OCS Study
MMS 2004-027

OCS-Related Infrastructure in the Gulf of Mexico Fact Book

MMS U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

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ABOUT THE COVER

The cover contains the following photographs clockwise from the upper left: Port of Houston (source - www.portofhouston.com); oil platform (source - www.portfourchonla.com); Port Fourchon (source - www.portfourchonla.com); and, Port Morgan City (source - www.portofmc.com).

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LIST OF ACRONYMS

AAPA – American Association of Port Authorities
AHT – Anchor Handling Tug
AHTS – Anchor Handling Tug/Supply Vessel
ANS – Alaskan North Slope
ATSDR – Agency for Toxic Substances and Disease Registry

bbl – Barrel
bcfd – Billion Cubic Feet per Day
BOE – Barrels of Oil Equivalent

CAA – Clean Air Act
CAAA – Clean Air Act Amendments
CDS – Construction Differential Subsidies
CERCLA – Comprehensive Environmental Response, Compensation, and Liability Act
CFC – Chlorofluorocarbon
CO – Carbon Monoxide
CWA – Clean Water Act

DOE – United States Department of Energy
dth – Decatherm (equivalent to 1 MMBtu)
DP – Dynamic Positioning
DSV – Diving Support Vessel
DWRRA – Deepwater Royalty Relief Act
DWT – Dry Weight Ton

E & P – Exploration and Production
EIA – Environmental Information Administration
EIS – Environmental Impact Statement
EPA – United States Environmental Protection Agency
EPCRA – Emergency Planning and Community Right-to-Know Act

FAA – Federal Aviation Administration
FERC – Federal Energy Regulatory Commission
FPSO – Floating Production, Storage, and Offloading
FSU – Floating Storage Unit

GDP – Gross Domestic Product
GIS – Geographic Information System
GOM – Gulf of Mexico

HAP – Hazardous Air Pollutant
HON – Hazardous Organic National Emissions Standards for Hazardous Air Pollutants

JU – Jack-Up Drilling Units

LDC – Local Distribution Company
LEPC – Local Emergency Planning Commission

LIST OF ACRONYMS
(continued)

LMOGA – Louisiana Mid-Continent Oil and Gas Association
LNG – Liquified Natural Gas
LPG – Liquified Petroleum Gas

MACT – Maximum Achievable Control Technology
MARAD – Maritime Administration
Mcfd – Million Cubic Feet per Day
MoDU – Mobile Drilling Units
MMS – Minerals Management Service
MRO – Material Requisition Order
MSB – Major Shipbuilding Base
MSC – Military Sealift Command
MSDS – Material Safety Data Sheet
MSV – Multi-function Service Vessel
MSW – Municipal Solid Waste

NDRF – National Defense Reserve Fleet
NESHAP – National Emission Standards for Hazardous Air Pollutants
NGL – Natural Gas Liquids
NHS – National Highway System
NOAA – National Oceanographic and Atmospheric Administration
NORM – Naturally Occurring Radioactive Materials
NOW – Nonhazardous Oilfield Waste
NPDES – National Pollution Discharge Elimination System
NSPS – New Source Performance Standards
NTSB – National Transportation Safety Board

OCS – Outer Continental Shelf
OEM – Original Equipment Manufacturer
OPA – Oil Pollution Act of 1990
OPEC – Organization of the Petroleum Exporting Countries
OSHA – Occupational Safety and Health Administration
OSV – Offshore Support Vehicle

PAD – Petroleum Administration for Defense
PCB – Polychlorinated Biphenyl
PIG – Pipeline Inspection Gauge
PM10 – Particulate Matter less than 10 microns in diameter
PMN – Pre-Manufacture Notice
PRP – Potentially Responsible Parties
PSV – Platform Supply Vessel
PTSA – Port and Tanker Safety Act of 1978
PWSA – Ports and Waterways Safety Act

RCRA – Resource Conservation and Recovery Act
RVP – Reid Vapor Pressure

LIST OF ACRONYMS
(continued)

SARA – Superfund Amendments and Reauthorization Act of 1986
SCADA – Supervising Control and Data Acquisition
SDWA – Safe Drinking Water Act
SERC – State Emergency Response Commission
SIC – Standard Industry Code

TAC – Texas Administrative Code
TAP – Toxic Air Pollutants
tcf – Trillion Cubic Feet
TEA-21 – Transportation Equity Act for the 21st Century
TEU – Twenty-Foot Equivalent units
TLP – Tension Leg Platform
TOC – Total Organic Compounds
TPH – Total Petroleum Hydrocarbons
TRI – Toxic Release Inventory
TSCA – Toxic Substances Control Act
TSDF – Treatment, Storage, and Disposal Facilities

USACE – United States Army Corps of Engineers
USDW – Underground Source of Drinking Water

VOC – Volatile Organic Carbon
VTSS – Vessel Traffic Service/Separation Schemes

1.0 INTRODUCTION

The history of the offshore oil and gas business is commonly dated to 1947 when Kerr McGee, an Oklahoma independent oil and gas company, drilled the first well out of the sight of land in the Gulf of Mexico ("GOM" or "Gulf"). Since that time, the offshore GOM has been a vibrant area of oil and gas exploration, development, and production. One significant challenge in the early days of offshore oil and gas development was getting men, equipment, and supplies to these remote production facilities. One could argue that half the innovation with offshore production was associated with just supplying these facilities.

Over the years, a network of support facilities, ports, roads, pipelines, and processing facilities have arisen to support offshore production. Since this infrastructure has been developed to support offshore activities, when the offshore industry experiences a downturn, so too do the supporting infrastructure businesses.

The period from 1950 to the 1970s was the high point of interest for the GOM. During that period, the GOM became one of the most explored and developed offshore basins in the world. By the late 1980s, however, the Gulf had become an area of decreasing interest for world-wide oil and gas development. The region was considered a relatively mature basin, with limited potential for growth relative to other emerging frontier areas around the globe. At the time, the Gulf was disparagingly referred to as the "Dead Sea."

However, in the mid 1990s, activity in the Gulf experienced a dramatic shift spurred in large part by the passage of the Deepwater Royalty Relief Act ("DWRRA" or "Act"). While deepwater development has its origins as early as 1978 with Shell's Cognac Field, deepwater drilling was technologically challenging as well as financially risky. Locating prospective oil and gas fields in deep water was difficult, while producing and extracting oil from deepwater areas was, for the most part, cost ineffective. In recent years, 3-D seismic technology has provided a more detailed look at potential reserves while advances have been made in exploration techniques and platform design and construction and subsea completions.

Even more of a limitation than technological obstacles was an economic impediment in the form of royalty payments. These payments were due immediately upon extracting oil and gas from federally leased offshore sites, creating a financial barrier in reaching the vast amounts of untapped resources in the Gulf. It was not until the passage of the DWRRA in 1995 that the appropriate incentives were sent to the industry to begin to explore this new frontier in the GOM. The DWRRA granted royalty relief.

The DWRRA, passed in 1995, allows the Secretary of the Interior to grant royalty suspension volumes for fields in the Gulf of Mexico that were: (1) under lease prior to the enactment of DWRRA; (2) have never produced other than test production; (3) would not be economic without relief; and, (4) are situated in water depths greater than 200 meters and lie west of 87 degrees, 30 minutes West longitude. From 1995 through 2000, the U.S. Department of the Interior (USDOI), Minerals Management Service (MMS) has granted requests for deepwater royalty relief for five fields in the Gulf. In a May 2000 press release, MMS (2000) noted that:

> "Today [May 2000] there are approximately 7,600 active leases in the Gulf of Mexico, 48 percent of which are in deepwater. Contrast this to 5,600 active

leases in 1992, only 27 percent of which were in deep water regions. By the end of 1999, there were 30 producing fields, up 30 percent in 12 months…. Advances in deepwater drilling and production technology are as remarkable as the strides made in the space industry. Exploratory drilling and production in the western and central portions of the northern Gulf of Mexico have steadily increased. Deepwater is driving the new millennium."

The Act has also had an extraordinary effect on bidding for Outer Continental Shelf lease areas. For example, Figure 1.1 shows the annual number of active leases in the Gulf since 1994. In the early 1990s, there were considerably more active leases in shallow water (i.e., < 200 meters) than in other deepwater depth categories combined. By 1996, these trends began to change considerably. In 2001, there were more active leases (3,434) in the deepwater Gulf (i.e., > 800 meters) than in shallow waters (3,366). Figure 1.2 shows this same information on the basis of active leases, by water depth, as a percent of the total.

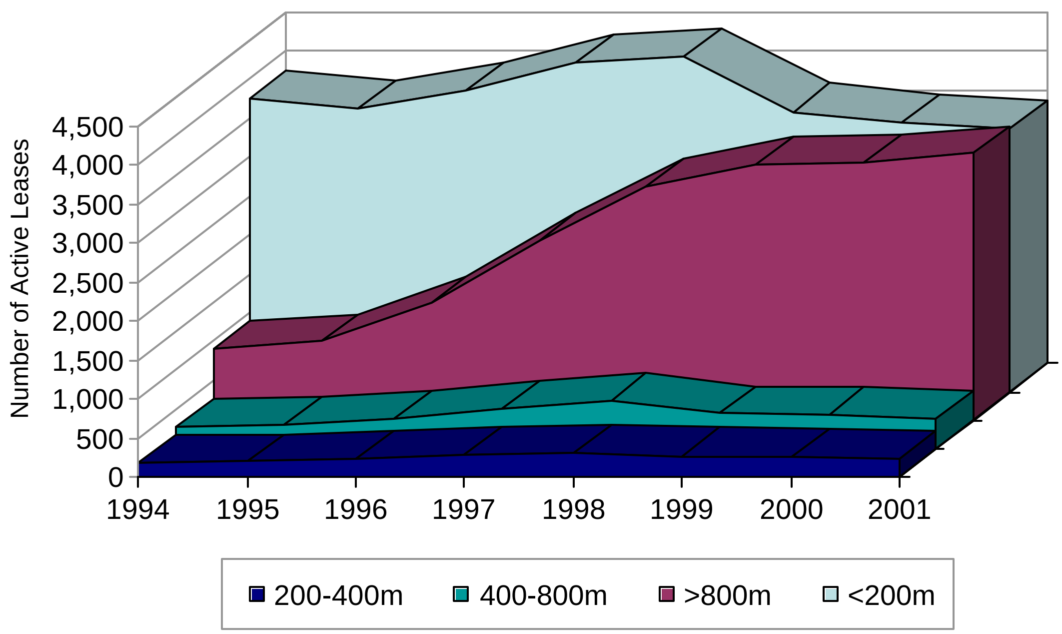

Figure 1.1. Active Leases in the Gulf of Mexico by Water Depth.

Source: USDOI, MMS (2002a)

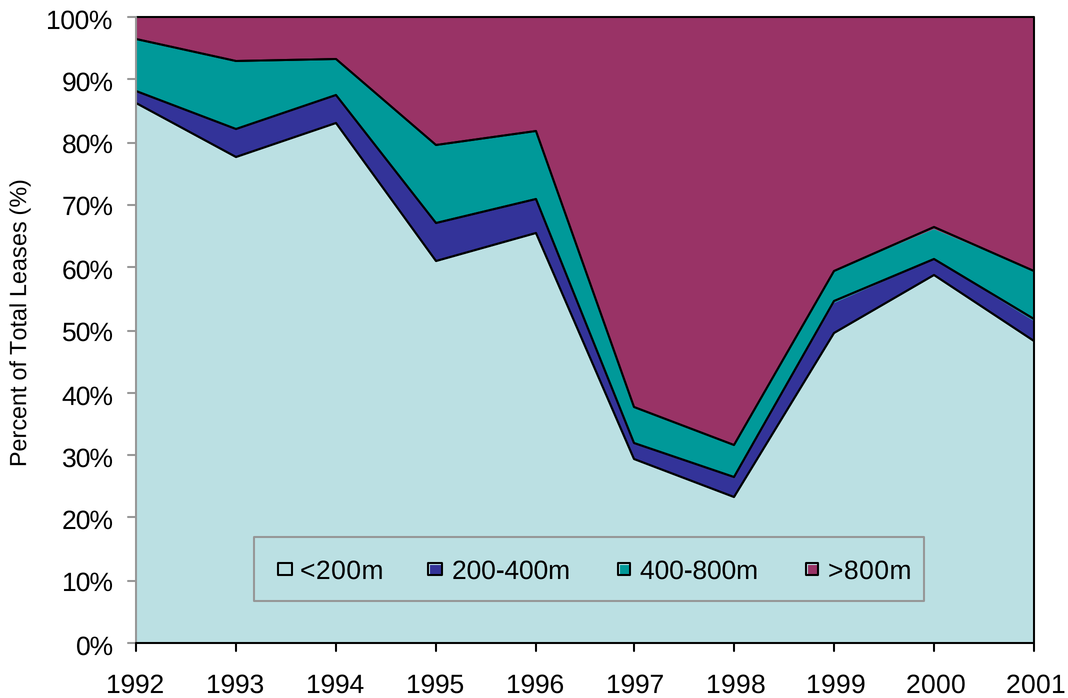

Figure 1.2. Annual Percent of Total Active Leases in the Gulf of Mexico by Water Depth.

Source: USDOI, MMS (2002a)

Exploring, developing, and producing oil and gas resources from offshore facilities have been a logistical challenge since its earliest days in 1947. Oil and gas development and production play an important role on the communities surrounding the Gulf of Mexico. These are the locations from which offshore operations are staged. Welders, caterers, engineers, roughnecks, boat crews, mechanics, helicopter crews, among many others, contribute to the logistical chain needed to maintain offshore operations. Regardless of where the exploration and production equipment, personnel and supplies are used, at some point, they come from, or through a Gulf community.

According to a recent study conducted on behalf of the Louisiana Mid-Continent Oil and Gas Association (LMOGA), there were over 62,511 employees associated with the oil and gas extraction, pipeline, and refining portions of the industry in the year 2000 (Scott 2002).[1] Wages associated with these employment opportunities amounted to nearly $3.5 billion. Energy jobs and earnings were found in at least 50 of Louisiana's 64 parishes in 2000. In addition, there were 14 parishes where more than 1,000 workers were directly employed in the oil and gas industry.

[1] Note that these employment figures, and other information associated with this report and cited elsewhere, include activities associated with both onshore and offshore activities.

Project Scope

The development of deepwater oil and gas resources only adds to the important role that the oil and gas industry plays on the coastal communities. Because of its statutory responsibilities, the MMS has an ongoing need to understand the role that this infrastructure plays on local communities. Specifically, MMS must

(1) Produce lease-sale Environmental Impact Statements (EISs) that depict existing, OCS-related infrastructure and its future growth and trends;
(2) Make a large number of permitting decisions that consider existing, future, and past infrastructure;
(3) Annually update maps that depict infrastructure supporting offshore activities; and,
(4) Guide and monitor long-range planning and development of OCS activities.

MMS executed this project in order to address each of the above issues. This Fact Book is but one component of the overall tasks of the project. The Fact Book incorporates data collected as part of the GIS database developed for the project. These data were collected in 2000 and 2001. The purpose of the Fact Book is to describe the existing infrastructure in the GOM and how it supports offshore activities. The Fact Book also examines historical data to identify past trends and to identify future trends in the construction, use and retirement of OCS-related infrastructure.

Eleven major infrastructure categories were identified for this study. These include:

- ***Platform Fabrication Yards:*** Facilities in which platforms are constructed and assembled for transportation to offshore areas. Facilities can also be used for maintenance and storage.

- ***Port Facilities:*** Major maritime staging areas for movement between onshore industries and infrastructure classifications and offshore leases.

- ***Shipyards and Shipbuilding Yards:*** Facilities in which ships, drilling platforms, and crew boats are constructed and maintained.

- ***Support and Transport Facilities:*** Facilities and services that support the offshore activities. This includes repair and maintenance yards, supply bases, crew services, and heliports.

- ***Waste Management Facilities:*** Sites that process drilling and production wastes associated with offshore oil and gas activities.

- ***Pipelines:*** Infrastructure that is used to transport oil and gas from offshore facilities to onshore processing sites, and ultimately to end users.

- ***Pipe Coating Yards:*** Sites that condition and coat pipelines used to transport oil and gas from offshore production locations.

- ***Natural Gas Processing Facilities:*** Sites which process natural gas and separate its component parts for the market.

- ***Natural Gas Storage Facilities:*** Sites that store processed natural gas for use during peak periods.

- ***Refineries:*** Industrial facilities that process crude oil into numerous end-use and intermediate use products.

- ***Petrochemical Plants:*** Industrial facilities that intensively use oil and natural gas, and their associated by-products, for fuel and feedstock purposes.

One of the challenges in preparing this Fact Book has been in the categorization and presentation of information. While the 11 categories presented above seem straightforward, they fail to note the important interaction between infrastructure types. Ports, in particular, is an infrastructure category for which separating the interactions can be almost impossible.

The interactions between infrastructure types can be highlighted more clearly if they are thought more in terms of their functions, relative to offshore activities, than their physical characteristics. There are two major functions for most onshore infrastructure types in the GOM region: (1) those areas of infrastructure that support oil and gas activities and (2) those areas that are supported by offshore oil and gas activities.

Figure 1.3 shows the relationship between supporting infrastructure areas and offshore activities. For instance, in this figure, we see a number of activities that are staged from onshore areas that are vital for offshore operations. An important point from this figure is the vital role that ports play as the point of departure to offshore regions.

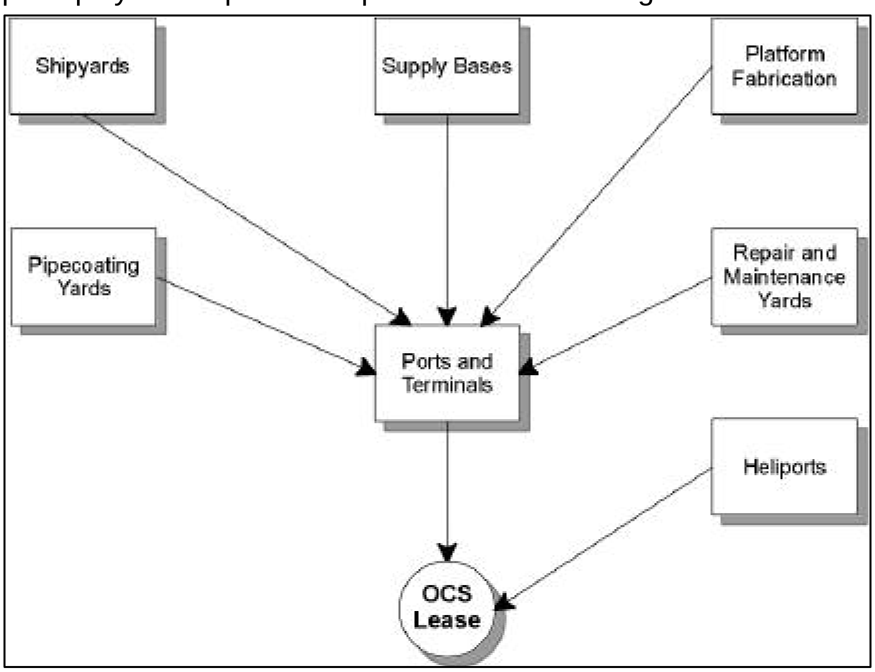

Figure 1.3. Onshore Support Infrastructure.

Supply bases, as well as repair and maintenance yards, usually housed at or very near port facilities, are major staging points for moving the significant amounts of equipment and materials needed to run an offshore oil and gas operation. Shipyards, on the other hand, are important pieces of support infrastructure since many drillships, drilling platforms, and crew boats are constructed and maintained at these facilities.

There are other significant pieces of onshore infrastructure that are highly dependent upon offshore oil and gas activities as shown in Figure 1.4. These industries facilitate the processing and transportation of oil and gas resources to the market. For instance, waste management facilities process the waste associated with the production process in offshore areas. Refineries, on the other hand, take crude oil, transported to their facilities via pipeline, and process it into various petroleum products. Natural gas is typically stored in facilities along the Gulf during off-peak periods for use during peak-periods.

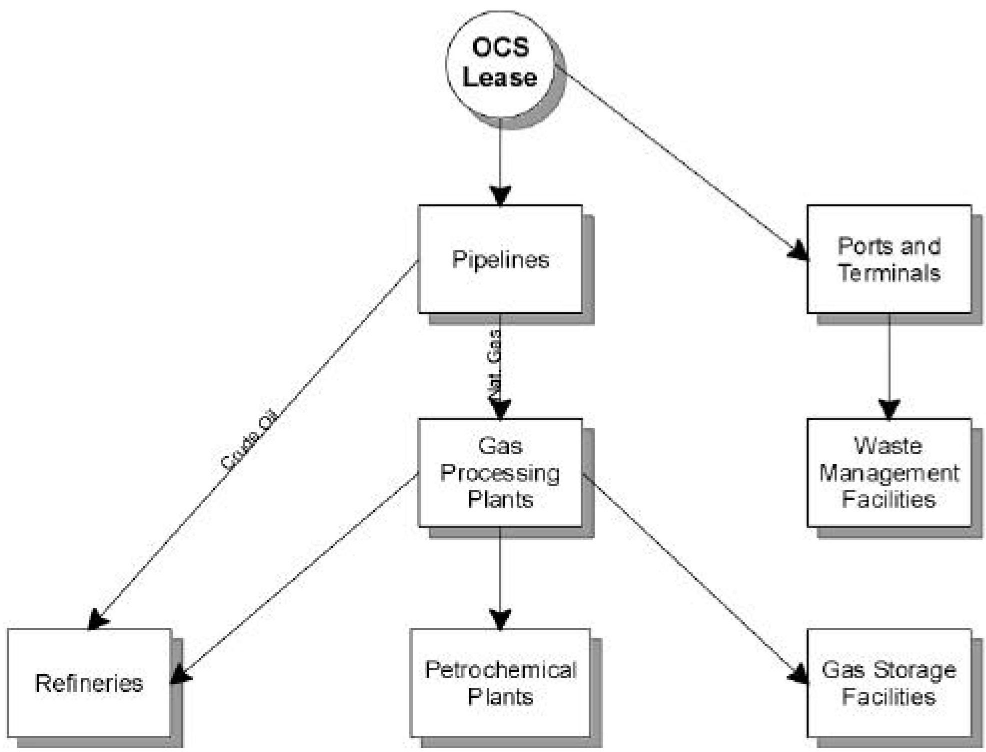

Figure 1.4. Onshore Infrastructure Supported by OCS Activities.

The following chapters of this Fact Book discuss each of these critical infrastructure areas and their relationship with offshore oil and gas activities. Each chapter outlines:

- ***Description and Typical Facilities:*** This section examines the infrastructure in question, and provides a description of its unique features. Typical facilities, or common characteristics, are also discussed.

- ***Industry Characteristics:*** This section discusses the industry characteristics associated with the infrastructure under examination.

- ***Regulations:*** This section discusses the salient regulations associated with the infrastructure.

- ***Industry Trends and Outlook:*** This section examines the current trends and future outlook of infrastructure development in the Gulf.

Also provided, in Appendix I, is a general description of the database and Geographic Information System (GIS) under this contract as well as a description of queries that can be made of the database elements.

2.0 PLATFORM FABRICATION YARDS

2.1 Introduction

During the 1920's and 1930's, drillers attempted different techniques in their efforts to extract oil from Louisiana's swampy terrain. By 1930, a successful solution was developed, and floating vessels containing drilling equipment were introduced. However, the limited technology only allowed for use in calm, shallow water without current, waves, tides, and wind. Although it had limitations, this seemingly simple concept became the starting point for one of the most important developments in offshore drilling - the mobile drilling rig.

G.E. McBride, a Texas Company (now Texaco) employee was quick to further this simple concept. His design consisted of using barges as floating vessels that carried a platform for derrick and equipment. The vessel was to be towed to the location, sunk on the spot, and would act as a fixed foundation for the platform, which would remain above the water. After attaining the patent permission of Louis Giliasso, the patent owner for McBride's concept, Texas Company began to construct the world's first submersible. This project was not met without criticism, however. The idea was rejected by many potential customers whose fear was that once the vessel had been sunk, it would remain in the mud and be forever lost. Despite criticisms, in 1933, the Texas Company named its first submersible 'Giliasso', after its inventor.

The Giliasso spurred new ideas and the Texas Company (as well as others) continued to develop new plans concerning oil exploration and production on water. The Giliasso had been a technological breakthrough, however, now logistic support was the problem. Once the Texas Company discovered oil with the Giliasso, crews had to live in piling-support camps suspended over the marsh muck. Drilling mud was hauled 35 miles to the drilling site, and aboveground storage was a problem. To meet the need for field storage, three obsolete oil tankers were grounded and connected to an old steel schooner, which was used as a loading dock. The oil was then lightered to vessels offshore. The problem was finally solved in 1952 with the completion of a 135-mile pipeline. However, in the meantime, a number of support industries had already arisen and taken their place in the offshore market.

Since the 1950s, more than 5,500 platforms have been installed in the Gulf of Mexico. Today there are more than 3,600 fixed structures at depths of up to 1,700 feet and floating structures have reached almost 10,000 ft water depths. Throughout the decades of technological progress, the fabrication industry along the Gulf Coast has been a principal contributor to the oil and gas industry advances and has expanded to handle the construction of structures and components necessary to continue exploration and production. The industry has grown significantly – parallel to that of the offshore industry itself. The fabrication corridor includes 1,000 miles of shoreline from the Texas/Mexico border on the western edge, to Alabama at the eastern boundary (Hunt and Gary 2000).

And, as the technology used in the offshore industry advances and changes, so must that of the fabrication yard. "Located along an extensive intracoastal waterway system, yet within access to the Gulf of Mexico, the industry hosts numerous specialized fabrication yards and facilities. For the most part, each yard has a specialty, whether it is the fabrication of separator or heater/treater skids, the construction of living quarters, the provision of hookup services, or the fabrication of jackets, decks and topside modules. While there are large facilities capable of handling current and next-generation deepwater structures, few facilities have complete capabilities for all facets of such a project. Even the largest fabrication facilities rely on specialized yards, shops, and subcontractors for many of a project's components" (Hunt and Gary 2000)." According to a survey conducted by Mustang Engineering of 51 yards, nine have single piece fabrication capacity of more than 10,000 tons and 12 indicate a capability to fabricate structures intended for water depths exceeding 1,000 ft (Hunt and Gary 2000).

2.2 Description and Typical Facilities

In the early days of offshore drilling, explorers simply fitted a derrick to a barge and towed it to their site. Today, four types of offshore rigs are used to drill wildcat or exploration wells (Australian Institute of Petroleum 2002):

- ***Submersibles:*** Submersibles can be floated to shallow water locations then ballasted to sit on the seabed. However, they are rarely used, mainly because, when towing submersibles, the greater the water depth, the greater the uncertainty of stability. Also, deeper waters require more space between the platform deck and the barge, resulting in an unstable configuration.

- ***Jackups:*** These are usually towed to a location. Their legs are then lowered to the seabed and the hull is jacked-up clear of the sea surface. They are used in waters to about 160 meters deep.

- ***Drill ship:*** These look like ordinary ships but have a derrick on top which drills through a hole in the hull. Drill ships are either anchored or positioned with computer-controlled propellers along the hull which continually correct the ships drift. Often used to drill wildcat wells in deep waters.

- ***Semi-submersible:*** Mobile structures, some with their own locomotion. Their superstructures are supported by columns sitting on hulls or pontoons which are ballasted below the water surface. They provide excellent stability in rough, deep seas.

Production Platforms: Once oil or gas is found, the exploratory drilling rig is replaced with a production platform, assembled at the site using a barge equipped with heavy lift cranes. Platforms vary in size, shape and type depending on the size of the field, the water depth and the distance from shore.

Today, offshore platforms play a pivotal role in the development of offshore oil and gas resources. The purpose of platforms is to house production and drilling equipment and living quarters for personnel (for manned platforms). As shown in Figure 2.1, several types of production systems are used in offshore oil and gas development.[2] They vary in size, shape and type depending on the size of the field, the water depth and the distance from shore. A platform consists of two major components: an underwater part (jacket or tower) and an above

[2] Although some recently developed production systems, such as the floating production system, are not platforms in the strict sense, platform-type structures continue to be the staple of the offshore oil and gas operations.

water part (deck). Other platform components are living quarters, control building, and production modules.

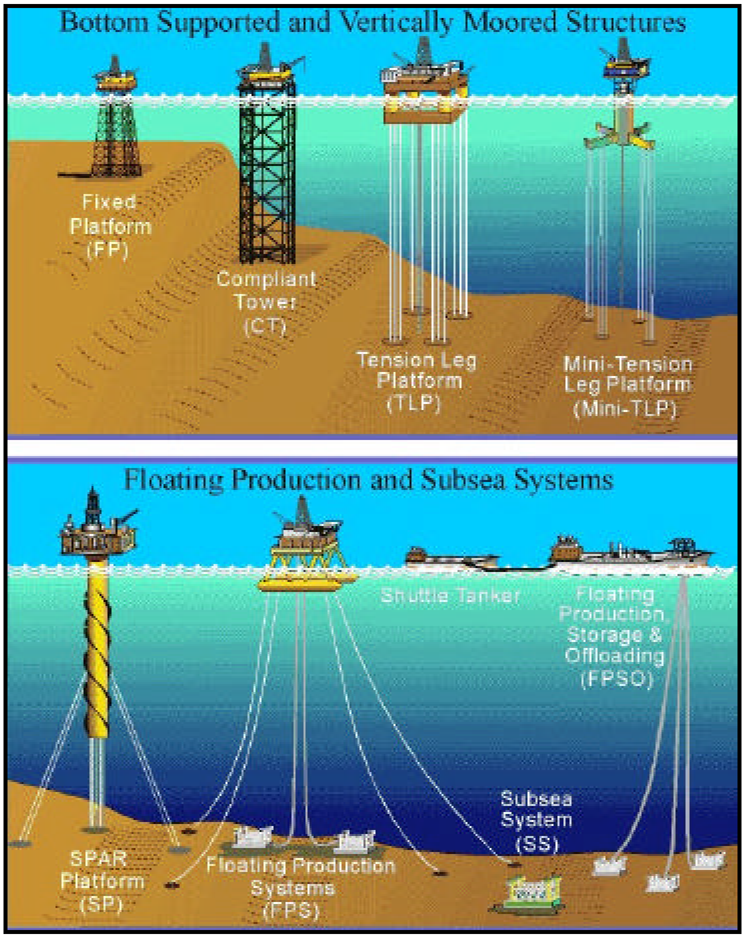

Figure 2.1. Permanent Production Systems on the GOM OCS.

Source: USDOI, MMS (2000a)

- ***Fixed Platform:*** This is the most commonly used type of production system in the U.S. Gulf of Mexico. A fixed platform is a large skeletal structure extending from the bottom of the ocean to above the water level. It consists of a metal jacket, which is attached to the ocean bottom with piles, and a deck, which accommodates drilling and production equipment and living quarters. Fixed platforms are typically installed in water depths up to 1,500 feet.

- ***Compliant Tower:*** Similar to a fixed platform, however the underwater section is not a jacket but a narrow, flexible tower which, due to the flexibility of its structure, can move around in the horizontal dimension, thereby withstanding significant wave and wind impact. Compliant towers are typically installed in water depth from 1,000 up to 2,000 feet.

- ***Tension and Mini-tension Leg Platforms:*** These do not have skeletal structures extending all the way to the ocean floor. Essentially, this is a semi-submersible anchored to the seabed with vertical, taut steel cables or solid pipes. Wellheads can be placed on the TLP's deck, unlike the free-floating platforms (like ships and "normal" semi-submersibles). Tension leg platforms can be used in different depth ranges, up to 4,000 feet.

- ***SPAR Platform:*** This platform consists of a large vertical hull, which is moored to the ocean floor with up to twenty lines. On top of the hull sits the deck with production equipment and living quarters. Presently, SPAR platforms are used in water depth up to 3,000 feet; however, SPAR technology allows installations in waters as deep as 7,500 feet.

- ***Floating Production System:*** This system consists of a semi-submersible unit which is kept stationary either by anchoring with wire ropes and chains or by the use of rotating thrusters, which self propel the semi-submersible unit. Floating production systems are suited for deepwater production, in depths up to 7,500 feet.

- ***Subsea System:*** A subsea system consists of a single subsea well or several wells producing either to a nearby platform or to a distant production facility through a pipeline and manifold systems. Currently, subsea systems are used in water depths exceeding 5,000 feet.

- ***Floating Production, Storage, and Offloading (FPSO) System:*** This system consists of a large vessel, which houses production equipment. It collects oil from several sub-sea wells, stores it, and periodically offloads it to a shuttle tanker. FPSO systems are particularly useful in development of remote oil fields where pipeline infrastructure is not available.

While recent trends in platform fabrication have been moving towards more specialization, there are still a number of large, comprehensive platform fabrication facilities (or yards) in the Gulf. For instance, J. Ray McDermott's Morgan City fabrication yard is the largest facility of its kind and one of the most advanced. It has 287 developed acres producing structures, facilities and components of every size. The Morgan City fabrication services include platform jackets (bases), deck sections, deck facilities; production modules, drilling modules and quarters modules; oil and natural gas processing, transfer and storage facilities; floating platforms and production facilities; offshore floating terminals; subsea production facilities; control systems for subsea production wells; process piping; process vessels; caissons (well protectors); and rig repair.

Other large, comprehensive fabrication yards include Gulf Island Fabrication, Inc. in Houma, Louisiana. Gulf Island has 250 acres devoted to fabrication facilities. Its services include: structural steel fabrication (jackets, decks, pilings, and piping); blasting and coating; hydrostatic and pneumatic testing and multiple load out capabilities.

These large integrated facilities typically span a broad, continuous geographic area. The yards are typically gated for security and safety reasons. These yards have to be large to handle the massive size of the platforms that are under construction. Consider that Shell Offshore's

Bullwinkle platform, the largest of its kind, is 1,353 feet tall. The Sears Tower, the largest building in North America, is 1,450 feet – a mere 97 feet taller than Bullwinkle.

A typical facility will be composed of numerous large buildings that open into large outdoor work areas. These buildings allow for construction and fabrication activities to be conducted at all hours of the day, and during inclement weather. These sites also typically have a number of "out-buildings" which in many instances are trailers or portable buildings. These out-buildings service as administrative areas and project management offices. Their modularity allows them to be moved near particular projects for close supervision and oversight on projects.

Sites often contain large amounts of stacked tubing, piping, steel beams and girders, and old platforms for re-use or re-furbishing. Usually a large canal and dock are attached to the yard so that the final product can be removed from the yard, and towed to a major waterway for transportation to its final destination which could be the GOM or other oil and gas producing areas of the world.

2.3 Industry Characteristics

Platforms are fabricated onshore, and then towed to an offshore location for installation. Facilities where platforms are fabricated are called platform fabrication yards. Production operations at fabrication yards include cutting and welding of steel components, construction of living quarters and other structures, as well as assembling platform components. Fixed platform fabrication can be subdivided into two major tasks: jacket fabrication and deck fabrication.

- ***Jacket Fabrication:*** The jacket is constructed by welding together steel plates and tubes to form a tower-like skeletal structure. Because the height of a jacket is several hundred feet, jackets are made lying horizontally on skid runners. Once the jacket is completed, it is pulled over, maintaining the same horizontal position, to a barge that transports it to an offshore location where the jacket is installed. Along with the jacket is the construction of smaller ancillary structures such as pile guides, boat landings, walkways, buoyancy tanks, handrails, etc. These structures are attached to the jacket while it is still in vertical position.

- ***Deck Fabrication:*** The deck is fabricated separately from the jacket. A typical deck is a flat platform supported by several vertical columns (deck legs). The deck provides the necessary surface to place production equipment, living quarters, and various storage facilities. Once the deck fabrication is completed, it is loaded onto a barge and transported to the site of the platform, where it is lifted by derrick barges and attached to the already installed jacket.

Location of platform fabrication yards is tied to the availability of a navigable channel sufficiently large to allow towing of bulky and long structures such as offshore drilling and production platforms. Thus, platform fabrication yards are located either directly on the coast of the Gulf of Mexico or inland, along large navigable channels, such as the Intracoastal Waterway. Average bulkhead depth for water access for fabrication yards in the Gulf is 15-20 feet.

Due to the size of the fabricated product and the need to store a large quantity of materials such as metal pipes and beams, fabrication yards typically occupy large areas, ranging from just a few to several hundred acres. Typical fabrication yard equipment includes lifts and cranes, various types of welding equipment, rolling mills, and sandblasting machinery. Besides large open spaces required for jacket assembly, fabrication yards also have covered warehouses and shops. Because the construction of platforms is not likely to be standardized, an assembly-line approach is unlikely and most fabrication yards work on projects one at a time. Once a platform is complete, it is towed to its offshore location, and then work on the new platform commences. The number of employees between fabrication yards may vary from less than a hundred to several thousand. Relative to the international market, Gulf coast yards have a low number of employees (Hunt and Gary 2000). Hunt and Gary (2000) reported that only nine yards had a work force of more than 1,000.

Platform fabrication is not a mass production industry; every platform is custom built to meet the requirements of a specific project. This feature has given rise to the great degree of specialization in the platform fabrication. There are no two identical fabrication yards; most yards specialize in the fabrication of a particular type of platform or platform component. Examples of specialization include construction of living quarters, provision of hook-up services, and fabrication of jackets and decks. According to a published 1999 survey of fabrication yards in the Gulf, out of 50 yards, 23 fabricate jackets, 15 fabricate decks, 29 fabricate modules, 22 fabricate living quarters, and 20 fabricate control buildings (Gary and Nutter 2000). Despite the specialization of these yards, most facilities do include:

- steel stockyards and cutting shops which supply and shape steel;
- assembly shops which put together a variety of components such as deck sections, modules, and tanks;
- paint and sandblasting shops;
- drydocks which work on small vessels;
- piers which work on transportation equipment and the platform components that are mobile and can be transported onto barges; and
- pipe and welding shops.

Despite a large number of platform fabrication facilities in the Gulf, only a few facilities can handle large-scale fabrication. According to a 1999 survey of fabrication yards, nine yards have single piece fabrication capacity over 100,000 tons and twelve have capacity to fabricate structures for water depth over 1,000 feet (Gary and Nutter 2000). Only a few yards fabricate structures other than fixed platforms: one fabricates compliant towers (J. Ray McDermott, Inc.'s Morgan City yard located in Amelia, Louisiana), and two fabricate tension leg platforms (Gulf Island fabrication Inc., in Houma, Louisiana and Friede Goldman Offshore in Pascagoula, Mississippi).

Another important characteristic of the industry is a high degree of interdependency and cooperation among the fabrication yards. Because offshore platforms, particularly the ones destined for the deep water, are such complex engineering projects, most facilities do not have technical capabilities to complete an entire project "in-house," without subcontractors and specialized yards.

Many production companies are starting to stray away from the traditional onshore yards. There are numerous offshore structures that support the main production platforms that are interconnected via bridges. The Freeport-McMoran Resource Partners Platform includes thirteen different connecting bridges - the largest of its kind in the Gulf of Mexico (J. Ray McDermott 2000). Bridges connect mobile and stationary structures, like barges. Barge fabrication has evolved to carry multi-deck units. The barges are "spread-moored with six anchor chains at each corner" (Naklie 1998). The multi-deck units house production equipment and other submersible pumps and tanks, living quarters, mechanical shops and warehouses which traditionally use onshore fabrication yards. Having shops offshore provide obvious advantages; operators do not have to wait for spare parts from onshore sites.

2.4 Regulations

All platforms located in the OCS must be designed, fabricated, installed, used, inspected and maintained to assure their structural integrity for the safe conduct of operations at specific locations. Applications for platform approval are filed in accordance with 30 CFR 250.901:

- Applications for all new platforms or major modifications must be submitted in triplicate and contain the following information:

  - General platform information including the platform designation, lease number, area name, and block number; Longitude and latitude coordinates, Universal Transverse Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection system, and a plat drawn to a scale of 1 inch = 2,000 feet showing surface location of the platform and distance from the nearest block lines;

  - Drawings, plats, front and side elevations of the entire platform, and plan views that clearly illustrate essential parts, i.e., number and location of well slots, design loadings of each deck, water depth, nominal size and thickness of all primary load-bearing jacket and deck structural members, and nominal size, makeup, thickness, and design penetration of piling;

  - Corrosion protection or durability details which consist of the corrosion-protection method; expected life; and durability criteria for the submerged, splash, and atmospheric zones;

  - A summary of environmental data, which has a bearing on the platform's design, installation, and operation, e.g., wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperatures;

  - Foundation information including a geotechnical investigation report; and,

  - Structural information including the design life of the platform and the basis for such determination.

The platform lessee evaluates characteristic environmental conditions associated with operational functions to be performed. Factors such as waves, wind, currents, tides, temperature, and the potential for marine growth on the structure are considered.

In addition, a program has been established by the MMS to assure that new structures are designed, fabricated, and installed using standardized procedures to prevent structural failures. This program facilitates review of such structures and utilizes third-party expertise and technical input in the verification process through the use of a Certified Verification Agent. All platforms are inspected during the construction process considering the following:

- All pile-supported and gravity platforms covered by this subpart must be inspected during the construction phase. The phases of construction subject to inspection include material manufacture, fabrication, loadout, transportation, positioning, installation, and final field erection.

- Inspections during construction are to verify that the platform is constructed in accordance with the approved construction plan. Any unusual or innovative application of materials or methods of construction not adequately covered by the requirements of this section must receive special attention during compliance inspections relevant to its effect on the integrity of the platform.

- If construction inspection results reveal that materials, procedures, or workmanship deviate significantly from the approved design, remedial action must be taken.

- The origin of materials used in the platform and the results of relevant material tests for all significant structural materials must be retained and made readily available for inspection by MMS representatives during all stages of construction.

- Records shall be kept of the locations throughout the platform of the various heat numbers for such materials.[3]

After installation, all platforms in the OCS are inspected periodically in accordance with the provisions of API RP 2A, Section 14, Surveys. Use of an inspection interval which exceeds 5 years requires prior approval by the Regional Supervisor. Proper maintenance needs to be performed to assure the structural integrity of the platform as a workbase for oil and gas operations. A report must be submitted annually on November 1 to the Regional Supervisor stating which platforms have been inspected in the preceding 12 months, the extent and area of inspection, and the type of inspection employed, i.e., visual, magnetic particle, ultrasonic testing. A summary of the testing results is submitted indicating what repairs, if any, were needed and the overall structural condition of the platform.[4]

2.5 Industry Trends and Outlook

Over the whole history of its existence, the ups and downs of the platform fabrication industry have been closely tied to the fortunes of the oil and gas industry. Drilling and production activities are sensitive to the changing prices for oil and gas. This sensitivity, in turn, is translated into "boom and bust" cycles for the fabrication industry, when a period of no work follows a period of more fabrication orders than a yard can complete. In order to shield themselves from the volatility inherent in the oil and gas industry, platform fabrication yards in the U.S. Gulf of Mexico have started to implement various diversification strategies. These

[3] 30 CFR 250.911
[4] 30 CFR 250.912

diversification strategies, coupled with the new challenges brought about by the deepwater oil and gas exploration and development, are significantly changing the industry.

In order to utilize the existing equipment and to keep the highly-skilled workforce in the periods with no fabrication orders, many fabrication yards are expanding their operations into areas such as maintenance and renovations of drilling rigs, fabrication of barges and other marine vessels, dry-docking, and survey of equipment. These projects, although much smaller in scale and scope than platform fabrication, nevertheless allow the yards to survive the recessions.

Another avenue of diversification is the pursuit of international work in platform fabrication. The U.S. Gulf of Mexico fabrication yards have a double advantage of great experience in fabrication work and good climatic conditions, allowing for year-round operations.

Companies have also developed new products like offshore management software and company-specific systems for managing and monitoring offshore sites onshore. New and improved platforms or platform upgrades and revamps complement many of the systems and software. The MinDOC Deepwater Drilling and Production System includes a simple template of "tubes and boxes" (MinDoc, L.L.C. 2000). This cost-efficient system can be assembled and installed in one piece, "without the need of offshore mating or derrick barge assistance at uprighting." Moreover, the components can be modified for different deepwater depths and reused towards different production sites.

There are a number of new software products that facilitate an accurate exploration and production activity. Many, like the product by Multi Products Co., called WellTest are compatible to MS Excel, Windows and other existing data managing software. WellTest provides the operator with the number of cycles per day and the amount of liquids produced with the complementing plunger (Lee et al. 2000). It provides travel time per cycle, plunger fall time based on plunger type, number of cycles per day, and production scenarios for various schemes. Kenonic Controls has created MaxOil management software which manages real-time well production information for more accurate analyses by operators. It takes data from various sources and combines events with well-specific engineering analysis to correct non-flowing conditions which lead to production loss and equipment damage. It is one of the software products that is useful for remote fields (Lea et al. 2000).

One problem the platform fabrication industry experienced in the past was the lack of skilled workers at the beginning of an upswing in the business cycle because the skilled labor had already migrated to other jobs during the downswing. Having learned from the past mistakes, some fabrication companies have organized technical training programs in the local communities. A locally-trained workforce provides a readily available pool of skilled labor for the fabrication yards. Other companies have found a solution to the workforce problem through the acquisition of several individual fabrication yards located within the single commuting area. This allows companies to dispatch their personnel to several yards to accommodate the existing need for workers at any given time.

With respect to the deepwater development, the challenges for the fabrication industry stem from the greater technical sophistication and the increased project complexity of the deepwater structures, such as compliant towers and floating structures. The needs of the deepwater projects are likely to result in two important trends for the fabrication industry. The first is the increasing concentration in the industry, with respect to the deepwater projects. As technical and organizational challenges continue to mount, it is expected that not every fabrication yard will find adequate resources to keep pace with the demands of the oil and gas industry. The second trend is the closer integration, through alliances, amalgamations, or mergers, among the fabrication yards and engineering firms.

With respect to the structure of the platform fabrication industry, it is undergoing a period of restructuring, which is characterized with transformation from privately to publicly held companies on the one hand, and with the consolidation of the industry through mergers and acquisitions. While implications of these changes are yet to be understood, it is clear that their impact will be significant.

Inventory: Table 2.1 provides results of a 2001 inventory of platform fabrication yards conducted as part of development of this Fact Book and GIS database. Of the 43 facilities inventoried, 31 were located in Louisiana, 7 in Texas, 4 in Mississippi, and 1 in Alabama. Land area covered by the facilities ranged from a few acres to several hundred acres.

Expansion of Offshore Drilling: The offshore drilling industry has come a long way since it installed the first subsea wellhead in 1961. The Gulf represents an expanding frontier with extraordinary growth – especially of deepwater – in oil and gas industry activity over the past 7 years. For instance, at the end of 2001, there were 51 producing fields in the deepwater Gulf; a 38 percent increase from the year before. In just a year (between 2000 and 2001), "remarkable" achievements have been made, for example (USDOI, MMS 2002a):

- The number of drilling rigs working in deepwater increased from 28 to 43;
- The number of ultra-deepwater (> 5,000 ft) capable rigs increased from 18 to 26 (44 percent) and the number of ultra-deepwater wells increased from 37 to 59 (59 percent);
- There was a 59 percent increase in the number of producing deepwater fields;
- Deepwater oil production is rapidly approaching the all-time shallow-water oil production record established in 1971; and,
- New deepwater drilling added over 4 billion barrels of oil equivalent (BOE), a 49 percent increase, to the Gulf of Mexico oil and gas inventory.

Table 2.1

Platform Fabrication Facilities in the Gulf (2001)

Name	Owner	City	State	Size (ac)	Platform Type
Mobile Yard	Atlantic Marine Alabama Shipyard	Mobile	AL	680	Unknown
Gulfport Yard	Friede Goldman Offshore	Gulfport	MS	110	Unknown
Pascagoula East Yard	Friede Goldman Offshore	Pascagoula	MS	180	FPSO
Pascagoula West Yard	Friede Goldman Offshore	Pascagoula	MS	13	FPSO
Pascagoula Yard	Ingalls Shipbuilding	Pascagoula	MS	800	FPSO
Abbeville (Port of Vermilion) Yard	Gulf Coast Marine Fabricators	Abbeville	LA	7	FIXED
Abbeville Yard	Acadian Contractors	Abbeville	LA	6.5	FIXED
Abbeville Yard	Mar-Con, Inc.	Delcambre	LA	10	FIXED
Amelia Yard	J. Ray McDermott, Inc.	Amelia	LA	589	CT
Baldwin Yard	Superior Fabricators, Inc.	Baldwin	LA	19.5	FIXED
Belle Chasse Yard	Omega Service Industries, Inc.	Belle Chasse	LA	18.5	FIXED
Delcambre Yard	Shaw Bagwell	Delcambre	LA	60	FIXED
East Yard	Bay Offshore Ltd. East Yard	Amelia	LA	6	FIXED
Gibson Yard	Max Welders, Inc.	Gibson	LA	27	FIXED
Harvey Yard	Chet Morrison Contractors, Inc.	Houma	LA	17	FIXED
Harvey Yard	Dynamic Industries, Inc.	Harvey	LA	3.7	FIXED
Harvey Yard	Houma Industries	Harvey	LA	3	FPSO
Harvey Yard	Metal Building Products	Harvey	LA	1.8	FPSO
Harvey Yard	Production Mgmt Industries,	Harvey	LA	9.5	FIXED
Harvey Yard	Southport, Inc.	Harvey	LA		Unknown
Houma Yard	Chet Morrison Contractors, Inc.	Harvey	LA	7	FIXED
Houma Yard	Dolphin Services, Inc.	Houma	LA	23	FIXED
Houma Yard	Gulf Island Fabrication, Inc.	Houma	LA	582	FIXED
Houma Yard	Offshore Specialty Fabricators, Inc.	Houma	LA	52	FIXED
Houma Yard	Sigma Industries, Inc.	Houma	LA	17.2	Unknown
Ingleside Yard	Offshore Specialty Fabricators, Inc.	Houma	LA	58	FIXED
Mosby Unit	Bay Offshore Ltd. Mosby Unit	Belle Chasse	LA	17.5	FIXED
New Iberia Yard	Allen Process Systems	New Iberia	LA	25	FPSO
New Iberia Yard	Dynamic Industries, Inc.	New Iberia	LA	44	FIXED
New Iberia Yard	L-Con Marine Fabricators	New Iberia	LA	18	FIXED
New Iberia Yard	Natco	New Iberia	LA	20	FPSO
New Iberia Yard	Omega Service Industries, Inc.	New Iberia	LA	62.5	FIXED
New Iberia Yard	Unifab International, LLC	New Iberia	LA	170	FIXED
Seawolf Group	Bay Offshore Ltd. West Yard	New Iberia	LA	15	FIXED
South Louisa Yard	Twin Brothers Marine	Morgan City	LA	57	FIXED
West Yard	Bay Offshore Seawolf Group	Amelia	LA	4	FIXED
Brownsville Yard	Amfels, Inc	Brownsville	TX	200	FPSO
Channelview Yard	Delta Engineering Corporation	Channelview	TX	31	FIXED
Galveston Yard	First Wave Newpark Shipbuilding	Galveston	TX	112	FIXED
Greens Bayou Yard	Brown & Root Energy Services	Houston	TX	184.9	FIXED
Ingleside Yard	Aker Gulf Marine	Ingleside	TX	400	FPSO
Ingleside Yard	State Service Co., Inc.	Ingleside	TX	14.5	FIXED
Turbofab Facility	Solar Turbine Inc.	Channelview	TX	50	Unknown

Source: Acadian Consulting Group, Inc., 2001; The Louis Berger Group, Inc. 2001

The growth in deepwater activity spans all phases of exploration and development, including leasing, drilling, and production. According to USDOI, MMS (2002a), in 2001 there are approximately 7,400 active leases in the Gulf of Mexico OCS, 53 percent of which are in deepwater. Contrast this to approximately 5,600 active Gulf of Mexico leases in 1992, only 27 percent of which were in deepwater. On average, there were 43 rigs drilling in deepwater in 2001, up from only 3 rigs in 1992 and 28 rigs in 1999. Likewise, deepwater oil production rose over 800 percent and deepwater gas production increased about 1,500 percent from 1992 to 2001 (USDOI, MMS 2002a).

New advances in technology are also stimulating investment in the Gulf. In May, 2001, the MMS announced that Unocal had set a new world record for drilling in deep water. An exploration well for oil and gas was drilled in 9,743 feet of water in Alaminos Canyon Block 903, less than 4 miles from the U.S.-Mexico boundary line. "[T]he number of wells being drilled in the so called ultra-deep water – those in 5,000 feet of water or greater – continues to grow significantly. Currently, there are ten wells being drilled in water depths of 5,000 feet or greater" (USDOI, MMS 2001a). The companies operating the ten wells and the water depths are displayed in Table 2.2.

Table 2.2

Water Depth Records

Operator	Water Depth (ft)
Union Oil Co. of California	9,743
Marathon Oil Company	7,742
BP Exploration & Oil Inc.	6,960
BP Exploration & Oil Inc.	6,612
Burlington Resources Offshore	6,308
Murphy Exploration & Production	5,881
Dominion Exploration & Production	5,610
Vastar Resources Inc.	5,422
Amoco Production Company	5,180
Shell Deepwater Production Inc.	5,150

Source: USDOI, MMS (2001a)

3.0 PORT FACILITIES

3.1 Introduction

Ports play a vital role in the support of offshore oil and gas exploration and production activities as well as the maritime industry as a whole. The relationship between the offshore industry and port facilities in the Gulf is unique in that the offshore industry relies heavily on ports with services tailored to its specific needs. This is explained later in the chapter with the discussion of support services such as offshore support vehicles, shipbuilding and repair facilities, fabrication yards, and supply bases. In general, port facilities can include waterways for shipping, wharves, piers, docks, and warehouses. Port services include the transfer and exchange of cargo and passengers between water and landside transportation modes (including rail, pipeline, truck, etc.). Ports handle a variety of cargo, including bulk, or loose cargo, break bulk cargo in packages such as bundles, crates, barrels and pallets, liquid bulk cargo such as petroleum, dry bulk such as grain, and general cargo in steel boxes called containers.

Leading commodities shipped for domestic and foreign trade through U.S. ports include (American Association of Port Authorities 2002a):

- Petroleum and petroleum products – oil, gasoline;
- Chemicals and related products – fertilizer;
- Coal – bituminous, metallurgical, steam;
- Food and farm products – wheat and wheat flour, corn, soybeans, rice, cotton, coffee;
- Crude materials - forest products, wood, and wood chips; soil, sand, gravel, rock, and stone; and, iron ore/scrap

Manufactured products including:

- Automobiles, automobile parts and machinery; and
- Clothing, shoes, electronics, toys.

Figure 3.1 illustrates the principal commodity groups transported on U.S. waters for 2001. Almost 44 percent of total waterborne commerce (both foreign and domestic) is attributed to petroleum and petroleum products. This is three times more commerce transported than any other commodity group – crude materials comprise the second largest group with 14.8 percent. If looking only at foreign commerce (waterborne import) the petroleum and petroleum products category is even higher, at 50.5 percent. This is five times higher than the next category of crude materials at 10.4 percent (Institute for Water Resources 2001).

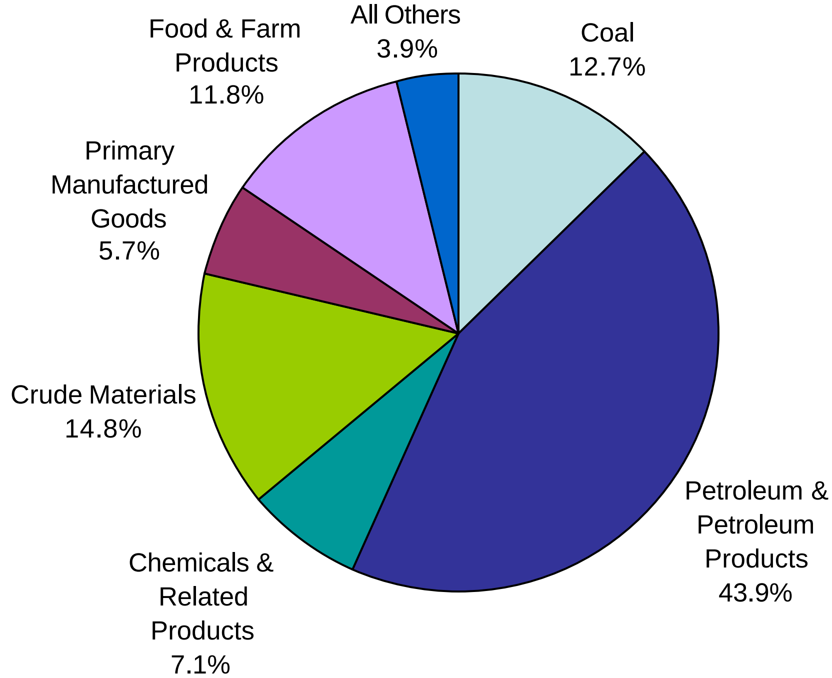

Figure 3.1. Principal Commodity Groups Carried by Water (2001) (percentage of tons).

Source: Institute for Water Resources (2001)

There are two major types of port facilities; 1) deep-draft seaports and, 2) inland river and intracoastal waterways port facilities. Deep-draft seaports are ports that mostly accommodate ocean going vessels, and are most likely to serve and supply offshore drilling platforms. Deep-draft seaports are also more likely to be publicly owned and operated. Inland ports, however, are located on rivers or intracoastal waterways, and are mostly privately owned – 87 percent of inland facilities are privately owned. More than 1,800 river terminals are located in 21 states within the U.S. These ports are unique in that although they have shallow water depths of 14 feet or less, they are less concentrated geographically and provide almost limitless access points to the waterways. "Overall, there are more inland facilities located outside traditional port boundaries than within. Terminal siting on the inland waterways is less constrained than coastal ports, which provides greater flexibility to the users in determining the location of plants requiring water access" (Maritime Administration 1999). Such inland terminals, abundant in South Louisiana, many along the Mississippi especially between New Orleans and Baton Rouge, and Southeastern Texas, have become increasingly important for the offshore industry.

Places where vessels dock are called berths. Berths can be specialized to serve specific types of freight and passenger transfers. For example, berths may be designed to handle containerized cargo, dry and liquid bulk cargo, automobiles and other cargo that can roll-on/roll-off vessels, and general cargo. Passenger berths handle ferries or large cruise vessels. As of 1997, 484 terminals on the Gulf Coast contained 786 berths (this includes both privately and publicly owned facilities) (Maritime Administration 1999). Many of the berths in ports on the Gulf

Coast are specialized to service the over 4,000 offshore drilling platforms in place to support offshore mineral development.

Table 3.1 shows the location of the major seaport facilities by coastal region. Twenty-eight states contain coastal ports (including those located on the Great Lakes). The largest number of terminals and berths are located in the Gulf States (484 and 786, respectively, in 1997), representing 25.3 percent of all U.S. terminals and 24.9 percent of all U.S. berths.

Table 3.1

U.S. Ports Handling More Than 10 Million Tons in 1997

Coastal Region	Number of Terminals[1]	Percent of Total	Number of Berths	Percent of Total
North Atlantic	421	22.0	761	24.1
South Atlantic[2]	197	10.3	349	11.0
Gulf	**484**	**25.3**	**786**	**24.9**
South Pacific[3]	223	11.6	414	13.1
North Pacific[4]	249	13.0	365	11.6
Great Lakes	340	17.8	483	15.3
Total	**1,914**	**100.0**	**3,158**	**100.0**

Notes:

1. Includes those commercial cargo handling facilities with a minimum depth alongside of 25 feet for coastal ports and 18 feet for Great Lakes ports.
2. Includes Puerto Rico and the U.S. Virgin Islands.
3. Includes Hawaii.
4. Includes Alaska.

Source: Maritime Administration (1999)

3.2 Description and Typical Facilities

Offshore exploration and production facilities need services that can only be supplied at nearby ports and local communities. Such services as repair and maintenance of supply vessels, fabrication yards, supply bases and companies supplying crew services will be found in ports nearest to offshore drilling operations. Other support facilities or services include ships' chandlers, stevedoring, warehousing and helicopter pads.

Offshore Support Operations: Any functioning offshore oil and gas production operation requires frequent deliveries and pick-ups of personnel, supplies, and materials to and from offshore platforms. The large scale of operations in the GOM has led to the development of a specialized fleet of vessels known as "Offshore Support Vessels" (OSV).

OSVs are required in every stage of the offshore drilling process. For instance, during the development process, operating companies may invite tenders to supply the assets and services they require, such as the drilling rigs and support vessels needed to put the particular type of rig required on location and supply the rig during its drilling campaign. In some cases, the tender will require the offshore support company to design and build a support vessel to particular specifications in order to meet the requirements of the exploration or production project (Swire Pacific Offshore 2003).

In addition to the requirement for support vessels during exploration, support vessels are also needed to assist in the construction phase of the development of a field, including the supply and installation of platforms, the laying of pipelines to shore-based storage facilities and the installation of associated offshore loading facilities. Once such infrastructure is in place, there is a continuing requirement for the transportation of food, stores, personnel and maintenance equipment to the platforms.

Up until the mid 1950s, offshore drilling units were supported by vessels which were not specially designed for offshore supporting roles, such as converted fishing vessels or tugs. However, as rigs increased in size and began to operate in deeper waters and drill to greater depths, special purpose support vessels began to be designed and built. Today, OSVs are highly specialized and can be described by a number of categories. The following is a list of categories of types of OSVs as listed by the publication, *Offshore Support Vessels of the World,* published by OPL.

- Accommodation Units
- Anchor Handling Tug Supply Vessels (AHTSs)
- Anchor Handling Tugs (AHTs)
- Cable Lay Vessels
- Deck Barges
- Decommissioning Vessels
- Derrick Barges
- Diving Support Vessels (DSVs)
- Dredgers
- Drilling Tenders
- Escort Tugs and Floating Storage Units (FSUs)
- Heavy Lift Vessels and Barges
- Hydrographic Survey Vessels
- Jacket Launch Barges
- Jack-up Drilling Units (JUs)
- Multi-function Service Vessels (MSVs)
- Pipe Bury Barges
- Pipe Carriers
- Pipe Laying Barges
- Platform Supply Vessels (PSVs)
- Pontoon Barges
- Salvage Tugs
- Seismic Survey Vessels
- Semi-submersible Drilling Units
- Shuttle Tankers
- Standby Vessels
- Supply Vessels
- Transportation Barges
- Well Stimulation Vessels

According to the USACE Navigation Data Center, in 2000, there were 1,155 registered vessels classified as OSV with bases in several ports in the five Gulf Coast states. A large number of bases are located inland and are not associated with traditional port facilities. The remaining vessels, however, are located at ports – indicating the importance these ports play in serving as offshore staging areas. Altogether there are 91 bases on the Gulf Coast; however, most of the bases (53) host 4 OSVs or less. Table 3.2 lists all the ports/bases with at least 5 OSVs and Figure 3.2 shows the geographical distribution of OSV bases in the Gulf.

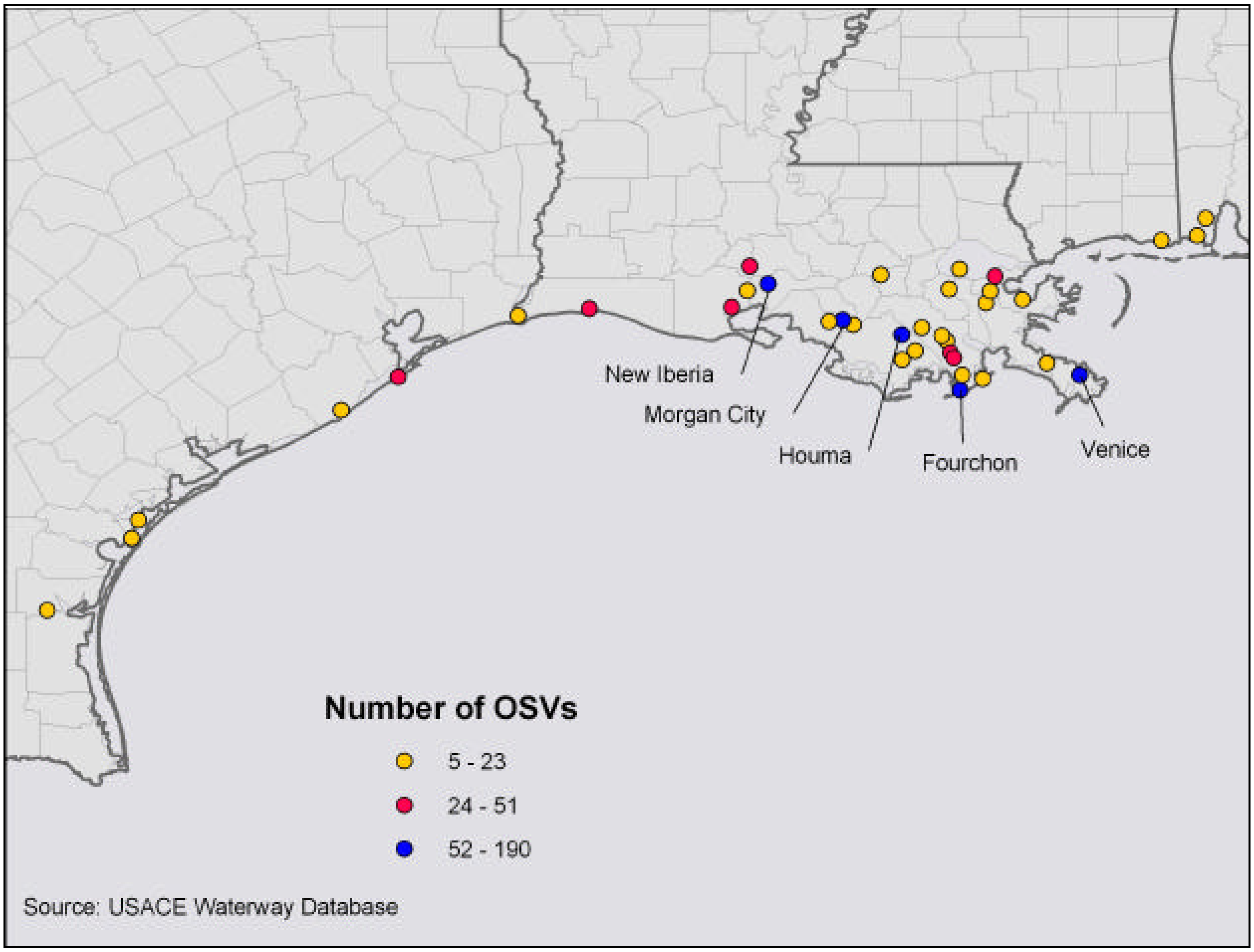

Figure 3.2. Distribution of OSV Bases in the Gulf (2000).

