



# Onshore Oil and Gas Infrastructure to Support Development in the Mid-Atlantic OCS Region



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## **ABSTRACT**

This report examines the wide range of energy infrastructure assets that would be required if the Outer Continental Shelf (OCS) of the Mid-Atlantic region were opened to oil and gas production. The report does not explore any testable hypotheses or other complex research questions, but merely describes, examines, and outlines the nature of a variety of different, yet important, energy infrastructure assets and their current status within the Mid-Atlantic region. This report examines these infrastructure assets' recent development trends and their outlook given ongoing and expected offshore oil and natural gas exploration and production (E&P) activities.

This report examines 11 major energy infrastructure categories significant to development in the Mid-Atlantic OCS region, including: platform fabrication and shipyards; port facilities; support and heliport facilities; oil spill response; oil field waste disposal; pipelines, pipe-coating yards; natural gas processing and storage; liquefied natural gas (LNG) facilities; refineries; and electric power infrastructure.

The report identifies and describes each type of onshore infrastructure that would potentially support OCS oil and gas projects in the Mid-Atlantic region. This includes an examination of the infrastructure, its unique features and how it is related to the oil and gas industry. Each type of infrastructure is inventoried and analyzed. A summary of the infrastructure type locations, operations, and capacities is provided. A list of existing facilities with descriptive statistics is provided in an accompanying project database. A discussion of potential infrastructure responses is included within each chapter, including a review of changes or additions to existing infrastructure to adapt to new development trends.

For purposes of this report, the Mid-Atlantic impact region is defined as the states along the East Coast of the U.S., from New Jersey, south to Georgia. The states included are: New Jersey, Delaware, Maryland, Pennsylvania, Virginia, North Carolina, South Carolina, and Georgia.

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## ABBREVIATIONS, ACRONYMS AND SYMBOLS

3LP	three-layer polyolefin
AAM	Alliance of Automobile Manufacturers
ACE	Army Corps of Engineers
ACJV	Atlantic Coast Joint Venture
ADIOS	Automated Data Inquiry from Oil Spills
AGA	American Gas Association
AHSV	anchor handling towing and supply vessel
AHTS	anchor handling towing supply
API	American Petroleum Institute
ARRA	American Recovery and Reinvestment Act
BCF	billion cubic feet
BOEM	Bureau of Ocean Energy Management
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CDS	construction differential subsidies
CSAPR	Cross-State Air Pollution Rule
CWA	Clean Water Act
CWC	concrete weight coating
DCP	Dominion Cove Point
DfE	Design for the Environment
DOE	Department of Energy
DWMIS	Drilling Waste Management Information System
EISA	Energy Independence and Security Act
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
EPC	engineer, procure and construct
EPIC	engineer, procure, install and commission
EPP	Enterprise Products Partners
ERD	extended reach drilling
FAA	Federal Aviation Administration
FCC	fluid catalytic cracking
FDG	flu-gas desulfurizer
FERC	Federal Energy Regulatory Commission
FHA	Federal Highway Administration
FPSO	floating production, storage, and offloading
FPU	floating production unit
FRCC	Florida Reliability Coordinating Council
FRP	facility response plan
FSRU	floating storage and regasification unit
FTA	free trade agreement

GBS	gravity-based structure
GDP	gross domestic product
GIS	geographic information systems
GOM	Gulf of Mexico
HRT	Hart Resource Technologies
IADC	International Association of Drilling Contractors
ID	internal diameter
IMO	International Maritime Organization
INGAA	Interstate Natural Gas Association of America
IPAA	Independent Petroleum Association of America
ISO	Independent System Operator
JITF	Joint Industry Oil Spill Preparedness and Response Task Force
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MAP-21	Moving Ahead for Progress in the 21 <sup>st</sup> Century
MARAD	U.S. Department of Transportation, Maritime Administration
MARPOL	International Convention for the Prevention of Pollution from Ships
MBbls/d	thousand barrels per day
Mm	millimeter
MMBbls/d	million barrels per day
MODU	mobile offshore drilling units
MOSCA	Miscellaneous Oil Spill Control Agents
MRO	Midwest Reliability Organization
MSB	major shipbuilding base
MSRC	Marine Spill Response Corporation
MSV	mini-supply vessel
MTS	Marine Transportation System
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NAPCA	National Association of Pipe Coating Applicators
NASSCO	North American Steel and Shipping Industry
NCP	national contingency plan
NERC	North American Electric Reliability Corporation
NGL	natural gas liquids
NGTS	NiSource Gas Transmission & Storage
NHS	National Highway System
NHTSA	National Highway Traffic Safety Administration
NIOSH	National Institute for Occupational Safety and Health
NOAA	National Oceanic and Atmospheric Administration
NOIA	National Ocean Industries Association
Non-FTA	non-free trade agreement
NORM	naturally-occurring radioactive materials
NOx	nitrogen oxides
NPC	National Petroleum Council
NPCC	Northeast Power Coordinating Council

NPDES	National Pollutant Discharge Elimination System
NRDA	Natural Resource Disaster Assessment
NRU	Nitrogen Rejection Unit
NSF	National Science Foundation
NSI	National Shipbuilding Initiative
NYH	New York Harbor
OBM	oil-based mud
OCM	oil content meter
OCS	Outer Continental Shelf
OLM	online monitoring
OMB	Office of Management and Budget
OSHA	Occupational Safety Act
OSPRS	Oil Spill Preparedness and Response Subcommittee
OSRO	Oil Spill Response Organization
OSV	offshore support vessel
OSW	offshore wind
PADD	Petroleum Administration for Defense Districts
PAH	polynuclear aromatic hydrocarbon
PAL	parking and lending
PE	polyethylene
PHI	Petroleum Helicopters Inc.
POTW	publicly-owned treatment works
PP	polypropylene
PSA	pressure swing adsorption
PSC	port state control
PSI	pounds per square inch
PSIG	pounds per square inch gauge
PSV	platform supply vessel
QF	qualified facility
RCRA	Resource Conservation and Recovery Act
REX	Rockies Express Pipeline
RFC	Reliability First Corporation
RFS	Renewable Fuel Standard
ROW	right-of-way
RTO	Regional Transmissions Organizations
SAFETEA-L	Safe, Accountable, Flexible, Efficient Transportation Equity Act
SBM	synthetic-based mud
SCR	steel catenary riser
SDWA	Safe Drinking Water Act
SEGCO	Southern Electric Generating Company
SERC	SERC Reliability Corporation
SO <sub>2</sub>	sulfur dioxide
SPCC	Spill Prevention, Control and Countermeasure
SPP	Southwest Power Pool
TEA-21	Transportation Equity Act for the 21 <sup>st</sup> Century
TEU	twenty-foot equivalent unit

TGP	Tennessee Gas Pipeline
TLP	tension leg platform
TRE	Texas Regional Entity
TRR	technically recoverable resource
ULSD	ultra low sulfur diesel
USCG	United States Coast Guard
USOGA	United States Oil and Gas Association
WBM	water-based mud
WECC	Western Electricity Coordinating Council

## SUMMARY

The purpose of this research has been to examine the wide range of energy infrastructure assets that would be required if the Outer Continental Shelf (OCS) of the Mid-Atlantic region were opened to oil and gas production. The infrastructure categories examined include: platform fabrication and shipyards; port facilities; support and heliport facilities; oil spill response; oil field waste disposal; pipelines, pipe-coating yards; natural gas processing and storage; liquefied natural gas (LNG) facilities; refineries; and electric power infrastructure.

A number of issues and topics have been examined for each of these sectors, including:

1. A basic description of the industry and the types of services provided;
2. A review of each sector's characteristics and an overview of the typical types of facilities;<sup>1</sup>
3. The geographical distribution of existing companies and locations within the Mid-Atlantic region;
4. The impact or scope of existing infrastructure to the regional economy;
5. Current trends and outlook for the industry as a whole, including changes in regulation and regulatory guidelines governing each industry sector;
6. Current trends and outlook for the industry in the Mid-Atlantic region;
7. A discussion of factors that would impact development of each infrastructure type in the Mid-Atlantic region;
8. A list of resources and data sources for each type of infrastructure.

For purposes of this fact book, the Mid-Atlantic impact region is defined as the states along the East Coast of the U.S. from New Jersey, south to Georgia. The states included are: New Jersey, Delaware, Maryland, Pennsylvania, Virginia, North Carolina, South Carolina and Georgia.

### ***Fabrication Yards***

Platform fabrication yards are defined as facilities where oil and gas drilling and production platforms are manufactured, assembled, or prepared for deployment to offshore locations. Production operations at fabrication yards include cutting and welding of steel components, construction of living quarters and other structures, and assembling platform components.

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<sup>1</sup> This is not a regionally specific overview, but rather a review of the types of facilities that exist within the industry.

Traditionally, platform fabrication yards are located onshore, near inter-coastal waterways. However, there is a growing tendency to locate certain assembly operations directly offshore to minimize costs and maximize assembly flexibility. On-shore platform fabrication yards usually specialize in the production of a particular type of platform or component, such as living quarters, decks, or modules. This creates interdependence among different yards to complete an entire platform.

There are no platform fabrication yards located in the Mid-Atlantic region. Development of these facilities is likely to depend on the degree to which offshore energy production progresses. Under a limited or moderate development scenario, it is likely that platforms and associated structures would originate in the Gulf of Mexico (GOM) region or international sites.

### ***Shipyards and Shipbuilding***

The shipbuilding and repair industry constructs, maintains, and repairs ships, barges and other large vessels, self-propelled or towed by other craft (i.e., barges). Most shipyards receive orders for offshore vessels through a competitive bidding process for individual projects or sets of individual projects. Each year, a small number of valuable orders are received by these shipbuilding yards that often take years to fill. Shipbuilding is a high-stakes industry represented by a high degree of competition between various different shipbuilders. It is uncommon for several yards to be engaged in various specialized aspects of very large projects.

There are eight shipyards in the Mid-Atlantic region, ranging from those that construct small vessels for coastal or inland use to those that focus on large oceangoing naval and commercial ships. Twenty facilities offer repair services. The repair facilities also vary in size, from those with only topside capability, to those that have dry-docking capability for small ships, boats and barges, and those that have dry-docking capability for large ocean-going vessels. The medium-sized shipyards located in Virginia, Maryland, and North Carolina would be likely candidates for offering support capabilities to the Mid-Atlantic region.

Shipyards dedicated to medium-sized vessels would be likely candidates for offering support capabilities in this region. Most of the medium-sized yards are centrally located in Virginia, Maryland, and North Carolina. To the extent that new ships and the facilities to construct and service these vessels are needed, the central Mid-Atlantic region would represent a good opportunity for expansion. It is unlikely that any new facilities would be constructed in support of anticipated offshore lease activities.

The shipbuilding industry is highly competitive and existing GOM yards may consider expanding existing operations to compete for these new markets. Existing yards along the GOM would have a number of important advantages over both Mid-Atlantic greenfield developments and expansions, including existing yards with adequate capacity; sizable skilled workforce; engineering and design experience; decades of construction experience across a range of offshore service vessels and crafts; relationships with input vendors; and relationships with service and production companies.

Further, shipyard industry trends over the past decade have focused on mergers and consolidations not necessarily on expansions, even along the GOM. These mergers and acquisitions have arisen, in large part, to take advantage of the scale efficiencies of consolidated operations at larger, more strategic locations. Thus, the development of new Mid-Atlantic shipyards may be a challenge without an expansive regulatory development scenario with tight oil and gas market conditions over an extended period of time.

### ***Port Facilities***

Ports have a vital role in the support of the offshore E&P sector and in the maritime industry as a whole. Ports are the bases from which the vehicles that support offshore platforms (notably ships, barges, and helicopters) are based and maintained. Ports are also the delivery, transfer, and launching points for the necessary structures, equipment, supplies, crew and other important products to offshore installations. Offshore exploration and production operations depend heavily on a readily-available supply of these goods and services, making ports an invaluable centralized location for meeting offshore E&P logistical needs.

The Mid-Atlantic region has good port coverage and it is unlikely that any new ports would be constructed to support offshore energy production. Port development would be influenced by: (1) the specific location where development is expected to occur; and (2) the degree to which offshore support activities compete, or are in conflict with, bulk container and cargo trade that is currently the focus of larger regional ports. There are a number of moderately-sized ports located in the Chesapeake Bay region that could serve as likely support bases for offshore oil and gas activities.

Many ports along the eastern seaboard, particularly the upper Mid-Atlantic region, are already highly developed and in locations that have expensive or limited expansion possibilities. Development at these ports will likely compete with alternative uses for waterfront and port surface space. Because of the cost and physical restrictions, smaller to medium sized ports may have a competitive edge to in the pursuit of oil and gas support activities.

There are a number of moderately-sized ports located in the Chesapeake Bay region that could serve as likely support bases for offshore oil and gas activities. These central Mid-Atlantic ports are the closest to anticipated regional offshore development.

### ***Support and Heliport Facilities***

Offshore oil and gas activities are supported by an extensive 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. Drilling muds, chemicals, lubricants, and other fluids are produced and transported from onshore support facilities. Many types of transportation vessels and helicopters are used to transport workers, equipment, and materials to and from offshore platforms. Typical facilities for this sector include: general support facilities; repair and maintenance yards; and supply bases, heliports and offshore service vessels.

Offshore support and transportation facilities depend on drilling and production activities, which, in turn, are dependent upon oil and gas commodity prices. The cyclical nature of the oil and gas industry places competitive pressure on support and transportation facilities to be efficient, cost effective, flexible, responsive to tenant needs, and to diversify wherever possible. Often, the supply and transport side of the offshore industry is one of the first sectors to feel the sting of oil and gas industry downturns. During periods of contraction, discretionary supply, repair, storage, and maintenance activities are the first to be cut to reduce E&P company costs.

No support and transport facilities have been identified on the Mid-Atlantic coast (with the exception of heliports). Although general offshore support and transportation is tied directly to ports, our research does not suggest the development of private (company-owned) service facilities arising. Like ports, development in response to offshore activity will be influenced by the specific location of offshore activity.

The capital cost of development of such types of facilities by an individual offshore operator may be too expensive for one company alone. Support facility development is likely to track port development. Factors weighing against private support base facilities include:

- a. Potential conflicts with recreation and residential development.
- b. Permitting challenges.
- c. Facility development costs.
- d. Offshore development scenario uncertainties.
- e. Lower cost commercial port opportunities.

### ***Oil Spill Response***

The efficacy of any oil spill response team starts with its preparation, well before any accident or spill occurs. However, once a spill occurs, action must be taken quickly and well-organized so that the spill can be contained and controlled quickly. The planning ahead takes the form of a “contingency plan” which is a set of instructions outlining steps to take before, during, and after an emergency. These plans attempt to outline different spill scenarios and situations and the steps to follow. The U.S. Environmental Protection Agency identifies four major common elements of a contingency plan: (1) hazard identification; (2) vulnerability analysis; (3) risk assessment; and (4) response actions.

A number of oil spill response companies are located in the Mid-Atlantic region, including companies that respond to marine situations. The Mid-Atlantic region has a number of refineries that receive cargo from water-borne suppliers and spills from these cargoes and other industrial activities, are likely to be greater than those associated with OCS development.

While oil spill response uses capital-related equipment, this is mostly a knowledge-based industry that is highly mobile and assets from other producing areas could be used if a catastrophic accident were to occur. It is unlikely that new oil spill response investments will be needed in the region.

### ***Waste Management Facilities***

A number of different types of wastes are generated by offshore oil and gas E&P activities. Some wastes are common to most commercial-scale operations (e.g., disposal of garbage, sanitary waste [toilets] and domestic waste [sinks, showers]), while other wastes are unique to the oil and gas exploration and production industry (e.g., disposal of different types of drill fluids, cuttings, and produced water). While some wastes can be discharged onsite, many others must be transported to shore-based facilities for reclamation, storage and disposal, or transfer to longer-term storage sites. The most common methods of disposal of oil and gas E&P waste includes sea discharge; subsurface injection (salt cavern or other subsurface reservoir); and landfill disposal.

A small number of oil field waste disposal facilities are located in the Mid-Atlantic states; and most have been developed to support Appalachian drilling activities. Development in the Mid-Atlantic region will likely require expanded oilfield waste disposal capacity. The amount of capacity will be a direct function of the level of drilling and production activity anticipated in the Mid-Atlantic OCS because more drilling or production will result in expanded capacity requirements.

### ***Pipelines***

The movement of natural gas from producing regions to consumption regions requires an extensive and elaborate transportation system. In many instances, natural gas produced from a particular well travels long distances before it reaches the point of further processing or use. The transportation system for natural gas consists of a complex network of pipelines and supporting equipment, designed to quickly and efficiently transport these commodities from points of production, to points of further processing (i.e., gas processing, fractionation), storage, or consumption.

The interstate natural gas transportation system within the Mid-Atlantic region has been developed to facilitate the movement of natural gas from its primary producing area (GOM) to market areas along the East Coast. A large number of the existing interstate natural gas lines run along the Appalachian Mountain Range and then northwards to New York. Currently, no natural gas interstate pipelines run along the Mid-Atlantic coast. However, Columbia Gas has a segment that runs through Virginia to the coast and Transco has a segment that runs from mid-Virginia down close to the North Carolina coast.

Future pipeline development in the Mid-Atlantic OCS is likely to be based on a series of line segment extensions from future coastal producing areas to the existing major trunk lines running along the Appalachian Mountain Range. The overall investment level needed to link this production will be a function of the ability of the asset to facilitate the movement of the expected volumes of natural gas in a safe and reliable manner, taking into account future commercial considerations and opportunities.

The number of major trunklines and individual gathering systems will be determined by the scope and scale of Mid-Atlantic OCS production. The specific location and interconnection of these extensions to major trunklines will likely be a function of ultimate production location. Larger volumes produced in a concentrated geographic region are likely to see a fewer number of large trunk or gathering system configurations. Larger volumes produced over a broad geographic region will have a tendency to be smaller in capacity (diameter) but more numerous in terms of trunk or gathering segments.

### ***Pipe-Coating Yards***

Pipelines that transport oil and natural gas have exterior coatings to protect against corrosion and other types of physical damage. Pipes may also be treated with interior coatings to protect against corrosion from the fluids moving within the pipe or to improve flow rates. Offshore oil and natural gas pipes are often also coated with a layer of concrete to increase line weight to ensure it will stay on the seabed.

Numerous threats to offshore pipeline integrity include third-party damage, geological activity, and corrosion. The most common threat, external corrosion, is recognized as the main structural problem with buried pipelines, including those offshore. In fact, corrosion ranks second only to human error as the leading cause of pipeline failure.

The pipe coating business is highly dependent on the cyclical nature of oil and natural gas markets. Currently, all existing pipe coating facilities in the Mid-Atlantic states are in the Appalachian region. The degree to which these existing facilities would be used to support offshore OCS activities is undetermined. Under a limited or moderate development scenario, it is likely that coated pipe would come from existing facilities in the Appalachian region or the GOM region. At this point, it is unlikely that any new pipeline coating or fabricating facility will be developed along the Mid-Atlantic. It is probable that existing regional facilities will expand given the increases in regional shale and Marcellus production and new pipeline projects bringing gas from the Rockies into the Midwest-Appalachian area.

### ***Natural Gas Processing Facilities***

All natural gas is processed in some manner to remove unwanted water vapor, solids and other contaminants that would interfere with pipeline transportation or marketing of the gas. The total number of gas processing plants operating in the U.S. has been declining over the past several years as companies merge, exchange assets, and close older, less efficient plants.

There are eight natural gas processing plants in the Mid-Atlantic region, however they are all in western Pennsylvania and used to support Appalachian production. The need for gas processing along the Mid-Atlantic OCS will be a function of the degree to which wet or sour gas volumes, or both, are anticipated to be produced from offshore areas. Assuming gas processing is needed, many of the same factors influencing gas transportation will be important, including location, volumes and commercial factors (the ability to store, transport and market natural gas liquids processed from the gas stream will be important in determining facility configuration).

### ***Natural Gas Storage Facilities***

Gas storage serves three central roles: to meet seasonal demands for gas (base-load storage), to meet short-term peaks in demand (peaking storage), and to take advantage of changes in volatile natural gas prices between peak and non-peak usage periods (hedging and price arbitrage). The ability to store natural gas is essential to efficient natural gas market operation. Withdrawals from storage provide additional gas supply during seasonal and short-term gas demand peaks, help keep pipelines and distribution systems in physical balance, and play an important role in commodity trading and management. Generally, underground natural gas storage is filled during low use (off-peak) periods (April-October) and withdrawn during high use (peak) periods (winter). This results in a cyclical up and down pattern of gas storage volumes across any given year.

A number of natural gas storage facilities have been identified in the Mid-Atlantic states. However, these facilities are associated with Appalachian production or intermediate storage requirements for New England LDCs. It is likely that gas storage will be developed along the Mid-Atlantic OCS to accommodate new production volumes.

Four important factors to consider in the development of natural gas storage are (1) gas storage will likely be located near new areas of production; (2) the size will be a function of location and geological capabilities; (3) developers will need to determine the availability and cost effectiveness of reservoir, aquifer, or salt cavern storage; and (4) the type of cavern and size of the injection well will be driven by deliverability goals, location, and the number of proximate pipelines and potential storage customers.

Reservoir-based storage would be the more likely type of facility needed to support Mid-Atlantic offshore production given its baseload nature.

### ***LNG Facilities***

Liquefied natural gas (LNG) is natural gas that has been converted to liquid form. This simple process allows natural gas to be transported from an area of abundance to an area of high demand where it can be stored as a liquid or converted back to natural gas and delivered to end-users.

Large marine-based onshore LNG terminals have been proposed across different areas of the coastal U.S., and have received increased media and public attention in recent years. In 2011, there were five LNG import facilities located in the Mid-Atlantic and Gulf coast regions. Four of these facilities are original legacy assets that were developed during the energy crisis of the 1970s and early 1980s. These four facilities are all onshore facilities that have been expanded in recent years and each have a peak sendout of one Bcf per day or more.

There have also been a considerable number of announcements and applications for new regasification and export facilities throughout the coastal U.S. Nine facilities have requested authorization to export LNG. Two of the Mid-Atlantic facilities, Cove Point and Elba Island, have requested this authorization.

### ***Refineries***

A refinery is an organized arrangement of manufacturing units designed to produce physical and chemical changes to turn crude oil into final petroleum products. Refineries remove most of the non-hydrocarbon substances from crude oil and break down these remaining hydrocarbons into various components that are blended into useful refined products. Refineries vary in size, sophistication, and cost depending on their location, crude input types, and products manufactured. Crude oil is not a homogeneous raw material; it varies considerably in color, viscosity, sulfur content, and mineral content. Many of these qualitative variations are a function of the different fields or geographic areas from which crude is produced, and lead to significant differences in both input values and refining profitability.

Of the 11 refineries located in the Mid-Atlantic region, two are currently idle. The remaining nine active refineries in the region are relatively large by East Coast standards. Six of these refineries have capacities in excess of 160,000 barrels per day. All have the ability to handle light, sweet and certain grades of heavier, sour crude oil. Most produce a wide range of refined products from the high to low end of the barrel. Furthermore, most, if not all, of these facilities get their crude oil input supplies from imports and not from other producing basins in the U.S. None of these refineries are currently connected to a major interstate crude oil pipeline and obtain most of their supplies by tankers.

Existing refinery capacity would likely be used to process Mid-Atlantic OCS crude oil. It is highly unlikely, given expected overall market conditions over the next several years, that any East Coast refinery would expand its current capacity without some exceptional type of guarantee. It would be nearly impossible to site a new greenfield refinery along the Mid-Atlantic OCS and this potential scenario should be eliminated from consideration.

### ***Electric Power Infrastructure***

Electricity is vital to life in the U.S. and is used for lighting, appliances, and electronic uses and for heating and cooling. Electricity is also indispensable to factories, commercial establishments, and most recreational facilities. More than 2,930 electric utilities in the U.S. are responsible for delivering an adequate and reliable source of electricity at a reasonable cost to all consumers within their respective service territories.

Electric power systems are based on a collection of generation, transmission, distribution and communication facilities that are physically connected and operated as a single unit under one control. Power plants (generation) can be grouped into the types of fuel or energy source they use to produce electricity. These include fossil fuels (coal, natural gas, or a refined oil product), nuclear energy, and renewable energy sources such as water (hydroelectric power), biomass, waste-to-energy, geothermal, wind, and solar energy, and other emerging alternative fuels. Power generation in the Mid-Atlantic is heavily dependent on natural gas as a fuel source. Thus, the price and availability of natural gas can have important implications for power generation supply and price.

According to the EIA, over the next 25 years total electricity sales are projected to increase significantly, including sales in the U.S. and Mid-Atlantic region. The largest increase will be seen in the residential and commercial sectors; industrial demand is projected to decrease.

# **1 PLATFORM FABRICATION AND SHIPYARDS**

## **1.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED**

### **1.1.1 Platform Fabrication**

In the early years of drilling, oil men tried many different techniques to extract oil from the swamplands of Louisiana. The most successful methods relied on using floating vessels or barges with drilling equipment over swamps, marshes, or open water. Even though these technologies were functional, they were crude and were limited to a small drilling area over water and marshes. Also, these technologies were operational only when and where the water was calm, shallow, and protected from wind exposure. Over time, technology continued to advance and eventually mobile drilling rigs were developed.

The world's first submersible oil platform was created in 1933. This prototype was named Giliasso and used barges to carry an equipment platform and a derrick or rig. Giliasso was towed and then sunk off the shore of Louisiana at a pre-determined location for use as a fixed foundation for the platform above water (Wilds et al. 1996). The development of the Giliasso ended the task of assembling and dismantling units for every well (Davis 2002). However, new problems arose in determining how to provide support for crews and to receive supplies needed for drilling.

Giliasso's success helped spawn a number of other technological advances related to modification of floating structures near-shore for exploration and production activities and logistical support. Initially, drilling crews lived in piling-supported camps which were suspended over the marsh. There was a lack of above-ground storage, and drilling mud had to be hauled 35 miles (56 kilometers) to the drilling site (Davis 2002). To solve the storage problem, rig workers used three old grounded oil tankers and connected them to an old steel schooner, which was used as a loading dock (Davis 2002). Eventually, a pipeline was constructed which ended the need for vessels to transport the oil onshore.

Since 1942, more than 6,900 platforms have been installed in the GOM (USDOJ, BOEM 2012a). Currently, there are about 2,900 active platforms, most of which are in water depths of less than 200 meters (USDOJ, BOEM 2012b). Platform fabrication, since its beginning, has been a principal contributor to technological advancements in the offshore oil and gas industry. Today platform fabrication facilities span regional and international areas, especially in the GOM from Texas to Alabama.

There are approximately 5,924 active leases in the GOM; 54 percent are in water depths greater than 1,000 meters, or "deepwater" (USDOJ, BOEM 2012b). A push for deeper water drilling in the GOM since the mid-1990s has forced the platform fabrication industry's advancement to meet the new challenges presented by being farther from land. Most obviously, rigs and wells have become significantly larger. Having a larger drilling structure also means that the fabrication yards, docks, and assembly facilities must adapt and increase in size.

This size shift has spawned a modular-based approach of fabrication. In the GOM, for example, each yard specializes in producing a specific component or type of platform and teams up with other yards to produce the other required parts. Even very large yards contract out for certain aspects of their platform projects. For example, a yard may focus on producing living quarters, decks, modules, or storage facilities. The modular based approach has created independence among different yards, and yet still produces coherent and complete platforms (USDOJ, MMS 2005).

### **1.1.2 Shipyards**

Shipyards are another vital aspect of the offshore oil and gas industry because they are responsible for building ships, barges, and other large vessels. Some of these vessels are self-propelled, but others are towed by other craft. Marine vessels are quite likely the most important means of transporting equipment and personnel from onshore bases and ports to offshore drilling and production platforms. Shipyards build vessels for use in the oil and gas industry and also fulfill orders for other industries such as towing and tugboat companies, petrochemical companies, commercial shipping companies, commercial fishing companies, passenger and cruise companies, ferry companies, and the federal government (Colton 2012).

The federal government is the largest customer of the shipbuilding industry, because of the high demand for naval and marine craft. These ships range from large navy combatant construction (i.e., aircraft carriers, destroyers, frigates, guided missile cruisers, etc.) to noncombatant tankers, patrol ships, and smaller experimental craft used for ocean and marine life observation (USEPA 1997). Besides the U.S. Navy, a number of other government agencies place orders for ships such as the Military Sealift Command, the Army Corps of Engineers, the U.S. Coast Guard, the National Oceanic and Atmospheric Administration, the National Science Foundation, and the Maritime Administration (USEPA 1997). The primary focus of shipyards in the Mid-Atlantic region is meeting the federal government demand.

The development of the U.S. shipbuilding industry was driven by military needs. For example, in 1932 there were eight shipyards: Bath Iron Works, Bath, Maine; Bethlehem's Fore River Plant, Quincy, Massachusetts; Bethlehem's Union Iron Works, San Francisco, California; Electric Boat Co., New London, Connecticut; Federal Shipbuilding, Kearny, New Jersey; New York Ship, Camden, New Jersey; Newport News Shipbuilding, Newport News, Virginia; and United Drydocks, Staten Island, New York. These eight shipyards employed 19,000 and focused primarily on naval shipbuilding (GlobalSecurity.org 2012).

The Maritime Administration was created in 1936 by the Merchant Marine Act, and worked to change the U.S. shipbuilding industry. The Maritime Commission began an extensive ship construction program towards the end of the 1930s, which intensified with the U.S. involvement in World War II (Lane 2001). Due to the expansion of the shipbuilding industry, when the war ended there were nine different federally-owned and operated shipyards and over 130 privately-owned shipyards (GlobalSecurity.org 2012).

After WWII ended, there was a corresponding decrease in the need for naval craft. However, the government believed that private shipyards were too essential to U.S. military and economic strength to let them go out of business. By 1961, up to 70 percent of naval construction funding went to private yards (GlobalSecurity.org 2012). Navy yards primarily performed maintenance and repair functions. Since the 1960s, the shipbuilding industry has evolved into a group of small to medium-sized shipyards that build vessels for foreign, inland, and coastal waterway use. The increase in offshore exploration and production activity has helped to expand market demand and the number of customers for shipyards to serve (Austin et al. 2008).

## **1.2 TYPICAL FACILITY CHARACTERISTICS**

### **1.2.1 Platform Fabrication**

Platforms are constructed onshore at a fabrication yard and then towed to an offshore location for installation and sea-fastening (SEC 2011a). Fabrication yards perform a variety of functions including cutting and welding of steel components, construction of living quarters and other structures, and assembling platform components (Gulf Island Fabrication 2011). These facilities often span areas of several hundred acres because they need space for large construction projects and equipment. For instance, yards must have on hand an inventory of necessary items used in platform fabrication: metal pipes and beams, cranes, welding equipment, lifts, rolling mills, and sandblasting machinery. Since platform jackets are so large, vast space is also required for proper assembly.

