months after suffering the devastating impact of Hurricane Katrina, the Mars TLP resumed production ahead of schedule. It boasted a new drilling derrick and repaired substructure. "We worked around the clock, 24 hours a day, seven days a week from November until startup in May," said T.J. Senter, the offshore operations manager for Mars (Hays 2007). Shell spent a total of $300 million fixing its Gulf infrastructure and covering relocation costs for employees who had lost homes and possessions, a large part of that total spent on the Mars Recovery. Pipeline repairs cost approximately $100 million of the total. The time, resources, and care that Shell and its contractors put into the Mars Recovery turned a terrible misfortune into a dramatic success. Mars produced at a higher rate immediately after the recovery than before, 160,000 bbl/d compared with 148,000 bbl/d. After being shut-in for nine months, Mars' compaction drive reservoir resumed with recharged energy. Upgraded replacement facilities helped to enhance production. "The Mars recovery operation is quite a success story," remarked Elmer Danenberger, chief of offshore regulatory programs at MMS (Hays 2007).

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[11] Ursa's Export Lines were merely dented rather than cracked. After successfully passing pressure tests and fatigue analysis, they were returned to service when Ursa TLP resumed operations in November 2005.

Shell E&P's achievements were all the more noteworthy because of the way the company integrated safety and training into meeting the technical challenges of a large-scale recovery effort. More than 1 million total man-hours were logged in the effort, with only 55 first aid cases and 21 near misses. Thankfully, there were no fatalities. Most amazingly, there were no lost-time injuries (Williams 2010). This was a testament to the application of Shell's behavior-based safety management and "Safety Case" procedures for risk identification and mitigation. It also reflected company's prowess at overall project management. These achievements were duly commended when the National Ocean Industries Association honored Shell E&P Company with its 2006 "Safety in Seas Award" for the Mars Recovery Project, in recognition of its "outstanding contribution to the safety of life offshore for energy workers" (National Ocean Industries Association 2007).

7. The Greater Ursa-Mars Basin Opportunity Project (GUMBO)

Mars and Ursa together make up a world-class hydrocarbon basin, arguably the premiere basin in the entire Gulf of Mexico (Gulf). Mars has provided the largest cumulative production of all deepwater fields there. Its companion, Ursa, is in second place. Along with Auger, Ram-Powell, and Cognac, Shell-operated fields have accounted for a major part of the Gulf's cumulative deepwater production so far (see figures 2.22, 2.23, and 2.24). Production from the Mars-Ursa basin was so prolific by the late 1990s that Mars oil emerged as a "benchmark" for pricing medium-grade, sour crude in cash or spot market trading in the Gulf Coast region. In 2003, the New York Mercantile Exchange (NYMEX) began offering a "Mars Blend" futures contract. The next year, 2004, the Energy Information Administration (EIA) of the US Department of Energy (DOE) started collecting crude oil stream price information for new categories that included a Mars Blend. In May 2009, Argus Media launched its Sour Crude Index (ASCI), a single, daily volume-weighted average price index for trading in three Gulf of Mexico component crude oil grades–Mars, Poseidon, and Southern Green Canyon (Argus 2015).

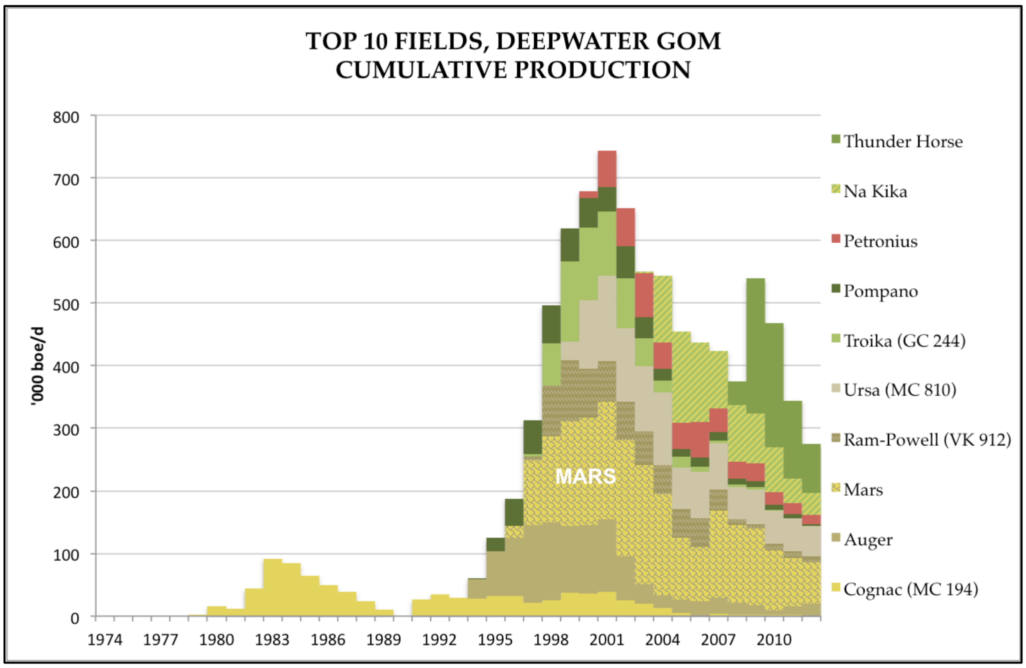

Figure 2.22. Top 10 fields, cumulative production, deepwater Gulf of Mexico.
Source: Data compiled from US Department of the Interior 2014.