Table 3.2

Principal Offshore Support Vehicle Bases for the Oil and Gas Industry in the Gulf of Mexico (2000)

Rank	State	Base Name	Number of OSVs	Percent of Total	Cumulative Percent
1	LA	MORGAN CITY	190	16.5%	16.5%
2	LA	HOUMA	117	10.1%	26.6%
3	LA	NEW IBERIA	105	9.1%	35.7%
4	LA	FOURCHON	88	7.6%	43.3%
5	LA	VENICE	52	4.5%	47.8%
6	LA	CAMERON	39	3.4%	51.2%
7	LA	NEW ORLEANS	32	2.8%	53.9%
8	LA	INTRACOASTAL CITY	31	2.7%	56.6%
9	TX	GALVESTON	31	2.7%	59.3%
10	LA	GALLIANO	29	2.5%	61.8%
11	LA	BROUSSARD	27	2.3%	64.2%
12	LA	GOLDEN MEADOW	26	2.3%	66.4%
13	LA	BELLE CHASSE	21	1.8%	68.2%
14	TX	SABINE PASS	21	1.8%	70.0%
15	LA	LAROSE	18	1.6%	71.6%
16	LA	PATTERSON	18	1.6%	73.2%
17	TX	FREEPORT	18	1.6%	74.7%
18	TX	ROCKPORT	16	1.4%	76.1%
19	LA	CHALMETTE	14	1.2%	77.3%
20	LA	LOCKPORT	14	1.2%	78.5%
21	LA	ST. ROSE	14	1.2%	79.7%
22	LA	CUT OFF	13	1.1%	80.9%
23	LA	AMELIA	12	1.0%	81.9%
24	LA	DULAC	12	1.0%	82.9%
25	LA	UNION	12	1.0%	84.0%
26	TX	RIVIERA	11	1.0%	84.9%
27	LA	CHAUVIN	9	0.8%	85.7%
28	LA	GRAND ISLE	8	0.7%	86.4%
29	LA	HOPEDALE	8	0.7%	87.1%
30	LA	DELCAMBRE	7	0.6%	87.7%
31	LA	LEEVILLE	7	0.6%	88.3%
32	LA	BURAS	6	0.5%	88.8%
33	AL	BAYOU LA BATRE	5	0.4%	89.3%
34	AL	THEODORE	5	0.4%	89.7%
35	LA	KENNER	5	0.4%	90.1%
36	MS	PASCAGOULA	5	0.4%	90.6%
37	TX	ARANSAS PASS	5	0.4%	91.0%

Bases located at Louisiana ports account for 86 percent of all Gulf OSVs, Texas ports host 10 percent of the bases, while the remaining 4 percent (just 36 vessels) are associated with Alabama, Mississippi, and Florida ports. All five major OSV bases are located in Louisiana: Venice, Fourchon, Houma, Morgan City, and New Iberia. These five ports account for almost half of all OSV bases in the Gulf.

Shipbuilding and Repair: Shipyards and repair facilities form an important part of the infrastructure in which ships, barges, vessels and drilling platforms are designed, built and repaired. According to the Maritime Administration (MARAD), there are at least 35 major shipbuilding and repair bases located on the Gulf Coast (Table 3.3).

Table 3.3

Major U.S. Shipbuilding and Repair Bases (October 1998)

	East Coast	Gulf Coast	West Coast	Great Lakes	Non-Contiguous	Total by Type
Shipbuilding	5	**8**	3	3	0	19
Repair w/Dry-dock	13	**8**	2	2	3	33
Topside Repair	10	**19**	2	2	1	40
Total (By Coast)	**28**	**35**	**7**	**7**	**4**	**92**

Source: Maritime Administration (1999)

Based on an inventory conducted as part of the development of a GIS database for this project, we recorded 162 shipbuilding and repair facilities of various sizes located within the Gulf region which support the oil and gas industry. Eighty-two facilities are located in Louisiana, 35 in Texas, 17 in Mississippi, 15 in Florida, and 13 in Alabama.

A shipbuilding facility can consist of a number of various structures depending on the size of the facility and the type of vessel it is designed to handle. Nineteen facilities in the U.S. comprise the "Major Shipbuilding Base" (MSB). These yards are typically found on or near deep channels allowing them to serve larger deepwater vessels. "The MSB includes shipyards having at least one shipbuilding position consisting of an inclined way, a launching platform, or a building basin capable of accommodating a vessel of at least 122 meters in length. With few exceptions, these shipbuilding facilities are also major repair facilities with dry-docking capability" (NOAA 2002). Second tier shipyards, comprised of small- or medium-sized facilities, engage primarily in the construction of vessels for use on the inland and coastal waterways as well as for foreign markets. Shipbuilding and repair and maintenance yards are discussed further in Chapters 4 and 5, respectively.

Fabrication Yards: As discussed in Chapter 2, offshore drilling platforms are a fundamental component in the development and production of offshore oil and gas resources. Not only do platforms house the drilling equipment, but also the staff needed to run this machinery. Before being installed at an offshore location, platforms are constructed or fabricated onshore at a facility called a platform fabrication yard. Production operations at fabrication yards include cutting and welding of steel components, construction of living quarters and other structures, as well as assembling platform components. The yards occupy large areas with equipment including lifts and cranes, welding equipment, rolling mills, and sandblasting machinery.

The location of these fabrication yards is directly tied to the availability of a large enough channel that will allow the towing of these bulky and long structures. The average bulkhead depth needed for water access to fabrication yards in the Gulf is 15-20 feet. A fabricator must also consider other physical limitations such as the ability to clear bridges and navigate tight corners within channels. Thus, platform fabrication yards must be located at deep-draft seaports or along the wider and deeper of the inland channels. "The fabrication corridor includes 1,000 miles of shoreline from the Texas/Mexico border on the western edge, to Alabama at the eastern boundary. Located along an extensive intracoastal waterway system, yet within access to the Gulf of Mexico, the industry hosts numerous specialized fabrication yards and facilities" (Hunt and Gary 2000).

Because facilities must be so large to carry out the construction of these enormous structures, few facilities have complete capabilities for all facets of a fabrication project. Generally, each yard has a specialty which can include: fabrication of separator or heater/treater skids; the construction of living quarters; the provision of hookup services; or the fabrication of jackets, decks and topside modules. According to a survey of 51 yards, nine have single piece fabrication capacity of more than 10,000 short tons and 12 indicate a capability to fabricate structures intended for water depths exceeding 1,000 ft (Hunt and Gary 2000).

As the drilling industry ventures further offshore in search of new fields, the fabrication yards are being challenged by the need for new technologies. Fabrication yards are affected directly by the trends and developments of the offshore industry, and as it grows and expands, so must the fabrication yards. "The [deepwater] trend has brought to the fabrication yard a multitude of new systems and challenges requiring risk, skill, size and ingenuity. … For many fabrication yards, these new technologies and floating structures represent a more precise, higher risk, and significantly larger project than they have had in the past, with a complexity requiring added involvement from engineering firms, vendors and component specialists" (Hunt and Gary 2000).

Supply Bases: Supply bases can range from large yards, offering all kinds of service including full logistics management, to smaller shops that supply one or many of the items needed on an offshore platform or marine vessel. From strategic locations along the Gulf, larger supply companies who offer supply chain management services move equipment and supplies from land-based supply houses to offshore drilling platforms. Other, smaller suppliers act more or less like a retail store, supplying anything from crane rentals, warehouse space, trailer rentals, and dispatch services, to engine parts, fuel, navigation tools, potable water, and lubricants including, motor oil, hydraulic oil, natural gas compressor oils, grease, gear oil, and synthetics.

Based on an inventory conducted as part of the development of a GIS database for this project, 95 supply base facilities that support the oil and gas industry were recorded within the Gulf region; 53 are located in Louisiana, 32 in Texas, 7 in Alabama, and 3 in Mississippi.

Crew Services: A number of companies provide services to the crews that live on the offshore rigs. These companies provide catering – delivering and serving hot meals – and laundry, cleaning, and maintenance services for crew barracks.

Based on an 2001 inventory conducted as part of the development of a GIS database for this project, 253 crew base facilities that support the oil and gas industry were recorded within the Gulf region; 125 are located in Texas, 83 in Louisiana, 2 in Florida, 6 in Mississippi, and 4 in Alabama.

3.3 Industry Characteristics

Rapidly developing technology has resulted in changing needs. This, in turn, has placed a burden on ports to provide the necessary infrastructure and support facilities in a timely manner to meet growing industry needs. This results in several important trends for ports (American Association of Port Authorities 2002b):

1. the volume of trade and cargo moving through ports is increasing;
2. vessel sizes are increasing and require deeper channels;
3. ports, as with other industries, need to maintain environmental and economic balance in their operations; and,
4. all of these trends create a greater need for capital investment in port infrastructure.

Increased Volume: Deep-draft ports accommodate ocean-going vessels which move over 95 percent of U.S. overseas trade by weight and 75 percent by value. Since the enactment of the North American Free Trade Agreement in 1993, U.S. waterborne exports to Mexico and Canada have increased by more than 60 percent. And, according to U.S. Customs, the volume of imported cargo moving through U.S. ports is projected to more than double by the year 2020 (American Association of Port Authorities 2002b).

According to a 1999 report to Congress assessing the Maritime Transportation System, "the demand for commercial use of the marine transportation system continues to grow, fueled by increases in world trade and domestic use of the waterways to transport goods and people…. Accordingly, there is a critical need to improve productivity, throughput capacity, mobility, and accessibility to meet the projected growth in world trade…" (Maritime Administration 1999).

As this waterborne trade continues to grow, so will the need for more efficient and effective cargo movement throughout the port system. The entire maritime system relies on the successful integration of freight modes – water, truck and rail – for the smooth transit of cargo and passengers from vessels through terminals and to and from inland destinations. Without efficient access, port and terminal investments cannot be fully realized or used (Maritime Administration 2002a). According to a survey by MARAD (published August 2002) the current state of the intermodal access system for U.S. ports is generally acceptable for handling the existing volume of cargo flows. However, "acceptable" is different than "optimal" and if the cargo flow is expected to increase, more attention will need to be focused on the intermodal system. Of the 59 ports responding to the MARAD survey, "[m]any indicated that intermodal access conditions were at or above acceptable levels to handle current cargo flows, reflecting the significant investments that have been made in the last several years by federal, state and local governments in the marine transportation system. However, a large portion of the ports still indicated that flow conditions remain unacceptable and, therefore, require additional attention. … Twenty-five percent of the ports indicated that the local roads used to access their facilities had unacceptable flow conditions. More than one-quarter of the ports indicated that channel depths were still unacceptable in federal waterway channels" (Maritime Administration 2002a).

Larger Ships/Deeper Channels: As cargo volumes increase, carriers look for ways to cut time and costs, and so the number and size of vessels are growing. Vessels that began service in the 1960s with capacities of less than 500 twenty-foot equivalent units (TEUs) have been replaced by vessels with capacities of 6,000 TEUs, and carriers planning for increased cargo volume have ordered ships that can carry over 8,000 TEUs.[5] By 2010, ships carrying 13,000 TEUs are possible (NOAA 2002). These enormous ships require sophisticated and efficient ports and terminal facilities with first-rate landside intermodal connections. "For a port to service these mega ships, the entire port structure will have to get bigger and more productive. Each channel, berth, and turning basin must be at least 50 feet in depth since 40 to 46 feet will be the maximum draft for the fully-loaded mega ships" (Maritime Administration 1998).

In addition to building ships, ocean carriers are merging, forming alliances and establishing partnerships to strengthen their bargaining power and profitability. These new vessels serve high volumes and long distances, with many operating as part of vessel sharing agreements or alliances. "In 1996, the top-20 lines operators owned some 54 percent of the total container ship fleet capacity and over half of these operators have now formed three large alliances" (van der Veer 2001).

As a result of the greater volumes of cargo, larger ships and larger companies, ports are under pressure to increase their scale as well. The major consideration for ports when planning for larger ships is channel depth. Channel depths at most U.S. ports typically range from 35 to 45 feet. The current generation new large ships require channels from 45 to 53 feet. Container ports around the world are deepening navigation channels down to between 49 and 53 feet.

Economy v. Environment: It is clear that the volume of trade done through ports is booming and there is a critical need to improve productivity, throughput capacity, and accessibility. However, this comes with a cost, or rather a trade off – environmental quality of the coastal landscape and its surrounding waters versus economic growth. "One of the critical challenges confronting the U.S. port industry is meeting the growing demands and diverse needs of waterborne transportation while protecting the environmentally sensitive harbor areas in which ports operate. Protecting the environment and providing an efficient and cost-effective transportation system are critical to the economic future of the United States" (Maritime Administration 1998). In American Association of Port Authorities (AAPA) member surveys conducted in 1993 and 1999, the top strategic issues for U.S., Canadian, Caribbean, and Latin American ports were facility expansion and the ports' ability to secure funding, followed by pricing pressures and meeting environmental requirements.

Ports and terminal operations pose environmental risks that conflict with habitat conservation objectives in the U.S.'s already congested waterways. Some of the potential impacts upon environmental quality that can result from many port operations and related activities include:

Port Development and Watershed Impacts: Port expansion, bulkhead installation, land filling, pier construction/ rehabilitation, dredging, and dredged material placement are among the port

[5] It's possible for a shipping company to save $4.5 million per voyage by switching from a 2,500 to 6,000 TEU vessel.

activities that directly affect water quality, including wetland and other habitat loss, degradation, and creation. U.S. coastal areas — including both the waterfront and the waterways — support an extensive and unique set of ecological, commercial, and recreational functions, and provide food, shelter, and nursery areas for birds, marine invertebrates, fish, and other wildlife. Many of these productive areas have been modified or lost to support residential, agricultural, industrial, and commercial growth, as well as expansions of ports and terminals.

In Louisiana, Port Fourchon is one of the primary port facilities that services oil and gas exploration and production. "What is of particular importance is that the facility and the highway system that connects it to the interstate highway system are protected by only the surrounding landscape, which happens to be coastal marshes. Without this critical landscape that functions as a 'marsh barrier,' the highway system would be threatened by winter storms, high tides, tropical storms, and hurricanes" (Battelle 2002). If the highway were to be damaged, so would the flow of natural gas and crude oil production and delivery. Another valuable and protective function provided by this landscape is the levees and miles of coastal wetlands in front of them that protect thousands of residents and businesses from floods, storms and waves. If this essential marsh barrier were removed, the existing levees would have to be enlarged and armored significantly.

In addition to the protective landscape, this coastal landscape also supports Louisiana's multi-billion dollar fishing industry. A healthy ecosystem depends on a habitat that will support the many estuarine species that are a part of the ecological web in the Gulf of Mexico. Without this landscape, Gulf fisheries and wildlife such as waterfowl, alligators and neotropical migrants would be detrimentally affected. Because of natural processes and lingering effects of past activities and destruction, the coastal landscape is being converted to open water at the rate of 30 to 35 square miles per year (Battelle 2002).

Vessel-Support Activities: Vessel maintenance and construction activities also pose environmental risks. In fact, it is one of the water transportation sector's greatest environmental concerns. The major waste streams are chemical paint stripping, abrasive blast and surface preparation, painting and painting equipment cleaning, solvent, and engine overhauling and repair. In addition to particulate emissions, ship maintenance and repair activities emit various chemicals such as volatile organic compounds into the air.

Painting a vessel to improve appearance and performance and to prevent corrosion and hull fouling is an important maintenance practice. Prior to applying new paint however, the surface must be stripped and the old paint removed. This is usually done with a chemical paint stripper based on methylene chloride or with abrasive blasting. Blasting is used primarily because the medium is not hazardous – like garnet, flint grit or steel shot (Office of Compliance 1997a).

Engine repairs and other types of vessel repairs are also performed at the port facilities. Repairs may vary from small automotive-type engines to large boilers and turbines of tankers and other cargo vessels. These repairs result in waste such as spent lubricants and engine oils, solvents, batteries and coolants. Other repairs may include sheet metal work, metal finishing, or other specialty operations. Table 3.4 displays typical materials used in this repair and maintenance sector and their resulting wastes.

Table 3.4

Vessel Maintenance Operations, Typical Raw Material Inputs, and Pollution Outputs

Operation	Raw Material Input	Pollution Output
Paint Removal	Chemical paint stripper, blast media	Wastewater containing blasting media, organic paint sludges, heavy metals, stripping chemicals, volatile organic carbons (VOCs)
Painting	Antifouling paints	Waste paints, thinners, degreasers, solvents, resins and gelcoat, VOCs
Engine Repair	Degreasing solvents, carburetor cleaner	Waste turbine oil, lubricants, degreasers, mild acids, batteries, carburetor cleaners, VOCs
Machine Shop	Solvents, cutting fluids, degreasing acids and alkalies	Spent cutting and lube oils, scrap metal, degreasers, VOCs
Metal Finishing	Cyanide, heavy metal baths, acids and alkalies	Cyanide solutions, heavy metal sludges, corrosive acid, and alkali solutions

Source: Office of Compliance (1997a)

Because most shipbuilding and repair takes place outdoors, over, in and around water – it exposes the marine waters to these potential pollutants. Repair and maintenance yards represent the most prevalent pollution risk in the industry. Also, by their very nature of being able to hold water, large impervious surface areas, and their location, many of the activities at marine facilities are exposed to nature's elements and, therefore, are also large generators of stormwater. Stormwater frequently carries sediments, chemicals and debris from the ground surface, as it runs off into the marine or river waters.

Many municipalities and some industries are incorporating wetlands into their wastewater treatment systems to remove nutrients, process some chemical and organic wastes, and reduce sediment loads prior to discharge into riverine and marine waters. This form of pretreatment reduces industry and municipality costs, protects shellfish and swimming areas from closures, and reduces the number of fish consumption advisories issued.

Cargo Handling/Landside Vehicle Emissions: Although most environmental hazards in a marine facility result from the repair and maintenance services provided to vessels, there are also problems that occur as a result of cargo handling. "A significant amount of diesel-powered equipment is used in a typical marine facility, such as forklifts, tractors, and front-end loaders. Air emissions from these vehicles, when combined with those from vessels, as well as from trucks and trains that deliver and remove cargo, may contribute to nonattainment of certain air requirements" (Office of Compliance 1997a).

The operations that handle bulk cargo use advanced equipment such as pneumatic continuous ship loaders and unloaders, conveyer belts, stockpiling and reclaiming machines or cranes with grab buckets and front-end loaders. As the industry expands, so will the need to unload cargo quicker and faster. These loading and unloading techniques produce high amounts of dust and solid waste accumulation. Dry bulk-transfer operations generally have dust control problems because dust is generated each time cargo is transferred. Liquid bulk-transfer operations can be a source of hydrocarbon emissions that are readily converted into photochemical smog by radiation from the sun (Office of Compliance 1997a).

Dredging: Proper depth in navigation channels allows ships to move safely through harbors and provides turning basins and adequate water depth alongside terminal facilities. To maintain this depth, several hundred million cubic yards of sand, gravel and silt must be dredged from waterways and harbors each year. However, this maintenance and improvement process is challenging and controversial because ports are located in or near some of the Nation's most environmentally sensitive areas – valuable wetlands, estuaries and fisheries. And, the materials that are dredged may uncover toxins or contaminated sediments that have accumulated over time.[6]

Legal and Regulatory Framework: Under the Clean Water Act (Section 404), the U.S. Army Corps of Engineers (USACE) manages the program that directs dredging and disposal of dredged material from navigation improvement and maintenance programs. The USACE is responsible for developing and maintaining Federal navigation channels. In addition, non-Federal permit applicants (e.g., port authorities, pipeline operators, terminal owners, industries, and private individuals) dredge another 100 million cubic yards annually. The USACE reviews potential projects and issues permits for dredging and disposal of the dredged material in accordance with Federal regulations.

The EPA oversees and develops the environmental criteria by which the USACE evaluates proposed disposal of dredged material. The EPA also designates and monitors ocean-dredged material disposal sites. A USACE permit is required when dredged sediments are disposed of in the ocean, inland, or near-coastal waters. If dredged material is disposed of on land, various Federal, State, and local regulations may apply.

The legal and regulatory framework regarding dredging consists of a number of statutes and regulations that are based upon a variety of different goals and objectives. For this reason dredging projects can become stalled in the review process. The problems that can hinder the dredging process fall into the following categories: planning; project review; scientific uncertainties; inconsistent funding allocations; and inconsistent vertical and horizontal collaboration among governmental offices and stakeholders. In 1995, the National Dredging Team was established to facilitate communication, coordination, and resolution of dredging issues among Federal agencies and to ensure that dredging of U.S. harbors and channels is conducted in a timely, environmentally sensitive, and cost-effective manner. Regional Dredging Teams have also been formed around the country to provide forums for local and regional issue resolution; foster the exchange of information with stakeholders; and provide liaison with local planning groups.

Reducing Contaminated Materials: The complexities of the physical, chemical, and biological composition of the sediment and the environmental conditions specific to each disposal site create uncertainties in scientific evaluations and testing of dredged materials. This increases

[6] Unless otherwise noted, the remainder of the discussion on dredging is derived from: Maritime Administration, *A Report to Congress on the Status of the Public Ports of the United States 1996 - 1997*, (Washington D.C.: Department of Transportation).

the need to develop scientifically dependable toxicity tests and a biological-effects database for contaminants that bioaccumulate. It is important to improve the understanding of the science involved in dredged material management because this information assists risk managers in making scientifically sound decisions that protect ecological resources and human health.

Although contaminated sediments pose a complex problem, so does the volume of sediment entering the waterway. Progress has been made in decreasing the contaminants that get discharged into waterways; however, stormwater runoff remains a major concern. Management practices (soil erosion control, reduced use of fertilizers, chemicals, etc.) and planned growth could be used to reduce pollution entering the waterway. Approaches that may help are: planning development to maintain buffers along the waterways, minimizing the burden on municipal sewer systems, and controlling runoff from paved surfaces. These efforts, combined with attempts to decrease contaminant discharge and the removal of existing contaminated sediments through dredging, should result in some reduction in the future amount of dredged material that is contaminated.

Reuse of Dredged Material: Although the dredging and resurfacing of contaminated sediments is a major topic, really, only "5 to 10 percent of dredged material is contaminated and some of this material may, in some cases, also be reused in beneficial applications" (Maritime Administration 1999). In recent years there has been a change in emphasis on dredged material management to maximize its potential use – dredged material can also be a resource to be used beneficially. Among the beneficial uses for dredged materials are beach nourishment, wetlands creation, habitat restoration, barrier island reclamation, manufactured soil, abandoned mine reclamation, contaminated site remediation, and landfill for development and recreation uses (Maritime Administration 1999).

"Ports will continue to explore beneficial uses of dredged material — options such as using the material as top soil, potting soil, aggregates, or even bricks. Options other than ocean disposal, however, inevitably increases project costs and requires longer lead times for planning dredging projects. Planning such projects is part of the role ports play to balance economic reality with environmental requirements" (American Association of Port Authorities 2002b).

Dredging Expenditures: Capital expenditures on dredging were 11.1 percent of total port expenditures in the U.S. for 2000. The Gulf Coast Region accounted for 29 percent of these expenditures, exceeded only by the North Atlantic Region at 34 percent. The Gulf Coast Region was followed by the South Pacific region with 27 percent, the North Pacific region with 6 percent, and South Atlantic with 4 percent. Dredging in the Great Lakes accounted for less than 0.1 percent of total dredging expenditures (Maritime Administration 2001a).

Investment in Infrastructure: As previously discussed throughout this report, improving and maintaining navigation channels is critical to sustaining the rapidly growing marine transport industry. Bottlenecks can occur when channels are not deep enough for ships to safely navigate and dock at berths. Unless ports are dredged, cargo cannot move in the most cost-effective way through the intermodal transportation chain. Also, as ship sizes and volumes of cargo increase, so must the intermodal transfer operations.

Efficient transportation depends on intermodal connections. In order to move waterborne cargo quickly to or from land based operations, trucks and railroads need to have clear access to ports. "For some ports, the weakest link in their logistics chain is at their back doors, where congested roadways or inadequate rail connections to marine terminals cause delays and raise transportation costs" (American Association of Port Authorities 2002 c). According to the AAPA, a 2000 Federal Highway Administration Report to Congress on the National Highway System (NHS) Intermodal Connectors cited that connectors to ports, as opposed to other freight terminals, were found to be in the worst condition and received the smallest level of funding. They also had twice as many miles with pavement deficiencies when compared to non-Interstate NHS routes. Like a pipeline, the nation's intermodal transportation system is only as efficient as its narrowest, most congested point – often, the landside connection. No matter how much ports invest or how productive their marine terminal facilities, the transportation system cannot operate to maximum efficiency unless cargo can move quickly, and cost-effectively, in or out of ports.

The importance of major intermodal marine linkages or connections to surface transportation was recognized in the National Highway System Designation Act of 1995. The Act listed directions for modifications to connections to major ports, airports, international border crossings, public transportation and transit facilities, interstate bus terminals, and rail and other intermodal transportation facilities. In 1998, the Transportation Equity Act for the 21st Century (TEA-21) was signed, authorizing highway, highway safety, transit and other subsurface transportation programs for the next 6 years. Within TEA-21, there are a number of programs that could potentially benefit port industry access concerns. Although these programs do not earmark specific funds for port related projects, they may meet program eligibility requirements.[7]

Financing Improvements: To keep up with changing vessel sizes and industry trends, ports must continuously update, modernize, and expand their facilities. Since 1946, U.S. ports have invested $21.9 billion in capital improvements and related infrastructure. During this period, the Gulf Coast region accounted for over 18 percent of these expenditures, only to be exceeded by the South Pacific region (30 percent). From 1996 through 2000, the public port industry invested over $6 billion in capital improvements. Approximately 16.5 percent of this 5-year spending was in the Gulf Coast region. The Gulf region's spending was exceeded by South Pacific region at 39 percent and the South Atlantic region at 17 percent.

During the five-year period of 2001-2005, public port expenditures are predicted to reach a record total of $9.4 billion – an increase of 12.8 percent compared to last year. The South Pacific region continues as the focus of future investment activity with proposed expenditures of $3.1 billion (33.8 percent). Four other regions are projecting investment levels in excess of $1 billion – the South Atlantic at $1.7 billion (18.8 percent), the Gulf at $1.6 billion (17.1 percent), the North Atlantic at $1.5 billion (16.6 percent), and the North Pacific at 1.2 billion (12.8 percent). From a coastwise perspective, the West Coast is projecting to invest over $4.3 billion, with East Coast expenditures at $3.3 billion and the Gulf at $1.6 billion (Maritime Administration 2001).

3.4 Regulations

Public ports are usually established by state and local governments to develop, manage and promote the flow of waterborne commerce in the area. Ports can also be developed by private companies. A port authority – which can be a state or local government, private agency or firm

[7] This discussion was derived from: Maritime Administration, *A Report to Congress on the Status of the Public Ports of the United States 1996 - 1997*, (Washington D.C.: Department of Transportation).

– is the governing body that oversees the ports operations. In addition to maritime functions, port authority activities may also include jurisdiction over airports, bridges, tunnels, commuter rail systems, inland river or shallow draft barge terminals, industrial parks, Foreign Trade Zones, world trade centers, terminal or shortline railroads, ship repair, shipyards, dredging, marinas and other public recreational facilities.

The port authority is governed by a commission with members that are appointed by city and county governments. For instance, the seven-member Port of Houston Commission is the governing body for the Port of Houston Authority. The City of Houston and the Harris County Commissioners Court each appoint two commissioners. These two governmental entities jointly appoint the chairman of the Port Commission. The Harris County Mayors and Councils Association and the City of Pasadena each appoint one commissioner.

In addition to the Commission, the port authority may have an executive office. The staff is responsible for overseeing the day-to-day operations of the port and implementing policies and directives given by the Port Commission. They also supervise other divisions of the authority such as: Administration, Facilities, Operations, Trade Development, Protection Services and Public Affairs.

Legislation: The Ports and Waterways Safety Act (PWSA)[8] is designed to promote navigation, vessel safety, and protection of the marine environment. The PWSA applies in any port or place under the jurisdiction of the U.S. Waters subject to the jurisdiction of the U.S. are defined as navigable waters, other waters on lands owned by the U.S., and waters within U.S. territories and possessions of the U.S.

The PWSA requires the U.S. Coast Guard to promulgate regulations regarding "design, construction, alteration, repair, maintenance, operation, equipping, personnel qualifications and manning of vessels… necessary for the increased protection against hazards to life and property, for navigation and vessel safety and for enhanced protection of the marine environment."[9] The Act also authorizes the U.S. Coast Guard to establish vessel traffic service/separation (VTSS) schemes for ports, harbors, and other waters subject to congested vessel traffic. These schemes help provide order and predictability to vessel movements by establishing lanes with a "separation zone" between opposing vessel traffic similar to the "median" between opposing traffic on the highway system. VTSS apply to commercial ships, other than fishing vessels, weighing 300 gross tons or more.

The PWSA was amended by the Port and Tanker Safety Act of 1978 (PTSA). Under this amendment, Congress found that navigation and vessel safety and protection of the marine environment are matters of major national importance and that increased vessel traffic in the nation's ports and waterways creates substantial hazard to life, property or the marine environment. Also, increased supervision of vessel and port operations was found necessary in order to:

1. reduce the possibility of vessel or cargo loss, or damage to life, property, or the marine environment;

[8] The PWSA was amended by the Port and Tanker Safety Act of 1978 (PTSA), Public Law 95-474, and the Oil Pollution Act of 1990 (OPA).

[9] 46 USC 3703(a)

2. prevent damage to structures in, on, or immediately adjacent to the navigable waters of the U.S. or the resources within such waters;
3. ensure that vessels operating in the navigable waters of the U.S. shall comply with all applicable standards and requirements for vessel construction, equipment, manning, and operational procedures; and
4. ensure that the handling of dangerous articles and substances on the structures in, on or immediately adjacent to the navigable waters of the U.S. is conducted in accordance with established standards and requirements.[10]

Under the PTSA, it was also determined that advanced planning is critical in determining proper and adequate protective measures for the nation's ports and waterways and the marine environment, with continuing consultation with other federal agencies, state representatives, affected users and the general public, in the development and implementation of such measures.

"The PTSA provided broader regulatory authority over regulated and non-regulated areas. It provided for improvements in the supervision and control of all types of vessels operating in navigable waters of the U.S., and in the safety of foreign or domestic tank vessels that transport or transfer oil or hazardous cargoes in ports or places subject to U.S. jurisdiction" (NOAA 2002).

3.5 Industry Trends and Outlook

The offshore drilling industry has come a long way since it installed the first subsea wellhead in 1964. The Gulf of Mexico represents an expanding frontier with extraordinary growth – especially of deepwater oil and gas industry activity over the past 7 years. And, the point of discussing the growth of the offshore industry in the Gulf Mexico is that, as it grows, so does the need for support services provided by regional ports. As previously stated, regardless of where the exploration and production equipment, personnel and supplies originate, at some point these resources must pass through a port to reach the drilling site. This point of intermodal transfer is vital to maintaining reliable, uninterrupted production of oil and gas from the Gulf.

According to a recently released MMS report, "[t]he large volume of active deepwater leases, the increased drilling program, and the growing deepwater infrastructure all indicate that the deepwater GOM will increase in importance as an integral part of this nation's energy supply and will remain one of the world's premier oil and gas basins" (USDOI, MMS 2002a). According to the MMS report, 59 percent of all oil production in the Gulf comes from deep water. And even in the short time since the MMS's last report in 2000 (USDOI, MMS 2002a), several "remarkable" achievements have been made, for example:

- The number of drilling rigs working in deepwater has increased from 28 to 43;
- The number of ultra-deepwater (> 5,000 ft) capable rigs has increased from 18 to 26 (44 percent) and the number of ultra-deepwater wells increased from 37 to 59 (59 percent);
- There was a 59 percent increase in the number of producing deepwater fields;

[10] 33 USC 1221

- Deepwater oil production is rapidly approaching the all-time shallow-water oil production record established in 1971.
- New deepwater drilling added over 4 billion BOE, a 49 percent increase, to the Gulf of Mexico oil and gas inventory.

New advances in technology are also stimulating investment in the Gulf, although the oil majors remain a leading force on the shelf, the independents are starting to gain more acreage (Energy Day 2002). In March 2002, independent producers accounted for 70 percent of the $363.2 million bid on blocks offered in the Central Gulf of Mexico Lease Sale 182. Although Phillips Petroleum had the highest bid – $17.5 million for deepwater block 199 in Green Canyon – it was the independents that "really spread the cash around." For instance, Dominion Exploration & Production spent $37 million for 37 tracts and Spinnaker Exploration spent $28.8 million for 42 tracts. The two companies also teamed up to win about $20 million worth of other high-profile tracts (Gas Daily 2002a).

Another lease sale, in August 2002 – Western Gulf Lease Sale 184 – provided more opportunities for companies to gain acreage. As will the 11 additional block sales (shown in Table 3.5) as proposed by the MMS in their "Proposed Final Outer Continental Shelf Oil & Gas Leasing Program, 2002-2007."

Table 3.5

Gulf of Mexico Lease Sale Schedule – Proposed for 2002-2007.

Sale No.	Area	Year
184	Western Gulf of Mexico	2002
185	Central Gulf of Mexico	2003
187	Western Gulf of Mexico	2003
189	Eastern Gulf of Mexico	2003
190	Central Gulf of Mexico	2004
192	Western Gulf of Mexico	2004
194	Central Gulf of Mexico	2005
196	Western Gulf of Mexico	2005
197	Eastern Gulf of Mexico	2005
198	Central Gulf of Mexico	2006
200	Western Gulf of Mexico	2006
201	Central Gulf of Mexico	2007

Source: USDOI, MMS (2002b)

Inventory:

Table 3.6 provides results of a 2001 inventory of the major port facilities in the Gulf which provide support services such as those described in previous sections of this chapter to the offshore oil and gas industry.

Table 3.6

Major Port Facilities Servicing the Offshore Oil and Gas Industry in the Gulf

Name	Operator	City	State
Port of Mobile/Alabama State Docs	Alabama State Port Authority	Mobile	AL
Port of Manatee	Manatee County Port Authority	Palmetto	FL
Port of Panama City	Panama City Port Authority	Panama City	FL
Port of Pensacola	Pensacola Port Authority	Pensacola	FL
Port St. Petersburg	Port St. Petersburg	St. Petersburg	FL
Port of Tampa	Tampa Port Authority	Tampa	FL
Port of Greater Baton Rouge	Greater Baton Rouge Port Commission	Port Allen	LA
Port of Fourchon	Greater Lafourche Port Commission	Port Fourchon	LA
Port of Grand Isle	Grand Isle Port Commission	Grand Isle	LA
Port of Iberia	Port of Iberia	New Iberia	LA
Port of Lake Charles	Port of Lake Charles	Lake Charles	LA
Port of New Orleans	Port of New Orleans	New Orleans	LA
Port of Plaquemines	Plaquemines Parish Port, Harbor and Terminal District	Braithwaite	LA
Port of South Louisiana	Port of South Louisiana	LaPlace	LA
St. Bernard Port	St. Bernard Port	Chalmette	LA
Port of Pascagoula	Port of Pascagoula	Pascagoula	MS
Biloxi Port	Biloxi Port	Biloxi	MS
Port of Gulfport	Port of Gulfport	Gulfport	MS
Port of Beaumont	Port of Beaumont	Beaumont	TX
Port of Brownsville	Port of Brownsville	Brownsville	TX
Port of Corpus Christi	Port of Corpus Christi	Corpus Christi	TX
Port of Freeport	Port of Freeport	Freeport	TX
Port of Galveston	Port of Galveston	Galveston	TX
Port of Houston	Port of Houston Authority	Houston	TX
Port of Orange	Orange County Navigation and Port	Orange	TX
Port of Port Lavaca-Point Comfort	Calhoun County Navigation District	Point Comfort	TX
Port of Port Arthur	Port of Port Arthur	Port Arthur	TX
Port of Texas City Texas City/Terminal	Port of Texas City	Texas City	TX
Port of Victoria	Victoria County Navigation District	Victoria	TX

Source: The Louis Berger Group, Inc., 2001

Additional information regarding individual ports can be found in Appendix II.

With increased development comes a need for additional support and port expansion. For example, this need has already been experienced in Manatee County, Florida with the expansion of Port Manatee and its windfall from the Gulfstream Pipeline Project.

Port Manatee: Port Manatee in Manatee County, Florida is in the middle of a considerable expansion effort with more than $60 million of projects under design or construction. It is hoped that the Port expansion will encourage investments and contracts from industries such as perishable commodities, cruise operations and containerized cargo.

Three berths are under construction or expansion. Berth 12 is 1,450 feet long and when complete will have a depth of 40 feet on a 400 foot wide channel. A utilitarian berth for providing service for cruise, general and containerized cargo will also be built. Berth 5 is being constructed for Vulcan/ICA. The 800 foot long berth will be home to Vulcan's 700 foot self discharging bulk ships. The berth should be completed by December 2003. Additionally, a new 60,000 square foot cold storage warehouse is being added to Port Manatee's Berth 11.

Theodore, AL: Bredero Price Co. has recently opened a 500-employee facility in Theodore, Alabama to coat piping for deepwater oil and natural gas applications. The project, initially costing approximately $45 million, was expanded beginning in late 2001, with an investment of at least $20 million. The Houston-based company is expected to install a new pipe welding area, pipe-coating line addition, and several batch concrete plants. Additionally, new docking facilities were installed to accommodate product loading onto the largest ocean-going vessels (Industrial Information Resources, Inc. 2001).

In addition to each of these major expansions is the economic windfall that has and will continue to result from the Gulfstream Natural Gas Project.

Gulfstream Natural Gas Project: The Gulfstream Natural Gas Project is a 753-mile pipeline that originates near Pascagoula, Mississippi and Mobile, Alabama and crosses the Gulf of Mexico (with 431 miles of 36-inch diameter pipe) to Manatee County, Florida. Onshore, 306 miles of pipe, ranging in diameter from 36 inches to 16 inches, stretches across south and central Florida, terminating in Palm Beach County. Placed into service on May 28, 2002, the $1.6 billion pipeline project will provide approximately 1.1 bcf per day of natural gas to fuel new electric generation capacity throughout Florida.

Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities which represent long-term commitments for the majority of its 1.1 bcf per day. Subsidiaries of Duke Energy and Williams purchased 100 percent interest in the Gulfstream Project from Coastal Corporation in February 2001.[11]

The pipeline is expected to have added $10 million to $12 million to Port Manatee's bank account during construction, which includes the $3 million that has already been realized. The Gulfstream project ordered 450,000 tons of steel pipe from Berg Steel Pipe Corp. of Panama City. The project required Berg to import about 40 percent of the pipe from its European parent company because of the time constraints of the project. The project created opportunities for two Port Manatee tenants, Eastern Cement Corporation and Lafarge Florida Inc., to sell products used for the pipeline construction. In addition to using the port for import, export and storage, the Project has leased 190 acres of port property for pipeline staging and storage (The Business Journal 2002). The project also included Bredero Price Co. of Theodore, Alabama coating approximately 60 percent of the pipe with concrete for deepwater placement (Scott 2002).

[11] Due to regulatory mandates related to Coastal Corporation's merger with El Paso Energy Corporation, Coastal was forced by FERC to divest the project.

3.6 Summary

It is apparent that the oil and gas industry continues to thrive in the Gulf of Mexico. With the industry has come a logistical support system that links all phases of the operation and extends beyond the local community. Land-based supply and fabrication centers are providing the equipment, personnel and supplies necessary for the industry to function through intermodal connections at the Gulf Coast ports. The necessary onshore support segment includes inland transportation to supply bases, equipment manufacturing and fabrication. The offshore support involves both waterborne and airborne transportation modes.

As the industry continues to evolve, so do the requirements of the onshore support network. With advancements in technology, the shore side supply network will continue to be challenged to meet the needs and requirements of the industry. All supplies must be transported from land-based facilities to marine vessels or helicopters to reach offshore destinations. This utilizes both water and air transportation modes. The intermodal nature of the entire operation gives ports (who traditionally have water, rail and highway access) a natural advantage as an ideal location for onshore activities and intermodal transfer points. Therefore, ports will continue to be a vital factor in the total process and must incorporate the needs of the offshore oil and gas industry into their planning and development efforts, particularly with regard to determining their future investment needs. In this manner, both technical and economic determinants must influence the dynamics of port development.

This extensive network of supply ports includes a wide variety of shore side operations from intermodal transfer to manufacturing. Their distinguishing features show great variation in size, ownership and functional characteristics. Basically, two types of ports provide this supply base. Private ports operate as dedicated terminals to support the operation of an individual company. They often integrate both fabrication and offshore transport into their activities. Public ports lease space to individual business ventures and derive benefit through leases, fees charged and jobs created. These benefits spread throughout the entire area and are viewed as economic development impacts. Thus, the public ports play a dual role by functioning as offshore supply points and as industrial or economic development districts. An efficient network of ports lowers costs associated with oil and gas production and significantly boosts the well being of citizens of the adjacent communities.

Port profiles present information depicting the basic characteristics of a few sample oil and gas ports. These exemplify the type of infrastructure and operational parameters that are common to oil and gas support bases. Their institutional framework indicates the governing hierarchy ultimately responsible for the future direction of the port and its impacts on the local community. It is anticipated that these characteristics are consistent with the level of effort and development necessary to support offshore oil and gas industrial development. However, to continue to offer a viable service and to stay current with technological trends and industry standards, ports must be able to incorporate this information into their planning for future infrastructure development, staffing needs, and other impacts associated with rapid industrial growth.

Issues and concerns that must be addressed at the local level have resulted from the significant prosperity that has followed the industry. These extend beyond specific port needs into the community itself. For example, additional commercial traffic has caused worsening road conditions. Additional population has generated housing problems and the need for more law enforcement. Greater demand for potable water has brought about shortages. The local schools are stretched to their limits in accommodating more children. All of these problems can be nullified with additional infrastructure. However, additional infrastructure is difficult to develop. It is expensive to construct and requires substantial planning and construction time prior to completion.

Even though local governments have gained revenue from the increased activity in their jurisdictions, the demands for additional services and facilities resulting from oil and gas operations have exceeded growth in the revenue stream. Local tax dollars cannot meet the demand for so many improvements in such a short time. State and federal matching funds are being sought where possible. But the acquisition of those funds often has built in delaying factors. Nevertheless, communities are attempting to meet the burgeoning demands of a rapidly growing population base.

Thus, the industry is determining the direction and scope of improvements being made at local levels. Communities, just like the ports, must be able to anticipate future demands for their services. In order to plan for this growth, they need timely information about trends in the industry. The ability to identify and quantify offshore needs and growth directions is essential for the economic well being of the citizens and the continued ability, of both the ports and communities, to provide the required offshore support.

4.0 SHIPYARDS/SHIPBUILDING

4.1 Introduction

The shipbuilding and repair industry builds ships, barges and other large vessels, whether self-propelled or towed by other craft. Shipyards, or facilities that build ships, operate on a job basis. Unlike most other industries, each year only a small number of valuable orders are received that often take years to fill. Orders for ships and ship repairs are primarily placed by the federal government or companies that can include: commercial shipping companies, passenger and cruise companies, ferry companies, petrochemical companies, commercial fishing companies, and towing and tugboat companies. The principal federal government agencies placing shipbuilding and repair orders include the Naval Sea Systems Command, the Military Sealift Command, the Army Corps of Engineers, the U.S. Coast Guard, the National Oceanic and Atmospheric Administration (NOAA), the National Science Foundation, and the Maritime Administration (Office of Compliance 1997b).

4.2 Description and Typical Facilities

Shipyards are often categorized into a few basic subdivisions either by type of operations (shipbuilding or ship repairing), by type of ship (commercial or military), and shipbuilding or repairing capacity (first-tier or second-tier). Ships themselves are often classified by their basic dimensions, weight (displacement), load-carrying capacity (deadweight), or their intended service. In the U.S., there are considerable differences between shipyard operations when constructing ships for commercial purposes and when constructing ships for the military.[12]

Commercial Ships: Commercial ships can be subdivided into a number of classes based on their intended use. Commercial ship classes include dry cargo ships, tankers, bulk carriers, passenger ships, fishing vessels, industrial vessels, and others. Dry cargo ships include break bulk, container, and roll-on/rolloff types.

Unlike the military market, the commercial ship market must also compete internationally, making it much more cost competitive. The cost of building and maintaining a ship must be low enough to allow owners to profit. This has a significant impact on the manner in which commercial ships are built and repaired. The intense global competition in this industry is the main reason that since World War II, U.S. shipyards have produced relatively few commercial ships. In this regard, since 1981 the U.S. shipyards received less than one percent of all commercial orders for large ocean going vessels in the world, and no commercial orders for large ocean going cruise ships.

Military Ships: Military ship orders have been the mainstay of the industry for many years. The military ship market differs from the commercial market in that the major market drivers are agency budgets as set by government policy. The military ship market can be divided into combatant ships and ships that are ordered by the government, but are built and maintained to commercial standards rather than military standards. Combatant ships are primarily ordered by the U.S. Navy and include surface combatants, submarines, aircraft carriers, and auxiliaries.

[12] Unless otherwise noted, this discussion and remaining descriptions are taken from: Office of Compliance, *Profile of the Shipbuilding and Repair Industry* (Washington D.C.: Office of Enforcement and Compliance Assurance, Environmental Protection Agency), 1997b, p. 3-4.

Government owned noncombatant ships are mainly purchased by the Maritime Administration's National Defense Reserve Fleet (NDRF) and the Navy's Military Sealift Command (MSC). Other government agencies that purchase non-combatant ships are the Army Corps of Engineers, National Oceanic and Atmospheric Administration, and the National Science Foundation. Such ships often include cargo ships, transport ships, roll on/roll off ships, crane ships, tankers, patrol ships, and ice breakers.

First and Second-Tier Shipyards: U.S. shipyards are also classified by the Maritime Administration (MARAD) as either first-tier shipyards or second-tier shipyards. First-tier shipyards make up the "U.S. major shipbuilding base" (MSB). As defined by MARAD and the Department of Transportation in *Report on Survey of U.S. Shipbuilding and Repair Facilities, 2001* the MSB is comprised of privately owned shipyards that are open and have the capability to construct, drydock, and/or topside repair vessels with a minimum length overall of 122 meters, provided that water depth in the channel to the facility is at least 3.7 meters. Facilities are further classified as (Office of Shipbuilding and Marine Technology 2001):

- ***Active Shipbuilding Yards:*** The Active Shipbuilding Yards are comprised of those privately owned U.S. shipyards/facilities, that are open, with at least one building position capable of accommodating a vessel 122 meters (400 feet) in length and over, and are currently engaged in the construction of naval ships and/or major oceangoing merchant vessels 122 meters (400 feet) in length and over.

- ***Shipyards with Build Positions:*** Privately owned shipyards/facilities that are open, with at least one build position capable of accommodating a vessel 122 meters in length and over, and that have not constructed a naval ship or major oceangoing merchant vessel in the past two years.

- ***Repair (with Drydocking):*** Shipyards that have graving docks, floating drydocks or marine rails capable of handling naval ships and/or major oceangoing merchant vessels 122 meters in length and over.

- ***Topside Repair:*** Shipyards that have sufficient berth/pier space, including dolphins, to accommodate a naval ship or major oceangoing merchant vessel of 122 meters in length or over.

Second-tier shipyards are comprised of the many small and medium-size shipyards that construct and repair smaller vessels (under 122 meters) such as military and non-military patrol boats, fire and rescue vessels, casino boats, water taxis, tug and towboats, off-shore crew and supply boats, ferries, fishing boats, and shallow draft barges. A number of second-tier shipyards are also able to make topside repairs to ships over 122 meters in length. These facilities are also further classified (Office of Shipbuilding and Marine Technology 2001):

- ***Boatbuilding and Repair Companies:*** Privately owned shipyards capable of building and/or repairing commercial and military vessels less than 122 meters (400 feet) in length.

- ***Vessel Repair Companies:*** Facilities that only provide repair services, either repair with drydocking or topside repair, to vessels less than 122 meters (400 feet). These companies must have their own waterfront facilities.

- ***Fabricators/Manufacturers of Maritime Vessels:*** Companies that build small commercial crafts less than 76 meters (250 feet).

4.3 Industry Characteristics

The Maritime Administration (1999) reported that there are approximately 93 private shipyards in the MSB employing over 47,000 production workers. MSB shipyards employ about 60 percent of the total work force of the shipbuilding and repair industry. The remaining 40 percent are in smaller establishments with 10 or more employees (Maritime Administration 1999). As shown in Figure 4.1, the largest number of production workers are employed by shipyards of the smallest category. Over 29,000 workers are employed by nine active shipbuilders – this is more workers than the three other categories combined (15.7 thousand employees at 84 yards).

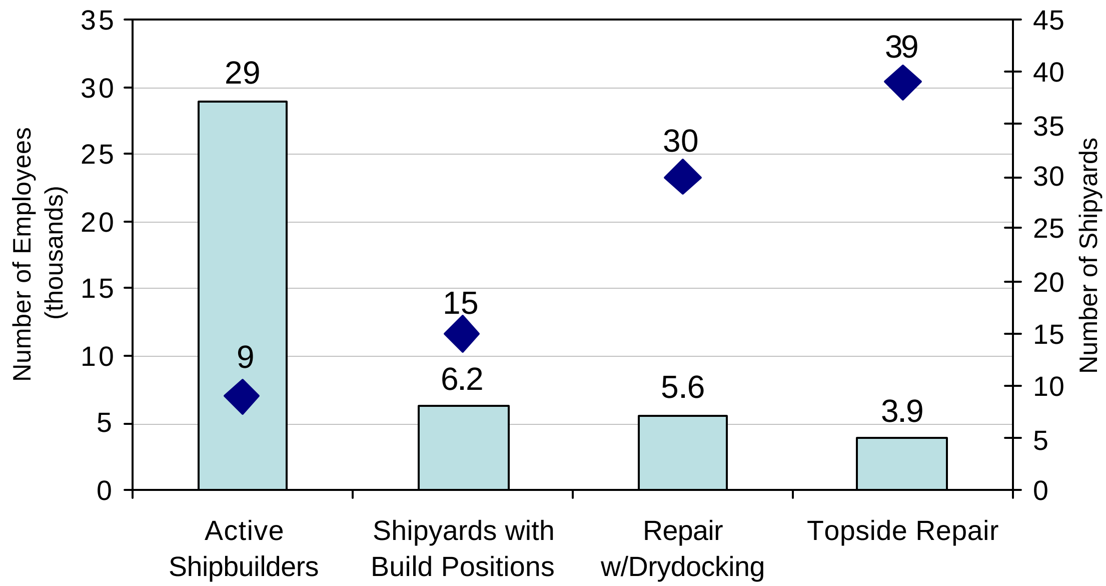

Figure 4.1. Number of Production Workers by Shipyard Type.

Source: Office of Shipbuilding and Marine Technology (2002)

According to the *1997 Census of Manufacturers* data (the most recent Census data available), there were approximately 700 shipbuilding and repairing yards under SIC code 3731 (including both first and second-tier yards). The payroll for 1997 totaled $3.4 billion for a workforce of 97,385 employees, and value of shipments totaled $10.6 billion. Based on this Census of Manufacturers data, the industry is very labor intensive. The value of shipments per employee (a measure of labor intensiveness) is $108,600 which is about one third that of the steel manufacturing industry ($356,000 per employee) and only five percent that of the petroleum refining industry ($2.4 million per employee). It is the relatively few (but large) shipyards, however, that account for the majority of the industry's employment and sales.[13]

As shown in Table 4.1, the geographic distribution of the shipbuilding industry is concentrated on the coasts. Of the 93 majors, over one-third (33 facilities) are located on the Gulf Coast, the majority of which are repair with drydocking. Another one-third is found on the East Coast with 32 facilities, and the West Coast has 18 (again, mostly repair).

Table 4.1

Number of Shipyards by Type and Region

	Active Shipbuilders	Shipyards with Build Positions	Repair with Drydocking	Topside Repair
East Coast	4	3	13	12
Gulf Coast	**4**	**6**	**6**	**17**
West Coast	1	2	7	8
Great Lakes	0	4	1	2
Non-Contiguous	0	0	3	0
Total	**9**	**15**	**30**	**39**

Source: Office of Shipbuilding and Marine Technology (2002)

<u>Offshore Supply Vessels:</u> Of particular importance to this report are the offshore supply vessels (OSV) – those that work solely to provide services to offshore oil and gas platforms. These services can include transportation of personnel, equipment and various supplies. One type of OSV, knows as PSVs, are involved in providing offshore drilling and production facilities with various supplies including equipment, pipes, lubricants, chemicals and drilling mud. They can also perform fire fighting as well as oil recovery operations in case of an oil spill at an offshore platform. The OSV category also includes vessels called "anchor handling tugs/supply vessels" (AHTS). These units spend a majority of their time working as supply vessels and only a small amount of time moving anchors.

The supply boat fleet has increased significantly in the past 5 years. As seen in Figure 4.2, the GOM supply vessel fleet has increased by approximately 100 boats (35 percent) since 1996. This incorporates a net impact of 116 newbuilds, the influx of vessels to the GOM from foreign markets and the attrition of older, obsolete boats (Pickering et al. 2000). As of 2000, there were 376 supply boats in the Gulf. Of these, 325 were being actively marketed. The remaining 51 were either undergoing major upgrades, or had been removed from service and not actively marketed.

[13] Unless otherwise noted, this section is from: Office of Compliance, *Profile of the Shipbuilding and Repair Industry* (Washington D.C.: Office of Enforcement and Compliance Assurance, Environmental Protection Agency), 1997b, p. 3.

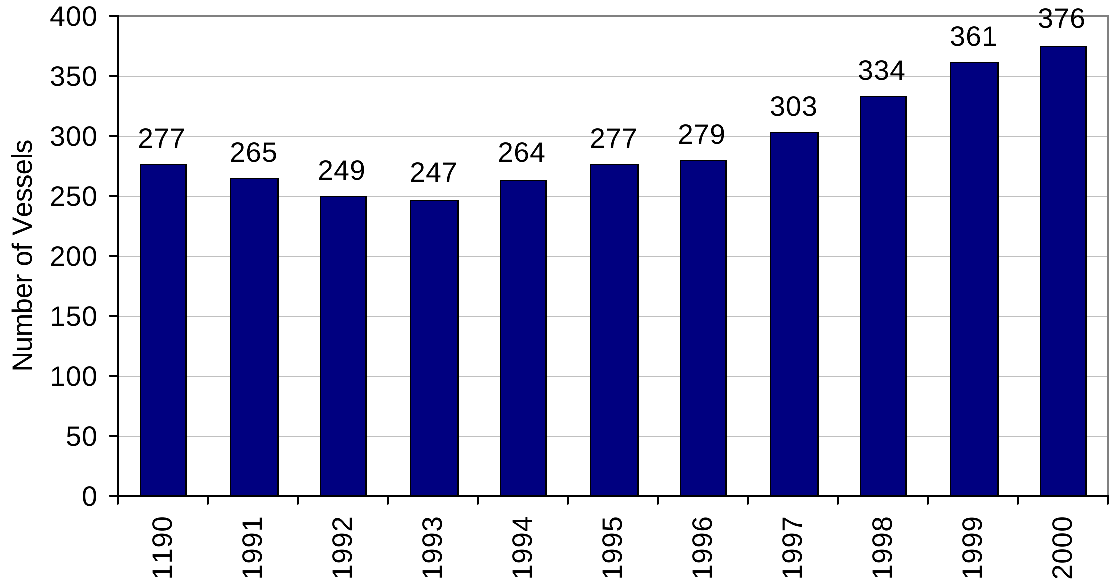

Figure 4.2. Gulf of Mexico Supply Boat Total Fleet Size.

Source: Pickering et al. (2000)

Although the traditional workhorse of the Gulf has been the standard 180 foot supply vessel, none of the boats built during this last cycle was less than 190 feet in length. Eighty-seven percent of newbuilds were 200 feet in length or greater. In fact, over half of the 116 newbuilds were at least 220 feet in length. “The increasing size of the newbuild fleet is directly related to the emergence of deepwater drilling in the GOM over the past four years” (Pickering et al. 2000).

The Gulf of Mexico supply vessel industry is very fragmented. There are a total of 24 boat operators in the Gulf. Sixteen of these operators own fleets of less than 10 boats. Nine of the operators own three boats or less. And, of these 24 operators, 6 are public companies and the other 18 are privately held. The public companies are: Tidewater, Trico Marine, Ensco Marine (subsidiary of Ensco International), Seacor Smit, Sea Mar (part of Nabors Industries) and Seabulk Offshore (part of Hvide Marine). These six companies currently control 70 percent of the total GOM supply boat fleet (Figure 4.3) (Pickering et al. 2000).

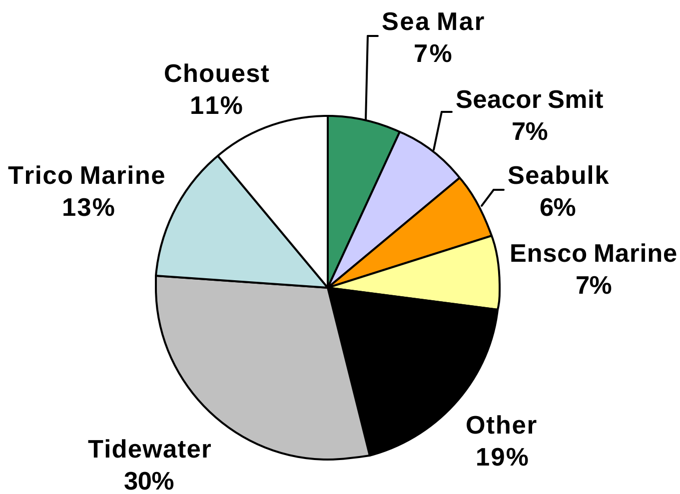

Figure 4.3. Supply Boat Market Share by Vessels in the Gulf of Mexico.

Source: Pickering et al. (2000)

The companies with the youngest fleets are Hornbeck Offshore Services (7 boats with an average age of 1.1 years), Otto Candies (5 boats averaging 1.2 years), Kim Susan (3 boats averaging 2 years), Edison Chouest (41 boats averaging 3.9 years) and Candy Fleet (8 boats averaging 4.5 years). These young fleets reflect a trend towards larger vessels as the average length for each fleet exceeds 200 feet (Pickering et al. 2000).

4.4 Regulations

This section discusses the Federal regulations that apply to this sector. The purpose of this section is to highlight and briefly describe the applicable regulations. The descriptions below are general information. Depending upon the nature or scope of the activities at a particular facility, these summaries may or may not necessarily describe all applicable regulatory requirements.

Merchant Marine Act of 1920: More commonly known as the Jones Act, it requires that all merchandise being transported by water between U.S. points must travel in vessels that are built in the United States, crewed by U.S. mariners and owned by U.S. citizens. It even restricts foreign cruise ships from transporting passengers between U.S. ports. The purpose of the Jones Act is to maintain a shipbuilding and ship repair industrial base, a trained merchant mariner manning pool, and assets to respond in times of national security emergencies. The U.S. Customs Service has direct responsibility for enforcing the provisions of the Jones Act.

The Jones Act has long been supported as it has generated jobs in all 50 states and is similar to the policies and laws of almost 50 foreign nations that also reserve their coastwide shipping and passenger trades for their domestic fleets. It keeps shipping and shipbuilding assets under U.S. control, subject to all U.S. laws and standards, and provides essential services in U.S. coastal states and waters and to the economies of Alaska, Hawaii and Puerto Rico. "Nationwide there are more than 37,000 vessels in the Jones Act fleet generating nearly 125,000 jobs, 80,000 of which are shipboard. The Jones Act fleet represents a $26 billion private sector investment in vessels and infrastructure and routinely moves more than 1 billion tons of cargo and 100 million passengers each year" (Maritime Cabotage Task Force 2003).

Critics of the Jones Act, however, state that it is an antiquated law that places severe restrictions on U.S. businesses and costs the economy billions of dollars because of its anti-competitive inefficiencies. Jones Act requirements inhibit the movement of grain by water within the U.S, especially in areas with insufficient rail service – U.S. agriculture bears the increased cost of transportation. This in turn affects rail congestion problems and reduces competition within the U.S. shipping market. Numerous attempts have been made to reform or repeal the Jones Act, none of which have been successful.

Resource Conservation and Recovery Act (RCRA): A material is classified under RCRA as a hazardous waste if the material meets the definition of solid waste, and that solid waste material exhibits one of the characteristics of a hazardous waste or is specifically listed as a hazardous waste. A material defined as a hazardous waste may then be subject to Subtitle C generator, transporter, and treatment, storage, and disposal facility requirements. The shipbuilding and repair industry must be concerned with the regulations addressing all of these.[14]

Several common shipyard operations have the potential to generate RCRA hazardous wastes. Some of these wastes are identified below by process.

- Machining and Other Metalworking
  - Metalworking fluids contaminated with oils, phenols, creosol, alkalies, phosphorus compounds, and chlorine

- Cleaning and Degreasing
  - Solvents
  - Alkaline and Acid Cleaning Solutions
  - Cleaning filter sludges with toxic metal concentrations

- Metal Plating and Surface Finishing and Preparation
  - Wastewater treatment sludges from electroplating operations
  - Spent cyanide plating bath solutions
  - Plating bath residues from the bottom of cyanide plating baths
  - Spent stripping and cleaning bath solutions from cyanide plating operations

- Surface Preparation, Painting and Coating
  - Paint and paint containers containing paint sludges with solvents or toxic metals concentrations
  - Solvents
  - Paint chips with toxic metal concentrations
  - Blasting media contaminated with paint chips

[14] The remainder of this section is taken from: Office of Compliance, *Profile of the Shipbuilding and Repair Industry* (Washington D.C.: Office of Enforcement and Compliance Assurance, Environmental Protection Agency), 1997, p. 93-96.

- Vessel Cleaning
  - Vessel sludges
  - Vessel cleaning wastewater
  - Vessel cleaning wastewater sludges

- Fiberglass Reinforced Construction
  - Solvents
  - Chemical additives and catalysts

Shipbuilding and repair facilities may also generate used lubricating oils which are regulated under RCRA but may or may not be considered a hazardous waste.

United States Code, Title 10, Section 7311: Title 10, Section 7311 of the U.S. Code applies specifically to the handling of hazardous waste (as defined by RCRA) during the repair and maintenance of naval vessels. The Code requires the Navy to identify the types and amounts of hazardous wastes that will be generated or removed by a contractor working on a naval vessel and that the Navy compensate the contractor for the removal, handling, storage, transportation, or disposal of the hazardous waste. The Code also requires that waste generated solely by the Navy and handled by the contractor bears a generator identification number issued to the Navy; wastes generated and handled solely by the contractor bears a generator identification number issued to the contractor; and waste generated by both the Navy and the contractor and handled by the contractor bears a generator identification number issued to the contractor and a generator identification number issued to the Navy.

Clean Air Act: Under Title III of the 1990 Clean Air Act Amendments (CAAA), EPA is required to develop national emission standards for 189 hazardous air pollutants (NESHAP). EPA is developing maximum achievable control technology (MACT) standards for all new and existing sources. The National Emission Standards for Shipbuilding and Repair Operations (Surface Coating) were finalized in 1995 and apply to major source shipbuilding and ship repairing facilities that carry out surface coating operations. Shipyards that emit ten or more tons of any one HAP or 25 or more tons of two or more HAPs combined are subject to the MACT requirements. The MACT requirements set VOC limits for different types of marine coatings and performance standards to reduce spills, leaks, and fugitive emissions. EPA estimates that there are approximately 35 major source shipyards affected by this regulation. Shipbuilding and repair facilities may also be subject to National Emissions Standards for Asbestos.

Both NESHAPs require emission limits, work practice standards, record keeping, and reporting. Under Title V of the CAAA 1990, all of the applicable requirements of the Amendments are integrated into one federal renewable operating permit. Facilities defined as "major sources" under the Act must apply for permits within one year from when EPA approves the state permit programs. Since most state programs were not approved until after November 1994, Title V permit applications, for the most part, began to be due in late 1995. Due dates for filing complete applications vary significantly from state to state, based on the status of review and approval of the state’s Title V program by EPA.

A facility is designated as a major source for Title V if it releases a certain amount of any one of the CAAA regulated pollutants (SOx, NOx, CO, VOC, PM10, hazardous air pollutants, extremely hazardous substances, ozone depleting substances, and pollutants covered by NSPSs) depending on the region's air quality category. Title V permits may set limits on the amounts of pollutant emissions; require emissions monitoring, and record keeping and reporting. Facilities are required to pay an annual fee based on the magnitude of the facility's potential emissions.