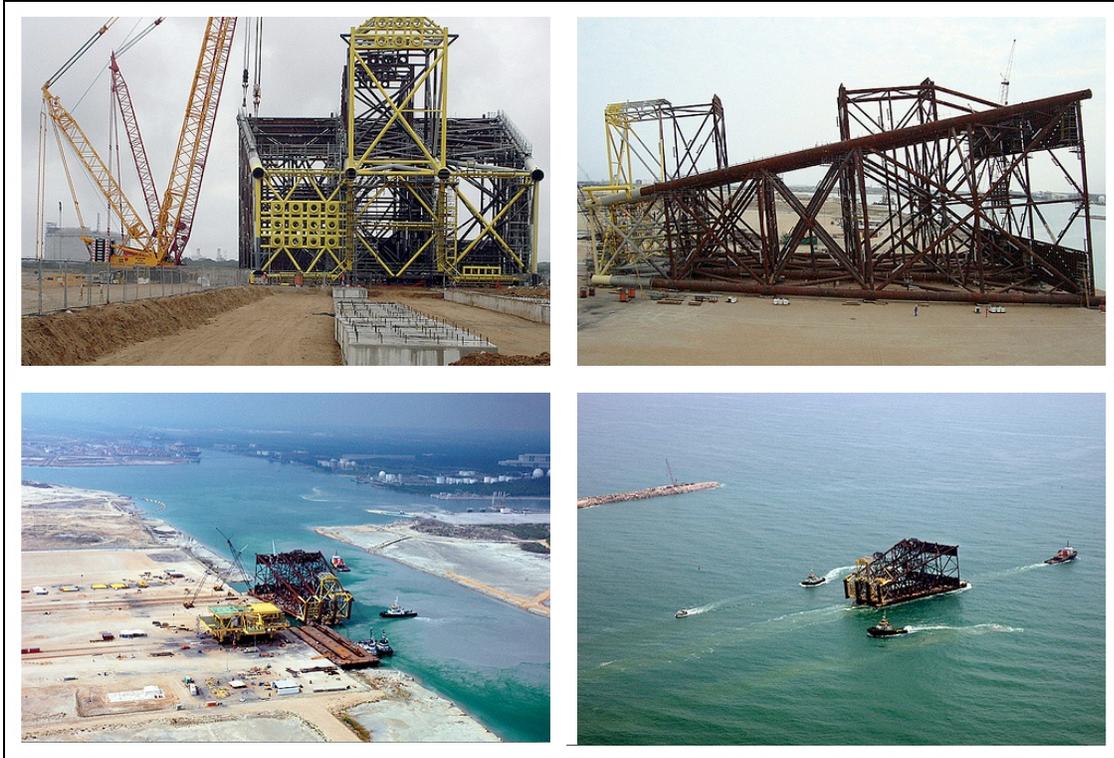
Figure 1 is a picture of Gulf Island Fabrication's main yard in Houma, Louisiana. This is one of three yards and covers 140 acres and 2,800 linear feet (853 meters) of water frontage (Gulf Island 2012).



**Figure 1. Gulf Island Fabrication, main yard.**

Source: Gulf Island 2012.

The pictures in Figure 2 emphasize the enormous size and magnitude of these fabrication yards and projects. These pictures are of McDermott International's engineering and construction of a two-level deck and jacket for the Maloob-C drilling platform on behalf of Mexican state-owned petroleum company, PEMEX (McDermott 2012). McDermott started construction of this platform in February 2008 and completed it in August 2009. The project included fabrication of the 2,535-ton deck (two levels) and the 3,527-ton jacket. The project also included factory testing, onshore pre-commissioning, and operational testing, load out, and sea fastening (Offshore 2009). This portion of the project was performed at the company's facility in Altamira, Mexico. More than 3,300 tons of piles were fabricated at the company's Morgan City, Louisiana facility (Offshore 2009).



**Figure 2. McDermott International, construction of the Maloob-C drilling platform.**

Source: McDermott International 2012.

Rather than using an assembly line approach, the platform fabrication industry is proficient at specialization. Fabrication yards work on only a few projects at a time because each requires individualization depending on the exact type of platform, platform characteristics, and the characteristics of the area where it will eventually be located. Often, customers split projects among fabricators, contracting with different companies for different parts of the platform (Gulf Island Fabrication 2011). For example, some yards produce jackets, and others specifically fabricate decks, living quarters, or piles (SEC 2011a).

Besides the individualized focus of each of these fabrication yards, many do share some of the following characteristics (SEC 2006):

- steel stockyards and cutting shops to supply and shape steel for fabrication;
- shops to assemble components as they are completed: deck sections, jackets, modules, and tanks;
- paint and sandblasting shops;
- dry docks for repairs and construction, generally of small vessels;
- piers used for work on transportation equipment and platform components that are mobile; and
- shops specializing in pipe construction and welding.

Fabrication yards use a number of materials and supplies, but the most often used are steel plates, standard steel shapes, fuel oil, gasoline, coatings, welding gases, and paints (SEC 2006).

### 1.2.1.1 Exploratory Rigs

A number of advancements have been made since Giliasso was first sunk off the shore of Louisiana. During the exploration phase, mobile offshore drilling units (MODUs) are typically used to drill and explore for oil and gas. If the drilling site turns out to be successful, then a more permanent production platform can be moved in. Five types of offshore rigs are primarily used to drill wildcat or exploratory wells.

**Drilling barges** are mostly used in inland, shallow waters. A barge or large floating platform with drilling equipment is towed by tugboat to a drilling site. It is held in place with anchors, and are really only suitable for shallow, calm waters. The drilling barge shown in Figure 3 is used by Maersk Drilling on Lake Maracaibo in Venezuela. This rig can operate in waters up to 120 feet (37 meters) and has a rated drilling depth of 20,000 feet (6,096 meters) (Maersk Drilling 2012).



**Figure 3. Drilling barge, Maersk Drilling.**

Source: Maersk Drilling 2012.

**Jack up rigs** are the most common type of drilling structure used. Typically, the rig is towed to its drilling location, and three or four legs are lowered to the seabed. The lowering of the legs allows the working platform to stay above the surface of the water. Jackups are usually used in water depths of up to 400 feet (122 meters) of water, (although there are some specialized rigs that can operate in water depths of 550 to 600 feet (168 to 183 meters) (Diamond Offshore 2012; and World Oil 2012). The jack up rig shown in Figure 4 is the GSP Prometeu, and is rated to operate at water depths of up to 300 feet (91 meters) and drilling depths of 20,000 feet (6,096 meters) (Grup Servicii Petroliere 2012).



**Figure 4. Jackup rig, GSP Prometeu**

Source: Grup Servicii Petroliere 2012

**Submersible rigs** are floating vessels that are supported primarily on large pontoon-like structures that are submerged below the water surface. Once the rig is positioned over the drill site, the air is let out of the pontoons, and the rig is lowered to the sea floor. Because the rig must actually sit on the seafloor, submersibles only operate in shallow waters (Schlumberger 2012; and NaturalGas.org 2012a). The Noble Joe Alford submersible (Figure 5) is rated to water depths of 70 feet (21 meters), and can drill up to 25,000 feet (7,620 meters) (Noble Corp 2012).



**Figure 5. Submersible rig, Noble Joe Alford.**

Source: Noble Corp 2012.

**Semisubmersibles** do not rest on the sea floor like submersibles or jack ups. The working deck of the rig is mounted on top of giant pontoons and hollow columns, or stilts. The pontoons are flooded with seawater and submerged. Because most of the unit is underwater, it becomes a more stable unit for drilling (stabilized by the weight of the hull) and can be used in deep and rough waters (Diamond Offshore 2012). To maintain their position, semisubmersibles use an eight- or 12-point anchoring system. Or, in deeper waters, dynamic positioning and GPS signals are used by computer-controlled motor-driven propellers (Diamond Offshore 2012). The *West Eminence* semi-submersible drilling rig, shown in Figure 6, is a state of the art, deepwater drilling unit that was built in 2009 and contracted to Petrobras. It has a water depth capacity of almost 10,000 feet (3,048 meters) (MarineLog 2009b).



**Figure 6. Semisubmersible rig, *West Eminence*.**

Source: Marine Log 2009b.

**Drill ships** are seagoing vessels, or ships, that are outfitted with drilling equipment on the top, a derrick in the middle and an opening called a “moon pool” through which to drill (NaturalGas.org 2012a). Drill ships can drill in water depths of 12,000 feet (3,658 meters) and are useful for drilling exploratory wells as they can move from location to location quickly (Diamond Offshore 2012). Like semisubmersibles, drill ships either use multiple anchors or dynamic positioning (or a combination of both) to maintain position at the drill site (Schlumberger 2012). The *Discoverer Deep Seas* drill ship was built in 2001, can operate in water depths up to 10,000 feet (3,048 meters), can drill to 35,000 feet (10,668 meters), and withstand winds of up to 80 to 100 knots (Transocean 2012).

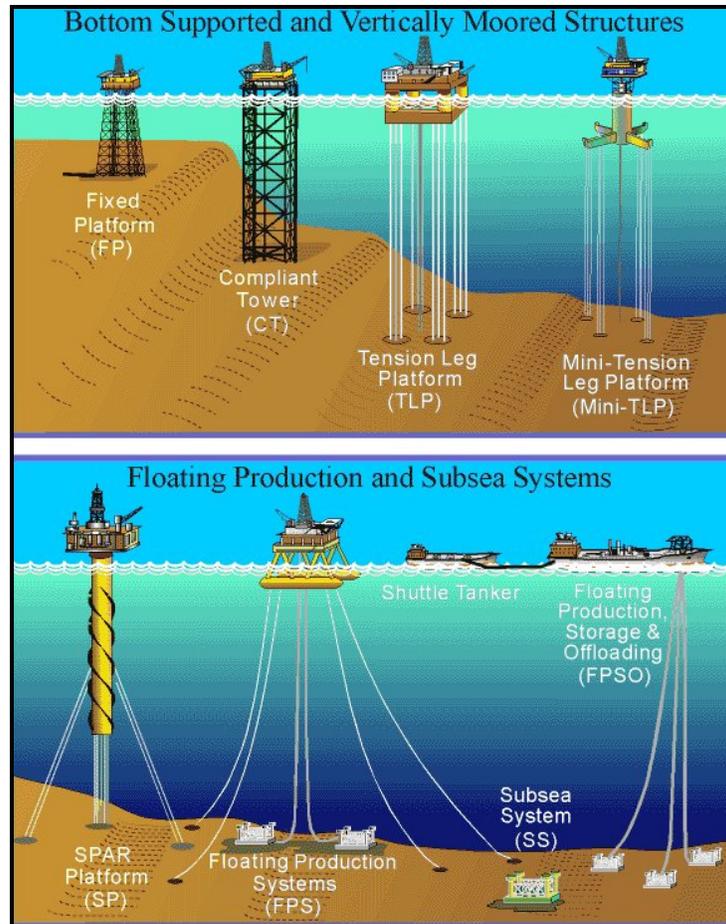


**Figure 7. Drill ship, *Discoverer Deep Seas*.**

Source: Transocean 2012.

#### **1.2.1.2 Production Platforms**

Once oil or gas is found, an exploratory drilling rig is replaced with, or converted to, a production platform. Platforms can vary in size and type depending on the size of the production field, the water depth and the distance offshore. As offshore drilling became possible in deeper waters, drilling rigs increased in size and complexity. Figure 8 illustrates the various types of production platforms, both fixed and floating or subsea systems.



**Figure 8. Fixed, floating, and subsea production systems.**

Source: Richardson et al. 2008.

**Fixed Platform:** A fixed platform has a tubular steel jacket and deck which provide a foundation for its surface facility. Piles are grounded in the seafloor and extend to water level, securing the jacket. The jacket supports the deck and surface facilities including machinery for drilling, production, other equipment, and living facilities for the crew. These types of platforms are generally not utilized in waters deeper than 2,000 feet (610 meters) because of the expense. Fixed platforms are the most commonly used platform type in shallow waters.

**Compliant Tower:** A compliant tower is similar in basic structure to a fixed platform, but is much more flexible. Instead of a jacket, a compliant tower has a narrow, more pliable tower in its horizontal position. This flexibility allows this platform structure to better withstand harsh lateral wind or water forces. These are generally used in water depths between 1,000 and 2,000 feet (305 and 610 meters) (API 2009).

Tension and Mini-tension Leg Platforms (TLP): Tension and mini-tension leg platforms use buoy systems to allow the platform to be partially submerged, similar to that used in semi-submersibles. These platforms are ship-based structures which are towed and then vertically moored to its specified location. The buoys are used to maintain tension in the mooring system, and wellheads can actually be placed on the deck of the TLP, unlike ships and semisubmersibles.

Semisubmersible platform: Semisubmersible platforms have pontoons, columns, and a deck. Pontoons and columns are buoyant so that the platform is partially, or “semi” submerged. The deck, as usual, contains crew living quarters and storage space. This type of platform can be used in a large range of water depths.

SPAR Platform: A SPAR is a floating platform, with buoyancy chambers at the top, a flooded structure in the midsection and a stabilizing keel at the bottom, underneath the water. There are three main variations: classic; truss; and cell. Living quarters and production equipment are fitted at the top of the structure. SPARs are more recent developments in offshore production, conceptually designed for deepwater production in waters up to 10,000 feet (3,048 meters) deep.

Floating Production Unit: A floating production unit (FPU) is a variation of a semi-submersible. It is a self-propelled unit which is kept stationary by wire ropes and chains or by dynamic positioning (API 2009). Though FPU’s can be used for processing from subsea facilities, they are not used for storage. Instead, after using some gas to fuel the vessel, remaining oil and gas are transported to pipelines via export risers. Generally FPU’s are used in water depths up to 7,500 feet (2,286 meters) (Richardson et al. 2008).

Subsea System: Subsea production systems are wells situated on the seabed, rather than the surface. Subsea systems can be a single subsea well producing to a nearby platform, FPU, or TLP, or multiple wells that produce through a pipeline system to a production facility (API 2009). Subsea systems can be defined in terms of two categories of equipment: surface and seafloor. Surface equipment on a host platform may be very far from the wells themselves, but is vital for operations as it is the control system and production machinery. The seafloor portion consists of the wells, manifolds, control umbilicals, pumping or processing equipment or both, and flowlines. Subsea systems are used in deep water, usually 7,000 feet (2,134 meters) or more. They do not have drilling capability and only extract and transport (NaturalGas.org 2012a).

Floating Production, Storage, and Offloading (FPSO) System: FPSOs are large tanker vessels similar to FPUs, but these vessels contain equipment to collect and store oil produced from numerous sub-sea wells. A FPSO processes and stores production and periodically offloads the stored production to a smaller shuttle tanker (API 2009). FPSOs were originally developed for use in the North Sea, because of their usefulness in areas with limited or no pipeline infrastructure. Petrobras America, Inc. began production on the first FPSO production in the GOM in February 2012. *BW Pioneer* has the capacity to process 80,000 barrels of oil per day and 500 thousand cubic meters of gas per day (Rigzone 2012a).

### **1.2.2 Shipyards**

Shipyards are often classified depending on the type of operation: shipbuilding or ship repairing; and the type of ship: commercial or military. Shipyards are also classified into four basic categories depending on capability: (1) major shipyards engaged in the construction and repair of ships; (2) major ship-repair and dry-dock facilities; (3) smaller shipyards that service inland waterways and coastal commerce; and (4) topside-repair facilities (USC, OTA 1995).

The U.S. major shipbuilding base (MSB) is defined as privately owned yards that have at least one shipbuilding position capable of accommodating vessels 122 meters or more in length (USC, OTA 1995). These facilities usually also serve as major repair facilities with dry-docking capability. There are several hundred medium- and small-sized, or second-tier shipyards that primarily support the inland waterway and coastal commerce business. These yards build and repair tugboats, ferries, fishing vessels, barges, small government-owned vessels and oil drilling equipment (USDOC, ITA 1994). The larger second-tier shipyards can handle steel and aluminum vessels up to 183 meters in length (USDOC, ITA 1994). These are the yards that also construct and service offshore service vessels, or “OSVs”. This is a broad term used to describe the vessels used to support the offshore oil and gas industry. Specifically, these OSVs transport materials, equipment and personnel necessary for daily operation on the offshore drilling rig.

Shipbuilding activities in the U.S. can vary considerably depending on the primary market a particular shipyard serves (EPA 1997).

#### ***Commercial Ships***

The U.S. commercial shipbuilding industry comprises about 600 mid-tier and smaller shipyards. These yards tend to build small to medium sized ships less than 650 feet (198 meters) in length (ICAF 2009). Commercial needs for ships are very diverse and can be classified into categories based on their use: dry cargo ships; bulk carriers; tankers; passenger ships; fishing vessels; industrial vessels; etc. Dry cargo ships can be further divided into break bulk ships, container, and roll-on and roll-off types. Although most vessels built in these yards are built for specific commercial orders, some yards do serve as subcontractors to larger yards.

The commercial market is very competitive even internationally, unlike the military market. It is vital for firms to construct cost-competitive commercial ships and to repair them efficiently. U.S. commercial shipbuilders face steep competition from shipbuilders in Asia who offer lower prices and are more efficient (ICAF 2009).

#### ***Offshore Supply Vessels***

OSVs are boats that serve exploratory and developmental drilling rigs and production facilities through offshore and subsea construction support, installation, and decommissioning activities. OSVs are unique from other vessels in that they have great cargo-carrying flexibility and capacity for things such as deck cargo (pipe, equipment, or drummed material), liquid mud, potable and drinking water, diesel fuel, dry bulk cement, and personnel. Vessels designed for use in very deepwater also may have additional cargo capacity, larger deck space, and dynamic positioning (anchorless station-keeping capability) for safety (SEC 2011b).

Seven major types of OSVs are: tugs, marine platform supply vessels (PSV), anchor handling towing and supply vessels (AHSV), fast support vessels (FSV), lift boats, mini-supply vessels (MSV) and floating, production, storage and offloading vessels (FPSO).

Every OSV type is designed and constructed specifically for its intended use and activity. Each has a different length, horsepower, and cargo capabilities. PSVs, for example, can range from 65 to 350 feet (20 to 107 meters) in length and are primarily used for the transportation of supplies and personnel to and from platforms. A PSV is equipped with tanks for transporting drilling mud, diesel fuel, water and chemicals used for drilling. It can also transport produced water, drilling muds, wellbore treatment chemicals, and fuels that must be returned to shore for proper disposal (Maritime-Connector 2012). Anchor handling or tug supply vessels (AHTS) are ships with both anchor towing and supply carrying capabilities. These vessels are capable of towing and mooring deepwater rigs (Edison Chouest 2012).

### ***Military Ships***

Orders for military ships have been the main driver in the shipbuilding industry for a long time, mainly because government policies set agency budgets and ship demand, as opposed to the commercial market. There are two main types of military ships: combatant ships and ships used for commercial purposes. The U.S. Navy orders the majority of combatant ships, which include submarines, aircraft carriers, and auxiliaries. Most of the noncombatant ships purchased by the government are purchased by the Maritime Administration's National Defense Reserve Fleet and the Navy's Military Sealift Command. The Army Corps of Engineers (ACE), National Oceanic and Atmospheric Administration (NOAA), and the National Science Foundation (NSF) also purchase noncombatant ships from shipyards in the U.S. Non-combatant ships can include cargo ships, transport ships, crane ships, patrol ships, roll on-roll off ships, tankers, and ice breakers (USEPA 1997).

Major shipyards and repair facilities have the ability to dry dock and can repair vessels of 122 meters (about 400 feet [122 meters]). These facilities must also have a waterway channel that is large enough to accommodate large vessels (at least 12 feet (3.7 meters) in depth) (USDOT MARAD 2004). Smaller shipyards construct and repair vessels under 400 feet (122 meters) that can include: patrol boats (both military and non-military); casino boats; water taxis; tugboats; towboats; fire and rescue ships; ferries; and offshore crew and supply boats. Many second-tier shipyards are capable of making topside repairs to ships over 400 feet (122 meters) in length. More specific distinctions between the capabilities of different shipyard types are listed in Table 1.

**Table 1. Types of shipyard facilities in the U.S. (owned privately).**

Type of Shipyard	Number	Description
<b>Major Shipyard Facilities</b>		
Active Shipbuilding Yard	9	Privately owned U.S. shipyards that are open, having at least one shipbuilding position capable of accommodating a vessel 122 meters (400 feet) in length or greater. In addition, these shipyards must own or have in place a long-term lease (1 year or more) on the facility in which they intend to accomplish the shipbuilding work, there must be no dimensional obstructions in the waterway leading to open water (i.e., locks, bridges), and the water depth in the channel to the facility must be a minimum of 3.7 meters.
Other Shipyard with Building Positions	15	Privately owned shipyards that are open with at least one building position capable of accommodating a vessel 122 meters in length or greater, and that have not constructed a naval ship or major oceangoing merchant vessel in the past two years.
Repair Yard with Drydock Facilities	27	Facilities with at least one drydocking facility that can accommodate vessels 122 meters in length or greater, with water depth in the channel to the shipyard of at least 3.7 meters. These facilities may also be capable of constructing a vessel less than 122 meters in length overall.
Topside Repair Yards	34	Facilities with sufficient berth or pier space for topside repair of ships 122 meters in length or greater, provided that water depth in the channel to the facility itself is at least 3.7 meters. These facilities may also have drydocks or construction capability for vessels less than 122 meters in length. Services rendered by these firms vary from a simple repair job to a major topside overhaul, particularly when the work on oceangoing ships can be accomplished without taking the ships out of the water.
<b>Medium and Small Shipyard Facilities</b>		
Boatbuilding and Repair	50	Capable of building or repairing maritime vessels less than 122 meters (400 feet) in length.
Vessel Repair	37	Facilities that only provide repair services, either repair with drydocking or topside repair, to maritime vessels less than 122 meters (400 feet). These companies must have their own waterfront facilities.
Fabricators and Manufacturers of Maritime Vessels	63	Companies that build small commercial crafts less than 76 meters (250 feet).
Barge Building and Repair	43	Companies that build or repair barges.
Recreational Crafts	28	Yards that build and repair recreational crafts such as yachts.
Shipyards with No Available Information	22	Facilities known to be shipyards, but with no other available information at this time.

Source: USDOT MARAD 2004.

Shipyards may also be classified based on the type of dock being used. There are two ways for ships to be docked: wet-docks or dry-docks (USDOT MARAD 2004). A wet-dock, also called a berth, is an in-water slip where a ship can dock and tie up. In a dry dock, a ship is lifted out of the water and has its entire hull exposed (USEPA 1997). Dry docks are used for repairs and maintenance, such as removal of marine growth, cleaning, painting, and significant repairs that would be impossible if the ship was even partially submerged. It is possible however, to perform less serious repairs while a ship is still in the water. The classification of docks is described in Table 2.

**Table 2. Positions used for ship construction and repair in the U.S.**

<b>Dock Type</b>	<b>Number</b>	<b>Definition</b>
Shipways	24	Only used for building and releasing ships.
Graving docks	32	Artificial rectangular bays used to float ships in when full of water, then the water is pumped out of the bay into adjacent waters so that the boat can be repaired while out of the water. May also be used for ship construction.
Floating drydocks	44	Land-secured floating vessels which can be submerged and then lifted to repair ships above water level. Ballast tanks are filled with water to submerge the drydock, then the ship can be brought in on the water, followed by pumping out the ballast tanks to raise the dock and the ship above the water surface. These are rarely used for ship construction.
Marine railways	2	Used in repairing smaller ships, but also can retrieve and launch vessels. Consists of a rail-car platform, railroad tracks, and an inclined platform that extends in to water deep enough to dock vessels. The rail-car platform and ship are pulled ashore by a motor and pulley system located at the marine railway.
Land Levels	24	Land based repair and construction facilities, often with track-based cranes to maneuver the ships as needed.
<b>Total</b>	<b>126</b>	

Source: USDOT, MARAD 2004; and General Dynamics 2012.

Shipyards must accommodate the flow of materials and the ease of assembly. Like platform fabrication yards, growth and expansion of the facility is piecemeal and dependent upon technology and the availability of land and water access. There are no “typical” examples of shipyards, though there are characteristics that are common to most facilities:

- dry-docks;
- shipbuilding, piers, and berthing positions;
- electrical, pipe cutting and machining, assembly, painting and sanding workshops;
- areas for carpenter, sheet metal and construction work;

- warehouses and storage (primarily for steel);
- service and fueling stations; and
- offices.

## **1.3 GEOGRAPHIC DISTRIBUTION**

### **1.3.1 Platform Fabrication**

Platform fabrication yards must have access to a navigable channel that is large enough to accommodate the towing of bulky and long structures like offshore drilling and production platforms. Thus, platform fabrication yards are located either directly on the coast, or inland, along large channels such as the Intracoastal Waterway. Some waterway locations can actually limit the size and scope of various projects that can be developed at a particular location. For instance, the dimensions of the Houma Navigation Canal prevent the transport of most jackets designed for water depths exceeding 800 feet (244 meters) (SEC 2011a). However, the Gulf Intracoastal Waterway and the 45-foot depth of the Corpus Christi Ship Channel provide unrestricted access to the GOM and allow for any size structure that is in use today (SEC 2011a).

There are no platform fabrication facilities located in the Mid-Atlantic impact region.

### **1.3.2 Shipyards**

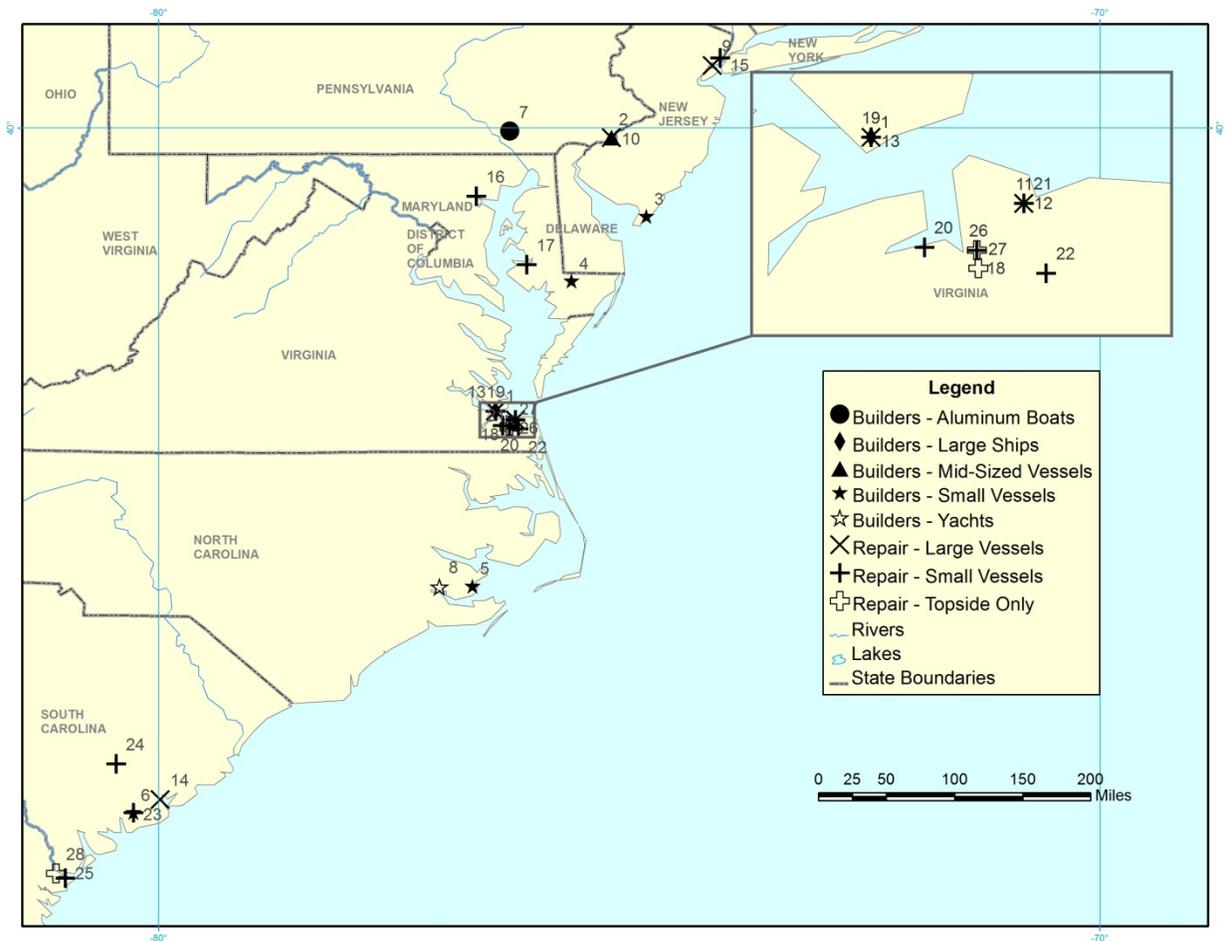
Eight boat building shipyards were identified in the Mid-Atlantic impact region. Most handle smaller coastal ships, boats, and barges. There are 20 repair yards, a number of which can handle large oceangoing vessels and most have dry-docking capability.

**Table 3. Mid-Atlantic impact region shipyards.**

<b>Shipyard Type / Yard</b>	<b>City</b>	<b>State</b>
<b>Builders - Large Oceangoing, Naval and Commercial Ships<sup>1</sup></b>		
1 NGSB Newport News Operations	Newport News	VA
<b>Builders - Mid-sized Oceangoing Commercial Ships, Rigs or Barges<sup>2</sup></b>		
2 Aker Philadelphia	Philadelphia	PA
<b>Builders - Small Ships, Boats and Barges for Coastal or Inland Use<sup>3</sup></b>		
3 Yank Marine	Tuckahoe	NJ
4 Chesapeake Shipbuilding	Salisbury	MD
5 Custom Steel Boats	Merritt	NC
6 Metal Trades Inc.	Hollywood	SC
<b>Builders - Aluminum Boats<sup>4</sup></b>		
7 Susquehanna Santee	Willow Street	PA
<b>Builders - Yachts<sup>5</sup></b>		
8 Hatteras Yachts	New Bern	NC
<b>Repair - Large Ships, Capable of Dry-Docking an Oceangoing Vessel<sup>6</sup></b>		
9 Bayonne Drydock	Bayonne	NJ
10 Atlantic Marine Philadelphia	Philadelphia	PA
11 BAE Systems Norfolk SR	Norfolk	VA
12 Metro Machine of VA	Norfolk	VA
13 NGSB Newport News Operations	Newport News	VA
14 Detyens Shipyards	N. Charleston	SC
<b>Repair - Small Ships, Boats and Barges with Dry-Docking Capability</b>		
15 Union Dry Dock & Repair	Hoboken	NJ
16 General Ship Repair Corp.	Baltimore	MD
17 Yacht Maintenance	Cambridge	MD
18 Colonna's Shipyard	Norfolk	VA
19 Davis Boat Works, Inc.	Newport News	VA
20 Earl Industries	Portsmouth	VA
21 Lyon Shipyard	Norfolk	VA
22 TEC-Skanska, Inc.	Virginia Beach	VA
23 Metal Trades Inc.	Hollywood	SC
24 Stevens Marine Services	Yonges Island	SC
25 Thunderbolt Marine	Thunderbolt	GA
<b>Repair - Topside Capability Only</b>		
26 Marine Hydraulics	Norfolk	VA
27 Tecnico	Chesapeake	VA
28 Savannah Marine Services	Savannah	GA

Notes: <sup>1,2</sup>These yards are fully equipped with in-house design capabilities; <sup>3</sup>These yards have limited facilities and capabilities; <sup>4</sup>Aluminum boats for commercial and governmental use; <sup>5</sup>Yachts, i.e., custom-designed and built yachts that are at least 100 ft (30 m) in length; <sup>6</sup>Large ships, i.e., one capable of dry-docking an oceangoing vessel of at least Panamax beam (106 ft (32 m)).

Source: USDOT, MARAD 2004.



**Figure 9. Location of Mid-Atlantic impact region shipyards.**

Source: Author's construct using USDOT, MARAD 2004.

Two firms dominate the U.S. shipbuilding industry: General Dynamics and Huntington Ingalls (a sister company to Northrop Grumman) (Colton 2012). These two firms operate the “big six” shipyards and focus almost exclusively on military and government contracts. General Dynamics owns three of the big six, two of which are on the East Coast and one is on the West Coast. General Dynamics’ Electric Boat is in Connecticut, contracts with the U.S. Navy, and has been the world’s leading submarine builder since 1899 (General Dynamics 2012). General Dynamics’ other East Coast subsidiary, Bath Iron Works is located in Bath, Maine and was historically a merchant shipbuilder. Since 1982, Bath Iron Works has specialized in cruiser and destroyer construction for the U.S. Navy. The third yard, North American Steel and Shipping Industry (NASSCO), is in San Diego, California.