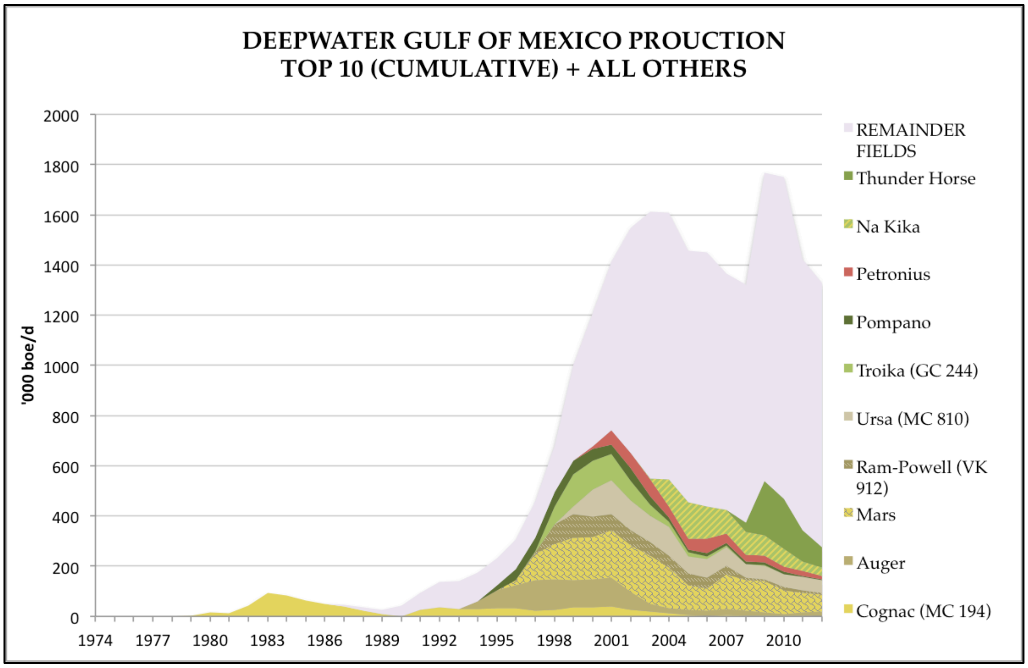

Figure 2.23. Top 10 fields cumulative production plus all others, deepwater Gulf.
Source: Data compiled from US Department of the Interior 2014.

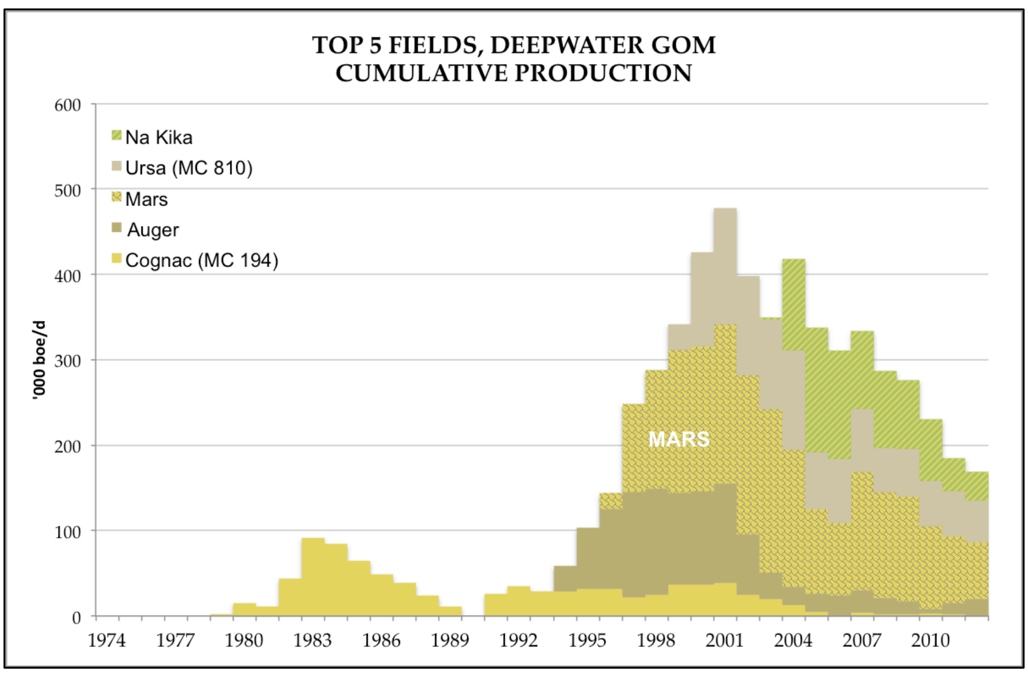

Figure 2.24. Top 5 fields, cumulative production, deepwater Gulf.
Source: Data compiled from US Department of the Interior 2014.