Clean Water Act: Shipbuilding and repair facility wastewater released to surface waters is regulated under the CWA. National Pollutant Discharge Elimination System (NPDES) permits must be obtained to discharge wastewater into navigable waters. Facilities that discharge to a POTW may be required to meet National Pretreatment Standards for some contaminants. General pretreatment standards applying to most industries discharging to a POTW are described in 40 CFR Part 403. In addition, effluent limitation guidelines, new source performance standards, pretreatment standards for new sources, and pretreatment standards for existing sources may apply to some shipbuilding and repair facilities that carryout electroplating or metal finishing operations.

Stormwater rules require certain facilities with stormwater discharge from any one of 11 categories of industrial activity defined in 40 CFR 122.26 be subject to the stormwater permit application requirements. Many shipbuilding and repair facilities fall within these categories. Required treatment of stormwater flows are expected to remove a large fraction of both conventional pollutants, such as suspended solids and biochemical oxygen demand (BOD), as well as toxic pollutants, such as certain metals and organic compounds.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA): The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and the Superfund Amendments and Reauthorization Act of 1986 (SARA) provide the basic legal framework for the federal “Superfund” program to clean up abandoned hazardous waste sites. Metals and metal compounds often found in shipyards’ air emissions, water discharges, or waste shipments for off-site disposal include chromium, manganese, aluminum, nickel, copper, zinc, and lead. Metals are frequently found at CERCLA's problem sites. When Congress ordered EPA and the Public Health Service's Agency for Toxic Substances and Disease Registry (ATSDR) to list the hazardous substances most commonly found at problem sites and that pose the greatest threat to human health, lead, nickel, and aluminum all made the list.

4.5 Industry Trends and Outlook

The 1980's were dismal times for the U.S. shipbuilding industry. A combination of factors including a lack of a comprehensive and enforced maritime policy, failure to continue funding subsidies established by the Merchant Marine Act of 1936 and the collapse of the U.S. offshore oil industry, not only hurt the shipbuilding industry but all support industries such as small shipyards and repair yards. Approximately 120,000 jobs for shipyard workers and shipyard suppliers were lost.

At its height in the mid-1970s, the industry held a significant portion of the international commercial market while maintaining its ability to supply all military orders. Then in the 1980s, new ship construction, the number of shipbuilding and repair yards, and overall industry employment decreased sharply. Especially severe was the decline in the construction of commercial vessels at first tier shipyards – falling from about 77 ships (1,000 gross tons or more) per year in the mid-1970s to only about eight ships total through the late 1980s and early 1990s. In the 1980s, the industry’s loss of the commercial market share was somewhat offset by a substantial increase in military ship orders. However, the industry entered the 1990s with a much smaller military market and a negligible share of the commercial market. The second tier shipyards and the ship repairing segment of the industry have also suffered in recent decades; however, the decline has not been as drastic (Office of Compliance 1997b).

The U.S. shipbuilding and repairing industry's loss of the commercial shipbuilding market has been attributed to a number of factors. First, a world wide shipbuilding boom in the 1970s created a large quantity of surplus tonnage which suppressed demand for years. Another significant factor reducing U.S. shipbuilding and repair industry's ability to compete internationally are the substantial subsidies that many nations provide to their domestic shipbuilding and repair industries. Also, until 1980, over 40 percent of U.S.-built merchant ships received Construction Differential Subsidies (CDS) based on the difference between foreign and domestic shipbuilding costs. The program was eliminated in 1981, further reducing the industry's competitiveness (Office of Compliance 1997b).

The U.S. government and the shipbuilding industry have made great strides in their efforts towards industry revitalization and market transformation. The industry is experiencing a come back, as shown in Figure 4.4. The number of commercial ships on order is slowly increasing from the lows of the early 1990s. One major stimulus has been the surge in activity relating to offshore exploration, drilling and servicing sectors. These shipyards are expected to prosper in the next decade (Maritime Administration 1999).

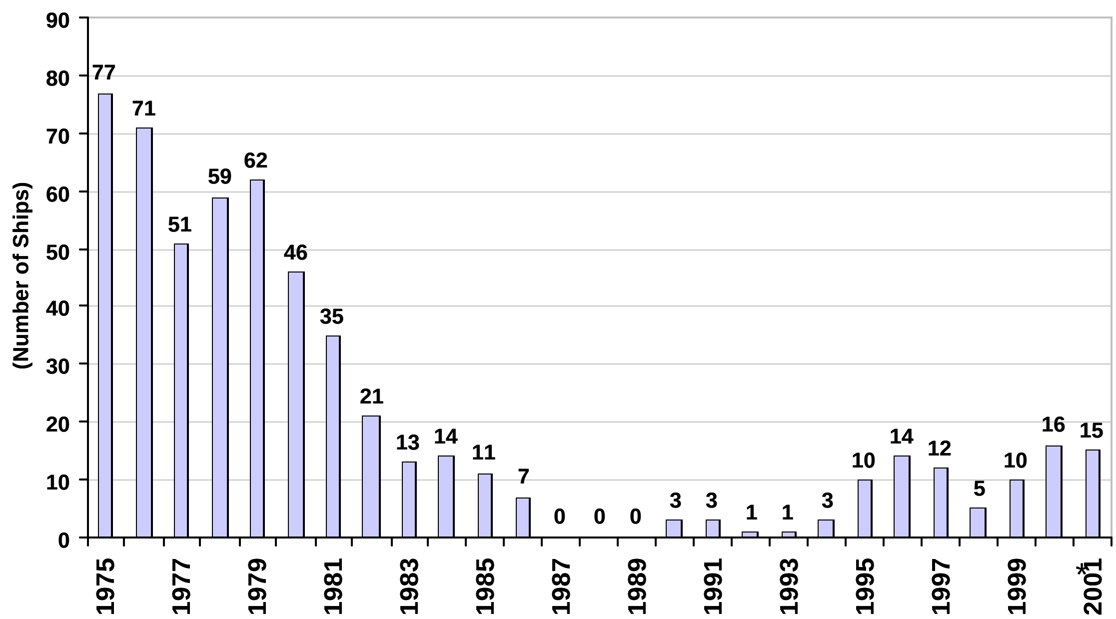

Figure 4.4. Commercial Shipbuilding Orderbook History.

* 2001 Data as of June 1, 2001.

Source: Maritime Administration (2002b)

<u>Capital Investments:</u> During FY 2002, the U.S. ship construction and ship repair industry invested more than $408 million in the upgrade and expansion of facilities (Figure 4.5). Much of this investment was to improve efficiency and competitiveness in the commercial shipbuilding arena. Improvements were made to update and convert shipyard facilities to be more commercially viable. Examples of recent capital investments are new pipe and fabrication shops, drydock extensions, military work enhancement programs, automated steel process buildings and expanded design programs. Many of these improvements have been necessary due to the increased utilization of U.S. shipyards, particularly those along the Gulf Coast, resulting from the resurgence of the Oil Patch Industry. In 2003, the industry planned to spend about $325 million in the upgrade and expansion of facilities, according to data received by the Maritime Administration. The industry's capital investments since 1970 have totaled approximately $8.5 billion. The actual expenditures between 1985 and 2001, with the exception of 1990 and 2001, have consistently exceeded those planned (Office of Shipbuilding and Marine Technology 2002).

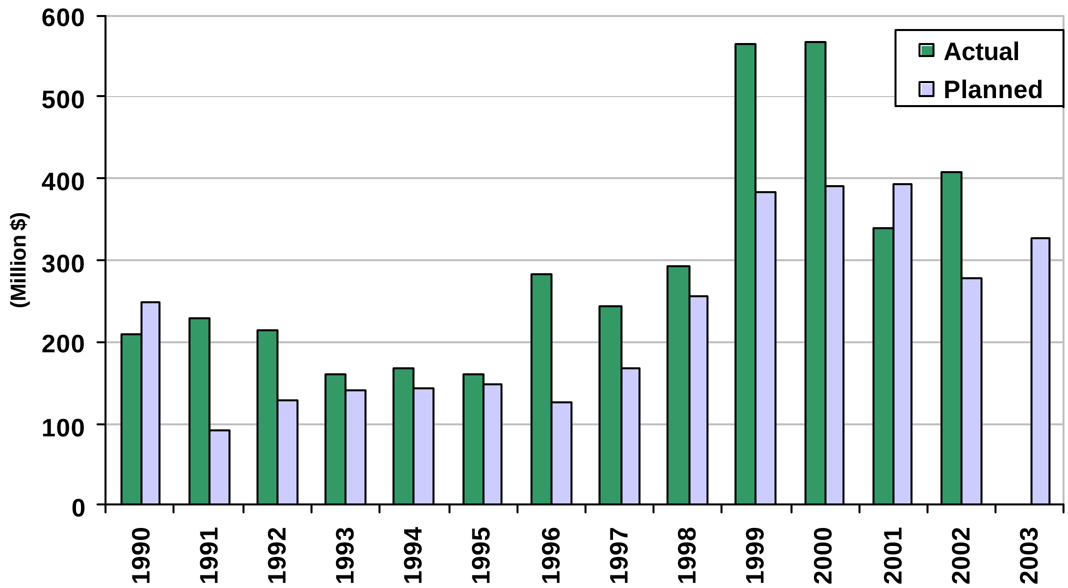

Figure 4.5. U.S. Shipbuilding and Repair Industry Capital Investments.

Source: Office of Shipbuilding and Marine Technology, (2002)

Other issues that may affect the future of shipbuilding in the United States, particularly along the Gulf Coast, include the following:

Maritime Policy: The debate over the Jones Act will continue. Supporters stress that before World War I, the majority of the United States' trade was carried by foreign ships. As a result, shipping rates experienced a 2000 percentage increase when the war began. That shortage prompted Congress to pass the Jones Act, in an attempt to eliminate the country's dependence on foreign ships. However, opponents of the Act claim that it places too much restriction on U.S. business and is anti-competitive. Whichever way this debate is decided, it will affect the shipbuilding industry more so than any other in the U.S.

Oil Pollution Act of 1990: This legislation requires that all new liquid bulk vessels trading in U.S. waters be equipped with double hulls and that existing tankers without double hulls be retrofitted or be removed from oil production transportation. It is difficult to know the number of tankers that will have to be rebuilt, scrapped or constructed as a result of this legislation. But by 2015, a double hull will be required for all tankers entering a U.S. port.

Financing: Title XI of the Merchant Marine Act (and later amended) started a National Shipbuilding Initiative program to support the U.S. shipbuilding industry and help establish it as a self-sufficient internationally competitive industry. The U.S. government insures and guarantees full payment to the lender of the unpaid principal and interest of the obligation in the event of default by the vessel owners or general shipyard facility. As of September 2001, Title XI guarantees in force totaled about $4.9 billion, covering 871 vessels and 89 individual ship owners. In 2001, Title XI applications totaling approximately $730 million in loan guarantees were approved – covering construction of 295 vessels (Maritime Administration 2001b). "The availability of long-term Title XI guarantees for vessels constructed in U.S. shipyards will continue to be a major factor in the revitalization of commercial shipbuilding in U.S. shipyards. The U.S. shipbuilding industry has to make significant strides in building efficient ships at lower prices with on-time deliveries for the Jones Act trade to demonstrate to the international market its ability to produce high quality commercial vessels" (Industry Pro 2000).

Other Opportunities: The U.S. shipbuilding industry has a bright future – significant capital investment has been made to enhance productivity; and shipbuilding companies have been working with the federal government to increase production and position in the international arena. In addition, opportunities are available in each of the following growing markets:

- ***Casino Boat Market*:** River boat gambling has offered construction opportunities for small to medium boat yards. Obviously, the more states that legalize gambling, the greater impact on the shipbuilding industry.

- ***Ferry Boat Market:*** Ferries continue to be a popular secondary mode of transportation. ISTEA offered incentives for ferry construction through federal grants. It was hoped that this would help to alleviate the number of automobiles in congested urban areas. Again, small and medium shipyards have opportunities in this area.

- ***Offshore Market:*** The offshore market is undergoing a rapid expansion since the marked decline of the 1980's. Advancements in deep-water drilling has encouraged exploration, leading to greater production and activity in the coastal areas. The need for supply and other types of industry support vessels has increased. With changing technology has come the need for more sophisticated and higher capacity vessels.

- ***River Tonnage Market:*** The bulk of the nation's barges and towboats operate in the Mississippi River and the Gulf Intracoastal Waterway. As a greater amount of goods and commodities are transported through this network, Louisiana shipyards are in a good position to offer services to that industry.

Offshore Supply Vessels: In 1998, the OSV industry experienced a downturn and a great deal of consolidation. Numerous small players left the OSV business due to bankruptcy, asset sales to larger competitors or asset sales outside the industry. "We estimate that more than half of the smaller boat operators that operated three or fewer boats in the last cycle are no longer in business."[15]

As shown in Figure 4.6, the market share for several major companies has experienced significant changes since 1997. The most noticeable change is the decline in Tidewater's market share from 42 percent in 1997 to 30 percent in 2000. This is a result of Tidewater's restraint from building during the last upswing of newbuilds. Chouest gained the most in terms of market share – almost doubling from 6 to 11 percent in three years. Of the public companies, only Sea Mar and Trico Marine did not experience market share erosion. Trico's market share gain was the direct result of industry consolidation – Trico made four acquisitions and added a total of 24 boats.

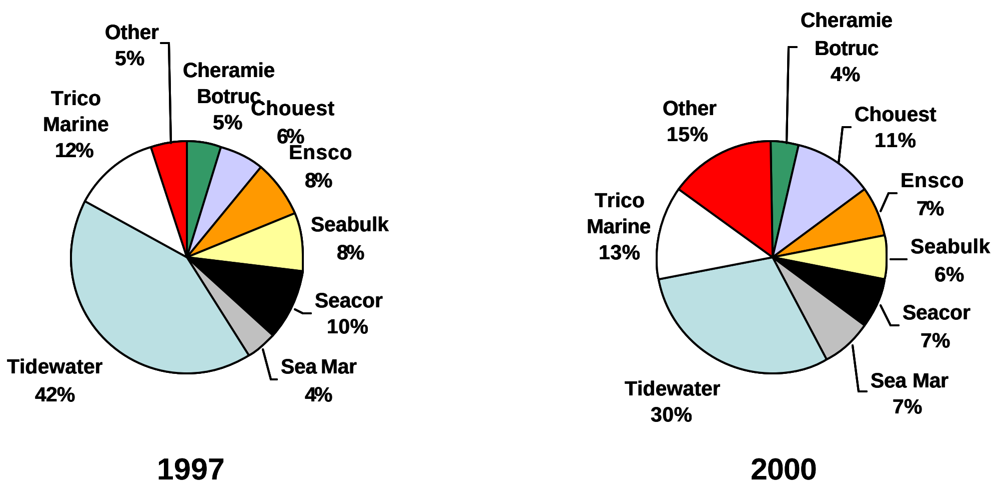

Figure 4.6. Percentage of Total Gulf of Mexico Fleets for Large Companies (more than 10 Vessels).

Source: Pickering et al. (2000)

Fleet Age: The Gulf supply boat industry does not have a young fleet. Nearly 40 percent of the entire fleet is at least 20 years old, reflecting the massive fleet expansion that occurred in the late 1970s and early 1980s. Only 26 percent of the fleet is 10 years old or younger. A majority of the younger boats were built during the 1996 and 1999 newbuild cycle.

Combined with the scrappage of obsolete, older vessels, the recent significant newbuild program has decreased the average age of the Gulf supply vessel fleet by roughly two years. The average age of the fleet in 1997 was 17.9 years. As of 2000, the average age of the total fleet in the Gulf of Mexico is 15.7 years.

[15] Unless otherwise noted, the information in this section is taken from: Daniel R. Pickering, Jennifer Hu, and Justin J Tugman, *The Gulf of Mexico Supply Vessel Industry, A Return to the Crossroads,* (Houston: Energy Industry Research, Simmons & Company International), November 2000.

Recovery in Drilling Demand: The primary driver of supply vessel demand in the Gulf is offshore rig activity. As discussed throughout this report, the offshore drilling industry, especially in deepwater, is booming. This surge in rig activity has been the most important driver for improvements in supply vessel utilization.

The number of drilling rigs capable of drilling in over 3,000 feet of water has quadrupled since 1996. However, in comparison to the shallower areas of the Gulf, support of deepwater drilling requires a significantly enhanced supply boat.

- ***Larger liquid mud capacity:*** In deepwater, the well extends from the ocean surface to the ocean floor and then into the earth. The wells also have risers with much larger diameters than shallow water wells. Thus, more drilling mud is required to fill the wellbore and riser. This is usually 3,000 to 4,000 barrels and can be as much as 6,000 barrels in water depths over 5,000 ft. Thus, deepwater supply boats need large liquid mud capacities. A standard 180 ft supply vessel typically has a liquid mud capacity of 1,000 to 1,600 barrels.

- ***Dynamic positioning capability:*** Deepwater drilling rigs generally operate further away from shore than conventional shallow water units. Weather patterns can be violent and the sea conditions are typically rougher. With total deepwater drilling costs at $200,000 to $500,000 per day, it is very costly for the drilling process to be interrupted because weather conditions limit the transfer of supplies or drilling mud from a boat to the rig. In order for a supply vessel to safely maintain its position near a deepwater rig, dynamic positioning (DP) is required. With DP capability, a supply vessel uses global positioning satellites to determine an exact location and small engines or thrusters to maintain the boat's position. Although most older supply vessels are not dynamically positioned, this function can be added, but often times at costs that make the upgrade uneconomical.

Assuming no new capacity additions from newbuilds or vessels returning from international markets tip the scales toward a softer market, "the GOM deepwater market is the place to be for domestic supply vessel operators" (Pickering et al. 2000).

4.6 Inventory of Major Gulf Coast Facilities

The American Shipbuilding Association is the professional organization for those in the industry who are capable of constructing mega vessels which are in excess of 400 ft in length and weigh in excess of 20,000 DWT. For this reason, their membership consists of only six companies. Of those six, two have a presence in the Gulf of Mexico. Both Avondale Shipyard of New Orleans, LA and Ingalls of Pascagoula, MS have enormous capabilities and expertise in the design, construction and repair of vessels. This highly developed level of specialized knowledge has made these two companies ideal contractors for the nation's defense efforts. Therefore, most of the work that has been accomplished in these two yards has been for the U.S. Military.

The existence of enormous commercial needs has lead to the development of a very large number of boat and barge builders. These companies direct their effort toward the specific requirements of industries such as the offshore oil and gas industry. Therefore, the vessels they produce are not as large as those being built by the two previously mentioned companies who are building primarily for the national defense. However, as the oil and gas industry has evolved and become more sophisticated, particularly with deep-water drilling, so too has the capability of this segment of the boat building industry. Many of these companies are now producing ships in the 300 ft range.

Based on an inventory conducted as part of the development of a GIS database for this project, we recorded 162 shipbuilding and repair facilities of various sizes located within the Gulf region which support the oil and gas industry. Eighty-two facilities are located in Louisiana, 35 in Texas, 17 in Mississippi, 15 in Florida, and 13 in Alabama. A list of the primary shipyards present in the Gulf is provided in Table 4.2.

Table 4.2

Primary Shipyards in the Gulf Region which Support the Offshore Oil and Gas Industry (2000)

Texas	**City**
Bludworth Marine LLC dba Vessel Repair	Houston
Carotex, Inc.	Port Arthur
Channel/Lynchburg Shipyard	Highlands
Channel Shipyard Company, Inc.	Highlands
First Wave Marine/Newpark Brady Island Facility	Galveston
First Wave Marine/Newpark Greens Bayou Facility	Houston
First Wave Marine/Newpark Galveston Island Facility	Galveston
First Wave Marine/Newpark East Pelican Island Facility	Galveston
First Wave Marine/Newpark Pasadena Facility	Pasadena
First Wave Marine/Newpark West Pelican Island Facility	Galveston
Bollinger Houston	Houston
Bollinger Texas City	Texas City
Halter TDI - Central	Port Arthur
Halter TDI - Dockyard	Port Arthur
Halter TDI - North	Port Arthur
Halter TDI - Orange	Orange
Halter TDI - Pier I	Orange
Halter TDI - Sabine Pass	Sabine Pass
Halter TDI - South	Sabine Pass
Southwest Shipyard, L.C.	Channelview
Trinity Marine Industries Beaumont Facility	Beaumont
Trinity Marine Industries Orange Facility	Orange
Trinity Marine Products	Dallas
Louisiana	
Bollinger Algiers	Algiers
Bollinger Amelia Repair	Amelia
Bollinger Chand Corporation	Mathews
Bollinger Fourchon	Golden Meadow
Bollinger Larose	Larose
Bollinger Marine Fabricators	Amelia
Bollinger Morgan City	Morgan City
Bollinger Quick Repair	Harvey

Table 4.2

Primary Shipyards in the Gulf Region which Support the Offshore Oil and Gas Industry (2000) (Continued)

Louisiana (Continued)	**City**
Bollinger Shipyards Lockport	Lockport
Bollinger Calcasieu	Lake Charles
Bollinger Gretna	Gretna
Bollinger Gulf Repair	New Orleans
Channel Shipyards, Inc.	New Orleans
Avondale Shipyards	New Orleans
Edison Chouest Offshore	Galliano
North American Shipbuilding	Larose
North American Fabricators	Houma
Halter Equitable	New Orleans
Halter Lockport	Lockport
Leevac Shipyards, Inc.	Jennings
L. M. S. Shipmanagement, Inc.	New Orleans
L. M. S. Shipmanagement, Inc.	Lafitte
L. M. S. Shipmanagement, Inc.	Algiers
McDonough Marine Services	Metairie
T. T. Barge Services	Donaldsonville
T. T. Barge Services	Westwego
T. T. Barge Services	Hahnville
T. T. Barge Services	Harahan
Trinity Marine Products, Inc.	Madisonville
Trinity Marine Products, Inc.	Baton Rouge
Trinity Marine Products, Inc.	Brusly
Mississippi	
Halter Marine Group	Gulfport
Halter Gulf Coast FAB	Pearlington
Halter Moss Point Marine	Moss Point
Halter Pascagoula	Pascagoula
Halter Gulfport Marine	Gulfport
Mississippi Marine Corporation	Greenville
Superior Boat Works	Greenville
Ingalls Shipyard	Pascagoula
Litton Ship Systems	Pascagoula
Alabama	
Alabama Shipyard	Mobile
Atlantic Marine, Inc.	Mobile
Bender Shipbuilding & Repair Company	Mobile
Harrison Brothers Dry Dock & Repair Yard	Mobile
Henry Marine Service	Mobile

Table 4.2

Primary Shipyards in the Gulf Region which Support the Offshore Oil and Gas Industry (2000) (Continued)

Florida	**City**
Atlantic Marine, Inc	Jacksonville
Friede Goldman Halter	Panama City
Sun State Marine Services, Inc.	Green Cove Springs

The following are brief descriptions of some of the major shipyards along the Gulf of Mexico:

Bollinger Shipyards

P.O. Box 250
8365 Hwy. 308 South
Lockport, LA 70374
Phone: 504-532-2554
Fax: 504-532-7225
webmaster@bollingershipyards.com

Begun in 1946, the company specializes in the repair, conversion and new construction of a wide variety of small to medium-sized offshore and inland vessels. It primarily addresses the energy, commercial and government marine markets in the Gulf of Mexico region.

The company currently operates fourteen shipyards located throughout South Louisiana and Texas with direct access to the central Gulf of Mexico. With 42 dry docks ranging in capacity from 100 tons to 22,000 tons, Bollinger provides a wide variety of dry-docks and services for both shallow and deepwater vessels and rigs.

Locations include the following:

Bollinger Algiers	Bollinger Gulf Repair	Bollinger Quick Repair
Bollinger Amelia Repair	Bollinger Houston	Bollinger Shipyards Lockport
Bollinger Calcasieu	Bollinger Larose	Bollinger Texas City
Bollinger Fourchon	Bollinger Marine Fabricators	Chand
Bollinger Gretna	Bollinger Morgan City	NorthShore Engineering

Bollinger has established a range of designs and has the capability of developing new designs and/or existing design modification to meet specific customer requirements. The designs are divided into six different categories: Patrol Craft, Offshore Supply Vessels, Liftboats, Barges, Specialties and Tugs.

Harrison Brothers Dry Dock & Repair Yard, Inc.

P.O. Box 1843
200 6th Street
Blakely Island
Mobile, AL 36633-1843
Phone: 334-432-4606
Fax: 334-438-3188

Harrison Brothers is an established shipyard engaged in the repair of tugboats, barges, supply boats, small ships, and other commercial vessels. It has been in operation for 103 years. Their drydocks can handle vessels up to 300 feet and 2000 tons. They also offer dockside repair facilities for floating repairs. Ancillary repair equipment includes a host of cranes, derricks, and shift tugs.

First Wave/Newpark Shipyards

2102 Broadway
Houston. TX 77012
Phone: 713-847-4600
Fax: 713-847-4601
info@fwav.com

FirstWave/Newpark Shipbuilding provides repair, conversion, new construction, and related services for barges, boats, ships, offshore rigs, and other vessels in the offshore and inland marine industries. It operates a network of six yards, three in the Houston Ship Channel area and three in the Galveston area.

The company's Galveston Division is headquartered at the East Pelican Island Facility. This yard is configured for mobile offshore rig and drillship repairs and conversions. A 7,500 ton drydock located there accommodates OSVs, small ships, barges and other vessels.

With more than twenty haul-out facilities (consisting of drydocks and marine railways), the Houston Division can handle large volumes and a variety of shipyard work. The company is also equipped to provide fabricated products and services, with 280,000 sq ft of manufacturing space under roof and crane capacity up to 500 tons at the West Pelican Island Facility in Galveston.

An environmental services division in Houston offers gas-freeing services to its shipyard customers as well as non-hazardous wastewater treatment and other environmental services to a variety of industrial customers.

New construction is directed toward inland barges, tugboats, pushboats, dredges, ferries, specialty vessels and rig components. Repairs, conversions and modifications are also offered for offshore drilling and production rigs and rig components, inland barges, offshore supply vessels, tugboats, pushboats and other inland river boats, dredges, ferries, government vessels, specialty vessels, FPSOs, and cargo and passenger ships.

Edison Chouest Offshore (ECO)

P. O. Box 310
Galliano, LA 70354
Webmaster@eco.chouest.com

Louisiana Edison Chouest Offshore (ECO) was founded in 1960, has doubled in size since 1993, and now has over 3,000 employees worldwide. Design and construction capabilities have made ECO prominent in the offshore boat service industry. Chouest has chosen a unique approach by designing, building, owning, and operating each of their vessels while leased to clients. Today, ECO has under charter the largest number of privately owned and operated special-purpose vessels to the U.S. Government. The company also owns and operates the largest independently owned fleet of seismic and research vessels in the world. ECO owns and operates a growing fleet of new generation offshore deep-water service vessels supporting over 90 percent of the U.S. Gulf deepwater market. ECO's high-tech, high-capacity offshore vessels range from 87 ft to 320 ft.

- **North American Shipbuilding in Larose Louisiana (an ECO affiliate)**

  North American Shipbuilding (NAS) was founded in 1974, and has built many specialized offshore vessels. Since it was purchased by ECO, it has designed and constructed vessels only for ECO and affiliated companies. NAS built the first U.S. Antarctic icebreaking research vessel, the largest and most powerful anchor handling vessel in the U.S. fleet, the first dynamically positioned vessel in the U.S. fleet, the world's first floating production system installation vessel, and the largest water throw capacity vessel in the U.S. fleet. It has a formal welding training program and on the job apprenticeship training for all other trades.

- **North American Fabricators in Houma Louisiana (an ECO affiliate)**

  Since its founding in 1996, North American Fabricator (NAF) has developed into a state-of-the-art, world-class shipbuilding facility. NAF currently employs over 250 shipyard workers who build modern, highly specialized offshore supply vessels from 190 feet long and up. NAF's first vessel delivered was the C-Commander, the largest offshore supply vessel in the U.S. fleet at that time, at 240 ft long and 56 ft wide. NAF's new construction projects will be designed to accommodate deepwater oil and gas production and global research expeditions.

Litton Ship Systems

Litton Ship Systems (LSS), headquartered in Pascagoula, Mississippi, was formed on August 1, 1999, and includes Litton Ingalls Shipbuilding and the Litton Ship Systems Full Service Center, also in Pascagoula, and Litton Avondale Industries, in New Orleans, Louisiana, and Gulfport, Mississippi. LSS employs more than 17,000 shipbuilding professionals, primarily in Mississippi and Louisiana, and is one of the nation's leading full service systems companies for the design, engineering, construction, and life cycle support of major surface ships for the U.S. Navy, U.S.

Coast Guard and international navies, and for commercial vessels of all types. Northrop Grumman acquired Litton Industries in 2001.

Avondale\The Shipyards Division

P.O. Box 50280
New Orleans, LA 70150-0280
5100 River Road
Avondale, LA
Phone: 504-436-2121
Fax: 504-436-5200
www.avondale.com

Avondale's main shipyard is located on the Mississippi River twelve miles upriver from the Port of New Orleans. This facility includes two separate construction areas. One construction area has three building positions and utilizes a 900-foot floating launch platform. The second area has five building positions where ships are side-launched into the river. These integrated assembly areas are supported by a state-of-the-art marine steel fabrication facility. Included at the facility are a fully-equipped machine shop, semi-automated pipe shop, electrical shop, and sheet-metal shop.

Since 1982, Avondale has used modular construction technology to build ships. This technology was acquired from a leading Japanese shipbuilder and has been mastered by Avondale's work force. Simply stated, modular construction consists of building 150 to 200 modules or units and completely outfitting them with pipe, ventilation systems, etc. The modules are then joined just prior to launching.

Litton Avondale Industries in New Orleans, Louisiana, and Gulfport, Mississippi, is the prime contractor for the Navy/Marine Corps Team's SAN ANTONIO (LPD17) Class of amphibious assault ships. Avondale is also building seven T-AKR Ro/Ro Sealift ships for the U.S. Navy, with three delivered and four currently under construction. These Sealift ships are 950 feet long, making them second in size only to aircraft carriers in the U.S. Navy's fleet. Avondale is also building three double-hull oil tankers (the first to be built in the U.S.), for ARCO Marine. These giant ships are world's most environmentally safe product tankers.

Ingalls Shipyard

P.O. Box 149
Pascagoula, MS 39568-0149
1000 Access Road
Pascagoula, MS 39567
Phone: 228-935-1122
Fax: 228-935-1126
www.ingalls.com

Litton Ingalls Shipbuilding Headquartered in Pascagoula, Mississippi, is the sole builder of the Navy/Marine Corps Team's WASP (LHD 1) Class of large-deck multipurpose amphibious assault ships, which operate as the centerpiece of an Amphibious Ready Group (ARG). Ingalls is one of two builders of the Navy's ARLEIGH BURKE (DDG 51) Class of Aegis guided missile destroyers, which provide primary antiair protection for the fleet. Currently, Ingalls is engaged in the production of the first major cruise ships built in the U.S. in more than 40 years.

5.0 SUPPORT AND TRANSPORT FACILITIES

5.1 Introduction

Offshore oil and gas activities are supported by a considerable and diverse onshore supply and support logistics train. Support activities range from products and services such as engine and turbine construction and repair, electric generators, chains, gears, tools, pumps, compressors, and a variety of other tools and equipment. Additionally, drilling muds, chemicals, and fluids are produced, and transported from onshore support facilities. Many types of transportation vessels, including helicopters, are used to transport workers, equipment, and materials to and from offshore platforms.

In the past, a large number of these activities were "internal" to offshore oil and gas firms. Over time, more and more of these activities have been employed on a contract service basis. Today, the majority of onshore support and transportation services are provided by outside third parties. Downsizing and specialization have been the primary reasons for utilizing these services on a contract basis. Industry downsizing, in particular, has reduced the numerous layers associated with oil and gas operations by many offshore producers. The use of contract services allows producers to utilize supply, transport, and logistics resources on an "as needed basis." Utilizing these services on a contract basis gives offshore producers a significant degree of flexibility and allows them to keep costs down during periods of oil and gas commodity price downturns.

Onshore support and transportation services are employed by major and independent producers alike. While the support sector of the industry is very heterogeneous in nature, all firms that operate in this sector share one common problem: their business, profits, and earnings are highly dependent on the cyclical nature of the oil and gas industry. As will be discussed in greater detail later, this dependency has led to two different survival tactics by support and transportation firms in the Gulf: concentration and diversification. Concentration has occurred from general merger and acquisition activity, while diversification has resulted from taking on a broader number of support and service activities to dampen earnings impacts from falling oil and gas prices.

5.2 Description and Typical Facilities

General Support Facilities: Support facilities are diverse and, depending upon function, can take on a number of different characteristics. Many, however, have similar features such as being located at, or near, a marine port facility. Ports, in addition to serving as points of disembarkment, tend to have physical attributes that complement support activities. Moreover, business practices at most ports are directed at developing and providing the necessary infrastructure to support these types of activities. For the support and transport sector of the oil and gas industry, important physical infrastructure attributes of ports include:

- Protected wharfs, docks, and drydocks;
- Storage and demurrage facilities;
- Crew housing;
- Intermodal transportation access (i.e., roads, inter-coastal waterway, railways);

- Communication facilities/equipment; and,
- Workshops and machine and tooling shops.

Repair and Maintenance Yards: A significant portion of repair and maintenance support work that is conducted at these facilities is associated with maintaining vessels and equipment for drilling and production activities. Specific repair methods vary from job to job in both time and scope. Jobs can last from one day to over a year. Repair jobs often have severe time constraints requiring work to be completed as quickly as possible in order to get the equipment back to service. This is particularly true during periods of high oil and gas prices, where working equipment is of high value. During periods of low oil and gas prices, repairs may be allowed to linger over longer periods of time, since equipment may be unneeded in the field.

In many cases, a number of tasks are pre-fabricated and then taken offshore for final assembly and repair. This can often be the case with such activities as piping, ventilation, electrical and other machinery. Typical maintenance and repair operations include:[16]

- Blasting and repainting the ship hulls, freeboard, superstructure, and interior tanks and work areas;

- Major rebuilding and installation of machinery such as diesel engines, turbines, generators, pump stations, etc;

- Systems overhauls, maintenance and installation (e.g., piping system flushing, testing and installation);

- System replacement and new installation of systems such as navigational systems, combat systems, communication systems, updated piping systems, etc.;

- Propeller and rudder repairs, modification, and alignment; and,

- Creation of new machinery spaces through cut outs of the existing steel structure and the addition of new walls, stiffeners, vertical, webbing, decking, etc.

Supply Bases: Supply bases can range from large yards, offering all kinds of service including full logistics management, to smaller shops that supply one or many of the items needed on an offshore platform or marine vessel. From strategic locations along the Gulf, larger supply companies who offer supply chain management services move equipment and supplies from land-based supply houses to offshore drilling platforms. Other, smaller suppliers act more or less like a retail store, supplying anything from crane rentals, warehouse space, trailer rentals, and dispatch services, to engine parts, fuel, navigation tools, potable water, and lubricants including, motor oil, hydraulic oil, natural gas compressor oils, grease, gear oil, and synthetics.

Crew Services: A number of companies provide services to the crews that live on the offshore rigs. These companies provide catering – delivering and serving hot meals – and laundry, cleaning and maintenance services for crew barracks. A number of companies also provide on-site paramedics – they are not simply there to wait for someone to become ill or injured, but

[16]In part from: Office of Compliance, *Profile of the Shipbuilding and Repair Industry* (Washington D.C.: Office of Enforcement and Compliance Assurance, Environmental Protection Agency), 1997b, p. 20-21.

rather, they are part of the crew, offering an additional service which improves operational efficiency and productivity.

Heliports: Heliports are centralized locations for which fixed and rotary wing aircraft (i.e., helicopters) are disembarked for offshore service. Helicopters move crew and equipment to offshore areas. Supply boats are typically used for short-haul service while helicopters are the primary means of transportation for distances of 150 to 175 miles out into the Gulf (approximately one and a half hours). This would include most deepwater platforms and facilities (Murphy 1990).

Heliports are typically located at small and medium sized regional airports throughout the Gulf of Mexico. There can be main and auxiliary (or remote) heliport facilities. Main facilities, usually located at regional airports, host most of the main aircraft hangers, aircraft repair yards, as well as administrative offices. Over the past several years, helicopter and air transportation has become concentrated with private contract firms. Individual oil and gas companies still own and operate company aircraft, but are increasingly turning to third parties to perform these tasks.

There are three main independent providers of air transportation services: Air Logistics (New Iberia, Louisiana); PHI, Inc (Lafayette, Louisiana)[17]; and Evergreen Helicopter, Inc. (Galveston, Texas).[18] Each company operates numerous locations along the Gulf in addition to those activities conducted at their main headquarters. The primary business of all three is to provide crew and equipment transportation services to offshore oil and gas companies.

Air Logistics and Evergreen Helicopter maintain a fleet of 170 fixed and rotary wing aircraft each. PHI, the largest provider of transportation service in the Gulf, maintains a fleet of 300 helicopters and operates the largest heliport in North America with 46 helipads in Morgan City, Louisiana. All three companies maintain aircraft ranging from Bell 212s and 206s, the workhorse of the industry, to heavy duty Sikorsky S-76s which are also used in medical air transportation.

At the height of drilling activity, from 1981 to 1983, up to 100,000 workers a day were being transported back and forth from oil and gas drilling and production platforms (Murphy 1990). Shortly afterwards, the number dropped to around 25,000 to 30,000 and today, estimates range in the 16,000 to 20,000 range. One factor leading to the different transport levels is the size of the average crew typically operating in the Gulf. During the drilling heydays, drilling crews typically ranged from 30 to 50 people. However, today in a mostly production-oriented environment, production crews are much smaller, in the 2 to 6 person range.

Based on an inventory conducted as part of the development of a GIS database for this project, 247 heliport facilities that support the oil and gas industry were recorded within the Gulf region; 122 are located in Texas, 81 in Louisiana, 34 in Florida, 6 in Mississippi, and 4 in Alabama.

5.3 Industry Characteristics

The offshore oil and gas industry was projected to spend about $100 billion in 2000 on deepwater oil and gas fields, pipelines, drilling rigs, and production platforms around the world,

[17] PHI is formerly known as Petroleum Helicopters, Inc.

[18] Evergreen Helicopter's main point of presence in the Gulf is in Galveston, Texas. However, the Company's headquarters is located in McMinneville, Oregon.

and those expenditures can only increase as the ultra-deepwater moves into full development. Typically, each oil and service company is basically on their own to provide spare parts and material requisition orders (MRO) for their assets in oil fields around the world, although there is some sharing of assets and resources (Anderson and Esser 2000).

Industry-wide supply chain transactions involving original equipment manufacturer spare parts are estimated to be a hefty $90 billion per year. Of that, $25 billion is spent on MRO expendables. There are more than 27,000 suppliers of MRO and OEM (Original Equipment Manufacturer) parts to the oil industry, and 90 percent of parts are supplied by 2,000 of those companies – an unusually large number indicative of a fragmented supply chain network (Anderson and Esser 2000).

Along the Gulf coast of the United States, there are many onshore facilities that support the offshore industry. Exploration and production in the Gulf is concentrated in three areas: Western, Central and Eastern Gulf regions. Located adjacent to these three regions, there are hundreds of contractors operating ports, maintenance and shipbuilding facilities, as well as crew bases, and other supporting industries such as pipe-making and pipe-laying.

<u>Western:</u> The Western Gulf of Mexico Planning Area extends from South Padre Island Texas to the Sabine River, on the Texas – Louisiana border (Figure 5.1). According to December 1999 MMS estimates, the western Gulf area has approximately 421 million barrels of oil and 5.9 tcf of gas of remaining proved reserves (USDOI, MMS 2002c). The major onshore key ports and facilities are located near the Corpus Christi, Galveston, and Port Arthur areas.

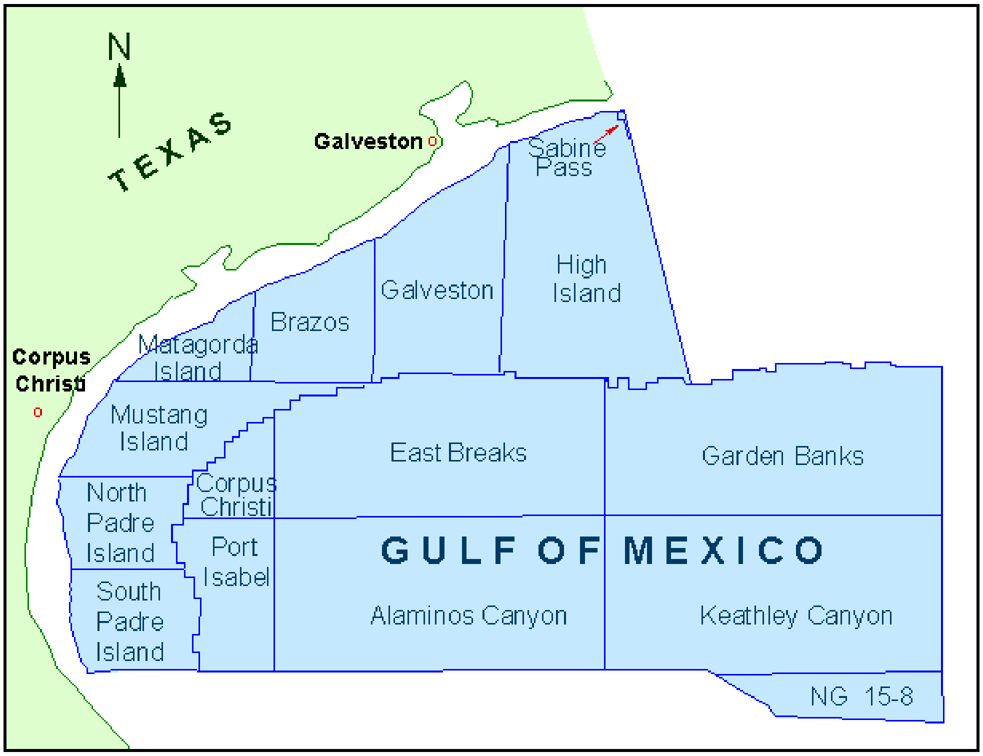

Figure 5.1. Western Gulf Planning Area.

Central: The Central Gulf of Mexico Planning Area extends from the Sabine River to Baldwin County, Alabama (Figure 5.2). According to December 1999 MMS estimates, the central Gulf area has approximately 2,556 million barrels of oil and 17.6 trillion cubic feet (tcf) of natural gas of remaining proved reserves (USDOI, MMS 2002c). Major ports and facilities are located in Morgan City, Venice, Intercoastal City, Cameron and Fourchon, LA. Additional facilities are located near Biloxi, MS.

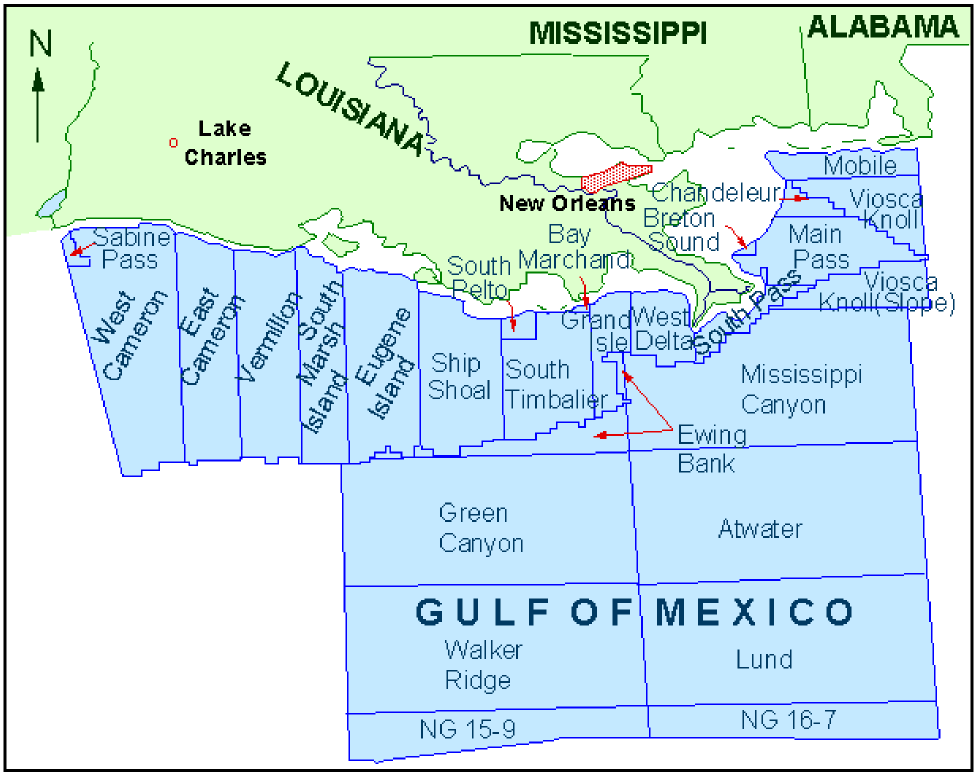

Figure 5.2. Central Gulf Planning Area.

Eastern: The Eastern Gulf of Mexico Planning Area extends along the Gulf's northeastern coast for some 700 miles, from Baldwin County, Alabama, southward to the Florida Keys. The area encompasses approximately 76 million acres, with water depths ranging from tens of feet to over 9,900 feet. Since the late 1980's, a limited amount of OCS activity has taken place in this planning area because of administrative deferrals and annual congressional moratoria. In 2000, MMS estimated that between 6.95 and 9.22 tcf of natural gas and 1.57 and 2.78 billion barrels of oil and condensate are contained in the Eastern Gulf of Mexico Planning Area (USDOI, MMS 2002d).

Due to the environmental and military concerns, little activity has taken place among shore facilities in regard to infrastructure support in the Eastern Gulf. What activity is underway is supported, in part, from many of the Central Gulf on-shore support facilities, though a growing support industry has existed in Mobile Bay, Alabama for some time. In the past, Mobile Bay drilling activities have largely been supported by Central Gulf facilities, as the Mobile area has minimal infrastructure to support offshore gas exploration and development. The coastal areas of Texas and Louisiana are home to specialized industries that support offshore oil and gas drilling in the Mobile Bay area. Contractors from these areas provided the majority of workers needed to drill and develop Coastal Alabama gas. If exploration expands into the Eastern Gulf region, this area will likely see a significant expansion.

With the expanding interest in deepwater activities, many onshore facilities have migrated somewhat to areas that have capabilities of handling deepwater vessels, which require more draft. Since fewer ports have such access, dredging operations at existing facilities or contractor expansion to areas that can handle such vessels has occurred. This has also led to heated competition between port facilities. Many support industries have multiple locations among the key port facilities. For instance, Bollinger Shipyards has locations in Texas City, Galveston, Calcasieu, Morgan City, Houma, Lockport, Fourchon, as well as other locations in the Central Gulf Region.

5.4 Regulations

General Support and Repair Facilities: Although repair and maintenance and other onshore support services are not economically regulated, they are subject to numerous environmental statutes and guidelines. Repair and maintenance – because it is a part of, and often referred to in conjunction with, the shipbuilding industry – is subject to the same regulations as discussed in Chapter 4, Section 4. This includes the Resource Conservation and Recovery Act, United States Code, Title 10, Section 7311, the Clean Air Act, the Clean Water Act, and the Comprehensive Environmental Response, Compensation, and Liability Act.

Other regulations that affect the onshore support industries may include:[19]

Emergency Planning and Community Right-To-Know Act: The Superfund Amendments and Reauthorization Act (SARA) of 1986 created the Emergency Planning and Community Right-to-Know Act (EPCRA, also known as SARA Title III), a statute designed to improve community access to information about chemical hazards and to facilitate the development of chemical emergency response plans by State and local governments. EPCRA required the establishment of State emergency response commissions (SERCs), responsible for coordinating certain emergency response activities and for appointing local emergency planning committees (LEPCs). EPCRA regulations establish four types of reporting obligations for facilities which store or manage specified chemicals:

- EPCRA §302 requires facilities to notify the SERC and LEPC of the presence of any extremely hazardous substance (the list of such substances is in 40 CFR Part 355) if it has such substance in excess of the substance's threshold planning quantity, and directs the facility to appoint an emergency response coordinator.

- EPCRA §304 requires the facility to notify the SERC and the LEPC in the event of a release equaling or exceeding the reportable quantity of a CERCLA hazardous substance or an EPCRA extremely hazardous substance.

[19] The following list is taken from: This section is taken from: Office of Compliance, *Profile of the Shipbuilding and Repair Industry* (Washington D.C.: Office of Enforcement and Compliance Assurance, Environmental Protection Agency), 1997, p. 81-92.

- EPCRA §311 and §312 require a facility at which a hazardous chemical, as defined by the Occupational Safety and Health Act, is present in an amount exceeding a specified threshold to submit to the SERC, LEPC and local fire department material safety data sheets (MSDSs) or lists of MSDSs and hazardous chemical inventory forms (also known as Tier I and II forms). This information helps the local government respond in the event of a spill or release of the chemical.

- EPCRA §313 requires manufacturing facilities included in SIC codes 20 through 39, which have ten or more employees, and which manufacture, process, or use specified chemicals in amounts greater than threshold quantities, to submit an annual toxic chemical release report. This report, known commonly as Form R, covers releases and transfers of toxic chemicals to various facilities and environmental media, and allows EPA to compile the national Toxic Release Inventory (TRI) database.

All information submitted pursuant to EPCRA regulations is publicly accessible, unless protected by a trade secret claim.

Safe Drinking Water Act: The Safe Drinking Water Act (SDWA) mandates that EPA establish regulations to protect human health from contaminants in drinking water. The law authorizes EPA to develop national drinking water standards and to create a joint Federal-State system to ensure compliance with these standards. The SDWA also directs EPA to protect underground sources of drinking water through the control of underground injection of liquid wastes. EPA has developed primary and secondary drinking water standards under its SDWA authority. EPA and authorized States enforce the primary drinking water standards, which are contaminant-specific concentration limits that apply to certain public drinking water supplies.

Toxic Substances Control Act: The Toxic Substances Control Act (TSCA) granted EPA authority to create a regulatory framework to collect data on chemicals in order to evaluate, assess, mitigate, and control risks which may be posed by their manufacture, processing, and use. TSCA provides a variety of control methods to prevent chemicals from posing unreasonable risk.

TSCA standards may apply at any point during a chemical's life cycle. Under TSCA §5, EPA has established an inventory of chemical substances. If a chemical is not already on the inventory, and has not been excluded by TSCA, a pre-manufacture notice (PMN) must be submitted to EPA prior to manufacture or import. The PMN must identify the chemical and provide available information on health and environmental effects. If available data are not sufficient to evaluate the chemicals effects, EPA can impose restrictions pending the development of information on its health and environmental effects. EPA can also restrict significant new uses of chemicals based upon factors such as the projected volume and use of the chemical. Under TSCA §6, EPA can ban the manufacture or distribution in commerce, limit the use, require labeling, or place other restrictions on chemicals that pose unreasonable risks. Among the chemicals EPA regulates under §6 authority are asbestos, chlorofluorocarbons (CFCs), and polychlorinated biphenyls (PCBs).

Under TSCA §8, EPA requires the producers and importers of chemicals to report information on chemicals' production, use, exposure, and risks. Companies producing and importing chemicals can be required to report unpublished health and safety studies on listed chemicals and to collect and record any allegations of adverse reactions or any information indicating that a substance may pose a significant risk to humans or the environment.

Heliports: Heliports are regulated by a number of different federal and state agencies. All flight operations, for instance, are regulated by the Federal Aviation Administration (FAA). Aircraft accidents are regulated by the National Transportation Safety Board (NTSB). Standards related to workplace health and safety are regulated by the federal Occupational Safety and Health Act (OSHA).

The FAA holds jurisdiction over most aspects of the air transportation business. This includes oversight of flight operations, personnel, aircraft, and ground facilities. Air transportation providers must obtain an Air Taxi Certification from the FAA, to transport personnel and equipment to offshore regions. The FAA requires air transportation companies to file periodic reports associated with flight operations.

Most air transportation companies are also subject to certain regulations associated with the Communications Act of 1934 because of ownership and operation of radio and communications equipment used for flight operations.

5.5 Industry Trends and Outlook

General Support Facilities/Repair and Maintenance Yards: As noted earlier, offshore support and transportation facilities are highly dependent upon drilling and production activities, which in turn, are highly dependent upon oil and gas commodity prices. In many ways, the supply and transport side of the offshore industry are one of the first to feel the sting of industry downturns. During periods of contraction, discretionary supply, repair, and maintenance activities are the first to be cut to reduce E&P companies' costs, thereby maintaining profitability.

Over the past 10 years, oil and gas commodity prices have been relatively low.[20] Depressed prices and offshore activities have had a number of impacts on the support side of the industry. This includes a move towards diversification, concentration, and losses of qualified workers.

Firms supporting shipbuilding and platform fabrication activities have been the most noticeable in terms of expanding operations into supply and support activities not only for the oil and gas industry, but for other industries as well. A number of general attributes associated with these facilities have led to their successful diversification. These characteristics include: general large geographic areas for work and storage; varied sources of unskilled and skilled labor (i.e., electricians, pipefitters, welders); and, access to supporting infrastructure (i.e., roads, waterways, ports, communications). Many firms that provide support activities to the offshore industry have diversified into other areas both within and outside the oil and gas industry.

The support activities that many shipbuilders and platform fabricators are conducting include dry-docking, inspections, maintenance and surveys of stacked rigs and equipment. Another new area includes work on production systems. While relatively low-dollar-per-task work, it is more stable than traditional fabrication work and can help keep important yards economically viable during downturns.

[20] One exception to this trend would be the significant natural gas price spike that occurred during the 2000-2001 heating season.

Another trend in the support industry has been in concentration. As noted above, in the past, several support activities were conducted by numerous contractors spread across the Gulf in different firms and different industries. Larger firms now, however, are diversifying into support work to diversify and smooth variation in revenues. These firms can be successful given the attributes discussed above, as well as their ability to bring some economies of scale to service provision. The merger and acquisition activity in the industry has also brought about a significant number of changes and concentration in oil and gas E&P support.

As one industry observer recently noted: “trying to follow the merger and acquisition news in the U.S. shipbuilding industry these days is almost like playing the shell game. You don’t know where the little pea is going to wind up” (Snyder 2002). Litton Industries, Inc. – the parent of Ingalls Shipbuilding in Pascagoula, MS – completed its acquisition of Avondale Industries Inc., in the summer of 1999. Ingalls Shipbuilding is one of the Big Six defense oriented shipyards and its activities associated with the oil and gas industry have been of growing importance. The transaction was an all cash deal, valued at approximately $529 million. The newly created Litton Ship Systems organization will have combined revenues of approximately $1.8 billion in the shipbuilding and ship-modernization market, and with its 17,000 employees, will be capable of producing any class of non-nuclear ship for military and commercial customers (Aerotech News and Review 2002). These commercial customers include the oil and gas industry.

Previously, Newport News had made an earlier bid to acquire Avondale, but withdrew from its pursuit when Litton got involved. Litton had also made a separate offer to acquire Newport News, but backed off after Defense Secretary William Cohen publicly opposed the merger of Litton and Newport News, saying it would dilute competition in the U.S. Navy shipbuilding market. More recently, in April 2001, Northrop Grumman Corporation announced that it had completed the purchase of all tendered shares of Litton Industries Inc. common and Series B preferred stock, after receiving all required U.S. and international governmental and regulatory approvals (Northrup Gruman 2002).

The Big Six (or now Big Three) are united for lobbying purposes under the American Shipbuilding Association banner. “Of course, the Big Six are not the only shipbuilders that have been doing the merger tango” (Snyder 2002). In the late 1990s new companies with old roots and familiar names have emerged in the commercial shipyard sector. Conrad Industries, First Wave/Newpark Shipbuilding, Friede Goldman International, and United States Marine Repair have all either been formed through mergers or grown through acquisitions.

Offshore energy is an important driver of new construction at U.S. shipyards. Excluding inland barges, equipment for the offshore energy sector represented the largest percentage of deliveries by U.S. shipyards in 1998, according to Marine Log's shipbuilding database. Anchor handlers, offshore supply vessels, lift boats, and mobile offshore drilling units represented roughly 36% of all the self-propelled vessels delivered in the U.S. Most of these vessels were built by facilities along the Gulf Coast (Snyder 2002).

Perhaps the visible and important impact of price volatility on support industry organization is associated with the flight of so many experienced personnel to industries that are less cyclical. When experienced workers leave the industry, it is very difficult to entice them back. These shortages have led to a greater emphasis on diversification among contractors, and often results in mergers and acquisitions, leaving fewer contractors. While technological developments have led to increased production with lower costs, qualified workers remain in short supply. The DOE found that one of the greatest risks to the success of offshore development is the critical shortage of expertise in several key areas. Over the next decade, it reports, nearly half of the technology and business leaders in the ultra-deepwater area alone will retire (Office of Fossil Energy 2000). With fewer people entering the fields, colleges, universities and trade schools re-focus their efforts, leading to a further decline in employee and experience replacement.

Heliports: The helicopter and air transportation market in the Gulf is highly competitive. Most contracts are awarded through a competitive bidding process. Bids are typically evaluated on a number of considerations including price, safety, reliability, availability, and service (PHI, Inc. 2001). As noted earlier, there are three major providers of helicopter services in the Gulf: PHI, Inc.; Air Logistics, Inc.; and Evergreen Helicopters, Inc. All three garner significant amounts of their business from the oil and gas industry. In addition, all three companies, to varying degrees, operate and/or maintain aircraft that are owned by E&P companies.

Most all of the providers of air transportation services in the Gulf are dependent upon the oil and gas industry. For instance, in its recent Annual Report, PHI notes that approximately 72 percent of 2001 operating revenue is attributable to helicopter support for the oil and gas industry. Air Logistics recently noted that approximately 97 percent of its revenues come from providing oil and gas air transportation services world wide – about 36 percent of all air transportation revenues were from the Gulf.[21] For all of these companies, their air transportation services are not limited to the Gulf alone. All three provide services internationally in other global basins.

In addition to being concentrated within the oil and gas industry, many of these air transportation providers have revenues that are concentrated with one oil and gas company. For instance, Offshore Logistics noted that during 2000-2001, one customer accounted for 13 percent and 12 percent of consolidated operating revenues (Air Logistics 2001a). PHI, Inc. noted that Shell Oil Company accounted for 15 percent of 2001 operating revenues (PHI, Inc. 2001).

There are a number of risks to air transportation service providers in the Gulf. These risks include:

- Dependence on the oil and gas industry, including concentration of customers;
- Adverse weather conditions and seasonality;
- Political, economic, and regulatory uncertainty; and,
- Safety and insurance.

Most major air transportation providers in the Gulf have attempted to diversify over the years to balance their revenues. For instance, after the 1986 oil price decrease, Evergreen Helicopters turned its attention to spraying crops and other agricultural applications. Evergreen, as well as PHI, Inc. have also turned to emergency medical transportation as a means for revenue diversification. PHI, for instance, was one of the first to use Sikorsky S-76s for air transportation through Air Med affiliate, which provides air services to Acadian Ambulance in south Louisiana (Oil Daily 1990).

In addition to diversifying into other areas of air transportation services, one helicopter service provider has expanded into production activities of the oil and gas industry. Grasso Production Management (GPM), a wholly owned subsidiary of Air Logistics, is an offshore production

[21] This is based upon an estimate from the Company's 10-K filing for 2001 before the Securities and Exchange Commission. No estimates were available for Evergreen, which is a privately held company.

management company. GPM employees are assigned to over 200 platforms, serving independent as well as major oil companies (Air Logistics 2001a). According to the company, GPM's services include furnishing personnel, engineering, production operating services, paramedic services, and the provision of boat and helicopter transportation between onshore bases and offshore platforms. The company's investment in GPM was influenced by its belief that a restructuring in the U.S. oil and gas industry was taking place, creating opportunities to provide production management services to both independent and major oil and gas companies as they either grow, contract, or refocus their activities (Air Logistics 2001b).

6.0 WASTE MANAGEMENT FACILITIES

6.1 Introduction

The purpose of this chapter is to provide information regarding waste streams generated by oil and gas exploration and production activities on the OCS of the Gulf and methods used to manage them, both currently and prospectively. Capacity of the waste management infrastructure is a particular focus. Capacity of a waste facility has two dimensions – short-term capacity and life-of-site capacity. In the short term, a waste facility can face limits to the volume of waste it accepts either from permit conditions or from physical limitations to the site, such as unloading bays, traffic conditions, or equipment capacity. Life-of-site capacity is also a limiting factor for disposal facilities. Limitations of storage space or service life make it necessary to consider what must happen after existing facilities have exhausted their capacity. For example, it may be difficult to replace facilities using older and arguably less protective technology. New permitting of some of the older technologies are either banned or burdened with additional requirements under environmental regulations that were not in place at the time the facilities were opened.

For OCS exploration and production (E&P) wastes that are returned to land for management, the infrastructure network needed to manage the spectrum of waste generated by OCS exploration and production can be divided into three categories:

- Transfer facilities at ports, where the waste is transferred from supply boats to another transportation mode, either barge or truck, toward a final point of disposition;

- Special-purpose oilfield waste management facilities, which are dedicated to handling particular types of oilfield waste; and,

- Generic waste management facilities, which receive waste from a broad spectrum of American industry, of which waste generated in the oilfield is only a small part.

For the first two categories, this chapter presents a comprehensive inventory of Gulf Coast waste management facilities and their capacities. Generic waste management facilities do not lend themselves to such an analysis for several reasons, one being that these facilities have unique permit terms that render physical capacity only a small factor in a site's longevity. Solid waste landfills, likewise, receive only a small fraction of their total loading from OCS activities. These types of facilities will be addressed generically by means of discussion of typical waste management facilities, but are not included in the waste management facilities database developed as a part of this project because; 1) no site by itself is important to the OCS waste management issue, 2) OCS waste is not important to any of these sites as a source of business, and 3) difficulties related to predictability and identification.

Both the Gulf Coast OCS and the oil and gas waste management industry appear to be undergoing significant changes. New drilling technologies and policy decisions as well as higher energy prices should increase the level of OCS activity, and with it, the volumes of waste generated. The oilfield waste industry, having been mired in somewhat stagnant conditions for almost two decades, may develop new increments of capacity under stricter environmental permitting rules, such as zero discharge, than those in place when the existing infrastructure was developed. For this reason, this chapter includes information on new developments that may be important to long-term projections but do not form a part of the current waste management infrastructure network.

6.2 Description and Typical Facilities

Types of Waste Generated: A number of different types of waste are generated as a result of offshore exploration and production activity. These include:

- Solids, such as drill cuttings, pipe scale, produced sand, and other solid sediments encountered during drilling, completion, and production phases.

- Drilling muds, either oil-based, synthetic, or water-based.

- Aqueous fluids having relatively little solids content, such as produced waters, waters separated from a drilling mud system, clear brine completion fluids, acids used in stimulation activities, and wash waters from drilling and production operations. Although most of these are potentially dischargeable under the National Pollution Discharge Elimination System (NPDES) general permit, the possibility always exists that some amount of material will become contaminated beyond the limits of treatment capabilities and will require disposal in a land-based facility.

- Naturally Occurring Radioactive Materials (NORM), such as tank bottoms, pipe scale, and other sediments that contain naturally high levels of radioactive materials. NORM occurs as a sludge and also as scale on used steel vessels and piping when equipment has been exposed to other NORM materials after very long periods of use.

- Industrial hazardous wastes, such as solvents and certain compounds with chemical characteristics that render them hazardous under Subtitle C of the Resource Conservation and Recovery Act and thus not subject to the exemption applicable to wastes generated in the drilling, production, and exploration phases of oil and gas activities.[22]

- Nonhazardous industrial oily waste streams generated by machinery operations and maintenance, such as used compressor oils, diesel fuel, and lubricating oils, as well as pipeline testing and pigging fluids. Some operators and state regulators may choose to handle waste from drilling and production machinery as industrial wastes. Used oil generated by exploration and production operations may legally be mixed with produced oil, but refineries discourage the practice. These streams often become commingled with wash water. They may be handled in drums or in bulk as part of a larger waste stream.

- Municipal solid waste generated by the industry's personnel on offshore rigs, platforms, tankers, and workboats.

[22] 40 CFR 261.4 (b)(5)

The different physical and chemical characteristics of these wastes make certain management methods preferable over others. In Section 6.3 – Industry Characteristics, we address how different waste management methods are used for different circumstances.

Quantification of Wastes Generated: This chapter integrates much of the available information on the quantities of wastes generated by OCS exploration and production activities into a comprehensive Gulf of Mexico waste generation model (OCSGEN). The spreadsheet model attached as Appendix III uses recent MMS assumptions about the number of wells, the required maintenance over their life, and the volume of hydrocarbon produced as inputs. At present, they are set as the average of the High and Low cases that have been used in recent MMS impact analysis. These inputs may be changed at any time in response to new leasing decisions, alternative resource estimates, or future energy economics. The inputs are multiplied by estimates of averages generation rates for each type of waste and each type of activity to arrive at estimates for total volumes generated and total volumes transported ashore by planning area and for the Gulf Coast as a whole.

OCSGEN is a first step in integrating waste management decisions into considerations of broader impacts. Further research that uses more detailed, special-purpose data collection could result in more accurate estimates of waste generation. With relatively little effort, for example, the total transportation impacts of an alternative discharge rule could be modeled and compared to existing rules. MMS has this type of analysis within relatively easy reach as a result of other research efforts into resource valuation considering social costs and future platform requirements.

Inventory: Based on an inventory conducted as part of the development of a GIS database for this project, 41 waste management facilities that service the oil and gas industry were recorded within the Gulf region; 25 in Louisiana, 11 in Texas, 3 in Mississippi, and 2 in Alabama (Table 6.1).