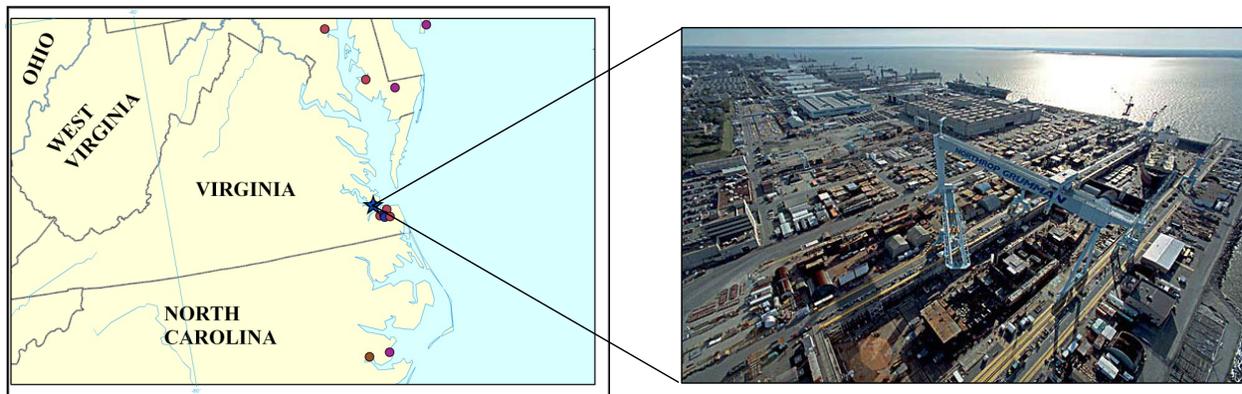
Huntington Ingalls operates Newport News Shipbuilding (Virginia), Ingalls Shipbuilding (Mississippi), and Avondale Shipyards (Louisiana) (Huntington Ingalls 2012). Huntington Ingalls was created in 2008 as a spinoff company of Northrop Grumman. Newport News repairs merchant vessels, and the two in the GOM work exclusively for the U.S. Navy and U.S. Coast Guard (Colton 2012).

Of the big six, only NASSCO accepts commercial contracts; the others process only military orders. The majority of commercial shipbuilding along the East and West Coasts is handled by a little over 100 active smaller shipyards (Colton 2012).

The largest facility in the Mid-Atlantic impact region, the Newport News facility focuses mainly on designing, building, overhauling and repairing ships for the U.S. Navy and the U.S. Coast Guard. This facility is (Huntington Ingalls 2013):

- the sole supplier of U.S. Navy aircraft carriers the world’s largest warships;
- one of two builders constructing the Virginia-class nuclear powered submarines;
- home of the Western Hemisphere’s largest dry dock and crane.
- exclusive provider of refueling services for nuclear-powered aircraft carriers.
- largest non-governmental provider of fleet maintenance services to the Navy (Huntington Ingalls 2013).

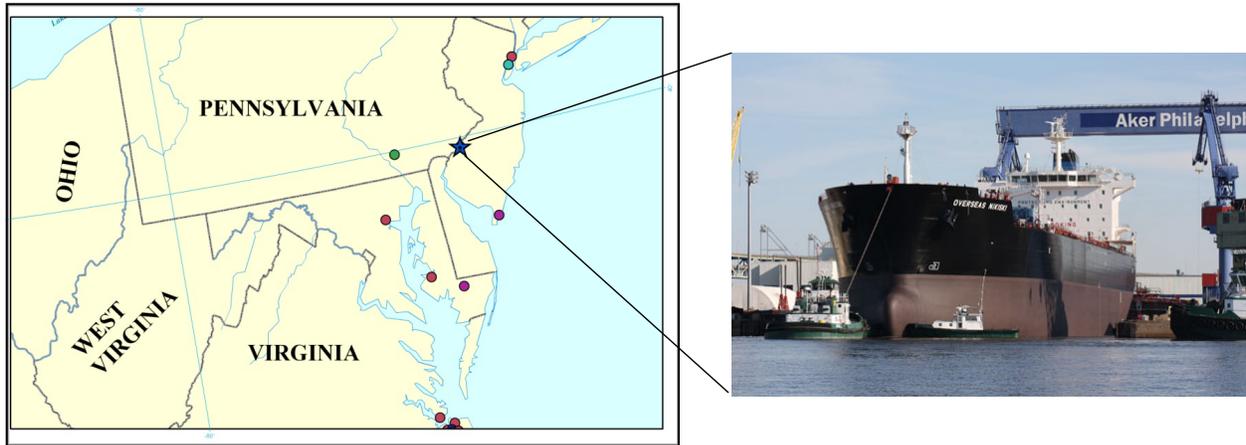
The Newport News facility is located on over 550 acres with two miles (three kilometers) of waterfront. There are approximately 19,000 employees, making it the largest industrial employer in Virginia.



**Figure 10. Northrup Grumman, Newport News, Virginia.**

Source: Huntington Ingalls 2013.

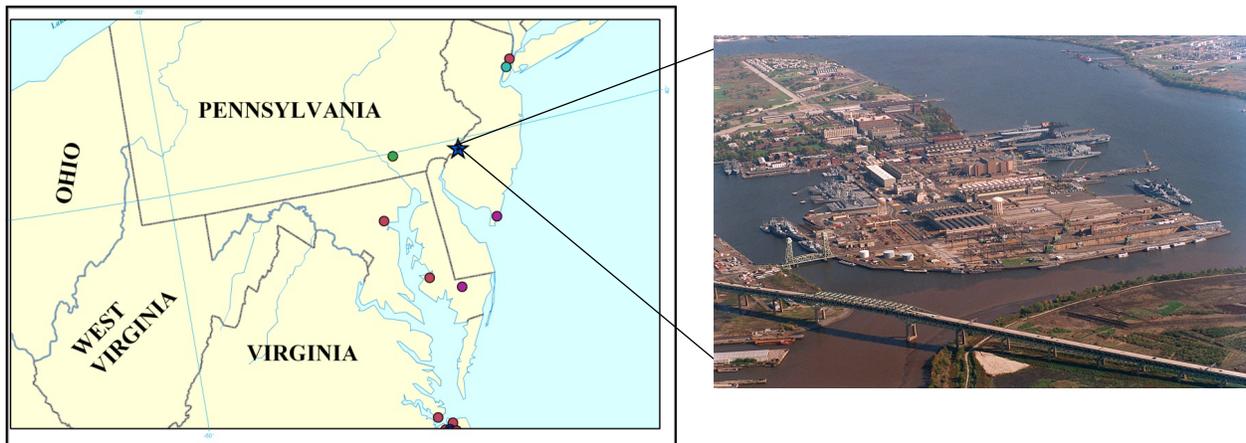
The Aker Philadelphia shipyard has a workforce of 1,200 consisting of its own employees and subcontractors. The company has delivered 12 large ocean-going commercial vessels since powering up in 2003 and is currently building two more to be used in the Jones Act Market. The shipyard has a Goliath Crane with a maximum lift capability of 660 tons; specialized vehicles to transport grand blocks weighing more than 600 tons; and numerous other high-capacity and automated cranes (Aker Philadelphia 2012). This yard employs a highly automated process with a specific focus on steel production, resulting in an annual steel fabrication capacity of 25,000 tons per year (Aker Philadelphia 2012). (See Figure 11.)



**Figure 11. Aker Philadelphia Shipyard.**

Source: MarineLog 2009a.

Atlantic Marine is another Philadelphia-located shipyard. Located on 450 acres in the Philadelphia Navy Yard, the site has a graving dock that can accommodate vessels up to 984 feet (300 meters) in length and 114 feet (35 meters) in breadth. Its repair facility offers a dry dock, topside repair berth, rail service, and cranes with 50 ton lifting capacity.



**Figure 12. Atlantic Marine Shipyard.**

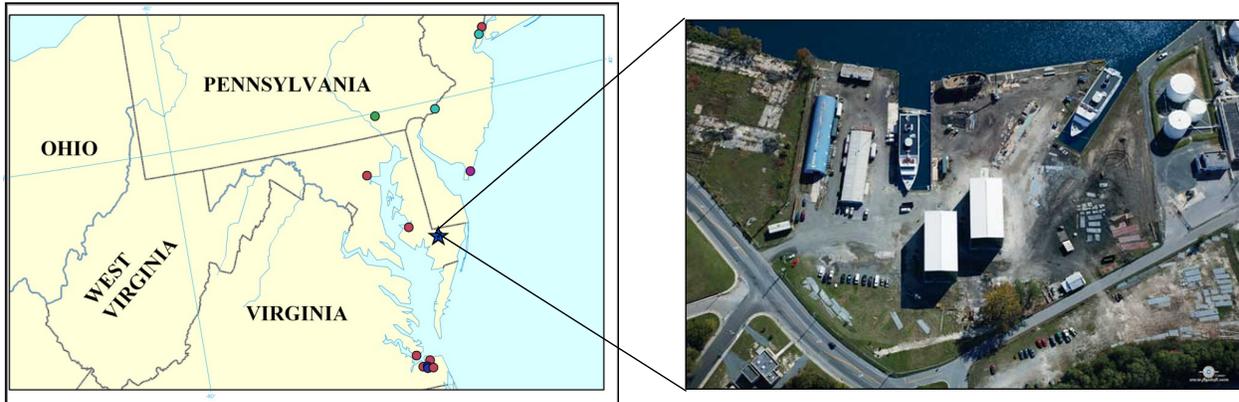
Source: Wikimedia Commons 2012.

Chesapeake Shipbuilding in Salisbury, Maryland builds commercial ships up to 375 feet in length. This yard specializes in the design and construction of passenger vessels, tugboats and ferry boats. It is located on 13 acres on the Wicomico River and its facilities include:

- 2,000 feet (610 meters) of deepwater bulkhead;
- two construction basins;
- three level construction and side launch systems;

- a ground transfer system; and
- various hull fabrication buildings and shops (Chesapeake Shipbuilding 2012).

In the past year, Chesapeake has added two new hull fabrication buildings for the ability to construct complete tugs in a controlled environment. The buildings are outfitted with automatic welding equipment, a compressed air system, and a rail system that allows vessels to be moved to the launch ways (Chesapeake Shipbuilding 2012).



**Figure 13. Chesapeake Shipbuilding, Salisbury, Maryland.**  
Source: Chesapeake Shipbuilding 2012.

#### **1.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY**

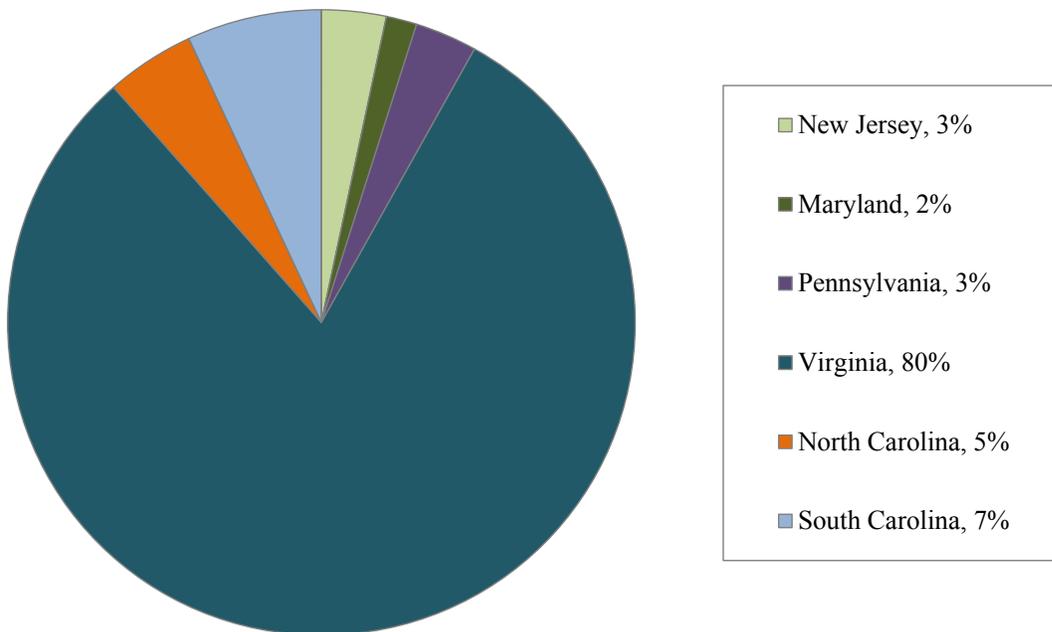
Table 4 shows that each state's total ship and boat building employment contributions are relatively small in comparison to the total employment in each of the impact region's states. None of the states in the Mid-Atlantic impact region have ship and boat building employment totals that are over seven-tenths of one percent of the overall statewide employment totals.

Ship and boat building employment in Virginia, by far, makes up the most of the total regional ship and boat building employment (see Figure 14). Likewise, Virginia has the highest employment contributions to total U.S. ship and boat building employment. In fact, Virginia accounts for almost 20 percent of total U.S. ship and boat building employment and the region accounts for just under 25 percent of total U.S. ship and boat building employment.

**Table 4. Regional and national employment contribution, ship and boat building, 2011.**

	Number of Jobs		Ship and Boat Building Employment as a Percent of Total State Employment	Ship and Boat Building Employment as a Percent of Total U.S. Ship and Boat Building Employment
	Ship and Boat Building	Total State	----- (%) -----	----- (%) -----
New Jersey	1,012	3,156,538	0.03%	0.82%
Delaware	n.a.	342,585	n.a.	n.a.
Maryland	481	1,991,055	0.02%	0.39%
Pennsylvania	973	4,825,064	0.02%	0.79%
Virginia	24,486	2,889,435	0.85%	19.95%
North Carolina	1,387	3,158,293	0.04%	1.13%
South Carolina	2,113	1,450,840	0.15%	1.72%
Georgia	n.a.	3,135,735	n.a.	n.a.
<b>Total Region</b>	<b>30,452</b>	<b>20,949,545</b>	<b>0.15%</b>	<b>24.81%</b>
<b>U.S.</b>	<b>122,718</b>	<b>108,184,795</b>	<b>0.11%</b>	<b>100.00%</b>

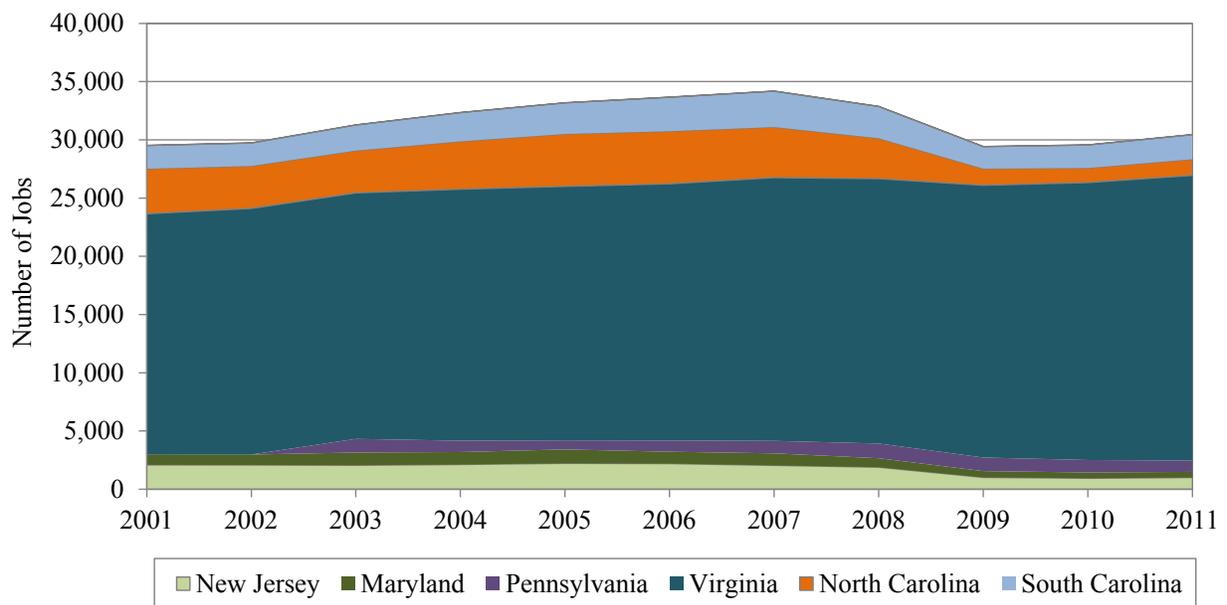
Note: n.a. is “not available.”  
 Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 14. Mid-Atlantic impact region ship and boat building employment shares, 2011.**

Note: n.a. is “not available.”  
 Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.

From 2001 through 2011, ship and boat building employment in the Mid-Atlantic region increased at an average annual rate of 0.3 percent. In Virginia, ship and boat building employment increased steadily, at an average annual rate of 1.7 percent. In the other states, however, employment in this sector fluctuated. Ship and boat building employment was on the rise between 2002 and 2005, increasing by an annual average of 3.7 percent. In 2006 the increase began to taper off and in 2008 regional ship and boat building employment decreased by 3.8 percent. It fell again by 10.5 percent in 2009. In 2010 and 2011 however, employment numbers were back up, increasing by 0.5 percent and 3.0 percent, respectively. The largest decreases in 2008 and 2009 were in Maryland and North Carolina (29.7 percent in Maryland [2009]; and 58.9 percent decline in North Carolina [2009]).



**Figure 15. Trends in Mid-Atlantic impact region ship and boat building employment, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Regional wage contributions, shown in Table 5, follow trends similar to employment levels discussed earlier; the regional totals are dominated by the states with the largest shares of ship and boat building employment. Regional shares of total wages paid by ship and boat building facilities are shown in Figure 16.

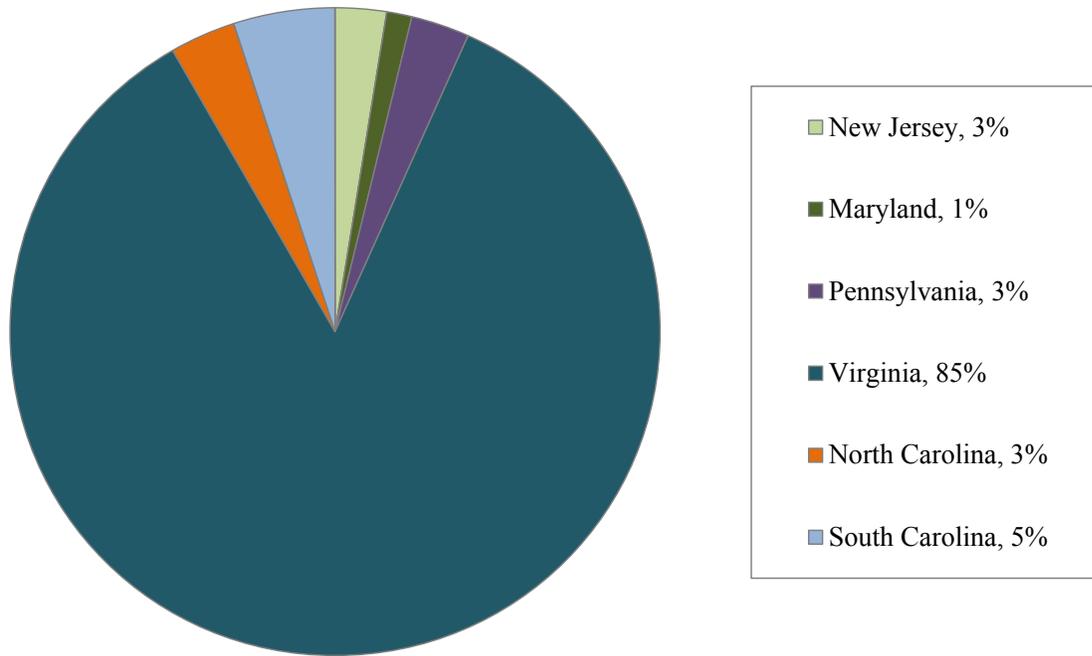
**Table 5. Regional and national wage contribution, ship and boat building, 2011.**

	Wages		Ship and Boat Building Wages as a Percent of Total State Wages ----- (%) -----	Ship and Boat Building Wages as a Percent of Total U.S. Ship and Boat Building Wages
	Ship and Boat Building ----- (million \$) -----	Total State		
New Jersey	\$ 46.6	\$ 179,559	0.03%	0.67%
Delaware	n.a.	\$ 17,313	n.a.	n.a.
Maryland	\$ 22.9	\$ 100,787	0.02%	0.33%
Pennsylvania	\$ 53.3	\$ 225,147	0.02%	0.76%
Virginia	\$ 1,553.7	\$ 145,225	1.07%	22.27%
North Carolina	\$ 59.7	\$ 132,436	0.05%	0.86%
South Carolina	\$ 92.2	\$ 54,746	0.17%	1.32%
Georgia	n.a.	\$ 142,928	n.a.	n.a.
<b>Total Region</b>	<b>\$ 1,828.4</b>	<b>\$ 998,140</b>	<b>0.18%</b>	<b>26.21%</b>
<b>U.S.</b>	<b>\$ 6,976.0</b>	<b>\$ 5,172,844</b>	<b>0.13%</b>	<b>100.00%</b>

Note: n.a. is "not available."

Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

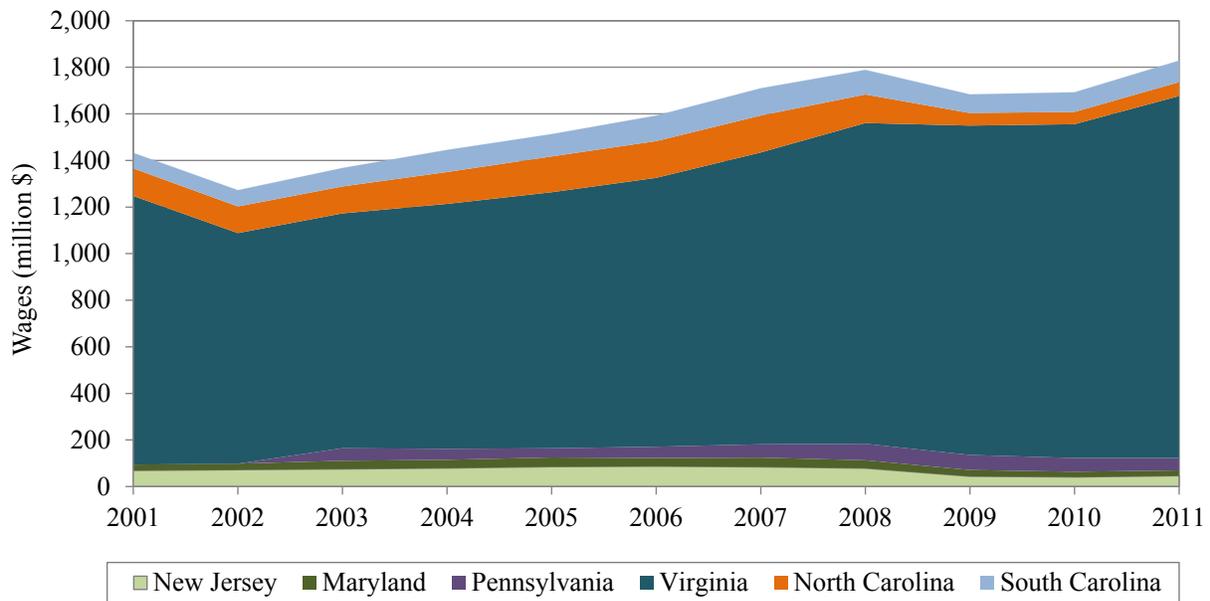


**Figure 16. Mid-Atlantic impact region ship and boat building wage shares, 2011.**

Note: n.a. is “not available.”

Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.



**Figure 17. Trends in Mid-Atlantic impact region ship and boat building wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Table 6 provides a comparison of the average annual wages paid to employees in the ship and boat building sectors of the Mid-Atlantic impact area. Except in New Jersey and Maryland, annual wages for ship and boat building employees are higher than the average state wage. However, when compared to the average wage for ship and boat builders in the U.S., only Virginia ship and boat building employees exceed the national average while all other states in the Mid-Atlantic impact area are below the national average wage for ship and boat building.

**Table 6. Regional and national average annual wage contribution, ship and boat building, 2011.**

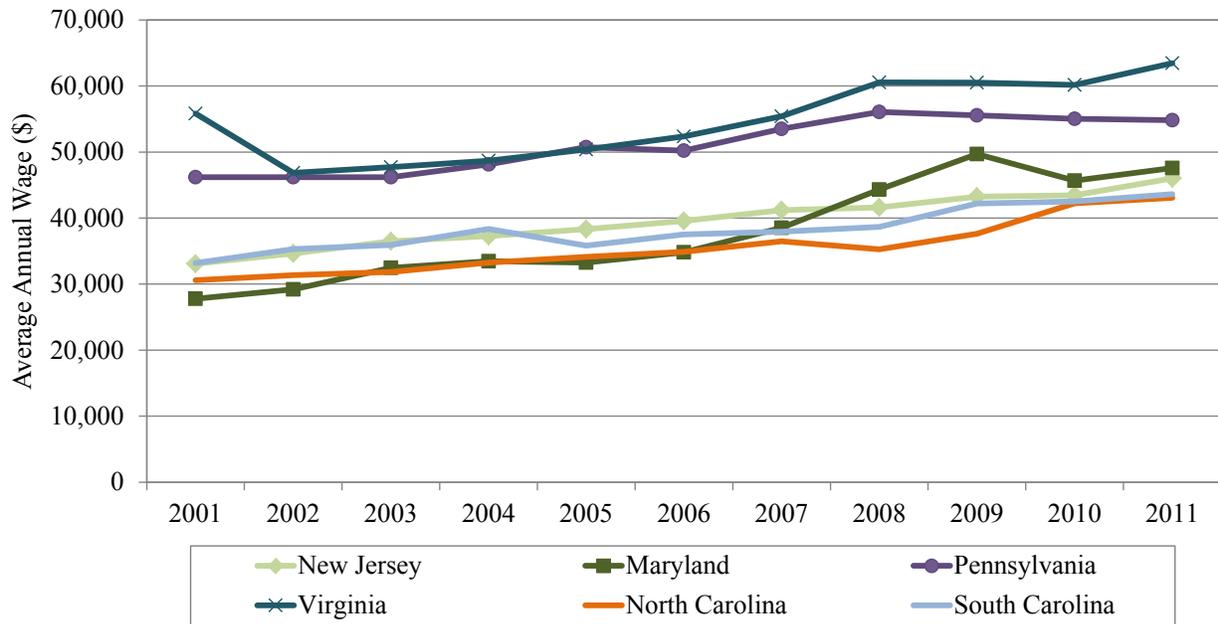
	Average Annual Wage		Ship and Boat Building Average Annual Wage as a Percent of Total Average Annual Wage	Ship and Boat Building Average Annual Wage as a Percent of Total U.S. Average Annual Wage
	Ship and Boat Building	Total State		
	----- (\$)	-----	----- (%)	-----
New Jersey	\$ 46,030	\$ 56,885	80.9%	81.0%
Delaware	n.a.	\$ 50,535	n.a.	n.a.
Maryland	\$ 47,564	\$ 50,620	94.0%	83.7%
Pennsylvania	\$ 54,810	\$ 46,662	117.5%	96.4%
Virginia	\$ 63,454	\$ 50,261	126.2%	111.6%
North Carolina	\$ 43,062	\$ 41,933	102.7%	75.8%
South Carolina	\$ 43,627	\$ 37,734	115.6%	76.7%
Georgia	n.a.	\$ 45,580	n.a.	n.a.
<b>Total Region</b>	<b>\$ 49,758</b>	<b>\$ 47,526</b>	<b>104.7%</b>	<b>87.5%</b>
<b>U.S.</b>	<b>\$ 56,845</b>	<b>\$ 47,815</b>	<b>118.9%</b>	<b>100.0%</b>

Note: n.a. is "not available."

Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Trends in average annual wages for regional ship and boat building employees are shown in Figure 18. The trends show that average annual wage has been increasing at an average annual rate of 3.3 percent, with the greatest increases in 2007 (5.5 percent) and 2008 (5.1 percent). In 2008, Maryland and Virginia showed the largest increases in average annual ship and boat building wages, with increases of 15.0 percent and 9.3 percent, respectively.



**Figure 18. Trends in Mid-Atlantic impact region ship and boat building average annual wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Georgia do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

## 1.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

### 1.5.1 Trends

#### 1.5.1.1 Platform Fabrication

The cyclical nature of the oil and gas industry strongly influences how the platform fabrication industry operates. As with other support industries, when oil prices are high, business is generally good; when oil prices are low, business opportunities are limited and fabrication yards may need to scale back or diversify into other marine-related activities. During industry downturns, many fabrication yards diversify, or expand operations into other areas so that they can use existing equipment and retain their skilled workforce. The yards may engage in maintenance or renovations of drilling rigs, fabrication of barges and other marine vessels, dry-docking, or equipment surveying. Though these projects are significantly smaller in scale, they allow the platform fabrication firms to survive the cyclical nature of their business and maintain functionality until the “good times” return.

Construction activities for platform fabrication have evolved to support the increasing importance of deepwater activities in the GOM. For instance, the Independence Hub<sup>2</sup> (Figure 19) is a semisubmersible production facility responsible for setting a number of installation and operation records. At the time, it was the world's deepest platform located in 8,000 feet (2,438 meters) of water and setting the record for deepest subsea completion, steel catenary riser (SCR) installation, and export pipeline. The Independence Hub spans one of the largest geographic areas in the GOM, and covers 142 blocks or 1,800 square miles (4,662 square kilometers) in Mississippi Canyon block 921. A 12-line mooring system is connected to twelve suction piles and holds the platform in place (Paganie 2007a). The Independence Hub taps 16 wells in 10 discovery fields using 10 to 45 mile-long (16 to 72 kilometers) umbilical lines (Murdock 2009). And touch screens located on the deck and control room of the central processing platform control the valves of the subsea infrastructure (Paganie 2007a).

The hub's hull was fabricated in Singapore and the hull and mooring systems were designed, constructed, and transported to the staging site from Ingleside, Texas (by Atlantia Offshore of Houston) (Paganie 2007b). Heerema Marine Contractors transported the hull and mooring systems from Singapore, Alliance Engineering of Houston designed the topsides, and Kiewit Offshore Services of Ingleside, Texas fabricated and installed those topsides (Kammerzell 2005; and Tubb 2005). Allseas USA was awarded the contract to install the flowlines and gas export pipeline (Tubb 2005). FMC Technologies supplied subsea trees, manifolds, valves, and connector hubs (Paganie 2007b).

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<sup>2</sup>The Independence Hub is the result of a combined effort. Six companies worked together to facilitate the development of a number of ultra-deepwater natural gas and condensate discoveries in the Eastern GOM. The hub is an affiliate of Enterprise and the Atwater Valley Producers Group, which includes Anadarko, Dominion, Kerr-McGee, Spinnaker, and Devon Energy (Offshore-Technology 2009a).



**Figure 19. Independence Hub.**

Source: Murdock 2009.

More recently, Shell broke the water depth record for subsea production with its Perdido Development in the Tobago Field, 200 miles (322 kilometers) southwest of Houston in the GOM (Rigzone 2011). The well is at a water depth of 9,627 feet (2,934 meters). The platform is moored in 8,000 feet (2,438 meters) of water and is jointly owned by Shell (33.34 percent), BP (33.33 percent) and Chevron (33.33 percent) (Rigzone 2011). From this platform, the Great White, Tobago, and Silvertip oil and gas fields are accessed through subsea wells up to seven miles (11 kilometers) away. This project records a number of firsts including (Rigzone 2011):

1. Deepest water depth record for an offshore oil drilling and production platform;
2. First water injection in 8,000 feet (2,438 meters) of water in the GOM (Great White GB001) helps push oil through the reservoir, from the injector wells to the production wells;
3. First commercial production from the Lower Tertiary geological formation, which many see as the next big opportunity in deep water;
4. Deployment of an innovative subsea separation and boosting system that compensates for the low-pressure reservoir and about 2,000 psi of backpressure from the wells. The system includes five specially designed 1,500-horsepower electric pumps embedded in the seafloor to boost production to the surface;
5. First spar with direct vertical access wells and production hardware on the seafloor at a depth of more than 8,000 feet (2,438 meters);

6. Perdido weighs 50,000-tons and sits in water six times deeper than the height of the Empire State Building; and
7. The entire Perdido project has achieved 13 million man-hours without a lost-time injury, testifying to the effectiveness of the safety regimes put in place by the construction and operating teams.