The significance of the ASCI became apparent in 2010 when Saudi Aramco, the Saudi Arabian state oil company, dropped West Texas Intermediate (WTI), a type of light crude traded at the Cushing oil terminal Oklahoma, and switched to ASCI for pricing its US sales. Using Mars crude as an index better reflected the quality of sour Saudi crude and aligned Saudi shipments with the geography of Saudi Aramco's US customers, the refineries located along the Gulf Coast. "Argus Mars is the pivotal Americas medium sour benchmark and is the most actively traded sour crude market in the Americas," advertises Argus Media. "Argus Mars is widely used in hedging, term contracts, mark to market and in pricing spot deals" (Argus 2015).

The value of the Mars and Ursa fields and the scale of investment put into them by Shell meant that the company had an interest in siphoning out as much oil as possible. In the early 2000s, Shell E&P began targeting sands in the Mars and Ursa fields for "enhanced recovery" through waterflooding and exploring the deeper reaches of the basin for additional hydrocarbons. These projects proved to be so successful in extending the life of the fields and creating new development opportunities in the surrounding area that in 2013 Shell installed a second TLP, "Mars B" or *Olympus*, just one mile away in the same block, to breathe new life into these projects for at least another 25 years, and maybe as much as another half century.

The waterflood at Mars was Shell's first effort to pull more oil from the basin. Waterflooding is a technique for recovering additional oil that involves injecting water into a field to increase reservoir energy and output. Its earliest use in the industry dates back to the 1930s. In deepwater, however, operators had little experience with waterflood projects. This was due to the fact that deepwater fields had high rates of well production and excellent primary recovery, drilling deepwater wells was extremely expensive, and deepwater facilities had limited space for waterflood equipment. But as Adam Wilson writes in the Journal of Petroleum Technology, "waterflooding [in deepwater] can supply additional reservoir energy for producing substantial quantities of oil trapped by limited displacement drive and poor sweep efficiency" (Wilson 2014: 113). "Displacement drive" refers to the mechanism for pushing oil through the reservoir, while "sweep efficiency" is a measure of how evenly oil moves through it.

After observing the behavior of the Mars reservoir during its first five years of operation, Shell engineers decided that it was a good candidate for secondary recovery. In June 2000, production from the Mars field peaked at 208,000 bbl/d of oil and 217 MMscf/d of gas and then began declining. The predicted primary production from the reservoir had little support from a natural aquifer, and its sands were overpressured and highly compacting. On the positive side, the reservoir had good vertical and horizontal permeability, significant structural relief, and relatively continuous well-connected horizons across the formation (Wilson 2014).

In the spring of 2004, Shell initiated waterflooding at Mars. The project had three main objectives: to decrease the rate of pressure decline, reduce the risks of compaction for well completions in compressible areas, and prevent the three main sands (Green, Yellow, and Pink) from producing below their bubble point, which is the pressure and temperature at which natural gas bubbles out of solution in oil. The project was expected to increase the lifetime recovery in the field by more than 100 million barrels of oil (Tallin et al 2005). Three wells–A12, A16, and A18–were designated as injectors. A 6,850-psi seven-stage-centrifugal-pump discharge system was prepared to deliver up to a combined 82,000 barrels of filtered water per day (Wilson 2014). Reservoir engineers from Shell and log analysts from Halliburton monitored the waterflood with a surveillance program using "pulsed neutron capture" (PNC) well logging tools, which provide carbon-oxygen ratios and other data that measure hydrocarbon saturation, water breakthrough, and fluid contact changes over time (Weiland et al 2008).

During its initial phase, the Mars waterflood encountered a series of setbacks and shutdowns. Shortly after startup of the program, in May 2004, engineers were forced to temporarily shut-in production from the Mars TLP after detecting a small leak from a flex joint on the oil export riser and deterioration on a gas riser. The nine-month suspension of production from September 2005 to May 2006 following Hurricane Katrina also interrupted the waterflood project. Then, an injector-tubing leak took one of the injection wells offline. The project resumed and water was injected continuously from July 2006 to March 2010. As of June 2009, Shell had injected 46 million barrels of water. The project appeared to stabilize the production decline and boost the estimated ultimate recovery (Wilson 2014).