6.3 Industry Characteristics

The U.S. EPA has established a hierarchy of waste management methods that it deems preferentially protective of the environment. For those technologies applicable to oil and gas production waste, the following general waste management techniques are described in order of EPA's preference:

- ***Recycle/re-use:*** When usable components such as oil or drilling mud can be recovered from a waste this means that these components are not discarded and do not burden the environment with impacts from either manufacturing or disposal.

- ***Treatment/detoxification:*** When a waste cannot be recycled or re-used it can sometimes be treated to remove or detoxify a particular constituent prior to disposal. Neutralization of pH or removal of sulfides are examples of technologies that are used with oil and gas wastes.

- ***Thermal treatment/incineration:*** Wastes with organic content can be burned, resulting in a relatively small amount of residual ash that can be incorporated into a product or sent to disposal. This technology results in air emissions, but the residuals are generally free of organic constituents.

Table 6.1

Waste Management Facilities in Gulf which Support Offshore Oil and Gas Industry

Owner	City	State	Class	Primary Type
Environmental Treatment Team	Theodore	AL	Tr	Other
Waste Mgmt. Chastang Landfill	Chastang	AL	Di	LFill
BFI	Ridgeland	MS	Di	LFill
Waste Mgmt.	McNeil	MS	Di	LFill
Waste Mgmt. Grove Landfill	Pass Christian	MS	Di	LFill
ETT (Env Treatment Team	Morgan City	LA	Tr	Unknown
Habetz Oilfield Saltwater Disposal	Crowley	LA	Di	SD
Hallar Enterprises Inc.	Pierre Part	LA	Di	Inj
Houma Saltwater Disp Co.	Houma	LA	Di	Inj
J&R Systems Inc.	Rayne	LA	Di	Inj
L & S Service Corp.	Oil City	LA	Di	Inj
Louisiana Tank Inc.	Lake Charles	LA	Di	Inj
Miller SWD	Gueydan	LA	Di	Well
NES Nonhaz Injection Disp Facility	Winnie	LA	Di	Inj
NES Now Transfer Facililty #2	Port Fourchon	LA	Tr	SD
NES Now Transfer Facility	Venice	LA	Tr	Not Listed
NES Transfer Facility	Morgan City	LA	Tr	SD
NES Transfer Station	Cameron	LA	Tr	SD
NES Transfer Station	Intracoastal City	LA	Tr	SD
NES Transfr Facility #1	Port Fourchen	LA	Tr	SD
Oilfield Brine Disposal	Abbeville	LA	Di	Well
Philip Services	Jeanerette	LA	Di	Inj
Pool Company	Sarepta	LA	Di	Inj
Saline Injection Systems Company	Egan	LA	Di	Inj
SWD Inc.	Iowa	LA	Di	Well
SWD Inc.	Lacassine	LA	Di	Inj
US Liquids	Elm Grove	LA	Di	LFarm
US Liquids	Jennings	LA	Di	3 Inj and Lfarm
Waste Mgmt. Kelvin Landfill	Kelvin	LA	Di	SD
Waste Mgmt. Woodside Landfill	Baton Rouge	LA	Di	SD
Burns Saltwater Disposal	Victoria	TX	Di	SD
Eco Mud Disposal	Alice	TX	Di	LFill
Key Energy Services	Brookeland	TX	Di	SD
NES	Port Arthur	TX	Di	SD
NES (Newpark Env Services)	Ingleside	TX	Tr	SD
NES Norm Processing & Inj Facility	Winnie	TX	Di	Inj
NES Now Injection Facility	Hamshire	TX	Di	SD
Norm Services Group		TX	Di	Inj
Smith Disposal Facility		TX	Di	LFill
Trinity	Anahuac	TX	Di	SD
Waste Facilities Inc.	Premont	TX	Di	LFarm

NOTE:

Class Di = Direct
Tr = Transfer
Primary Type
LFill = Landfill; SD = Saltwater Disposal; Inj = Injection; LFarm = Land farm

Source: RPC, 2001; The Louis Berger Group, Inc. 2001

- ***Subsurface land disposal:*** This technology places waste below usable drinking water resources and is viewed as superior to land filling due to the low potential for waste migration. Injection wells and salt cavern disposal are examples of this type of technology.

- ***Surface land disposal/treatment:*** This type of technology involves placement of wastes into a landfill or onto a land farm. Although well-designed and constructed landfills minimize the potential for waste migration, generators remain concerned about migration of contaminants into water resources and avoid it whenever practical. EPA classifies surface land disposal as the least desirable disposal method (USEPA 1995).

Several waste management methods are used to handle the spectrum of wastes generated by OCS activity, and most types of wastes lend themselves to more than one method of management. Choice of method will depend on the following factors:

- An operator's perception of long-term liability for the waste;
- Physical characteristics of the wastes, such as solids content or oil content;
- Processing or disposal cost;
- Cost of transportation from the point of generation to the waste management facility; and,
- Preexisting business relationships with a waste management facility.

Each of these options has a different set of environmental impacts, regulatory constraints, costs, and capacity limitations. For example, industrial nonhazardous oily waste streams are managed at facilities that manage oily wastes for a broad range of industries. The same is true for municipal solid waste and hazardous waste. Most NORM and nonhazardous oilfield wastes (NOW) are only handled by specialized oilfield waste facilities in the Gulf Coast area, although there are exceptions. The most common oilfield waste management methods are provided in the rest of this section.

Discharge into the Sea: Wastes discharged into the sea must be virtually free of hydrocarbons and any other chemicals that would be harmful to marine life. Produced water, by far the most abundant oil and gas waste stream, can meet this definition after appropriate treatment steps. Water-based drilling muds that are: 1) made from clean barite, 2) without certain chemical additives, and 3) have not encountered hydrocarbons are also dischargeable into the sea under emerging regulations (USEPA 1999). Finally, domestic and sanitary sewage from rig employees, after certain pretreatment steps, may also be discharged into the sea under most circumstances (USEPA 1996).

This practice is prevalent in offshore production and is regulated under 40 CFR, Part 435, Subpart A, which addresses application of the National Pollution Discharge Elimination System (NPDES) for Gulf Coast discharges in the Western and Central Planning Areas. The principal concern is that oil is properly separated from the saltwater before discharge – often requiring one or more pretreatment steps to achieve the limitations of total organic compounds (TOC) set out in the General NPDES permit for EPA's Region 4.[23]

Costs: Discharge into the sea clearly has an overwhelming cost advantage because transportation costs are avoided. Cost for simple, continuous streams of produced water is virtually nothing, while setup to treat the most difficult intermittent stream might cost over a million dollars. Cost per barrel depends on the nature of the waste stream and life span of the wells served by the installation.

Siting Requirements and Environmental Issues: The Federal regulations set forth in the NPDES permit for the eastern Gulf apply in areas with water depths in excess of 200 meters. The NPDES permit prohibits discharges within 1,000 meters of an environmentally sensitive area – which really only comprise less than 1 percent of the OCS. The most prevalent environmentally sensitive areas are the benthic (bottom-dwelling) communities found around small areas where methane vents into the sea and provides a food source and unique habitat for the specialized organisms that have developed around them.

Areas closer to shore generally have greater environmental sensitivity due to more prevalent soft substrates and greater nutrient loading. In areas along the western Florida shelf, seagrass beds are a dominant feature of the sea floor. In addition, commercial and recreational fishing grounds are present.

Although EPA has amassed considerable data indicating the discharge restrictions are protective of the environment, many members of the public disagree and question the industry's willingness to comply, given the abuses possible under the self-reporting rules in NPDES. Future OCS operations may in some cases occur closer to more environmentally sensitive areas than historical activities, prompting renewed scrutiny of the impacts of discharges. In any event, the question of discharge impacts is sure to be a prominent issue in the public eye for years to come.

Outlook and Capacity Issues: EPA has reserved the right to monitor the effectiveness of these restrictions and to change them later if they prove not to be fully protective. For example, a well-publicized violation or accident with significant impacts could cause modifications to EPA policy on discharges. Any prominent spill, or failure of a treatment system to perform properly, could prompt a call for more restrictive discharge rules that could include an outright ban in some situations. Future lease blocks closer to Florida, if any, could face different requirements or even be subject to a zero-discharge policy.

For planning purposes, it must be assumed that there is at least a possibility that discharges will be further limited in the future. If this were to be the case, both costs and logistics would indicate that on-platform subsurface injection facilities, perhaps complemented by salt dome disposal facilities for drilling muds (both discussed below), would accommodate the overwhelming volume of offshore waste. The prospect of many millions of barrels per year coming ashore, as indicated by OSCGEN, implies far more costs, transportation equipment and shipping traffic than would be tolerated by any stakeholder, given the relative ease of subsurface injection.

[23] Federal Register Vol. 63, No 200, Oct 16, 1998

Subsurface Injection:[24] Subsurface injection is the management method used for more than 90% of the 16 billion barrels of saltwater produced by onshore oil and gas production each year in the U.S. (Figure 6.1) (ICF 2000). An injection well can best be envisioned as a producing well operating in reverse, with very similar drilling and completion procedures. (Depleted producing wells are, in fact sometimes converted to injection wells.) Subsurface injection of aqueous fluids into a porous rock formation is the oldest and most established technology for disposal of produced waters onshore or when discharge is not allowed offshore.

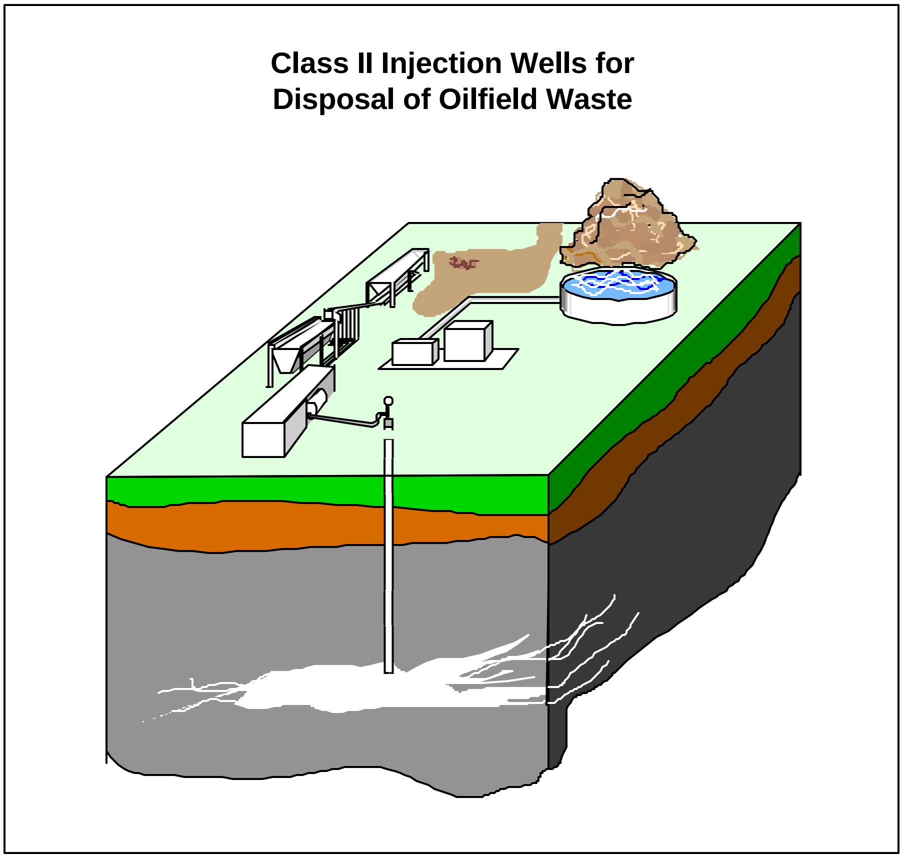

Figure 6.1. Injection Wells for Oilfield Waste.

About 70 percent of the volumes injected in the U.S. serve the dual purpose of waterflooding the field, which is essentially pushing residual hydrocarbons to selected wells in a secondary oil recovery project (ICF 2000). Less often, the injection zone is either depleted or otherwise not productive of hydrocarbons. Underground injection is most suitable for relatively solids-free liquids – fluids are often filtered before injection because many injection formations cannot tolerate significant levels of solids without plugging. In these cases, the filtrate and sometimes

[24] We use the term "subsurface injection" of waste in its more traditional sense of meaning injection into a porous rock formation as opposed to the newer waste management method of salt cavern disposal, which is also technically subsurface injection but significantly different from this method both technically and legally.

the filters themselves then become a solid-form waste stream that must be managed.[25] Some formations, on the other hand, are sufficiently porous and tolerant of solids so as to present a viable method of disposing of sludges. The most prominent example of the latter is the Newpark facility located near Fannett, Texas in Jefferson County.

The Newpark facility is the most important NOW facility for the offshore industry, having received some 5,000,000 barrels of offshore waste (generated in state-waters) in 1998, constituting about 75 percent of the total offshore NOW or NORM streams shipped ashore. (Volumetrically, the NORM components are miniscule).[26]

Costs: The cost of an underground injection system varies greatly with the scale and the difficulty associated with the fluid being managed. A high-volume pipeline-gathered injection system can be operated between $.05 and $.10 per barrel. In contrast, land-based commercial disposal wells, which serve wells that do not have sufficient volumes to justify a captive pipeline system typically charge $.25 to $.40 per barrel in the Gulf Coast region, with transportation usually adding two or three times that amount.

A slurry injection facility, such as the one at the Newpark facility, has all the requirements of a liquids injection facility, and additional equipment to store, pump, and grind sludge to the uniform required particle size. Disposal prices at slurry injection facilities typically range from $8.00 to $14.00 per barrel at the wellhead. The cost for NORM waste disposal is relatively high ($100 to $200 per barrel) due to the significant handling restrictions necessary to manage this type of waste. In addition, the material is often managed in drums, a practice that by itself commands a significant premium over wastes handled in bulk.

Siting Requirements and Environmental Issues: All facilities employing a form of underground injection rely on the availability of a suitable underground formation or structure for emplacement of wastes. Most areas along the Gulf Coast have at least one subsurface geologic formation suitable for underground injection. To be suitable for injection, a geologic formation must be of sufficient thickness and permeability to accept reasonable amounts of fluid as well as the residual solids that escape filtration. The injection zone must also be situated with sufficiently impermeable formations above and below it to isolate the injected material from usable groundwater and other resources. The most porous and permeable formations can be extremely tolerant of solid particles--to the extent that they can be used for the disposal of slurried solids if the particles are uniformly small enough to pass through formation pore spaces.

Subsurface injection wells are regulated as Class II injection wells under the EPA's underground injection control program authorized by the Safe Drinking Water Act and pursuant to regulations set forth in 40 CFR Part 144 that were first promulgated in 1983. EPA directly regulates injection wells in Federal waters and delegates authority for the state programs to the Texas Railroad Commission, the Louisiana Department of Natural Resources, Mississippi Oil and Gas Board, and the Alabama Department of Environmental Management. The regulatory program is

[25] A similar technology, annular injection, is used at the point of generation and sometimes used onshore in a commercial mode, but has generally been less accepted due to concerns about the fate of the waste once injected. Some newer approaches involve extensive characterization of the receiving formation and seem to hold the promise of broader acceptance, especially for offshore applications.

[26] Newpark Resources Form 10-K, 1999, and telephone contact with Chief Technical Officer, December 1, 2000 by Steve Mobley, RPC.

mature and the technology has an established record of good performance, despite decades of operations under considerably less protective regulation than those that exist today.

Disamenities associated with this method are the visual and noise issues one might encounter at a producing well with a relatively large amount of tankage and pump noise. If the products received are sour – containing sulfurous compounds - odor problems can be significant to a larger area; otherwise, they are rarely an issue beyond the immediate proximity of the site. Facilities that receive waste via truck have the potential for large traffic impacts on smaller roads. Injection wells are sometimes perceived by regulators not familiar with them to present a threat to groundwater resources, although the historical record of waste migrating out of the injection zone to a higher freshwater formation is very sparse. For the most part, regulators in energy-producing regions, who have a long experience with injection wells, are comfortable that the technology is protective of groundwater resources.

Outlook and Capacity Issues: Waste is isolated in the injection zone from zones above it by overlying formations that form a seal, although there are typically no well-defined edges to the formation that would serve as the sides of what might incorrectly be envisioned as a container. For this reason, injection zones usually do not have capacity limits that can be meaningfully measured against the relatively finite amount of waste that may be generated within the local area.

Subsurface injection facilities have two limitations. Any given injection zone will accept fluid at a certain rate, depending on porosity, permeability, and thickness of the formation. This tends to govern the maximum amount of waste that may be disposed of daily in a given well. Second, any given injection well is subject to irreparable failure of the casing or the cement around the casing as well as to "skin damage" to the formation at its interface with the wellbore. With proper design and operation, most wells can be expected to last 15 or 20 years. When a well fails, redrilling within a few hundred feet is often an option, although the oil and gas production that led to the requirement of a well in the first place may well play out before then. Life-of-site capacity at a given location, then, is usually not an issue as much as how long saltwater from nearby wells will be produced.

Long term, capacity to install subsurface injection facilities onshore is itself not scarce and oilfield waste injection well permits do not generally attract much public opposition. With the volume of produced water frequently exceeding the volume of oil a well produces by tenfold or more, the main limitation to widespread use of land-based subsurface injection facilities is the space at docks and the traffic in and out of ports.

Salt Cavern Disposal: Almost anything that can physically be pumped downhole can be disposed of in a salt cavern. Salt cavern disposal has an advantage over subsurface injection as disposal of solids-laden sludges may be difficult to get into the rock formation. Although salt caverns can easily accept liquid, cost factors dictate that liquids will generally be disposed of through subsurface injection instead of salt cavern disposal. The reason is that salt caverns require an injection well for disposal of brine displaced from the salt cavern as waste is injected. As such, salt dome disposal creates a barrel-for-barrel requirement for injection well disposal. Thus, no fluids that can easily be managed by underground injection would be disposed of in salt caverns by choice.

Muds and solids that have been slurried can be pumped into synthetic voids formed within salt domes for the purposes of storage (Figure 6.2). These caverns are drilled and completed using solution-mining techniques and are used for storage of natural gas, crude oil, and other hydrocarbons. To create the cavern, a well must be drilled into the salt dome. Fresh water is then pumped into the salt dome where it becomes saturated with salt. Saturated saltwater is circulated out of the dome through the annulus of the same well, which then must be disposed of through a subsurface injection well operation of the type described in above. Before waste is introduced, the completed cavern then resembles a giant salt-sided jug of brine. Injection wells are an integral part of a salt cavern disposal operation, because every barrel of saltwater displaced must be disposed. Waste materials are then pumped into the cavern, displacing an equal volume of saltwater, which is injected in the disposal well operation. Temporary salt cavern storage of natural gas, natural gas liquids, and petroleum is well established in the U.S. in over 1,000 caverns, although their use for permanent disposal is a newer development.

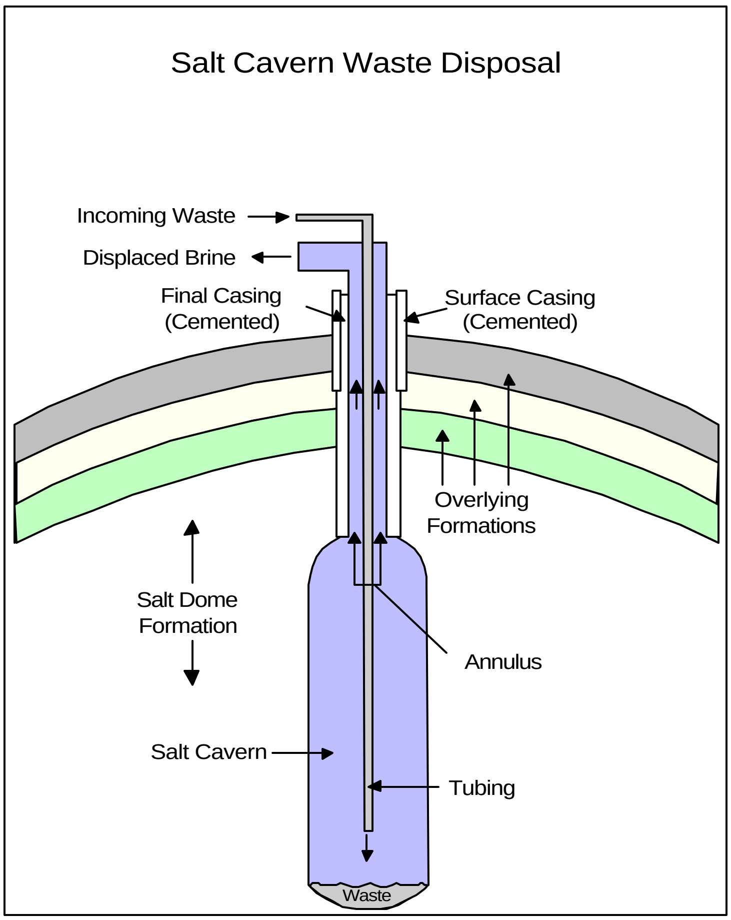

Figure 6.2. Salt Cavern Waste Disposal.

Costs: One commercial salt cavern, operated by Trinity Field Services, has recently opened near Hamshire, Texas on the Trinity River. It presently receives waste only by truck, although management expects a barge mooring to be permitted within a year. Trinity Field Services publicizes prices of $8-15.00 per barrel, with discounts undoubtedly available for large volumes. Commercial salt caverns in other parts of Texas charge from $5 to $15 per barrel (bbl) for NOW, with surcharges applicable if the material must be blended into a pumpable state. This technology has an advantage over typical subsurface injection in that the size of the solids pumped downhole is not an issue and it avoids the need to grind solids to a uniform particle size. NORM prices at Lotus, L.L.C. (a commercial salt dome in Andrews County, Texas) are approximately $150/bbl, plus approximately $5 bbl freight from Corpus Christi.

Siting Requirements and Environmental Issues: These facilities are only possible in parts of the country where salt deposits are found, in either bedded or domal formations. The Gulf Coast region, both onshore and offshore, has an abundance of salt caverns, many with barge access. As discussed in Chapter 10, many Gulf Coast salt domes are already in service for hydrocarbon storage. Salt caverns otherwise introduce no particular siting criteria except the need to maintain a sensible buffer from residential and commercial areas for reasons associated with odors and equipment noise.

Like subsurface injection operations, salt cavern disposal facilities have minimal permanent impacts on the surface. Land is required for a wellhead, truck unloading, a small office, blending equipment, and tankage for short-term storage. The recently opened Trinity facility near Liberty, Texas occupies 40 acres but actually uses considerably less land than that.

Outlook and Capacity Issues: With the addition of Trinity Field Services to the market in 2001, the OCS market has its first salt dome disposal operation in a competitive location, with 6.2 million barrels of space available initially -- enough to take eight to ten year's worth of OCS liquids and sludges at current generation rates and a potential of several times that amount with additional solution mining. Salt domes are well-known and well-documented geological structures, and others could be placed into service as demand dictates. Salt caverns are a finite resource, but nevertheless have the potential to take decades' worth of OCS offsite NOW generation.

Land Application: Drilling muds, produced sand, and other fine solids are candidates for land application, often called landfarming. Muds and other solids are spread on land and mixed with earth to be incorporated into the soil, or deposited into dedicated pits. Muds with no hydrocarbons and low chloride content can sometimes be beneficially applied to pasture land, although the practice is increasingly avoided. In a pit system, hydrocarbon levels in the wastes are reduced using bioremediation techniques. Once hydrocarbon levels have been reduced to acceptable levels, the material can be used for landfill cover or road building material, an application in which the oil's plasticity characteristics and water-resistivity are desirable. Alternatively, the whole cell can be closed in place as a monofill, which is essentially a special-purpose landfill with only one waste stream.

Costs: Costs for disposal of NOW at landfarms range from $8.00 to $16.00 per barrel with the higher costs associated with higher liquid levels.

Siting Requirements and Environmental Issues: Modern landfarm siting criteria are similar in many respects to landfill siting criteria, although less stringent in some respects simply because landfarms are by any measure much smaller operations than landfills. These criteria include:

- Sufficiently far from residences that odors and equipment noise are not an issue;
- Served by roads with gross vehicle weight rating of 80,000 pounds;
- Out of wetlands or 100-year floodplain;

- Pits are sometimes lined with an oil-resistant material such as high-density polyethylene plastic;
- If objective is to produce construction material from oil-based mud, pits should be sized to allow for 3-in high windrows and sufficient residence time to bioremediate the material down to a suitable hydrocarbon level (approximately 500 mg kg^{-1} TPH); and,
- If the treated waste is to be closed in place, keeping the areal extent of the pit as small as possible is a more important criteria.

Landfarming regulations in the Gulf Coast states depend on site-specific permits except for on-site disposal of onshore drilling waste. Landfarming carries a risk of long-term liability from either leakage of the monofill or liability from use of the recycled material. While any method has its risks, landfarming is perceived as riskier than either of the two injection methods by many operators and is avoided by many operators, and prohibited by still others.

Outlook and Capacity Issues: Landfarm capacity and fill rates are difficult to estimate because they are typically small operations and because capacity is limited not only by physical size, but by toxic constituent loading. These facilities typically have permits that limit the total amount of toxic metals that can be applied per acre of land. Wastes with relatively high levels of toxic metals would cause a landfarm to reach its maximum metals loading much faster than relatively clean wastes. The facilities are available to accept offshore waste but actually accept very little because other methods are preferred by the operators and have stronger commercial and logistical links to the offshore community.

The use of landfarming of OCS waste is likely to decline further, particularly with greater availability of injection methods for wastes containing solids. Future regulatory efforts are likely to discourage the practice by adding requirements that damage the economics if not by an outright ban on future permits.

Landfilling: Workers on a rig or production platform generate the same types of waste as any other consumer in industrial society, and are therefore responsible for their fair share of municipal solid waste (MSW). A large volume of industry-specific trash and industrial junk also makes its way to a landfill.

A modern landfill is an engineered facility with protective liners and caps to isolate the waste from the larger environment (Figure 6.3). MSW is placed in an excavated cell, usually lined with high-density polyethylene to prevent leakage into the groundwater. MSW must be covered daily to control odors, birds, and vermin brought about by rotting food wastes.

Cuttings, muds or watery waste streams can be treated by mixing with a stabilizing agent such as cement kiln dust, lime, or often even a simple bulking agent such as sawdust or waste from papermaking processes. These materials will be introduced in a mixing vessel at the landfill and stirred with a track hoe until it has a desired consistency. Depending on the solids content of the original waste stream as well as the bulking agent, the growth in volume will vary; a cubic yard of fresh water could become two cubic yards of landfillable waste.[27] Thus, an incoming cubic yard (approximately five barrels) of waste will occupy the landfill space of as much as four gate yards of MSW, which will be compacted in the landfill to half of its volume at the gate.

[27] 5 bbls = 1 cubic yard. 2 cu. yds of MSW in place = 4 cu. yds of MSW at the gate.

This, along with the considerable treatment cost, argues for a much higher price for these streams than their incoming volumes would initially suggest. In other circumstances, described below, such streams may be attractive to a landfill operator as cover material.

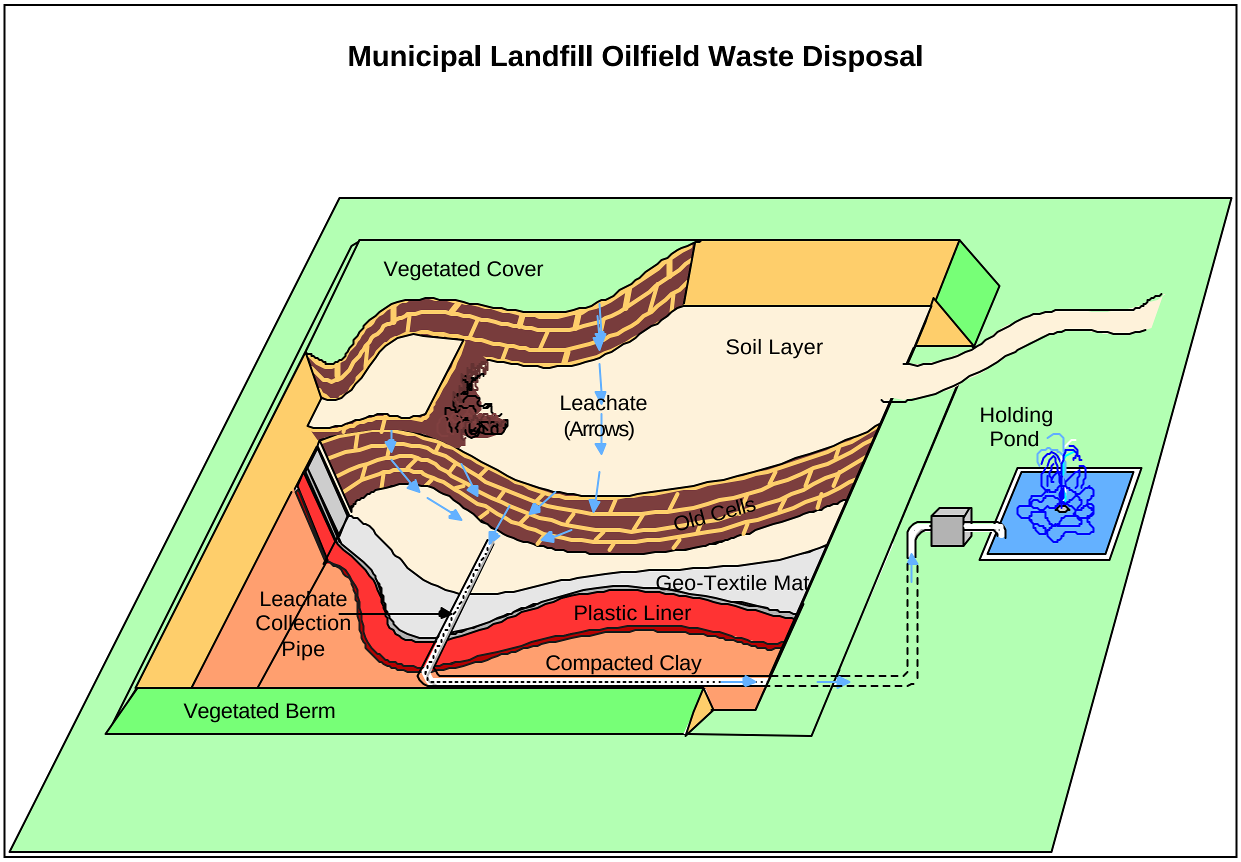

Figure 6.3. Municipal Landfill Oilfield Waste Disposal.

A landfill must apply cover material of earth or some kind of non-putrescible material to the working face of the MSW daily. Drilling muds and wastewater streams that have been solidified may often serve as daily cover. Use of this type of material often improves a site's soil balance, meaning the volume of soil required over the life of the landfill for its construction and operation will be less than if these materials were not available and other soils had to be hauled in at a cost. Up to a point, the materials consume no airspace since they are merely displacing soils that would be used for cover in any event. For this reason, landfills will often accept these materials at a reduced price, or even at no charge. Once a site has its daily cover requirements being met from revenue-positive gate receipts, its management would look quite differently at incremental volumes of such materials.

Costs: Landfill prices in the Gulf Coast region range from approximately $18.00 to $35.00 per ton for MSW - toward the low end of U.S. landfill prices.[28] For NOW sludges, the range will

[28] Source: SWANA tipping fee survey

depend greatly on the processing cost and the volume increase associated with adding stabilization agents. Generally speaking, the range will be between $8.00 and $16.00 per barrel.

Siting Requirements and Environmental Issues: Landfill siting criteria are at once exacting but vague. Nearly every landfill siting application results in an evidentiary hearing or is otherwise the subject of intense debate. The level of impacts that sites will have on adjacent land users is hotly debated by both applicant and intervening neighbors. Nevertheless, there are certain qualitative factors that describe the spirit, if not the letter, of what a successful application for a new landfill must contain. A new landfill should have the following characteristics:

- Not in the 100-year floodplain;
- Away from population centers;
- More than six miles from an airport (for landfills that receive putrescible waste);[29]
- Accessible by public roads built to withstand maximum legal truckloads with significant excess capacity;
- Geologically simple and well-understood subsurface stratigraphy characterized by an absence of faulting, fracturing or folding;
- Groundwater deeper than maximum depth of excavation;
- Large enough tract of land for minimum of 20-year site life at expected opening fill rates (usually a minimum of 250 acres); and
- Established or expected use of neighboring land is industrial.

Environmental issues raised by landfills ultimately come down to: 1) potential threats to local groundwater, 2) impacts on local traffic, and 3) aesthetic considerations associated with truck traffic, nuisance odors, equipment noise, visual impairment of the landscape, and blown trash. All of these issues are generally confined to a very small area relative to the trade area of the modern landfill, which is typically at least a fifty-mile radius. If a landfill is properly sited, engineered, and operated, these impacts are minimized. Examples exist where quality residential development has developed concurrently and harmoniously with nearby landfills.

Outlook and Capacity Issues: MSW disposal from OCS activities currently imposes only a small incremental load on the landfills examined in this study—for example, probably no more than 5 percent of total receipts by all the landfills serving south Louisiana. Growth in these volumes can be expected to increase with increased OCS drilling and production activity although not strictly in a linear manner since the average number of workers per rig is declining. Recycling, seen in many applications as a replacement for landfills, should not be expected to have a significant impact on future landfill requirements from this sector. In work environments more amenable to recycling, where lack of time and space do not make for such a difficult environment for source separation, recycling causes at best a modest reduction in landfill volumes. The conservative assumption, from the MMS planning standpoint, is that it will continue to be a small factor in the reduction of trash generated by OCS activity. Assuming a landfill: 1) presently had OCS waste constituting 5% of its waste stream, 2) the remaining life of a landfill was 20 years at current fill rates, and 3) OCS waste doubled but the rest of the incoming waste stream remained flat, then the OCS activities would cause the landfill to be

[29] This standard is for landfills that receive putrescible waste and can be relaxed with Federal Aviation Administration consent.

closed at the end of 19 years as a result of the OCS contribution increase. With no waste received from OCS activities at all, the landfill would close in 21 years.

Economics of stabilization and the relatively high value of MSW airspace compared to the costs of subsurface injection or salt cavern disposal generally make landfills a poor choice where drilling and production sludges and liquids are concerned. Landfills seem to receive drilling and production waste from OCS activities in unusual circumstances: 1) when landfills need cover material and will negotiate prices, 2) when other options present some kind of schedule problems, and 3) when the physical form of the material make it a better choice. Some landfills will have a limited appetite for some solids originated from drilling and production activities, but for the most part it is not likely that landfills will gain a larger share of this market – thus limiting the impact on airspace life.

Separation and Reclamation of Drilling and Completion Fluids: Drilling and completion fluids with a high value often justify considerable effort to reclaim and store them for a future use. Some drilling and completion fluids used offshore are very expensive either because of their petroleum-product content or because of their use of expensive clear brines such as calcium bromide and zinc bromide. At times, these fluids can be cleaned up through centrifugation in the field. At other times, they will be returned to the fluids company's supply base, where separation equipment is used to return the fluid to a useable condition.

Costs: Reclaiming a barrel of fluid with a market value of $300 or more can understandably justify a large budget. The fluids service companies usually maintain title to the fluid as well as responsibility for disposal. Thus, reclaiming avoids a disposal charge but more important, provides material to be used in another sale. Costs vary widely with circumstances and no representative figures have been found. Even at the high end of transportation and disposal charges discussed elsewhere, the economics of reclamation would be compelling.

Siting Requirements and Environmental Issues: These operations will typically occur on the fluids service company's yard. The tankage and separations equipment used offshore are available on the service yard and no permits or additional authorizations are needed.

Reclamation operations generate sludge, which enters into the oilfield waste management system just as any other sludge would. Depending on the filtration system used, filter media may be incorporated into the sludge or may be handled separately as relatively dry trash. Apart from these wastes, the reclamation operations present no impacts that are not inherent to the fluids themselves. If the fluids are carefully managed in both spent and ready-to-use forms, then the environmental impacts will be minimal. The value of the fluid in all stages of its uses argues that it will be conserved and reused whenever economically possible.

Outlook and Capacity Issues: Although reclamation is at the top of the RCRA hierarchy and has compelling economics in many cases, the economics of recovering fluid will get better only to the extent that the oil component in an oil-based drilling system, or the cost of clear brines, becomes more valuable. Capacity to reclaim is not limited in any sense other than in the very short term, when separation equipment to accomplish the processing may be short. This activity will only expand or contract directly with the number of barrels being used in the market at any given time.

Separation and Recycling of Industrial Wastes: Certain industrial wastes generated in the course of oil and gas development do not fall under an oil field waste exemption under RCRA Subtitle C. If they are not uniquely oilfield wastes, then the oil and gas waste exemption does not apply. Examples of such streams are lubricating oils for drilling machinery, oil filters, oil-based paint solvents, and parts degreasers. These activities are characteristic of painting metal and maintaining machinery, and are not unique to the oilfield. Generation of hazardous wastes has declined markedly in recent years as more environmentally friendly products have replaced them and the use of hazardous materials has been minimized in other ways.

Costs: Table 6.2 presents a range of disposal costs for the different industrial wastes that fall into this category.

Table 6.2

Disposal Costs for Various Industrial Wastes

Waste Type	Disposal Price Range
Industrial organic hazardous wastes	\$75 to \$150 /gal
Inorganic liquid hazardous wastes	\$50 to \$125 /gal
Oil filters	\$8 to \$15 per 55 gallon drum
Used oil	\$ 0 to \$0.15 per gallon
Oily wastewater	\$0.10 to \$0.25 per gallon

Source: RPC, 2001

6.4 Regulations

Federal regulations govern what may be discharged in Gulf waters and establish different standards in different parts of the Gulf Coast. Table 6.3 summarizes Federal rules presently in place. Wastes that cannot be discharged or injected offshore must be brought to shore. Transportation, packaging, and unloading of the waste at port are governed by U.S. DOT regulations while the Coast Guard regulates vessel fitness. Once on the dock, transportation and packaging is subject to an overlay of U.S. DOT and state law. State regulations governing reporting and manifesting requirements may vary somewhat, but Federal law has for the most part preempted the field of transportation waste regulation. Dockside facilities that serve as transfer points from water to land modes of transportation are regulated by both Coast Guard and state regulations covering the management of oilfield wastes. Once at a waste management facility, regulation regarding storage, processing, and disposal varies depending on the type of waste. Most would fall under the oil and gas waste exemption of RCRA Subtitle C and would be subject only to state regulations regarding the disposal of oilfield wastes. A minute volume of the waste would be subject to federal regulation as hazardous waste under RCRA Subtitle C.

Table 6.3

Summary of Federal Rules Governing OCS Discharges and Injections

MMS Planning Region	Rules	Key Features
Western	63 FR 58722 NPDES General Permit Rules	General permit restricting discharges to 29 mg/l monthly average and 49 mg/l maximum daily total oil and grease
Territorial Seas of Louisiana	62 FR 59687 NPDES General Permit Rules	General permit restricts discharges to 29 mg/l monthly and 49 mg/l maximum daily total oil and grease. Requires monitoring for benzene, thallium, phenol, and lead. No free oil, cuttings or drilling fluids.
Central	63 FR 55717 NPDES	General permit for >200 meters of water depth restricting discharges to 29 mg/l monthly and 49 mg/l maximum daily total oil and grease
Eastern	63 FR 55717 NPDES	General permit for > 200 meters of water depth restricting discharges to 29 mg/l monthly average and 49 mg/l maximum daily total oil and grease
All of the above citations contain rules restricting discharge of domestic and sanitary sewage (including standards) and prohibiting discharge of trash in each of the MMS planning regions. Facilities located offshore of EPA Region 6 (and some in Regions 9 and 10) are subject to a general Clean Water Act permit that covers all facilities in certain geographic locations. Offshore exploration and production facilities in Regions 4, 9 and 10 are also permitted individually in some cases. EPA Regions 6 and 9 have a Memorandum of Agreement with MMS, whereby MMS agrees to conduct Clean Water Act preliminary inspections for EPA.		
All	CWA § 308, 402, 403	Discharge rate limitations and monitoring; toxicity limitations; minimize discharge of surfactants, dispersants and detergents; no rubbish, trash, or refuse, and no discharge in areas of biological concern
All	40 CFR 144	Underground injection control program rules

State laws governing hazardous wastes are allowed to be more restrictive than federal law, but no material differences exist between state and federal law in Texas, Louisiana, Mississippi, or Alabama. For the most part, the wastes generated by oilfield activities, called nonhazardous oilfield waste ("NOW") are exempt from hazardous waste regulation by federal law because they are produced from the exploration, development, or production of hydrocarbons and thus fall under what is generally referred to as the oil and gas waste exemption found in 40 CFR Part 261. Thus, even if an oilfield waste has characteristics that would otherwise render it hazardous under 40 CFR Part 261, its origin in the exploration, drilling, or production of hydrocarbons generally renders it exempt from federal hazardous waste regulations. Although none of the states listed above have chosen to regulate oilfield waste as hazardous waste, a state has the option of doing so, and California, for one, does. The used oils, oily wastewater, and filters associated with the maintenance and repair of machinery used in oil and gas drilling and production are not subject to the oil and gas waste exemption but are classified as nonhazardous by federal definitions. As such, regulation of these materials are covered by other, less expansive federal regulations and tend to vary more from state to state. Oil producers are specifically allowed by the terms of these exemptions to commingle their used machine oils with their produced crude oil, but refineries discourage the practice because it presents them with processing problems.

Waste fluids and solids containing Naturally Occurring Radioactive Materials (NORM) are subject to state regulations that require special handling and disposal techniques. There are currently no federal regulations governing NORM. Each state regulatory agency sets the threshold level of radiation for classifying waste as NORM. The threshold level for classification as NORM ranges from 30 picoCuries per gram (pCi/g) to 50 pCi/g. The special handling and disposal requirements for NORM generally result in the segregation of these materials from NOW and in substantially higher disposal costs when managed by commercial disposal firms.

Disposal of oil and gas NORM waste in Texas is regulated by 16 TAC Part 1, §3.94. In general, NORM, including treated NORM within 5 piC/g of background is eligible for on-site disposal by injection into a well that will be plugged. It may also be injected in a well on another lease with written permission from the owner. Commercial disposal of NORM is available in Texas at two different sites. Alabama has not fully developed its NORM regulatory program, but waste within 5 piC/g of background is considered acceptable for on-site disposal.

NORM waste generated in Mississippi, Alabama and Florida is typically shipped to Louisiana or Texas. In Louisiana, oil and gas production waste with NORM levels of 30 piC/G or less may be disposed as NOW.

Differences in laws among the states lead to differences in waste management methods as well as industry preferences in siting of waste facilities in certain states. The substantive differences that distinguish the states are comparatively few. Texas allows and regulates salt dome disposal of waste, while no other state does. Louisiana, Alabama and Mississippi allow the landfilling of used oil filters and oil-based drilling muds, while Texas requires them to be recycled. Texas generally has stricter limits on hydrocarbon content of waste going into municipal landfills. Texas has regulations allowing oil-based drilling mud to be recycled through bioremediation into road-building material, while none of the other states have enabled oilfield waste land application recycling operations in their regulatory framework.

6.5 Industry Trends and Outlook

Florida Gulf Coast: For the purpose of this analysis, we have assumed that Florida's waste disposal regulations, as they now exist, will remain static as they pertain to disposal of any wastes that may come ashore there associated with OCS drilling. Special accommodations to the unique requirements of offshore oil and gas waste are not likely. This section will address the following questions:

- What waste management facilities can be legally used or developed under Florida regulations?
- What geological or land use considerations hinder or help the development of such facilities?
- What are the economics of using existing local facilities or developing new ones versus transporting waste back to facilities in established OCS support bases?

Transfer Facilities: Florida has adopted the transfer facility requirements listed in 40 CFR 265 Subparts B, C, D, and I. Nothing in these regulations would appear to prohibit a transfer operation similar to the ones operated by Newpark along the Louisiana and Texas Gulf Coast.

Subsurface Injection: Subsurface injection in Florida for oil and gas waste is allowed under rules much like U.I.C. programs in other states. These rules were developed to regulate Florida's tiny land-based oil and gas industry in the western panhandle of the state. Whether such wells would be technically and legally feasible in a proximity to a port that may develop capabilities to serve offshore drilling is a question that has not been examined.

Landfills: Waste coming ashore from OCS activities would invite some of the same opposition that Floridians have already expressed with respect to cruise ship waste, which has sometimes been disposed of in communities where these volumes had a material impact on capacity available for locally generated waste. Although outright restrictions on the importation of waste by a state has been found to be a violation of the commerce clause of the United States Constitution, terms of a landfill permit often restrict the served market of a particular landfill to a certain radius, which could result in an effective prohibition against receipt of OCS waste. If such prohibitions were implemented successfully, they would render Florida impractical as an operating base for supply boats.

Land Application: Land application of oilfield materials does not appear to be allowed under Florida rules.

Salt Cavern Disposal: Salt cavern disposal is not allowed under Florida rules.

Separation and Reclamation of Drilling and Completion Fluids: Only storage regulations relating to these types of chemicals would come into play and no significant barriers to reclamation exist. Fluid selections for wells closer to Florida will be determined by the drilling conditions encountered and could possibly be chemically different from those used elsewhere in the Gulf.

Conclusions: Florida is not expected to develop special-purpose regulations to accommodate OCS waste, but nevertheless, limited waste management activities might develop there, under the assumption that any support activities develop in Florida. A successful restriction of Florida landfills' service area could possibly serve as an effective barrier against an offshore marine service center developing in Florida.

7.0 PIPELINES

7.1 Introduction

After raw gas is brought to the earth's surface, it is processed – to remove impurities such as water, carbon dioxide, sulfur or inert gases – and transformed into a saleable, useful energy source. It is then moved into a pipeline system for transportation to an area where it is sold. Because natural gas reserves are not evenly spaced across the continent, an efficient, reliable gas transportation system is essential.

Over 200,000 miles of steel pipe, ranging in diameter from 20 to 42 inches, serve as the "interstate highway" system for natural gas throughout the U.S. (Figure 7.1). As of June 2001, there were approximately 44,218 km (27,569 mi) of pipeline on the seafloor of the Gulf (USDOI, MMS 2001b). MMS (2000a) provides a detailed description of offshore pipeline installation methods, seafloor spanning, and maintenance of flows. When moved through a pipeline, natural gas is transmitted at higher pressures to reduce the volume and to provide force to propel the gas through the pipeline. In order to maintain the level of pressure, the gas needs to be compressed periodically as it moves through the pipeline. Therefore, compressor stations are installed every 70 to 100 miles along each pipeline.

Figure 7.1. Natural Gas Pipes.

Source: Natural Gas Information and Educational Resources (1998a)

When transmission pipelines deliver gas to utilities, the fuel passes through a "gate station" or "city gate". The pressure in the pipeline is reduced from transmission levels – usually anywhere from 200 to 1,500 pounds per square inch – to distribution levels – 1 to 200 pounds per square inch. Meters at the gate measure how much gas is being received by the utility, and a sour-smelling odorant is added to help customers smell even small quantities of natural gas. The local utility then uses distribution pipes, or mains, to bring natural gas service to home and businesses (Interstate Natural Gas Association of America 2000).

7.2 Description and Typical Facilities

The need for new or additional pipeline capacity can be implemented in several ways. Pipeline designers have various options available, each with its own physical and financial advantages and disadvantages. Some of the options for adding new natural gas transmission capacity include building a new pipeline, converting an oil or product pipeline or expanding an already existing system. The least expensive option, often the quickest and easiest, and usually the one with the least impact environmentally, is to upgrade facilities on an existing route. However, this may not be feasible, especially if the market to be served is not currently accessible to the pipeline company (Energy Information Administration 1999a).

On average, an interstate construction/expansion project may take about 3 years from the time it is first announced until it is placed in service, even longer if it encounters major environmental obstacles or public opposition. [30] The life-cycle for a natural gas pipeline project involves several milestones. After first detecting market indications that enough potential need may exist in a particular supply or market area to support construction of new capacity, the sponsors of the project, be it a new pipeline or an expansion of an existing one, publicly announce their belief that a project of particular magnitude and location could be built if there is enough interest. To gauge the level of market interest, an open-season is held (1 to 2 months), giving potential customers an opportunity to enter into a nonbinding commitment to sign-up for a portion of the capacity rights available on the pipeline project. If enough interest is shown during the open-season, the sponsors will arrive at a preliminary project design and move forward.

The development of the final project design and obtaining firm financial commitments from customers may take from 2 to 3 months, after which the project specifications are filed with the appropriate regulatory agency. While there are no data available on the average length of time a project may require to receive a final determination from a State agency, generally a FERC review takes from 5 to 18 months, with the average time being about 15 months. Usually, approval by the regulating authority is conditional, but most often the conditions are minor. Regardless, it is then up to the project sponsor to accept or reject the conditions or refile with an alternative plan.

Construction typically is completed within 18 months following final regulatory approval, and sometimes in as little as 6 months. Construction of an approved project may be delayed because of the extended time required to acquire local permits from numerous towns and land use agencies located along the proposed construction route. In 2000, two major pipeline expansion projects were postponed until the summer of 2001 because they were unable to acquire all of the local approvals in time to construct and complete the project before the beginning of winter.

Commissioning and testing of the completed pipeline project usually takes about 1 to 3 weeks and involves subjecting the completed segments of the projects to hydrostatic and other required testing of the line in place. Line packing, or filling the line with the initial baseload gas volumes, is usually needed only on new pipelines or larger expansion projects.

[30] The remainder of this subsection is taken from: Energy Information Administration, *Natural Gas Transportation – Infrastructure Issues and Operational Trends,* (Washington D.C.: Department of Energy), October 2001, p. 8.

Costs of Development: The cost of pipeline construction depends on the type of facilities being built and the distance involved. Usually, a new pipeline, for which right-of-way land must be purchased and all new pipe laid and operating facilities installed, will cost much more than an expansion of an existing route. The difference is demonstrated in Table 7.1, where the new pipeline projects averaged about $0.48 per cubic foot and an expansion, about $0.29 per added cubic foot (Energy Information Administration 1999a).

Table 7.1

Major Additions to U.S. Interstate Natural Gas Pipeline Capacity (1991-2000)

	All Type Projects						New Pipelines[a]		Expansions	
Year	**No. of Projects**	**System Mileage [b]**	**New Capacity (MMcf/d)**	**Project Costs (million $)**	**Avg. Cost per Mile ($ 000)[c]**	**Costs per Cubic Foot Capacity (cents)**	**Avg. Cost per Mile ($ 000)[c]**	**Costs per Cubic Foot Capacity (cents)**	**Avg. Cost per Mile ($ 000)[c]**	**Costs per Cubic Foot Capacity (cents)**
1996	26	1,029	2,574	552	448	21	983	17	288	27
1997	42	3,124	6,542	1,397	415	21	554	22	360	21
1998	54	3,388	11,060	2,861	1,257	30	1,301	31	622	22
1999	36	3,753	8,205	3,135	727	37	805	46	527	31
2000	19	4,364	7,795	6,339	1,450	81	1,455	91	940	57
Total	**177**	**15,658**	**36,176**	**14,284**	**862**	**39**	**1,157**	**48**	**542**	**29**

Notes:

[a] New pipelines include completely new systems and smaller system additions to existing pipelines, i.e. a lateral longer than 5 miles or an addition that extends an existing system substantially beyond its traditional terminus.

[b] Includes looped segments, replacement pipe, laterals, and overall mileage of new pipeline systems.

[c] Average cost per mile is based upon only those projects for which mileage was reported. For instance, a new compressor station addition would not involve added pipe mileage. In other cases final mileage for a project in its initial phases may not yet be final and not available. In the latter case, cost estimates may also not be available or be very tentative.

Source: Energy Information Administration (1999a)

The major cost components associated with the building or expansion of a natural gas pipeline are usually placed under the following categories: labor (including survey and mapping), right-of-way acquisition, facilities (compressor stations, meter stations, etc.), materials (compressors, pipe, wrapping), and miscellaneous (administration, supervision, interest, Federal Energy Regulatory Commission fees, allowances for funds during construction, and contingencies). Generally, labor costs represent the largest component, although on new, long-distance pipeline projects, with pipe diameters greater than or equal to 36 inches, material costs approach labor costs. Right-of-way costs also represent a larger proportion of costs in the latter case (Energy Information Administration 1999a).

Monitoring and Maintenance of Pipelines: "The huge investment in pipe, pumps, compressors, drivers, control systems, and other equipment and the cost of downtime make maintenance of pipeline systems critically important" (Kennedy 1993). Combining preventative maintenance (such as cathodic protection and pipeline coating, discussed further in Chapter 8), frequent inspection and the selection of steel with the proper properties for a specific service makes oil and gas pipelines one of the safest industrial operations.

Traditionally, pipelines were inspected visually by going over the route on the ground or patrolling the pipeline route in aircraft. Aerial inspection is still done, but today instrumentation and monitoring equipment provide more rapid and precise location of leaks or potential leaks.

Today, pipelines are monitored 24 hours a day, 365 days a year. Data acquisition systems, or SCADA are computerized systems that allow pipeline operators to keep accurate, constant information on sections of pipeline. Information can be retrieved from remote sections of pipeline and the flow of gas can be controlled by using computers that are linked to satellite communication and telephone communication systems. SCADA systems allow not only pipeline operators to obtain timely information, but they also allow producers to have access to some of the same information so they can purchase distribution services according to the current volume of gas in a pipeline (Natural Gas Information and Educational Resources 1998b).

One method that pipeline companies use to maintain their pipelines is through the use of intelligent robotic inspection devices, know as PIGs. These PIGs are able to travel through a pipeline, inspecting the interior walls for corrosion and defects, measuring the interior diameter of a section of pipe, and removing accumulated debris from a section of pipeline. The PIG uses sensors to take thousands of measurements that can later be analyzed by computers to show possible problems. Magnetic-flux leakage PIGs are used to detect metal loss (from corrosion – see below) in pipeline walls, locating potential problems without the cost and risk of using other methods.

Although cathodic protection is used for many newer sections of pipelines, corrosion is still a potential problem that weakens some parts of the pipeline. Cathodic protection refers to the method of mitigating corrosion in metal structures that involves using electric voltage to slow or prevent corrosion. It is used along natural gas pipelines, as well as in certain bridges or other large metal structures that need to resist corrosion over an extended period of time. Cathodic protection is discussed in more detail in Chapter 8 – Pipe Coating.

Pipeline Repair: If a leak is discovered, the method of repair may vary. A short length of pipe may be inserted where the leak is found (called a "pup joint"), or the entire joint of the pipe may be replaced. Onshore pipelines may also be plugged temporarily on either side of a problem area, and flow is redirected through a bypass so work can be done on the isolated area. A variety of plugging equipment is available, and can be applied in a wide range of situations.

The repair of offshore pipelines is much more complex and costly. Each repair alternative is reviewed to ensure the selection of the method that is most compatible with the overall requirements of each situation. "Factors which should be taken into account here are location, water depth, [pipeline] size, amount of coverage, age, design and operating pressures, vessel traffic in the area, special hazards (i.e., mud slides, unusual currents, severe weather conditions, etc.) as well as any other special conditions under which the pipeline is operating" (Woods 1982). The importance of the pipeline to the producing field should also be considered.

To minimize the downtime of an out-of-service line, formal emergency repair plans are often made for offshore pipelines. There are a variety of methods available for repairing underwater pipelines, but they generally fall into three categories (Woods 1982):

- ***Surface repair:*** This method involves lifting the pipeline to the surface and repairing it completely by welding a new section of pipe to replace the damage area or by welding flanges, misalignment fittings, etc. onto each end of the pipe after removal of the damaged area. The pipe is then lowered back to the sea floor and carefully reconnected. Since this method relies upon all major work being performed on the surface, it is probably the most weather sensitive of the three types of repair methods.

- ***Underwater hyperbaric welding:*** If a totally welded repair without lifting the pipe is the most desirable solution, then this can be achieved on the bottom, eliminating the necessity of raising the pipeline to the surface. The variations on this method allow for a welder-diver to weld the pipe either completely enclosed in a dry habitat or with the welder-diver working in the wet while the weld point on which he is working is enclosed in a dry, environmentally controlled chamber. Although not as weather sensitive as surface repairs, underwater welding is probably the most skill-sensitive method due to the fact that specific qualification levels for welding the pipe material at a given water depth must be present in the welding team.

- ***Mechanical connectors:*** There are a number of these types of products currently available which allow for the repair of pipelines in place without the necessity of lifting them to the surface or performing underwater welding. These products are available in a variety of configurations and degrees of sophistication ranging from the containment of a pin-hole leak with a simple split-sleeve clamp through a complete spool-piece repair in deep water either through diver intervention or in an automatic, diver-less profile. Generally, this method is not as weather or skill sensitive as the other two but, due to the manufacturing lead time of many of these items, it is almost imperative that they be purchased and stocked well in advance of any requirement.

“It must be noted that this is a very general review of the most typical approaches and that many combinations of these and other methods have been used. Also, there is a great deal of attention now being focused on the problem, and quite a bit of development work is being carried out by contractors and manufacturers in an effort to improve on the cost and jobsite efficiency of their methods and equipment” (Woods 1982).

7.3 Industry Characteristics

Trends

Oil: During 2002, the U.S. produced approximately 8.1 million barrels per day of oil, of which 5.8 million bbl/d was crude oil, and the rest natural gas liquids and other liquids. U.S. total oil production in 2002 declined by 24 percent from the 10.6 million bbl/d averaged in 1985. U.S. crude oil production, which declined after the oil price collapse of late 1985 and early 1986, leveled off in the mid-1990s, and began falling again following the sharp decline in oil prices of late 1997 and early 1998. Since March 1999, however, world oil prices have rebounded and U.S. crude production leveled off in 2000 and 2001, but then rose again in 2002.

U.S. crude production still remains near 50-year lows. However, exploration and development spending has been increasing, and improved technology and increases in offshore production have also been boosting production levels. Crude oil production in the lower 48 states is expected to increase slightly in 2003, to 4.85 million bbl/d, while Alaskan crude production is expected to fall slightly to 0.95 million bbl/d. Deepwater production has been increasing rapidly and now accounts for about two-thirds of total Gulf output.

Gas: Domestic dry natural gas production fell by 1.8 percent in 2002, but is expected to increase by approximately 1.4 percent in 2003. Strong increases in U.S. natural gas production and net imports will be needed over the next two decades to meet demand – which increased by 21 percent from 1990 through 2002. Increased natural gas production is expected to come mainly from onshore sources, although offshore Gulf production also is forecast to grow significantly. In August 2001, for instance, ExxonMobil began production at its $330 million Mica natural gas project in the deepwater Gulf. Alaska's North Slope fields also represent a large potential natural gas source, with an estimated 30-35 tcf of natural gas reserves.

Future increases in natural gas production likely will come mainly from lower 48 sources, with increased use of cost-saving technologies expected to result in continuing large natural gas finds, including in the deep waters of the Gulf but also in conventional onshore fields. Currently, top natural-gas-producing states (in descending order) include Texas, Oklahoma, New Mexico, Louisiana, Wyoming, Colorado, Alaska, Kansas, California, and Alabama.

Overall, the United States depends on natural gas for about 24 percent of its total primary energy requirements (oil accounts for around 39 percent and coal for 23 percent).

Liquified Natural Gas (LNG): According to industry experts, the Gulf coast is the most promising location for LNG terminals and plants (Daily 2003). The push to construct LNG plants has been driven by decreasing North American production and USDOE predictions that natural gas demand will increase from the current 22 tcf to 35 tcf by 2025. Approximately half of the more than 30 proposed plants to process LNG are planned for the Gulf. Cheniere LNG (part of Cheniere Energy, Inc.) applied for a permit for a plant in Texas and was expected to seek approval for two more by the end of 2003 (Daily 2003). Sempra Energy received preliminary approval to build a $700 million, 1.5 bcf per day plant in Louisiana. The four active LNG terminals in the U.S. have a total capacity of 2.6 bcf a day.

Natural Gas Pipelines: The United States has a complex, extensive pipeline infrastructure for transporting natural gas from production areas to ultimate consumers. More than 80 U.S. interstate pipeline companies operate over 200,000 miles of mainline transmission lines, hundreds of compressor stations, and numerous storage facilities, allowing gas delivery throughout the lower 48 States (Figure 7.2). About 50 of these pipelines are characterized as major by the Federal Energy Regulatory Commission (FERC). Another 60 or so pipelines operate only within the borders of individual states – in the intrastate market – the intrastate portion of the pipeline system accounts for another 73,000 miles of pipelines (Energy Information Administration 2001a).

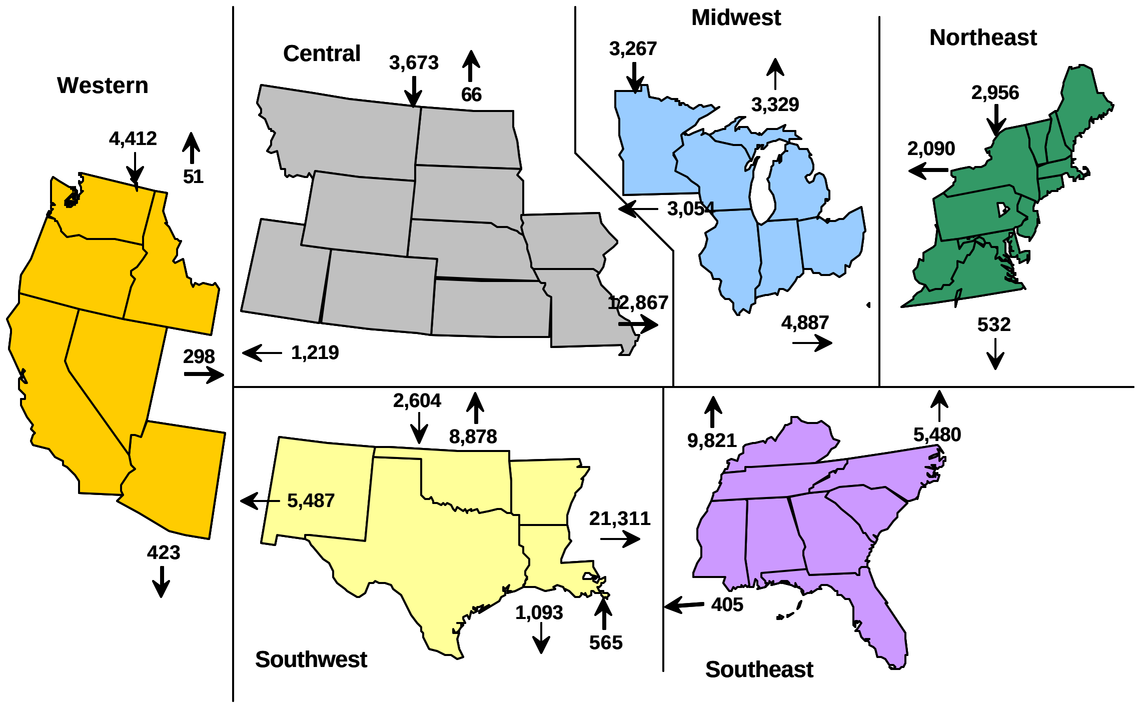

Figure 7.2. Estimated Region-to-Region Natural Gas Pipeline Capacity at the End of 2000 (MMcf/d).

Source: Energy Information Administration (2000a)

Over the past decade, natural gas consumption grew by 17 percent. During this time (1991 through 2000), enough pipeline capacity was installed to satisfy demand as it grew. Natural gas pipeline capacity grew in excess of 5 Bcf/d per year, totaling almost 20 Bcf/d. At least 65 natural gas pipeline construction projects were completed and placed into service in the United States: 35 in 1999 and 30 in 2000 (Energy Information Administration 2001a). During this time, very few capacity constraints or bottlenecks were observed with little or no disruptions in service. "However, in the past year, the demand for natural gas pipeline capacity appears to have approached its limit in some fast-growing market areas such as California and New York. In most cases though, the conditions that have contributed to these situations appear to be short term in nature and readily resolved" (Energy Information Administration 2001a). More detailed discussion of capacity additions and construction projects can be found below, in Section 7.5 - Industry Trends and Outlook.

Oil Pipelines: In addition to natural gas pipelines, there are petroleum or oil pipelines that carry nearly two-thirds of the ton-miles of oil transported in the U.S. There are approximately 200,000 miles of oil pipe that move domestic crudes from producing areas like California, the Rockies and West Texas and imported crudes from receiving ports. The U.S. also relies on pipelines to transport petroleum products from refining centers, such as the Gulf Coast, to consuming regions, like the East Coast. As the primary option for transcontinental transportation, pipelines are much more cost-effective than any alternative such as rail, barge or road. Replacing even a modest-sized pipeline, which might transport 150,000 barrels per day, would require 750 tanker truck loads per day, a load delivered every two minutes around the clock (Association of Oil Pipelines 2003a).

Interstate oil pipelines deliver over 13 billion barrels of petroleum each year. About 59 percent of the petroleum transported by pipelines is crude oil, the remainder is in the form of refined petroleum products. As previously noted, the oil market's infrastructure moves oil from the producing regions to consuming regions. The profiles below and accompanying Figure 7.3 and Table 7.2 display the inter-regional flows in the U.S:[31]

- ***The Gulf Coast (PADD 3)***[32] is the largest supply area of the U.S. accounting for 55 percent of the nation's crude oil production and 47 percent of its refined product output. It is the largest oil supplier in interregional trade, accounting for 90% of the crude oil shipments and 80% of the refined petroleum production shipments among PADDs. Most of the crude oil goes to refineries in the Midwest, while most refined products go to the East Coast and, to a lesser extent, to the Midwest.