The development of platform technology and efficient design has been critical in the move to deepwater. Besides the typical civil and marine architecture developments, these advancements also include improved systems and software innovations. One major development was the movement to unoccupied platforms by using remote power systems. For example, the MT-Power™ is supplied by Northern Power System's Inc. and uses a fully-integrated fossil-fuel based micro turbine in a continuous run mode as its primary source of power generation (PR Newswire 2005a). Other remote technologies exist as well, the most recent for subsea hot tapping, "Subsea 1200 RC Tapping Machine" (World Oil 2012b). Another innovative software is called Online Monitoring (OLM), and is a cost-effective way to monitor the safety of jacket structures. Not only can OLM detect member severance, but it is accurate and can provide guidance on the specific location of the problem (Offshore-Technology 2007). This is being used in the North Sea, West Africa, Malaysia, and the GOM.

The platform fabrication industry is intensely competitive because it is a global market. The majority of GOM facilities compete with yards domestically, and also with those located in South Korea, countries in the North Sea, and Italy. To effectively compete with international companies (many of whom receive aid from their own governments), many companies seek aid from state and federal sources. The goal of this aid is to improve facilities to enhance their competitiveness regionally. For instance, Gulf Island Fabrication, Inc., in Houma, Louisiana, received \$2.3 million dollars of state funding to assist in its \$29.3 million plan for expansion to develop a new operating division for barge building on the Houma Navigational Channel in Terrebonne Parish. Press releases claimed this expansion would bring 200 new jobs to Houma and would secure a commitment for Gulf Island to keep its headquarters in Louisiana (Perilloux 2008). Gulf Island headquarters remain in Houma in 2012 (SEC 2011a).

Technological developments that have increased the feasibility of drilling at deeper and deeper depths, along with global competition, increase the difficulties faced by fabrication yards and the industry as a whole. Deepwater development is impacting the industry in two main ways: industry consolidation and closer integration. First, companies are finding it optimal to purchase other, smaller companies and form larger corporations. For example, Gulf Island Fabrication purchased Gulf Marine Fabricators of Texas in 2006 along with their facilities, machinery, and equipment (SEC 2006a). Gulf Island explained that the acquisition would allow them to perform dockside integration, to construct 1,300 foot conventional jackets and tendons needed for floating platforms, increase rolled goods capabilities, and would provide 45 feet (14 meters) of water depth access. Even more important, Gulf Island would be able to fabricate and assemble all components of deepwater construction projects, which it could not have done previously because of limitations of the physicality of its Houma yard. The additional facility also increased Gulf Island's dockside lifting capacity to 4,000 tons (SEC 2006a). Similar examples can be seen in nearly all of the larger platform fabrication companies.

The second impact of enhanced deepwater development is closer integration of the industry. This results from alliances, relationships stemming from special projects, and joint ventures. Gulf Marine was owned by Technip-Coflexip before being acquired by Gulf Island. As a result of this acquisition, however, these two companies entered into a cooperative agreement in which the companies agreed to work together on “mutually agreed upon engineer, procure and construct (EPC) projects and engineer, procure, install and commission (EPIC) projects requiring fabrication work in the Gulf Coast region” (SEC 2006). According to this agreement, Gulf Island has the right of first refusal for fabrication work in connection with specific bids that Technip may submit.

The number of employees at a platform fabrication yard varies from fewer than one hundred up to several thousand depending upon the size of the fabrication yard. Also, because the work is project-oriented and seasonal, companies often use temporary, contract workers during busy times. Employment trends are cyclical and seasonal, as is the case with most oil and gas related industries. Similarly, employment relies heavily upon large orders and fluctuations of client needs (SEC 2011a). A typical workforce of a platform fabrication company can vary throughout the year with increases and decreases in contract labor dependent upon backlog and the specific orders underway.

Skilled personnel are necessary for a fabrication yard to remain productive and profitable, though during periods of high activity the supply of these workers can be quite limited. Specifically, yards must be able to attract and retain talented construction workers, welders, fitters, and equipment operators (SEC 2011b). Because the majority of construction occurs outdoors, there are significantly fewer labor hours during the winter months. Note however, that some work does continue year-round in covered areas of yards (SEC 2011a). To deal with this seasonality, some firms in other industries may choose to lay off workers; however, because skilled personnel are so vital in the fabrication industry, firms use other tactics. For example, Gulf Island Fabrication chooses to reduce the number of hours worked per day based on the hours of sunlight, by all employees instead of letting employees go. Interestingly, in recent years the impact of seasonality has been decreasing due to increased investment in machinery and covered areas for fabrication use (SEC 2011a).

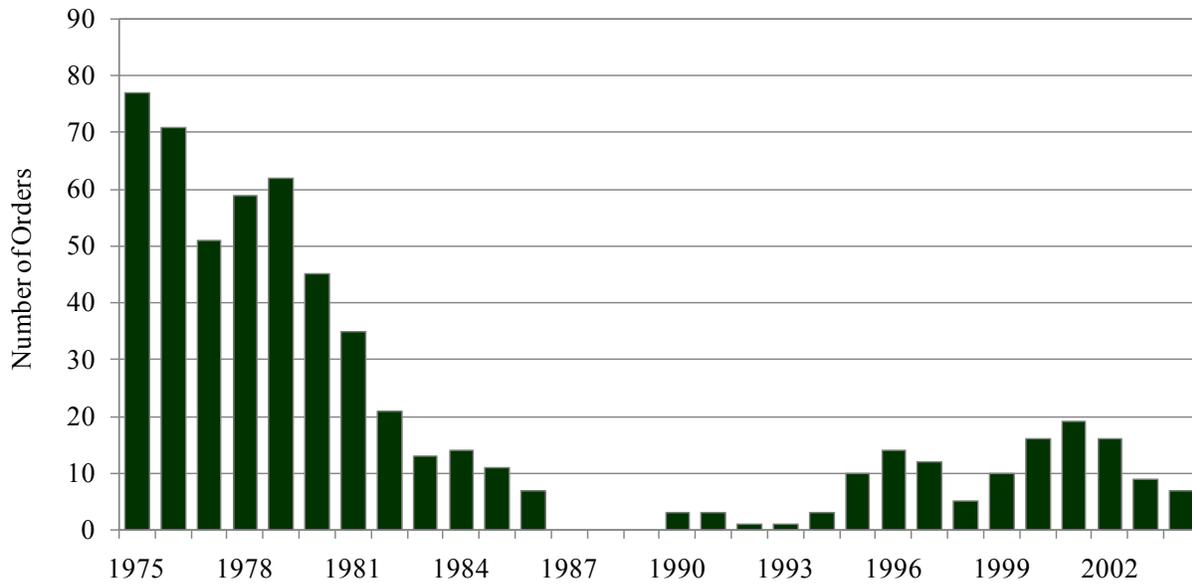
### **1.5.1.2 Shipyards**

The U.S. shipbuilding industry was at its peak by the mid-1970s; it supplied all military orders and also controlled a significant portion of the international commercial market. Unfortunately, the years following were bleak. There was a widespread perception that maritime policies were being ignored due to lack of enforcement and a lack of funding for subsidies established by the Merchant Marine Act of 1936. In the 1980s, the number of shipbuilding and repair yards in the U.S. and orders for new construction decreased drastically. First tier shipyards experienced most of the decline in their commercial construction as numbers fell from an average of 1,000 gross tons (approximately 77 ships) per year in the mid-1970s to just eight ships through the late 1980s and early 1990s. The 1980s decline was slightly offset by an increase in military orders, but with the end of the Cold War and a contracting commercial demand, by the 1990s the U.S. industry saw a smaller military market share and an insignificant commercial market share. As mentioned, this severe impact was most visible in first-tier shipyards, but second-tier and ship repairing companies also suffered in recent years, but not as drastically. The U.S. offshore industry collapse following 1986 damaged the shipbuilding industry along with all other even remotely related sectors (all supporting industries such as repair yards, local crafts and trades professionals who worked on a contract basis were also impacted) (USEPA 1997).

A number of factors contributed to the U.S. shipbuilding and repair industry's fall from the commercial shipbuilding market. First, a worldwide shipbuilding boom in the 1970 created a capacity bubble of surplus tonnage and other countries were offering subsidies to their own domestic shipbuilding and repair entities making it difficult for U.S. companies to compete effectively. Instead, foreign shipyards gained a competitive advantage and were able to attain shipbuilding work previously held by U.S. companies. The U.S. Federal government did take temporary action by implementing policies to reduce the "Construction Differential Subsidies" (CDS) in 1980, by providing allowances to reduce the difference between foreign and domestic shipbuilding costs. More than 40 percent of the U.S. shipbuilding industry was eligible for these monetary allowances; however, the program was cancelled in 1981 (USEPA 1997).

The U.S. government and the shipbuilding industry have taken steps to revitalize the industry and transform the market to be more internationally competitive. In 1994, the Maritime Administration established the National Maritime Resource and Education Center to explicitly increase competitiveness of the market (USDOT, MARAD 2012).

Figure 20 depicts historical trends in new ship orders from the 1970s to the mid-2000s. The rapid deterioration in domestic shipbuilding activity is readily recognizable on this chart. Though activity increased somewhat in 2000 to 2002, new shipbuilding activity is still a fraction of the level of effort observed in the late 1970s. One major stimulus for the increase in shipbuilding activity has been the increase in deepwater oil and gas activity (USDOT, MARAD 1999). The graph shows an increase in shipbuilding orders that corresponds with the passage of the Deepwater Royalty Relief Act of 1995.



**Figure 20. Commercial shipbuilding order history (through 2004).**

Source: USDOT, MARAD 2004.

The decline of commercial shipbuilding demand in the 1980s negatively impacted the industry’s ability to attract and retain skilled labor. A survey conducted by the U.S. Department of Commerce’s Bureau of Industry and Security (2001) considered the operating and labor conditions in U.S. shipyards and found the lack of skilled labor has reduced shipyard profits, negatively altered construction costs, and resulted in significant schedule delays for projects at a majority of shipyards. More recent studies have found that these issues are still prevalent (ICAF 2008; ICAF 2011). For example, from 1996 to 2006 the number of private shipyard workers decreased from 98,000 to 47,000, a 49 percent decrease (USDOT, MARAD 1996 and USDOT, MARAD 2006a).

Turnover rates at shipyards are high, relative to other manufacturing industries. The work can be strenuous and is almost entirely outdoors where workers are exposed to uncomfortable environmental conditions, especially during the summers of coastal high heat and humidity. This exacerbates the problem of finding skilled labor in today’s market, and has compelled many shipyards to contract out work they historically did in their own yard (USDOT, BIS 2001).

In an attempt to diversify and endure downturns in the industry, shipbuilders and platform fabricators have expanded into supply and support activities for the oil and gas industries and other related industries. Some general attributes related to successful diversification are general large geographic areas for work and storage; various unskilled and skilled labor (i.e., electricians, pipefitters, welders); access to supportive infrastructure (i.e., roads, waterways, ports, communications). Now shipbuilders and fabricators can engage in dry-docking, inspections, maintenance, and surveys of stacked rigs and equipment. Employees can also work on production systems, and, despite its low dollar per task, it is a more stable employment than traditional fabrication work and helps keep important yards economically viable during downturns.

The OSV market has become much more global in recent years, and its stability is reliant upon the number of rigs (especially in deepwater areas, which is where the bulk of new developments are). As of January 1, 2012, 64 floating rigs and 78 high-spec jack-up rigs were under construction or on order. Because each drilling rig working on deepwater projects generally requires more than one OSV for service, it is likely the demand for OSVs will remain strong in the near future (SEC 2011b).

### **1.5.2 Outlook**

Much has changed in the offshore drilling industry since the first subsea wellhead was installed in 1961. Drilling activity is expected to increase by about 4 percent in the U.S. in 2012 (Petzet 2012). And, forecasts estimate that exploration and production spending will grow double digits each year from 2013 to 2015 (Keppel Offshore and Marine 2011).

Exploration in deeper water, particularly in the GOM, is a strong motivator for the platform fabrication industry's decisions on development and expansion. Gulf Island is one clear example because its motivation for the Gulf Marine acquisition was its ability to construct larger structures for use in deepwater exploration (SEC 2006a). Similarly, Keppel Offshore and Marine (2011) cites deepwater development and expected increases in oil and gas drilling expenditures as reasons for their expected growth and increasing profits in the future.

Platform fabrication and shipyards supporting the oil and gas industry face very similar challenges, as do other sectors that support offshore activities. These challenges include cost pressures, labor shortages, and the engineering and economic challenges created as new technologies are developed and exploration extends to deeper waters.

The shipbuilding sector has faced issues due to overbuilding, which has caused rates to decrease. However, there is an expectation of increased repair demand for the aging OSV fleet, which could mean improvement for the sector (Keppel Offshore and Marine 2011). Similarly, customer requirements and expectations about safety, along with regulatory concerns are driving OSV demand for innovative improvements to operational efficiency and safety. However, the sector is still dependent on military contracts, and is not adequately competitive internationally. To improve competitiveness, the industry needs to continue to invest in worker training, efficiency, research and development, and efficiency improvements.

Like other offshore support industries and other heavy construction and manufacturing sectors, workforce development is a major concern. A lack of skilled labor can hamper efficiency and profits. Companies in this situation may face financial pressures of lower profits, impacted construction costs, and delayed or untimely completion of projects. In an attempt to compensate for such shortages, yards may employ contract workers, especially during busy times. This problem is expected to compound with the retirement of the existing workforce, especially for shipyards, because workers require many years of experience and take ample time to replace adequately (ICAF 2008). Over one third of shipyard workers are over the age of 50 and the average age of a worker is 45 (ICAF 2008).

The U.S. shipbuilding industry has also had a concern with a lack of necessary capital. Title XI of the Merchant Marine Act of 1936 began a program to provide financial capital support and debt-underwriting. The program was entitled, the “National Shipbuilding Initiative” (NSI) and provided an assurance of payment by the federal government. Specifically, the NSI guarantees full payment to the lender of the unpaid principal and interest in the event of default by the vessel owners or general shipyard facility.

In January 2009 a \$267 million loan guarantee was approved to construct five articulated tug and barge units. Also, there are nine pending applications for the construction of 53 barges, five tugs, three articulated tug or barge units, two shuttle tankers, six platform supply vessels and seven drill rigs (Transportation Institute 2012). Title XI has funded over 75 projects, including passenger vessels, supply vessels, tugs and shipyard modernization projects (USDOT, MARAD 2006b). In 2007 the American Shipbuilding Association’s president boasted that Title XI helps American shipyards to retain their skilled employees, expand the fleet of U.S. built commercial ships available to the Department of Defense in time of war, and provide the highest construction standards in the world (MarineLink 2007).

### **1.5.3 Regulatory Changes**

A number of regulations impact the platform fabrication and shipbuilding industries in regard to environmental regulation and vessel or labor standards. These regulations can be found in MARAD’s Compilation of Maritime Laws and BOEM’s 2012 infrastructure report (Eastern Research Group 2010). Relevant environmental regulations include the Oil Pollution Act of 1990, the Resource Conservation and Recovery Act (Subtitle C with regard to dumping waste), the Comprehensive Environmental Response, Compensation, and Liability Act, and the Clean Water Act. There are also a number of non-environmental regulations. The Jones Act and the Byrnes-Tollefson Amendment have had significant impacts on the U.S. shipbuilding industry.

Merchant Marine Act of 1920 (The Jones Act): Requires that any vessel sailing between U.S. ports must be owned and operated by U.S. citizens and sail under the U.S. flag. This Act was designed to ensure that the U.S. shipbuilding industry was protected and would continue to flourish (Goure 2011). Vessels must fit into one of three categories: be U.S. built and flagged; be reconstructed in the U.S. and U.S. flagged; or be foreign-built but forfeited under violation of U.S. law and now U.S. flagged (USDOT, MARAD 2011).

Byrnes-Tollefson Amendment: This requires that vessels and major components of the hull or superstructure for the U.S. armed forces be built in U.S. shipyards. There are two exceptions to this amendment: 1) presidential waiver for national security interests and 2) exception for inflatable boats or rigid inflatable boats, or both (10 U.S.C. §7309).

Other, more recent regulatory changes include the following.

National Defense Authorization Act of 2006: This granted MARAD the authority to make grants, under the Small Business Act, to shipyards that were classified as a “small business concern” and had fewer than 600 employees. The funds were originally appropriated to MARAD in the amount of \$25 million for each of the fiscal years 2006 to 2010 (Public Law 109-163 Sec. 3506). Yearly updates of this Act have continued the program, which is referred to as the Assistance to Small Shipyard Grant Program.

Consolidated Appropriations Act of 2008: This Act provided additional grant money (\$10 million in total) to small shipyards (those covered in NDAA), which improved infrastructure development and thereby impacted the quality of domestic ship production (H.R. 2764 – 559, 110th Congress of the United States of America).

## **1.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

### **1.6.1 Platform Fabrication**

Because there is currently no drilling off the Atlantic Coast, there are no platform fabrication facilities located on the East Coast of the U.S. If and when these facilities are developed depends strongly on the degree of progression in the production process in this area. Under a limited or moderate development scenario, most likely the GOM or international sources would be the main producer of these materials and equipment, rather than the development of production facilities in the Mid-Atlantic OCS area. Development of production facilities in the Mid-Atlantic OCS is increasingly less likely as the production technologies become more complex and require a greater and greater upfront capital investment (particularly the investment of space).

The capital costs of a platform fabrication facility are considerable and likely to be too large to support only limited offshore activities in the Mid-Atlantic OCS. For instance, Gulf Island Fabrication's main fabrication yard in Houma, Louisiana is situated on 140 acres and has 2,800 linear feet (853 meters) of water frontage (SEC 2011a). This is a hefty commitment to surface development and is only the initial necessary commitment. There also must be other supporting equipment and site investments for a platform fabrication yard to function effectively and efficiently. Developments of this kind would require a significant offshore drilling market in the Mid-Atlantic OCS. A more reasonable expectation would be a more limited offshore development scenario. Under such an expectation, it is most likely that 1) the GOM region would continue to fabricate platforms and other structures and export them to necessary locations (or even international construction); 2) the Mid-Atlantic OCS would be supported by a system of FPSOs; or 3) a combination of 1) and 2).

Perhaps with a long-term commitment to offshore oil and gas exploration in the Mid-Atlantic OCS, new platform fabrication facilities may begin to operate in this region. It would likely take at least moderate offshore development to support such a facility in the area. As we increase the scale and scope of the development scenarios, the potential profit for project investors increases. This is vital for development, because investors will undertake the large upfront costs only if they believe there will be a long period of use and potential earnings.

### **1.6.2 Shipyards**

There are 28 shipyards identified in the Mid-Atlantic impact region. These facilities range in size from those that construct or repair small vessels for coastal or inland use, to those that focus on large oceangoing naval and commercial ships. A limited number of the facilities are used for new construction; the majority are for repairing existing vessels. Repair facilities, like the yards themselves, vary in size and capabilities: some have only topside capabilities and others have dry-docking options for smaller ships, boats, barges, and then some facilities have dry-docking capability for large ocean vessels. There are medium-sized shipyards in Virginia, Maryland, and North Carolina, and these would be the most likely to offer support for expansion of the oil and gas industry to the Mid-Atlantic OCS.

If drilling were to begin in the Mid-Atlantic OCS region, it is most likely that medium-sized vessel construction and repair shipyards would best serve the industry. The majority of medium-sized shipyards in this area are in Virginia, Pennsylvania, and New York. Massachusetts and Maine also have a good number of yards (Colton 2012). Because these yards already exist, it is unlikely that any new facilities would be constructed to support oil and gas activity, but existing yards may expand to meet demand.

New shipyards in the Mid-Atlantic area would still compete with other shipyards in all coastal regions of the U.S., especially in the GOM. The three most likely scenarios for supplying the Mid-Atlantic OCS with OSVs, tugs, barges, and other support craft are summarized in the following sections.

### **1.6.2.1 Scenario 1: Greenfield Development**

One or several shipyard facilities could be developed along the Mid-Atlantic coast, which will be dedicated to the construction of various offshore vessels to support oil and gas activities. This scenario could only occur with development of a several hundred-acre tract of land along navigable water. There is a large upfront capital requirement, which includes new construction pads, electricity, lighting, roads, terminals, slips, bulkheads, construction shelters, maintenance buildings, storage buildings, transportation and construction equipment, and much more. Because this would be a significant capital investment, this scenario is unlikely unless there is a well-defined and expansive Mid-Atlantic oil and gas industry development plan. An extensive development would be necessary in order for shipyard developers to gain an adequate assurance of profitability upon their investment.

### **1.6.2.2 Scenario 2: Expansion within the Mid-Atlantic OCS**

Existing shipyards along the Mid-Atlantic coast may expand to take on the additional demand resulting from drilling and other oil and gas activities in the area. Currently, the majority of facilities in the area specialize in construction or repair of craft similar to what is used for oil and gas activities. This scenario requires incremental investments, rather than the large upfront investment required with the construction of a new yard. Therefore, this scenario would require less strong assurance of the future drilling activity in the area for yards to take action. The actual unfolding of this scenario is uncertain; it depends on the existing configurations of shipyards in the area, and their financial and business interests regarding expansion. For many of these facilities, a moderate oil and gas development scenario would likely be enough motivation to take on the new business prospects and investments to expand onsite facilities. Many existing facilities are already equipped to serve in a repair capacity for oil and gas industry support vessels, even in a limited oil and gas development scenario.

### **1.6.2.3 Scenario 3: GOM Construction**

No new shipyard development will take place; instead, the new demand in the Mid-Atlantic region will be met by existing producing areas along the GOM. It could also happen that during early phases of Mid-Atlantic OCS development, craft from the GOM are diverted for use in the Mid-Atlantic, and no new craft are built at all. Depending on the state of the industry when Mid-Atlantic OCS development takes place, if industry conditions are tight with high use of existing vessels and high commodity prices, diversion of existing craft will be much less likely.

This scenario is likely to occur because existing facilities in the GOM will have cost-effective opportunities for expansion and to create geographic diversity to their vessel construction operations and businesses. The shipbuilding industry is extremely competitive. The GOM firms may want to expand to increase their competitive edge and would have advantages, such as they already possess yards with adequate capacity, skilled workforce, experience in engineering and design, relationships with input vendors and with service and production companies.

This is even more likely given the recent history of mergers and consolidations of firms along the GOM. Firms are trying to take advantage of the scale efficiencies and larger, more strategic locations. The development of new firms in the Mid-Atlantic OCS may be challenging in the absence of expansive regulation with tight oil and gas market conditions for an extended period of time.

## 1.7 FACTORS IMPACTING EAST COAST DEVELOPMENT

Both shipbuilding and platform fabrication for the oil and gas industry depend on the industry itself, which is impacted by the following (among others) (SEC 2011a):

- a. Local and international political and economic conditions and policies,
- b. customer capital spending budget changes,
- c. unavailability of exploratory or drilling rigs, or both,
- d. oil and natural gas prices and expectations about future prices and volatility,
- e. worldwide demand for oil and gas,
- f. availability and rate of discovery of new oil and natural gas reserves in offshore areas,
- g. cost of offshore exploration for, production of, and transportation of oil and natural gas,
- h. environmental and other regulations concerning oil and gas producers and their service providers.

Both the shipbuilding and platform fabrication industries must be resilient to the inevitable downturns in demand as demand in the oil and gas industry decreases. Also, firms are extremely competitive and this increases the difficulty of new firms entering the market, or creating a new supporting structure in the Mid-Atlantic impact region.

The oil and gas industry supports offshore development in the Mid-Atlantic OCS, but as of yet there are no major platform fabrication companies suggesting any future investments in the region. This is a result of governmental policies regarding drilling, but for a company to undertake such an investment there must also be:

- a. The availability of a suitable location with water access and (preferably) multi-modal transportation;
- b. A skilled workforce with trade experience;
- c. Favorable local siting conditions; and
- d. Favorable local business conditions.

The extent of offshore alternative energy development may influence the siting of a new platform fabrication yard. Offshore wind (OSW) energy is going to have a particularly strong role. There are currently at least seven states across the eastern seaboard actively promoting OSW development, and it is uncertain exactly what influence this will have on development of the oil and gas industry in the area. The two technologies can be complimentary; one company, Keppel Offshore and Marine, engages in support activities for oil and gas, from platform fabrication to shipbuilding and repair, but in recent years is also investing in research and development of OSW technologies (Keppel 2011). There is the potential for OSW activity coupled with policy support to actually increase business support for a platform fabrication facility; however, this is speculative.

The most significant factor for platform fabrication yard development and shipyard expansion along the Mid-Atlantic OCS is a long-term commitment to oil and gas development for the area.

## **2 PORTS**

### **2.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED**

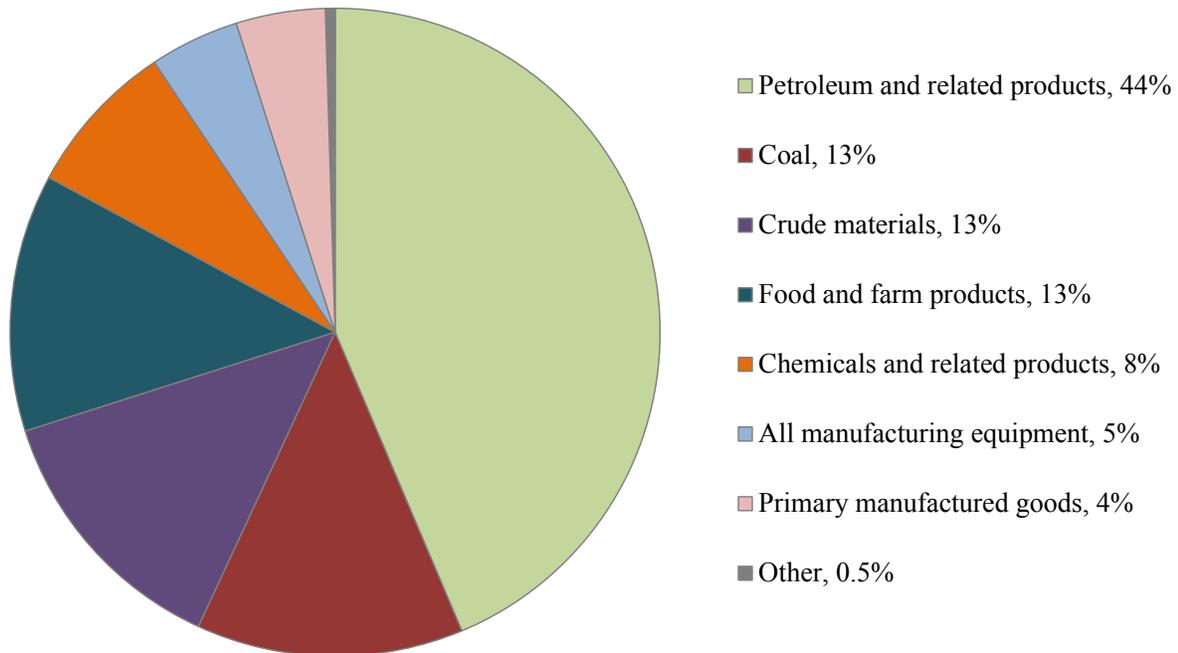
Ports have a vital role in the support of the offshore oil and gas exploration and production sector and the maritime industry as a whole. The vehicles that support offshore platforms (notably ships and helicopters) are based, kept, and maintained at the ports. Ports are also the delivery, transfer, and launching points for the necessary structures, equipment, supplies, crew, and other elements important to offshore installations. Offshore exploration and production operations depend heavily on these goods and services, and thus ports are critical to the entire industry.

Large traditional ports that support various degrees of offshore activity do not generally focus exclusively on offshore oil and gas exploration and production. Examples of this are the Port of Houston and the Port of New Orleans located near the GOM. These traditional ports focus most of their attention on supporting large-scale conventional port bulk operations, such as handling a variety of cargo, including bulk or loose cargo; break bulk cargo in packages, such as bundles, crates, barrels and pallets; liquid bulk cargo like petroleum; dry bulk such as grain; and general cargo in steel boxes called containers (AAPA 2012).

Leading commodities shipped for domestic and foreign trade through U.S. ports include (AAPA 2012):

- Crude petroleum and petroleum products (such as gasoline, aviation fuel, natural gas).
- Chemicals and related products (such as fertilizer).
- Bituminous, metallurgical, and steam coal.
- Food and farm products, including wheat and wheat flour, corn, soybeans, rice and cotton.
- Forest products (such as lumber and wood chips).
- Iron and steel.
- Soil, sand, gravel, rock, stone.
- Automobiles, automobile parts and machinery.
- Clothing, shoes, electronics, toys.

Figure 21 shows the makeup of principal commodity groups carried by water in 2010. As can be seen, most of U.S. waterborne commerce (about 44 percent) is attributed to petroleum and petroleum products (USACE 2011). As will be discussed in subsequent sections, many ports in the Mid-Atlantic region already have the capabilities to deal with petroleum products that are being imported from other countries.



**Figure 21. Principle commodity groups carried by water, 2010.**

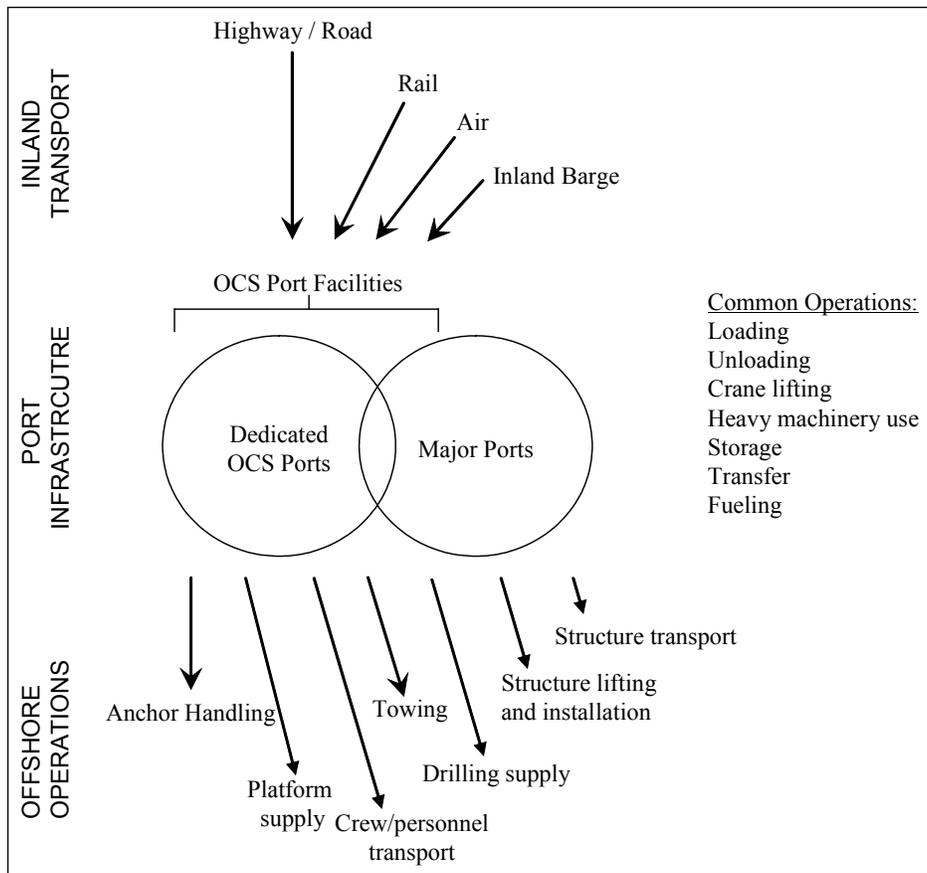
Source: USACE 2010.