Meanwhile, Shell also introduced a waterflood program at Ursa and the nearby Princess field, which began producing in December 2003 through a subsea tieback to the Ursa TLP. The fields had a common main reservoir–the Yellow sand, also the main reservoir at Mars–and were in pressure communication. Shortly after Princess came online, Shell engineers initiated field studies to evaluate how recovery of the two fields could be improved (Al-Kindi et al 2008: 404). The main challenges were squeezing the waterflood equipment onto an already cramped platform and minimizing the number of expensive new wells that had to be drilled. In order to remove sulfates that might cause reservoir souring (increased presence of dangerous hydrogen sulfide), the injection water had to be treated at the platform. Installing the treatment facilities was one of the largest construction projects ever completed on an existing platform in the Gulf. It involved "very high activity levels and simultaneous construction, commissioning, maintenance and well servicing activities, while performing production operations on a large facility located 100 miles offshore" (Drilling Contractor 2008). The equipment consisted of a 427-ton filtration unit, a 635-ton sulfate reduction module, and a 675-ton water injection unit, all constructed at J. Ray McDermott's year at Amelia, Louisiana. The system employed two high-pressure pumps powered by a 15,000-horsepower turbine to inject water at 7,500 psi. The pumps sent 30,000 bbl/day of filtered and treated water through two separate flowlines to three subsea sites. Two were existing wells northwest and southeast of the TLP, and one was a new well site northeast of the platform. The Ursa-Princess waterflood, which came on stream in 2008, was expected to extend the lives of the two fields by 10 years (Drilling Contractor 2008; Shell 2012). By the time the Ursa-Princess waterflood was underway, Shell E&P was advancing on other prospects in the basin. Around the turn-of-the-century, using the latest seismic imaging and processing technologies, company geophysicists and geologists identified a new prospect immediately to the west of Mars in deeper layers beneath the salt. Seismic technologies had been evolving since the mid-1990s, when a new computing algorithm called "pre-stack depth migration" had given geophysicists a tool to reposition return seismic signals to plot the coordinates of subsalt reflections in a more accurate way. The Gulf subsalt play began in 1993 with Phillips Petroleum's discovery of the Mahogany field, followed closely by Shell Oil's discovery in 1994, in partnership with Amerada Hess and Pennzoil, of the Enchilada field. The subsalt play progressed slowly after this, as computers were still not powerful enough to run the algorithms necessary to create subsalt seismic images with high-enough resolution to be reliable. Drilling a well through salt also posed difficult technical challenges. By the late 1990s, however, capabilities were dramatically improving. Computing technology and processing algorithms could handle increasing amounts of seismic data, and a new method of economically gathering large volumes of data, such as "wide-azimuth" surveying, allowed seismic crews to acquire data in multiple directions from several seismic vessels in a single survey. During 1998–2002, BP made a number of major subsalt discoveries in deepwater–most notably, Mad Dog, Atlantis, and Crazy Horse (renamed Thunder Horse)–that led other companies, such as Shell, to look for similar opportunities using advanced seismic technologies (National Commission on the BP Oil Spill and Offshore Drilling 2011).

Shell exploration leaders logically explored for subsalt prospects in the areas they knew the best, one of which was in the Mars basin beneath the Antares salt structure. "We stepped back and looked back at the opportunities remaining at the Mars field purely as a deepwater giant," said Shell Business Opportunity Manager, Derek Newberry. "It has a hydrocarbon column that spans from 10,000 feet below sea-level to 22,000 feet below sea level" (Musarra 2014). In September 2002, Transocean's *Deepwater Nautilus* semi-submersible made a significant discovery beneath the Antares salt on a prospect called Deimos (MC Blocks 762 and 806), named after the smaller and outer of Mars's two moons and the son of Mars in Roman mythology. The drill encountered nearly 248 vertical net feet of oil in multiple sands of the exploratory section and 290 feet of oil in the known producing field pays" (Offshore Technology.com 2015). Deimos turned out to be a deeper extension of the Mars field underlaid by older subsalt reservoirs (Sloan et. al 2011). Further appraisal drilling confirmed Deimos as a significant discovery and led to a 2005 decision to develop the field in two phases. Phase I consisted of three subsea wells tied back to the Mars TLP through a single flowline. With a peak capacity of 30,000 bbls/day, Deimos Phase I delivered first production in 2007 (Offshore Technology.com 2015).

Phase II depended on additional information gathering and appraisal of Phase I. Subsequent development could either go the route of additional subsea tiebacks, or, if newly discovered volumes justified it, another stand-alone facility, as planned for by the original Mars development strategy in the early 1990s. The project team recognized that the discovery of deeper reservoirs, the old Mars field could be larger than originally anticipated. Combined with a collection of satellite fields, a second platform might be required to develop this new "opportunity." Although there were still many uncertainties about the basin's ultimate potential, Shell began engineering work on a second TLP, provisionally named "Mars B." In 2005, Shell managers called the larger two-phase strategy the "Greater Ursa-Mars Basin Opportunity project," or GUMBO, after the dish that is a staple of South Louisiana cuisine (Hollowell 2013).