- ***The East Coast (PADD 1)*** has virtually no indigenous crude oil production, limited refining, and the highest regional, non-feedstock demand for refined products. Its refineries process predominately foreign crude oil. To meet regional demand, their output is augmented by refined product shipments from the Gulf Coast as well as imports from abroad. The East Coast receives more than 60% of the refined products shipped among regions and almost all of the refined product imported into the U.S.

- ***The Midwest (PADD 2)*** has significant regional crude oil production, but also processes crude oil from outside of the region: Canadian crude oil imported directly via pipeline, crude oil imported from other nations and then shipped to the Midwest via the Gulf Coast, and crude oil produced in the Gulf Coast region. These supplies from outside of the region – imports and domestic – account for 88% of its refinery input. Refined product output from regional refineries is also supplemented with supplies from outside the region, primarily shipments from the Gulf Coast.

- ***The Rocky Mountain Region (PADD 4)*** has the lowest petroleum consumption, but has shown relatively rapid regional growth in recent years. It imports crude oil from Canada to augment local production for its refineries. Its distances are long, its topography steep and its infrastructure thin, however. Therefore, the inter-regional trade, while small in nationwide standards, is an important factor in keeping the region's supply and demand in balance.

- ***The West Coast (PADD 5)*** is logistically separate from the rest of the country. Its crude oil supply is dominated by production from the Alaskan North Slope oil fields, which now accounts for 55% of PADD 5 production, down from 65% when those fields were in peak production in the late 1980s. Essentially all of the rest of the region's production comes from California. Because of unique product quality

[31] This section taken from: Allegro Energy Group. 2001. *How Pipelines Make the Oil Market Work – Their Networks, Operation and Regulation*, (Prepared for the Association of Oil Pipe Lines and the American Petroleum Institute's Pipeline Commission). 22 pp.

[32] The five regions referred to as "Petroleum Administration for Defense Districts," or PADDs, were delineated during World War II.

requirements in California, the largest consuming state, essentially all of that state's refined product demand is met by output from the state's refineries.

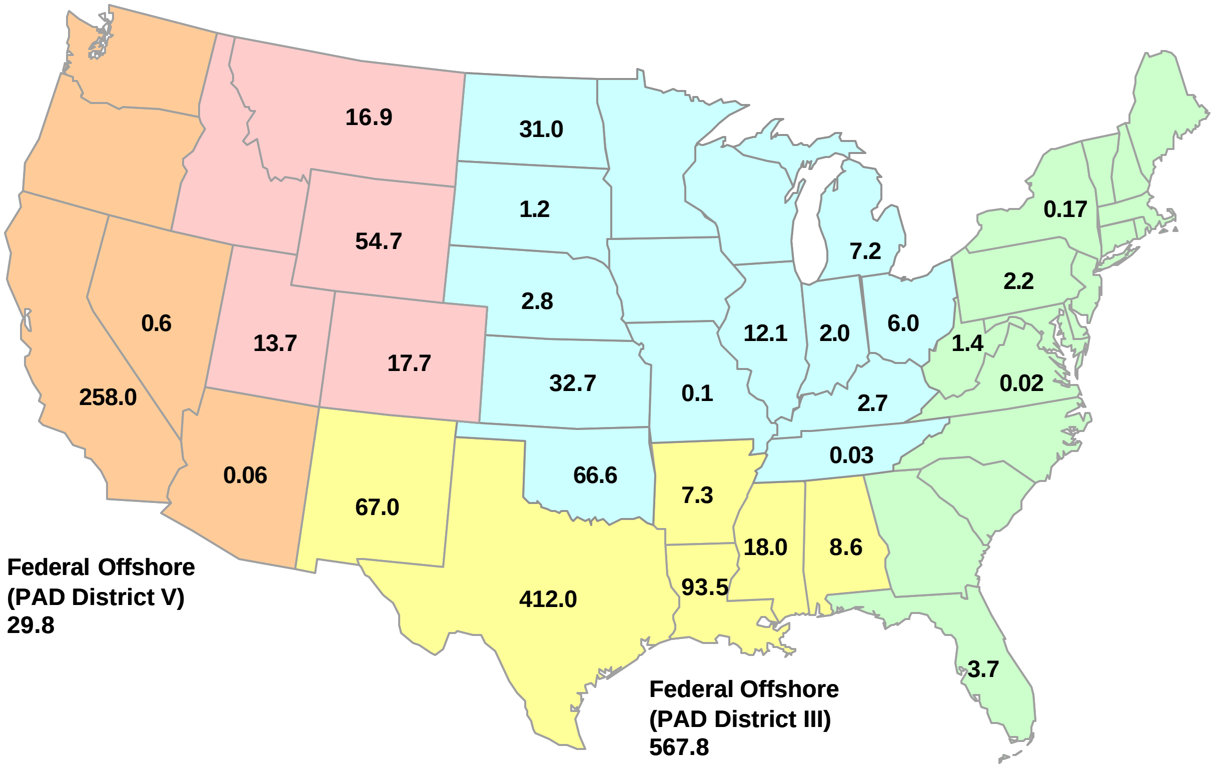

Figure 7.3. Production of Crude Oil by PAD District and State (million barrels).

Source: Energy Information Administration (2003a)

Table 7.2

Movements of Crude Oil and Petroleum Products by Pipeline Between PAD Districts, 2002 (thousand barrels)

	Crude Oil	Petroleum Products	Total
	---------- (thousand barrels) ----------		
From PAD I to:			
PAD II	-	108,705	108,705
PAD III	3,043	-	3,043
From PAD II to:			
PAD I	2,479	12,806	15,285
PAD III	12,159	51,719	63,878
PAD IV	11,901	22,633	34,534
From PAD III to:			
PAD I	-	857,497	857,497
PAD II	654,447	306,947	961,394
PAD IV	-	18,813	18,813
PAD V	-	33,411	33,411
From PAD IV to:			
PAD II	32,747	22,469	55,216
PAD III	8,112	55,565	63,677
PAD V	-	11,287	11,287
From PAD V to			
PAD III	-	-	-
PAD IV	-	-	-

Source: Energy Information Administration (2003a)

Pipelines are an essential mode for moving oil between regions. In 2000, for instance, pipelines moved nearly all of the crude oil and about 70 percent of the products transported between PADDs. "Pipelines are also irreplaceable in moving oil within the PADDs, from producing fields and coastal ports to refineries (crude oil and other refinery feedstocks) and from refineries and large redistribution centers to smaller regional supply centers, to airports, and even directly to large consumers (refined petroleum products)" (Allegro Energy Group 2001).

Gulf of Mexico: The Federal offshore region of the Gulf of Mexico has become an increasingly important source of natural gas – expanding from 16 to 51 producing fields from 1997 to 2001. Deepwater production rates have risen by well over 100,000 barrels of oil per day and 400 million cubic ft of gas per day, respectively, each year since 1997 (USDOI, MMS 2002a). "This stands in impressive contrast to just two decades ago when the Gulf of Mexico was considered to be a mature oil and gas region with limited potential for further discovery and development. In fact, the region was so lacking in promise that it was then called the 'Dead Sea.' A 1973 report by the U.S. Department of the Interior stated that all potentially productive blocks in water depths up to 600 feet in the Federal Offshore Louisiana would be leased by 1978 and all exploration and development would be completed by 1985" (Energy Information Administration 1999a). To the contrary, the offshore drilling industry in the Gulf has come a long way. The Gulf represents an expanding frontier with extraordinary growth – especially of deepwater – oil and gas industry activity over the past 7 years.

According to a recently released MMS report, "[t]he large volume of active deepwater leases, the increased drilling program, and the growing deepwater infrastructure all indicate that the deepwater GOM will increase in importance as an integral part of this nation's energy supply and will remain one of the world's premier oil and gas basins" (USDOI, MMS 2002a). Even in recent years, the oil and gas industry in the Gulf has witnessed an incredible expansion (USDOI, MMS 2002a):

- While only 16 deepwater projects were on production in early 1997, this number grew to 51 by the end of 2001.

- A record 14 deepwater projects initiated production during 2001, and another 13 are projected to begin in 2002.

- By the end of 2001, deepwater oil production had risen 500 percent and gas production had risen 550 percent since 1995.

- Fifty-nine percent of all oil production in the Gulf now comes from the deepwater.

An essential factor needed for supporting these expanding offshore supply operations is adequate transmission capacity to move supplies to onshore pipelines and then to market. In 1998 alone, an additional 2.6 bcf/d of pipeline capacity was completed to increase flow to onshore Louisiana (Energy Information Administration 1999a). As previously noted, further discussion of recent offshore capacity expansions can be found in Section 7.5 – Industry Trends and Outlook.

According to Table 7.3, there is currently over 12,000 miles of offshore pipeline in the Gulf of Mexico. Almost 88 percent are off the coast of Louisiana, with Central and Western Louisiana making up the greatest proportion (71 percent). Ninety-two percent of pipe over 27 inches in diameter is found off the coast of Louisiana, the greatest amount (66 percent) from Western Louisiana. Texas accounts for 8 percent of pipe greater than 27 inches in diameter.

Table 7.3

Summary of Federal Offshore Pipeline Miles by Area and Diameter in the Gulf

	Miles by Area and Diameter					
Diameter	**Eastern Louisiana**	**Central Louisiana**	**Western Louisiana**	**Texas**	**Eastern Gulf**	**Total**
≤ 8"	952	1,735	1,528	616	117	4,949
> 8"-18"	721	1,440	1,628	432	42	4,262
19"-27"	368	989	575	249	24	2,206
> 27"	52	284	874	105		1,315
Total	2,093	4,448	4,605	1,402	182	12,730

	Percent of Total Miles by Area					
Diameter	**Eastern Louisiana**	**Central Louisiana**	**Western Louisiana**	**Texas**	**Eastern Gulf**	**Total**
≤ 8"	19%	35%	31%	12%	2%	100%
> 8"-18"	17%	34%	38%	10%	1%	100%
19"-27"	17%	45%	26%	11%	1%	100%
> 27"	4%	22%	66%	8%	0%	100%
Total	16%	35%	36%	11%	1%	100%

Source: Foster Associates (1998)

7.4 Regulations

Natural Gas Pipelines: Interstate natural gas pipelines are regulated by the Federal Energy Regulatory Commission (FERC). FERC regulates both the construction of pipeline facilities and the transportation of natural gas. It is important to note however, that FERC does not have jurisdiction over all gas transmission. Gas pipelines that are restricted to intrastate operation are regulated by the States in which they operate and are not subject to FERC authority. These intrastate pipelines are a significant part of gas transportation capacity in some states, especially those that produce large quantities of gas such as Texas, Louisiana, and Oklahoma.

Under the Natural Gas Act of 1938, FERC regulates both the construction of pipeline facilities and the transportation of natural gas in interstate commerce. Companies providing services and constructing and operating interstate pipelines must first obtain Commission certificates of public convenience and necessity. In addition, FERC approval is required to abandon facility use and services, as well as to set rates for these services. FERC oversees construction and operation of facilities needed by pipelines at the U.S. point of entry or exit to import or export natural gas.

FERC's Transformation of the Pipeline Industry: Until the 1980s, pipeline systems brought natural gas from producers, transported it along their pipelines, and then resold it to local distribution companies (LDC's). In 1985, Order 436 initiated a transformation of the natural gas transportation industry, which culminated in Order 636 in 1992. These two orders (with a number of additional orders in between) effectively unbundled these services so that interstate pipeline companies no longer own the gas transported on their pipeline systems, but transport it for third parties. Purchasers of natural gas now can negotiate price provisions and contract terms with various suppliers, while contracting separately with pipeline companies for transportation, storage, and numerous other services, selected and combined, to satisfy their needs.[33]

Order 436 ruled that a pipeline could choose "open-access" status – offering to transport gas purchased by any of its customers. Customers not choosing transportation could continue to use the resale services previously offered by the pipelines. If a pipeline did not choose to offer open-access, it would provide resale service only and not be allowed to transport any third party gas. FERC enticed the pipelines by offering to grant those that did choose open-access an "optional expedited certificate" for new facilities. Traditionally, obtaining a permit to build new facilities would mean a costly and often contested FERC proceeding that could take years. FERC presumed that a company looking for an optional expedited certificate had a project that was in the public interest if the pipeline was willing to bear the risk. "A pipeline that wished to compete needed open-access, since otherwise all of its projects risked delays in certification. Order 436 changed the industry. Within months every important interstate pipeline had applied for open access status. Within two years, 75 percent of all interstate throughput was transported rather than resold" (Michaels 2002a).

Order 436 was successful in encouraging the start of competition in the natural gas transportation industry. However, there were problems with FERC's neglect of take-or-pay issues.[34] The DC Court of Appeals wanted FERC to address the possible conditioning of a producer's access to a pipeline on the resolution of take-or-pay contracts. The Court sympathized with FERC's reluctance to alter contracts. However, these contracts had been written in the all resale era as a response to regulation that required, then resale only, pipelines to find adequate gas supplies in a shortage period. Thus, FERC should have the power to modify them if the regulatory order changed.

In response to the Court of Appeals remand, FERC issued Order 500 in August, 1987. Order 500 required that a producer credit any gas transported for it against the transporting pipeline's take-or-pay liability. To minimize the intrusion, Order 500 mandated cross crediting only on a subset of all contracts that had been written during 1986 and 1987. To force rapid settlements, the Order imposed a sunset deadline of December 31, 1988. And, to avoid further take-or-pay

[33] Unless otherwise noted, the source for this subsection is: Robert J. Michaels. "The New Age of Natural Gas. How Regulators Brought Competition." *Regulation; The Cato Review of Business & Government,* <http://www.cato.org/pubs/regulation/reg16n1e.html>, (27 May 2002).

[34] Take-or-pay is a contract clause in a gas supply contract that provides a minimum quantity of gas that must be paid for, whether or not delivery of that gas is accepted by the purchaser, for a specified period. Most contracts contain a time period in which the buyer may take delivery of the gas without penalty.

problems, FERC adopted the ratemaking principle of a gas inventory charge, which would compensate the pipeline for standing ready to provide its resale customers' requirements.

With transported gas still dominating their throughput, pipelines still entered the 1990s with residual responsibilities to those customers who still elected resale service. They also remained responsible for reliable operation and for coordinating receipts, deliveries, and storage, both for themselves and for the third-party transporters. Most pipelines owned marketing affiliates that sold gas in competition with producers and brokers. Transporters were concerned that a pipeline could use its operational knowledge and its information about their transactions to advantage itself as a gas merchant, particularly during peak periods. Conversely, pipeline resales were disadvantaged by burdensome abandonment regulations that did not apply to transport service.

To address these and other issues, in April 1992, FERC issued Order 636, completing the transformation of the natural gas transportation industry. This final restructuring rule mandates transportation "basis that is equal in quality for all gas supplies whether purchased from the pipeline or from any other gas supplier." The ruling issues blanket sales certificates to pipelines so that they can offer unbundled firm and interruptible sales services at market-based or competitive rates. In addition, pipelines will be required to provide a variety of transportation services to their shippers. This includes a new unbundled "no-notice", firm transportation service, firm transportation service that is unbundled and improved in quality, unbundled storage services, and interruptible transportation services, among others. The order permits gas purchasers and gas sellers to choose the exact transportation service that they want, including a combination of services that will ensure that the pipelines can deliver an adequate supply of gas to the city gate from various sources when that supply is needed.[35]

The Order also loosened requirements that a pipeline continue to provide services that are uneconomic. Under Order 636, transportation rates were updated to conform to the straight-fixed variable method – a method which puts all fixed-costs in the capacity charge, and all variable costs in the transport charge. These new rates make users responsible for the costs of capacity that they actually use in peak periods. "Converting pipelines into transporters allows customers the benefits of being able to search for attractive purchases, rather than obligating them to take whatever gas the pipeline chooses to buy. Allowing customers to resell their pipeline rights further increases their options. The advent of open access transportation and a market in released capacity provided an important lesson in economics: although a pipeline is technologically a natural monopoly, a market is arising in which the services of that monopoly will be allocated competitively" (Michaels 2002b).

Since Order 636, competition has increased among sellers, and a strong resale market for transportation capacity on interstate pipelines has developed. Numerous new services have also been introduced as companies positioned themselves to take advantage of new market opportunities. In response to new market conditions, many pipeline companies have consolidated or formed strategic alliances to increase market share and gain access to new customers. For example, the gas industry has seen a strong growth in the number of gas marketing affiliates and "all energy" service companies.

[35] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Federal Energy Regulatory Commission, 59 FERC ¶ 61, 030, Order 636, April 8, 1992.

Purchasers of natural gas now can negotiate price provisions and contract terms with many different suppliers, while contracting separately with pipeline companies for transportation, storage, and various other services, selected and combined, to satisfy their needs. To facilitate this, a new type of industry player has emerged, the independent gas marketer, who in addition to marketing gas supply can serve as the purchaser's agent in making all the arrangements necessary to get the gas delivered; providing, in essence, a "package" of sales and transportation services. Deregulation and market restructuring have directly contributed to growth in gas storage for managing seasonal inventories, the development of a secondary transportation market, and better information about commodity and transportation prices via commodity markets and electronic bulletin boards. Price signals for natural gas are quickly transmitted between the consumer and the producer, and regional markets are more integrated (Natural Gas Information and Educational Resources 1998b).

Oil Pipelines: Like natural gas pipelines, most interstate liquid petroleum pipelines operate as "common-carriers" – pipelines must allocate space to all shippers who meet their conditions of service. FERC regulates the rates that an interstate pipeline can charge for service. (States generally also regulate rates for intrastate pipelines.) Prior to FERC rate regulation, the Interstate Commerce Commission determined an oil pipeline's tariff rates to be "just and reasonable" based on an allowed rate of return on the "valuation" of the pipeline's common carrier assets. When the FERC assumed jurisdiction, it explored a number of different methods for determining "just and reasonable" rates.

Under a regulatory system established in 1995, an interstate oil pipeline carrier may use a variety of methods to justify new tariff rates. These include a percentage change in accordance with a government-set economic index, application of market based rates, application of the former cost of service standard and negotiated rates for service that have been agreed to between the oil pipeline carrier, and relevant shippers. The vast majority of oil pipeline industry tariff rates now in effect were set under the economic index method. The second most used method of tariff rate justification is agreement on negotiated rates between the pipeline and its shippers. The fastest growing application is market-based rates, which requires the Commission to determine that the pipeline lacks market power in the applicable regional market.

In addition to economic regulation, the design, construction, operation and maintenance of interstate liquid petroleum pipelines is regulated by the Department of Transportation's Office of Pipeline Safety (OPS). If the pipeline is an intrastate pipeline and the state has established an office overseeing pipeline safety, there may be additional state regulatory requirements. In some cases, states have received approval from the federal OPS to inspect interstate pipelines for compliance with federal pipeline safety regulations, although enforcement authority remains under the jurisdiction of the federal OPS to assure continuity in interstate commerce. Offshore pipelines (e.g., in the Gulf of Mexico) are regulated by the Minerals Management Service.

Pipeline safety regulations govern the entire life of pipeline operations, including design, construction, inspection, record-keeping, worker qualification, and emergency preparedness. Other agencies have complementary regulatory jurisdictional roles related to pipeline safety such as:

- ***National Transportation Safety Board*** for investigation of certain pipeline accidents;

- ***Occupational Safety and Health Administration*** for worker safety and hazardous material emergency response;
- ***Environmental Protection Agency*** (and/or corresponding state environmental agencies) for permitting of emission from tanks and some other facilities and response and remediation of liquid petroleum spills;
- ***U.S. Coast Guard*** relative to preparedness and response to spills in navigable waters; and
- ***State and County Emergency Management Agencies*** may have regional emergency planning and notification requirements and, along with local emergency responders, would be involved in oversight of the company's response to a pipeline incident.

7.5 Industry Trends and Outlook

As previously stated, at least 65 natural gas pipeline projects, accounting for more than 12.3 bcf/d, were completed in the United States in 1999 and 2000 – an increase of 15 percent from the level completed in 1998 (Energy Information Administration 2001a).

Figure 7.4 shows annual additions to natural gas pipeline capacity from 1998 through 2002. Proposed capacity additions in 2002 are more than half those of 2000, and significantly more than any other year. Figure 7.5 shows the annual natural gas pipeline construction expenditures for the same years. An estimated 5 billion dollars is expected to be spent in 2002, about one-half of which is in the Southeast.

Natural gas consumption is expected to continue to grow steadily with demand forecasted to reach at least 32 trillion cubic feet by 2025. Although rising demand by electricity generators accounts for 33 percent of the projected increase, growth is also expected in the residential, commercial, industrial, and transportation sectors. Natural gas consumption in the electricity generation sector is projected to grow steadily as demand for electricity increases and retiring nuclear and older oil and gas steam plants are replaced by newer, more efficient facilities. Natural gas consumption for electricity generation (excluding cogeneration) is projected to increase from 5.3 trillion cubic feet in 2001 to 10.6 trillion cubic feet in 2025 (Energy Information Administration 2003a).

Projected growth in natural gas consumption will require additional pipeline capacity. Expansion of interstate capacity will be needed to provide access to new supplies and to serve expanding markets. Expansion is projected to proceed at an average rate of 1.0 percent per year. The greatest increases in capacity are expected along the corridors that provide access to Canadian, Gulf Coast, and Mountain region supplies and deliver them to the South Atlantic, Pacific, and Northeast regions. In all regions, growth in new pipeline construction is expected to be tempered by higher utilization of existing pipeline capacity (Energy Information Administration 2003a).

It is estimated that an investment of between $40 and $80 billion in new pipeline and expansion of current pipelines would need to occur. The Energy Information Administration reported that approximately $9.3 billion was spent in 2001, $4.4 billion was spent in 2002, and estimated $4.1 billion to be expended in 2003 (Energy Information Administration 2003b).

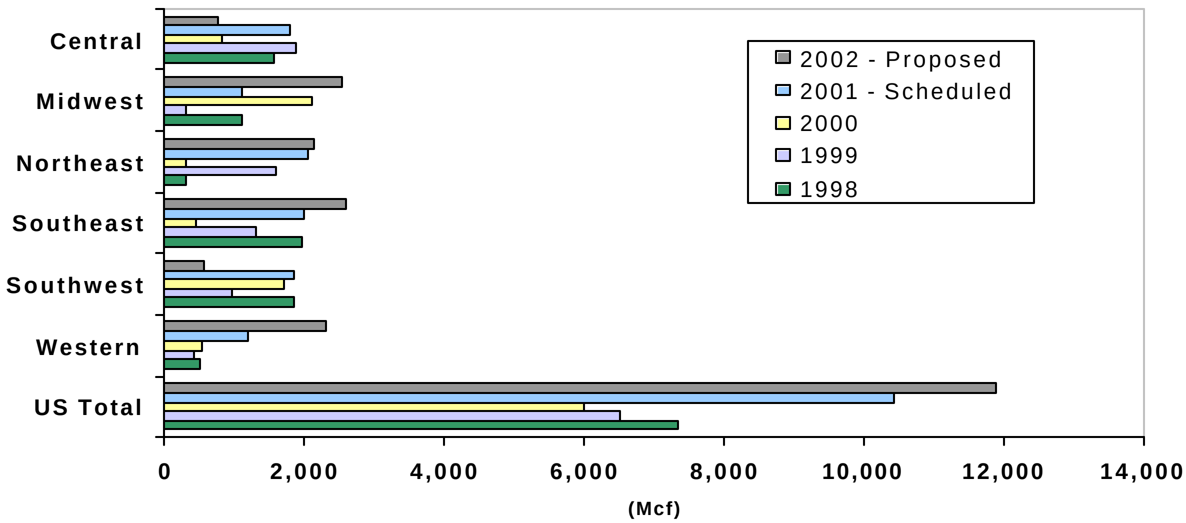

Figure 7.4. Annual Additions to Natural Gas Pipeline Capacity by Region.

Source: Energy Information Administration (2001a)

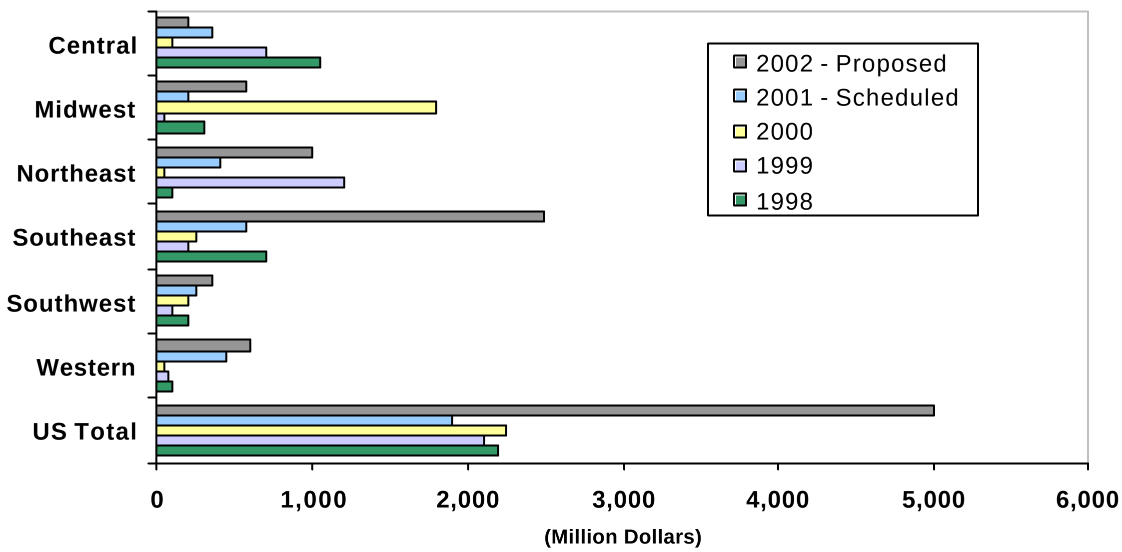

Figure 7.5. Annual Natural Gas Pipeline Construction Expenditures by Region.

Source: Energy Information Administration (2001a)

Regional Trends – Southeast: Of the six regions in the U.S., the Southeast actually uses the least amount of natural gas compared to the overall energy mix – 14 percent versus the national average of 24 percent (Figure 7.6). However, between 1990 and 1997, natural gas use for electric power generation increased at an annual rate of 8.5 percent. Since 1990, the region has also shown substantial growth in the industrial sector overall, with natural gas usage increasing at an annual rate of 3 percent per year as the number of new industrial customers also grew (Energy Information Administration 1999).

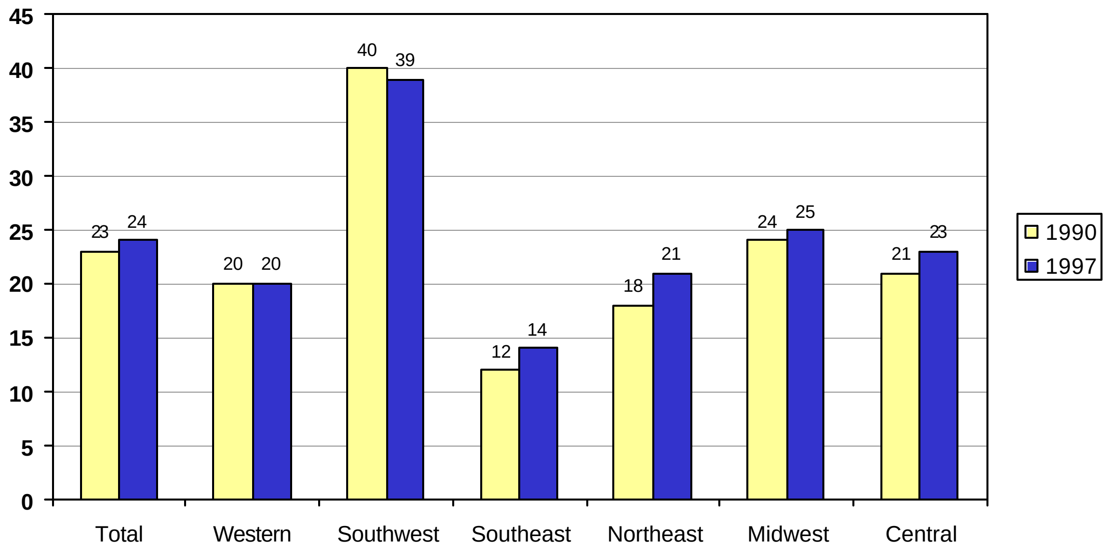

Figure 7.6. Percent of Total Energy Fueled by Natural Gas in the United States.

Source: Energy Information Administration (1999a)

Between 1990 and 2000, pipeline capacity into the Southeast Region grew by 10 percent. A significant amount of the volume flows through this region and into markets in the Northeast and Midwest. Use of available interstate pipeline capacity during peak demand periods is high in most states in the region. Nevertheless, enough additional capacity is expected to be installed in the next few years to preclude any major capacity shortfall. Nine natural gas pipeline expansions have already been completed in the Southeast Region to improve deliverability within the region – primarily in North and South Carolina, Georgia and Alabama. Approximately 1.9 bcf/d of additional capacity was also added in the region in 1999-2000. This included enhancement of the Columbia Gulf Transmission system and completion of several Transcontinental system projects that totaled 863 MMcf/d of added system capacity. The Transcontinental projects included completion of the Cardinal intrastate pipeline and Pine Needle LNG link in North Carolina, and the southern most expansion of Transcontinental's mainline in Alabama and Georgia.[36]

Other proposed projects within the region include expansion of pipeline access to underground storage sites that are also expanding, development of new capacity on intrastate pipelines to improve service to expanding end-use markets, and installation of new interstate capacity that will complement these intrastate expansions. For instance, Southern Natural Gas, East Tennessee Gas, and Transcontinental Gas Pipeline companies will increase their existing system capacity in the region by up to 200 MMcf/d each within the next two years. Most of this capacity will either provide direct delivery to end users, such as new gas-fired power plants, or increase deliveries to expanding intrastate systems such as the Sandhills Pipeline (300 MMcf/d) built in North Carolina in 2001.

[36] Unless otherwise noted, text in this subsection is from: Energy Information Administration, *Natural Gas Transportation – Infrastructure Issues and Operational Trends,* (Washington D.C.: Department of Energy), October 2001, p. 14-15.

The increasing importance of access by shippers and other pipeline customers to the high-deliverability underground storage located in the region is exemplified by the several pipeline expansion projects that are predicated upon expected expansions of existing storage facilities currently interconnected to the pipelines:

- In conjunction with the approved 2002 Petal Gas Storage site expansion, for example, its operator has proposed building a 59-mile, 36-inch, 680 MMcf/d capacity pipeline from that storage facility to new interconnections with Transcontinental Gas, Southern Natural Gas, and Destin Pipeline companies.

- Another storage facility that is expected to be expanded is the Bay Gas McIntosh facility in Alabama. Its operators will build an additional 18-mile pipeline from the site to provide shippers a new interconnection with Gulf South Pipeline Company.

GulfStream Natural Gas Project: The most significant pipeline development in the region is the construction of the 1,130 MMcf/d Gulfstream Pipeline. Placed into service in May 2002, the Gulfstream Natural Gas Project is a 753-mile pipeline that originates near Pascagoula, Mississippi and Mobile, Alabama, crosses the Gulf of Mexico (with 431 miles of 36-inch diameter pipe) to Manatee County, Florida (Figure 7.7). Onshore, 306 miles of pipe, ranging in diameter from 36 inches to 16 inches, stretches across south and central Florida, terminating in Palm Beach County. The pipeline provides approximately 1.1 bcf per day of natural gas to fuel new electric generation capacity throughout Florida.

Figure 7.7. Gulfstream Natural Gas Project.

Source: Natural Gas System, L.L.C. (2002)

Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities which represent long-term commitments for the majority of its 1.1 bcf per day.

Subsidiaries of Duke Energy and Williams purchased 100 percent interest in the Gulfstream Project from Coastal Corporation in February 2001.[37]

Completion of the Gulfstream Pipeline means that the Florida Gas Transmission Pipeline is no longer the only source of gas available to the state's natural gas shippers and customers. Nevertheless, the Florida Gas Transmission Company still continues to expand its system. In 2001, it completed a 200-MMcf/d expansion and expects to add another 200 MMcf/d in 2002 with completion of its Phase V expansion.

Regional Trends – Southwest: The rate of capacity growth in the Southwest Region has been decreasing – reflecting the maturity and the large amount of pipeline capacity already in place that is directed out of the Southwest. This downward trend also reflects the increase in resources within the region, as rising consumer demand competes for available natural gas supplies. Even so, the natural gas pipeline systems exiting these producing states, for the most part, still maintain high utilization rates, and the region itself still remains the principal supplier of natural gas to the rest of the nation (Figure 7.2).[38]

Among the few areas of the Southwest Region where natural gas production is growing is in the Gulf of Mexico, specifically in the central portion of the Gulf. According to a study published by the Gas Research Institute, "offshore Gulf of Mexico is the only area of the US. that offers potential new gas supplies for gatherers/processors. This is also the only region where any significant exploration is occurring." Extensive development of deepwater leases in particular has increased natural gas production offshore of Louisiana, Mississippi, and Alabama by 10 percent since 1995. Much of this increased production has come from new platforms that have had to be serviced by new gathering pipeline and/or large capacity pipelines designed to transport this production onshore. Between 1997 and 2000, for instance, 22 natural gas pipeline projects were completed that added a total of 8.2 bcf/d of new pipeline capacity in the Gulf. The largest three new pipelines to onshore Louisiana were:

- Destin Pipeline – With a capacity of one bcf/day, 67 percent of the Destin Pipeline is owned by BP-Amoco and 33 percent by Shell Destin, LLC. This 255-mile pipeline started transporting natural gas in September 1998. It extends from Viosca Knoll Block 900 to Main Pass Block 260 then north to a processing plant operated by BP-Amoco at Pascagoula, MS, and then extends north to interconnections with five major interstate gas pipelines.

- Nautilus Pipeline – With a capacity of 600 MMcf/d, the Nautilus Pipeline is owned 50 percent by Shell Gas Transmission, LLC, and approximately 25 percent each by Marathon and Leviathan. It is 101 mile in length, 33 inch diameter, and started transporting in December 1997. It extends from Ship Shoal Block 207 to onshore Louisiana interconnects with 4 interstate and 3 intrastate pipelines, and straddles the existing Exxon Garden City Gas Plant and the Neptune Gas Plant, which became operational in late February 2000.

[37] Due to regulatory mandates related to Coastal Corporation's merger with El Paso Energy Corporation, Coastal was forced by FERC to divest the project.

[38] Unless otherwise noted, figures and text in this subsection is from Energy Information Administration, *Natural Gas Transportation – Infrastructure Issues and Operational Trends,* (Washington D.C.: Department of Energy), October 2001, p. 10.

- Discovery Pipeline – Currently owned by Texaco and Williams, it serves as a main line extending from a platform in Ewing Bank Block 873, on the edge of the deepwater province, to a processing plant near Larose, LA and a fractionator near Paradis, LA. The 105 miles of 30 inch pipe has a capacity of 600 MMcf/d.

Almost all (98 percent) of the 1.7 bcf/d of new natural gas pipeline capacity scheduled to be developed and placed in service in the Gulf consists of new gathering pipelines. The largest of these, in capacity, will be the 500 MMcf/d Canyon Express system. The Canyon Express Pipeline System, operated by TotalFinaElf, S.A. is the deepest pipeline ever. The 55-mile, dual 12-inch line is being laid in more than 7,000 feet of water to connect the Kings Peak, Aconcagua, and Camden Hills deepwater gas fields on Mississippi Canyon to the Canyon Station platform on East Main Pass 261. The three fields are located about 120 miles southeast of New Orleans in water depths ranging from 6,700 to 7,300 feet – setting a new record for commercial production water depths. The lines completed in 2002 are able to move 500 MMcfd of gas to the platform, which was installed second quarter 2002 (Oil and Gas Journal 2002, Gas Daily 2000).

Elsewhere in the Southwest Region, the level of proposed pipeline capacity expansion is minimal. While five of the seven remaining pipeline projects scheduled for 2001-2002 address the needs of shippers and producers to gain additional access to the few onshore areas in the region that are experiencing production expansion, the level of potential added capacity of these projects is less than 0.5 bcf/d. Furthermore, the region's largest onshore pipeline project scheduled in the next 2 years represents only 427 MMcf/d of capacity to transport natural gas from Louisiana to supply a 2,700 megawatt power plant located in southern Arkansas. Overall, the potential additional capacity currently slated for the Southwest Region in 2001 and 2002 totals only about 3.0 bcf/d. This is the smallest amount of planned capacity additions of the six regions.

Corporate Realignments: Over the past 15 years, a number of regulatory and market changes have greatly affected the operations and structure of the natural gas transmission industry (Figure 7.8). "While the Order 636 had the effect of reducing pipeline revenues (although not necessarily profitability) because interstate pipelines no longer were sellers of natural gas, the revised rate design allowed them to collect most of their costs in fixed demand charges, which reduced the risk of recovering these costs. Order 636 also established a release (reseller) market for transportation and storage capacity, which provided a mechanism for the marketing of unused or underutilized pipeline capacity" (Energy Information Administration 1999a). This industry restructuring encouraged pipeline companies to revise their strategies, which may account for the increased level of mergers and acquisitions in recent years.

There have been some very large consolidations of pipeline assets under single corporate umbrellas. The corporate strategies behind these moves have varied, but the outcomes have been profound. For instance, when gas pipeline companies were no longer permitted to engage in the sale of natural gas, many companies created affiliated natural gas marketing arms or subsidiaries and transferred the merchant functions to these new divisions. Today, many of these marketing entities also engage in the marketing of other types of energy as well (Energy Information Administration 2001a).

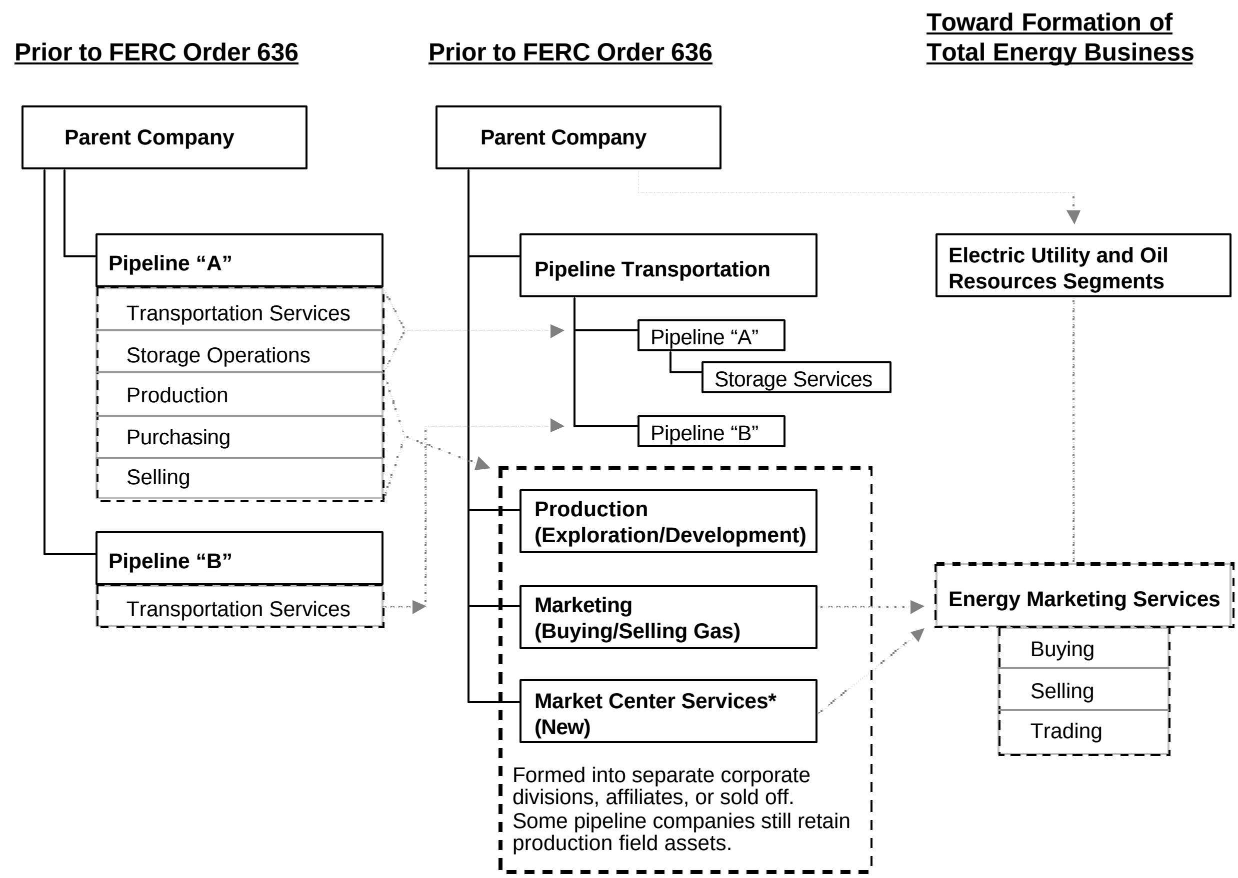

Figure 7.8. Corporate Realignments.

Source: Energy Information Administration (1999b)

Mergers and Acquisitions: Driven by rapidly changing conditions in traditionally regulated markets, energy companies are under tremendous pressure to execute successful new business strategies to survive and prosper. Mergers, acquisitions and joint ventures are important tools that can be used to take advantage of opportunities and withstand the challenges presented in a changing industry. "The recent trend toward industry consolidation is changing this loose configuration of companies as producers, gathering companies, marketers and LDCs all jockey for position, while many seek to take advantage of structural changes in the industry, and some struggle simply to survive" (Energy Information Administration 1999a).

The largest instance of consolidation has been carried out by the El Paso Energy Corporation. Once the owner of only one major pipeline, since 1997, it has acquired eight other interstate pipelines systems (Table 7.4). The original gas sales and marketing arm of the El Paso Natural Gas Pipeline became El Paso Merchant Energy Company, one of the top 10 natural gas and energy marketing companies in the U.S. in 2000.[39]

[39] The remainder of this subsection is taken from: Energy Information Administration, *Natural Gas Transportation – Infrastructure Issues and Operational Trends,* (Washington D.C.: Department of Energy), October 2001, p. 17-18.

Table 7.4

Shifts in Ownership of Selected Major Interstate Natural Gas Pipeline Companies since 1990

Parent / Pipeline Name	Marketer Affiliate / Prior Ownership	Merger Year	Market Area Served	System Mileage	System Capacity (MMcf/d)
CMS Energy Corp	**CMS-MST**				
Panhandle Eastern Pipeline Co	Panhandle Eastern Corp	2000	Midwest	6,467	2,765
Sea Robin Pipeline Co	SONAT Corp	2000	Gulf Coast	470	1,241
Trunkline Gas Co	Panhandle Eastern Corp	2000	Midwest	4,134	1,884
Duke Energy Corp	**Duke Energy Trading Co**				
Algonquin Gas Transmission Co	Panhandle Eastern Corp	1999	Northeast	1,092	1,586
East Tennessee Natural Gas Co	Tenneco Energy Corp	2000	Southeast	1,100	700
Maritimes & Northeast PL Co	Built in 1999	n/a	Northeast	304	440
Texas Eastern Transmission Corp	Panhandle Eastern Corp	1999	Northeast	12,100	5,939
El Paso Corp	**El Paso Merchant Energy**				
ANR Pipeline Co	Coastal Corp	2000	Midwest	9,553	5,846
Colorado Interstate Gas Co	Coastal Corp	2000	Central/Denver	4,123	2,350
El Paso Natural Gas Co	El Paso Energy Co	n/a	Western/Southwest	10,009	5,344
Mojave Pipeline Co	Built in 1993	n/a	Western	362	550
Portland Gas Transmission Co	Built in 1993	n/a	Northeast	242	178
South Georgia Natural Gas Co	SONAT Corp	1999	Southeast	909	129
Southern Natural Gas Co	SONAT Corp	1999	Southeast	7,612	2,536
Tennessee Gas Pipeline Co	Tenneco Energy Corp	1999	Northeast	9,270	5,587
Wyoming Interstate Gas Co	Coastal Corp	2000	Central	425	1,175
Enron Corp	**ENRON Online Trading**				
Florida Gas Trans Co	No Change	n/a	Southeast	5,203	1,405
Northern Natural Gas Co	No Change	n/a	Midwest	15,637	3,800
Transwestern Gas Co	No Change	n/a	Western	2,532	2,700
Kinder-Morgan Corp	**KM Gas Services Division**				
Kinder-Morgan Interstate PL Co	KN Energy Corp	1999	Central	6,081	1,075
Kinder-Morgan Texas PL Co	MidCon Corp	1999	Southwest (TX)	2,101	na
Natural Gas Pipeline Co of America	MidCon Corp	1998	Midwest	10,076	5,001
Trailblazer Pipeline Co	MidCon Corp	1998	Central/Midwest	436	605
Koch Corp	**Koch Energy Trading Co**				
Gulf South Pipeline Co	United Gas Corp	n/a	Southeast	7,252	3,476
Mobile Bay Pipeline Co	Built in 1993	1998	Southeast	26	600
Leviathan Gas Pipeline Partners					
High Island Offshore System	KN Energy Corp	2000	Gulf Coast	247	1,800
UT Offshore System	KN Energy Corp	2000	Gulf Coast	30	1,040
NiSource Corp					
Columbia Gas Transmission Corp	Columbia Energy Corp	2000	Northeast	11,215	7,276
Columbia Gulf Transmission Co	Columbia Energy Corp	2000	Southwest/Northeast	4,200	2,317
Crossroads Pipeline Co	Built in 1995	n/a	Midwest	205	250
Granite States Gas Trans Co	Northern Utilities Inc.	1999	Northeast	na	na
Northern Border Partners					
Midwestern Gas Transmission Co	Tenneco Energy Corp	2001	Midwest	350	785
Northern Border Pipeline Co	No Change	n/a	Midwest	1,214	2,355
Reliant Energy Corp	**Reliant Energy Wholesale Group**				
Mississippi River Trans Co	No Change	n/a	Midwest/Central	1,976	1,670
Reliant Energy Gas Trans Co	No Change	n/a	Southwest	6,228	2,797
Williams Companies, Inc	**Williams Energy Services**				
Cove Point LNG LP	Columbia Energy Group	2001	Northeast	87	585
Kern River Transmission Co	Built in 1992	n/a	Western	922	800
Northwest Pipeline Co	No Change	n/a	Western	3,932	2,900
Transcontinental Gas Pipeline Co	Transco Energy Corp	1997	Northeast	10,562	7,000
Williams Gas Pipeline - Central	No Change	n/a	Midwest	5,926	2,800
Williams Gas Pipeline - SouthCentral	Transco Energy Corp	1997	Central	5,573	2,000
Xcel Corp					
Viking Gas Transmission Co	Northern States Power Co	2000	Midwest	662	516

Source: Energy Information Administration (2001a)

Similarly, the Williams Company also succeeded in creating a nationwide pipeline network through the acquisition of other pipeline companies. These pipelines include: Kern River Transmission, Northwest Pipeline, and Transcontinental Gas Pipeline. Its natural gas marketing and trading arm, Williams Energy Services Inc., ranked about 18th in the United States in 2000, based on contracted volume.

The Duke Energy Corporation, a regional (Southeast) electric power company at the start of the 1990's, began acquiring interstate pipeline companies in the mid-1990's. Its original objective appears to have been the development of a nationwide pipeline network of affiliates. But in 1997 the company changed course and sold those interstate pipeline company affiliates that did not serve its historic southeastern marketplace or the eastern United States. It retained the natural gas marketing expertise from its original acquisitions. Duke Energy Marketing has grown substantially and was the second-largest natural gas marketer (by volume) in the United States in 1999 and 2000.

Similar to Duke Energy Corporation, CMS Energy Corporation was a regional (Midwest) energy company that did not own any interstate pipeline companies before 1993. When it did enter the interstate pipeline market, it did so by buying the several pipelines that Duke Energy divested itself of in the Midwest. Today, CMS has integrated these interstate pipeline companies into its regional (Midwest-Southwest) energy marketing operations. Its CMS-MST (Marketing, Services and Trading) subsidiary ranked among the top 20 natural gas marketers in 2000.

Kinder-Morgan Corporation is a relative newcomer to the interstate pipeline community. In 1998 it acquired the Mid-Con Corporation and its two interstate pipelines. In 1999, it acquired the KN Energy Company with its one wholly owned system and one joint-venture pipeline (TransColorado Gas Transmission Co). Nevertheless, even with these acquisitions, it still remains focused on markets in the mid-continent region of the United States. While it has a natural gas marketing arm (KM Gas Services Division), its operations are primarily confined to services within its regional service area.

Oil Pipelines: The total amount of crude and petroleum products transported in 2001 totaled 869.8 billion ton-miles – 66 percent of which was transported by pipelines. For crude oil only transport, pipelines carried almost 74 percent of the total 376.6 billion ton-miles transported in the U.S. This represented a decrease of 0.2 percent from 2000, however, there was an overall decrease of 0.4 percent in total ton-mile movements for all modes of transportation during the same period. Pipeline transport of crude and petroleum products however, has increased over the last 20 years (Association of Oil Pipelines 2003b). Figure 7.9 shows that petroleum transported by pipeline – as a total of all modes of transportation – has increased by 43 percent since 2001. This reflects an average annual increase of almost 2 percent per year.

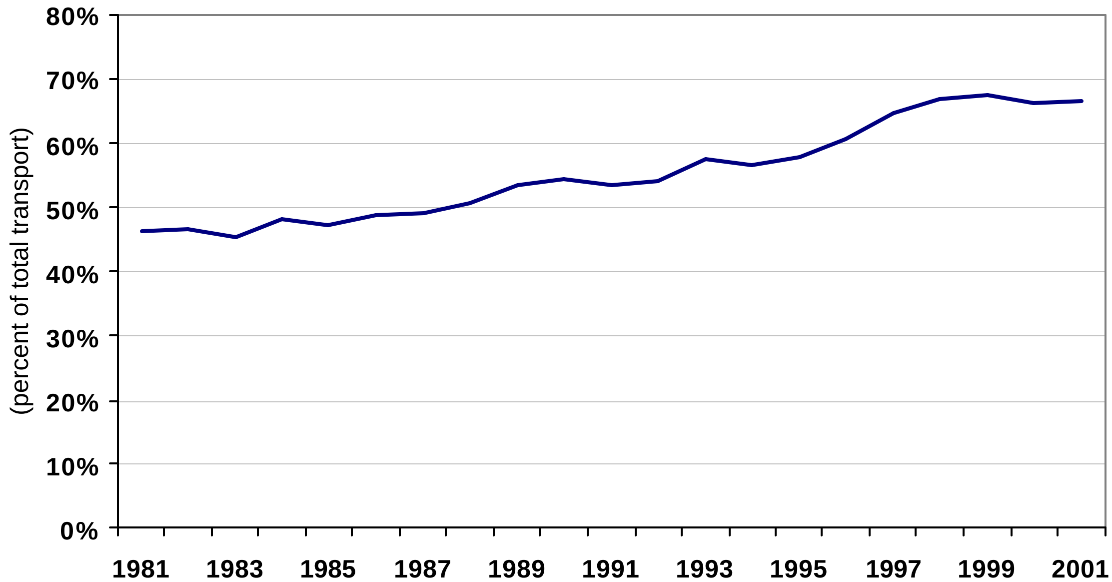

Figure 7.9. Total Crude Petroleum and Petroleum Products Carried by Pipelines as a Percent of Total Petroleum Transported.

Source: Association of Oil Pipelines (2003b)

With the increase in production from the deepwater areas of the Gulf, an extensive underwater pipeline network has formed. By 2001, 7,835 miles of pipe had been laid in the Gulf (in both shallow and deep water) – 4,121 miles of which are in deepwater with more projects underway. One such project is the Mardi Gras transportation system which, when completed, will be the largest-capacity deepwater pipeline system ever built; capable of transporting more than one million barrels per day of oil and 1.5 billion cubic feet of gas. The system, being developed by BP America and partners, will consist of five pipelines, three of which are oil pipelines (Oil and Gas Journal 2003):

- The Caesar Oil Pipeline – capacity of 450,000 b/d;
- The Proteus Oil Pipeline – capacity of 420,000 b/d; and
- The Endymion Oil Pipeline – capacity of 420,000 b/d.

In the Green Canyon area, BP and partners BHP Billiton Petroleum, Shell Pipeline Co. LP, and Union Oil Co. of California formed Caesar Oil Pipeline Co. LLC to undertake construction of the Caesar pipeline. This 450,000 b/d line will consist of a 28-inch mainline and 24-inch laterals to the Holstein and Mad Dog spars and the Atlantis semi-submersible platform. It is due online in 2004.

In Mississippi Canyon, BP and ExxonMobil Pipeline Co. formed Proteus Oil Pipeline Co. LLC to build the Proteus pipeline from the Thunder Horse semisubmersible platform to a new-build platform, to be installed on South Pass Block 89E in about 400 ft of water. The platform will enable tie-in of shelf discoveries in the area, as well as the future installation of 50,000-hp pumps to increase pipeline capacity, when needed. This 28-inch high-pressure line will have an installed capacity of 420,000 bbl/d, expandable to 580,000 bbl/d.

The related 30-inch Endymion pipeline -- undertaken by another BP-ExxonMobil Pipeline Co. entity, Endymion Oil Pipeline Co. LLC -- will have a capacity of 420,000 bbl/d, expandable with booster pumps to 750,000 bbl/d. The oil will be transported from South Pass 89E to landfall at Grand Isle, then on to the LOOP facilities.

Oil shipped in the Proteus and Endymion lines will have access to southern Louisiana area refineries, via pipelines, including LOCAP LLC's line from Clovelly to St. James, LA; the Clovelly-Alliance-Meraux line; and Shell Oil Pipeline to Norco, LA, and Texas. Both pipelines are due on line in 2005 (Oil and Gas Journal 2003).

8.0 PIPE COATING FACILITIES

8.1 Introduction

Pipelines that transport oil and gas are coated on the exterior to protect against corrosion and other damage. Pipes may also be coated on the inside to protect against corrosion from the fluids being transported or to improve the flow. In addition to corrosion protection, pipes that will be used offshore are also coated with a layer of concrete to increase the weight of the line to ensure it will stay on the seabed.

Among the many threats to pipeline integrity are third-party damage, geological activity and corrosion. The most common threat, external corrosion, is recognized as the main deterioration mechanism that can reduce the structural integrity of buried pipelines. In fact, corrosion ranks only second to human error as a cause of pipeline failure (Taylor 1994). Because coatings are the first line of defense in protecting pipelines against corrosion, they must be well bonded, continuous and resist the effects of their environments. "The application of corrosion-protective coatings to pipelines has emerged as an industry because of economics. It is a cost-effective means of extending the life of a pipeline. It is the economics of the coatings system as well as its performance which justifies the industry" (McConkey 1982).

To be effective, pipeline coating must satisfy several properties (Kennedy 1993):

- easy to apply
- adheres well to pipe
- resists impact
- is flexible
- resists soil stress
- resists flow (of coating)
- is resistant to water
- is resistant to electricity
- is chemically and structurally stable
- resists bacteria, marine organisms, and cathodic disbondment.

8.2 Description and Typical Facilities

Pipeline construction methods differ depending on the geographical area, the terrain, the environment, the type of pipeline, and the restrictions and standards imposed by governments and regulatory agencies. The biggest differences exist between land construction and offshore construction; however, all pipeline construction projects have a number of features in common (Kennedy 1993):

- The methods of designing the system – arriving at the optimum pipe diameter, determining the amount of horsepower required for pumping or compression, meeting safety standards – are similar for all pipelines.

- There are a number of design criteria that are set by government or regulatory agencies to insure safe operation of a pipeline and the safety of personnel and property near the pipeline. These standards vary depending on the location of the pipeline, both geographically and in relation to populated areas and other facilities.

- Comprehensive environmental impact studies are required in many countries before construction permits can be issued. Construction plans must provide for the protection of scenery, wildlife, archeological sites, and other historic assets.

- Most oil, gas, and products pipelines are constructed by welding short lengths, or *joints*, of pipe together. There are a few exceptions to the use of welded connections, but these are in short lines within a producing field or in similar applications.

- Extensive testing of welders and the welds they produce is an important part of the construction of all long-distance petroleum pipelines.

- Almost all oil and gas pipelines are buried below ground level, even most offshore pipelines are buried below the sea bed for protection. There are cases in which large segments of a major pipeline are not buried, the most notable example of which is the trans-Alaska crude pipeline where above ground sections were installed to protect permafrost areas.

- All pipelines are tested for leaks following construction before the line is put in service. Several techniques can be used, but the most common is hydrostatic testing – filling the line with water and subjecting it to a pressure greater than the design operating pressure.

- Most pipelines are coated on the exterior to prevent corrosion. Offshore pipelines are also "weight-coated" with a concrete coating to overcome the force of buoyancy and to prevent the pipe from floating to the surface.

- Most pipelines must have one or more pumping stations or compressor stations along the route to provide energy to overcome pressure loss and keep the fluid in the pipeline moving.

- The construction of all pipelines follows this general sequence: design and route selection, obtaining rights of way, installation, tie-in to origin and destination facilities and pumping or compressor stations, and testing.

Corrosion: Corrosion is an electrochemical process involving an area of higher potential – the anode (a piece of metal that readily gives up electrons); and an area of lower potential – the cathode (a piece of metal that readily accepts electrons). The electrolyte is a liquid or some conveyor that helps the electrons move from the anode to the cathode. The anode will become corroded, while the cathode will not be subject to damage. When a piece of metal corrodes, the electrolyte helps provide oxygen to the anode. As oxygen combines with the metal, electrons are liberated. When they flow through the electrolyte to the cathode, the metal of the anode disappears, swept away by the electrical flow or converted into metal cations in a form such as rust. In the case of a buried pipeline, the soil is the electrolyte. These areas of different potential exist along a pipeline. The magnitude of the potential difference depends on soil conditions, among other factors.

The electrical potential between the anode and cathode is what causes the corrosion current to flow (Allied Corrosion Industries, Inc. 1998). The anode is the area that is subject to corrosion and the severity of which is directly proportional to the amount of current flow. There are many types of corrosion. Some common industry types include (Allied Corrosion Industries, Inc. 1998):

- Dissimilar metal corrosion (or galvanic corrosion): Occurs when two metals with different compositions are metallically contacting each other in a common current flow. The negative potential composition of each metal determines which metal acts as the anode and the rate of corrosion.

- Differential aeration corrosion: Occurs when part of the pipe is exposed to well-aerated soil (cathode region) and the other part exposed to a poor supply of oxygen.

- Corrosion can also occur when new sections are used and welded with old sections in repairs and additions. “The unfortunate thing about this type of corrosion is that the newer structure will normally become the anode.”

<u>Cathodic Protection:</u> Cathodic protection refers to the method of preventing corrosion in metal structures that involves using electric voltage to slow or prevent corrosion. It is used along natural gas pipelines, as well as in certain bridges or other large metal structures that need to resist corrosion over an extended period of time.

In a cathodic protection system, anodes are installed and an electrical current is made to flow between the pipe and the anodes through the soil. The pipeline becomes the cathode of the system, and corrosion is decreased. The anodes, the part of the system that is corroded, are “sacrificed.”

Cathodic protection eliminates anodic areas on an underground metallic structure. With the implementation of cathodic protection, constant surveying of how the protection is holding up, whether it is disbondment of the coating or if new coating faults arise, is a significant implementation that has arisen in the industry. During pipeline fabrication, all possible measures are taken to detect and repair coating faults.

It is possible to calculate the electrical resistance of a coated pipeline, given the coating specifications and pipeline dimensions, but it is impossible to calculate the actual resistance of the total pipeline over time with varied external conditions affecting the structure. The magnitude of the corrosion currents for a given potential difference between two electrodes (cathode and anode) depends on several factors (Kennedy 1993):

- Soil resistivity - This is determined by temperature, moisture content, and the concentration of ionized salts present. Generally, corrosion is high in low-resistivity soils and can be low in high-resistivity soils.

- Chemical constituents of the soil - The type of salts in the soil affect the rate of corrosion.

- Separation between anode and cathode - Corrosion is more likely to occur when the anode and cathode are close together. Increasing the distance between two dissimilar metals (electrodes) reduces corrosion current intensity.

- Anode and cathode polarization - Protective films formed at the anode and cathode affect corrosion rate.

- Relative surface areas of cathode and anode - For a given magnitude of corrosion current, the depth of corrosion on the anode will be inversely proportional to anode area.

External Corrosion Coating: Pipeline coating inhibits the flow of electric current from the pipe and the resulting loss of steel. Once the coating is applied, tape is wrapped around the pipe in a spiral pattern with the edges overlapping slightly so that all of the pipe coating is covered. Wrapping tape, normally either a heavy paper or plastic, protects the coating from damage.

The earliest anti-corrosion coatings for buried pipelines were bitumen-type coatings – asphalt mastic and enamel and coal tar enamel. However, over time, it has been found that these types of coating are subject to cracking, leading to contact of water with the pipe and coating disbondment. The asphalt coatings were also found to absorb water to a greater degree than other coatings. Developments in epoxy based adhesives have led to more desirable coatings such as fusion-bonded epoxy, polyethylene and polypropylene. Traditional pipeline anti-corrosion coatings are being progressively replaced by complex multi-layer composite systems. These new coatings start with a fusion-bonded epoxy layer, combined with a robust shield of thick extruded polyethylene or polypropylene.

"The ability of a coating system to perform as a corrosion barrier depends upon the resistance to damage exhibited by the coating as well as its inherent corrosion-protective properties as determined by adhesion to the steel and resistance to the corrosive environment. This ability is a function of the properties of the coating material combined with the coating process which produces the coating system. The coating process must be capable of applying the coating in such a manner as to achieve the final performance properties of the material" (McConkey 1982). Table 8.1 is a comparison of the advantages and disadvantages of different types of coatings systems used on pipelines today.

Table 8.1

Comparison of Pipeline Coating Systems Currently Used

	Advantages	Disadvantages
Asphalt/Coal tar: 1940 to 1970	- Easy to apply - Minimal surface preparation required - Long track record in certain environments w/o failure - Permeable to cathodic protection in event of failure	- Subject to oxidation and cracking - Soil stress has been an issue - Limitations at low application temps - Environmental and exposure concerns - Associated with corrosion and stress crack corrosion failures
Tape wrap (two layer): 1960 to present	- Simple application	- Poor shear stress resistance - Many documented failures related to corrosion and stress crack corrosion - Shielding of cathodic protection - Adhesives subject to biodegradation
Two-layer extruded polyethylene: 1960 to present	- Excellent track record - Good handling	- Limited temperature range - Poor shear stress resistance - Limited pipe sizes (<24 in. outside diameter)
Fusion-bonded epoxy: 1975 to now	- Excellent adhesion and corrosion resistance - Does not shield cathodic protection	- Low impact resistance - High moisture absorption and permeation
Three-layer polyolefin: 1986 to present	- Excellent combination of properties	- Best suited for electrical resistance welded pipes - High thickness to eliminate weld tenting
Composite coating: 1990 to present	- Excellent combination of properties - Conforms well to external raised well profiles	- Suitable only for large diameter pipes and is not designed for small diameter pipes

Source: CorrosionSource (2002)

<u>Fusion-Bonded Epoxy:</u> One of the most popular coatings used today is the fusion-bonded epoxy. The use of fusion-bonded epoxy pipe coatings began to expand in the early 1980s, and they are considered to offer a number of advantages. "The high-temperature performance, chemical resistance, resistance to soil stress, and excellent resistance to cathodic disbondment in comparison to traditional coatings has led to the increased use of fusion-bonded epoxy. Fusion-bonded epoxy coatings have become more attractive due to several advances in both the application process and in the raw material" (McConkey 1982). Fusion-bonded epoxy coatings provide a more controllable application process and a product whose quality can be assured before the laying of the pipeline.

Concrete Coating for Offshore Pipe: Offshore pipelines are coated with concrete in addition to the corrosion coating to provide negative buoyancy (a weight greater than the buoyant force of the water) to the pipeline. This added weight is necessary to cause the pipeline to sink to the ocean floor and remain in position on the seabed. To be effective, a concrete coating must resist damage during installation and after it is in place. In addition to providing needed weight, the concrete coating protects the corrosion coating.

There are three major requirements of concrete coating in maintaining the stability of pipeline on the seabed (Kiernan 1982):

- **Negative buoyancy** – Originally, the chief function of negative buoyancy was to add sufficient weight to the pipeline to achieve the required negative buoyancy, hence the term “weight coating.” This primary function has not changed over the years since the first offshore lines were laid in the Gulf in the late 1940s. However, experience has proven that weight coating must meet additional requirements as follows.

- **Resistance to damage** – To remain in position during pipeline life, a concrete coating must have resistance to damage during laying and trenching operations, from natural environmental hazards during the life of the pipeline at the bottom of the sea, and from the effects of human hazards such as fishing trawls and trailing cables from floating vessels.

- **Protection of anticorrosion coating** – Presently used techniques of anticorrosion coating are subjected to damage when exposed to trawl gear or trailing cables.

Design of the concrete coating is critical if it is to withstand laying stresses and resist damage from anchors, fishing gear, and other hazards during operation. Considerable research has been aimed at the improvement of concrete coatings and application methods, based in part on the performance of early concrete-coated pipelines. One of the most critical considerations in concrete coating design is the overbend area where the pipe leaves the lay barge’s pipe ramp during installation. If laying stresses are not properly calculated and maintained within design limits, concrete coating can crack during installation (Kennedy 1993).

8.3 Industry Characteristics

Pipeline corrosion coating can be applied either before the pipe is delivered (yard applied) or after the pipe lengths are welded together and suspended above the trench. When pipe lengths are coated and wrapped at a coating yard before being delivered to the job site, a short distance at each end of each length of pipe is left bare so the joints can be welded together. When field welding is complete, coating and wrapping material is applied to the bare pipe sections.