## 2.2 TYPICAL FACILITY CHARACTERISTICS

Ports vary considerably by size, specialty, and defining characteristics. In general, however, there are two major types of port facilities: 1) deep-draft seaports; and 2) inland river and intra-coastal waterways port facilities. Deep-draft seaports are ports that accommodate mostly 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 or terminals are located on rivers or intra-coastal waterways, and are mostly privately owned. These shallow water ports are generally less than 14 feet (4 meters) in depth (USDOT, MARAD 1999). They are less concentrated geographically than deepwater facilities and provide almost limitless access points to the waterways. These inland terminals are abundant in the Mid-Atlantic region, especially in New Jersey, Pennsylvania, and Delaware.

Despite their differences, all ports typically have similar logistical systems (major shipping ports included) that can be divided into three principal components (Jayawardana and Hochstein 2004). Because the OCS has not been developed in the Mid-Atlantic region, Figure 22 shows a schematic diagram of a typical OCS port's logistic systems in the GOM.

1. The inland transport component: almost all ports must transport supplies, equipment and personnel from land-based locations to the port for transfer. As a result, all ports will typically have access by highway, road, rail, air, or inland barge to their port facility; many ports may have more than one inland transportation system.
2. The physical port component: a port's physical and fixed infrastructure varies considerably depending on its size and specialty. The physical port system includes docks, berths, buildings, storage facilities, transfer machines, such as cranes and lifts, fabrication capabilities. It also includes channels and their depths, turning basins, and additional amenities and utilities, such as electricity, water treatment capabilities, and roads.
3. The offshore component: the actions and operations of the vessels based from a particular port. Depending on the port, offshore operations may vary considerably; therefore, ports with similar port structural capabilities may have dissimilar offshore components.



**Figure 22. OCS port facilities: three part logistics system.**

Source: Author's reconstruction based on work published in Jayawardana and Hochstein 2004.

A port's inland and physical infrastructure components are responsible, to a large extent, for the type of offshore operations that are based out of a particular port. Of course, other factors are important as well, such as geography, risk and security, and proximity to supply considerations. The best supply bases typically have more than one of the following important attributes:

1. Strong and reliable transportation systems;
2. Adequate depth and width of navigation channels;
3. Adequate port infrastructure facilities;
4. Existing petroleum industry support infrastructure;
5. Location central to OCS deepwater activities;
6. Adequate worker population within commuting distance; and
7. Insightful strong leadership.

Deep and wide navigation channels are also particularly important for the offshore support industry ports, especially as a new generation of larger boats is built to service deepwater installations.

### **2.3 GEOGRAPHIC DISTRIBUTION**

There are more than 100 port cities located in states along the Mid-Atlantic coast. Table 7 has a complete list of all port cities located in these states.

**Table 7. Port cities in Mid-Atlantic impact region.**

<b>City</b>	<b>State</b>	<b>City</b>	<b>State</b>	<b>City</b>	<b>State</b>
New Castle	DE	Nags Head	NC	Philadelphia	PA
Wilmington	DE	New Bern	NC	Eddystone	PA
Indian River	DE	Ocracoke	NC	Chester	PA
Lewes	DE	Oriental	NC	Marcus Hook	PA
Delaware City	DE	Sneads Ferry	NC	Penn Manor	PA
Brunswick	GA	Southport/Bald Head	NC	Pittsburgh	PA
Savannah	GA	Island	NC	Charleston	SC
Crescent	GA	Surf City/Topsail Beach	NC	Beaufort/Port Royal	SC
Saint Mary's	GA	Swan Quarter	NC	Burton	SC
Saint Simon's Island	GA	Swansboro	NC	Edisto Beach	SC
Thunderbolt	GA	Varnamtown	NC	Georgetown	SC
Tybee Island	GA	Vendermere/Mesic	NC	Green Pond	SC
Valona	GA	Wanchese	NC	Hilton Head Island	SC
Garden City	GA	Wrightsville Beach	NC	Isle of Palms	SC
Baltimore	MD	Charleston	NC	Little River	SC
Cambridge	MD	Camden	NJ	McClellanville	SC
Ocean City	MD	Paulsboro	NJ	Mt. Pleasant	SC
Annapolis	MD	Trenton	NJ	Murrells Inlet	SC
Cambridge	MD	Atlantic City	NJ	North Charleston	SC
Morehead	NC	Avalon	NJ	Port Royal	SC
Wilmington	NC	Barneгат Light/Long	NJ	Saint Helena Island	SC
Atlantic	NC	Beach	NJ	Seabrook Island	SC
Atlantic Beach	NC	Belford/Middletown	NJ	Wadmalaws Island	SC
Aurora	NC	Belmar	NJ	Hampton Roads	VA
Avon	NC	Brielle	NJ	Hopewell	VA
Bath	NC	Cape May	NJ	Richmond	VA
Bayboro	NC	Cape May Court House	NJ	Carrolton	VA
Beaufort	NC	Highlands	NJ	Cheriton	VA
Belhaven	NC	Point Pleasant	NJ	Chincoteague	VA
Carolina Beach	NC	Port Norris	NJ	Newport News	VA
Columbia	NC	Sea Isle City	NJ	Poquoson	VA
Elizabeth City	NC	Toms River	NJ	Seaford	VA
Engelhard	NC	Waretown	NJ	Virginia Beach	VA
Harker's Island	NC	Wildwood	NJ	Wachapreague	VA
Hatteras	NC	Elizabeth	NJ	Piney Point	VA
Kill Devil Hills	NC	Jersey City	NJ	Norfolk	VA
Lowland	NC	Port Newark	NJ	Portsmouth	VA
Manteo	NC	New York	NY/NJ		

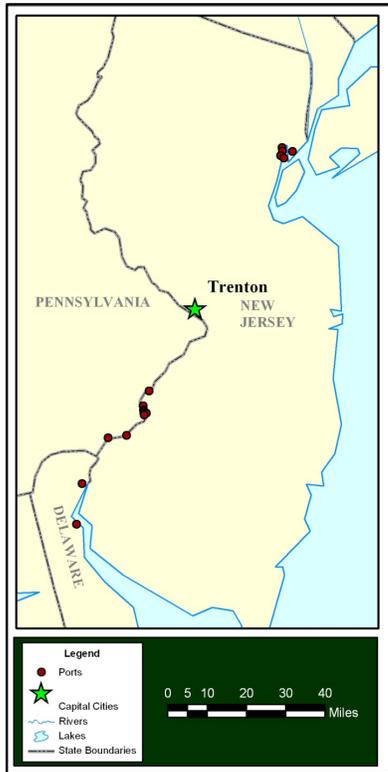
Source: USACE 2010.

The next section of this report focuses on 35 of the ports located between Newark (Elizabeth), New Jersey and Brunswick, Georgia. Some 26 of these terminals are considered major, while the remaining nine are considered minor or simply covered piers. The median low water depth at dock for all major Mid-Atlantic coast ports is 40 feet (12 meters), certainly large enough to support not only major service vessels, but also offshore platform fabrication, should activity levels in the region reach critical mass.



**Figure 23. Mid-Atlantic impact region ports.**

The largest active port along the upper Mid-Atlantic OCS region defined earlier is Port Newark, New Jersey. This port comprises a total of 2,230 acres of space and 41,000 linear feet (12,497 meters) of berthing for ships. Though large, this port is primarily associated with cargo and international trade. Oil and gas activities may be of limited interest to these areas and, from a geographic perspective, may be too far from initial areas of offshore development along the Virginia coast.

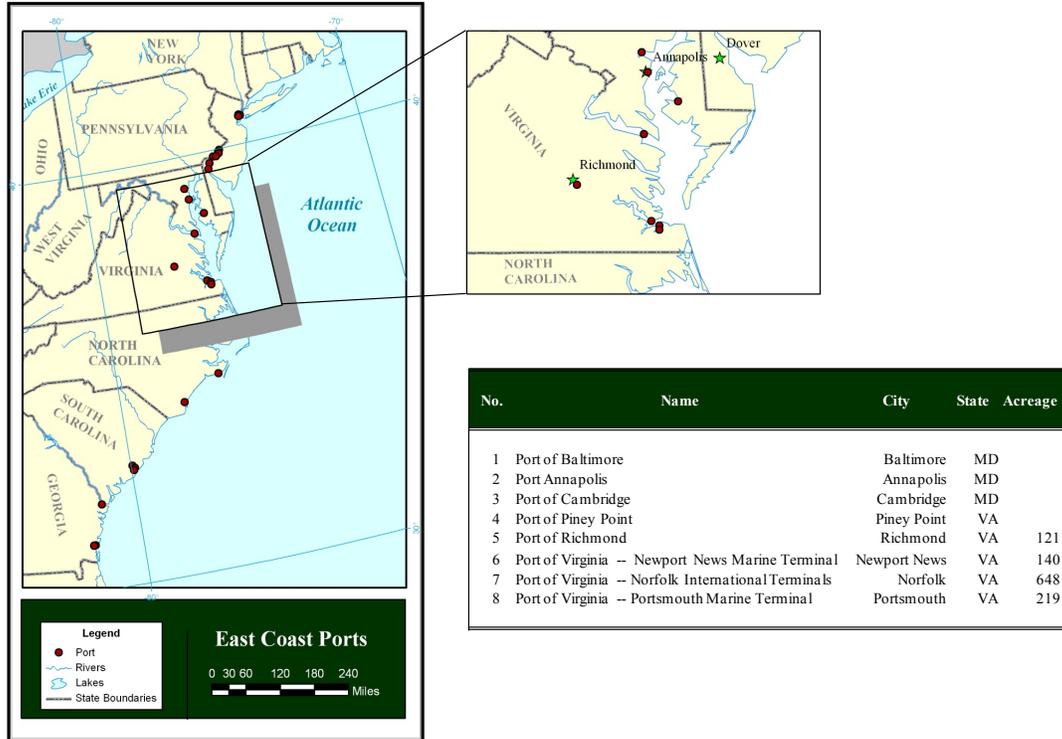


No.	Name	City	State	Acreege
1	APM Terminal	Elizabeth	NJ	350
2	Global Marine Terminal	Jersey City	NJ	98
3	Maher Terminal	Elizabeth	NJ	445
4	Port Newark / Elizabeth	Port Newark	NJ	2,230
5	Port Newark Container Terminal	Port Newark	NJ	180
6	South Jersey Port Corp -- Beckett Street Terminal	Camden	NJ	125
7	South Jersey Port Corp -- Broadway Terminal	Camden	NJ	180
8	Port of Philadelphia - Packer Avenue Marine Terminal	Philadelphia	PA	112
9	Port of Philadelphia - Pier 84	Philadelphia	PA	14
10	Port of Philadelphia - Piers 38 & 40	Philadelphia	PA	12
11	Port of Philadelphia - Piers 78 & 80	Philadelphia	PA	44
12	Port of Philadelphia - Piers 96 & 98 Annex	Philadelphia	PA	55
13	Port of Philadelphia - Tioga Marine Terminal	Philadelphia	PA	116
14	Penn Terminals	Eddystone	PA	80
15	Port of Delaware City	Delaware City	DE	
16	Port of Wilmington	Wilmington	DE	308

**Figure 24. Mid-Atlantic impact region ports, New Jersey, Pennsylvania and Delaware.**

The Port of Philadelphia is also a significant and large facility in the upper Mid-Atlantic OCS region. It spans a combined total of some 689 acres in various locations. However, like Port Newark, the Port of Pennsylvania may be too preoccupied with supporting cargo and military needs (Port of Philadelphia 2012). The Port of Wilmington, in Delaware, is relatively sizeable at 308 acres (Port of Wilmington 2012). In comparison, Port Fourchon on the GOM is 1,700 acres (Port Fourchon 2012).

The central portion of the Mid-Atlantic OCS region has a number of suitable ports that may be candidate sites to support future offshore oil and gas activities. These ports have been highlighted in Figure 25.

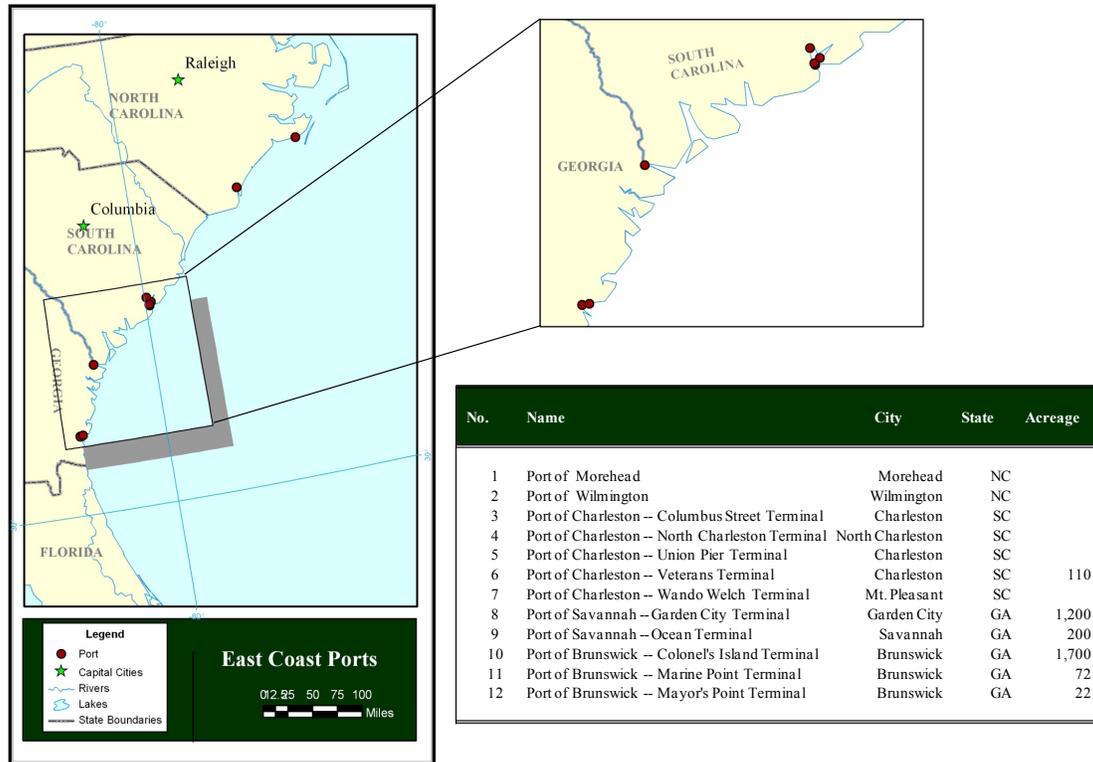


**Figure 25. Mid-Atlantic impact region ports, Maryland and Virginia.**

A potential high-profile candidate site is the Norfolk International Terminal that is part of the Port of Virginia system. The Norfolk port is centrally located and has over 648 acres of property. Though considerably smaller than many of the upper Mid-Atlantic ports, Norfolk is still one of the largest in its area and is also dedicated at the current time primarily to cargo traffic. It is impossible to know exactly which existing ports, if any, will be used for OCS expansion, but this particular port has as good a chance as any.

Smaller facilities in Virginia include the Newport News and Portsmouth terminals that span surface spaces of between 140 acres and 219 acres, respectively. These ports currently support break bulk, container storage, and roll-on/roll-off cargo, and may be suitable locations to support offshore oil and gas activities.

Another area of candidate port sites is the lower Mid-Atlantic region. This primarily includes the ports located in the Carolinas and in Georgia. These ports have been highlighted in Figure 26.



**Figure 26. Mid-Atlantic impact region ports, South Carolina and Georgia.**

Candidate sites in South Carolina and Georgia are similar to those in the central portion of the Mid-Atlantic region. However, their distances from offshore Virginia, where initial federal OCS activities are expected to begin, are much greater than those of Portsmouth, Newport News, or Norfolk. The ports in Georgia, for instance, are farther than those located in Pennsylvania and New Jersey. However, unlike those areas, South Carolina, and, to a lesser degree, Georgia, have discussed opening state waters to some form of offshore oil and gas activities.

Major shipping ports, such as the Port of Newark, Port of Philadelphia, and Port of Wilmington, engage in bulk shipping, among other principal operations. Millions of tons of cargo flow through these ports annually.

The 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. Supply base functions can be provided by either private or public port facilities. Private ports operate as dedicated terminals to support the operation of an individual company, or possibly a consortium of a few companies. Private ports often integrate fabrication and offshore transport activities. Public ports charge fees and lease space to individual business ventures and can be thought of as water-based industrial or manufacturing parks that create economic benefits throughout a local region. The public ports have a dual role by functioning as offshore supply points and as industrial or economic development districts.

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, is the governing body that oversees the ports operations. In addition to maritime functions, a port authority may have jurisdiction over other types of transportation terminals such as airports, bridges, tunnels, rail systems, shipyards, and marinas.

## **2.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY**

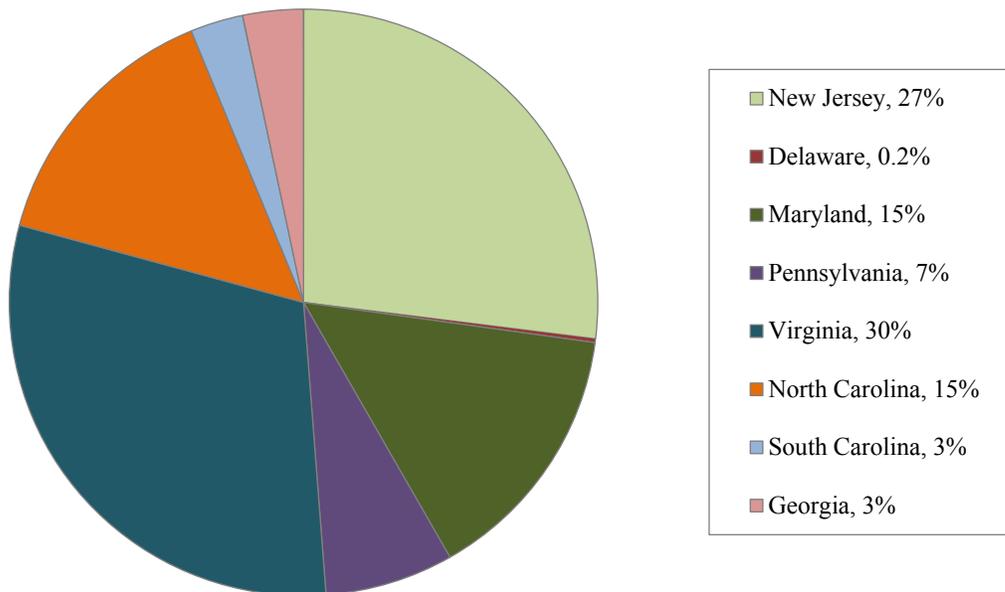
The water transportation sector for the impact area is relatively small in comparison to each state's overall gross domestic product (GDP) and the economic contribution made by the water transportation sector overall to the U.S. GDP. North Carolina has the highest percentage ports of GSP contribution at 0.19 percent, with Virginia in second at just 0.14 percent. In the region as a whole, water transportation contributes less than one tenth of one percent towards the total GDP. Though these impacts are quite small, the water transportation sector accounts for only 0.2 percent of the total GDP for the entire United States, and is therefore relatively larger in the Mid-Atlantic region than in the U.S. as an aggregate.

**Table 8. Regional and national GDP contribution, water transportation sector, 2010.**

	GDP		Water Transportation GDP as a Percent of Total State GDP	Water Transportation GDP as a Percent of U.S. Water Transportation GDP
	Water Transportation (millions of current \$)	Total State	----- (%)	-----
New Jersey	\$ 520	\$ 480,446	0.11%	3.5%
Delaware	\$ 4	\$ 64,010	0.01%	0.0%
Maryland	\$ 280	\$ 293,349	0.10%	1.9%
Pennsylvania	\$ 136	\$ 558,918	0.02%	0.9%
Virginia	\$ 587	\$ 419,365	0.14%	4.0%
North Carolina	\$ 280	\$ 424,562	0.07%	1.9%
South Carolina	\$ 56	\$ 160,374	0.03%	0.4%
Georgia	\$ 64	\$ 403,230	0.02%	0.4%
<b>Total Region</b>	<b>\$ 1,927</b>	<b>\$ 2,804,254</b>	<b>0.07%</b>	<b>13.1%</b>
<b>U.S.</b>	<b>\$ 14,670</b>	<b>\$ 14,416,601</b>	<b>0.10%</b>	<b>100.0%</b>

Source: USDOC, BEA 2012.

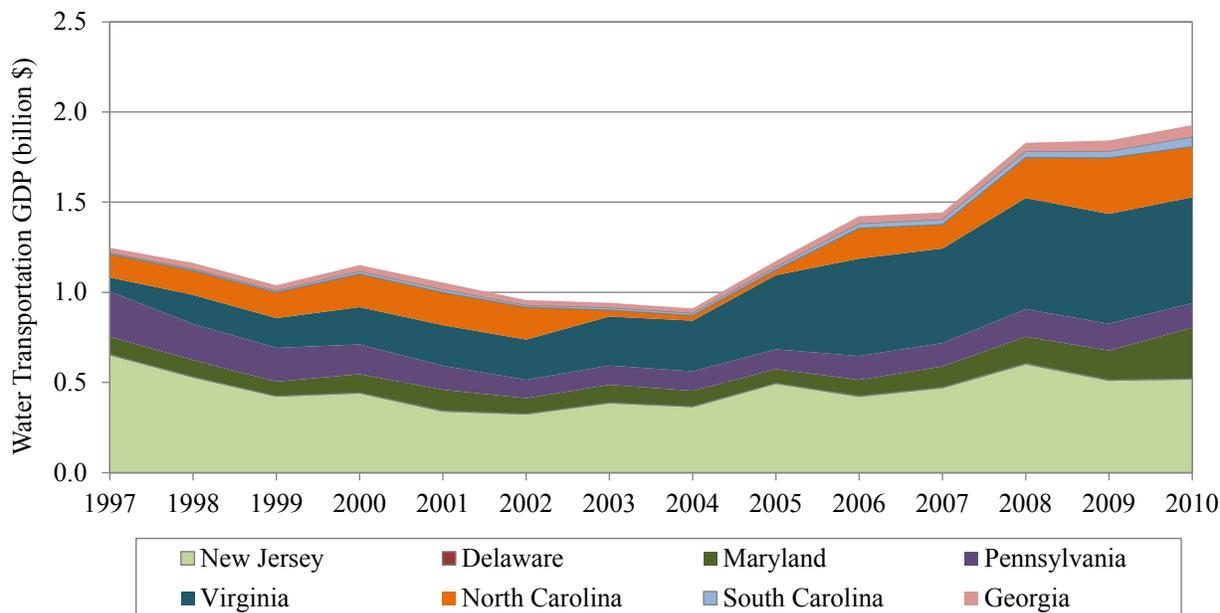
Figure 27 highlights the relative share of each Mid-Atlantic state’s water transportation GDP shares relative to the regional water transportation total. Virginia makes up the majority, with 30 percent of the total regional water transportation GDP, and New Jersey follows with 27 percent.



**Figure 27. Mid-Atlantic impact region water transportation GDP shares, 2010.**

Source: USDOC, BEA 2012.

Figure 28 compares the trends in water transportation GDP for each Mid-Atlantic impact state since the mid-1990s. Water transportation GDP has a relatively constant value until 2004, when an increasing trend begins. Virginia's growth accounts for much of this increase, growing at an average annual rate of 13 percent from 2004 through 2010.



**Figure 28. Trends in Mid-Atlantic impact region water transportation GDP, 1997-2010.**

Note: Delaware's water transportation GDP is large enough to be reported, but it is too small to be visible on this graph.

Source: USDOC, BEA 2012.

Because there is no specific NAICS code for ports, the remaining discussion in this section defines a port as the sum of the following NAICS categories:<sup>3</sup>

- 48831: Port and Harbor Operations
- 488320: Marine Cargo Handling
- 713930: Marinas
- 488330: Navigational Services to Shipping

Total ports employment contributions are relatively small in comparison to the total employment in each of the impact region's states. Like GSP, none of the states in the Mid-Atlantic impact region have ports employment totals that are over one percent of the overall statewide

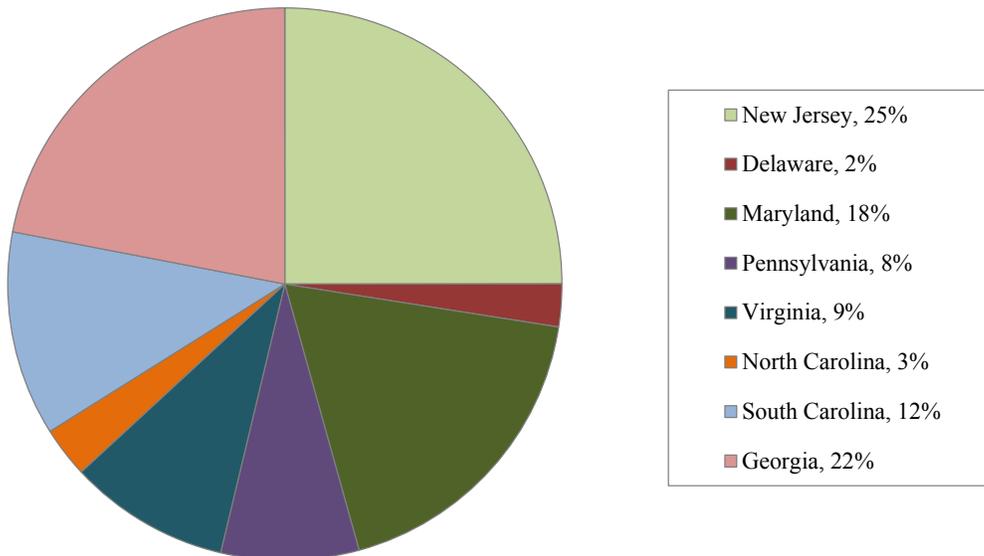
<sup>3</sup> The North American Industry Classification System (NAICS) was developed under the direction and guidance of the Office of Management and Budget (OMB) as the standard for use by Federal statistical agencies in classifying business establishments for the collection, tabulation, presentation, and analysis of statistical data describing the U.S. economy. Use of the standard provides uniformity and comparability in the presentation of these statistical data. NAICS is based on a production-oriented concept, meaning that it groups establishments into industries according to similarity in the processes used to produce goods or services. NAICS replaced the Standard Industrial Classification (SIC) system in 1997.

employment totals. On a regional basis, Maryland has the highest share of total ports employment. Notice though that while the ports employment makes up a relatively small portion of total employment, the port employment in these states makes up 19 percent of total port employment in the U.S.

**Table 9. Regional and national employment contribution, ports, 2011.**

	Number of Jobs		Ports	Ports
	Ports	Total State	Employment as a Percent of Total State Employment	Employment as a Percent of Total U.S. Ports Employment
			----- (%) -----	-----
New Jersey	5,348	3,156,538	0.17%	4.80%
Delaware	534	342,585	0.16%	0.48%
Maryland	3,894	1,991,055	0.20%	3.49%
Pennsylvania	1,719	4,825,064	0.04%	1.54%
Virginia	2,009	2,889,435	0.07%	1.80%
North Carolina	629	3,158,293	0.02%	0.56%
South Carolina	2,565	1,450,840	0.18%	2.30%
Georgia	4,699	3,135,735	0.15%	4.22%
<b>Total Region</b>	<b>21,396</b>	<b>20,949,545</b>	<b>0.10%</b>	<b>19.20%</b>
<b>U.S.</b>	<b>111,438</b>	<b>108,184,795</b>	<b>0.10%</b>	<b>100.00%</b>

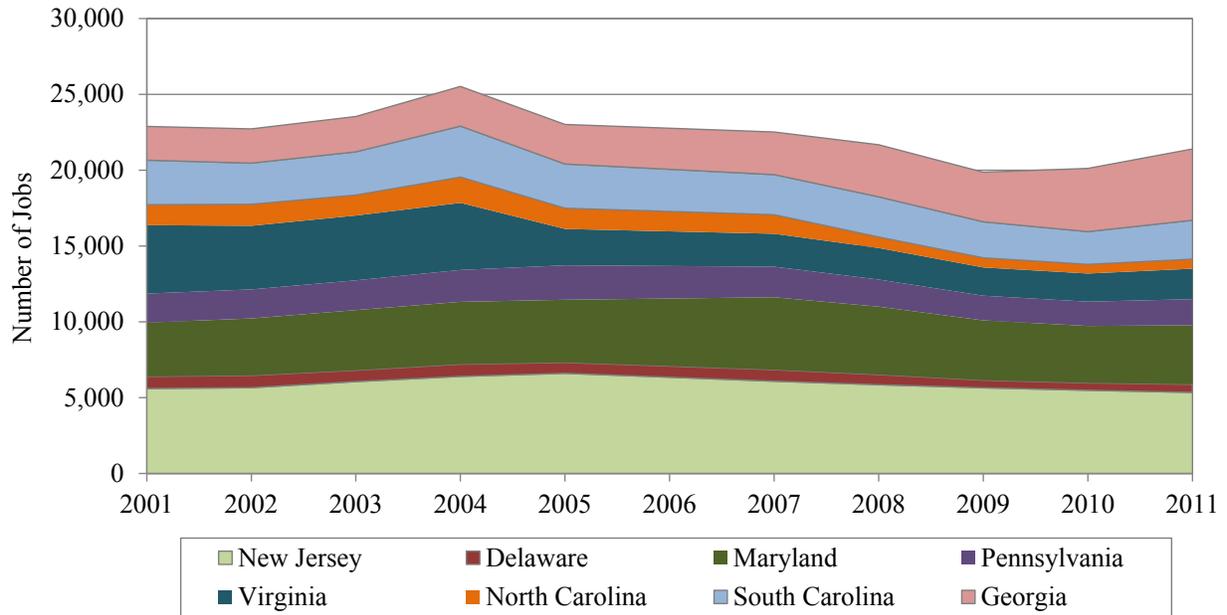
Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.  
Source: USDOL, BLS 2012.



**Figure 29. Mid-Atlantic impact region ports employment shares, 2011.**

Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.  
Source: USDOL, BLS 2012.

Employment in Mid-Atlantic impact region ports has been falling since 2004. Before 2004, the region had between 22,700 and 25,000 ports jobs. From 2004 to 2006, port employment fell until 2009 when it leveled off at just under 20,000 jobs. In 2010 and 2011, port jobs increased 1.3 percent and 6.4 percent, respectively. Increases in South Carolina and Georgia made up for the majority of this increase.



**Figure 30. Trends in Mid-Atlantic impact region ports employment, 2001-2011.**

Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.

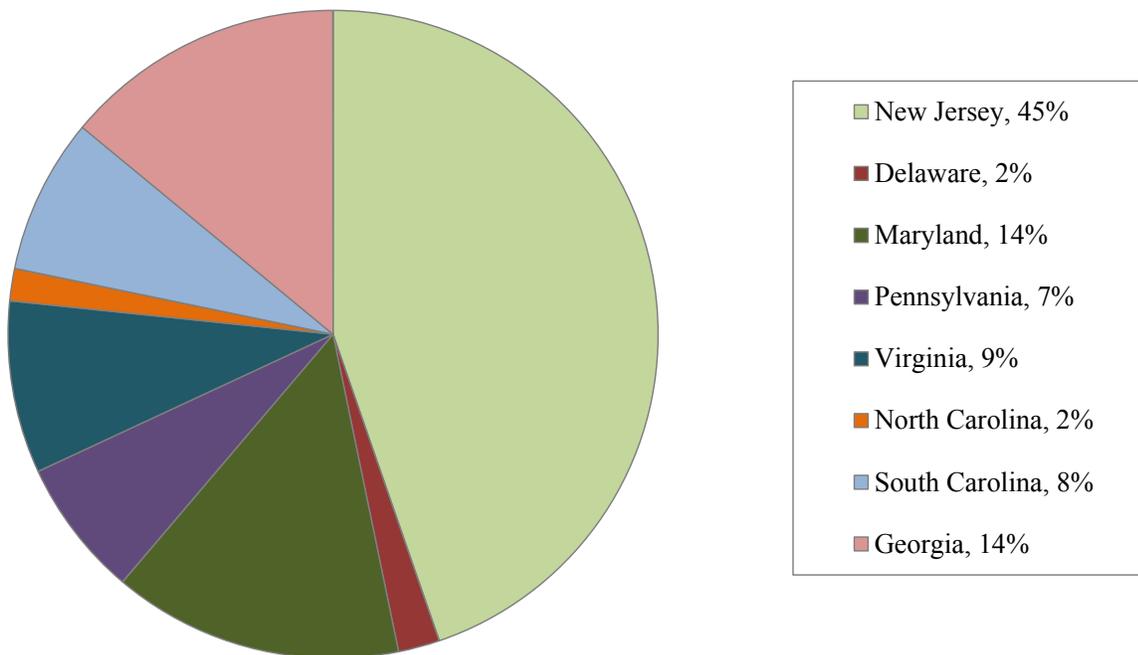
Source: USDOL, BLS 2012.