Shell explorationists went into Phase II of GUMBO quite confident that they understood the subsalt geology at Deimos. In fact, they were overconfident. In 2004, a highly anticipated follow-up wildcat well (MC 762 #3), named Boreas (Greek god of the North Wind), drilled updip from the Deimos reservoir, proved disappointing. "It did not strike the mother lode we had expected," Matthias Bichsel, Projects & Technology Director at Royal Dutch Shell, recalled understatedly in a 2013 speech. "There was oil on the drill cuttings; so we knew we were close. But we obviously had misinterpreted the squiggles on the seismic images–even though we were using state-of-the-art processing" (Bichsel 2013).

The Antares salt fooled the appraisal team. "Salt plays havoc with seismic sound waves, which travel through salt at a much higher velocity than the surrounding sediments and also get refracted," explains a staff report by the US National Oil Spill Commission, "similar to how the image of a pencil gets bent when stuck in a glass of water" (National Commission on the BP Oil Spill and Offshore Drilling 2011). Moreover, data from the Boreas well indicated the presence of a major fault that offset the Boreas sub-basin from the Mars basin. This had not been visible on the seismic imaging that guided the drilling. The Boreas prospect moved down Shell's priority list for further exploration (Sloan et al 2011).

The Boreas disappointment forced the appraisal geologists and geophysicists to refocus on improving their understanding of the geology surrounding the Deimos field. In late 2007, they launched a new seismic survey that placed receivers on the ocean floor, only the second ocean-bottom survey ever in deepwater. Called an Ocean Bottom Seismic-Wide Azimuth (OBS-WAZ) node survey, it gathered a tremendous amount of subsurface information. The survey consisted of a 400 x 400 meter grid of 807 seafloor receiver nodes, covering approximately 125 square kilometers, including a portion of the Boreas sub-basin. The sound-source or "shot grid" was 50 x 50 meters and extended up to eight kilometers outside the receiver area for a total coverage of 511 square kilometers (Sloan et al 2011; Burch et al 2010).

The Deimos appraisal team interpreted the seismic data using an "anisotropic corrected velocity model." Sedimentary rock formations are composed of different materials, deposited under different conditions. Each layer has different properties. A velocity model maps these layers by building in predictions of the speed with which different kinds of seismic waves travel through them. There are two types of seismic waves. First is the "P-wave," the primary wave, which moves longitudinally. In other words, the vibrations move in the same direction as the sound travels. P-waves move through both solid rock and fluid. They have the highest velocity and thus are the first waves to be recorded. The "S-wave," called the secondary, shear or transverse wave, vibrates perpendicularly to the direction of travel. S-waves are slower and can only move through solid rock. A complicating factor in the geophysics of seismic waves is that some rocks, like sedimentary layers composed of different materials and containing oil and gas, are "anisotropic," meaning that they have different properties depending on the direction of measurement. In an anisotropic medium, the S-wave splits into horizontal and vertical components, with one wave traveling faster than the other. Velocity models that do not account for anisotropy are prone to making microseismic location errors. With better processing algorithms that took advantage of the ever-increasing number-crunching power of computers, Shell geophysicists were able to develop a velocity model that corrected for anisotropic effects. They processed and migrated the OBS-WAZ data with this model and delivered it to geological interpreters in early 2008. "The improvement over the conventional 3D NAZ [narrow azimuth] seismic resulted in a step change in our geologic and stratigraphic understanding and exploration strategy within the sub-salt portion of the western Mars basin," Robert Sloan and Kevin King noted in a 2014 Offshore Technology Conference presentation in Houston (Sloan and King 2014, 4).

These technologies enabled the geophysicists to bring a murky subsalt picture into sharper resolution. "It allowed us to 'illuminate' the sub-salt structure with seismic waves from all different directions and angles," said Mattias Bichsel (Bichsel 2013). This illumination showed that the 2004 Boreas well had missed a significant hydrocarbon deposit, designated West Boreas, only 200 feet away across a fault that had not been detected on the original seismic images. Amplitude anomalies on the new seismic images pointed to West Boreas and another prospect, South Deimos, as direct hydrocarbon indicators, or bright spots. "West Boreas started shining through right off the bat," marveled subsurface coordinator, Robert Sloan, at the 2014 Offshore Technology Conference. "It was amazing how we had such an image below salt. It was very crisp data. When we first wanted to go out and drill another well in the Boreas, people kind of thought we were crazy. But this data was good enough to show its potential" (Eaton 2011).

Drilling confirmed the new model and data. In March 2009, Transocean's *Cajun Express* semi-submersible, working in 3,094 feet of water, drilled into more than 200 net feet of pay sand at the West Boreas prospect, a significant discovery, at least 100 million barrels. Nine months later, in January 2010, *Cajun Express* made another discovery at South Deimos, another 50 million barrels, located due south of West Boreas and directly southwest of Deimos (see Figure 2.25). Biostratigraphic data indicated that they were Upper Miocene deposits of the same age as the adjacent Deimos reservoir. Mars had always been special, but now it rose to become a one-of-a-kind, world-class basin, stacked with more than 50 reservoir targets that extended deeper and to the west under the Antares salt structure. A one-of-a-kind basin demanded a unique approach. In September 2010, following a "holistic" evaluation of the new discoveries, Shell announced it would install a second tension-leg platform over the Mars field, bringing Mars B off the drawing board (Sloan and King 2014; Van den Haak et al 2014).