When all coating and wrapping is done at the job site, individual lengths are first welded together and the pipeline is suspended over the trench. Special machines then move along the pipeline and apply coating to the entire pipe, welds and all. Tape is wrapped over the coating by a tape machine in a spiral. The wrapping machine maintains tension on the tape so it is fitted tightly over the coating (Kennedy 1993).

Application of Fusion-Bonded Epoxies: The process of applying fusion-bonded epoxy coating to pipelines involves four major steps: surface preparation, heating, powder application, and curing (Figure 8.1). Proper surface preparation assures that maximum adhesion will develop at the interface between the pipe and the coating. The steel is blast-cleaned to a near white metal finish using abrasive grit – cleaning the pipe of contaminants, mill scale and rust. It also roughens the surface to give it a textured profile – texturing the surface also facilitates adhesion by increasing the exposed surface area of the steel and by providing more opportunity for the coating to chemically bond. After blast-cleaning, the steel is heated to approximately 450 degrees F using electrical induction heaters.

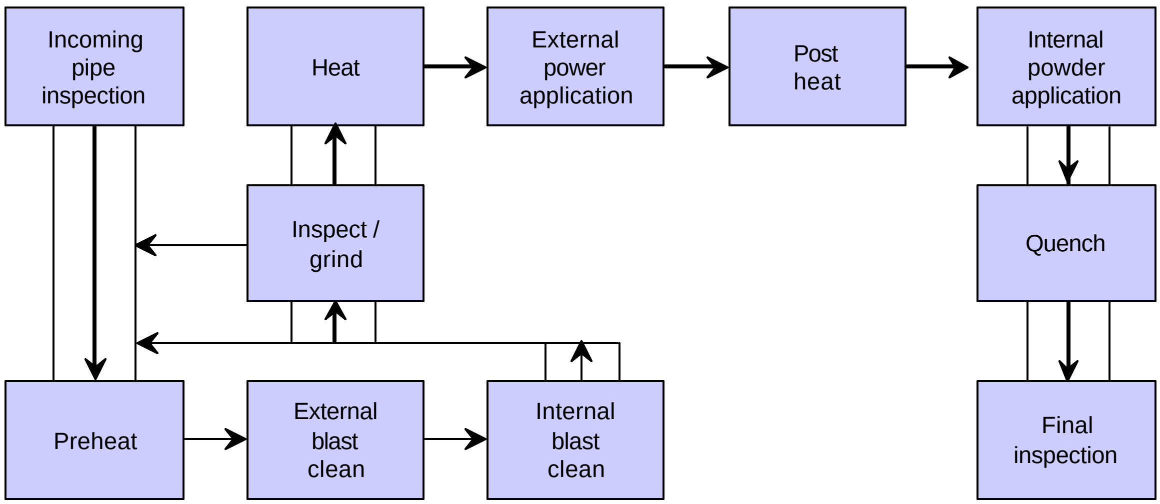

Figure 8.1. External/Internal Fusion Bonded Epoxy Coating Plant.

Source: Kennedy (1983)

The heated pipes are then passed through a powder spray booth where dry epoxy powder is emitted from a number of spray nozzles. As the powder leaves the spray nozzle, an electrical charge is imparted to the particles. These electrically charged particles are attracted to the grounded steel surface providing an even coverage of the coating. When the dry powder hits the hot steel, it melts and flows into the textured profile and conforms to the ribs and deformations of the pipe. The heat also initiates a chemical reaction that causes powder molecules to form the complex cross-linked polymers that give the epoxy coating its beneficial properties. Following powder application, the coating is allowed to cure for a short period (approximately 30 seconds) during which it hardens. To facilitate handling, the curing period is often followed by an air or water quench that quickly reduces the bar temperature.

8.4 Regulations

Although not economically regulated like other segments of the natural gas industry, pipe coating techniques do have to meet industry specifications as established by the Department of Transportation and recommended by the National Association of Pipe Coating Applicators.[40]

[40] The remainder of this section is taken from: 49 CFR 195, Parts 236-244 and 414-418, October 1, 1999.

Part 195, under Title 49 (Transportation) of the Code of Federal Regulations is titled “Transportation of Hazardous Liquids by Pipeline.” Section 195.238 lists the requirements for external coatings:

- No pipeline system component may be buried or submerged unless that component has an external protective coating that:
  - Is designed to mitigate corrosion of the buried or submerged component;
  - Has sufficient adhesion to the metal surface to prevent underfilm migration of moisture;
  - Is sufficiently ductile to resist cracking;
  - Has enough strength to resist damage due to handling and soil stress; and
  - Supports any supplemental cathodic protection.

In addition, if an insulating-type coating is used, it must have low moisture absorption and provide high electrical resistance. All pipe coating must be inspected just prior to lowering the pipe into the trench or submerging the pipe, and any damage discovered must be repaired.

Regulations for cathodic protection systems are also included in Section 195.242. A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A test procedure must be developed to determine whether adequate cathodic protection has been achieved. A cathodic protection system must be installed not later than one year after completing the construction. Except for offshore pipelines, electrical test leads used for corrosion control or electrolysis testing must be installed at intervals frequent enough to obtain electrical measurements indicating the adequacy of the cathodic protection.

External Corrosion Control: According to the CFR, every pipeline operator must, at least once each calendar year, conduct tests on each buried, in contact with the ground, or submerged pipeline facility in its pipeline system to determine whether the cathodic protection is adequate. In addition, pipeline operators must inspect each of its cathodic protection rectifiers on a bi-monthly basis.

Once every five years, an operator must inspect the bare pipe in its pipeline system that is not cathodically protected and must study leak records for that pipe to determine if additional protection is needed. Whenever any buried pipe is exposed for any reason, the operator must examine the pipe for evidence of external corrosion. If any active corrosion is found, that the surface of the pipe is generally pitted, or that corrosion has caused a leak, further investigation must be undertaken to determine the extent of the corrosion.

Any pipe that is found to be generally corroded so that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances must either be replaced with coated pipe that meets industry requirements or, if the area is small, must be repaired. However, the pipeline operator need not replace generally corroded pipe if the operating pressure is reduced to be commensurate with the limits on operating pressure, based on the actual remaining wall thickness.

If localized corrosion pitting is found to exist to a degree where leakage might result, the pipe must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe based on the actual remaining wall thickness in the pits.

Internal Corrosion Control: An operator may not transport any hazardous liquid or carbon dioxide that would corrode the pipe or other components of its pipeline system, unless it has investigated the corrosive effect of the hazardous liquid or carbon dioxide on the system and has taken adequate steps to mitigate corrosion. If corrosion inhibitors are used to mitigate internal corrosion the pipeline operator must use inhibitors in sufficient quantity to protect the entire part of the system that the inhibitors are designed to protect and shall also use coupons or other monitoring equipment to determine their effectiveness. Twice each calendar year, the monitoring equipment must be examined to determine the effectiveness of the inhibitors or the extent of any corrosion.

Whenever any pipe is removed from the pipeline for any reason, the operator must inspect the internal surface for evidence of corrosion. If the pipe is generally corroded such that the remaining wall thickness is less than the minimum thickness required by the pipe specification tolerances, the operator shall investigate adjacent pipe to determine the extent of the corrosion. The corroded pipe must be replaced with pipe that meets industry requirements, or based on the actual remaining wall thickness, the operating pressure must be reduced to be commensurate with the limits on operating pressure.

8.5 Industry Trends and Outlook

Based on an inventory conducted as part of the development of a GIS database for this project, 16 pipe coating facilities that support the oil and gas industry were recorded within the Gulf region; 7 in Texas, 5 in Louisiana, 3 in Alabama, and 1 in Florida. As discussed in Chapter 7, with increases in natural gas demand, and promising developments in the Gulf of Mexico, transmission capacity will also need to expand, and thus the need for pipeline coating. In turn, pipeline coating companies have increased output to meet the increased demand for services. Chapter 3 previously outlined the new Bredero Price facility in Theodore, AL which replaced a smaller site in Harvey, Louisiana. Additionally, Bayou Companies in New Iberia, LA claims to have coated over 5,000 miles of pipe in the past year, up from an approximate 2,000 mile annual average for the five year period ending in 1999.[41]

Pipe coatings have evolved from simple coal-tar applications to more sophisticated fusion-bonded epoxies and polypropylene coatings. Companies continue to try new methods and materials, in the battle against corrosion and extreme environmental effects.

One new product, recently introduced to the market is the Reilly Shrink Sleeves. The Reilly Pipeline Coating Group (PCG) is offering these sleeves that consist of a cross-linked polyolefin backing, a closure for mechanical protection and an anti-corrosive adhesive that will prevent corrosion at pipeline joints. Reilly PCG is working in concert with Fameim S.A. to produce the sleeves. The partnership will provide consumers with an end-to-end, single vendor solution for anti-corrosion pipeline coating products, as well as a high-quality joint coating for oil, gas, and water pipelines to provide total pipeline corrosion protection (Pipeline and Gas Journal Online, May 2002).

[41] The Bayou Companies website, http://www.bayoupipe.com/3-Proj-Fr.htm, (June15, 2002).

The increased activity in the Gulf should continue to push the development of new products and services that increase pipeline lives and repair. Companies with Gulf of Mexico facilities capable of accommodating large, deepwater projects stand to be great benefactors of the current pipeline marketplace.

9.0 NATURAL GAS PROCESSING PLANTS

9.1 Introduction

Natural gas, as it is produced from a reservoir rock, is typically a mixture of light hydrocarbon gases, impurities and liquid hydrocarbons. Natural gas processing removes the impurities and separates the light hydrocarbon mixture into its useful components. Natural gas is found below the earth's surface in three principal forms:

- ***Associated gas*** is found in crude oil reservoirs, either dissolved in the crude oil, or combined with crude oil deposits. Associated gas is produced from oil wells along with the crude and is separated from the oil at the head of the well.

- ***Non-associated gas*** is found in reservoirs separate from crude oil – its production is not a result of the production of crude oil. It is commonly called "gas-well gas" or "dry gas." Today about 75% of all U.S. natural gas produced is non-associated gas (Natural Gas Information and Educational Resources 1998c).

- ***Gas Condensate*** is a hydrocarbon that is neither true gas nor true liquid. It is not a gas because of its high density, and it is not a liquid because no surface boundary exists between gas and liquid. Gas condensate reservoirs are usually deeper and have higher pressures, which pose special problems in the production, processing and recycling of the gas for maintenance of reservoir pressure.

The quality and quantity of components in natural gas varies widely by the field, reservoir or location from which the natural gas is produced. Although there really is no "typical" make-up of natural gas, it is primarily composed of methane (the lightest hydrocarbon component) and ethane. Table 9.1 provides a list of substances often present in natural gas:

Table 9.1

Components Found in Natural Gas

Hydrocarbons		Inerts	
Substance	**Formula**	**Substance**	**Formula**
Methane	CH_4	Helium	He
Ethane	C_2H_6	Nitrogen	N_2
Propane	C_3H_8	Argon	Ar
Iso-butane	C_4H_{10}	**Sulphur Compounds**	
Normal-butane	C_4H_{10}	**Substance**	**Formula**
Iso-pentane	C_5H_{12}	Hydrogen Sulfide	H_2S
Normal-pentane	C_5H_{12}	Mercaptan	
Hexane	C_6H_{14}	Sulphur	S
Heptane	C_7H_{16}	**Other Gases**	
Octane	C_8H_{18}	**Substance**	**Formula**
Nonane	C_9H_{20}	Oxygen	O_2
Decane	$C_{10}H_{22}$	Carbon Dioxide	CO_2

Source: EnerPro, Inc. (1990)

In general, there are four types of natural gas – wet, dry, sweet, and sour. Wet gas contains some of the heavier hydrocarbon molecules and water vapor. When the gas reaches the earth's surface, a certain amount of liquid is formed. The water has no value, however, the remaining portion of the wet gas may contain five or more gallons of recoverable hydrocarbons per thousand cubic feet. If the gas does not contain enough of the heavier hydrocarbon molecules to form a liquid at the surface, it is a dry gas. Sweet gas has very low concentrations of sulfur compounds, while sour gas contains excessive amounts of sulfur and an offensive odor. Sour gas can be harmful to breathe or even fatal (Berger and Anderson 1992).

Hydrocarbons have a distinctive weight, "boiling point", vapor pressure and other physical properties that make the removal and separation of individual hydrocarbons possible.[42] Each hydrocarbon has a specific combination of pressure and temperature at which it will change from liquid to gas – the heavier the component, the higher the temperature, or boiling point.

9.2 Description and Typical Facilities

All natural gas is processed in some manner to remove unwanted water vapor, solids and/or other contaminants that would interfere with pipeline transportation or marketing of the gas. Typical contaminants include water, hydrogen sulfide, carbon dioxide, nitrogen, and helium. Centrally located to serve different fields, natural gas processing plants have two main purposes: (1) remove essentially all impurities from the gas; and, (2) separate the gas into its useful components for eventual distribution to consumers.

Figure 9.1 demonstrates the variety of natural gas compositions produced and the variety of natural gas processing equipment requirements.[43] Fields A and B produce natural gas and water. Field C produces only natural gas, no impurities. Field D produces natural gas contaminated with some non-hydrocarbon gases.

Fields A and B share a field-gas process facility that removes some of the water – enough to make it marketable.[44] Field C does not require a field gas process facility because it produces only natural gas with no impurities. Field D requires a field facility to remove the non-hydrocarbon gases to make the remaining marketable. All four fields are connected to the gas processing plant, where essentially all of the water and impurities are removed and sent to disposal sites. (See Chapter 6 for detailed discussion of Waste Management Facilities.) Natural gas liquids such as ethane, propane and butane are separated within the plant and sold as liquid fuel, as feedstock for petrochemical manufacturers, or as an additive for blending with refined crude oil products.

[42] "Boiling point" is when a liquid will boil whenever the vapor pressure of a liquid is equal to the pressure being exerted on it.

[43] This example is replicated from: Anthony J. Welker, *The Oil and Gas Book*. (Tulsa: SciData Publishing), 1985, p. 192.

[44] The facilities located at or near the natural gas field are usually limited to making the natural gas stream marketable. Therefore, field gas processing facilities typically remove gas impurities only to the extent actually required by the transportation company taking the gas to the processing plant.

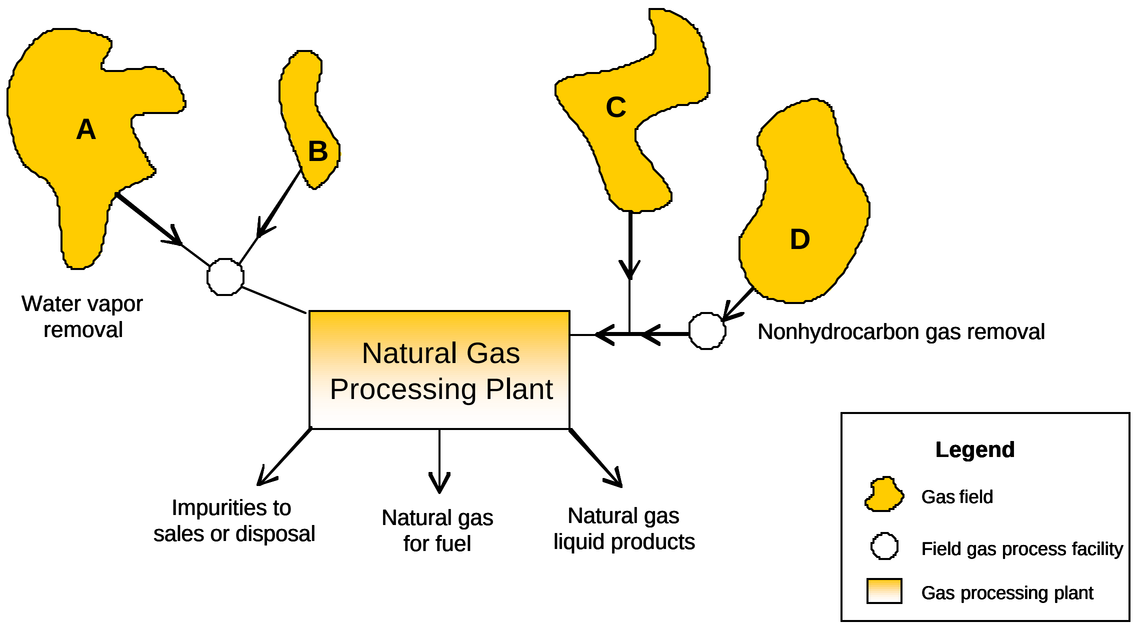

Figure 9.1. Variety of Natural Gas Processing Procedures.

Source: Welker (1985)

As natural gas is cooled, heavier substances, like pentane and butane, will change from gases to liquids before the lighter components, like methane, which requires a very low temperature to condense. At cool enough temperatures and/or high enough pressures, methane will theoretically be the only hydrocarbon left in a gaseous form while the remaining substances will have been transformed to liquids (Figure 9.2).

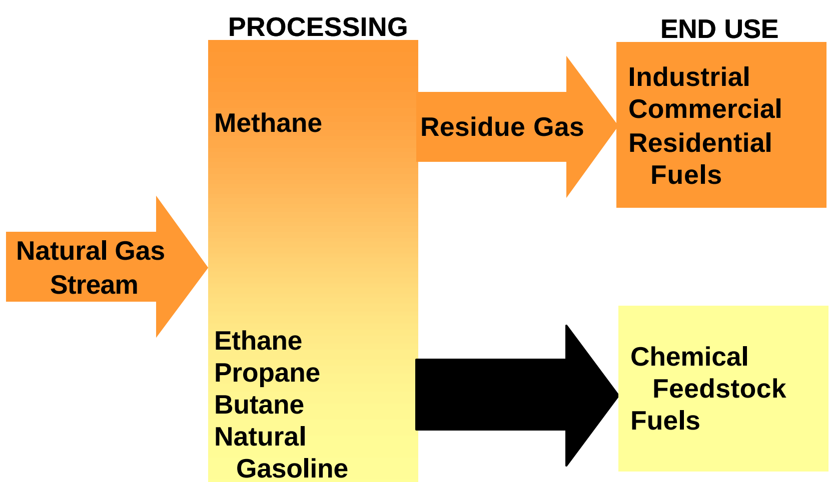

Figure 9.2. Natural Gas Processing Products.

In general, these “phase changes” are what enable most gas processors to separate the heavier hydrocarbons from the methane. The efficiency of the extraction will depend on the type of process utilized. The following procedures are common to natural gas processing systems (EnerPro, Inc. 1990).

- ***Lease Separation*****:** The mechanical removal of condensate and free water from the natural gas stream at the lease separator.

- ***Impurities Removal*****:** The removal of problem, corrosive and/or toxic substances, such as water, carbon dioxide and hydrogen sulfide, as well as the removal of substances which reduce the overall heating value of the gas, such as nitrogen.

- ***Natural Gas Liquid Extraction*****:** Various processes capable of liquefying and extracting heavier hydrocarbons from methane.

- ***Residue Gas Conditioning*****:** Any necessary dehydration and recompression of the residue gas in preparation for pipeline transmission.

- ***Separation of Natural Gas Liquids*****:** The fractionation process that isolates natural gas liquids into distinct components. Many gas plants do not possess fractionation facilities and sell only the combined liquid stream.

Types of Processing Plants: Gas processing plants use several methods to extract the liquid components from the natural gas. At the temperatures and pressures existing in the gathering systems, the hydrocarbon components or natural gas liquids (NGLs or liquids) remain mixed with natural gas in vapor form. In order to extract these NGLs, the gas must either be compressed, refrigerated, passed over liquid/solid agents which absorb/adsorb the liquids or some combination thereof. The following are common types of gas processing plants (EneroPro 1990).

- ***Adsorption Plants*****:** The incoming gas is passed through a solid agent, often activated charcoal or molecular sieve, to extract the NGLs. The agent adsorbs the NGLs and they are later recovered through heating. These types of plants are inefficient and virtually obsolete.

- ***Refrigeration Plants*****:** Straight refrigeration plants utilize a simple cooling process that condenses the liquids for recovery. These plants are fairly common and relatively inexpensive to operate, but often have capacity restrictions.

- ***Lean Oil Absorption Plants*****:** The raw gas is passed through oil utilizing a recirculation process which allows the NGLs to be absorbed. Quantities of methane are also recovered with the NGLs and must be rejected before the other liquids are separated from the oil. These liquids are then recovered through the application of heat. This is an outmoded process, though some plants are still in operation. Additionally, these plants are complex and expensive to operate.

- ***Refrigerated Lean Oil Plants*****:** These plants use the same general method as the Lean Oil Absorption, but refrigerate the oil to improve the efficiency of the recovery.

Like the regular lean oil plants they are very complex and expensive, though several are still in use.

- ***Cryogenic Plants*:** Cryogenic plants use very low temperatures in the proper combination with pressure to achieve the desired product recovery. These plants employ special insulated equipment with good thermal expansion properties and require thorough dehydration and scrubbing of the gas to avoid hydrate formation and exchanger fouling. The expansion turbine cools the gas to very low temperatures and improves the efficiency of the recovery. Turbo Expander and Joule-Thomson are the most commonly found types of cryogenic plants. These plants are efficient and relatively inexpensive and easy to operate.

The modern gas processing industry uses a variety of sophisticated methods to treat natural gas and extract natural gas liquids from the gas stream. The two most important extraction methods are the absorption and cryogenic processes. Together, these account for an estimated 90 percent of total natural gas liquids production (Natural Gas Information and Educational Resources 1998c).

9.3 Industry Characteristics

There are approximately 585 gas processing plants operating in the United States (as of January 2001) – the majority of which are located in seven states: Texas, Louisiana, Oklahoma, Colorado, Wyoming, California and New Mexico (Table 9.2). These seven states account for about 83 percent of the total number of plants. However, they only account for 70 percent of processing capacity and 70 percent of throughput. As shown in Table 9.2, some states have processing facilities that have higher capacities than those in others. For instance, Alaska only has three natural gas processing facilities, but those facilities have a higher total capacity than all of the facilities listed in Table 9.2 from Kansas to Kentucky combined. The same holds true for throughput.

Total U.S. gas plant average capacity is almost 72,000 MMcfd and current throughput represents about 70 percent of capacity.

The total number of natural gas processing plants operating throughout the U.S. has been declining over the past several years as companies merge, exchange assets, and close older, less efficient plants (Figure 9.3). However, this trend was reversed in 1999 with a “rush of new capacity that has been ongoing in Louisiana” (True 2000). This recent growth is discussed further in Section 9.5 – Industry Trends and Outlook.

With more than 4.3 bcf of natural gas processed in 2000, Louisiana continues to lead the U.S., followed closely by Texas with almost 4.1 bcf natural gas processed. Between them, the two states represent almost one half of natural gas processed within the U.S. in 2000 – as shown in Figure 9.4. Louisiana and Texas also extracted 56 percent of NGLs in 2000, with the majority of liquids being produced in Texas – nearly 41 percent (Figure 9.5).

Table 9.2

Natural Gas Processing Plants in the United States (as of January 1, 2001)

	Number of Plants	Gas Capacity	Gas Throughput
		(MMcfd)	
Texas	205	17,111	12,358
Louisiana	76	19,110	12,828
Oklahoma	73	4,197	2,676
Colorado	40	1,238	1,020
Wyoming	35	4,005	2,591
California	31	1,859	1,417
New Mexico	25	2,926	2,443
Michigan	15	700	226
Kansas	13	3,102	2,231
Alabama	11	1,966	924
Utah	11	499	275
Mississippi	10	1,877	764
West Virginia	6	360	304
Montana	5	14	8
North Dakota	5	97	56
Pennsylvania	5	27	18
Arkansas	4	876	519
Kentucky	4	165	114
Alaska	3	9,525	9,298
Ohio	3	25	10
Tennessee	2	8	2
Florida	1	90	25
Illinois	1	2,100	
Nebraska	1	10	8
Total U.S.	**585**	**71,886**	**50,115**

Source: Stell (2001)

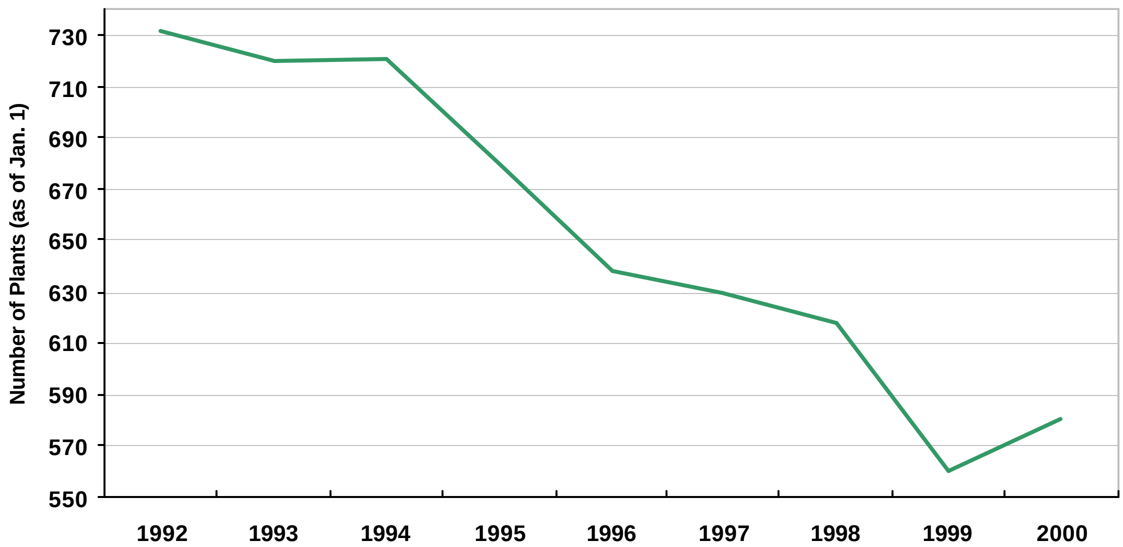

Figure 9.3. U.S. Natural Gas Processing Plants.

Source: True (2000)

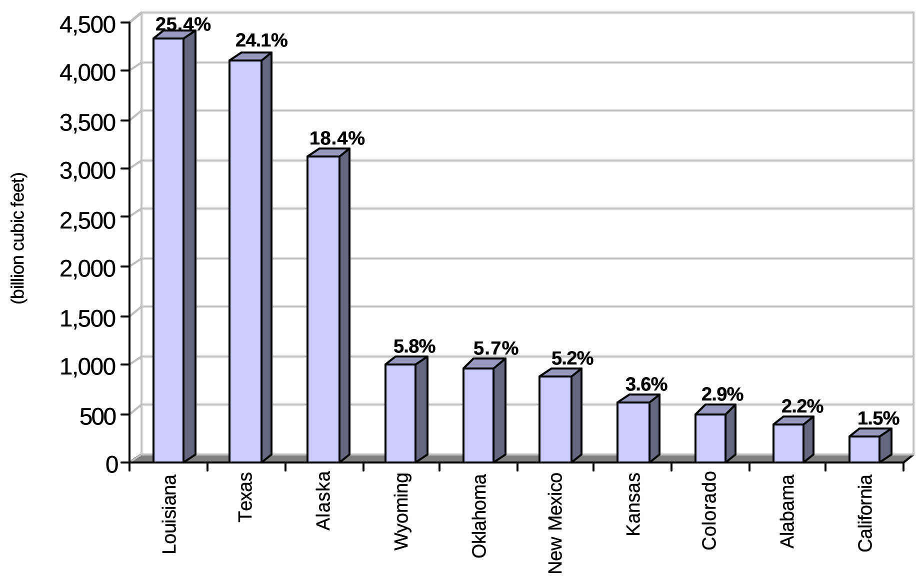

Figure 9.4. Natural Gas Processed by Top Ten States (2000).

Note: Percentages used as labels in this figure represent the percent of total natural gas processing within all 22 reported states – not just within these 10 states shown in the figure.

Source: Energy Information Administration (2001b)

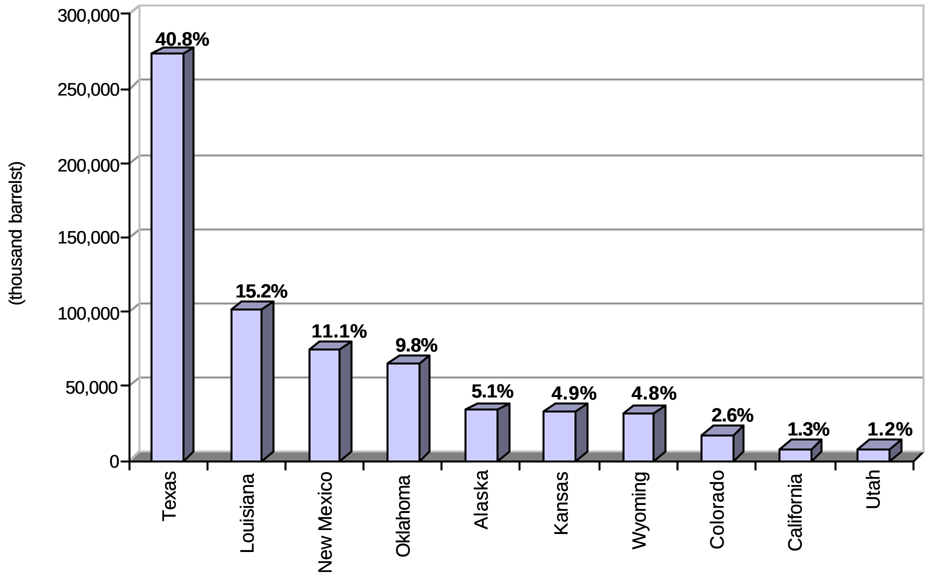

Figure 9.5. Total Liquids Extracted by Top Ten States (2000).

Note: Percentages used as labels in this figure represent the percent of total natural gas processing within all 22 reported states – not just within these 10 states shown in the figure.

Source: Energy Information Administration (2001b)

9.4 Regulations

Natural gas producers and marketers are not directly regulated. This is not to say that there are no rules governing their conduct, but instead there is no government agency charged with the direct oversight of their day-to-day business. Production and marketing companies must still operate within the confines of the law; for instance, producers are required to obtain the proper authorization and permitting before beginning to drill, particularly on federally-owned land. However, the prices they charged are a function of competitive markets and are no longer regulated by the government.

9.5 Industry Trends and Outlook

A number of factors are fueling the growth of the natural gas processing industry in the Gulf region. Major successes in deep-water exploration and production are increasing the volumes of liquids that come on shore for processing. Not only is supply of natural gas increasing from offshore, but onshore, demand for natural gas – in large part driven by power generation, is also rising. Adding to the increased need for natural gas, is the development of the liquids market – where NGLs are increasing in value.

Because of increased demand for natural gas as the preferred fuel for power generation and continued industrial growth, demand is forecasted to increase by 21 bcf/d day to approximately 93 bcf/d by 2010 and to 102 bcf/d by 2015. In the next ten years, the compound annual growth rate of demand is expected to be 2.5 times greater than the growth rate for the previous twenty years. To supply this growth, producers are challenged to find new sources of natural gas and further exploit reserves from mature basins.

Production from deepwater developments in the Gulf of Mexico is expected to be a significant new source of natural gas. This production is forecasted to increase from 2.9 bcf/d in 2000 to approximately 5.7 bcf/d by 2010 and to 8.2 bcf/d 2105. New supplies from the deepwater are expected to supply 20 percent of natural gas demand growth in the United States by 2010 and 25 percent of U.S. demand growth by 2015.

The deepwater Gulf is even more strategic to the U.S. in terms of crude oil and condensate production. In 2000, the Gulf of Mexico accounted for approximately 24 percent of total U.S. crude oil and condensate production. It is forecasted that by 2005, the Gulf will supply 37 percent of total U.S. production, primarily from new production from deepwater developments. By 2010, the Gulf is expected to account for 43% of total U.S. crude and condensate production (Enterprise Products Partners L.P. 2002).

Historically, U.S. Gulf Coast natural gas production has contained marginal amounts of recoverable NGL. Newer deepwater production, however, has shown higher levels estimated in the 2-4 gallon per Mcf range. As a result, several cryogenic processing facilities are under construction along the U.S. Gulf Coast, the first of which is operational in Southeast Louisiana (Currence et al. 1999). The Discovery Project includes a 600,000 Mcf/d interstate pipeline, a condensate handling facility, a 600,000 Mcf/d cryogenic gas processing plant, a 42,000 bbl/d fractionator and 400,000 Mcf/d of deepwater gathering laterals. The assets extend from the deepwater Gulf offshore Louisiana to onshore delivery points about 30 miles south of New Orleans (Gas Daily 2002b). The Discovery project marks the first major grassroots offshore gathering and processing system along the Louisiana Gulf Coast in more than a decade (Bodenhamer and Laguens 1998).

Also, responding to the recent successes of deepwater exploration and production in the Gulf of Mexico, the Destin pipeline and Pascagoula gas processing plant have come online. The Destin pipeline originates at a junction platform at Main Pass 260 and, after coming ashore near Pascagoula, Mississippi, connects with 5 interstate gas transmission pipelines. The line has a 121-mile offshore segment and a 134-mile onshore segment. The gas processing plant is located where the pipeline comes ashore, just before the first compressor station.

The Pascagoula plant straddles the Destin pipeline adjacent to slug-catching facilities that are designed to remove retrograde condensate that may form in the pipeline.[45] The slug catcher holds 5,000 bbl of liquids from the pipeline. Gas handling capacity is 1 bcf/d. Liquid from the slug catcher feeds into the condensate stabilizer. Gas from the slug catcher is dehydrated, then processed in two identical trains, each with a capacity of 500 MMscf/d. Each train provides inlet-gas cooling, dehydration, expansion, demethanization, NGL recovery and residue-gas compression. Condensate is delivered to truck loading, NGL is delivered by pipeline, and residue gas is compressed and returned to the pipeline network. Train A started up in March 1999 and Train B started in late 1999 (True 2001).

Other recent projects are presented in Table 9.3 and include:

[45] Straddle plants are situated on mainline natural gas pipelines and allow operators to extract natural gas liquids from a natural gas stream when the market value of natural gas liquids separated from the natural gas stream is higher than the market value of the same unprocessed natural gas.

- In February 2000, along the Louisiana Gulf Coast, the Neptune gas-processing plant came online. The 300 MMcfd cryogenic plant near Centerville, Louisiana is a joint venture between Shell's Tejas Natural Gas Liquids LLC and Marathon Oil Co. For the past 30 years, Exxon's Garden City plant was the only gas processing plant for gas coming ashore through the Nautilus pipeline. Now a significant portion will be processed through Neptune. Presently, the plant is processing 200 MMcfd of natural gas stemming primarily from the Gulf. Approximately 16,000 bbl/d of NGLs are being yielded and transported via the Nautilus pipeline to the Promix fractionator for separation into NGL products. At maximum capacity, the plant is capable of producing over 25,000 bbl/d of NGLs. Plans are already under study to expand the Neptune plant (Gas Processors Report 2000).

- Williams completed a 600 MMcf/d gas processing plant in Coden, Alabama to service Mobile Bay in May 1999. Also newly completed is a 300 MMcf/d processing plant in Markham, Texas. Fully operational since the end of 2001, the Markham plant is designed to process volumes from three companies – Kerr McGee Oil & Gas Corp, Enterprise Oil Gulf of Mexico, Inc., and Ocean Energy Inc. The producers have developed deepwater leases in the Nansen and Boomvang fields, located approximately 150 miles south of Houston in 3,500 to 3,700 feet of water (Gas Services Division 2001).

Table 9.3

U.S. Processing Facilities under Construction

Company / Location	Project	Added Capacity (MMcf/d)	Status	Expected Completion
Burlington Resources				
Los Cabin gas plant, WY	Gas Plant	180	Construction	2002
Cheniere Energy Inc.				
Brownsville, TX	LNG Regas*	550	Planning	2007
Freeport, TX	LNG Regas*	550	Engineering	2007
Sabine Pass, TX	LNG Regas*	550	Planning	2007
CMS Energy Corp				
Lake Charles, LA	LNG Regas*	1200	Planning	2005
Duke Energy Field Services				
Artesia, NM	NGL	70	Engineering	2003
Dynegy Inc.				
Chico, TX	Gas plant	150	Construction	2002
Hackberry, LA	LNG Regas*	750	Planning	2003
El Paso Corp				
Elba Island, GA	LNG Regas*	360	Planning	2005
Enterprise Products				
Neptune, LA	Gas plant	300	Construction	2003
ExxonMobil Corp				
Point Thompson, AK	Gas plant	920	Planning	2002
Global Energy				
Champ plant, TN	Gas plant	1 MMbtu	Construction	2002
Louisiana Land & Expl.				
Lysite, WY	Gas plant	180	Planning	2002
Mitchell Gas Services, L.P.				
Bridgeport, TX	Gas plant	693,000	Construction	2002
Pioneer Natural Resources				
Irving, TX	Gas plant	75	Planning	2002
Williams Cos. Inc.				
Cove Point, MD	LNG Storage	3 bcf	Construction	2002
Markham, TX	Gas plant	300	Construction	2002

Note: Regas* is Regasification plant.

Source: Stell (2002)

10.0 NATURAL GAS STORAGE FACILITIES

10.1 Introduction

Demand for natural gas is primarily shaped by its use in heating homes and businesses. This demand results in an average winter demand that more than exceeds summer demand. Demand is more variable on a daily basis – because weather controls the duration, location and volume of peak demand, gas demand is essentially unpredictable. However, the gas supply industry must be able to deliver gas when and where it's needed. The key element allowing this to happen is the underground gas storage system.

Gas storage serves two central roles: to meet seasonal demands for gas (base-load storage) and to meet short-term peaks in demand (peaking storage). Peaks in demand can range from a few hours to a few days. To ensure that adequate natural gas supplies are available to meet seasonal base-load customer requirements, storage is filled during low utilization periods (April through October). During high utilization periods (November through March), pipeline capacity is supplemented with storage supplies to meet demand. Typically, gas withdrawn from storage can supply up to 30 percent of daily gas requirements during winter months.

By balancing production and transmission flows throughout the year, underground storage enables greater system efficiency and decreases the amount of new transmission pipelines needed to connect producing regions to consuming regions. Pipeline companies can avoid the need to expand transmission facilities by using or establishing new storage facilities in markets where there is a strong fluctuation in demand. Customers also gain from this efficiency with reduced costs reflected in lower rates.

In recent years, increased demand for natural gas in the electricity generation sector during the traditional off-peak period has increased competition for gas that was traditionally used to refill storage. This has also put an upward pressure on prices. Another trend that has changed the market is the use of storage to take advantage of expected price movements and to support futures market trading. Gas marketing entities, ranging from major corporations to individual brokers, are aggressively entering the market as developers, clients, and agents.

Measures of Storage: The two most important characteristics of an underground storage facility are its capability to hold natural gas for future use and the rate at which gas inventory can be withdrawn or its deliverability rate.

Capacity: The total capacity of a storage facility is simply the maximum volume of gas that can be stored as determined by the physical characteristics of the site (Figure 10.1). Total capacity is the total of two measurements, base gas (or cushion gas) and working gas. Base gas is the volume of gas required to maintain adequate pressure within the storage vessel. Base gas is rarely, if ever, produced – it is a permanent inventory, kept to ensure the deliverability of the working gas. The amount of base gas required is dependent upon the reservoir quality, number of wells, gas withdrawal schedule and field operating parameters. Because base gas is seldom produced, the ratio of base gas to working gas has a significant impact on the economics of new storage fields.

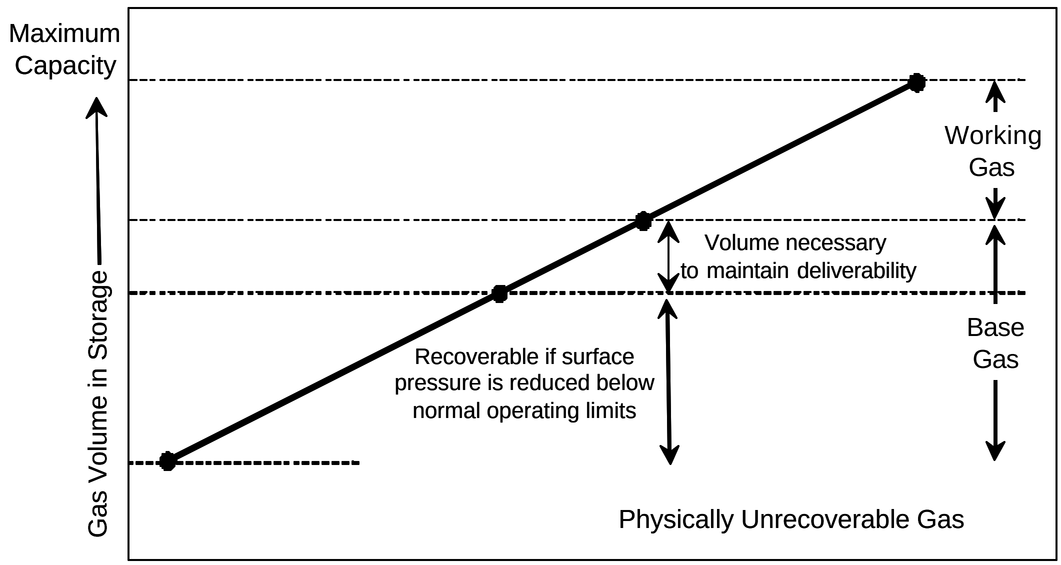

Figure 10.1. Pressure and Volume Relationship for a Storage Reservoir.

Source: Gas Technology Institute (1997)

Base gas can also include a measurement of "physically unrecoverable gas." This is gas that is trapped by physical forces in the pores of the rock – it cannot be removed. In the case when a depleted gas reservoir is converted to storage, this is the gas that is already in the formation as irreducible gas saturation.

Gas that is injected and produced during the storage cycle is working gas. This is the volume of gas above the designated level of the base gas – that which is available to the marketplace. Working gas capacity is essentially defined as total capacity minus base gas.

Deliverability: Deliverability is a measure of the amount of gas that can be withdrawn from a storage facility on a daily basis. Deliverability, also known as the deliverability rate, withdrawal rate, or withdrawal capacity, is measured in terms of million cubic feet or dekatherms per day. Like any pressurized container, as gas is pumped into a storage reservoir, the pressure in the container rises. As gas flows out of the container, the rate of flow decreases, as does the deliverability.

"The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the amount of base and working gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn" (Energy Information Administration 2001c).

10.2 Description and Typical Facilities

There are three principal types of reservoirs common to the underground storage of natural gas:

- Depleted reservoirs in oil and/or gas fields;
- Aquifers – water-bearing rock formations conditioned to hold natural gas; and,
- Caverns hollowed out in salt "bed" or "dome" formations (several reconditioned mines are also used as gas storage facilities).

Each reservoir has its own physical characteristics. Some are more porous than others, some are more permeable, and others have higher deliverability rates and cycling capacity. For instance, as shown in Table 10.1, salt caverns have much more flexibility than reservoirs and aquifers because of the lower requirements of base gas and shorter injection and withdrawal periods. Reservoirs and aquifers typically require a cushion of 50 percent or more of the total volume of gas in a facility, while the salt cavern needs only about 33 percent. In addition, the withdrawal period for salt caverns is only about 10 to 20 days, whereas it is 2 to 3 months for reservoirs and aquifers. Although salt caverns have the highest deliverability per storage site, they account for the least number of actual facilities and storage capacity in the U.S. The majority of stored gas is found in depleted oil and gas reservoirs. More detailed descriptions about each type of facilities are provided below.

Table 10.1

Characteristics of Natural Gas Storage Facilities

Storage Type	Number of Facilities	Cushion to Working Gas Ratio	Injection Period	Withdrawal Period	Injection/ Withdrawal Flexibility
Depleted Reservoir	336	2:1	7-8 months	2-3 months	Low
Aquifer	49	2:1	7-8 months	2-3 months	Low
Salt Cavern	28	1:2	20-40 days	10-20 days	High

Source: Energy Information Administration (2001b) and Lagrasta et al. (1999)

Depleted Reservoir: The most common type of underground storage is depleted reservoirs. These shallow, high-deliverability fields take advantage of existing wells, gathering systems, and pipeline connections. Reservoirs are most commonly used because of their wide availability and existence near existing pipeline infrastructure and major consumption areas. The geology of these fields is also well known since they have already been used as producing fields.

However, because these reservoirs are old, they require a considerable amount of maintenance and monitoring to ensure gas is not being lost through a leak or into other permeable reservoirs. Also, as mentioned previously, reservoirs typically require 50 percent base gas.

Aquifer Storage: Aquifers offer a storage alternative when depleted reservoirs and salt caverns are not available. An aquifer storage field is defined as a "sub-surface facility for storing natural gas consisting of water-bearing sands topped by an impermeable cap rock" (Energy Information Administration 2001c). Natural gas is injected at the top of the formation (which is saturated with water), and displaces the water down throughout the structure.

Aquifers exist mainly in the upper Midwest due to that region's lack of depleted oil and gas reservoirs. Typically, aquifers are close to end user markets, have high deliverability from the combination of high quality reservoirs and the water drive during the withdrawal cycle. This increases the ability to cycle the working gas volumes more than once per season.

Aquifers do, however, have drawbacks. Primarily, because of the water drive mechanism, the base gas requirement can be as high as 80 percent of the total gas volume. And a large percentage of base gas is not recoverable after the site has been abandoned. In addition, the lack of wells or production infrastructure – like those found at depleted reservoirs – and the need to test and characterize the geology and suitability of the rock formations for storage, can result in long development times and high development costs. Although existing water can help to increase the deliverability of the gas, it adds to operating costs as water production is often experienced during the withdrawal cycle.

Salt Cavern Storage: Salt cavern storage sites are mined or leached underground cavities. This includes either salt caverns (in either bedded salt formations or salt domes) or rock caverns (e.g., coal mines). Caverns are ideal in that when filled with natural gas, they act as high pressure storage vessels with low base gas requirements (33 percent and can approach 0 percent in emergencies) and operational flexibility. Because of the low base gas requirements and high deliverability from pressure, these facilities can cycle working gas four to five times per year. They also provide excellent seals – the salt cavern walls are essentially impermeable barriers – and the risk of gas leaks is small.

The primary disadvantage of the salt cavern is the high cost of development. The leaching process – a process in which water is flushed through the cavern to dissolve the salt and flush it out – involves the circulations and disposal of enormous amounts of fresh water. "Cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas capacity, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each thousand cubic feet of gas injected and withdrawn" (Energy Information Administration 2001c).

10.3 Industry Characteristics

As of December 2000, there was about 3.9 tcf of underground natural gas storage working gas capacity in the U.S., with an associated maximum deliverability of nearly 78 bcf/d. There are currently about 415 storage facilities operating in the U.S. Based on capacity, 86 percent of these facilities are depleted reservoirs, 10 percent are aquifers and 4 percent are salt caverns. As shown in Figure 10.2, working gas capacity is compared to deliverability; the salt caverns' percent of total expands from 4 percent to 15 percent, whereas depleted reservoirs fall from 86 percent to 74 percent. Aquifers stay about the same at 10 and 11 percent.

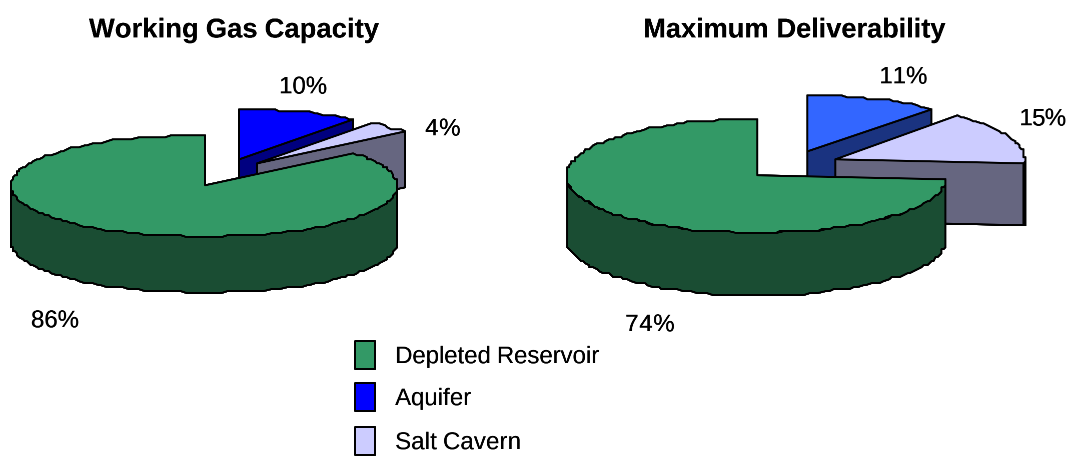

Figure 10.2. U.S. Natural Gas Storage Distribution.

Source: Gas Technology Institute (1997)

Geographic Locations: As shown in Table 10.2 and Figure 10.3, many reservoirs are located near major Northeast and Midwest centers for winter heat demand. As shown in the figure above, depleted reservoirs account for 86 percent of working gas capacity in the U.S. One half of this capacity and 55 percent of depleted reservoir deliverability is found in the Northeast. In the Midwest, depleted reservoirs are supplemented by storage in groundwater aquifers, which account for 9 percent of total U.S. working gas capacity and 10 percent of total U.S. deliverability.

Table 10.2

Summary of Underground Storage, by Region and Type (2000)

Region	Depleted Gas/Oil			Aquifer Storage			Salt Cavern			Total		
	no.	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	no.	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	no.	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	no.	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)
East	243	1,690	31,888	33	351	7,457	4	4	298	280	2,045	39,643
West	31	590	8,620	6	39	1,175	-	-	-	37	628	9,795
Gulf	74	1,089	17,166	1	1	12	23	135	11,118	98	1,226	28,296
Total	348	3,369	57,674	40	391	8,644	27	139	11,416	415	3,899	77,734

Note: Regions are established by the American Gas Association. AGA defines the Producing (Gulf) Region as TX, LA, MS, AR, OK, KS, NM; the Eastern Consuming Region as all States east of the Mississippi River less MS, plus IA, NE and MO; the Western Consuming Region as all States west of the Mississippi River less the Producing Region and IA, NE and MO.

Source: Energy Information Administration (2001c)

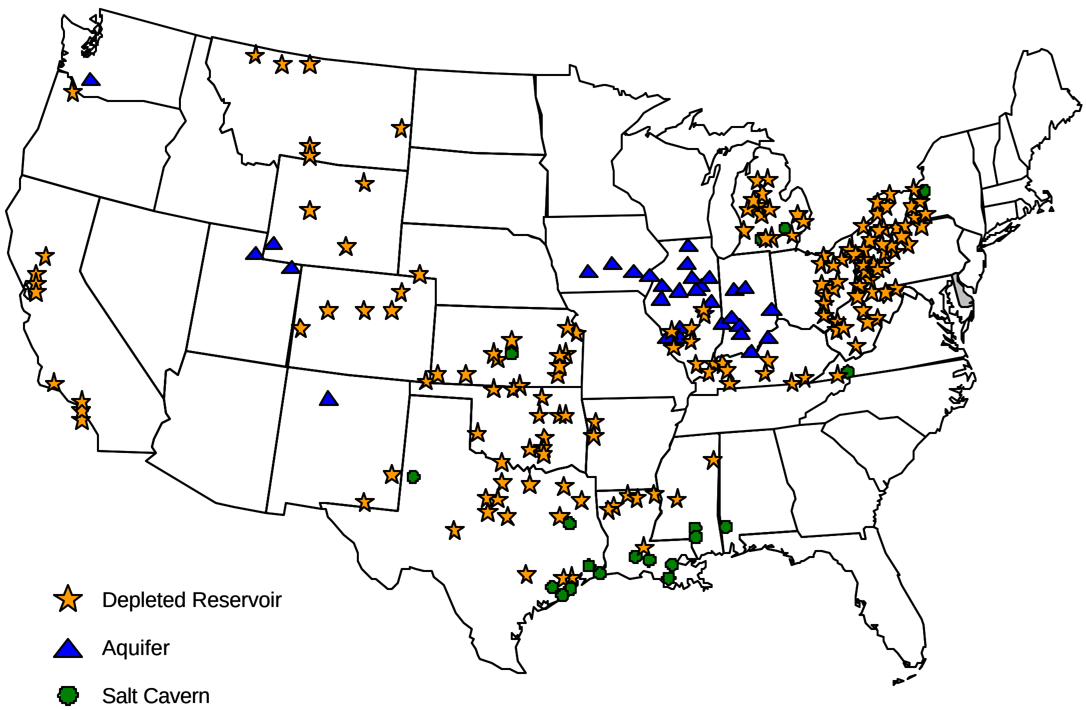

Figure 10.3. Locations of Existing Natural Gas Underground Storage Fields in the U.S.

Note: This figure is for illustrative purposes only. Exact locations and number of fields in this figure cannot be guaranteed.
Source: Energy Information Administration (2001b)

The Gulf Coast has a mix of depleted reservoir and salt cavern storage. In fact, almost all of salt cavern storage facilities operating in the U.S. have been developed in Gulf Coast states. Out of all the facilities in the U.S., Gulf Coast salt caverns account for only 3.5 percent of working gas capacity and 14 percent of deliverability. But, because there are only 4 other salt caverns located in areas outside of the Gulf States, the working gas capacity of salt caverns and deliverability in the Gulf region is over 97 percent of all salt caverns.

Users of Underground Storage: Although the functions of market players in the storage industry have changed over the past decade, in general, the same end-users have benefited from service from the same facilities (pipelines and storage) and received their gas from the same group of producers. Once, it was the interstate pipelines that owned the majority of storage capacity. Storage was an essential organizational function for interstate pipelines. However, as explained in Chapter 7, the passing of Order 636 created open access and eliminated merchant gas sales making the pipelines' storage areas essentially function as warehouse operations. Pipelines may still operate the storage facilities, but the Local Distribution Company (LDC) owns the gas stored in them, basically paying rent. Pipelines are allowed to retain gas in storage only as required for operational integrity. Today, a number of major pipelines systems are able to operate without the benefit of storage service for the shippers or the pipeline's operational control.

Interstate Pipelines own 66 percent of the total working-gas storage capacity, but most of this capacity is under contract to others. About 8 percent of the storage capacity owned and operated by pipeline companies is actually used by the pipelines for operational balancing. The remainder is contracted to others, primarily the LDCs that were granted access to storage and transportation when the pipelines were required to abandon their merchant services under Order 636 (Cates 2001).

LDCs own and operate about 31 percent of the total working-gas capacity in the U.S. LDCs are also the primary contract holders of pipeline storage capacity, giving them ownership or contractual rights to about 73 percent of the total storage capacity (Cates 2001). LDCs are responsible for serving their customers during peak demand periods regardless of price. They use storage for seasonal baseload and peaking service – to serve their customers directly. This type of capacity owner is primarily located in the northeast and usually inject into storage starting in May and ending in October. In some cases, LDCs are required to make injections into storage to meet their anticipated winter demands, regardless of price.

The regulatory changes that led to the commoditization of natural gas created the environment in which gas marketing companies were born. *Gas Marketers* move gas in and out of storage as changes in price levels present arbitrage opportunities.[46] The use of storage to support arbitrage and hedging of natural gas contracts can be extremely profitable, but also carries a great degree of risk. Although this opportunity is available to LDCs, most do not participate due to restrictions placed by the state regulatory commissions. Not subject to these restrictions, marketers have taken positions in storage facilities around the nation to enhance their opportunities. For marketers, seasonal factors no longer govern the use of underground storage inventory – supply, demand, and prices play a larger role. This role is so large that marketers have increased their effective control of storage assets from nearly nothing just a few years ago to nearly 25 percent of all capacity available today.

Recently, however, in the wake of the Enron scandal and the exposure of other marketers' unscrupulous tactics, the midstream sector of the natural gas industry has been transformed. Existing players are fighting for financial survival. "The ranks of the middlemen marketers who did much of the fixed price trading of monthly baseload have been decimated, and those remaining are laboring under creditworthy burdens and a constant stream of new accusations and ratings hits. It will take time for the new entrants in the market to expand their trading books" (Foster Natural Gas Report 2003).

Intrastate pipelines use storage for operation balancing and system supply as well as to serve end-use customers. "The value of storage for intrastate pipelines, whether procured as an equity investment or as a service lease, is essentially identical to that for a [marketer]. Thus, the value is defined by the contribution that the storage service brings to their gas sales function. This includes the value available to suppliers in swing supply gas sales, emergency back-up gas sales, balancing, and no-notice service sales as well as incidental income from arbitrage opportunities and peaking sales" (Gas Technology Institute 1997).

The newest members to the group of storage owners are independent storage developers. These are typically small firms that are able to secure institutional or private financing. They are not associated with LDCs, pipeline companies, or oil and gas firms – hence the name "independent." As with marketers, developers have the ability to take advantage of price

[46] Arbitrage refers to the trading of the same commodity on multiple markets in order to capture the value of any pricing variations that occur between those markets.

variations, employ arbitrage strategies, and develop an asset from which to sell value-added gas supply services.

10.4 Regulations

Almost all storage facilities are subject to either state or federal regulation. A storage facility may or may not be subject to Federal Energy Regulatory Commission (FERC) regulation depending on the market it serves. Just like pipelines, if the facility serves the interstate market, it is subject to FERC regulations. Otherwise, the facility is state regulated. Today, almost all of the underground storage facilities that are subject to FERC jurisdiction operate on an open-access basis. This means that the major portion of working gas capacity at each site must be made available for lease to third-parties on a nondiscriminatory basis. Before Order 636, how capacity was used was the decision of the pipeline owner.

The open-access regulations originally enacted in 1985 with FERC's Order 436 began the transformation of the natural gas commodity market from a tightly regulated "cost of service" pricing structure to the free and open market in place today. FERC issued Order 636 in 1992, completing the transition to a deregulated natural gas commodity market. This marked the end of most of the traditional pipeline merchant services. Pipelines' access to storage was one aspect to which FERC paid particular attention. FERC felt storage provided pipelines an unfair competitive advantage by making the transportation component of firm pipeline sales service far superior to the service pipelines offered to unaffiliated shippers (Cates 2001).

Since this transformation, many storage projects have received approval to charge market-based rates. This allows pipelines to collect for project financing, which was not allowed with cost-based rates. Market-based rates are particularly important in the development of new storage projects because they give the project sponsors the flexibility to craft rates and terms of service tailored to their customers' needs.

Unbundling at the state level may be a much more important issue for the growth of the storage industry than federal regulatory change has been. It is likely that LDCs will become more peak sensitive, requiring more balancing across shippers, resulting in continued disaggregation of utility loads, and shifting gas supply responsibilities back to suppliers. Meanwhile, the uncertainty of outcomes will likely preclude significant investment by LDCs in storage assets and may result in the growth of large supplier/aggregators.

10.5 Industry Trends and Outlook

Figure 10.4 highlights the difference between the utility storage holders of the East Coast region and energy marketers of the Gulf Coast region. The gas storage patterns show that the East Coast region working gas volumes have peaked at 1,918 bcf over the last 7 years with a variance of only 17 bcf. Utilities meet their commitments to deliver gas in the winter by filling their storage during the summer. Gulf Coast storage levels are more variable, averaging 770 bcf at the beginning of the withdrawal season over the last 7 years with a variance of 250 bcf – gas marketers fill and withdraw storage based on their ability to capture price arbitrage.

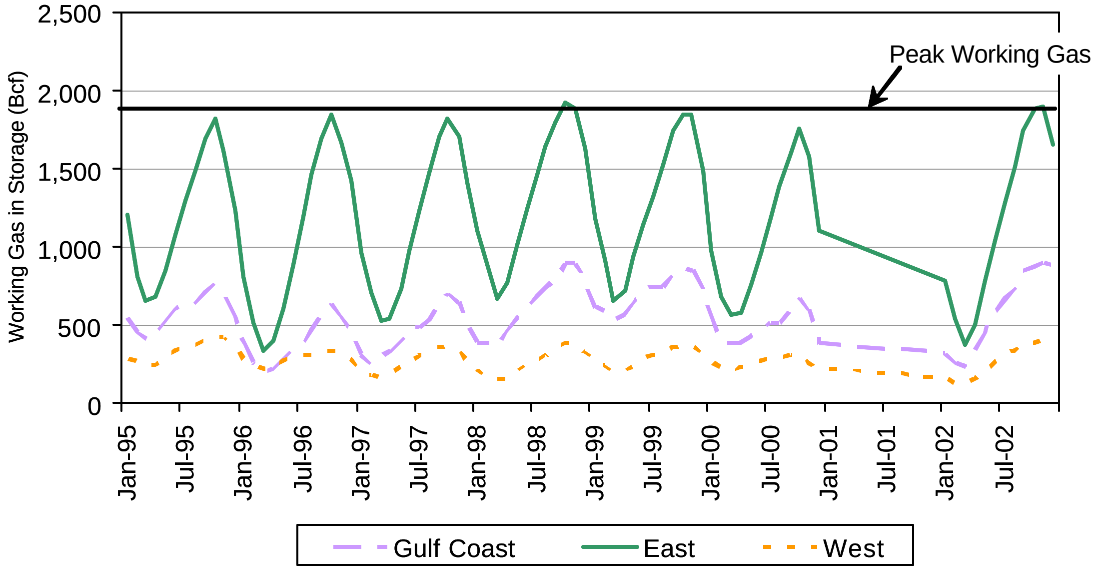

Figure 10.4. Working Gas in Storage by Region.

Source: Dietert and Pursell (2000) and Energy Information Administration (2002a)

West Coast working gas is significantly smaller than the other regions and has a limited impact on the overall natural gas storage market. Storage levels are relatively consistent seasonally and they are somewhat isolated from the East Coast and Gulf Coast regions by the Rocky Mountains.[47]

The refill season of 2000 experienced somewhat high natural gas prices, driving storage injections down by about 10 percent compared to 1999. Many storage users limited their rate of injections, in anticipation that prices would drop later in the season. This led to low storage levels and in turn, increased the pressure on natural gas prices entering the winter of 2000-2001. Generally, LDCs can recover the costs of higher gas prices through their cost-of-service rates; however, restructuring has placed storage operators and marketers at greater risk of not recovering costs.

Then the 2000-2001 heating season began with two very cold months. November and December were colder than normal; 43 and 32 percent colder than the previous year, respectively. When gas demand suddenly increased in the winter of 2000-2001, gas storage levels were well below average, and gas prices reached peak levels. By the end of December, natural gas storage levels were almost 27 percent below the 5-year average for that point in the heating season. Nationally, working gas inventories ended the heating season about 5 percent below the all-time end-of-season low of 758 bcf in March 1996 (Energy Information Administration 2001d). Fortunately, milder temperatures in late January through mid-February

[47] This discussion and following figure is a replication of a discussion in the following publication, with updated data from the EIA Natural Gas Monthly, 1995 through 2001: Jeff A. Dietert and David A. Pursell, *Underground Natural Gas Storage,* (Houston: Energy Industry Research, Simmons & Company International), June 2000.

relieved the pressure on withdrawals. Had withdrawals continued at the same rate as earlier in the winter, U.S. gas in storage could have dipped below the 500 bcf level, at which withdrawals would have been very problematic. As it turned out, the U.S. storage level at the end of the season stood above that critical level at 724 bcf (Gas Daily 2001a).

The goal of 2001 was to replenish storage to normal levels. By the middle of June – only two-and-a-half months into the refill season – storage levels were half full. For the week ending June 15, 2001, 106 bcf was placed into underground facilities, putting storage levels 115 bcf ahead of where they were in 2000 and 42 bcf ahead of the previous 5-year average (Gas Daily 2001b). Injections continued at a record pace, and by July, storage inventories were 59 percent full. Despite four consecutive weeks of colder temperatures in February and March of 2002, an overall milder winter in 2002 kept working gas at almost 39 percent or nearly 500 Bcf above the 5-year average of 1,251 bcf (Energy Information Administration 2002b).

Inventory: Based on a 2001 survey conducted as part of development of this Fact Book and GIS database, 20 natural gas storage facilities are located in the Gulf region; 9 in Texas, 7 in Louisiana, 3 in Mississippi, and 1 in Alabama. Of the 20 fields, 15 are salt domes and the remaining five are depleted reservoirs. Capacity ranges from 2,700 to 120,000 MMcf.

New Additions: A number of new storage facilities were announced in 2002 – a number of which are salt caverns located in Gulf States. Some of these additions/expansions include:

- Market Hub Partners (a unit of Duke Energy Gas Transmission) is proceeding with plans to convert an underground salt dome in Copiah County, Mississippi into a 3 bcf storage facility. Market Hub Partners estimates the facility to be online as early as spring 2004. The facility is in close proximity to a number of interstate pipelines and already plans on expanding by as much as 6 bcf of additional storage capacity (Gas Daily 2001c).

- A new storage facility in Lamar County, Alabama will have a capacity of 2 bcf with deliverability of 20 MMcf/d. Northwest Alabama Gas District is in the process of completing the conversion of the depleted gas reservoir and says that it may be able to expand the facility to 8 bcf with 120 MMcf/d of deliverability. Since the utility will only use about 1 bcf to serve the needs of its customers, it is looking for interested parties and is also working with power companies that are considering building a power plant at the site of the storage facility (Gas Daily 2001d).

- Bay Gas Storage is in the process of leaching the McIntosh salt dome formation in McIntosh, Alabama. The cavern, when complete will have a total working gas capacity of 3.5 bcf. The leaching process is scheduled for completion by December 2002. This is the company's second gas storage cavern in McIntosh. When it is completed, Bay Gas will have a total working gas capacity of 6 bcf and a withdrawal capacity of 225 MMcf/d (Gas Daily 2001e).