Regional wage contributions, provided in Table 3, corroborate the employment levels discussed above. Regional shares of total wages paid by Mid-Atlantic coast ports are provided in Figure 31. New Jersey makes up 45 percent of total ports wages, yet accounts for 25 percent of total regional port employment.

**Table 10. Regional and national wage contribution, ports, 2011.**

	Wages		Ports	Ports
	Ports	Total	Wages as a	Wages as a
	(million \$)	State	Percent of Total	Percent of Total
	-----	-----	-----	-----
			(%)	U.S. Ports
				Wages
New Jersey	\$ 492.0	\$ 179,559	0.27%	7.98%
Delaware	\$ 22.6	\$ 17,313	0.13%	0.37%
Maryland	\$ 158.7	\$ 100,787	0.16%	2.57%
Pennsylvania	\$ 75.7	\$ 225,147	0.03%	1.23%
Virginia	\$ 94.5	\$ 145,225	0.07%	1.53%
North Carolina	\$ 17.8	\$ 132,436	0.01%	0.29%
South Carolina	\$ 85.3	\$ 54,746	0.16%	1.38%
Georgia	\$ 153.9	\$ 142,928	0.11%	2.50%
<b>Total Region</b>	<b>\$ 1,100.5</b>	<b>\$ 998,140</b>	<b>0.11%</b>	<b>17.85%</b>
<b>U.S.</b>	<b>\$ 6,164.6</b>	<b>\$ 5,172,844</b>	<b>0.12%</b>	<b>100.00%</b>

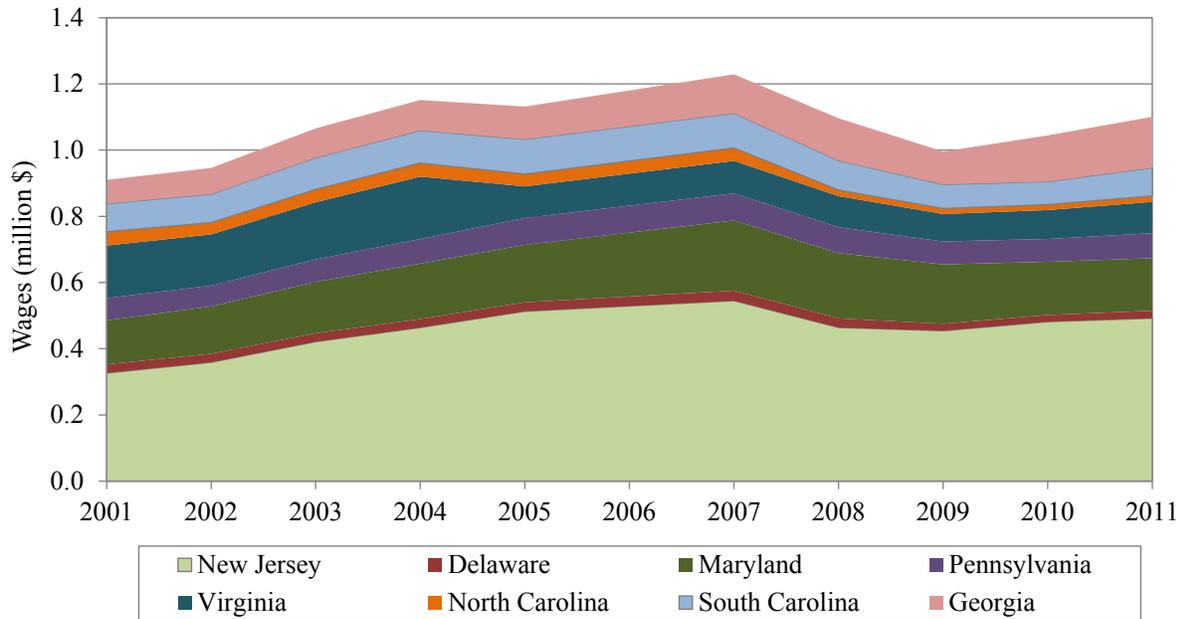
Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.  
Source: USDOL, BLS 2012.



**Figure 31. Mid-Atlantic impact region ports wage shares, 2011.**

Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.  
Source: USDOL, BLS 2012.

Trends in port wages, as illustrated in Figure 32, have followed trends in regional port employment.



**Figure 32. Trends in Mid-Atlantic impact region ports wages, 2001-2011.**

Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.

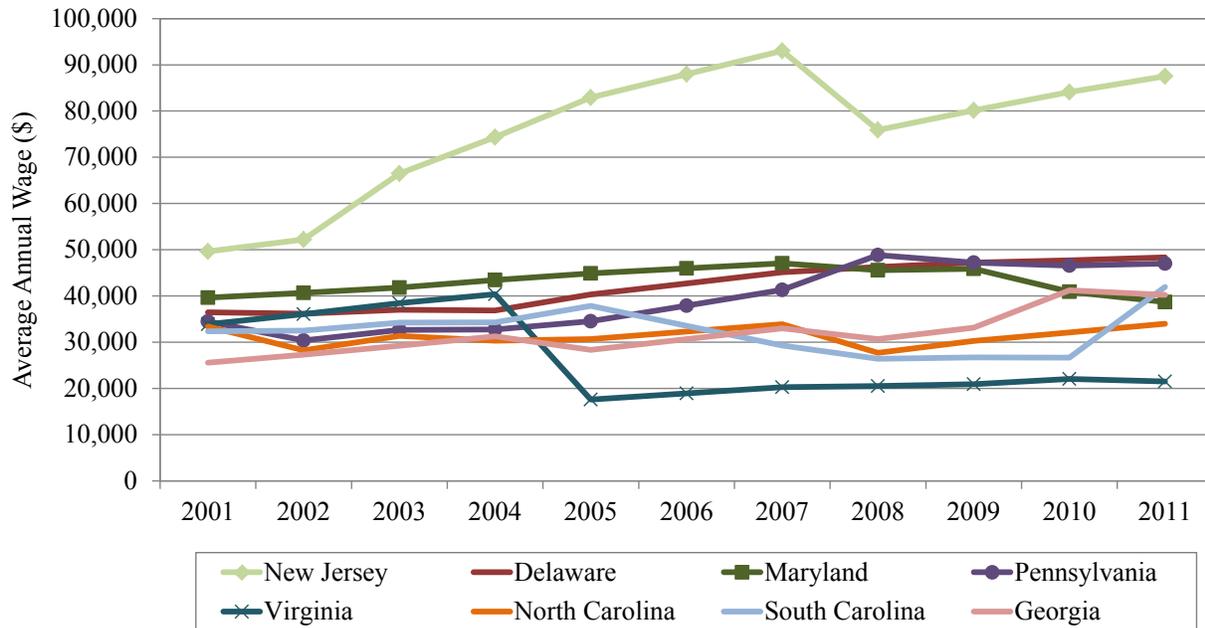
Source: USDOL, BLS 2012.

In New Jersey, Pennsylvania, and South Carolina, average wages in ports are higher than average wages in those states. For the region as a whole, however, port wages are just 94 percent of the regional wage. And, in comparison to the U.S. average wage, port wages are just 75 percent. New Jersey port jobs are the highest paid on average, making an annual average wage of \$87,000 per year. The next highest is Delaware, with an average wage of almost \$48,000. Figure 33 shows the trend of average port wages by state.

**Table 11. Regional and national average annual wage contribution, ports, 2011.**

	Average Annual Wage		Ports Average Annual Wage as a Percent of Total Average Annual Wage	Ports Average Annual Wage as a Percent of Total U.S. Average Annual Wage
	Ports	Total State		
	----- (\$)		----- (%)	
New Jersey	\$ 87,518	\$ 56,885	153.8%	146.3%
Delaware	\$ 48,378	\$ 50,535	n.a.	n.a.
Maryland	\$ 38,674	\$ 50,620	76.4%	64.6%
Pennsylvania	\$ 47,040	\$ 46,662	100.8%	78.6%
Virginia	\$ 21,534	\$ 50,261	42.8%	36.0%
North Carolina	\$ 33,976	\$ 41,933	81.0%	56.8%
South Carolina	\$ 41,950	\$ 37,734	111.2%	70.1%
Georgia	\$ 40,217	\$ 45,580	n.a.	n.a.
<b>Total Region</b>	<b>\$ 44,911</b>	<b>\$ 47,526</b>	<b>94.5%</b>	<b>75.1%</b>
<b>U.S.</b>	<b>\$ 59,826</b>	<b>\$ 47,815</b>	<b>125.1%</b>	<b>100.0%</b>

Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.  
Source: USDOL, BLS 2012.

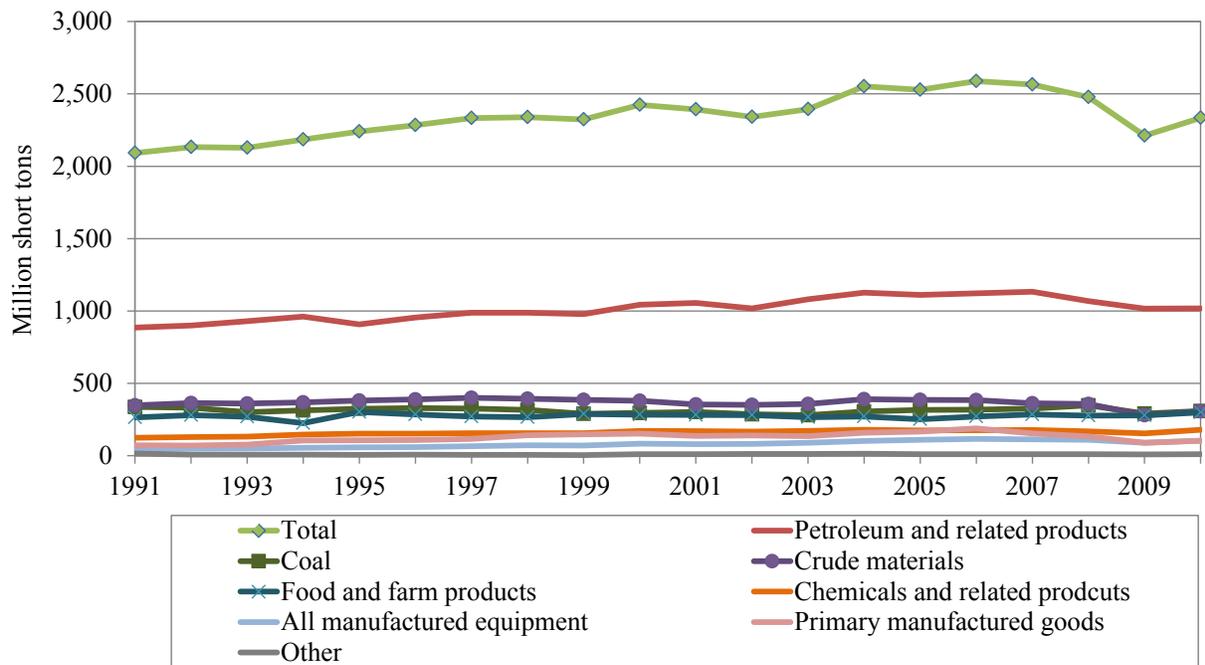


**Figure 33. Trends in Mid-Atlantic impact region ports average annual wages, 2001-2011.**

Note: Port employment is defined as the sum of the following NAICS categories: 48831, 488320, 713930, 488330.  
Source: USDOL, BLS 2012.

## 2.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

Increased port activity creates economic benefits in the form of increased employment, economic output, and other value-added benefits, such as tax revenue, fees, and royalty and proprietor's income growth. The quantity of goods and services transferred at ports has increased over the past decade. According to a 2010 report by the U.S. Army Corp of Engineers, commercial demand for marine transportation continues to grow and has been driven in significant part by the increase in international trade (USACE 2010). Figure 34 shows the growth of total waterborne commerce in the U.S. from 1991 through 2010. Despite a drop in 2009, total commerce as a general trend has been rising.



**Figure 34. Total waterborne commerce of the U.S., 1991 - 2010.**

Source: USACE 2010.

To accommodate for this growth in demand, ports will need to enhance efficiency. The entire maritime system relies on the successful integration of freight modes—water, truck, and rail—for the efficient transportation of cargo from vessels through terminals to and from inland destinations. Efficient access and the intermodal transfer of goods and cargo is critical to maximizing the returns from increasing terminal investments and also could be instrumental in maximizing port competitiveness and growth opportunities (USDOT, MARAD 2002).

According to an August 2002 MARAD survey, the state of the intermodal access for U.S. ports was generally acceptable for handling the existing volume of cargo flows. However, more than one-quarter of the ports indicated that channel depths were “unacceptable in federal waterways” (USDOT, MARAD 2002). A 2005 MARAD and DOT report found that the U.S.’s port and intermodal freight system is quickly approaching capacity limits as congestion increases in metropolitan areas and passenger and freight corridors are pushing existing infrastructure limits. The report concluded that the Marine Transportation System’s (MTS) greatest challenge is accommodating the projected growth in our international trade and the report noted that “[o]ur marine, highway and rail systems will need to be able to manage the increased volumes of freight shipments that are so vital to our nation’s continued economic growth”(USDOT, MARAD 2005a). An updated 2009 MARAD and DOT report echoed the earlier concerns about the effects of a rapid growth in international trade on the nation’s ports system, and also detailed many new factors that the ports system will need to address. As the maritime trade industry grows along with the fleet of vessels that serves it—in both physical size and number—new infrastructure improvements will be needed across all modes of intermodal transportation. Channel deepening is a main necessity as technological advances are producing wider, taller, and heavier vessels. Also, without any dedicated Federal source of funding for marine infrastructure, a coordinated Federal response to capacity and flow issues is very difficult to manufacture. That being said, the Federal Government has a strong presence in marine transportation, with nearly 20 departments and agencies. This causes complications when the time arrives to make industry decisions due to the large number of parties that have input. Another concern deals with the environmental concerns that impact the MTS. Now, more than ever, as environmental awareness and sustainability are in the national spotlight, a comprehensive green program for system development or sustainability practices in the maritime industry does not exist (USDOT, MARAD 2009a).

As cargo volumes increase, carriers will seek other transport and port alternatives in order to cut time and costs. The primary way of increasing efficiencies and lower unit transportation costs are to move cargoes through increasingly larger vessels. Vessels began service in the 1960s, with capacities of less than 500 twenty-foot equivalent units (TEUs), and now current shippers are beginning to place orders on ships that can carry over 10,000 TEUs. Average container vessel size was 2,900 TEUs in 2000, but in 2012 that average has increased to 6,100 TEUs<sup>4</sup>. Today, ships exist that can carry 14,000 TEUs<sup>5</sup>, while vessels that can carry 18,000 TEUs are on order for 2013 (Institute for Water Resources, USACE 2012a). These enormous ships require sophisticated and well-organized ports and terminal facilities with first-rate landside intermodal connections.

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<sup>4</sup>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 (Industry Studies: Transportation, The Industrial College of the Armed Forces National Defense University, 2001).

<sup>5</sup>Examples include the MSC *Danit* and MSC *Beatrice*.

Larger cargo volumes, ships, and operating companies are putting pressure on ports to increase their scale of operations, and channel depth appears to be the most significant factor of consideration in these expansion decisions. Channel depths at most major U.S. ports typically range from 35 to 45 feet (11 to 14 meters). The current generation of new large ships requires channels from 49 to 53 feet (15 to 16 meters) (ICAF 2001b).

Channel depth is a critical issue driving port operations and growth opportunities. Channel depth is a major factor in the size of ships that will move into and through a given port, because it affects these ships' ability to move safely through harbors, and breadth of turning basins, and terminal-side water depths. Annual and periodic channel dredging requires the removal of several hundred million cubic yards of sand, gravel, and silt each year. These dredging activities can be challenging and controversial because ports are located in or near environmentally sensitive areas, including wetlands, estuaries, and, in some instances, fisheries. There is also the potential that materials dredged may uncover toxins or contaminated sediments that have accumulated over time (USDOT, MARAD 1998).

Total capital infrastructure expenditures for the period 2004 through 2008 at public U.S. ports are estimated at around \$10.6 billion. Of this, \$1.1 billion, or about 10.5 percent, will be spent on dredging (USDOT, MARAD 2005b). The latest update to these figures was in 2009 and issued projected data for years 2007-2011. Total projected capital infrastructure expenditures for the period 2007 through 2011 at public U.S. ports was \$9.4 billion. Of this, \$0.964 billion, or about 10.3 percent, was to be spent on dredging (USDOT, MARAD 2009b). Improving and maintaining navigation channels is critical to sustaining the rapidly growing marine transport industry. Bottlenecks can ensue when waterways are not deep enough for ships to safely navigate and dock at berths. Some ports must be dredged, so that cargo can move in the most cost-effective and efficient way through the intermodal transportation chain. Also, as ship sizes and volumes of cargo increase, so must the intermodal transfer operations.

Efficient transportation also depends on intermodal connections. To move waterborne cargo quickly to or from land based operations, trucks and railroads need to have clear access to ports. According to the AAPA, "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" (AAPA 2009c). The AAPA also references a recent Federal Highway Administration (FHA) Report to Congress on the National Highway System (NHS) Intermodal Connectors that found connectors to ports, rather than other freight terminals, were in their worst condition and received only minimal levels of federal funding and support over the past several years. The FHA Report also found that port facilities had twice as many miles with pavement deficiencies 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, which is often the landside connection. No matter how much ports invest, or how productive ports make their marine terminal facilities, our transportation system cannot operate to maximum efficiency unless cargo can move quickly and cost effectively in and out of ports" (AAPA 2012).

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 (USDOT, MARAD 1998). 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 six year period 1998 through 2003. Although the TEA-21 did not earmark specific funds for port-related projects, there were a number of port access projects that could meet TEA-21 eligibility requirements (USDOT, MARAD 1998). After the expiration of TEA-21, the Safe, Accountable, Flexible, Efficient Transportation Equity Act (SAFETEA-LU) enacted in 2005 and the Moving Ahead for Progress in the 21st Century Act (MAP-21) enacted in 2012, expanded on many of the topics originally included in TEA-21. SAFETEA-LU focuses on “improving safety, reducing traffic congestion, improving efficiency in freight movement, increasing intermodal connectivity, and protecting the environment” (FHA 2005c). Similarly, MAP-21 builds a “streamlined, performance-based, and multimodal program to address the many challenges facing the U.S. transportation system...includ[ing] improving safety, maintaining infrastructure condition, reducing traffic congestion, improving efficiency of the system and freight movement, protecting the environment, and reducing delays in project delivery” (FHA 2012b).

## **2.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

Ports along the Mid-Atlantic coast have been expanding in preparation of receiving larger vessels due to the near-future opening of an expanded Panama Canal. State governments and their port authorities are aiming to spend billions to build larger and expand existing ports in the quickest manner. In general, ports along the West Coast are already able to handle these larger vessels because they are naturally deeper than those along the East Coast (Holeywell 2012). The current administration has started to speed up the process for development and deepening of several major ports including New York/New Jersey; Charleston, South Carolina; and Savannah, Georgia (Schwartz 2012).

By the end of 2014, the Panama Canal will have completed a massive expansion, increasing the width of its locks and adding a third lane that will at least double the canal’s capacity. The Canal will be able to accommodate mega-ships that are almost three times as large as any vessel that has traveled through the canal before. These newer Post-Panamax ships are up to 1,200 feet (366 meters) in length, 160 feet wide (49 meters), and need a channel depth of 50 feet (15 meters) to travel through. In comparison, the older Panamax ships top out at 965 feet long (294 meters), 106 feet (32 meters) wide, and need a channel depth of 39 feet (12 meters) (Johnson 2012). The East Coast ports are rushing to accommodate these larger vessels because “the ports that become the first go-to destinations for larger vessels will have a huge competitive advantage over their peers”. In turn, this would create a more efficient trade industry along with increased maritime activity and many new domestic jobs (Holeywell 2012).

- The Ports of Baltimore and Norfolk currently have channel depths of 50 feet (15 meters) and will be able to accommodate the larger Post-Panamax vessels. Both ports are adding additional freight features with Norfolk adding new train services and Baltimore adding a new double-stack intermodal rail terminal (Journal of Commerce 2012a).
- The federal approval process for deepening and expansion for the Ports of Charleston, New York/New Jersey, and Savannah was recently fast-tracked which may have some of these projects completed by 2015 (Journal of Commerce 2012a).
- The Port of New York/New Jersey currently has the capabilities to handle Post-Panamax vessels with its channel depths but container terminals on Newark Bay have height restrictions arising from the Bayonne Bridge. A 5-year, \$1 billion plan is in the works to raise the bridge 64 feet (20 meters) for clearance (Holeywell 2012).
- The Port of Charleston grants access to overseas markets to over 20,000 companies in two dozen states. It is estimated the project cost of deepening the channel to 50 feet (15 meters) will be \$300 million while the annual economic impact brought to the state of South Carolina by the port is \$45 billion (Limehouse 2012).
- The channel deepening project at the Port of Savannah is estimated to cost \$652 million but will return \$174 million in annual net benefits to the country. The port was the second busiest container port for the export of U.S. goods by tonnage in FY2011 (Journal of Commerce 2012b).

## **2.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

All areas of the Mid-Atlantic impact region have good port coverage and it is highly unlikely that any new ports would be constructed to support offshore energy production activities under any development scenario. There are two primary factors that may influence port development in response to offshore activity: (1) the specific offshore location where development is expected to occur; and (2) the degree to which offshore support activities compete, or are in conflict with, bulk container and cargo trade that is currently the focus of larger regional ports.

Our research in the Mid-Atlantic OCS and experience along the GOM suggests that smaller and medium-sized ports in the central portion of the Mid-Atlantic impact region may be more suitable for offshore support activities since they are: (a) more likely to offer affordable and flexible leasing arrangements; (b) less likely to have significant competing bulk cargo activities; (c) will have access to marine craft that operate in activities comparable to oil and gas supply and support; and (d) are proximate to potential lease areas under consideration.

Consider that along the GOM, small specialized ports like Port Fourchon (Louisiana) Venice (Louisiana), Freeport (Texas) and Port Arthur (Texas) serve as primary support facilities for offshore oil and gas activities. Larger facilities such as the Port of Houston, the Port of South Louisiana, and the Port of Mobile tend to focus on major international trade opportunities and not smaller niche markets like offshore oil and gas development. This is not to suggest that major ports are not interested in potentially serving offshore activities, but simply to recognize that major ports (unlike their smaller counterparts) have certain opportunity costs in pursuing support activities for offshore activities.

For instance, many major ports along the eastern seaboard, particularly the upper areas of the Mid-Atlantic impact region, are in highly developed locations that have relatively expensive or limited expansion possibilities. Offshore oil and gas support development at these ports will need to be evaluated against the alternative uses for waterfront and port surface space. These returns, particularly for cargo-oriented activities, will be heavily influenced by the economies of scale associated with bulk operations that are entirely different than the smaller sized specialized activities associated with offshore oil and gas service activities. In other words, focusing on bulk cargo is likely to yield a higher return for limited port capacity than specialized oil and gas activities.

Smaller and medium-sized ports may have more incentives and greater interest in pursuing oil and gas support activities. Smaller facilities, being located in relatively less congested areas are more likely to have available surface and marine terminal expansion opportunities. These ports are also less likely to see a trade-off, or competition, between offshore oil and gas activities and cargo traffic since few of these facilities currently handle large-scale bulk cargo operations. In addition, state and federal funding mechanisms for infrastructure development can be defined by cargo tonnage, often creating a circular challenge for smaller ports. These ports do not qualify for additional funds given their low cargo tonnages, but cannot reach these critical tonnage levels without further investment.

Thus, smaller to medium-sized ports may have a greater interest, and more incentives, to pursue oil and gas support activities than their larger counterparts. Smaller facilities, being located in relatively less congested areas, are more likely to have available surface and marine terminal expansion opportunities. Smaller ports are also less likely to see a trade-off, or competition, between offshore oil and gas activities and cargo traffic since few of these smaller ports currently handle large-scale bulk cargo activities.

In fact, it could be the case that oil and gas support activities will create additional sources of business that would be credited to these ports' annual tonnage amounts. Increased tonnage, in turn, could help facilitate additional on-site infrastructure development (through tonnage-based state and federal public investment or appropriation formulae), which, in turn, could assist these facilities in actually securing bulk cargo business. Thus, rather than competing, oil and gas activities could be complementary to current cargo activities at smaller sized ports.

Lastly, there are a number of moderately-sized ports located in the Chesapeake Bay region that could serve as likely support bases for offshore oil and gas activities. These central Mid-Atlantic impact region ports are the closest to anticipated regional offshore development.

### **3 SUPPORT AND HELIPORT FACILITIES**

#### **3.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED**

The offshore oil and gas industry relies on an extensive onshore support system to provide its supplies and transportation. These support activities range from the supply products and services like electric generators, chains, gears, tools, pumps, compressors, to engine and turbine repair and construction. Additionally, there are inputs required for daily operation which must be transported from onshore support facilities to offshore structures: drilling muds, chemicals, lubricants, and other fluids. Many types of transportation vessels and helicopters are also used to transport workers, equipment, and materials to and from offshore platforms. Typical facilities for this sector include: general support facilities, repair and maintenance yards, supply bases, heliports, and offshore service vessels.

Historically, these support activities were “internal” to offshore oil and gas companies, but over time third party companies have developed. This third party influx was a result of downsizing and specialization, and they now provide a large amount of the onshore support and transportation services on a contract basis. Industry downsizing specifically has reduced the numerous layers and complicated nature of oil and gas operations by many offshore producers. In using contract services, producers are able to utilize supply, transport, and logistics resources on an as needed basis as opposed to providing the services permanently. One additional benefit of outsourcing is the degree of flexibility for offshore operators, allowing them to keep costs down during periods of oil and gas commodity price downturns (Oceanwide 2012).

Because offshore support and transportation facilities are highly dependent upon the drilling and production markets, they are also strongly impacted by the cyclical nature of oil and gas commodity prices. Specifically, the supply and transport side of the offshore industry are likely to be the first to be impacted by oil and gas industry downturns. During an economic contraction, the first things to be cut to reduce exploration and production company costs are discretionary supply, repair, storage, and maintenance activities. Support and transportation facilities are thus under pressure to perform efficiently, and to be able to diversify when possible, be cost effective, and adequately respond to tenant needs.

Both major corporations and independent producers provide onshore support and transportation services. Firms involved in the support sector of this industry are heterogeneous; however, all firms have one major source of volatility in common: a large proportion, or perhaps even the entirety, of support firms’ business activity, profits, and earnings are greatly impacted by the cyclical nature of the oil and gas industry. This relationship has led to two different survival tactics employed specifically by these firms: concentration and diversification. Concentration has occurred as a result of general merger and acquisition activity. Alternatively, diversification stems from taking on a broader number of support and service activities from other maritime-based industries so that falling oil and gas prices have a reduced impact on earnings.

The support and transport sector is crucial to the oil and gas industry. It consists of a variety of components to function efficiently including: management, personnel, construction, and design innovations. As energy prices increase, offshore oil and gas activity increases, and in turn generates a greater level of demand for offshore logistical support.

## **3.2 TYPICAL FACILITY CHARACTERISTICS**

Due to the number of different and specialized products and services that are contained within the title of “support industry” it is not easy to define any aspect as “typical.” Firms can be very large corporations or private businesses with few employees. For example, land-based supply and fabrication centers are generally very large as they provide the equipment, personnel and supplies necessary for the industry to function through intermodal connections. Other onshore support services include inland transportation to supply bases, equipment manufacturing, and fabrication. Also, offshore support includes waterborne and airborne transportation.

Ports, as discussed in the previous chapter, determine the number and type of tenants and port users for support services as well. For example, the Port of Iberia is the Gulf Coast’s largest shallow water draft port at over 2,000 acres. It houses over 100 companies and employs more than 5,000 workers (including welders, pipefitters, mechanics, managers, secretaries, accountants and other occupations) (Port of Iberia 2012).

### **3.2.1 General Support Facilities**

Support facilities can also take many forms, however one common feature is close proximity to a port. The port is a centralized location for crews to disembark, storage and loading facilities for materials, and generally also has physical attributes that complement support activities. In fact, this has become an explicit business practice at ports: developing and providing the necessary infrastructure to support offshore drilling and production activities. Most support or service companies have one or more of the following characteristics:

- Access to intermodal transportation access such as roads, inter-coastal waterways, railways, etc.;
- Protected wharfs, docks, and dry-docks to load materials destined for offshore locations (also can be used for short-term storage);
- Storage and demurrage facilities for longer term equipment and material storage;
- Crew housing;
- Communication facilities and equipment; and
- Workshops and machine and tooling shops.

### **3.2.2 Repair and Maintenance Yards**

Much of the repair and maintenance support work done at platform fabrication facilities and shipyards is associated with maintaining equipment and vessels for drilling and production activities. However, the specific method of repair varies from job to job in both time and scope. Depending upon the requirements of the repair or maintenance task, it can take anywhere from one day to over a year. As with other aspects of the oil and gas industry, repair jobs are sensitive to oil and gas prices. When prices are high work needs to be completed as quickly as possible so that the equipment can be put back into service. Similarly, there are strong time constraints during hurricane restoration and recovery because of the limited amount of working equipment and personnel. In many cases, a number of repair-oriented tasks are pre-fabricated and then taken offshore for final assembly and repair. This is often the case with such activities as piping, ventilation, electrical and other machinery. Some of the more typical maintenance and repair operations consist of the following (USEPA 1997):

- 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;
- Creation of new machinery spaces through cut outs of the existing steel structure and the addition of new walls, stiffeners, vertical, webbing, decking, etc.; and
- Creation of raw materials (pipes, sheet metal, machinery, etc.) or provision of specialty services (carpentry, maintenance, warehousing, etc.) by support shops working for the yard.

### **3.2.3 Supply Bases**

Supply bases are a vital part of the logistics chain and can consist of large yards with a range of services and logistics management to smaller shops that supply one or a few of the supplies needed on an offshore platform or vessel. Some of the larger companies offering supply chain management services operate from various locations and move equipment and supplies from land based supply houses to offshore drilling platforms. Many of the smaller suppliers can be thought of more as combined retail and equipment rental stores which supply anything from crane rentals, warehouse space, trailer rentals, and dispatch services, to engine parts, fuel, navigation tools, potable water, and lubricants (motor oil, hydraulic oil, natural gas, compressor oils, grease, gear oil, and synthetics).

### 3.2.4 Heliports

A heliport is a central location where helicopters land and take off for offshore service. Helicopters are used to move crew and equipment to areas 150 to 175 miles (240 to 282kilometers) offshore. A trip of this distance takes about one and a half hours and can reach the majority of deepwater platforms and facilities. Supply boats, discussed below, are used for shorter distances and are able to carry heavier loads. One other important distinction is that helicopters are utilized in instances where speed of delivery (equipment, personnel) may be pressing. For example, the Bell 206L Long Ranger has a fuel capacity of 110 gallons, can travel up to 320 nautical miles (515 kilometers), and has a cruising speed of about 130 knots (Flight Safety Foundation 2005). A supply boat (specifically a crew boat for transporting personnel), on the other hand, has a cruising speed to 20 to 30 knots (Sun Machinery 2012).