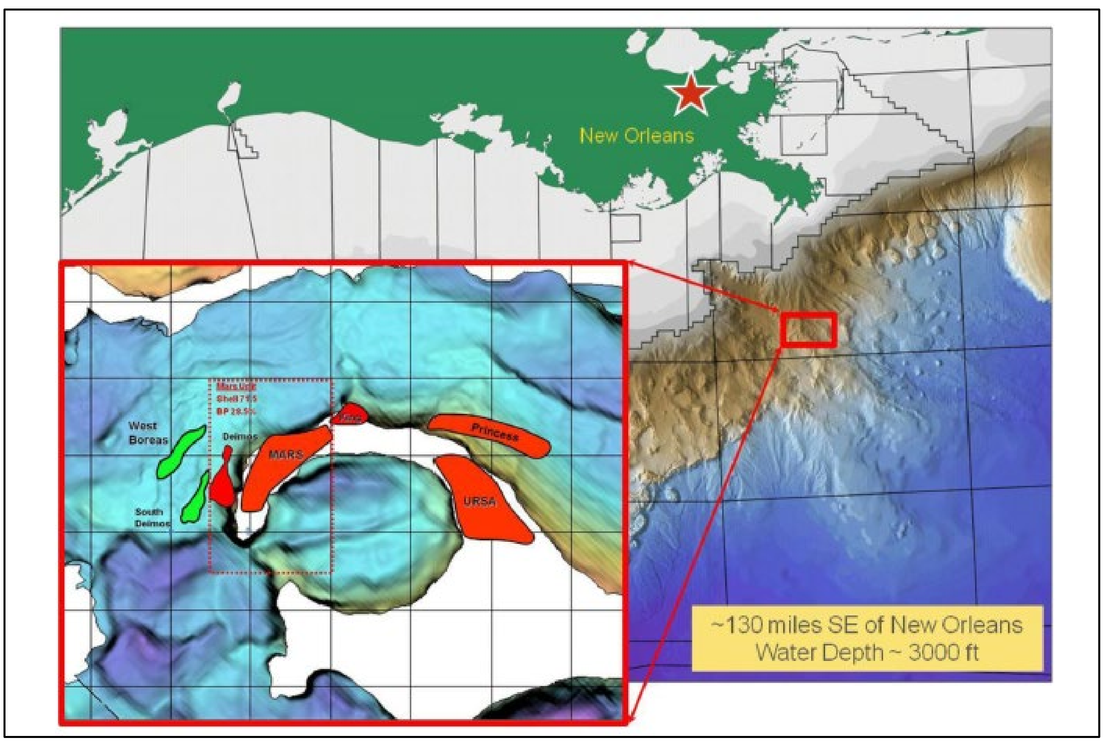

Figure 2.25. Location map of Mars Basin in Mississippi Canyon of the Gulf.

Inset shows oilfields discovered prior to 2014 in red and green and salt structures in shades of blue. Source: Sloan and King 2014. Reproduced with permission from Shell Exploration & Production Co.

Between the South Deimos discovery in January and the final investment decision in September, however, Shell's deepwater organization had to go through some soul-searching and adapt to changed circumstances. On April 20, a well drilled by Transocean's *Deepwater Horizon* semi-submersible, drilling for BP in 5,000 feet of water at the Macondo prospect in the Mississippi Canyon, blew out, killing eleven men, injuring many others, and causing environmental damage that is still being assessed. The well's underwater connection lines broke as the vessel sank in a mass of flames and smoke, leaving an open well that released an estimated 5 million barrels of crude oil and natural gas into the Gulf. On May 27, US Secretary of the Interior Ken Salazar imposed a six-month moratorium on deepwater drilling while emergency response efforts tried to control the wild well, and also to give government authorities time for a review of safety systems and regulations. A live, 24-hour underwater camera feed of the gushing well mermerized audiences around the world, turning the *Deepwater Horizon* disaster into the most viewed news story of the year. The uncontrolled well was finally capped on July 15, 87 days after the blowout. On September 19, two relief wells finished killing the well. While environmentalists called for greater restrictions on offshore leasing and drilling, offshore operators fumed about the drilling moratorium and the punishing economic impact it was having along the Gulf Coast region. Many commentators wondered if the Gulf would regain its stature in the world of oil. Others questioned the future viability of deepwater drilling in general.

Shell remained committed to the deepwater Gulf. Its management and technical staff believed that safety practices and regulations could be reformed, and that spill response procedures and technologies could be improved (a separate and ongoing story that is beyond the scope of this essay). As the undisputed technological leader in the Gulf, Shell's drilling methods drew, from industry observers, favorable comparisons to the scorned and beleaguered BP, although perhaps uncomfortably so, because BP was a partner with Shell at Mars, Ursa, and other deepwater projects. On September 28, nine days after the Macondo well had been killed, and undeterred by post-Macondo uncertainty and opprobrium, Shell Offshore became the first company to demonstrate a renewed commitment to the Gulf by sanctioning the second Mars TLP. The timing of the decision also came at an opportune time for Shell, given the spare capacity in Gulf shipyards and fabrication centers, which allowed the company to bargain for a better price for various aspects of the project (Hollowell 2013; Holeywell 2014).