- Unocal Global is constructing a high deliverability salt cavern near Kermit, Texas called the Keystone Gas Storage Project. The facility should begin operations in the summer of 2002. It is projected that the Keystone project will initially have 3 bcf of capacity, with 100 MMcf/d injection and 200 MMcf/d withdrawal capacity (Unocal 2001).

- Virginia Gas and Duke Energy are working on expanding capacity at a Saltville, Virginia facility. The companies plan to expand the salt cavern facility from 1.1 bcf to 10 bcf and build an interconnect with East Tennessee Natural Gas System (also owned by Duke). At full capacity the Saltville site will be able to deliver up to 500 MMcf/d to area markets (Gas Daily 2001f).

- Seneca Lake Storage plans to develop a high deliverability natural gas storage facility in depleted salt caverns in Reading, New York. The facility should be operational by November 2002 and will have a working gas capacity of 300,000 decatherms (dth) and a deliverability of 50,000 dth/d.

Evolution of R&D Needs: "As peak day natural gas demand continues to grow, the need for more flexible gas storage will also increase. With increasing peak requirements for all regions, caused primarily by growth in residential space heating, peaking storage (5 to 20 days) rather than seasonal storage (over 70 days) will be needed. The need for increased deliverability is also influenced by the fact that overall storage deliverability will naturally decline due to factors related to the age and condition of the wells and infrastructure" (Gas Technology Institute 1997). This does not include the amount of natural gas that will be needed to fuel new electric power plants projected to be built in the next 20 years.

New methods of storing gas are being researched. Particularly in areas that do not have the right geology for conventional gas storage in underground formations (i.e., South Atlantic, Pacific Northwest). And in some areas, where suitable geology exists, existing conventional storage does not meet the requirements of end users. The Department of Energy's Strategic Center for Natural Gas has awarded over $2.5 million in contracts to major universities and corporations to research and develop ways to help expand the gas storage system. Current technology development efforts include (Office of Fossil Energy 2002):

- Novel and advanced fracture simulation technologies and improved remediation treatments that will increase storage reservoir deliverability and help to offset the reported 5.2 percent annual decline in deliverability.

- The development of improved gas flow metering and energy measurement technologies that will provide real-time, automated monitoring of pipeline gas flow and energy content, increasing system deliverability, and optimizing gas sales to customers; and

- Advanced storage technologies that will meet the specific storage needs of new and growing industrial and power generation markets, specifically the short-term or hourly requirements of the power generation sector.

The development of advanced technologies would result in a more efficient natural gas storage system, benefiting both industry and consumers. The industry would gain from increased deliverability, decreased revitalization costs, and increased operating efficiency. Improved system reliability and flexibility would benefit LDCs, industrial, and power generation end-users, while residential customers would gain from lower costs of service.

11.0 REFINERIES

11.1 Introduction

Petroleum is a mixture of liquid hydrocarbons usually located beneath the earth's surface. The exact composition of these hydrocarbons – which are found in both gaseous and liquid form – varies according to locality. Hydrocarbons found in the gaseous state are called "natural gas", whereas that in the liquid form is "petroleum". Crude oil is a mixture of hydrocarbon compounds and relatively small quantities of other materials such as oxygen, nitrogen, sulfur, salt, and water. It varies by site in color and composition, from a pale yellow, low viscosity liquid to a heavy black 'treacle' consistency. Because it is of little use in its raw state, further processing of crude oil is necessary to unlock the full potential of this resource.

A refinery is an organized arrangement of manufacturing units designed to produce physical and chemical changes to turn crude oil into petroleum products. In the refinery, most of the non-hydrocarbon substances are removed from crude oil and it is broken down into its various components, and blended into useful products.

Petroleum provides many such products, the most notable being motor gasoline and heating fuel. Its many uses include fuel for automobiles, trucks, agricultural and industrial machinery, trains, ships, and aircraft. Petroleum is used to heat homes, offices, and factories and to grow, process, package, distribute, refrigerate, and cook food. Petroleum is also a source of synthetic fabric for cloths as well as detergents and dry cleaning solvent. Moreover, it provides a chemical base for cosmetics and pharmaceutical products as well as for many plastic products from toys to building materials (Energy Information Administration 1999c). The following are just a few products that get their start in a refinery:

- Ammonia
- Antiseptics
- Bubble gum
- Crayons
- Denture adhesive
- Eyeglass frames
- Fertilizer
- Floor polish
- Guitar strings
- Heart valves
- Ice chests
- Insect repellant
- Life preservers
- Liquid detergent
- Mascara
- Paint
- Pingpong paddles
- Plastic beverage containers
- Roller-skate wheels
- Sneakers
- Synthetic fibers
- Telephones
- Tobacco pouches
- Volleyballs

Figure 11.1 provides a depiction of additional petroleum products and 1999 percent refinery yields for each product category.

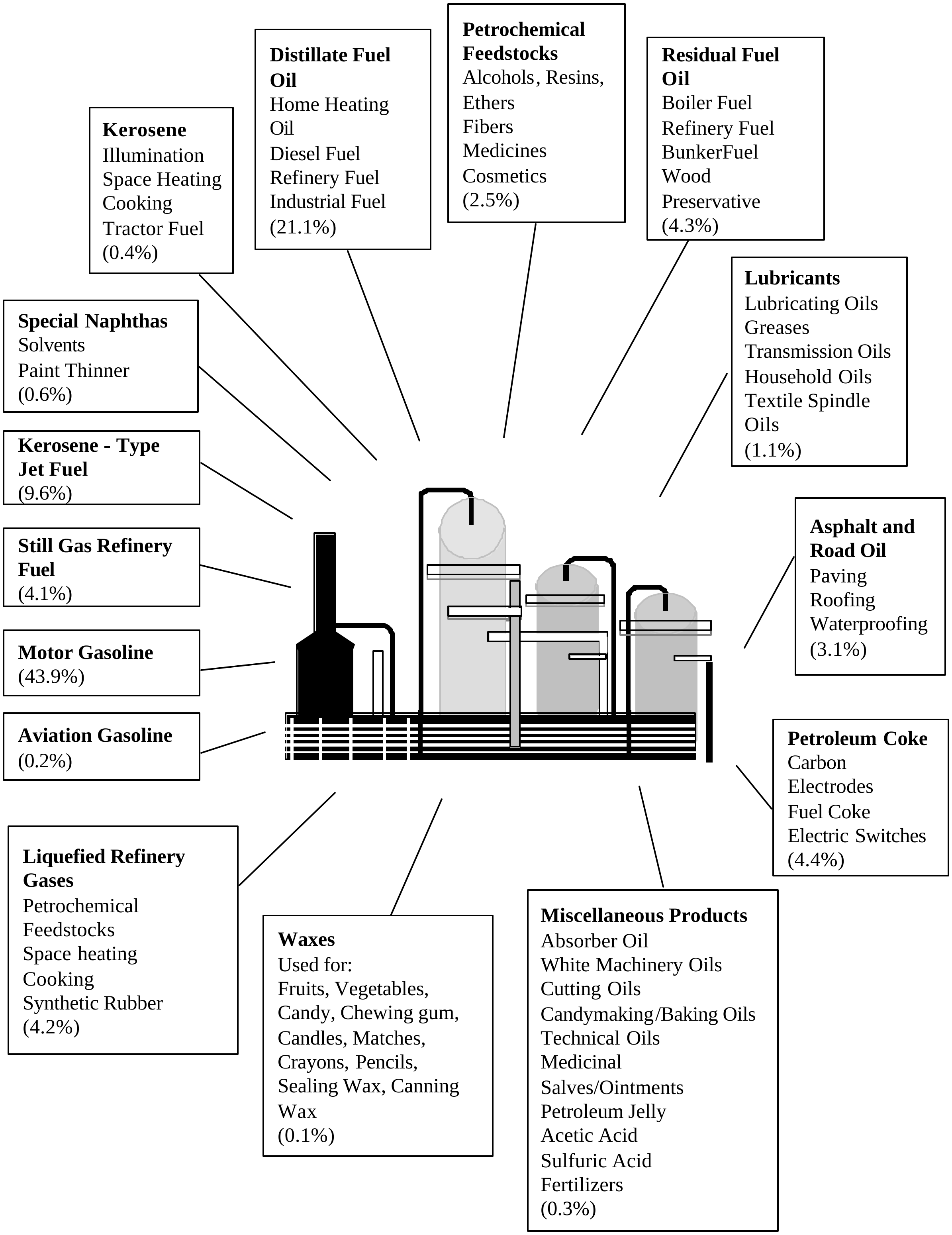

Figure 11.1. Petroleum Products and Uses (1999 Percent Refinery Yield).

Source: Energy Information Administration (1999c)

11.2 Description and Typical Facilities

Refineries vary in size, sophistication and cost depending on their location, the types of crude they refine and products they manufacture. Because crude oil is not a homogeneous raw material – varying in color, viscosity, sulfur content and mineral content – that which is produced from different fields or geographic areas have different quality characteristics that give rise to different values.

Every refinery begins with the separation of crude oil into different fractions by distillation. The fractions are further treated to convert them into mixtures of more useful saleable products by various methods such as cracking, reforming, alkylation, polymerization and isomerization. These mixtures of new compounds are then separated using methods such as fractionation and solvent extraction.

Because there are various blends of different crude oils available, different configurations of refining units are used to produce a given set of products. A change in the availability of a certain type of crude oil can affect a refinery's ability to produce a particular product. For instance, one important crude quality is gravity. Gravity is a measure of the density of the crude oil – the lower the gravity of the crude, the "heavier" the crude. Heavy oil is viscous, does not flow well and has a high carbon to hydrogen ratio along with a high amount of carbon residues, asphaltenes, sulphur, nitrogen, heavy metals, aromatics and/or waxes. Conversely, if crude oil has a higher gravity, the crude oil is lighter.

A second quality measure is sulfur content. Sulfur content is usually measured in terms of the percentage of the crude's weight that is comprised by sulfur. Low sulfur or "sweet" crudes typically have less then 0.5 percent sulfur. Crude oil considered high sulfur or "sour" typically has over 0.5 percent sulfur content. These quality characteristics are often identified in crude oil naming conventions, e.g., Heavy Louisiana Sweet, West Texas Intermediate, and Wyoming Sour. Each of these names corresponds to a crude stream from a particular producing area or field with a well-recognized set of quality characteristics.

These two qualities (gravity and sulfur content) are important in refining. Heavy crudes require more sophisticated processes to produce lighter, more valuable products; therefore, they are expensive to manufacture. Because of its corrosive qualities, higher sulfur content makes crude more expensive to handle and process. In general, light crudes are more valuable, i.e., they yield more of the lighter, higher-priced products than heavy crudes. The product slate at a given refinery is determined by a combination of demand, inputs and process units available, and the fact that some products are the result (co-products) of producing other products.

Development of the Refining Process: Refinery processes have developed in response to changing market demands for certain products. A summary of the refining process is presented in Figure 11.2.

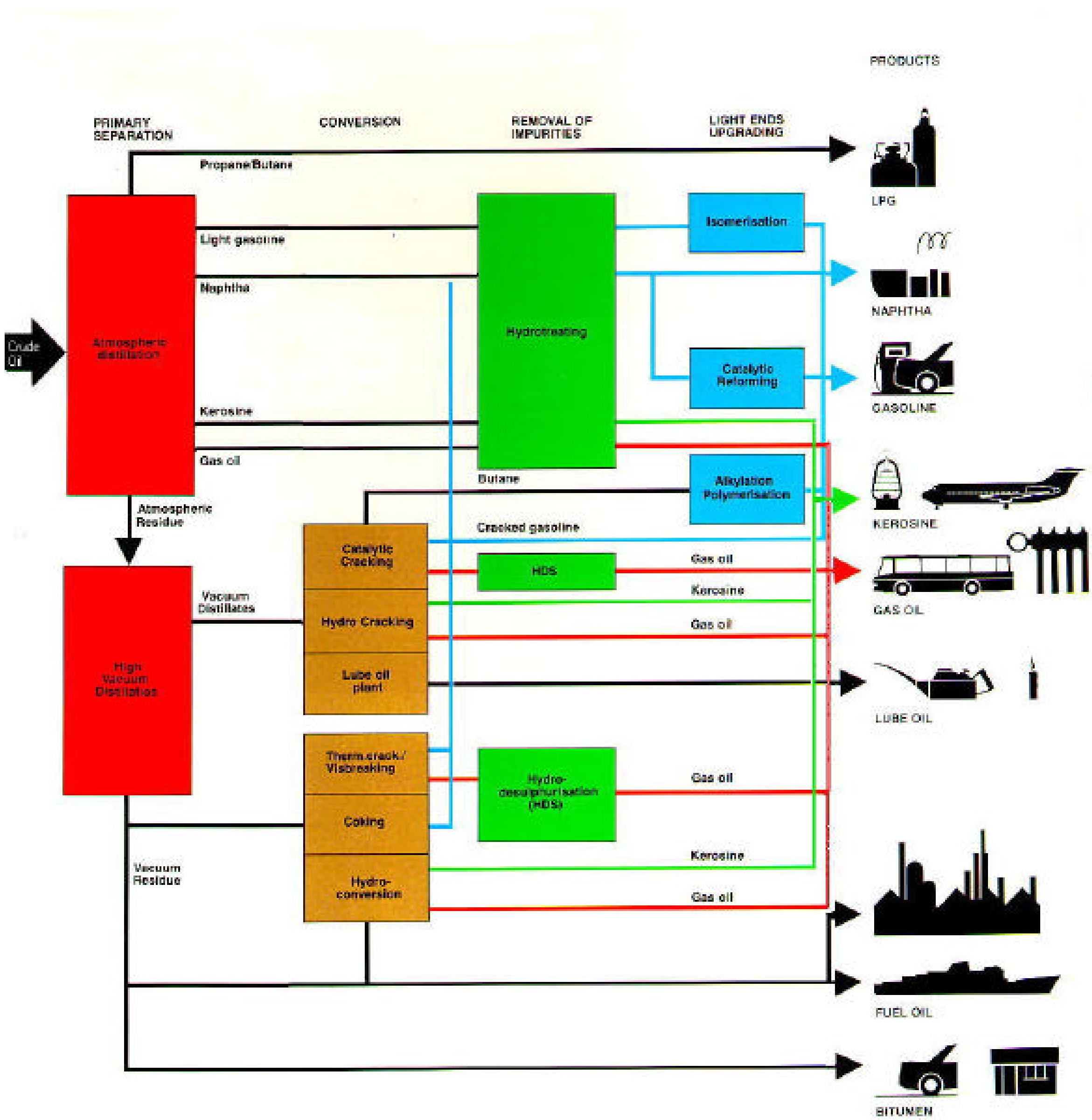

Figure 11.2. The Refining Process.

Source: Australian Institute of Petroleum (2000)

The practice of refining began with the simple distillation of many different raw materials in Europe in the 18th century to see if new products could be obtained. Coal, shale, tar, and whale oil were all experimented with. As the demand for coal oil and kerosene, although odorous and smoky, began to grow with an increasing need for illumination, the discovery of a process for making a clean burning fuel met a ready market.[48]

The new industry of petroleum refining focused on crude oil distillation for kerosene until two significant events changed the market: (1) the invention of electric light decreased the demand for kerosene and (2) the invention of the internal combustion engine created a demand for diesel fuel and gasoline. In the early 1900's, the growing number of automobiles rapidly increased the demand for motor fuel and stimulated the development of new refinery processes to increase gasoline yields and improve the quality of the finished product.

The first downstream process that changed the petroleum refining industry was *thermal cracking*, which subjects heavy fuels to both pressure and intense heat, physically breaking the large molecules into smaller ones to produce additional gasoline and distillate fuels.

Other refining developments followed in the late 1920's and early 1930's:

- ***Polymerization*** produces high octane gasoline from by-products of thermal cracking (olefins).

- ***Vacuum distillation*** further processes the product remaining in the bottom of the crude oil distillation column that will not distill at atmospheric pressure.

- ***Vis-breaking***, another thermal cracking process can make product left from the vacuum distillation flow more easily. This process reduces the product's viscosity (the thick, gluey quality that impedes product flow).

- ***Coking***, another severe thermal process, produces fuel gas, gasoline blending stocks, distillates, and petroleum coke from products left from atmospheric or vacuum distillation.

- ***Alkylation**,* a process in which a catalyst is used to produce a high quality gasoline component was developed during World War II when the petroleum industry focused its technological expertise on products essential to the war effort, especially high quality aviation fuel. This process became widely used after the war to produce gasoline blending stocks.

Other technological advances included *catalytic cracking* and *isomerization*. Similar to thermal cracking, catalytic cracking utilizes a catalyst to accelerate the rate of the reaction. Isomerization uses heat and a catalyst to convert straight-chained hydrocarbon molecules to branched-chained hydrocarbon molecules with the same chemical composition. This produces high quality gasoline blending stocks called isomers and increases the octane number of the light gasoline components, normal pentane and normal hexane, that are found in light, straight run gasoline.

A major development in the late 1940s was *catalytic reforming*, a process for converting low grade naphthas to high octane gasoline. In the mid-1950s a process called *hydrotreating* was

[48] Unless otherwise noted, the information in this sub-section is based on: Energy Information Administration, *Petroleum: An Energy Profile*, (Washington D.C.: Department of Energy), July 1999c, pg. 27-28.

developed to remove contaminants that would damage the catalyst used in catalytic reforming. *Hydrocracking*, a process using hydrogen and catalysts to convert middle boiling range or residual products into lighter products was developed in the 1960's.

11.3 Industry Characteristics

As of January 1, 2001, the 150 petroleum refineries in the U.S. ranged in size from small refineries able to process 5,000 barrels of crude oil per day to those able to process more than 400,000 barrels per day. Their combined crude oil refining capacity totaled over 16 million barrels per calendar day.

As with most aspects of the U.S. oil industry, the Gulf Coast is by far the leader in refinery capacity (Figure 11.3). Over 45 percent of the total U.S. refining capacity resides in the Gulf Coast region, which holds over one-third of the petroleum refineries in the U.S. As shown in Figure 11.3, most of the region's refineries are located in Texas and Louisiana. Texas has 26 refineries, with a combined crude oil distillation capacity of over 4 million barrels per day. Louisiana has 17 refineries with over 2.6 million barrels per day of distillation capacity. [49]

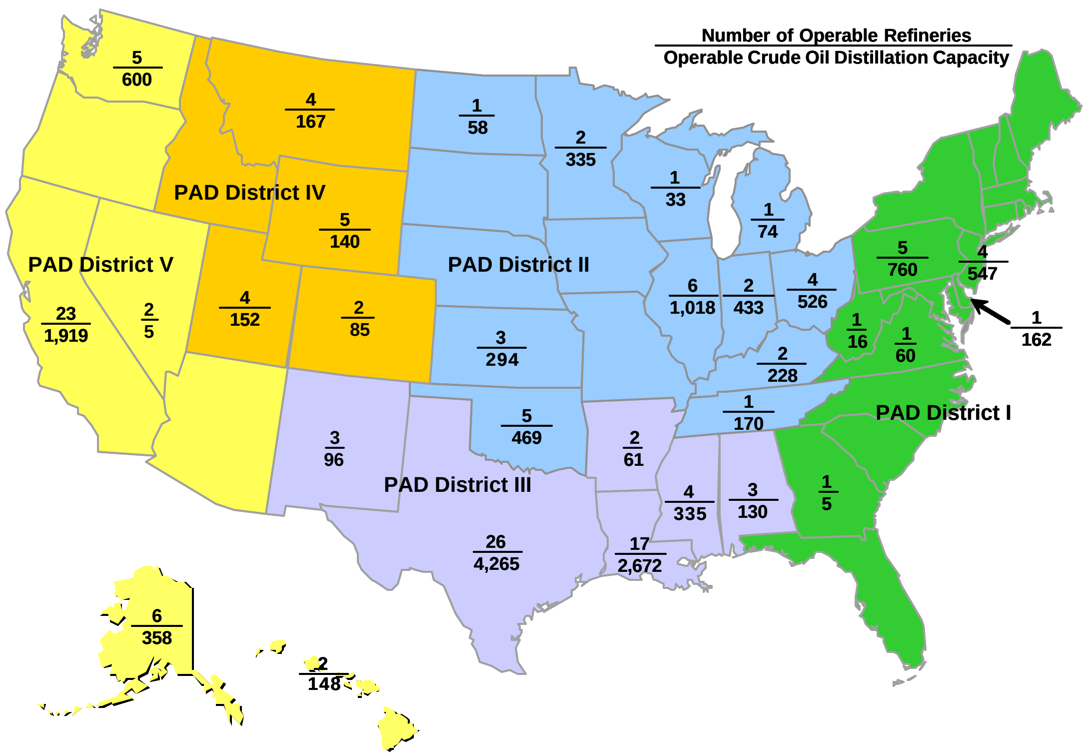

Figure 11.3. U.S. Refineries and Capacity by State as of January 1, 2001.

Note: PAD District stands for Petroleum Administration for Defense Districts. These districts were delineated during World War II to facilitate oil allocation.

Source: Energy Information Administration (2001e)

[49] This discussion is replicated from Energy Information Administration, *Petroleum: An Energy Profile*, (Washington D.C.: Department of Energy), July 1999, pg. 29-30; with figures updated from Energy Information Administration, *Petroleum Supply Annual 2000, Volume 1,* (Washington D.C.: Department of Energy), June 2001, p. 80.

Table 11.1 shows the "top ten" refining states in the U.S. These states – with the highest individual crude oil distillation capacity – account for 65 percent of the number of operable refineries and 81 percent of the U.S. total distillation capacity.

Table 11.1

Top Ten Petroleum Refining States as of January 1, 2002

State	**Number of Operable Refineries**	**Operable Crude Oil Distillation Capacity**
		(bbl/d)
Texas	26	4,265,430
Louisiana	17	2,672,200
California	23	1,919,150
Illinois	6	1,017,885
Pennsylvania	5	760,000
Washington	5	599,880
New Jersey	4	547,000
Ohio	4	525,500
Oklahoma	5	469,095
Idaho	2	433,000
Subtotal	**97**	**13,209,140**
U.S. Total	**150**	**16,320,171**

Source: Energy Information Administration (2001e)

The Gulf Coast is also the nation's leading supplier in refined products as in crude oil. It ships refined product to both the East Coast (supplying more than half of that region's need for light products like gasoline, heating oil, diesel, and jet fuel) and to the Midwest (supplying more than 20 percent of the region's light product consumption).[50]

As shown in Figure 11.4, the East Coast imports over half of all of the products that come to the U.S., because it is the largest consuming area in the U.S. And, for historical reasons, it has only enough capacity to meet around one-third of those needs from its own refining capabilities. As shown in Figure 11.5, the East Coast fills the product gas with supplies from other parts of the U.S., particularly the Gulf Coast and with imports. Its limited volume of refining capacity also keeps it a distant third as a crude importer. However, because its local production is so small, its crude import dependency is the highest of all regions, at almost 100 percent.

[50] This, and the rest of this Section's discussion is taken from: Energy Information Administration, *Oil Market Basics,* (Washington D.C.: Department of Energy), http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/oil_market_basics/default.htm, (4 June 2002).

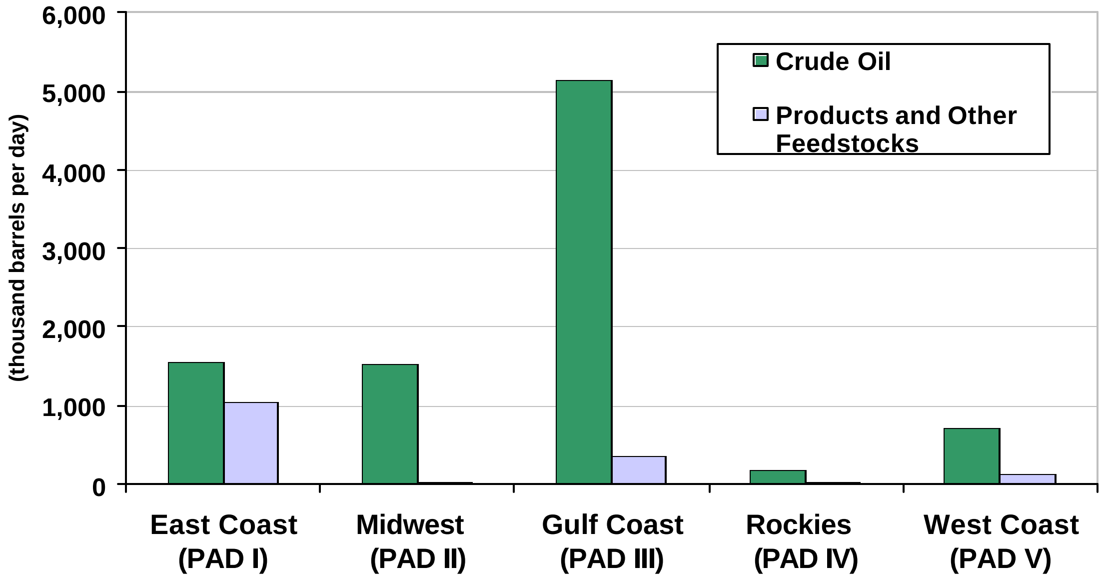

Figure 11.4. Imports of Crude Oil and Petroleum Products by PAD District (2000).

Note: PAD District stands for Petroleum Administration for Defense Districts. These districts were delineated during World War II to facilitate oil allocation.

Source: Energy Information Administration (2002b) and Energy Information Administration (2001e)

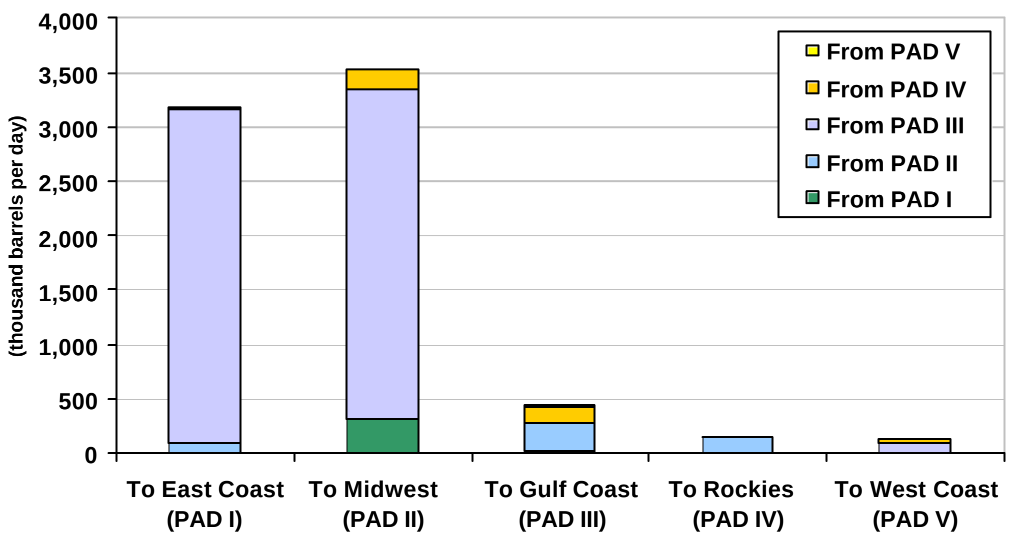

Figure 11.5. Movements of Petroleum Products between U.S. Regions (2000).

Note: PAD District stands for Petroleum Administration for Defense Districts. These districts were delineated during World War II to facilitate oil allocation.

Source: Energy Information Administration (2002b) and Energy Information Administration (2001e)

The only other region that imports significant amounts of products is the Gulf Coast. Its focus is not, like the East Coast's, on products that can be supplied directly to the consumer, but on refinery feedstocks and blendstocks, to support its role as the main U.S. refining and petrochemical center. That role, plus the need for all the Midwest's non-Canadian crude imports to move through the Gulf Coast's ports and pipelines too, has also led to the Gulf Coast being by far the most important crude oil importing region in the United States, accounting for nearly two-thirds of the total.

As seen in Figure 11.5, the trade among regions of the U.S. is focused on the eastern half of the country. The Midwest and East Coast account for 90 percent of the inter-regional flow, the flow between PAD Districts. The Gulf Coast is by far the largest supplier, accounting for more than 80 percent of the inter-PADD flow. In contrast, the Rockies and the West Coast are isolated, in petroleum logistics terms, from the rest of the country. The easy flow of petroleum from the Gulf Coast to the Midwest and the East Coast mean that incremental supply is more readily available to those markets in the event of a demand surge or supply drop. In contrast, the West Coast, and the California market in particular, cannot so readily attract incremental supplies. Thus, the California refinery outages that occurred in the spring of 1999 resulted in a large price increase as market players scrambled for additional supply, none of which was available close at hand, or cheaply. The California market's isolation is more than just geographic: the state imposes unique and stringent quality restrictions on both its gasoline and its off-highway diesel, making what otherwise might be available to augment California product supplies unsuitable.

11.4 Regulations

Although actual refineries are not regulated economically per se, they are affected by environmental and political legislation. Also affecting the refining industry are regulations placed on the way petroleum is produced, imported, stored, transported and consumed in the U.S. The following is a description of three major changes in the petroleum industry that have directly impacted the refineries as well.[51]

Petroleum Price and Allocation Decontrol: In early 1981, the U.S. Government responded to the oil crisis of 1978-1980 by removing price and allocation controls on the oil industry. For the first time since the early 1970s, market forces replaced regulatory programs and domestic crude oil prices were allowed to rise to a market-clearing level. Decontrol also set the stage for the relaxation of export restrictions on petroleum products.

Soon after deregulation, many small refineries and older, inefficient plants could no longer compete and were forced to shut down. The loss of so many small, low-conversion refineries, which were a large source of unfinished oils, sent many sophisticated refiners overseas for intermediate oil supplies. From 1980, the last full year of price and allocation controls, to 1981, imports of unfinished oils more than doubled, jumping from 55,000 barrels per day to 112,000 barrels per day. Unfinished oils imports continued to rise and in 1993, peaked at 491,000 barrels per day. In 2000, the U.S. imported an average of 274,000 barrels per day of unfinished oils.

[51] The following descriptions are taken from: Energy Information Administration, *Petroleum Chronology of Events 1970-2000,* (Washington D.C.: Department of Energy), May 2002, <http://www.eia.doe.gov/pub/oil_gas/petroleum/analysis_publications/chronology/petroleumchronology2000.htm> (3 June 2002).

Decontrol of crude oil prices allowed producers to raise prices to the market-clearing level for the first time since the early 1970s, and domestic crude oil prices became more closely aligned with foreign crude oil prices. The production sector responded by increasing crude oil exploration and production in the lower 48 states during the first half of the 1980s. However, sharply falling oil prices in 1986 reversed this upward trend in domestic exploration and production. Increases in Alaskan North Slope (ANS) production during this period aided the domestic crude oil situation. This helped to stem the flow of imported crude oil, greatly reducing U.S. reliance on OPEC crude oil. Imports remained low until crude oil prices collapsed in 1986.

<u>Reid Vapor Pressure Regulations of 1989 and 1992:</u> To combat emissions of volatile organic compounds (VOC's) and other ozone precursors, the Environmental Protection Agency implemented a two-phased program limiting summertime motor gasoline volatility (the rate at which gasoline evaporates into the air) in some U.S. urban areas in the spring of 1989. VOC's react photochemically in the atmosphere and are a major component of smog. Lowering the vapor pressure of motor gasoline reduces concentrations. At warm temperatures and high altitudes, gasoline evaporates more readily, increasing the amount of VOC's released to the atmosphere. Alaska and Hawaii are exempt from the volatility restrictions.

- Phase I summer volatility standards went into effect in 1989. This phase mandated that the average summer Reid Vapor Pressure (RVP) in motor gasoline be reduced from 11.5 pounds per square inch (psi) to a maximum of 10.5 psi RVP, and as low as 9.0 psi RVP in certain areas of the country.

- Phase II summer volatility standards were implemented in 1992 and stayed in effect through the summer of 1994. In 1995, RVP requirements changed again with the implementation of the reformulated gasoline program. Phase II set a nationwide maximum summer RVP standard of 9.0 psi. Gasoline sold in southern cities that do not meet Federal ozone standards must meet an even stricter standard of 7.8 psi RVP.

Refiners met the Phase I standards by reducing the amount of normal butane blended into motor gasoline. Butane is a lower-cost gasoline blending component that has a relatively high RVP and high octane. To compensate for the loss in volume and octane in motor gasoline when butane was removed, refiners increased crude oil inputs and the use of catalytic cracking and alkylation units. The more stringent Phase II standards increased requirements for downstream processing (further processing of crude oil and unfinished oils that occurs after they are initially run through the crude oil distillation unit). Some refiners made large capital investments to produce high-octane, lower RVP blending components, to meet these standards.

<u>Clean Air Act Amendments of 1990:</u> Amendments to the Clean Air Act of 1970 imposed strict new controls to reduce mobile sources of air pollution. The Amendments contained six provisions to be implemented by the EPA in stages between November 1, 1992, and January 1, 2000. Four major programs to reduce harmful emissions from highway fuel were to go into effect between November 1, 1992, and January 1, 1996. These programs included:

- ***Oxygenated Fuels Program:*** As of November 1, 1992, all motor gasoline sold in most of the 39 areas of the country designated as carbon monoxide (CO) non-attainment areas must contain a minimum of 2.7 percent oxygen by weight during at least four winter months. Adding oxygenates to gasoline lowers the level of carbon monoxide produced when a car engine is turned on. Concern over poisonous nitrogen oxide emissions from the higher winter oxygen content resulted in a winter maximum of 2.0 percent oxygen by weight in California's CO non-attainment areas.

- ***Highway Diesel Fuel Program:*** As of October 1, 1993, the sulfur content of highway diesel fuel was reduced from a maximum of 0.25 percent to 0.05 percent by weight. In addition, the cetane index, which measures the self-ignition quality of diesel fuel, must be maintained at a minimum of 40. Small refineries received relief from the sulfur limit in the form of tradeable credits until December 31, 1999.

- ***Reformulated Gasoline Program:*** As of January 1, 1995, reformulated gasoline was required in the nine metropolitan areas with the worst ozone problems. Other areas may "opt in" to the program by applying to the EPA. The "opt-in" provision may be delayed for up to three years if EPA determines that not enough reformulated gasoline is available. Reformulated gasoline must meet specific composition and emission performance criteria. The core emission requirements for 1995 to 1999 prohibit any increase in nitrous oxides emissions and mandate a year-round reduction of toxic air pollutants and a summertime reduction of volatile organic compounds of 15 percent below 1990 "baseline" gasoline. By 2000, TAP and VOC emissions are to be reduced by a minimum of 20 percent. If technically feasible, a 25-percent cut will be mandated.

- ***Leaded Gasoline Removal:*** Sales of leaded motor gasoline were prohibited after 1995.

In preparation of this program, refineries began constructing oxygenates production facilities – at least 33 refineries had facilities for producing oxygenates in 1992. By the beginning of 1993, production capacity for oxygenates had increased 59 percent from 1991. Construction of desulfurization units, in particular catalytic hydrocracking and hydrotreating units, accelerated after 1980 as heavier, higher-sulfur crude oils became available to U.S. refiners. More projects were started to increase desulfurization capacity to remove sulfur from products and to comply with the 1990 Amendment's on-highway diesel fuel regulations. Small refineries lacking desulfurization equipment could choose to produce only distillate fuel oil for non-highway use or modify their current refinery processes.

11.5 Industry Trends and Outlook

The U.S. refining industry's ability to meet short-term increases in demand can also be measured by the rate at which operable capacity is utilized. The utilization rate is expressed as a percent and represents gross inputs to crude oil distillation units divided by operable capacity. This rate fluctuates as refinery operations adjust to changes in demand. It reflects changes in refinery operations more rapidly than capacity changes do. For example, capacity expansions began in response to high demand levels through the early and mid-1970s, and continued to come online even after demand peaked in 1978. At the same time, gross inputs to distillation units leveled off and turned downward in response to declining demand. As a result, refinery utilization declined steadily from 1978 to 1981, evidencing a slowdown in refinery activity that was not reflected in capacity figures until 1982 (Energy Information Administration 1999).

However, during the 1980s, the U.S. refining industry experienced a net loss of 120 refineries and approximately 3 million barrels per day of operable capacity. Conversely, there was a steady rise in U.S. demand for petroleum products after 1983. Consequently, the amount of gross inputs to refineries rose steadily every year since then. In response to rising demand for refined petroleum products, the average annual refinery utilization rate increased from 69 percent in 1981 to almost 93 percent in 2000.

The refining industry in the 1990s was also characterized by low product margins and profitability. Although demand for refined products was strong and inventories were low, capacity had "simply outpaced demand growth and industry participants have played a game of chicken in which competitors are waiting for each other to shut down their units… [b]ut nobody wants to be the first" (National Petroleum News 1996). In addition to the extra capacity, another factor that had an impact on the industry was regulatory requirements. New requirements for reformulated gasoline contributed to the overcapacity by sparking a round of upgrades that added to production ability and capacity. In addition, amendments to the Clean Air Act impaired refiners by adding capital costs in a time of flat demand.

As shown in Figure 11.6, the number of operable refineries in the U.S. has been steadily declining since the large decrease of the 1980s. However, the operable capacity has remained stable – indicating that although there has been a significant loss in the number of refineries, operating capacity in those that remain is increasing. "Falling demand for petroleum and the deregulation of the domestic refining industry in the 1980s led to 13 years of decline in U.S. refinery capacity. That trend was reversed in 1995, and 1.2 million barrels per day of distillation capacity had been added by 2000. Financial, [environmental,] and legal considerations make it unlikely that new refineries will be built in the United States, but additions at existing refineries are expected to increase total U.S. refining capacity [in the long-run]" (Energy Information Administration 2000b). Today, the refinery business is at the other end of the spectrum from the previous two decades. As stated above, the annual refinery utilization rate in 2000 was almost 93 percent. Refineries are now operating at peak capacity almost year-round, there's no spare capacity to bring on in an emergency (Fletcher 2001).

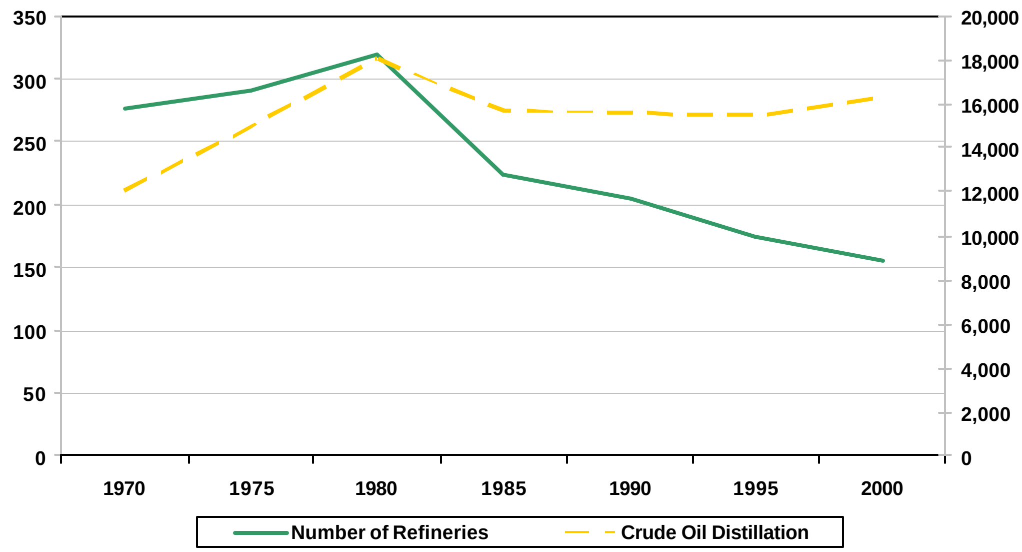

Figure 11.6. Number and Capacity of Operable Petroleum Refineries.

Source: Energy Information Administration (2001e)

According to the EIA's Annual Energy Outlook 2001, distillation capacity is projected to grow from the 2000 year-end level of 16.3 million barrels per day to 18.2 million in 2020 in the low economic growth case and 18.8 million in the high growth case, compared with the 1981 peak of 18.6 million barrels per day. Almost all the capacity additions are projected to occur on the Gulf Coast. Existing refineries are expected to continue to be utilized intensively throughout the forecast, in a range from 91 percent to 95 percent of design capacity. In comparison, the 2000 utilization rate was 93 percent, well above the rates of the 1980s and early 1990s. Additional "downstream" processing units are expected to allow domestic refineries to produce less residual fuel, which has a shrinking market, and higher value "light product" such as gasoline, distillate, jet fuel, and liquefied petroleum gases.

Inventory: Table 11.2 provides results of a 2001 inventory of refineries located in the Gulf region servicing the offshore oil industry conducted as part of development of this Fact Book and GIS database. Of the 36 facilities inventoried, 23 were located in Texas, 2 were located in Alabama, and 1 was located in Mississippi.

Table 11.2

Refineries in the Gulf Region

Name	City	State
COASTAL MOBILE REFINERY	CHICKASAW	AL
SHELL CHEMICAL	SARALAND	AL
BP AMOCO REFINERY	BELLE CHASSE	LA
CALCASIEU REFINERY	LAKE CHARLES	LA
CITGO REFINERY	LAKE CHARLES	LA
CONOCO REFINERY	WEST LAKE	LA
CONVENT REFINERY	CONVENT	LA
EXXON MOBIL REFINERY	CHALMETTE	LA
MARATHON/ASHLAND REFINERY	GARYVILLE	LA
MURPHY OIL REFINERY	MERAUX	LA
PLACID REFINING CO	PORT ALLEN	LA
ST. ROSE REFINERY	NORCO	LA
CHEVRON USA INC	PASCAGOULA	MS
BP AMOCO CORPORATION	TEXAS CITY	TX
CITGO REFINING & CHEMICALS	CORPUS CHRISTI	TX
COASTAL REFINING & MKTG	CORPUS CHRISTI	TX
CROWN CENTRAL PETROLEUM CORP	PASADENA	TX
DEER PARK REFINERY	DEER PARK	TX
EXXON COAL USA INC	BAYTOWN	TX
FINA OIL AND CHEMICAL CO	PASADENA	TX
FINA OIL AND CHEMICAL CO	PORT ARTHUR	TX
HOWELL HYDROCARBONS & CHEMICALS	CHANNELVIEW	TX
JAVELINA CO	CORPUS CHRISTI	TX
KOCH PETROLEUM	CORPUS CHRISTI	TX
LUBRIZOL CORP	DEER PARK	TX
LUBRIZOL CORP	PASADENA	TX
LYONDELL-CITGO REFINING	HOUSTON	TX
MARATHON ASHLAND PETROLEUM	TEXAS CITY	TX
MOBIL OIL CORP	BEAUMONT	TX
MOTIVA ENTERPRISES LLC	PORT ARTHUR	TX
PHILLIPS PETROLEUM	SWEENY	TX
PREMCOR REFINING GROUP INC	PORT ARTHUR	TX
SARTOMER CO INC	HOUSTON	TX
VALERO REFINING CO	HOUSTON	TX
VALERO REFINING CO	TEXAS CITY	TX
VALERO REFINING CO & MKTG CO	CORPUS CHRISTI	TX

Source: Acadian Consulting Group, Inc., 2001; The Louis Berger Group, Inc. 2001

12.0 PETROCHEMICAL PLANTS

12.1 Introduction

The chemical industry converts raw materials (oil, natural gas, air, water, metals, minerals) into more than 70,000 different products (Figure 12.1). After natural gas is processed and crude oil is refined, the non-fuel components remaining are known as petrochemicals. Petroleum is composed mostly of hydrogen and carbon compounds (called hydrocarbons). It also contains nitrogen and sulfur, and all four of these ingredients are valuable in the manufacture of chemicals. Because these chemicals are derived from petroleum, they are named *petrochemicals*.

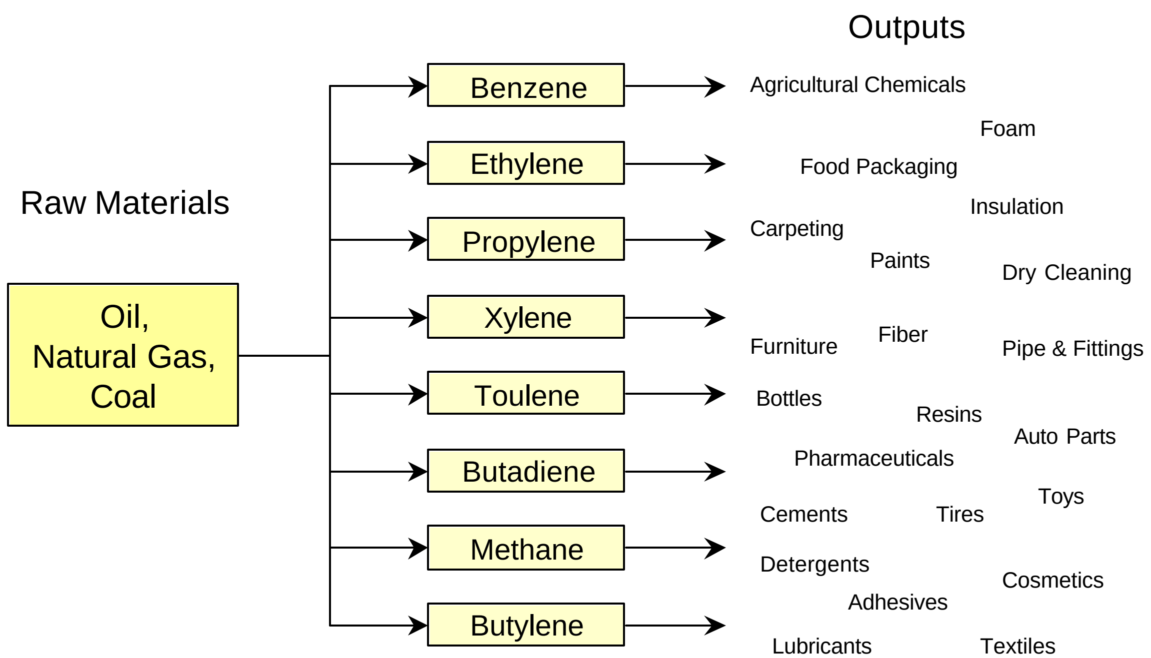

Figure 12.1. Organic Chemicals and Building Blocks Flow Diagram.

Source: Office of Compliance (1995)

"The boundaries of the petrochemical industry are rather fuzzy. On the 'upstream' end, they blend into the petroleum refining sector, which furnishes a major share of petrochemical feedstocks; 'downstream,' it is often impossible to draw a clear line between petrochemicals manufacturing and other organic chemistry-based industries such as plastics, synthetic fibers, agricultural chemicals, paints and resins, and pharmaceuticals" (Tussing and Kramer 1981). Operating in this field are petroleum companies who have broadened their interests into chemicals, chemical companies who buy petroleum raw materials, and joint ventures between chemical and petroleum companies, amongst many others.

Petrochemicals are part of a group known as organic chemicals – those containing carbon. This group or sector is classified by the Bureau of Census with an SIC code of 286. The 286 category includes gum and wood chemicals, cyclic organic crudes and intermediates, organic dyes and pigments, and industrial organic chemicals not elsewhere classified. This SIC 286 includes a number of integrated firms that are also engaged in petroleum refining and manufacturing of other types of chemicals at the same sites.

Processes: The transformation of raw materials into chemical products requires chemical, physical and biological separation and synthesis processes (Table 12.1). These processes expend large amounts of energy for heating, cooling or electrical power (refer to Figures 12.2 and 12.3 later in this chapter). Separations play a critical role and account for 40 to 70 percent of both capital and operating costs. The most widely used separation process is distillation, which accounts for as much as 40 percent of the industry's energy use (Energy Information Administration 2000c). Chemical synthesis and process heat also play major roles in nearly all chemical operations.

Table 12.1

Industry Specific Technologies

Unit Operation	Purpose	Major Technologies
Separations	Separate products, remove contaminants, dry solids	Distillation, extraction, absorption, crystallization, evaporation, drying, steam stripping or cracking membranes
Chemical Synthesis	Synthesize chemicals, polymers and resins	Catalytic reactions (oxidation, hydrogenation, alkylation) and polymerization, hydration, hydrolysis, electrolysis
Process Heating	Drive chemical reactions and separations; can be direct or indirect	Direct heating: furnaces, kilns, dryers Indirect heating: boilers, heat exchangers Heat transfer fluids: steam, boiling water, organic vapors, water, oils and air

Source: Energy Information Administration (2000c)

The industrial organic chemical sector includes thousands of chemicals and hundreds of processes. In general, a set of building blocks (feedstocks) is combined in a series of reaction steps to produce both intermediate and end-products. Among the processes of importance in petrochemical manufacture are (Waddams 1969):

- ***Distillation:*** A technique of separation which makes use of the difference in volatility or boiling point of different components in a mixture. The use of successive vaporization and condensation, separates the mixture into lighter and heavier portions.

- ***Solvent Extraction:*** This is the separation of a component(s) of a mixture by using a liquid with selective solvent characteristics. This operation is used for the separation of components by types, for example, the separation of aromatics from paraffins.

- ***Crystallization:*** By chilling a solution in a filter or centrifuge, solid crystals that have been separated out can be recovered.

- ***Absorption:*** A form of solvent extraction, a component of a gas or vaporized mixture is separated by selective absorption, usually in a liquid solvent. The operation is commonly carried out in a packed tower.

- ***Adsorption:*** Certain highly porous materials (e.g., activated charcoal, silica gel) have the power of condensing on their surfaces large amounts of vapors. Where this adsorption can be operated selectively, it represents a technique for the separation of one component from a mixture.

- ***Cracking:*** In petroleum terminology, this means the breaking down of the large hydrocarbon molecules into molecules of lower molecular weight. This is achieved in the absence of air, by high temperature along or by combination of high temperature and catalytic activity.

- ***Reforming:*** This refers to processes designed to upgrade gasoline quality in petroleum refining. This uses heat and usually a catalyst to transform hydrocarbons into other hydrocarbons or mixtures of hydrocarbons and oxides of carbon, with air or steam taking part in the reaction.

- ***Alkylation:*** This is usually the reaction of a hydrocarbon such as an alkane or aromatic with an olefin using an acid or other catalyst.

- ***Isomerization:*** Designed to induce a rearrangement of atoms within a particular molecule, in the petroleum field it is commonly applied to the conversion of a normal paraffin to the isoparaffin.

- ***Polymerization:*** A polymer results from a catalyst being employed to form very large molecules from small molecules.

12.2 Description and Typical Facilities

Industrial organic chemical facilities have an unusual distribution when compared to downstream manufacturing facilities. Most significantly, a small number of very large facilities account for the majority of the industry's value of shipments (Table 12.2). In 1992, 113 of the 986 industrial organic chemical facilities had more than 250 employees. Nonetheless, these facilities accounted for at least 65 percent of the value of shipments for the industry. About 25 percent of the total value of shipments came from the largest 16 plants (greater than 1,000 employees) (Office of Compliance 1995).

Table 12.2

Organic Chemical Facility Characteristics

Number of Employees	Number of Facilities	Percent of Facilities	Percent of Shipment Value
< 10	259	26%	1%
10 – 49	301	31%	5%
50 – 249	313	32%	27%
250 – 499	60	6%	16%
500 – 999	37	4%	26%
1,000 +	16	2%	25%
Total	986	100%	100%

Source: Office of Compliance (1995)

The chemical industry uses a variety of fuel sources, nearly 50 percent of which are used as feedstocks. The industry is the single largest consumer of natural gas (over 10 percent of the domestic total) and uses virtually all the liquified petroleum gas (LPG) consumed in U.S. manufacturing (Figure 12.2). Other energy sources include byproducts produced onsite, hot water, and purchased steam (Energy Information Administration 2000c).

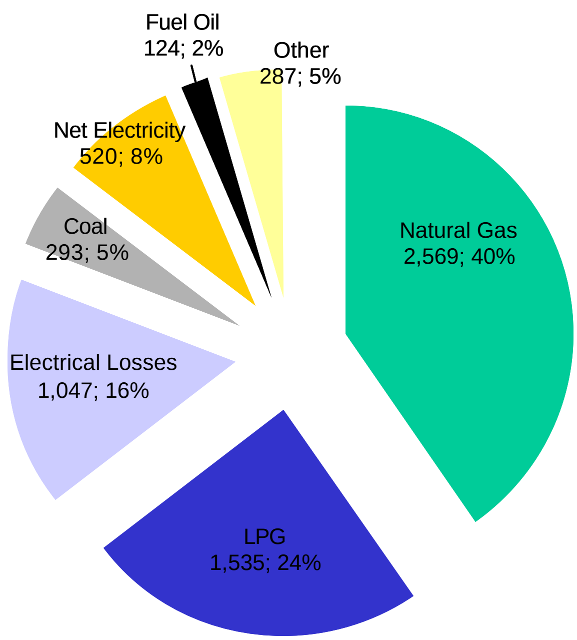

Figure 12.2. Chemical Industry Energy Use by Fuel – 1994 (trillion Btu).

Source: Energy Information Administration (2000c)

Sites for chemical manufacturing facilities are typically chosen for their access to raw materials and to transportation routes. And, because the chemical industry is its own best customer, facilities tend to cluster near such end-users.

Laid out like industrial parks, most petrochemical complexes include plants that manufacture any combination of primary, intermediate, and end-use products. Changes in market conditions and technologies are reflected over time in the changing product slates of petrochemical complexes. In general, petrochemical plants are designed to attain the cheapest manufacturing costs and thus are highly synergistic. Product slates and system designs are carefully coordinated to optimize the use of chemical by-products and to use heat and power efficiently.

Nearly 50 percent of the energy used within the industry is transformed into chemical products. For example, liquefied petroleum gases (a mixture of gases such as ethylene, ethane, propane, propylene) serve as feedstocks for the manufacture of polyethylene, polypropylene, and a host of other products. Also, natural gas is used to produce ammonia, a raw material used in the production of many fertilizers (Energy Information Administration 2000c).

Organic chemicals (ethylene, propylene, and many others) have by far the highest energy requirements of all chemical sectors – about 50 percent of total industry energy use (Figure 12.3). More than 50 percent of energy consumed in organic chemicals manufacture is in the form of energy feedstocks (natural gas and LPG). Inorganic chemicals are made from ores, air and water and therefore require little or no feedstock energy.

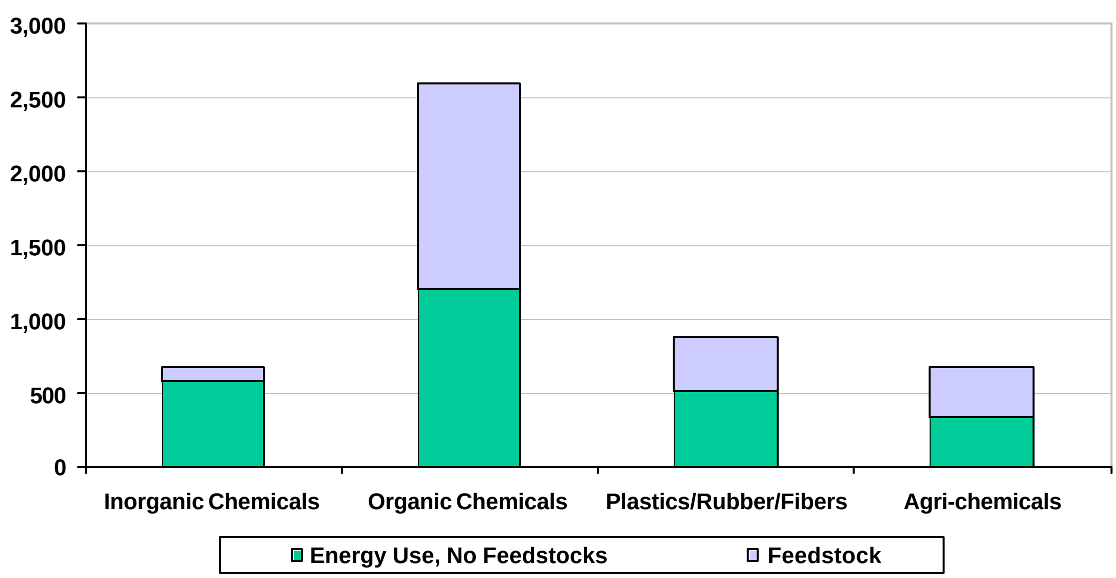

Figure 12.3. Sector Energy Use – 1994 (trillion Btu).

Source: Energy Information Administration (2000c)

Ethylene Production: Because different facilities are operated by different companies, using different supplies of raw materials and producing various different end-products, there is really no "typical" petrochemical plant or facility. However, we can discuss one type of product that is produced and seen as the industry's most basic building block. Ethylene is used in myriad consumer products such as detergents, cosmetics, textiles, and antifreeze. It is also used for many different types of plastics, including polyethylene plastics, from which items such as trash bags and milk jugs are made. Ethylene is also used within the industry for the production of other derivative products.

Ethylene is mainly produced through the steam cracking of hydrocarbon feedstocks. Feedstocks used for steam cracking range from ethane to naphtha and gas oils. Some ethylene is also produced as a byproduct of petroleum refining. Stored in large underground caverns ethylene is then transported to customers through a pipeline system or fully refrigerated ships.

Olefin plants, which produce petrochemicals, have existed for well over 50 years. These plants have grown considerably in size over the past few decades. The output of olefin plants that was formerly recorded in pounds per year, now is measured in tons per year. The so-called world-scale plant (the size that achieves whatever is currently considered full economies of scale) is larger than many medium-sized refineries (Burdick and Leffler 1990).

The early olefin plants were designed to use only ethane and propane as feedstocks mostly because of the high output ratio of ethylene that these two fuels could produce. During the energy crisis of the late 1970s, it was believed that natural gas resources were going to be exhausted and therefore new plants that used heavier feedstocks, such as naphtha and gas oils, were developed. As late as the early 1990s, these plants produced approximately half of ethylene yields. With the introduction of the mega-plants and the increased availability of natural gas, the industry is currently moving back toward the use of propane and ethane as feedstocks.

Of the top 10 ethylene production complexes in the world, six are found in the U.S.; five are located in Texas and one in Louisiana. These six production complexes only account for 35 percent of the U.S.'s ethylene production capacity (Nakamura 2002).

12.3 Industry Characteristics

Texas, New Jersey, Louisiana, North Carolina and Illinois are the United State's top chemical producers. However, most of the basic chemicals production is concentrated along the Gulf Coast, where petroleum and natural gas feedstocks are available from refineries. About 70 percent of all primary petrochemicals are produced in Texas and Louisiana. Ten states accounted for 62 percent of chemicals production and 60 percent of chemical industry employment in 1996 (Figure 12.4). [52]

[52] Unless otherwise indicated, this section is based on: Energy Information Administration. 2000c. *Chemical Industry Analysis Brief*, (Washington D.C.: Department of Energy), January 2000, <http://www.eia.doe.gov/emeu/mecs/iab/chemicals/ index.html>, (2 October 2000).

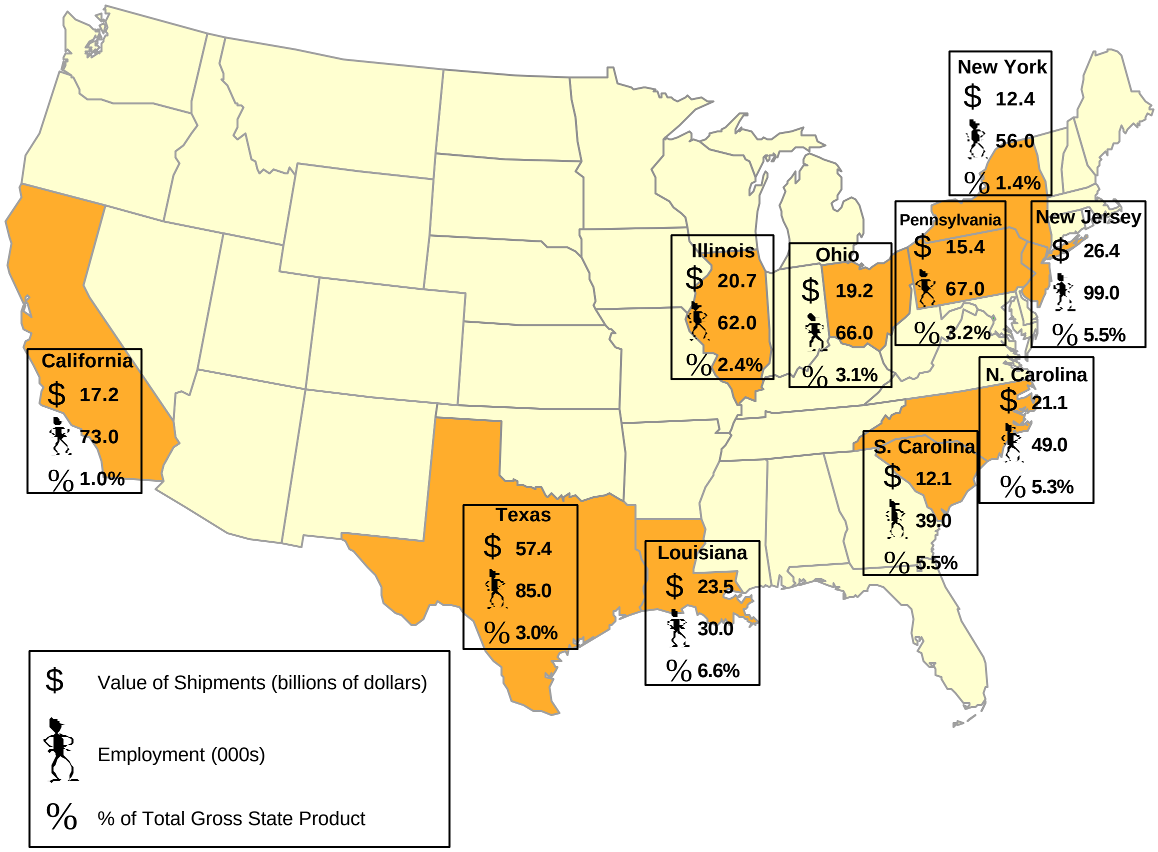

Figure 12.4. Value of Shipments for Top Ten States (1996).

Source: Energy Information Administration (2000c)

As previously mentioned, six of the top 10 largest ethylene production complexes in the world are found on the Gulf Coast. Louisiana gets 6.6 percent of its GDP from these petrochemical shipments, higher than any other state. The chemical industry in Texas accounts for 3 percent, which may seem small, but it's the largest value – $57.4 billion. Production in these states also seems to be the most efficient. According to Figure 12.4, it takes only 30,000 employees in Louisiana to produce a value almost comparable to that of New Jersey's 99,000 employees. Twice the number of employees in Illinois produce a value that is almost $3 billion less than that of Louisiana. And, Texas' value of shipments is almost double that of New Jersey, with 14,000 thousand fewer employees.

A keystone to the U.S. economy, the chemical industry provides over 2 percent of the total GDP and almost 12 percent of the manufacturing GDP. The U.S. is the largest chemical producer in the world and achieved a record trade surplus in 1997 of $19.2 billion. The industry continues to grow, with profits in 1997 reaching $44.8 billion. Shipments have increased more than 5 percent every year over the last decade. Industry composition has changed, however, with an increasing emphasis being placed on high-technology fields (e.g., pharmaceuticals, biotechnology, advanced materials). Pharmaceuticals is the highest valued sector (24% of shipments), followed by organic chemicals (21%) and plastics (16%) (Table 12.3) (Energy Information Administration 2000c).

Table 12.3

Value of Shipments within Chemical Industry (billion dollars, 1996)

Product	Value of Shipment
Pharmaceuticals	$ 86.5
Organics	$ 75.7
Plastics	$ 59.6
Soaps/Cleaners	$ 51.8
Inorganics	$ 27.7
Misc.	$ 24.5
Agri-chemicals	$ 23.4
Paints	$ 18.3

Source: Energy Information Administration (2000c)

12.4 Regulations

Although petrochemical plants are not regulated economically per se, they are affected by nearly all federal environmental statutes. The industry is also subject to numerous laws and regulations from state and local governments designed to protect and improve the nation's health, safety and environment. The following is a summary of the major federal regulations that affect the chemical industry (Office of Compliance 1995).

Toxic Substances Control Act (TSCA): TSCA gives the EPA comprehensive authority to regulate any chemical substance whose manufacture, processing, distribution in commerce, use or disposal may present an unreasonable risk of injury to health or the environment. Three sections are of primary importance to the organic chemical industry. TSCA §5 mandates that chemical companies submit pre-manufacture notices that provide information on health and environmental effects for each new product and test existing products for these effects. TSCA §4 authorizes the EPA to require testing of certain substances. TSCA §6 gives the EPA authority to prohibit, limit or ban the manufacture, process and use of chemicals.

Clean Air Act (CAA): The original CAA authorized EPA to set limits on chemical plant emissions. Many of these new source performance standards (NSPS) apply to organic chemical manufacturers including those for flares, storage vessels, synthetic organic chemical manufacturers equipment leaks, synthetic organic chemicals manufacturers using air oxidation processes, distillation operations, reactor processes, and wastewater.

The Clean Air Act Amendments of 1990 set control standards by industrial sources for 41 pollutants to be met by 1995 and for 148 other pollutants to be reached by 2003. Several provisions affect the organic chemical industry. Under the air toxics provisions of the CAAA, more sources are covered including small businesses. In April 1994, the EPA proposed regulations to reduce air toxics emissions at chemical plants. The Hazardous Organic National Emissions Standard for Hazardous Air Pollutants, also known as HON, covers hundreds of chemical plants and thousands of chemical process units. The HON also includes innovative provisions such as emissions trading that offer industry flexibility in complying with the rule's emissions goals. Subsets of the industry are regulated under other National Emission Standards for Hazardous Air Pollutants (NESHAP). These include vinyl chloride manufacturers, benzene emission from ethylbenzene/styrene manufacturers, benzene equipment leaks, emissions from storage tanks, benzene emissions from benzene transfer operations, and benzene waste operations.