**Figure 35. EC155 Helicopter.**

Source: SNS 2012.

Heliport service providers usually retain a mix of size and quantity of aircraft, with their fleets categorized into small, medium, and large helicopters. The small helicopters, which can carry four to six passengers, are better suited for support of production management activities, daytime flights and shorter routes (SEC 2012a). Medium helicopters are the most versatile part of an air transportation company's fleet since they can fly in a variety of operating conditions and can handle longer distances and larger payloads than small helicopters. Medium and large helicopters are most often used for crew changes on offshore production facilities and drilling rigs (SEC 2012a).

Helicopters are an important means of transportation, and there are many companies that currently support the offshore industry with this endeavor. Three major providers to the existing offshore oil and gas industry in the U.S. include: Bristow Group (a portion of which was Air Logistics prior to 2010), Petroleum Helicopters Inc. (PHI), and Evergreen Helicopter, Inc. The Bristow Group (formerly Offshore Logistics) is the largest provider of helicopter transportation services globally, with a fleet of 556 aircraft (SEC 2012a). In the U.S., the Company has four bases in Alaska, seven bases in Louisiana and one in Texas (Bristow Group 2012). Services pertaining to the offshore industry specifically include offshore and onshore transportation, emergency night flights, and transportation for company officials or key personnel including special security precautions (Bristow Group 2012). PHI is primarily used for service related to the offshore oil and gas industry, but a secondary focus is emergency healthcare transportation. This company also specializes in deepwater support for rigs more than 200 miles (322 kilometers) offshore. They have provided some service internationally, but mainly support the Gulf region with locations spanning the Gulf Coast and headquarters in Lafayette, Louisiana (PHI 2012). Evergreen International Aviation, Inc. provides a multitude of services including search and rescue; firefighting; forestry; construction and heavy lifting; and cargo and personnel shuttle. It also services the oil and gas industry. In the U.S., the Company has locations in Rhode Island, Washington, DC, Oregon and Alaska (Evergreen 2012).

### **3.2.5 Crew Services**

Many companies exist solely to support the crew and staff required for successful offshore drilling. For example, crew members who live on the offshore rigs need catering (hot meal delivery and service), laundry, and cleaning and maintenance services for crew barracks. A number of companies provide temporary personnel to operate offshore rigs, act in human resource positions, and provide on-site services like paramedics and food service (WMMS 2012 and Oceanwide 2012). Additionally, though drilling companies sometimes hire medics directly, it is particularly common to hire a third-party medic as part of the crew to ensure safe and efficient operations (SMS 2012).

Platforms used for accommodations provide housekeeping services including laundry and maintenance of living quarters. Offshore accommodations are a large contributor to operating costs, but are unavoidable as a result of strict safety regulations. Also, there is a strong need for skilled labor, and in order to attract these workers it is necessary to have comfortable accommodations and other non-salary work environment benefits. Many companies now are even building accommodation barges, such as the one in Figure 36. This barge is the Offshore Olympia and is one of many variations of crew vessels. It has capacity for up to 478 people “in 126 fully air conditioned cabins with ensuite bathrooms and fitted with lockers, desk and chair.” (Barges.com 2012). There is also an onsite hospital facility and numerous recreational options for the crew: cinema, gym, television and game rooms.



**Figure 36. Accommodation barge with helipad.**

Source: Barges.com 2012.

These crew services companies also provide medical, entertainment, security, and waste management services. A critical service is potable water transportation and waste management. There are numerous federal and state laws which require the safe disposal of offshore drilling wastes, some of which necessitate being returned to shore. Many offshore supply companies use special tanks on OSVs to transport waste to specialized onshore transfer facilities which will later send the waste to their final disposition point. The specific details of this process will be discussed in a later chapter.

### **3.2.6 Offshore Support Vessels**

Regular transportation of supplies, materials, and personnel is necessary for any functioning offshore oil and gas production operation. Offshore Support Vessels (OSVs) performing these operations are required at practically every stage of the offshore drilling and production process. Drilling companies may even solicit and bid for specific support vessels for a particular activity or project.

OSVs can take many forms: Platform Supply Vessels (PSV), Anchor Handling Towing Supply (AHTS) vessels, crew boats, and Seismic Survey Vessels. All of these support vessels perform a range of services like drilling, production, exploration, pipe and cable laying, subsea construction, towing and salvage, heavy lift, and related operations (Swire 2012a; and IMCA 2012). For example, the PSV shown in Figure 37 can carry up to 1,600 tons of deck cargo, 300 cubic meters of bulk cargo capacity, and additional tanks for fuel, water, brine, and liquid mud (Swire 2012b). Though these OSV's are discussed as distinguishable types, often many boats are built with functionality that crosses over into another type class (Barrett 2008).



**Figure 37. An example of a platform supply vessel.**

Source: Swire 2012b.

The main purpose of PSVs is to deliver supplies needed for drilling and production: fuel, water, drilling fluids, dry bulk cement, drill pipe, casing, etc. These boats are fundamental in the support of offshore drilling and production and are easily adaptable to serve more specialized needs (GulfMark Offshore 2012). PSVs can often provide assistance with construction tasks, along with vessels specifically designed as construction support vessels. These boats are generally pipe-laying barges, diving support vessels, pipe carriers used to aid in building offshore platforms and pipelines to shore-based storage facilities and the installation of associated offshore loading facilities (GulfMark Offshore 2012).

AHTS vessels are used primarily in the towing, positioning and mooring of drilling rigs and other equipment. These vessels are also used to transport supplies and equipment to offshore drilling rigs, platforms and other installations (SEC 2011c).

Crewboats (fast supply vessels) are much smaller than their OSV counterparts, likely due to the fact they are used to transport crew members to, from, and between rigs offshore. Therefore, their cargo is significantly smaller than other OSVs. New generation crew boats have been built with the capability to carry some supplies, although those amounts are very small and meant to be used in emergencies or time-sensitive situation (Barrett 2008).

There are still other types of vessels, with more specific functions that include collection of geophysical data by survey vessels, fracturing and acidizing of producing wells (well stimulation), maintenance work, and multi-purpose supply vessels which can service most deepwater operations (Barrett 2008). OSVs can also be also equipped for firefighting and oil recovery operations in the event of an oil spill at an offshore platform. Once the necessary infrastructure of the offshore site and support is in place, there is a continuing requirement for the transportation of food, supplies, personnel and equipment to the platforms.

The services companies operating in the GOM can be used to illustrate the diversity between companies and services provided. For instance, the Atlantic Communications 2011 Gulf Coast Oil Directory lists 30 companies in the “Marine Supply Bases- Expeditors” section. While the majority of companies employ between 1 and 25 people, some have between 100 and 250 or even over 1,000 employees and up to seven locations in multiple states (Atlantic Communications 2011). Supply bases provided by these companies are equally diverse from large yards with many services to smaller shops specializing in one or a few items needed by an offshore platform or marine vessel. The following is a simplified list including some products and services provided by these bases:

- Dock(s) for loading and offloading, crane services, and pipe storage.
- Personnel: dispatchers, material expeditors, and rig clerks.
- Office space, computer sales and rentals.
- Brokering tug, offshore, and crew boats and barges.
- Fueling for rigs and other vessels.
- Ability to purchase, sell, store and deliver marine diesel fuel and lubricants.
- Complete galley, deck and engine supplier.
- Electrical cables for offshore marine applications.
- Wire rope, marine and lifting equipment.
- Navigational supplies and weather instruments.
- Marine supplies, dock, harbor and vessel mooring, hardware.
- Living quarters and temporary accommodation cabins, galleys, diners, utility buildings.

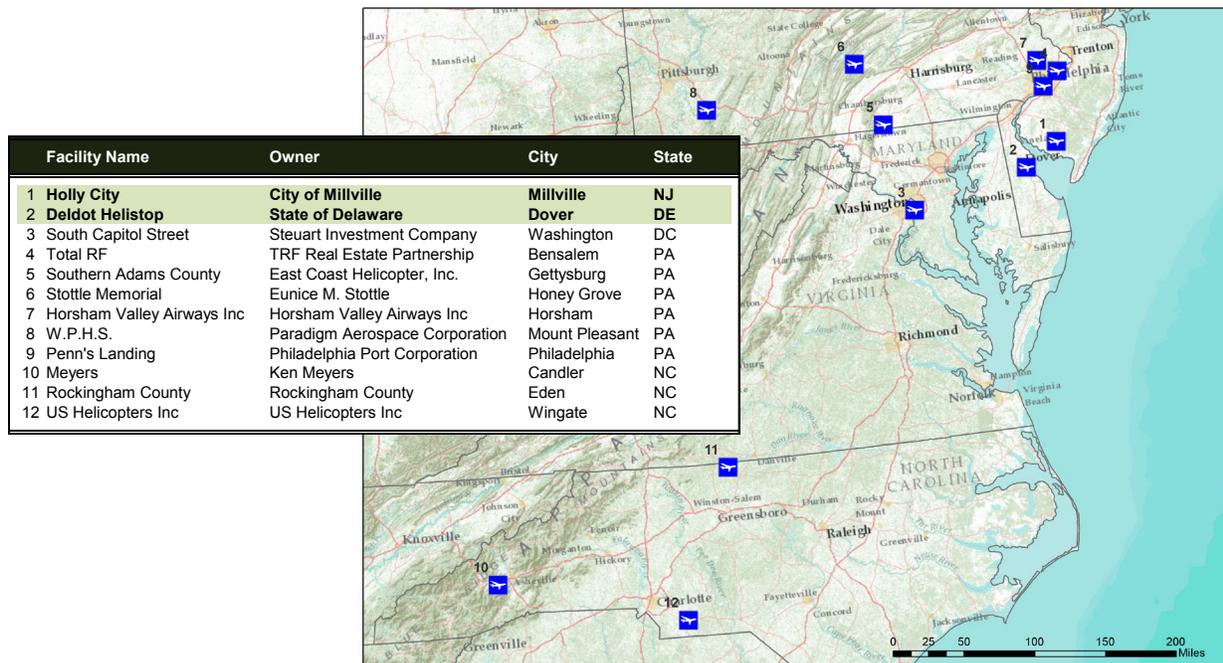
The directory also has a section for Catering Services. Some of the 26 companies listed provide chef and catering services, while others delivery groceries. For example, Affiliated Marine of Houma, LA delivers all groceries from meat to fresh produce, and even has butchers on staff (Affiliated Marine 2012). Taylors International Services, Inc. is a large company operating in the GOM and internationally, and employs 500 to 1,000 people (Atlantic Communication 2011). Taylors catering services provide a range of cuisines and fresh produce (and claim to do so under any weather conditions), but also other support services such as management services, accommodations, and personnel like cooks, stewards, bakers, utility hands, etc. (Taylors International 2012).

The only support and transport facilities currently located in the Mid-Atlantic impact region are heliports. Repair and maintenance facilities have been included with the shipyards database, so heliports are discussed throughout the remainder of this chapter. However, support facilities will be a necessity should drilling occur in the Mid-Atlantic OCS.

### 3.3 GEOGRAPHIC DISTRIBUTION

Heliports are located throughout the United States, but those that service the offshore oil and gas industry are obviously more prevalent in the GOM region. The heliports identified in the Mid-Atlantic impact region are likely not being used for oil and gas operations. And the FAA, which is the source used to identify existing heliports, does not report data on the usage of the aircraft from each heliport.

According to the FAA there are 1,013 heliports in the Mid-Atlantic impact region states. The majority of these however, are either owned by the military, state and local government (e.g., New Jersey Turnpike Authority, Town of Ocean City) or private hospitals and corporations. Only 12 of the heliports in the Mid-Atlantic impact region states are classified as public entities and could potentially be involved in offshore support if such an industry existed in the area (FAA 2012). And actually, as visible from Figure 38, of these 12 only two are located within 20 miles (32 kilometers) of the coast.



**Figure 38. Public heliports in Mid-Atlantic impact region states.**

Source: FAA 2012.

### **3.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY**

Although we have identified a few heliports in the Mid-Atlantic OCS region, there is no drilling activity off of the Mid-Atlantic OCS, and therefore these heliports are not actively supporting the oil and gas industry. Similarly, there are no useful NAICS codes or industry data to use to analyze the contribution of the support economy to the area. Heliports are not only used in supporting the offshore industry, but also can be used agricultural support, air medical, tourism, firefighting, corporate transportation, traffic monitoring, police and military (SEC 2012a). Therefore, the economic contribution of this sector cannot be estimated, as it does not yet exist.

### **3.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY**

#### **3.5.1 Trends**

Support and transportation facilities serving the offshore oil and gas industry are dependent upon drilling and production activities and the price of oil and gas. This dependence requires support companies to diversify so that they can accommodate changes in the industry such as exploration in deeper waters. During the 1990s oil and gas companies consolidated and formed alliances in an attempt to protect value to shareholders. Contract support services followed with similar behavior and this has proved to be an effective defense at counteracting economic downturns: running efficiently, being innovative, diversifying, and consolidating through mergers and acquisitions. Evidence of this can even be seen in the helicopter industry (Bristow Group 2012 and PHI 2012).

The support and transport sectors are generally very competitive. For instance, oil and gas companies usually select one helicopter provider for all services within a region by competitive bidding (if not throughout all service regions). In some cases oil and gas companies have the capabilities to perform their own helicopter services, making the bidding process even more competitive (SEC 2012a). In Bristow Group's 2012 Annual Report they present a break-down of their clients' contributions to gross revenue. The top ten clients comprise more than 54 percent of their total revenue and their top client, Chevron, accounts for 11.9 percent of their revenues (SEC 2012a).

Over time deepwater activities in the GOM have forced significant changes on the transportation industry: rigs have moved to deeper water and often require greater resources (Barrett 2008). The helicopter and vessel industries must upgrade, especially given the older average age of fleets in operation so that they are able to meet the demands of the industry.

Domestic and international competition also forces companies to be efficient and to use more advanced technologies. Similarly, the lack of skilled labor forces companies to ensure offshore accommodations are attractive as possible. Fiber optic cables are one innovative example of new support technologies being used offshore. Undersea fiber optic cables allow companies to use digital information and manage operations collaboratively with onshore personnel while increasing productivity, reliability, and safety (Munier and Haaland 2008). Specifically, BP installed a new fiber optic network in the GOM which included a 1,100 kilometer, two optical fiber pair trunk cable between Pascagoula, Mississippi and Freeport, Texas (Munier and Haaland 2008). There are also built-in expansion nodes for added service to new and existing platforms (Munier and Haaland 2008). This type of network is also very useful during storm events because of the easier transition from offline to online.

The transportation sector of the support industry also utilizes technological developments to improve safety of boat and flight performance. In 2007 Air Logistics developed a memory card, ALERTS, to store flight data and allow the information to be uploaded and viewed from a helicopter (including those used currently in the GOM). Flight crews are thus able to review data after each flight and can apply this information to fly safer, assist in training and accident investigations (Bristow Group 2007).

### **3.5.2 Outlook**

Like most sectors that support the offshore oil and gas industry, if activity in oil and gas exploration, development, or production in any region declines drastically, the need for support services would also decline. This is difficult to predict. The U.S. Outer Continental Shelf Lands Act also may further restrict availability of offshore oil and gas leases, thus causing a similar impact on the support sector (SEC 2011b). Similarly, the price of crude oil and natural gas strongly influence the utilization of support services: resilient prices will lead to continued activity in shallow and deepwater producing areas.

If drilling were to begin off of the Mid-Atlantic coast, support and transport services would be needed by the oil and gas industry, which would create a boom (and a beginning) for the support and transport sector in this region. As true with most offshore drilling-related industries, the service industry is cyclical and dependent upon oil and gas prices. Higher prices stimulate exploration efforts and the extent of economic growth, which drive the construction market. There is an expectation of continued growth and strength in prices as evident from many companies and experts (e.g. Bristow 2012; PHI 2012).

### **3.5.3 Regulatory Changes**

There are a number of regulations which apply to the oil and gas industry, particularly concerning potential spills in water and other types of air and water pollution. These regulations therefore impact the support and transport sector as well. These regulations encompass international, federal, state, and local levels. Similarly, a range of U.S. governmental agencies have jurisdiction over these support and transport operations: the U.S. Department of Transportation, National Transportation Safety Board, the Federal Aviation Administration, Department of Homeland Security and its related agencies (U.S. Customs and Border Protection, U.S. Coast Guard), and the Environmental Protection Agency (EPA) (SEC 2011b).

Onshore support services are not explicitly regulated, however, they do have to follow environmental statutes because they coincide with other regulated industries. For example, repair and maintenance often falls under regulations applied to the shipbuilding industry and its regulations as discussed in a previous chapter of this fact book. Some regulations applicable here are: 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.

Specific regulations for the design and construction of offshore supply vessels were adopted by resolution by the International Maritime Organization (IMO). *The Guidelines for the Design and Construction of Offshore Supply Vessels 2006* are actually an amended and revised version of regulations originally adopted in 1981 (IMO 2006). Following, in May 2012, the U.S. Coast Guard issued a policy letter implementing the IMO's resolution and providing the United States' interpretations for the design, construction and operation of new and existing U.S. flagged OSVs (USCG 2012a). The provisions of both the IMO guidelines and the USCG interpretations "have been developed so that limited quantities of cargoes regulated under these Guidelines may be carried in bulk with minimum risk to the offshore support vessel, its crew, and to the environment" (USCG 2012a). The guidelines address stability, machinery and electrical installations, fire protection, lifesaving appliances, radio communications and the transport of hazardous and liquid noxious substances in bulk.

#### ***FAA Regulations***

There are specific state and federal regulations for heliports, in part due to the Federal Aviation Administration (FAA), which oversees all flight operations. The National Transportation Safety Board is responsible for reducing the number of accidents in all transportation media. They are an independent government entity which investigates past accidents and creates recommendations as needed to stop that from happening again (NTSB 2012). However, note that the NTSB has no true authority to regulate the transportation industry. The Communications Act of 1934 also has a minor role in regulatory concerns for heliport owners and operators. As with all other workspaces that have been discussed hereto, workplace health and safety standards are defined by the federal Occupational Safety Act (OSHA).

The FAA's jurisdiction is widespread and includes oversight of flight operations in general, to personnel, aircraft, and ground facilities. In order to transport personnel and equipment to offshore regions air transportation providers must have an Air Taxi Certification from the FAA. Similarly, air transportation companies are required to file flight operation reports periodically. Under the Federal Aviation Act, aircraft for hire must be registered with the FAA and the operator must receive an operating certificate (SEC 2012a). These operating certificates are only issued to U.S. citizens, and a company may be considered a U.S. citizen as long as: at least 75 percent of its voting interest is held by a citizen of the U.S., the president of the company and at least two thirds of the directors are a U.S. citizens (SEC 2012a).

Because heliports own and operate radio and communications equipment used in flight coordination, the air transportation companies are subject to certain regulations associated with the Communications Act of 1934.

### **3.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

From 1976 to 1983 there were 433 lease sales and 51 wells were drilled in the U.S. Atlantic Region. This was an exploration phase and only one "discovery" of gas shows was made. No production resulted from this exploratory event due to the distance from shore (about 100 miles (161 kilometers)) and the lack of both onshore and offshore support infrastructure (BOEM 2012). This is the extent of activity in the oil and gas offshore industry in the Mid-Atlantic OCS to date. However, the federal government has displayed an interest in this area for drilling in the future, where currently they are performing an assessment and exploration phase (NY Times 2012).

As shown in Figure 38 just 12 public heliports are located in the Mid-Atlantic region and most of these facilities are in Pennsylvania and North Carolina. Since heliports and support facilities are required in areas to enhance offshore production, this industry will only grow in the Mid-Atlantic region if drilling begins offshore. However, some more limited resources will be necessary if onshore shale drilling increases- not to the extent of what is required for offshore operations, but still enhancing to the surrounding economy (FAA 2012).

It is unclear whether the Mid-Atlantic OCS will begin producing offshore, and until that time there is no reason that a support structure will develop for drilling. Land-based supply and fabrication centers provide equipment, personnel, and supplies necessary for the industry to function through intermodal connections with ports. Other necessary onshore counterparts to offshore drilling are inland transportation to supply bases, equipment manufacturing, fabrication, and crew services. The offshore support includes a variety of waterborne and airborne transportation.

BOEM released a study in 2012 using data and information available as of January 1, 2009 to assess the undiscovered oil and gas resources for the Mid-Atlantic OCS. Nine conceptual plays and one high risk play with drilling depths from 7,000 to 30,000 feet (2,134 to 9,144 meters) were identified. Since drillships are now able to drill in 12,000 feet (3,658 meters) of water to depths of 40,000 feet (12,192 meters) there are no longer engineering or technology issues to limit exploration in the Mid-Atlantic OCS, though there is little supporting pipeline infrastructure to the coastal regions into the OCS (BOEM 2012). The assessment estimates the undiscovered technically recoverable oil and gas are between 1.30 and 5.58 Bbls of oil and 11.11 and 53.62 Tcf of natural gas in the Mid-Atlantic OCS (95 percent and 5 percent confidence intervals, respectively) (BOEM 2012).

### **3.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

No support and transport facilities have been identified on the Mid-Atlantic coast (with the exception of heliports). General offshore support and transportation is tied directly to ports. Our research does not suggest the development of private (company-owned) service facilities arising until offshore activity moves to the Mid-Atlantic OCS. Like ports, development in response to offshore activity will be influenced by the specific location of offshore activity.

The capital cost of developing such types of facilities by an individual offshore operator may be too expensive for one company alone. Support facility development is likely to track port development. Factors weighing against private support base facilities include:

- Potential conflicts with recreation and residential development.
- Permitting challenges.
- Facility development costs.
- Offshore development scenario uncertainties.
- Lower cost commercial port opportunities.

There are currently 12 publicly owned heliports in the Mid-Atlantic region. These heliports do not provide service to offshore oil and gas development since there is no development of the Mid-Atlantic OCS at this time. With support from the government for drilling in this region there is a chance that this support infrastructure will develop. Some influential factors for the expansion of the existing heliport system in the region to oil and gas support are below:

- alternative energy infrastructure utilization;
- current heliport services;
- regulatory issues;
- public funding and development incentives;
- general business conditions; and
- proximity to OCS development.

## **4 OIL SPILL RESPONSE**

### **4.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED**

Oil spills are widely regarded as serious man-made disasters with profound ramifications for regional ecologies and economies. Historically, two of the most well know offshore oil spills are the 1969 Santa Barbara oil spill and the 1989 Exxon Valdez spill. The 1969 Santa Barbara oil spill began January 28, 1969 about five miles (eight kilometers) off the coast of Santa Barbara, California, on a shallow drilling rig platform named Alpha operated by Union Oil. The spill last ten days before it was able to be capped with cement slurry, creating an oil slick covering 800 square miles (2,072 square kilometers) and effecting 35 miles (56 kilometers) of coast line (Clarke and Hemphill 2002). In subsequent analysis of the spill, it was determined that a major cause of the incident was a waiver issued by regulators allowing the use of lower quality casing materials than typically required. A second major oil spill occurred on March 23, 1989 as the Exxon Valdez tanker struck Bligh Reef in Prince William Sound, Alaska, while on autopilot. Before the ensuing leak was brought under control, the Exxon Valdez discharged 10.8 million gallons of crude oil into the surrounding ecosystem (Exxon Valdez Trustee Council 1990).

Subsequent to these offshore oil spills, the federal government and the petroleum industry ability to prevent and respond to these disasters has improved dramatically. First, the federal government has designated specific federal agencies with oversight of certain types of oil spills in different environments. For example, the U.S. Environmental Protection Agency is responsible for oil and other hazardous spills in U.S. inland waters, while the U.S. Coast Guard has been designated responsible for spills in deepwater ports and coastal waters (USEPA 2012a). The Coast Guard also certifies a number of private companies specializing in cleaning up oil spills: called Oil Spill Response Organizations (OSROs).

The EPA also created an “Emergency Management” program to focus on eliminating danger to the public and environment caused by oil or hazardous substance spill or release. There is a requirement for persons or organizations involved in an accident or release must notify the federal government when the spilled amount reaches a previously designated level. This designated level differs based upon what the released substance is, but for oil specifically this amount relates to whether it is enough to cause harm to the public or environment (USEPA 2012a). The specific guidelines of when the reporting threshold is reached can be summarized as follows:

- water quality standards are violated by the spilled oil;
- there is discoloration or a visible film or sheen on the water surface or adjoining shorelines;
- and there is a sludge or emulsion deposited beneath the surface of the water or upon adjoining shorelines.

There are some official exceptions which negate the need to report a spill. First of all, leakage from a properly functioning vessel engine is not considered report-worthy. If that oil is accumulated in the vessel's bilge, however, it is not "properly functioning" and should be reported. Case-by-case releases are allowed by the EPA Administrator if the discharge is for the purpose of research, demonstration projects, or studies relating to the prevention, control or reduction of oil pollution. Note, however, that the use of dispersants or emulsifiers is specifically forbidden if used in an attempt to circumvent the discharge regulations.

The EPA also has a list of permitted releases in the National Pollutant Discharge Elimination System (NPDES), which mainly fall under Section 402 of the Clean Water Act, once a permit is obtained (USEPA 2012b):

- if the discharge is in compliance with a permit under Section 402 of the Clean Water Act, and the permit includes an effluent limitation which applies to the oil itself, or another parameter designated as an indicator of oil;
- If the source, nature, and amount of a potential oil discharge was identified in the public record with respect to a permit under Section 402 of the Clean Water Act and if the treatment system capable of preventing the spill was made a permit requirement, therefore the spill is exempt from the notification regulation; and
- If the release is continuous or anticipated intermittently from a specific source which is identified in a permit or permit application, and those events which cause the spill occur within the scope of relevant operating or treatment systems. This exemption is particularly important for manufacturing or treatment systems of a facility or vessel, including periodic system failures which cause spills. However, discharges caused by spills or episodic events that release oil to the manufacturing or treatment systems are not exempt from reporting.

In the aftermath of a 1967 grounding of the oil tanker Torrey Canyon in the English Channel, The International Convention for the Prevention of Pollution from Ships (MARPOL) has also mandated specific allowances pertaining to environmental discharge into marine environments from operational or accidental causes. In accordance with MARPOL standards, all relevant vessels are required to discharge oil contents at rates no more than 15 parts per million (ppm). In the United States – a signatory to MARPOL – the U.S. Coast Guard enforces the convention through port state control (PSC) exams, which primarily examine monitoring equipment and ships logs for irregularities. The Coast Guard requires all oil tankers 150 gross tons and above to carry cargo monitors that provide continuous recordings of oil discharges from slop tanks, and oily water separators which clean oil-contaminated bilge and ballast water. Oily water separators are also required for non-oil tankers greater than 400 gross tons. Finally, the Coast Guard requires all ships 10,000 gross tons and greater to have an oil content meter (OCM) that measures the content of the oil in the discharge processed through the ship's oily water separator (Allain 2008).

## 4.2 TYPICAL FACILITY CHARACTERISTICS

In general, the oil spill response industry is knowledge-based and highly mobile, as many varying factors of an oil spill play a major role in the type of response effort employed. Some of the most influential factors include geographic isolation, weather, the type of water and shoreline impacted. For deepwater spills there are additional concerns including accommodations, access, and communication for volunteers on the site. Similarly, small communities may not be able to support a full-fledged emergency response effort with sufficient facilities, phone, or radio equipment. Warm water environments are most conducive to biodegradation and dispersing agents, while moderate wave activity renders gelling agents more effective. Moving water also acts as a natural cleaning agent, while spills in stationary water are more severe, since oil has a tendency to pool and stay in the same area for an extended period of time. The ecological environment of the spill site should also be considered when developing a response plan, so that the scheduled oil and cleanup operations do not threaten marine habitats. Depending upon the exact type of biological community, some are more sensitive to the physical intrusion that goes along with some commonly used methods of cleanup (USEPA 2012a).

Other factors also play a large role in oil spill response efforts, in particular the specific OSV category and the speed at which the OSROs can reach the site of an oil spill. Specific OSV categories, discussed in an earlier chapter of this Fact Book, typically play a strong role in oil spill response as well. OSVs can be differentiated by design, length, horsepower and cargo capabilities. For example, PSVs are involved in providing offshore drilling and production facilities with various supplies including equipment, pipes, lubricants, chemicals and drilling mud. However, these vessels can also perform firefighting and oil recovery operations in case of an oil spill at an offshore platform. In some cases, companies may redesign vessels to be more specifically suited for oil spill response (MSRC 2012).

The speed at which the OSROs can reach the site of an oil spill additionally determines the response efforts employed. Usually, if the OSRO are able to reach the site of a spill within the first few hours, the initial employed response is targeted towards containment, wherein special plastic booms are deployed to prevent the oil slick from dispersing further. Once contained, the OSROs can employ skimmers to pull oil from the surface of the water while leaving the water behind. This oil is collected in tanks or vacuum trucks to be disposed of or recycled. Additionally, OSROs can employ biological sorbents to safely break down oil compounds. The use of biological sorbents has the added benefits of being able to be used along shorelines if shorelines are contaminated (Triumvirate Environmental 2012).

### **4.2.1 Oil Spill Response**

The main goal of any oil spill response team begins in their preparation, well before any accident or spill occurs. Once a spill occurs, in order to minimize damage to human and environmental health, action must be taken quickly and well-organized so that the spill can be contained and controlled quickly. This planning ahead generally takes the form of a “contingency plan” which is a set of instructions outlining steps to take before, during, and after an emergency (USEPA 1999a). These plans attempt to outline different spill scenarios and situations and the steps to follow. The U.S. Environmental Protection Agency identifies four major common elements of a contingency plan: (1) hazard identification; (2) vulnerability analysis; (3) risk assessment; and (4) response actions.

#### ***Hazard Identification***

Identification of the dangers related to an oil spill is very difficult to prepare: it is impossible to know when and how much oil will be spilled in an accident before said accident has taken place. However, it is relatively easy to identify storage facilities for oil, where it travels, and which industries or firms use large quantities of oil. In this way, areas with a high probability of spill may be identified and “planned” for. Also, weather conditions, geography, isolated locations, spill size, can all affect the ability of response personnel to effectively clean after a disaster (USEPA 1999a).

Some standard information that is collected in the hazard identification stage is:

- Types of oil generally found in the area, both stored and transported through
- Locations where oil is stored in large quantities
- Mode of transportation used to move any large quantities of oil in the area (pipelines, railroads, trucks or tankers)
- Extreme weather conditions which are likely or possible in the area of concern during different times of the year
- Locations of response equipment and personnel who have been trained to use such equipment in spill response

#### ***Vulnerability Analysis***

Vulnerability analysis takes place after potential risk areas have been identified. This stage provides information about resources and communities which are in danger in the event of a spill. This wealth of information will assist personnel responding to the spill in making appropriate decisions about protecting public health and the environment.

Potential information which can be collected during the vulnerability analysis phase of contingency planning includes:

- Lists of the community’s public safety officials
- Lists of facilities which will need special attention: schools, nursing homes, hospitals, and prisons
- Lists of recreational areas like campgrounds or beaches
- Lists of special events; their dates, times, location

- Identification of exceptionally sensitive parts of the environment which may be impacted by oil or water pollution

### ***Risk Assessment***

The next phase, risk assessment, is when planners compare the hazard and vulnerability analyses for their location of concern to determine the level and kind of risk most likely. The plan addresses those concerns by finding the best option to control the spill, how to prevent high-risk populations or environments from oil spills. Lastly, the risk assessment addresses the options for repairing the damage done by a spill (USEPA 1999a). The risk assessment is created based upon findings in the hazard identification and vulnerability analysis, and then is used in determining necessary response actions.