The new TLP was officially named Olympus, after the gigantic shield volcano on the planet Mars, at 24,000 kilometers, three times the size of Mount Everest. Olympus was also the mountain home to the twelve Olympian gods of the ancient Greek world. The name befits the platform's size and scope. The hull and topside's structure stands more than 400 feet tall, 1.5 times the height of the Mercedes-Benz Superdome in New Orleans, and weighs 119,000 tons, more than double the weight of the original Mars TLP and 20 percent heavier than Ursa, the Gulf's largest TLP (see Figure 2.26). It accommodates 192 people, more than any other TLP in the Gulf. It is the first development to incorporate post-Hurricane Katrina environmental design loads and new post-Macondo regulatory requirements driven by Notice-to-Lessee (NTL)-6, addressing blowout prevention and response, and NTL-10, mandating spill response and well containment plans and resources. It is also the first Shell facility with fiber-optic connections to shore, which further enhance process safety. These allow for backup systems onshore and the remote controlling of tasks from Shell Offshore headquarters at One Shell Square in New Orleans. Such cables can transmit significantly more data than existing infrastructure, putting onshore technicians and offshore supervisors in closer communication and collaboration. Built to operate for 50 years, by far the longest of any facility in the Gulf, Olympus has 24 well slots and a peak production capacity of 100,000 bbl/d of oil and 100 mmcf/d of gas (Hollowell 2013).

Figure 2.26. Shell Olympus TLP under construction in Kiewit Offshore Services Ingleside, Texas yard, June 2013.

Source: Photo courtesy of Michael Zamora, Corpus Christi Caller Times.

The drilling and well challenges dictated a departure from traditional rig and facilities design. The estimated $2 billion platform was built to such massive scale in order to support a direct vertical access (DVA) drilling rig with a two-million-ton hook load, the largest in the world to sit permanently on a production platform (D'Souza and Aggarwal 2013, 13). This permits the drilling of deeper, higher-pressure reservoirs that are not possible to reach from Mars "A" and maximizes the recoverable volume from the many different zones within the Mars basin. The variety of pressure regimes, reservoir sands, production history, and well trajectories–from near vertical to high angle extended reach through sediment and salt–necessitated a novel "Type Well" design approach, with four generic well designs to match the different characteristics of Mars-type and Deimos-type pay intervals (Hollowell 2013; Grant et al 2014). "These highly complex wells," according to a Shell OTC paper, "required the matching of the DVA rig capabilities with the TLP well design rather than designing a well to operate within a predefined rig specification" (Van den Haak et al 2014). In addition to the direct vertical wells tapping into the Mars and Deimos reservoirs, Olympus also contained facilities to host six subsea wells from West Boreas and South Deimos that were tied back through a single seabed manifold and two production flowlines (Musarra 2014; Sloan and King 2014).

Drawing on contractors from around the world, Olympus provided "an emphatic vote of confidence in capital-heavy deepwater projects," reported World Expro (Turner 2014). The domestic impact on a US economy struggling to recover from deep recession could also not be discounted. During 2010–2014, more than 25,000 people from 37 US states worked on Mars B project. The Olympus hull, fabricated in South Korea by Samsung Heavy Industries and finished in Italy, left the shipyard in November 2012 and was towed across the ocean to Ingleside, Texas. There it was integrated with topsides built by the Kiewit Offshore Services company. In July 2013, the Olympus TLP arrived from a 425-mile journey on location, just one mile southwest of the Mars TLP. After installation, more than six months ahead of schedule, export pipelines were laid to bring oil and gas to a new shallow water platform at West Delta 143, which directed production to the onshore storage and pipeline network. On February 4, 2014, first production arrived at the platform. As more wells from the deeper and higher-pressure reservoirs were completed and brought in, the original Mars TLP began to shift focus to smaller reservoirs and future waterflood projects that would drive production to both TLPs. The combined Mars and Olympus facilities have the capacity to process over 350,000 barrels of oil equivalent per day. By June 2014, the Mars field had produced an estimated 770 million barrels of oil equivalent. Before the end of Olympus's life, the greater Mars basin is expected to produce another 1 billion barrels (Hollowell 2014; Holeywell 2014).