Clean Water Act: The Clean Water Act, first passed in 1972 and amended in 1977 and 1987, gives EPA the authority to regulate effluents from sewage treatment works, chemical plants, and other industrial sources into waters. The act sets "best available" technology standards for treatment of wastes for both direct and indirect (to a Publicly Owned Treatment Works) discharges. In 1987, EPA proposed final effluent guidelines for the organic, polymer and synthetic fiber industry. The majority of this rule was upheld by the federal courts. A final proposal for the remaining portions of the rule was issued in August 1993. The implementation of the guidelines is left to the states who issue National Pollutant Discharge Elimination System (NPDES) permits for each facility.

The Storm Water Rule requires the capture and treatment of stormwater at facilities producing chemicals and allied products, including industrial organic chemical manufacture. Required treatment will remove from stormwater flows a large fraction of both conventional pollutants, such as suspended solids and biological oxygen demand (BOD), as well as toxic pollutants, such as certain metals and organic compounds.

Superfund: The Comprehensive Environmental Response Compensation and Liability Act of 1980 (CERCLA) and the Superfund Amendments and Reauthorization Act of 1986 (SARA) provide the basic legal framework for the federal "Superfund" program to clean up abandoned hazardous waste sites. The 1986 SARA legislation extended those taxes for five years and adopted a new broad-based corporate environmental tax. In 1990, Congress passed a simple reauthorization that did not substantially change the law but extended the program authority until 1994 and the taxing authority until 1995. The chemical industry (all SIC codes) pays about $300 million a year in Superfund chemical feedstock taxes. A comprehensive reauthorization was considered in 1994. The industry believes several serious concerns need to be addressed including the liability standard which threatens Potentially Responsible Parties (PRPs) with the entire cost of clean-up at sites even though they may be responsible for only a tiny fraction of the waste; clean-up requirements, which are often unaffordable, unattainable, and unjustified by the risks presented by the sites; and the punitive, adversarial nature of the enforcement program.

Title III of the 1986 SARA amendments (also known as Emergency Response and Community Right-to-Know Act, EPCRA) requires all manufacturing facilities, including chemical facilities, to report annual information to the public about stored toxic substances as well as release of these substances into the environment (42 U.S.C. 9601). This is known as the Toxic Release Inventory (TRI). Between 1988 and 1993 TRI emissions by chemical companies to air, land, and water were reduced 44 percent. EPCRA also establishes requirements for federal, state, and local governments regarding emergency planning. In 1994, over 300 more chemicals were added to the list of chemicals for which reporting is required.

To date, EPA has focused much of its attention on measuring compliance with specific environmental statutes. This approach allows the Agency to track compliance with the Clean

Air Act, the Resource Conservation and Recovery Act, the Clean Water Act, and other environmental statutes. Within the last several years, the Agency has begun to supplement single-media compliance indicators with facility-specific, multimedia indicators of compliance. In doing so, EPA is in a better position to track compliance with all statutes at the facility level, and within specific industrial sectors.

12.5 Industry Trends and Outlook

According to the Oil and Gas Journal (2000), petrochemical construction projects have dominated worldwide expansion and construction forecasts in recent years (Figure 12.5):

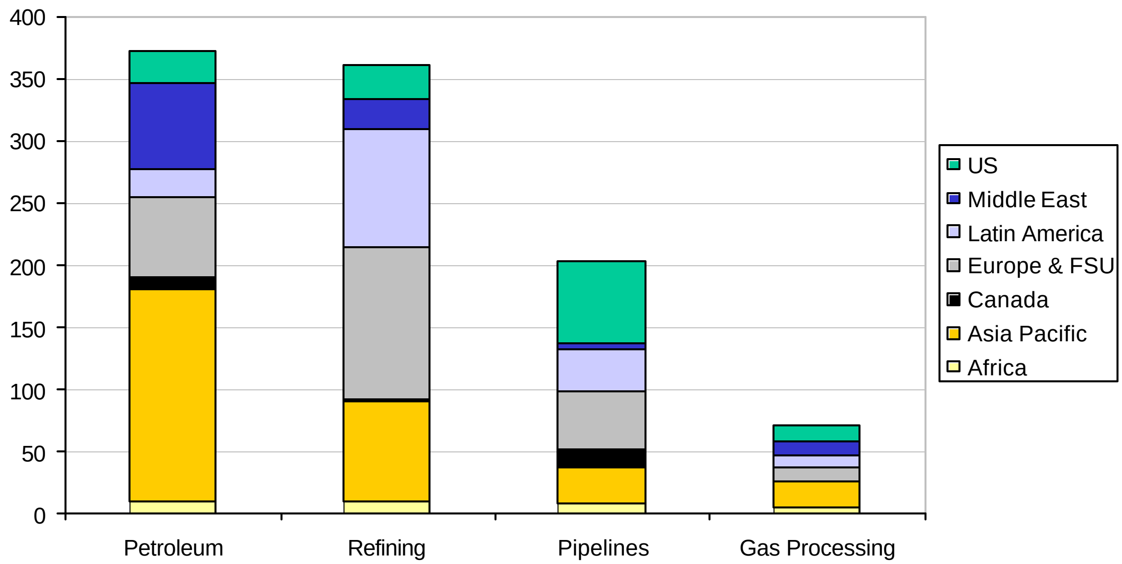

Figure 12.5. Type of Construction Projects – 1996 to 2000 Average.

Source: Oil and Gas Journal, (2000)

In 2001, ethylene markets experienced a slowdown in demand, mainly due to the economic turndown. As a result, many producers scaled back throughput. However, the downturn, combined with new capacity, led to historically low cash margins for U.S. producers. U.S. operating rates were also low, at 82 percent of total capacity in 2001 – the lowest levels since the early 1990s.

Excess capacity for all of North America was about 5.4 million metric tons for 2001. North American ethylene demand was 35.4 million metric tons in 2001; therefore, demand was about 30.0 million metric tons, a decrease of 1.0 million metric tons from 2000. Figure 12.6 shows that favorable economics for reinvesting in steam crackers will not occur until 2004 (Nakamura 2002).

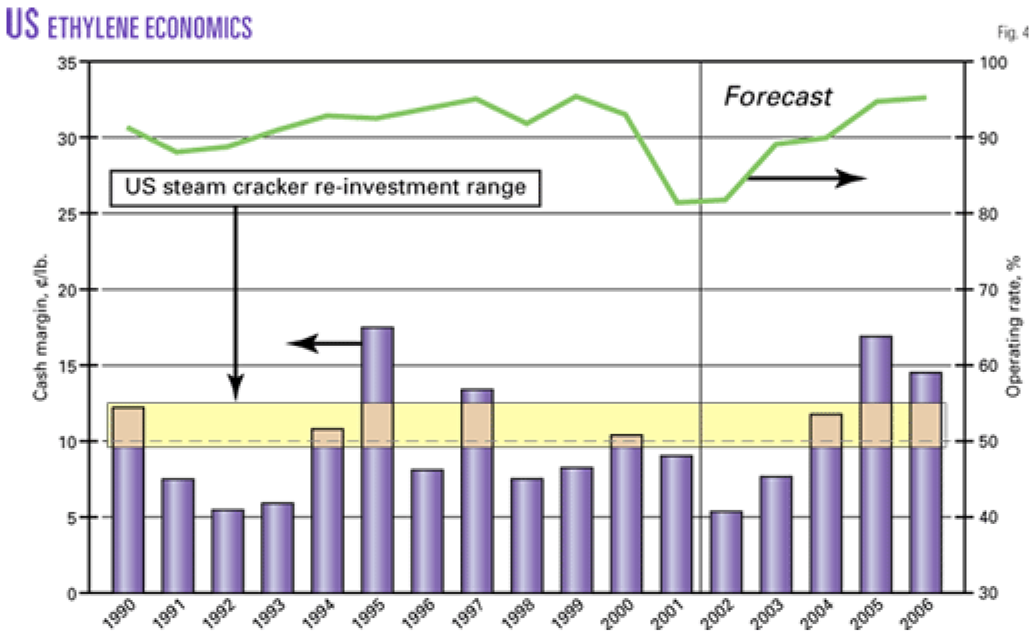

Figure 12.6. U.S. Ethylene Economics.

Source: Nakamura (2002)

Even with the decrease in demand, the industry has seen only one plant retired in the past year. Chevron Phillip's Sweeny plant, which could produce 181,000 tons of ethylene per year (a very small amount by today's plant sizes), was decommissioned as it had last been operated in December 2000 (Nakamura 2002).

Producer margins have also been impacted by the run up of natural gas prices that began in the year 2000. LPG, which closely follows natural gas prices, and natural gas have been the fuel of choice in the newest mega plants. Double-digit natural gas prices have added to the burden of slack worldwide demand for ethylene.

As methods of transporting petrochemical products are reduced, U.S. producers must consider international opportunities to compete with what have been historically regional markets. The tradeoff for many international opportunities is between the benefit of low-cost international gas resources and the political risks of their international investments. Countries that lack infrastructure to use natural gas as a fuel will either flare or reinject these gas resources. The economics in this situation are recognized as the price of natural gas and its byproducts continue to rise. Plant economics, therefore, can stack up favorably in countries where gas resources have little commercial value. This puts pressure on the competitiveness of U.S. plants since they must purchase marketable gas at existing market prices.

Mergers: The number of U.S. ethylene, low linear density polyethylene and benzene companies have decreased in recent years. These mergers have not lead to a major concentration of companies, but they have achieved scale and other fixed cost savings. In February 2001, Union Carbide Corp. became a wholly owned subsidiary of Dow Chemical Co. Dow is now the leading supplier of ethylene in the world. Second to Dow's 10.7 million metric tons per year capacity is ExxonMobil's 7.9 million metric tons per year. Chevron Phillips

Chemical Co. LP, based in Houston, now ranks seventh among worldwide ethylene producers. All of its plants are in Texas.

Figure 12.7 shows the difference between the top five shareholders of North American ethylene capacity between 1995 and 2005. Fewer companies are taking a larger share of the total ethylene market (Chang 2001). This trend, as mentioned previously, results from the economies of scale that the new mega-capacity facilities are able to achieve. For example, the largest plant in the U.S. is two-thirds the size of the tenth largest worldwide producer's total assets. Two plants of this size would put a producer at approximately seventh on the top ten list worldwide.[53]

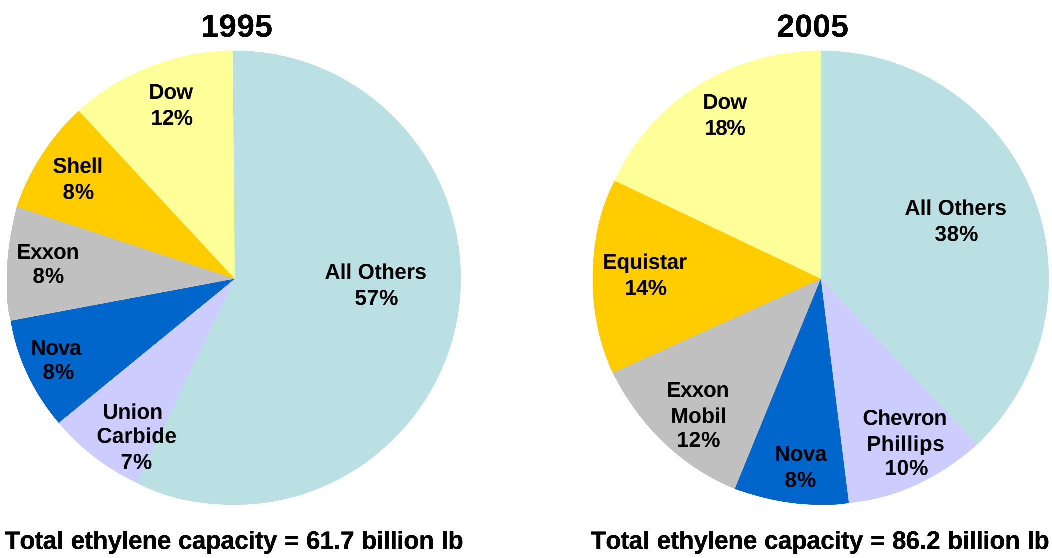

Figure 12.7. Top Shareholders of North American Capacity.

Source: Chang (2001)

Inventory: An inventory of petrochemical facilities located in the Gulf region was conducted in 2001 as part of development of this Fact Book and GIS database. Seventy-one petrochemical facilities were recorded within the Gulf: 53 were located in Texas, 17 in Louisiana, and 1 in Mississippi.

Table 12.4 presents a list of construction or expansion projects underway for petrochemical plants in the U.S. As the table illustrates, new facilities are still being added in the U.S. even though demand faded over the past year. Additionally, only two plants on the list are not located in Texas.

[53] This has been confounded by the merger and acquisition activities and consideration that has occurred throughout the past decade.

Table 12.4

Petrochemical Construction/Expansion Projects in the United States

Company / Location	Project	Added Capacity (tons/year)	Status	Expected Completion
Adkins Energy LLC				
Lena, IL	Ethanol	68,000	Construction	2002
American Acryl				
Bayport, TX	Acrylic acid	120,000	Construction	2002
Atofina Petrochemicals Inc.				
Carville, LA	Polystyrene	230,000	Engineering	2002
BASF Corp.				
Port Arthur, TX	Propylene	315,000	Planning	2003
BP America, Inc.				
Alvin, TX	Ethylene	220,000	Engineering	2005
Chevron Phillips Chemical Co LP / Solvay Polymers Inc.				
Baytown, TX	HDPE	318,000	Construction	2002
Shell Chemical LP				
Deer Park, TX	Ethylene	544,000	Construction	2003
Sterling Chemicals Co				
Texas City, TX	Acetic Acid		Engineering	2003

Source: Stell (2002)

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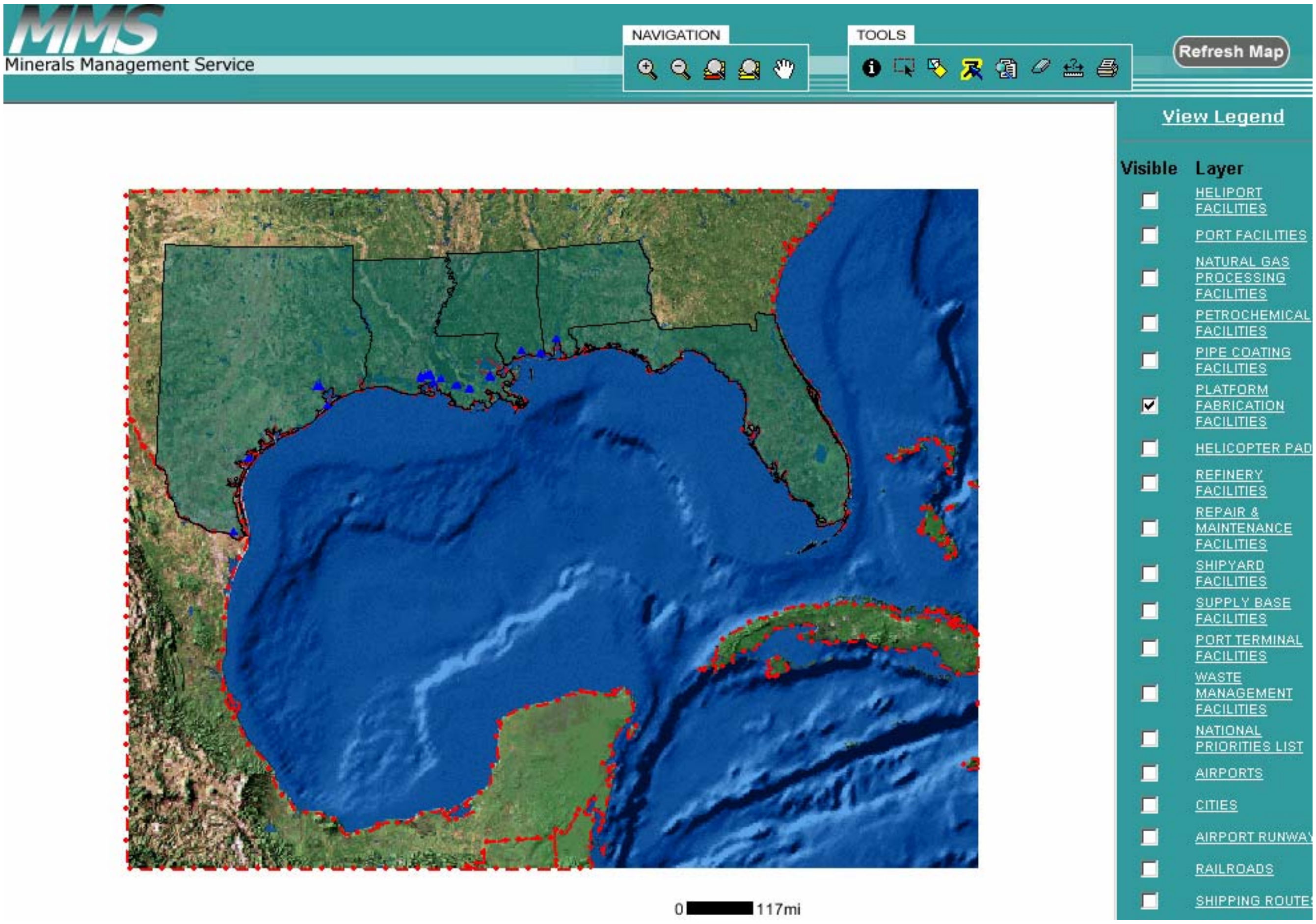
Appendix I

Infrastructure Database Description & Queries

Infrastructure Types/Data



Platform Fabrication Yards

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Platform Types

Port Facilities

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- USACE Waterway Name/Code
- USACE Waterway Name/Code

Shipyards/Shipbuilding

- Name
- Owner/Operator
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Shipyard Type Maximum Vessel length/width

Repair, Maintenance Yards and Supply Bases

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Total number stations, full-time employees
- Transportation access

Waste Management Facilities

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Permit/Permit Agency
- Facility Class
- Percentage Oil Waste
- Facility Type (e.g. salt dome, injection, land fill, landfarm, recycling)
- Waste types handled (e.g., NOW, NORM)
- Capacity
- Transportation access

Pipelines

- Location (lat/long)

Pipe Coating

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Yard capacity
- Maximum pipeline coating size (dia)

Gas Processing Plants

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Operation capacity in MMcf per day
- Total number pipelines connected (number offshore/number interstate)

Natural Gas Storage Facilities

- Location (lat/long)

Refineries

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Input delivery by e.g., pipeline, tanker, barge
- Products
- Production capacity (barrels per calendar day)
- Number employees
- Annual Operating Hours

Petrochemical Plants

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Commercial Operation Date
- Size
- Primary product & capacity
- Secondary product & capacity
- Other products & capacities
- Number employees
- Number production-related employees
- Annual operating hours

Heliports

- Name
- Owner
- Location (lat/long, address)
- Contact (phone #)
- Current status

Queries

Attribute

Infrastructure type
Name of Facility
Cities
Counties
States
Census Tracts
County Business Pattern
Urban Areas
Hydrological Features
Active Lease Areas
Offshore Blocks
CZM
Roads
Shipping Routes
Railroads
Airport Runways
National Priority List

Spatial

Location by state, county, city, lat long
Buffers
Nearest road, airport, pipeline, port

Appendix II

Additional Port Facility Information

PORT FACILITIES

Introduction

Gulf Coast states provide substantial amounts of support to service the oil and gas industry which is so active on the Outer Continental Shelf. Many ports offer a variety of services and support activities to assist the industry in its ventures. Rapidly developing technology has resulted in changing needs. This, in turn, has placed a burden on the ports to provide the necessary infrastructure and support facilities in a timely manner to meet the bourgeoning needs of the industry.

Previous sections have explained the network necessary to support this industry. Personnel, supplies and equipment must come from the land based support industry. All of those services must pass through a port to reach the drilling site.

When reviewing a database established by the U.S. Army Corps of Engineers which identifies facilities in the Gulf of Mexico region used as service base ports for the offshore industry, it is astounding to see the number of private port facilities. In Louisiana alone there are 120 listed in this database and there are none identified in the Port Fourchon area. A survey of that area revealed another 27 facilities. Texas shows 84 landside support operations and there are others identified in Florida, Alabama, and Mississippi. Even though these are private facilities, they operate within the jurisdiction of a public port authority. And, to attract these operations, the public port must offer certain infrastructural improvements to adequately accommodate these operations.

Port Profiles

The following profiles are examples of ports who are significantly involved in offshore support. An effort has been made to describe their operational structure as well as to describe their facilities and equipment. It is this level of development that ports must sustain in order to provide the required land based support.

Port Fourchon

(Port Fourchon)
P. O. Drawer 490
Galliano, LA 70354
(504) 632-6701

LOCATION:
Port Fourchon (pronounced: foo-shawn) is located at the mouth of Bayou Lafourche where it empties into the Gulf of Mexico. It is approximately 60 miles south of New Orleans. It's easy accessibility from any area in the Gulf of Mexico has made it one of the most active oil and gas ports on the coast. Port Fourchon's location at the end of Louisiana Highway #1 is in the center of one of the richest and most rapidly developing industrial areas of the Gulf region. When the growth of other ports has slowed, Port Fourchon has been expanding to meet the changing needs of the offshore oilfield industry.

ORGANIZATION:
The development and supervision of Port Fourchon is under the authority of the Board of Commissioners of the Greater Lafourche Port Commission with headquarters in Galliano Louisiana. It is composed of nine members who are elected to serve 6 year terms. Established in 1960, the GLPC Board is the only elected port authority in Louisiana and its members must be at least 21 years of age and residents of the 10th Ward of Lafourche Parish, Louisiana.

The Commission regulates commerce and vessel traffic within the Port Fourchon area, owns land and lease facilities, establishes 24 hour law enforcement through its Harbor Police Division, maintains paved roads and provides facilities for governmental coordination such as the US Customs Service and US Coast Guard. Over its 40 year history, it has cultivated opportunities for businesses and steady economic growth for Port Fourchon and the surrounding area.

GENERAL INFORMATION:
Louisiana's only port directly adjacent to the Gulf of Mexico is located on the coast of Lafourche Parish and is strategically positioned to serve industrial activity associated with exploiting oil and gas resources offshore in the Gulf. Recent developments in offshore deepwater oil and gas exploration and production have brought economic benefits to both the Port and Lafourche Parish. Increased economic activity is associated with the provision of onshore support for the oil and gas industry. Port Fourchon has grown considerably since 1978 when two companies were located on port property. As of August 1999, there were 124 companies leasing port land. The physical size of the port has grown from about 25 acres in 1980 to nearly 600 acres as of August 1999.[54]

Port Fourchon is a multi-use port servicing the needs of oil and gas development, commercial fishing, recreation and shipping as well as providing the land base for the Louisiana Offshore Port Authority. The Port has the only facility in the world that offers "one-stop" shopping. It is

[54] This paragraph is taken from: Minerals Management Service, "Technical Summary: MMS Publication 2001-019, Lafourche Parish and Port Fourchon, Louisiana: Effects of the Outer Continental Shelf Petroleum Industry on the Economy and Public Services, Part 1," (New Orleans: U.S. Department of the Interior) <http://www.gomr.mms.gov/homepg/regulate/environ/techsumm/2001/2001-019%20Fourchon.html> (July 23, 2002).

called C-Port and allows supply vessels to take on fuel, water, deck cargo, barites, cements, liquid muds and completion fluids all at one place, under a covered dock and in less than 24 hours. Anywhere else, this process would take two to three days, a heavy cost to ship owners and platform operators. The port is comprised of approximately 600 acres and has nearly 25,000 ft of waterfront facilities. The port has grown at a phenomenal rate due to the growth in the oil and gas industry and its development in the deepwater areas of the Gulf of Mexico. In 1999 there were 124 businesses located at the port and they were increasing by one per month.

One of the most active ports in its class, Port Fourchon has been designated as one of Louisiana's Enterprise Zones and therefore offers many tax advantages. Its close proximity to the Gulf of Mexico along with its planned development and multidimensional services, make Port Fourchon one of the most significant oil and gas ports on the Gulf Coast.

OPERATIONAL PARAMETERS: Port Fourchon

Facility Type	Physical/Operational Parameters
Location	On the Gulf of Mexico, at the mouth of Bayou Lafourche-about 60 miles south of New Orleans.
Channel Access	Channel entrance: 300 ft wide by 24 ft deep; Interior Channel 300 ft wide by 23 ft deep; E-slip 400 ft wide by 23 ft deep; Turning Basin 800 ft wide by 20 ft deep.
Land Access	Highway: LA 3090 2 miles to LA 1, 40 miles to U.S. 90.
Docking	No public dock suitable for handling general cargo, numerous privately leased facilities.
Intermodal transfer (on dock)	A large number of privately leased docks with crane service and loading/unloading equipment.
Warehouse Storage	A large number of privately leased warehouses. One 8,000 sq ft refrigerated warehouse.
Yard Storage	Numerous storage yards on individual leases. Improved and unimproved property available.
Inland Transport	Connection to the Intracoastal Waterway via Bayou Lafourche, Houma Navigation Canal and Barataria Waterway.
Cargo Throughput (per hour)	Cargo throughput varies among docks. Compatibility of heavy lifts up to 200 tons. Numerous 150 ton options.
	Planned Expansions/Dates The Northern Expansion Project is a 700 acre development consisting of 600' wide slips and over one mile of waterfront. Phase I of the expansion is to be complete in 2001.
	Constraints/Impediments Two-lane highway access and lack of rail access are major impediments. Location on the Gulf of Mexico is an advantage but has limited water access to major metropolitan centers.
	Potential Vessel Service Ocean/River vessel service, Shortsea Coastal service, Container Port services.

Morgan City Port Harbor and Terminal District

(Port of Morgan City)
800 Youngs Road
Morgan City, LA 70381
(504) 384-0850

LOCATION:

The Port of Morgan City is located within the community of Morgan City in St. Mary Parish. The port is on the east bank of the Atchafalaya River in a natural wide and deep harbor known as Berwick Bay. With immediate access to I-49, it is just one hour away from New Orleans, Lafayette and Baton Rouge. Centrally located along the Gulf coast, the Port is only 29 miles from the Gulf of Mexico. The Port of Morgan City has been an avenue of both domestic and international trade since 1957. The Atchafalaya River, the Gulf Intracoastal Waterway, and the Bayous Boeuf, Black, and Chene are the connections to traffic throughout the continental United States and abroad. The Atchafalaya River has its beginnings at the junction of Old River and the Red River in east-central Louisiana. Old River is a short connection between the head of the Atchafalaya and the Mississippi River. The Atchafalaya flows southward a distance of 135 miles and empties into the Atchafalaya Bay.

Traffic between points in the southwest United States and the Upper Mississippi River Valley saves approximately 342 miles per round trip by using the Atchafalaya River rather than the alternate link of the Intracoastal via the Harvey Locks at New Orleans.

ORGANIZATION:
The Port of Morgan City was created by Act 530 of 1952 . Since 1957, it has been active in both domestic and international trade. It is governed by a nine member Board of Commissioners that are appointed by the Governor and serve for a nine year term.

GENERAL INFORMATION:
Morgan City is the only medium draft harbor between New Orleans and Houston on the Gulf. Its 400 ft wide channel is maintained by the U.S. Army Corps of Engineers to a constant depth of 20 ft. Its docking and cargo handling facilities serve a wide variety of medium draft vessels.
There are over 200 private dock facilities located in the Morgan City vicinity. These facilities have heavy lift, barge-mounted cranes with capacities to 5,000 tons, track cranes to 300 tons, and mobile cranes to 150 tons.

The Intracoastal Waterway System and the Inland rivers of the Upper Mississippi River Valley reach markets in 37 U.S. states.

Facilities include a 500 ft dock with a 300 ft extension, a 20,000 sq ft warehouse, a large marshalling yard, a 50 ton capacity mobile track crane and a rail spur.

OPERATIONAL PARAMETERS: Port of Morgan City

Facility Type	Physical/Operational Parameters
Location	On the Lower Atchafalaya river 18 miles from the open waters of the Gulf of Mexico at the intersection of the Gulf Intracoastal Waterway and the Atchafalaya River in St. Mary Parish, LA.
Channel Access	Channel width: 400 ft - Depth 20 ft (minimum channel depth to the Gulf is 20 ft); the Gulf of Mexico is 18 miles to the south; Access East-West is through the Gulf Intracoastal Waterway.
Land Access	Highway: 1.1 miles to U.S. 90; Lafayette 71 mile to the West on U.S. 90 and New Orleans 68 miles East, Baton Rouge 71 miles north . Rail: Two thousand linear feet of rail spur and 1,500 linear feet of sidings connect the port warehouses with Burlington Northern mainline. Daily rail service is provided by Burlington Northern.
Docking	Dock length: 800 ft - Width: 180 ft – 300 ft at 40 ft wide with water frontage of 839' on Bayou Boeuf. Suitable to handle container, general and bulk cargo
Intermodal transfer (on dock)	Dock side mobile crane capable of lifting a fully loaded (70,000 lb.) 40 foot container. Three forklifts; 8,000 lb. & 10,000 lbs for warehouse use and one 15,000 lb. for the yard. Container crane 50 tons with 130 ft boom. Thirty-five ton cherry picker. Forty-ton container handler.
Warehouse Storage	3.75 acres of dock storage on the dock. A 20,000 sq ft warehouse with rail access.
Yard Storage	In addition to the 3.75 acres of on-dock storage, about 12 acres of auxiliary yard storage is available.
Inland Transport	Bulk cargo loading/unloading from/to barge 150-200 tons/hr. Bulk cargo transfer from/to yard from trucks and rail 100-150 tons/hr.
Cargo Throughput (per hour)	Break bulk cargo transfer rate 60-80 tons/hr. **Planned Expansion/Dates** Equipment: 30,000 lb. Forklift, three yard jockeys and six flat bed trailers and six chassis trailers are in the planning stage. Channel dredging to 35 ft. **Constraints/Impediments** A relatively new port with new facilities recently completed. Break bulk cargo transfer between warehouse and dock needs use of tractors and trailers. Bulk cargo transfer facilities not yet available. **Potential Vessel Services** Short sea vessel services; River/Ocean Vessel Services.

West St. Mary Port Harbor and Terminal District

(Port of West St. Mary)
P. O. Drawer 601
Franklin, LA 70538-0601
(337) 828-3410

LOCATION:
The Port of West St. Mary is located on the Central Gulf Coast of Louisiana at Mile Marker 133 on the Gulf Intracoastal Waterway. It is just eighteen miles from the City of Franklin, St. Mary Parish's official seat of government. The complex is off U.S. Highway 90, which connects the Interstate highway system between Lafayette and New Orleans, and all points in the Acadiana region of Louisiana.

The channel connecting the port with the Gulf Intracoastal Waterway, is -12 ft NGVD and has a bottom width of 150 ft to accommodate shallow draft shipping needs.

ORGANIZATION:
The Port of West St. Mary is operated by the West St. Mary Port, Harbor and Terminal District in Franklin, Louisiana. It functions under the direction of a Board of Commissioners. This nine member body has the power to regulate the commerce and traffic of the district in a manner that it judges to be in the best public interest. Each Commissioner is appointed for a seven year term.

GENERAL INFORMATION:
The port is a 1,500 acre complex with multi-modal transfer facilities, 6,700 ft of rail spurs, public loading and unloading dock with rail access, 1,350 ft of hard surface bulk headed property, and a public warehouse. It has highway connections with direct access to Highway 90 and Interstate 10. As of late 1999, the number of people employed at the Port of West St. Mary was about 276.

The port offers four miles of improved water frontage with a depth that allows access to vessels requiring up to a 16 ft draft. The dock is reinforced by a steel sheet pile bulkhead and provides four berthing spaces for ocean going coastal freighters and barges. The port is serviced by rail, shipping vessels and trucks. Generally, it can accommodate container, general and break bulk cargo.

OPERATIONAL PARAMETERS: Port of West St. Mary

Facility Type	Physical/Operational Parameters
Location	On the Gulf Intracoastal Waterway in St. Mary Parish.
Channel Access	Access is by the Gulf Intracoastal Waterway by a 16 ft deep channel.
Land Access	Highway: LA Highway 83 connects the port with U.S. 90, I-49 and I-10 Rail: 4000 ft of track Burlington Northern with La. Delta operations.
Docking	1,300 linear ft of bulkhead available to handle general cargo.
Intermodal transfer (on dock)	Mobile cranes and fork-loaders are available for cargo transfer between warehouse and vessel.
Warehouse Storage	65,000 sq ft of dockside warehouse is available.
Yard Storage	Paved storage and auxiliary yard space available - approx 7 acres.
Inland Transport	Direct transfer of cargo from vessel to rail and truck is possible.
Cargo Throughput (per hour)	60-80 tons of break-bulk cargo per hour.
	Planned Expansion/Dates The port has recently acquired an additional 380 acres of land adjacent to its location. Expansion of facilities is planned for this property. An additional 12,000 sq ft is being added to the existing marine fabrication facility. **Constraints/Impediments** Limited market opportunities and longer voyage time. **Potential Vessel Services** River/Ocean vessel service.

Port of Iberia District

(Port of Iberia)
P. O. Box 9986
New Iberia, LA 70562-9986
(337) 364-1065

LOCATION:
Located near the Louisiana coast in Iberia Parish, the Port of Iberia is a 2,000 acre industrial and manufacturing site surrounding a man-made port complex. The port has access to the Gulf Intracoastal Waterway and the Gulf of Mexico through its own Commercial Canal and has access to the Mississippi River through major ports in Baton Rouge and New Orleans.

Generally, the port is located along the Commercial Canal approximately 9 miles north of Weeks Bay on the Gulf of Mexico and 4.5 miles southwest of the City of New Iberia.

The Port Channel measures 8 miles in length from the main entrance of the Port to the Gulf Intracoastal Waterway. This waterway provides access to the Gulf of Mexico. Its depth is 13 ft. Its width is a minimum of 125 ft at the bottom and a minimum of 200 ft at the surface.

The Port of Iberia has direct access to the Intracoastal Waterway and the Gulf of Mexico through the Acadiana Navigational Channel. There are no overhead restrictions or obstructions in the approximately 24 miles from the Port of Iberia to the Gulf of Mexico. The Acadiana Navigational Channel measures 16 miles in length from Gulf Intracoastal Waterway across Vermilion Bay to the Gulf of Mexico. It is 9 ft deep and 150 ft wide at the bottom and 200 wide feet at the surface.

ORGANIZATION:
Created by Act 128 of the 1938 Louisiana State Legislature, the Port of Iberia's territorial limits originally encompassed a large portion of Iberia Parish. By Act 486 of 1978, the port's limits were expanded to cover most of Iberia Parish and the communities of Jeanerette and Loreauville. The port is governed by a seven member Board of Commissioners who serve a six year term. They are appointed by the parish government as well as the municipalities of Jeanerette and Loreauville.

GENERAL INFORMATION:
There are 80,000 linear feet of developed water frontage at the Port of Iberia. This provides work sites for over 75 industries currently located and operating at the port. More than 5,000 employees are working as welders, pipefitters, mechanics, managers, secretaries, programmers, accountants, and other occupations. The port's annual payroll is in excess of $150 million.

The Public Dock facilities include 3000 linear ft of bulkhead load-out area, stabilized yard, electric power, water, security lighting and fencing, restrooms, and parking. The total rail frontage is 13,000 linear ft.

The Port of Iberia has recently expanded to incorporate an additional 170 acres of waterfront property. This Phase I Expansion includes land acquisition, channel excavation, bulkhead construction, site stabilization, roadway construction, utility relocation, docking stations, fabrication facilities and fencing.

Import/Export tonnage at the port includes a diversity of products and commodities; gas and oil pipe and supplies, agricultural products, fabrication, limestone and aggregates, steel, bulk concrete, barge and vessel construction, and containerized cargo. Primary emphasis is on fabrication to support the off shore oil and gas industry.

OPERATIONAL PARAMETERS : Port of Iberia

Facility Type	Physical/Operational Parameters
Location	On Commercial Canal in Iberia Parish 24 miles North of the Gulf of Mexico, 8 miles North of Intracoastal Waterway. Mile Marker 141 on Intracoastal Waterway.
Channel Access	Commercial Canal is 12 ft deep and over 200 ft wide, intersects the Gulf Intracoastal Waterway and connects to the Gulf of Mexico via the Acadiana Navigation Channel.
Land Access	U. S. Highway 90 (future I-49 Corridor) links the Port with I-10. LA Highways 182, 14, and 83 also serve the Port. Rail access to the Port is provided by Burlington Northern-Sante Fe.
Docking	800 ft Public Barge Dock available for handling general cargo.
Intermodal Transfer (on dock)	Mobile cranes, forklifts, heavy hauling trucks, and other cargo handling equipment available.
Warehouse Storage	The Port is a 2,000 acre industrial and manufacturing facility with 100 industries located and operating.
Yard Storage	Stabilized yard storage available.
Inland Transport	Inland transport available.
Cargo Throughput (per hour)	50-75 tons of break-bulk cargo per hour.
	Planned Expansion/Dates 170 acre waterfront expansion completed on 8/1/00. One mile of new channels. Upgrading of public Port facilities is in progress. **Constraints/Impediments** 12 ft water depth. **Potential Vessel Services** Oil/Gas Supply Vessel Service; Small Cruise Ship Terminal.

Port of New Orleans

P. O. Box 60046
New Orleans, LA 70160
(504) 522-2551

LOCATION:
Ideally located at the mouth of the Mississippi River, the Port of New Orleans is America's gateway to the global market. New Orleans has been a center for international trade since 1718 when it was founded by the French.

ORGANIZATION:
The Port of New Orleans is governed by a seven member Board of Commissioners. The Board sets policies and regulates the traffic and commerce of the Port. The Commissioners are unsalaried and serve five-year staggered terms. The governor of Louisiana appoints board members from a list of three nominees submitted by 19 local business, civic, labor, education and maritime groups. The seven person board reflects the three-parish jurisdiction of the Board. Four members are selected from Orleans Parish, two from Jefferson Parish and one from St. Bernard Parish.

GENERAL INFORMATION:
Valued at more than $700 million, the port's facilities include 22 million square feet of cargo handling area and more than 6 million square feet of covered storage area. In the last 10 years, the Port of New Orleans has invested nearly $500 million in new facilities. Improved breakbulk and container terminals feature new multipurpose cranes, expanded marshalling yards and a new roadway to handle truck traffic. A new container terminal is under construction at Napoleon Avenue. The state-of-the-art complex will feature a new 1,739 linear ft wharf and 44-acre marshalling area. The terminal is scheduled to open in the fourth quarter of 2002.

The port's facilities accommodate an average of 2,400 vessel calls each year. The average general cargo volume is 11.2 million tons (1995-99), with a record 14.1 million tons in 1998. New Orleans is one of America's leading general cargo ports and has the USA's top market share for import steel, natural rubber, plywood and coffee.

New Orleans is the only deepwater port in the United States served by six class one railroads. In addition to excellent rail service, the Port of New Orleans is served by 70 steamship lines, 16 barge lines, and 75 truck lines.

OPERATIONAL PARAMETERS: Port of New Orleans

Facility Type	Physical/Operational Parameters
Location	On the Mississippi River between mile 81.5 AHP and mile 114.9 AHP. On the Inner Harbor Navigation Canal on the Mississippi River Gulf Outlet (MRGO)
Channel Access	Deep draft 45 ft in the main channel with a minimum width of 2,000 ft. Thirty-six feet in the MRGO with a bottom width of 500 ft.
Land Access	Highway access to I-10 and I-55. Rail: CSX, KCS, Canadian National, Norfolk Southern, Union Pacific, and New Orleans Public Belt Railroad.
Docking	22 miles of water frontage, wharves and terminals. For container cargoes, the multi-berthed France Road Terminal is equipped with container cranes.
Intermodal transfer (on dock)	Multi-purpose cranes at the Nashville Ave. terminal. Modern container cranes and all cargo handling equipment to handle container cargo. Dockside cranes and cargo handling equipment are available to handle break-bulk cargo at the general cargo terminals.
Warehouse Storage	The port offers more that 22 million sq ft of cargo handling area within its various facilities.
Yard Storage	All cargo storage areas are served by rail, and have adequate open yard areas.
Inland Transport	Advanced container cargo handling system with dockside cranes and handling at marshalling areas. Break-bulk and Neo-bulk cargo handling equipment.
Cargo Throughput (per hour)	Varies by operation and terminal location.
Cruise Terminals	Cruise Terminals at Julia Street Wharf and Robin Street Wharf. **Planned Expansion/Dates** A new container terminal is under construction and will be known as the Napoleon Avenue Container Yard. It will be operational by February 2002. **Constraints/Impediments** Market development in terms of improved services, networking with Mexican businesses, attention to small shippers. **Potential Vessel Services** Fast-Ferry Trailer Service; River/Ocean vessel service; Shortsea Coastal Service and refrigerated vessel service.

Port of Panama City

P. O. Box 15095
Panama City, FL 32406
(850) 769-7000

LOCATION:
Located on US 98 in Bay County adjacent to the Hathaway Bridge connecting Panama City to Panama City Beach. This is a deepwater port, along Florida's panhandle, specializing in break-bulk cargo plus some dry bulk products.

ORGANIZATION:
The port is governed by the Panama City Port Authority whose mission is to maintain, enhance and promote the economic development of Panama City and Bay County through the continued development of the Port of Panama City and its Industrial Park. There are 5 Commissioners who serve on the Port Authority and each is appointed to a five year term.

GENERAL INFORMATION:
Port Panama City is a relatively young port. When it was established in 1967, it had one deepwater berth and one 42,000 square foot warehouse. Currently the Port has five deepwater berths consisting of 2,590 linear ft with a 32-ft draft, 600 linear ft of barge facilities and 470,000 square ft of warehousing space. The Port is equipped with modern facilities to load and unload product from truck, rail, barge, container, RoRo vessel or deepwater vessel traffic. The Gulf Intracoastal Waterway is located adjacent to the Port and offers intracoastal shipment via barge. The maritime community of Panama City consists of various professionals such as longshoremen, steamship agents, freight forwarders, customhouse brokers, and others necessary to support a modern transportation facility.

Primary exports include linerboard, woodpulp, machinery, and miscellaneous general cargo; Imports are steel plate, steel coils, lumber, and liquid bulk. Tonnage throughput for FY 01/02 is projected to be 1.1 million tons.

The Port of Panama City has offered Foreign-Trade Zone status since November 11, 1981 when FTZ #65 came into existence. At that time the general-purpose foreign-trade zone was activated and made available to the public. On March 1, 1982, the second phase of FTZ #65 was activated. This phase contains Berg Steel Pipe Corporation.

OPERATIONAL PARAMETERS: Port of Panama City

Facility Type	Physical/Operational Parameters
Location	On the Gulf of Mexico in Bay County, Florida along US 98. It is adjacent to the Gulf Intracoastal Waterway.
Channel Access	Access is through a 32 ft channel.
Land Access	Rail service is provided by Bay Line, a class III railroad that runs between Dothan, AL and the port. It connects with CSX and Norfolk Southern.
Docking	3,100 linear ft of dock space.
Intermodal transfer (on dock)	Gantry crane - heavy lift capacity 45 mt at 155 ft out from center point, Ro/Ro berths.
Warehouse Storage	approximately 470,000 sq ft of covered warehouse area.
Yard Storage	300,000 sq ft of paved open storage.
Inland Transport	Cargo leaves the port by the Gulf Intracoastal Waterway, by rail or truck.
Cargo Throughput (per hour)	Varies with commodity and facility used.
	Planned Expansion/Dates Currently in the process of a South Dock extension for 162,000 sq ft equipped with 2 rail spurs and a 300 ton capacity lift; In 2001 plan to deepen West Dock to 32 ft. Plan to widen the Ship Channel to 150 ft. **Constraints/Impediments** Located at a heavily traveled city intersection with no adequate access to I-10 which is about 50 miles north. **Potential Vessel Services** Shortsea Coastal Vessels.

Alabama State Docks

(Port of Mobile)
P.O. Box 1588
Mobile, AL 36633
(334) 441-7001

LOCATION:
With its deepwater seaport facilities at the Port of Mobile, the Alabama State Docks is conveniently located on the central U.S. Gulf and is closer to open water than any other major port on the Gulf. There has been commerce in and out of the Port of Mobile since the early part of the 17th Century. It was not until 1826 that the U.S. Congress authorized money for the development of a navigable channel in Mobile Bay. The current navigation channel maintained by the U.S. Army Corps of Engineers provides a safe navigational depth of 45 feet from the Gulf of Mexico to the mouth of the Mobile River.

Four trunkline railroads serve the port, which is situated at the intersection of two major interstate highways. The state offers 1,500 miles of navigable inland barge routes and is served by the Tennessee-Tombigbee Waterway which connects 16,000 miles of interstate barge lanes with the Port of Mobile.

ORGANIZATION:
For the first two hundred years of its existence, the Port of Mobile did not have a central organization to guide the development and operation of the port. In 1920, the Alabama Legislature submitted a constitutional amendment to the people to develop Alabama's seaport with state financial assistance. The amendment was passed in 1922 under Governor Thomas E. Kilby, and the State Docks Commission was established with power to build, operate and maintain wharves, piers, docks, quays, grain elevators, cotton compresses, warehouses and other water and rail terminals, structures and facilities. Since that time, the Alabama State Docks has been a part of Alabama State government and functions as an independent department with a board of directors. Today, the Department operates as a self-supporting enterprise agency of the Executive branch of state government.

GENERAL INFORMATION:
About 375 employees operate, maintain and market these facilities. In 1999, the Port of Mobile was the 14th largest port in the nation in total tonnage. The economic impact to the State of Alabama was over $3 billion statewide. Tax payments of $467 million were made from activities in the International Trade sector. And most importantly, the Alabama State Docks supports the jobs of more than 118,000 Alabamians.

The Alabama State Docks offers 29 general cargo berths with about 4 million sq ft of covered storage space and an additional 4 million sq ft of open storage area adjacent to piers and tracks. The Docks' general cargo capabilities have been enhanced in recent years, with about $80 million invested in capital improvement projects. New state-of-the-art wharves and warehouses include the 360,000-sq ft Forest Products Terminal at Pier C, the 152,000-sq ft Blakeley Terminal on the east bank of the Mobile River and the Steel & Heavy Lift Operations Berth at Pier North C, to warehouses with a combined space of 253,000 square feet, a new pier for Roll On-Roll Off operations, and a concreted marshaling area.

The State Docks also provides a container port operation and other RO/RO berths accommodating some of the largest ocean-going vessels afloat. The inner harbor is accessible to ships drawing 40 ft of water. The outer harbor is dredged to accommodate vessels drawing 45 ft.

OPERATIONAL PARAMETERS: Port of Mobile

Facility Type	Physical/Operational Parameters
Location	The Alabama State Docks is located on the Mobile River. This river is formed some 45 miles north of the city with the joining of the Alabama and Black Warrior/Tombigbee Rivers.
Channel Access	The U.S. Army Corps of Engineers maintains the navigation channel to a depth of 45 ft from the Gulf of Mexico to the mouth of the Mobile River.
Land Access	Highway: approximately 2 miles from I-10. Rail: Terminal Railway operates on 75 miles of track using eight locomotives to transport cargo to and from piers, warehouses and terminals. It connects to four mainline railroads: Burlington Northern/Santa Fe; CSX; Illinois Central, and Norfolk Southern.
Docking	35 berths available for handling cargo (29 general cargo and 6 bulk).
Intermodal transfer (on dock)	
Warehouse Storage	more that 2.2 million sq ft of covered storage.
Yard Storage	McDuffie - 125 acres; Main docks cover 500+acres (about 100 is prepared storage area); Middle Bay has 200 acres; Choctaw Point has 276 acres.
Inland Transport	consists of 16,000 miles of navigable inland waterways through the Tenn-Tom Waterway.
Cargo Throughput (per hour)	varies according to commodity and dock.
	Planned Expansion/Dates Currently awaiting legislative approval for a $100 million appropriation that would fund a container intermodal facility **Constraints/Impediments** The port has excellent land and water access. The only impediment is financial limitations. **Potential Vessel Services** New liner services have been attracted to the port.

Port of Houston Authority

(Port of Houston)
P. O. Box 2562
Houston, TX 77252-2562
(713) 670-2429

LOCATION:
The Port of Houston has been an operational deep-draft port since 1914. It's central location on the Gulf Coast has helped it to become the world's 8th largest port. The port ranks first in the United States in foreign waterborne commerce and second in total tonnage. It consists of a 25-mile-long complex of diversified public and private facilities located on the Houston Ship Channel just a few hours' sailing time from the Gulf of Mexico.

Ample truck, rail and air connections allow shippers to economically transport their goods between Houston and inland points.

ORGANIZATION:
The Port of Houston Authority owns and operates eight public facilities along the Houston Ship Channel and is the channel's official sponsor. The Houston Ship Channel extends 50 miles inland and links the City of Houston with the Gulf of Mexico. The Authority is a navigation district and a political subdivision of the State of Texas.

The seven-member Port of Houston Commission is the governing body for the Port of Houston Authority. Each member is appointed for a 2-year term. The City of Houston and the Harris County Commissioners Court each appoint two commissioners. These two governmental entities jointly appoint the chairman of the Port Commission. The Harris County Mayors & Councils Association and the City of Pasadena each appoint one commissioner.

GENERAL INFORMATION:
Houston lies within close reach of one of the nation's largest concentrations of consumers. More than 17 million people live within 300 miles of the city, and approximately 60 million live within 700 miles.

Since the Port of Houston first opened to deep-water vessels in 1914, Houstonians have recognized that their port is an important economic catalyst. The port is one of the most significant sources of jobs and revenue in the community.

Each year more than 6,400 vessels call at the port. The 1997 figures show the port's public and private marine terminals generate $7.7 billion in business revenues annually. In addition, direct and related jobs associated with port activity totaled 204,520 in Texas and another 436,500 nationwide. Direct jobs are those generated by the companies providing support services to the cargo handling and vessel-related services of the port. Related jobs are those created locally and throughout the regional economy due to purchases of goods and services by those directly associated with port activity. Of the 75,487 direct jobs affiliated with Port of Houston activity, approximately 90% are held by Houston and Harris County residents. Related jobs totaled 129,033. Research shows the port also generates $525 million dollars annually in state and local taxes.

OPERATIONAL PARAMETERS: Port of Houston

Facility Type	Physical/Operational Parameters
Location	Located in the City of Houston along the 25-mile complex known as the Houston Ship Channel.
Channel Access	The Houston Ship Channel is accessed from the Gulf through Galveston Bay - depth 36 ft to 40 ft.
Land Access	All terminals have near access to Interstate highways. All terminals have rail access.
Docking	Barbours Cut Terminal-6,000 ft; Turning Basin Terminal-20,000 ft; Woodhouse Facility-1,910 ft; Jacintoport-1,830 ft; Public Grain Elevator-600 ft; Bulk Materials Handling Plant 650 ft; Care Terminal-1,118 ft; Galveston Container Terminal-1,436 ft.
Intermodal transfer (on dock)	Container cranes-30/50 ton capacity, lash dock, Ro/Ro ramp, 500 ton barge crane, two container gantry cranes, 20-300 ton shore cranes; Direct discharge of cargo, to truck or rail; Container cranes-40/60 ton capacity.
Warehouse Storage	Over 2,000,000 sq ft of covered storage.
Yard Storage	Over 300 acres of open storage and marshalling area.
Inland Transport	Inland transport is by rail and truck and the GIWW.
Cargo Throughput (per hour)	Varies with commodity and terminal being used.
	Planned Expansion/Dates 45' foot deep channel being constructed; planned expansion of container facilities; expansion and renovation of facilities at Turning Basin Terminals, Barbours Cut, Houston Ship Channel, Bulk Materials Handling Plant and Bayport. **Constraints/Impediments** **Potential Vessel Services** Potential cruise market.

Port of Victoria

Port Victoria, TX took its place as a port in 1968 when the 35-mile Barge Canal to Victoria was completed. The Port of Victoria in Texas is a joint effort supported by the Victoria County Navigation District and the West Side Calhoun County Navigation District. Major products transferred in at the port include liquid and dry bulk, general and project cargos.

The Port turning basin area is situated on over 400 acres and is served by rail and 4 lane divided highways. A 350 ft transit dock and a lighting system allow for 24 hour/7 day a week cargo operations. There are 20 mooring sites and 17,000 sq ft of shed space and over 3 acres of ground storage areas. A 7,300 sq ft office and storage building is also located at the turning basin.

The Victoria Barge Canal is a 35-mile long waterway that connects the Turning Basin in Victoria to the Gulf Intracoastal Waterway. The distribution advantage of the canal is its link with the Gulf Intracoastal Waterway and the major shipping lines that service ports on the Texas coast. The GIWW not only links the Gulf Coast from Brownsville, TX to Apalachee Bay, FL but also the Mississippi River, Ohio River and their connecting canals and river basins. This links Victoria to Minneapolis/St. Paul, Chicago and the Great Lakes, Pittsburgh, PA and Knoxville, TN to mention only a few locations on the 26,000 mile Inland Waterway system.

In March 2002, a $50 million widening and deepening project was completed. This partnership with the U.S. Army Corps of Engineers produced new channel dimensions of 12 ft in depth and 125 ft in width (the operational width is 75 ft and an air draft of 50 ft). The original dimension of the canal was a depth of 9 ft and width of 100 ft. This expansion will allow for larger vessels and heavier loads to access the Canal.

Also newly created at the Port of Victoria is a multi-modal industrial park. The Park is located within a free trade zone and a Texas Enterprise Zone. The Navigation Districts have the ability to build to suit and tailor a package specific to customer facility and transportation needs. The Port of Victoria is a center for the petrochemical, construction and steel fabrication industries. The most recent success in the Industrial Park is a 36,000 sq ft “build to suit” metal fabrication unit complete with 30-ton overhead cranes for a power generation manufacturing customer. The company will employ over 100 people and have an economic impact of over $25 million annually.

Companies that benefit from the barge canal and industrial park include DuPont, The Fordyce Company, BP Chemical, Seadrift Coke, Dow Operations, United Agri Products, and Technicoat. The Barge Canal generates over 11,000 jobs with a personal income of $364.2 million.

Port of Galveston

Located on the upper Texas coast at the mouth of Galveston Bay, 9.3 miles from the open sea, the Port of Galveston hosts facilities to handle all types of cargo including containers, dry and liquid bulk, breakbulk, RO/RO, refrigerated and project cargoes and cruise passengers. The Galveston channel has an authorized minimum depth of 40 ft and is 1,200 ft wide at its narrowest point.

The Port owns and operates for hire public wharves, transit sheds, open and covered storage facilities, warehouses and freight handling facilities. The majority of land and facilities are leased. Facilities include:

TERMINAL RAILWAY / Operator: Galveston Railroad, L.P.
- Provides rail connections to the Burlington Northern Santa Fe Railroad and the Union Pacific Railroad System

PIER 10 CONTAINER TERMINAL / Operator: Port of Houston Authority
- Import and Export Containers
- 1,346-ft, 2-berth dock
- Water depth of 40 ft
- 4 container cranes
- 38-acre terminal
- On-terminal rail ramp
- Truck and rail served

PIER 14 MARINE REPAIR FACILITY / Operator: Smith-Hamm, Inc.
- Maintenance and repair of vessels and drilling rigs
- 1,509 ft of berthing space
- Water depth of 24 ft to 25 ft
- 35,000 sq ft of backup space

PIER 16-18 FRESH FRUIT AND PRODUCE / Operator: Del Monte Fresh Produce
- Import fresh fruit, primarily bananas
- 1,203-ft, 2-berth dock
- Water depth of 34 ft
- 65,000 sq ft of refrigerated warehouse space
- Truck served

PIER 19 MOSQUITO FLEET / Operator: Marina for Commercial Fishing Boats
- Commercial Shrimping and Fishing Boats
- Deepsea Party Boats
- Wholesale Seafood Businesses
- Restaurants

PIER 19-22 WINDOW ON THE WATERFRONT / Tourist-Oriented Facility
- Ocean Star Drilling Rig Museum
- Shops
- Restaurants

- Theaters and art galleries
- Waterfront Inn
- 1877 Iron Barque ELISSA
- Restaurants
- Texas Seaport Museum

PIER 25 CRUISE SHIP TERMINAL / Operator: Port of Galveston
- 800-ft berth
- Water depth of 30 ft
- Efficient passenger and luggage handling
- Total PAX Embarkation Area - 44,000 sq ft
- Total PAX Disembarkation Area - 48,000 sq ft
- Total Cruise Terminal Area - 132,000 sq ft
- Supplier Staging Area - 53,000 sq ft
- Future Interior Expansion Area - 90,000 sq ft

PIER 30-32 EXPORT GRAIN ELEVATOR / Operator: ADM/Farmland Inc.
- Export bulk grain
- 1,000-foot berth
- Water depth of 40 ft
- 3,000,000 bushel storage capacity
- Railcar unloading capacity of 1,600 MT
- Vessel loading capacity of 2,000 MT per hour
- Truck and rail served

PIER 34 MANUFACTURING FACILITY / Operator: Deep Flex
- Manufacturing of flexible pipe for offshore oil and gas industry
- Export of flexible pipe
- Water depth of 40 ft
- 44,530 sq ft warehouse space
- Truck served

PIER 34 IMPORT/EXPORT VEHICLE HANDLING FACILITY / User: "K" Line
- Importation of vehicles - Primarily agricultural and construction equipment
- 632 ft berth
- Water depth of 38 ft
- Adjacent warehouse space of 184,795 sq ft
- Truck and rail served

PIER 35 MANUFACTURING FACILITY / Operator: EnviroLife, Inc.
- Manufactures floral foam used in the fresh flower marketing business

PIER 35-36 IMPORT SUGAR TERMINAL / Operator: Imperial Sugar Company
- Import bulk sugar
- 642-ft berth
- Water depth of 36 ft
- 30,000 ton storage capacity
- 2 shipside gantry cranes

- Truck and rail served

PIER 37 IMPORT/EXPORT VEHICLE HANDLING TERMINAL / Operator: Wallenius Wilhelmsen Lines

- Import vehicles primarily agricultural and construction equipment
- 1,160-ft berth
- Water depth of 34 ft
- 75,000 sq ft warehouse
- 12 acres of marshalling area
- Truck and rail served

MARINE REPAIR FACILITY / Operator: First Wave/Newpark Shipbuilding - Pelican Island, Inc.

- Maintenance and repair of vessels and drilling rigs
- 110-acre facility
- Water depth of 25 ft to 40 ft
- 5000 ton dry dock
- Repair, modifications, construction, engineering and environmental services to the marine and offshore industry
- Fabrication areas and equipment to support modular construction
- Pier space and services to accommodate all types of floating structures

Appendix III

Description of OCSGEN

Technical Description of OCSGEN

OCSGEN calculates volumes of waste generated by OCS activities that must be transported back to shore and handled by land-based waste management facilities from input estimates of average rates of waste generation and level of activity. In its current phase, broad estimates about the rates of waste generation are applied across the entire Gulf Coast OCS to arrive at gulf-wide estimates for waste generation over a 35-year planning period. The model allows the user to model more precisely the specifics of a particular lease sale, technology assumption, or rule by changing the inputs to reflect more accurate scenario-specific waste generation rates and activity rates.

OCSGEN allows for waste generation from either an active drilling rig, an active producing well, a completion, or a workover. Each activity event is assigned a waste generation rate such as barrels per well drilled, tons of MSW per active well per year, tons of MSW per active drilling rig per year, and so forth. These rates are found as inputs and the rows labeled as such.

For the Gulf-wide estimates, OSCGEN allows two different cases for each of three planning regions. Although these could be combined into as many as six scenarios, in the version presented here only the “High” and “Low” exploration scenarios for each of the three planning areas are presented. “High” and “Low” scenarios each contain the same waste generation rate assumptions. For a given exploration scenario, “High” and “Low” could just as easily be defined to represent a range of waste generation rates, resulting in a range of total waste generation volumes for the analysis at hand.

OCSGEN waste generation rates presented here represent conclusions based on professional judgment but draw on observations collected from the following sources.

- regulators
- trade associations
- generators
- waste management companies
- literature reviews

The subjective conclusions relied on reconciling numerous sources into a single-point estimate.

The estimates were not developed from a random sample with statistical precision due to limitations of budget and survey techniques. Regardless of how accurate the waste generation rate estimates may ultimately prove to be, the nature of oil and gas operations makes generalizations of Gulf-wide activity to a single well or field difficult. Any given well or particular type of well may vary widely from the mean. Further data gathering efforts by future researchers may well introduce valid statistical measurement into the quantification of waste generation rates. We must point out, however, that changes in exploration and production technology and regulation may do their part to render obsolete within a few years even an accurate estimate made at a given point in time.

	Eastern Planning Area		**Central Planning Area**		**Western Planning Area**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Oil, bbls.	75000000	140000000	9250000000	12350000000	1485000000	2735000000
Gas, MCF	1800000000	2710000000	82650000000	1.13475E+11	37780000000	54225000000
BOE	394715808.2	621349911.2	23930284192	32505417407	8195479574	12366438721
Existing wells (total)			12839	12839	2105	2105
Oil wells			5906	5906	397	397
Gas wells			5315	5315	1487	1487
Rigs years required to drill	47.8	204.7	1831.3	3212.0	1261.9	2424.4
Well Activity						
Exploration and delineation wells	80	420	3520	5020	1805	3265
Development wells	135	500	4710	9415	1685	3440
Oil wells	55	305	2710	5470	285	830
Gas wells	80	195	2000	3945	1400	2610
Workovers and completions	459	1700	113300	126300	20000	24600
Production Structures						
Existing structures	0	0	3454	3454	509	509
Number installed	15	55	685	1320	270	495
Structure removals using explosives	2	8	336	487	81	123
Total structure removals	6	21	490	720	120	190
Producing wells per structure	9.00	9.09	6.88	7.13	6.24	6.95
Method of Oil Transportation						
Percent Piped			90%	96%	95%	94%
Percent Barged				1%	1%	2%
Percent Tankered			10%	3%	4%	4%
Length of installed pipelines (km)			25,270	35,200	4,140	5,770
Length of installed oil pipelines (km)			5,260	9,950	790	1,510
Length of abandoned pipelines (km)			3,590	6,390	400	720
Length of removed pipelines (km)			26	380	4	70

Blowouts	25	29	79	124	27	50
Service-vessel trips	41,000	137,000	8,576,000	10,201,000	1,683,000	2,229,000
Helicopter trips	4,787,000	5,754,000	15,784,000	24,298	9,281	13,692
Waste transported ashore						
Barrels per exploratory well drilled:						
Mud	7,861	7,861	7,861	7,861	7,861	7,861
Cuttings	2,681	2,681	2,681	2,681	2,681	2,681
Barrels per development well drilled:						
Mud	5,808	5,808	5,808	5,808	5,808	5,808
Cuttings	1,628	1,628	1,628	1,628	1,628	1,628
Barrels per completion/workover:						
Fluids	150	150	150	150	150	150
Drilling, completion and workover waste discharged						
Barrels per exploratory well:						
Mud	7,861	7,861	7,861	7,861	7,861	7,861
Cuttings	2,681	2,681	2,681	2,681	2,681	2,681
Barrels per development well:						
Mud	5,808	5,808	5,808	5,808	5,808	5,808
Cuttings	1,628	1,628	1,628	1,628	1,628	1,628
Barrels per completion/workover						
Fluids	100	100	100	100	100	100
Produced waste discharged						
Barrels of water per day/oil well	450	450	450	450	450	450
Barrels of water per day/gas well	68	68	68	68	68	68
Produced sand, barrels per bbl of oil	0.005	0.005	0.005	0.005	0.005	0.005
Total waste discharged per year						
Produced water from oil wells	3,513,125	19,481,875	173,101,250	349,396,250	18,204,375	53,016,250

Produced water from gas wells	717,022	1,747,742	17,925,556	35,358,158	12,547,889	23,392,850
Workover/completion fluids	1,275	4,722	314,722	350,833	55,556	68,333
Produced sand	54,822	86,299	3,323,651	4,514,641	1,138,261	1,717,561
Waste volumes transported ashore						
Barrels per exploratory well:						
Mud	1,595	1,595	1,595	1,595	1,595	1,595
Cuttings	386	386	386	386	386	386
Barrels per development well:						
Mud	444	444	444	444	444	444
Cuttings	108	108	108	108	108	108
Barrels per completion/workover:						
Fluids	200	200	200	200	200	200
Drilling mud	187,540	891,900	7,705,640	12,187,160	3,627,115	6,735,035
Cuttings	45,460	216,120	1,867,400	2,954,540	878,710	1,631,810
Completion/workover fluid	9,180	34,000	2,266,000	2,526,000	400,000	492,000
Planning period total	242,180	1,142,020	11,839,040	17,667,700	4,905,825	8,858,845
Average per year	6,727	31,723	328,862	490,769	136,273	246,079
MSW, tons per rig/year	192	192	192	192	192	192
MSW, tons per producing well/year	0.64	0.64	0.64	0.64	0.64	0.64
Total MSW generated (tons)						
From established production	0	0	82802.34519	82802.34519	23414	23414
From new production	4866.628996	17109.94796	1041043.271	1175981.621	193220.520	245678.989
From drilling	9185.467372	39305.25573	351611.1464	616708.0071	242283.556	465476
Total MSW	14052.09637	56415.20369	1392654.418	1792689.628	435504.076	711154.989
Average MSW per year	390.3360102	1567.088991	38684.84494	49796.93411	12097.3354	19754.3052

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.