8. Conclusion

The Mars B *Olympus* project represents yet another major step forward in the decades-long quest for offshore oil. Although oriented 50 years into the future, the reincarnation of Mars is less a sharp departure from history than a continuation of a trajectory that began almost 50 years ago when Shell Oil started looking past the edge of the continental shelf. Technological change is usually not the product of individual genius and sudden inspiration. Rather, it results from collective endeavor that advances incrementally. Change often goes unnoticed until the parts come together in some kind of industrial art form like Olympus Mars B. "The beauty of the Mars B platform design," as John Hollowell, Executive Vice President of Deep Water for Shell Americas, explains, "is not its cutting-edge technology but its replication of design elements, equipment, and practices Shell has developed, fine-tuned, and standardized in implementing five other TLP projects in the deepwater Gulf" (Hollowell 2014). It is an expression of a long record of trial-and-error experimentation, learning-by-doing, and the nurturing of internal expertise in design, engineering, construction, and commissioning.

Of course, innovation at the Mars basin was not wholly contained within the Shell organization. A generation of scholarship on strategic management and business organization has shown that "network arrangements," characterized by "reciprocal patterns of communication and exchange," in contrast to market or hierarchical governance structures, have often been the locus of innovation, especially in high-technology industries (Powell 1990: 295; Thorelli 1986). This applies equally to the offshore industry and to information-age industries with which network theory is typically associated (Tuomi 2006). Since its origins in the 1940s and 1950s, offshore oil has progressed into deeper water as a collection or "fraternity" of companies specializing in various realms of activity, including geophysical exploration, drilling, production services, engineering and construction, and transportation and supply (Pratt, Priest, and Castaneda 1997). During the 1980s and 1990s, as the major oil operators scaled back their E&P research functions and in-house expertise, offshore contractors, service companies and research universities picked up much of the slack. Alliances, such as those promoted by Dan Godfrey and Shell in the fabrication of the Mars tension-leg platform (TLP), emerged as integral to networked forms of innovation and problem-solving. In the deepwater Gulf of Mexico (Gulf) , Shell maintained long and fruitful relationships with contractors, such as Sonat and later Transocean in drilling, Halliburton for well services, FMC for subsea engineering, Belleli for TLP hull construction, J. Ray McDermott and Kiewit Offshore Service for TLP topsides fabrication, Heerema for facilities installation, and Edison Chouest for transportation and supply.

As Hewett concludes in the first volume of this study, technological choice in the deepwater Gulf has been contingent and socially constructed. The development of the Mars TLPs resulted not from the linear march of objective technical superiority. Rather, it was predicated on "the geology of the Gulf, the actions of knowledge-constrained firms operating in deepwater, and especially the timing of the interaction between the two" (Hewett 2017). Most news stories about the installation of the latest offshore platform often celebrate or even fetishize the structure itself, ignoring the years of work needed to solve the geological puzzles that kept the oil hidden beneath thousands of feet of water and rock for thousands of years. Technology is a process as much as an artifact. Olympus symbolizes the evolving geological understanding of the Mars-Ursa basin that company geoscientists have been studying for decades. The placement and design of the TLP and its wells reflect deep, hard-earned knowledge about the geology, depositional history, and types of hydrocarbons generated in the Mississippi Canyon. Lessons learned about the basin's reservoir configurations, pore pressures and fracture gradients, and shallow water flows inform how technology, investment, and risk are managed in this part of the Gulf.

Why expend so much effort, money, and brainpower over such a long period of time in the quest for deepwater oil? Certainly society's demand for fossil fuel energy has been nearly unquenchable, and there was the chance for money, big money, to be made. Virtually nothing is more profitable than a producing oilfield. At production rates of 10,000 bbl/day or more, deepwater turbidites in the Gulf have become a tremendous revenue stream for oil companies. But this was far from guaranteed or generally accepted when petroleum geologists first trained their sights on deepwater. An important part of the explanation for the continuing commitment of companies like Shell to the Gulf rests with the desire to explore the unknown. The history of oil still comes down to the basic act of geologists chasing geology.

In this way, the spirit and technological challenges of Shell's pursuit of oil from Mars are analogous to the space exploration of the planet Mars. In science fiction writer Kim Stanley Robinson's imagined account of the human colonization of Mars, the thought of turning "a great sign, a great symbol, a great power" into a "place" shaped by humans is irresistible. Likewise, the Mars basin in the Mississippi Canyon, 130 miles south of the city of New Orleans in 3,000 feet of water, once a symbol and object of scientific curiosity, is now a place inhabited by people and a vital source of energy for the U.S.

More than an analogy, there seems to be an almost cosmic connection between the Mars basin and the planet Mars. The National Aeronautics and Space Administration (NASA) launched the first Mars rover in 1996, the same year that the first Mars TLP started producing. Now, as the second Mars platform ramps up production, discussions about manned missions to Mars are once again the news. In early 2015, a Washington conference of scientists, industry officials, and NASA staff presented a proposal for a 30-month orbital mission to Mars in 2033, to be followed by a landing in 2039. A private organization, The Netherlands-based Mars One, has even offered a one-way ticket to Mars funded by a reality-based TV show. It is possible, maybe even likely, that humans will visit the planet Mars before the Mars basin gives out producing oil. "It's hard to say when, but we will go with humans to Mars," assures Alain Bernstein, former director of planetary exploration for the Canadian Space Agency (Kizzia 2015, 49).

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