### ***Response Actions***

Lastly, response actions are created to address risks that may have been identified in the previous risk assessment, stage. These actions describe procedures to undertake when a spill occurs. The response is planned to take place immediately so that hazards to human and environmental health are minimized. Some common elements of response actions include:

- Notifying all entities (including private companies and government agencies) responsible for cleanup efforts;
- Quickly getting trained personnel and equipment to the location of the spill;
- Defining the magnitude, content, and location of the spill;
- Assessing the direction and speed of movement of the spill;
- Determining the likelihood of sensitive habitats being impacted, based upon location characteristics;
- Ensuring the safety of all response personnel and the public in the area;
- If possible, stopping the flow of oil and preventing ignition;
- Containing the spill to a limited area; and
- Removing and disposing of oil as it is taken from land and water.

Once these steps of planning are completed, it is important to run trials of the designed plan to ensure it works as designed (USEPA 1999a). There is a wide range of “trial runs” which can be as simple as a discussion about how a full-scale response effort would occur or as complicated as a true enactment of the planned response. Depending upon the choice of trial, it may take a few hours or several days. However, this type of practice enhances the response effort in the event of an actual spill by increasing training of response staff, discovering weaknesses of the plan and areas which need improvement, provides a lower stress environment to practice the procedures and new techniques without the associated risk, allows responders to meet and become familiar with one another before a true disaster setting thus building familiarity and teamwork. All of these advantages help to make the response effort more effective in the event of a real oil spill (USEPA 1999a).

In the unfortunate event that a spill occurs, oil spill response teams should always do a post-spill analysis of their contingency plan to determine areas which can be improved. For instance, were there issues that had not been considered in the original plan and were there unexpected problems or successes in the chosen cleanup techniques? These and similar questions can be used to revise and improve a contingency plan (USEPA 1999a). Contingency plans must always be evolving and improving as the approaches and methods to responding to spills are not constant.

Other facilities also focus on oil spill response, specific niches of resources that may be impacted in the event of a spill. For example, the Avian Conservation Center in South Carolina focuses on public education, avian medicine, and research. However, they also have a South Carolina Oiled Bird Response Facility on site, which is equipped to provide quality medical care to injured or orphaned birds of prey and shore birds and response in the event of an oil spill which impact native bird populations and their breeding habitats all along the South Atlantic Coast (ACC 2012). This group also strives to promote awareness of the ecological impacts of a spill and how to be proactive in reducing its chances. Personnel are trained on site in avian medicine and oil spill response pertaining to birds.

Another organization involved in conservation of habitat for native birds in the Mid-Atlantic region, the Atlantic Coast Joint Venture (ACJV), has a working group which focuses on oil spill response. Specifically, the ACJV Oil Spill Working Group aims to develop a standardized protocol for spill responses to help determine the impacts on seabird populations and to improve the Natural Resource Disaster Assessment (NRDA) process for data collection after events (ACJV 2012).

#### **4.2.2 In Situ Burning**

In situ burning is a commonly used technique which involves the controlled burning of spilled oil at the spill location. This technique is used because it can significantly reduce the amount of oil in water, and similarly, reduces the impacts of oil on the environment (NOAA 2012a). The most common method of in situ burning uses a fire-resistant boom and ignites the oil within the boom. Two boats usually tow the fire-resistant boom in a U shape to collect the oil for ignition away from the main slick. The process may be repeated with more booms filled with oil until no longer necessary (Barnea 1997).



**Figure 39. In situ burning at a crude oil spill**

Source: Kusnetz 2012.

There are many advantages of in situ burning: minimizing the spread of the slick, remove oil from the site of the spill, avoidance of using storage facilities, less waste and disposal concerns. This method is especially beneficial in areas where no other options are feasible like ice-covered water or marsh. However, in general this should be considered a complement to other means of spill response. Mechanical recovery using booms, skimmers, and dispersants should also be utilized immediately following a spill (Barnea 1997).

The effectiveness of in situ burning depends upon several factors. The key factor that determines whether or not the oil will ignite is slick thickness. For fresh, volatile crude, the minimum ignitable thickness is about 1 millimeter (mm); for aged, unemulsified crude oil and diesel, 3 to 5 mm; and for residual fuel oils, about 10 mm. Other factors include wind speed, emulsification of the oil, strength of the ignition source, ambient temperature, and waves. The maximum wind speed has been determined to be 10 to 12 meters per second; the water-in-oil emulsion should not be more than 25 percent water; and the ambient temperature must be above the oil's flash point (Buist, et al 1999). The need for such specific environmental conditions can be viewed as one major disadvantage of this technique of oil spill response.

There are other considerations to in situ burning. One is the fire-resistant boom. This boom is generally made from ceramic fireproof fabric which can withstand heat greater than 2,000 degrees Fahrenheit, wave action, and towing (Barnea 1997). Other types of booms may be lighter and made of fire-resistant fabrics; however, they are not designed for long-term use. With every type of boom, several factors affect the amount of times they can be used. The length of exposure to a burn and the wave action during the burn will affect the rate of deterioration. For some types of booms, it is more cost-effective to dispose of the boom rather than restoring it for future use (Buist, et al 1999).

Other disadvantages are related to the perceived human and environmental harm that may result from in situ burns: flames and heat from the burn; emission generated by the fire; and the remaining material left once the fire is out. Heat from the fire is a concern for responders and the safest distance is assumed to be four times the diameter of the fire from the edge of an in situ oil fire (Buist, et al 1999).

Carbon smoke particles are also a major concern, as they can cause severe health problems if inhaled in high concentration. Exposure to these smoke particles will pose the highest threat to workers as concentrations in the immediate vicinity of the fire will likely exceed public health standards. Workers should be screened for health conditions, such as asthma, that would make them more sensitive to the in situ burning conditions, and all workers should be provided with protective equipment (Buist, et al 1999). The National Institute for Occupational Safety and Health (NIOSH) and the Occupational Safety and Health Administration (OSHA) also provide guidelines for protecting response workers and volunteers (CDC 2012).

Because of the risk to humans and the environment, extensive policies and guidelines have been established to limit in situ burning to an extent that the general population will not be at risk (Barnea 1997). Though in general in situ burning can be considered helpful to natural resources since it limits the spread of the spilled oil, there are some situations or specific regions where it may actually threaten resources. Individual regions in the U.S. have adopted policies to protect these natural resources in regards to burning (Barnea 1997).

In order for in situ burning to be effective, its approval must come quickly. There is a limited time window where burning is feasible (while the oil is thick enough and environmental characteristics are suitable). For this reason there is often preapproval for burning, or extremely quick approval on a case by case basis (Barnea 1997).

The in situ burn is monitored extremely closely. Specifically, monitoring teams are placed downwind of the burn, especially at population centers or other sensitive locations. These teams collect samples before, during, and after the burn to check particulate concentration trends and notify a supervisor if these levels reach a concerning concentration. Data is also recorded at every stage, and is forwarded to the Unified Command (NOAA 2012a).

Research has been done and data collected which show that about 85 to 95 percent of burned oil is converted to carbon dioxide and water. Five to 15 percent that is not effectively burnt becomes particulates, which is mostly soot, and explains the characteristic black smoke that can be seen during an in situ burn. The remaining 1 to 3 percent becomes nitrogen dioxide, sulfur dioxide, carbon monoxide, polynuclear aromatic hydrocarbons (PAH), ketones, aldehydes, and other combustion by products (Barnea 1997).

### **4.2.3 Bioremediation**

Bioremediation is an oil-spill treatment technique used in all types of environmental areas including soils, ground water, and surface water (both freshwater and marine). Bioremediation utilizes bacteria and other microscopic organisms to breakdown petroleum hydrocarbons through biodegradation into water and carbon dioxide. In this regards, bioremediation results in actually removing oil contaminates from the environment (EPA 2001). Bioremediation is unique in this regards as the majority of most other treatment techniques transfer the oil from one medium to another, or dilute it, rather than breaking down contaminated oil altogether as bioremediation does (USDOE/PERF 2003).

It should be noted that biodegradation is a natural occurring process that is simply harnessed or optimized to enhance the rate of biodegradation. Most microbes that degrade petroleum hydrocarbons require oxygen, water, proper acidity, and nutrients such as nitrogen and phosphorous (USDOE/PERF 2003). Because of this, in some environments biodegradation can be slow and the environmental factors that affect biodegradation need to be modified. Bioremediation increases the rate at which this biodegradation occur by providing an optimal living environment for these microbes (EPA 2001).

Bioremediation techniques must therefore be optimized for the environment and medium being treated, and its associated biodegradation rate-limiting factors. For instance, biodegradation in groundwater can be limited by the amount of dissolved oxygen present, while biodegradation in seawater is usually limited by a lack of nitrogen and phosphorous concentrations. Bioremediation of seawater is additionally hampered by the potential for nitrogen and phosphorous compounds to result in toxicity to aquatic organisms (USDOE/PERF 2003).

Environmental factors also present the biggest disadvantage to bioremediation, as is it less effective or more difficult to cultivate microbes in specific environments. For instance, high concentrations of salt may be inhibitory or lethal to microorganisms as the high salinity disrupts osmotic balance and interferes with enzyme activity. Environments with high acidity (low pH) can also negatively affect bioremediation as the optimal range pH range for biodegradation is 6.0 to 8.5. Biodegradation naturally causes pH levels in soils to drop over time, causing the need for lime or limestone to be frequently added to adjust acidity levels. Cold weather below 65 degrees Fahrenheit and environments too arid have also been shown to have an adverse impact on biodegradation rates (EPA 2001 and USDOE/PERF 2003).

### 4.3 GEOGRAPHIC DISTRIBUTION

Historically, oil spills in the Mid-Atlantic OCS have occurred as a result of refinery operations which receive cargo from water-borne suppliers and other industrial activities.<sup>6</sup> Because of this, there exist a number of companies in the Mid-Atlantic impact region which provide oil spill response services.

The private companies involved in the oil spill response industry are extremely mobile; however, in that they may be stationed in one location, but offer their services across the entire U.S. or even internationally. For example, the Coast Guard lists the Marine Spill Response Corporation (MSRC) as an OSRO with ocean response capabilities in COTP zone five.<sup>7</sup> MSRC is headquartered in Virginia, but provides oil spill response services throughout all Coast Guard COTP zones. Environmental Expert Online provides a list of oil spill response companies, many of which are located outside of the U.S., but others are on the East and West Coast and in the GOM region.

The Coast Guard also provides a listing of all classified OSPROs within their Response Resource Inventory System (USCG 2012b). This listing illustrates a similar pattern of widespread locations for OSPROs, with some concentration in the GOM and along the coasts.

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<sup>6</sup> For instance, in 2004 a tanker preparing to dock at the refinery in Paulsboro, New Jersey struck a large, submerged anchor. The anchor punctured the hull of the vessel, resulting in a spill of 265,000 gallons of crude oil into the Delaware River and nearby tributaries (NOAA 2010).

<sup>7</sup> This zone includes most of New Jersey, Delaware, Maryland (Chesapeake Bay), Virginia and North Carolina.

Table 12 provides a list of these companies with physical locations in the Mid-Atlantic impact region.

**Table 12. Coast Guard COTP Zone 5 (Mid-Atlantic) OSRO Companies.**

OSRO Company Name	Zone 5 Operating Capabilities					Location
	Offshore	Near Shore	Ocean	Inland	River or Canal	
LCM Corporation				X	X	Roanoke, VA
Lewis Environmental Group				X	X	Royersford, PA
A Clean Environment Inc.					X	Tulsa, OK
Oil Mop Inc.				X	X	Belle Chasse, LA
Clean Harbors Environmental Services				X	X	Norwell, MA
National Response Corporation	X	X	X	X	X	Great River, NY
Miller Environmental Group				X	X	Calverton, NY
Marine Spill Response Corporation	X	X	X	X	X	Herndon, VA
HEPACO, Inc.				X	X	Charlotte, NC (Mid-Atlantic Regional Office in Norfolk, VA)
Industrial Marine Services, Inc.				X	X	Savannah, GA
Heritage Environmental Services, Inc.				X	X	Indianapolis, IN (Offices in Charlotte, NC)
Clean Venture, Inc.				X	X	Elizabeth, NJ
All State O.R.C.				X	X	West Milford, NJ
McCutcheon Enterprises, Inc.				X	X	Apollo, PA
Triumvirate Environmental	X	X	X	X	X	Somerville, MA (Offices in Baltimore, MD, and Durham, NC)
Accurate Marine Environmental				X		Portsmouth, VA
Moran Environmental Recovery				X	X	Randolph, MA
Allstate Power-Vac Environmental				X	X	Rahway, NJ
Restoration, LLC				X	X	St. Louis, MO (Offices in Raleigh, NC)

Source: USCG 2012b.

#### 4.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY

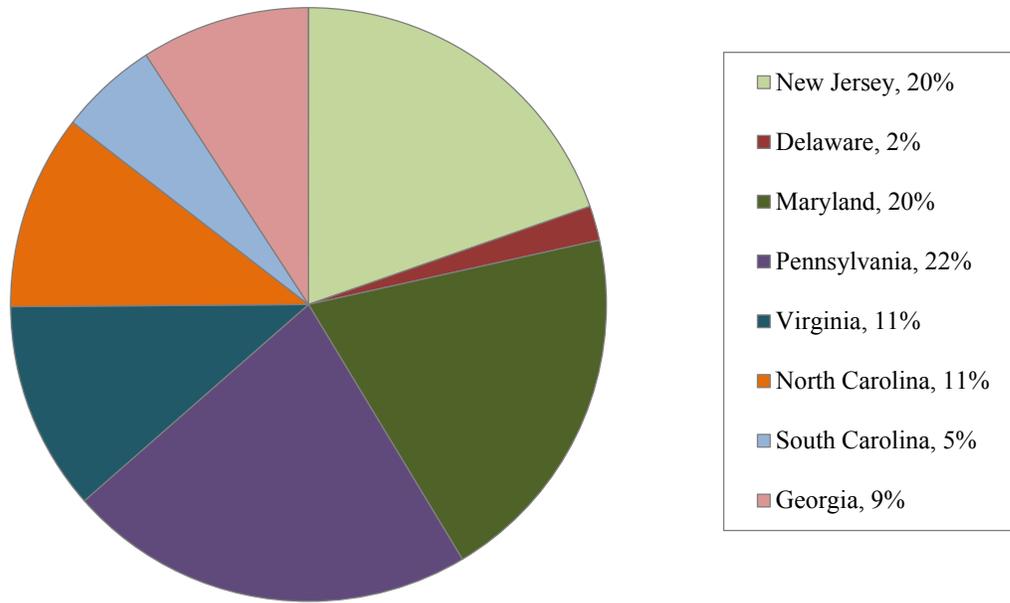
Oil spill response services are included in NAICS code 562910, Remediation Services. This includes remediation and cleanup of contaminated buildings, mine sites, soil, and ground water; waste water treatment; and the removal of hazardous material such as asbestos, lead paint, and other toxic materials. The development of remedial plans is classified as something different, however, and is compiled with a number of similar services, “Environmental Consulting Services.” Therefore, the results described below are likely larger than cleanup efforts for oil spills alone, but still present an applicable depiction of the industry’s influence in the area and over time (USDOL, BLS 2012).

Oil spill response employment comprises a very small portion of overall Mid-Atlantic region employment. Table 13 illustrates this fact, where the highest contribution is 0.13 percent of the state’s total employment (Maryland). Similarly, the Mid-Atlantic region oil spill response employment comprises a mere 17 percent of total U.S. oil spill response employment. Maryland, Pennsylvania, and New Jersey employ the greatest number of oil spill response workers in the Mid-Atlantic region, nearly 20 percent each, as can be seen in Figure 40.

**Table 13. Regional and national employment contribution, remediation services, 2011.**

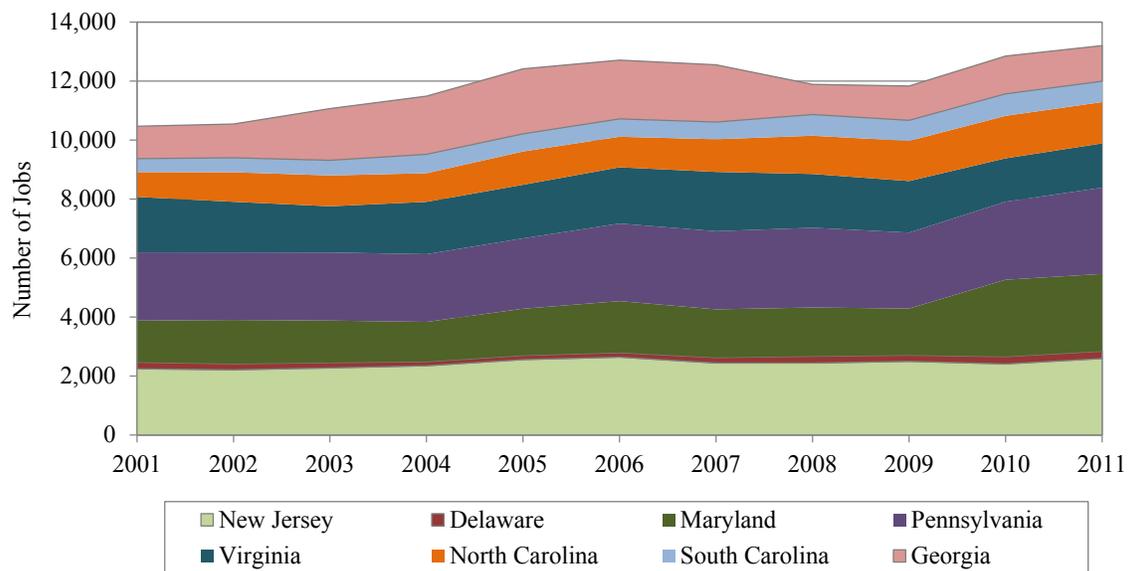
	Number of Jobs		Remediation Employment as a Percent of Total State Employment	Remediation Employment as a Percent of Total U.S. Remediation Employment
	Remediation	Total State	----- (%) -----	
New Jersey	2,593	3,156,538	0.08%	3.38%
Delaware	249	342,585	0.07%	0.32%
Maryland	2,618	1,991,055	0.13%	3.41%
Pennsylvania	2,926	4,825,064	0.06%	3.81%
Virginia	1,500	2,889,435	0.05%	1.95%
North Carolina	1,399	3,158,293	0.04%	1.82%
South Carolina	707	1,450,840	0.05%	0.92%
Georgia	1,208	3,135,735	0.04%	1.57%
<b>Total Region</b>	<b>13,200</b>	<b>20,949,545</b>	<b>0.06%</b>	<b>17.19%</b>
<b>U.S.</b>	<b>76,795</b>	<b>108,184,795</b>	<b>0.07%</b>	<b>100.00%</b>

Source: USDOL, BLS 2012.



**Figure 40. Mid-Atlantic impact region remediation services employment shares, 2011.**  
 Source: USDOC, BLS 2012a.

Remediation services employment in the Mid-Atlantic impact region has increased over time, at an average annual rate of 2.4 percent. These trends are shown in Figure 41. The number of jobs was at its highest in 2011. The largest increases in recent years were in Delaware, Maryland and Pennsylvania.



**Figure 41. Trends in Mid-Atlantic impact region remediation services employment, 2001-2011.**

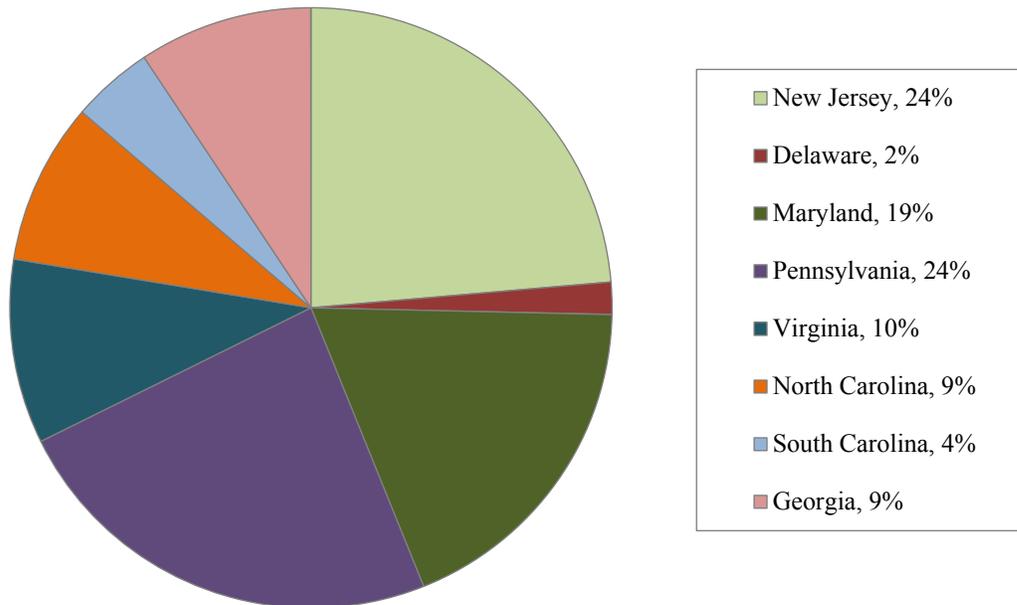
Source: USDOL, BLS 2012.

Total wages for the remediation services sector are presented in Table 14. Like employment, remediation services wages are a very small portion of total state wages. The Mid-Atlantic impact region wages account for about 16 percent of total U.S. remediation services wages. Of total wages paid for remediation services, New Jersey and Pennsylvania account for almost one-half of the wages paid.

**Table 14. Regional and national wages contribution, remediation services, 2011.**

	Wages		Remediation Wages as a Percent of Total State Wages	Remediation Wages as a Percent of Total U.S. Remediation Wages
	Remediation ----- (million \$) -----	Total State	----- (%) -----	
New Jersey	\$ 162.9	\$ 179,559	0.09%	3.74%
Delaware	\$ 11.8	\$ 17,313	0.07%	0.27%
Maryland	\$ 127.8	\$ 100,787	0.13%	2.93%
Pennsylvania	\$ 163.7	\$ 225,147	0.07%	3.76%
Virginia	\$ 68.5	\$ 145,225	0.05%	1.57%
North Carolina	\$ 59.9	\$ 132,436	0.05%	1.37%
South Carolina	\$ 30.2	\$ 54,746	0.06%	0.69%
Georgia	\$ 64.3	\$ 142,928	0.04%	1.47%
<b>Total Region</b>	<b>\$ 689.1</b>	<b>\$ 998,140</b>	<b>0.07%</b>	<b>15.81%</b>
<b>U.S.</b>	<b>\$ 4,359.6</b>	<b>\$ 5,172,844</b>	<b>0.08%</b>	<b>100.00%</b>

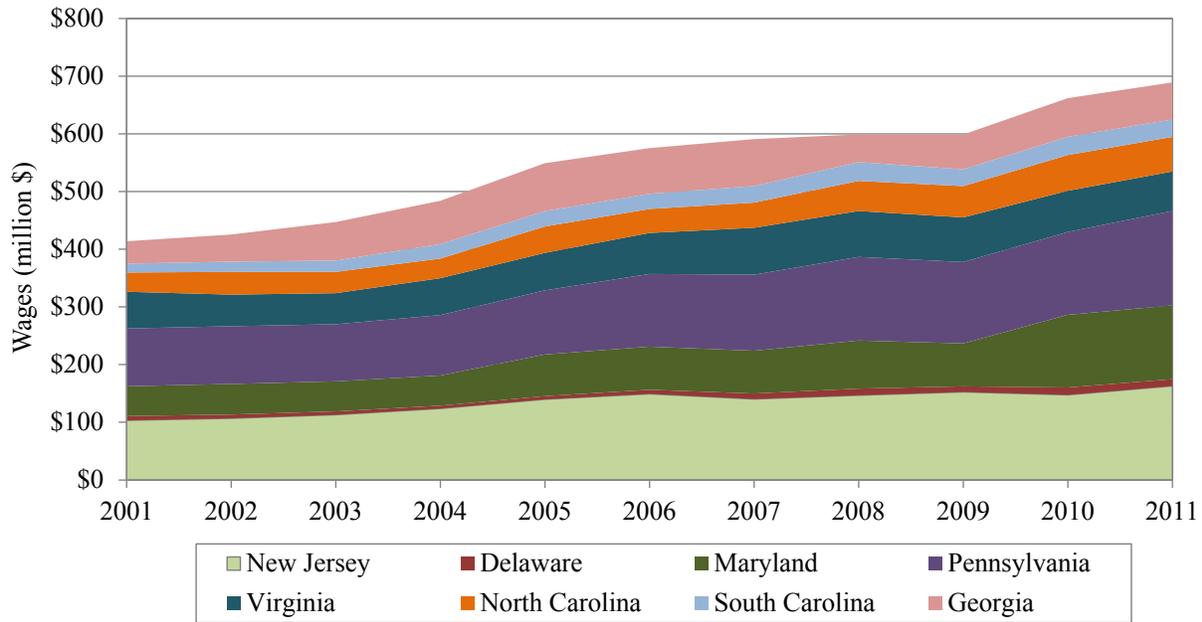
Source: USDOL, BLS 2012.



**Figure 42. Regional Mid-Atlantic OCS total wage shares, 2010.**

Source: USDOL, BLS 2012.

Similar to the trend in employment in the sector, total wages in remediation services increased steadily from 2001 to 2011, at an average annual rate of 5.3 percent annually. Only in 2009 was the growth rate negative, at -0.03 percent. This negative growth was driven by Delaware, Maryland, and South Carolina, but wages in those states jumped back up soon after.



**Figure 43. Historic trends in Mid-Atlantic OCS region oil spill response wages.**  
Source: USDOL, BLS 2012.

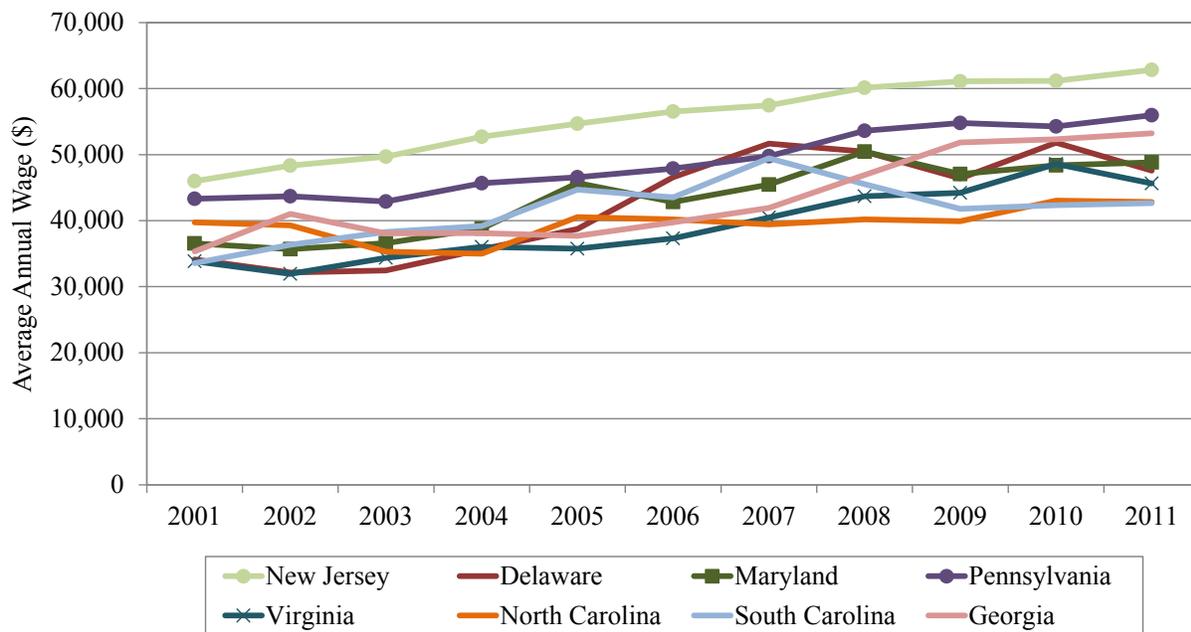
Table 15 illustrates that the average annual wage for remediation services are in general, greater than the average wage for the state (for all states except Delaware, Maryland and Virginia). However, the average annual wage for remediation services in the Mid-Atlantic impact region are lower than the average annual wage for remediation services in the U.S. (except New Jersey). Regionally, wages are approximately 88 percent of U.S. wages.

**Table 15. Regional and national average annual wage contribution, remediation services, 2011.**

	Average Annual Wage Remediation ----- (\$) -----		Remediation Average Annual Wage as a Percent of Total State Average Annual Wage ----- (%) -----	
		Total State	as a Percent of Total State Average Annual Wage	Remediation Average Annual Wage as a Percent of Total U.S. Remediation Average Annual Wage ----- (%) -----
New Jersey	\$ 62,828	\$ 56,885	110.4%	110.7%
Delaware	\$ 47,564	\$ 50,535	94.1%	83.8%
Maryland	\$ 48,818	\$ 50,620	96.4%	86.0%
Pennsylvania	\$ 55,949	\$ 46,662	119.9%	98.6%
Virginia	\$ 45,644	\$ 50,261	90.8%	80.4%
North Carolina	\$ 42,828	\$ 41,933	102.1%	75.4%
South Carolina	\$ 42,669	\$ 37,734	113.1%	75.2%
Georgia	\$ 53,222	\$ 45,580	116.8%	93.8%
<b>Total Region</b>	<b>\$ 49,940</b>	<b>\$ 47,526</b>	<b>105.1%</b>	<b>88.0%</b>
<b>U.S.</b>	<b>\$ 56,769</b>	<b>\$ 47,815</b>	<b>118.7%</b>	<b>100.0%</b>

Source: USDOL, BLS 2012.

The wage trend since 2001 has differed by state, although on average wages in the Mid-Atlantic impact region as a whole increased by 2.7 percent annually. Figure 44 depicts the growth in average annual wages for remediation services in all states individually in the Mid-Atlantic impact region.



**Figure 44. Trends in Mid-Atlantic impact region remediation services average annual wages, 2001-2011.**

Source: USDOL, BLS 2012.

#### 4.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

Contingency planners today are taking advantage of new technologies to improve their disaster plans. For example, planners in the EPA are using geographic information systems (GIS) to improve plans by incorporating electronic mapping data. They are able to make electronic maps which outline locations of sensitive environments, drinking water intakes, roads, oil storage and production facilities, pipelines, boat launches, etc. These tools and resources make prioritization much simpler, and quicker, which is vital in minimizing damage to human and environmental life. This wealth of knowledge is easily accessed and updated, and also aids in determining the types of cleanup equipment needed by illustrating the location of sensitive environments. Depending upon the type of land or water where the spill is found, it may be more beneficial to use booms than skimmers, or vacuum trucks. Mapping also helps to identify areas which will be difficult to access (USEPA 1999a).

Other technologies being used by planners include X-Band and Infrared technology which are placed on marine platforms to help better located oil in low visibility conditions (MSRC 2012).

As a result of advancements in data collection and storage, there are now databases which document types and properties of crude oil being stored and transported, which are extremely useful in the event of a spill. However, these are not current and many newer oils currently being produced are not documented in some cases. If data could be collected and gathered from operators including characteristics which may impact safety, behavior, fate, potential effects, and the best response actions and or techniques. This information can be input into existing technologies such as ADIOS from NOAA (OSR-JOP 2012).

ADIOS (Automated Data Inquiry for Oil Spills) is a database used to model how different oils and solutions change physically and chemically in marine environments. This service provides an immense amount of information useful to response teams for oil cleanup efforts. The database itself contains information about over one thousand crude oils and similar products. When a spill occurs, its specific details about environmental conditions, the type of substance spilt, and the planned cleanup strategies can be entered and then predictions can be made about the effects. This software helps inform crews and better shape cleanup efforts to minimize damage by providing predictions pertaining to cleanup techniques like dispersant use, skimming, and burning the oil. Specifically, ADIOS uses mathematical equations to predict changes in density, viscosity, and water content after release for the relevant details of the spill (NOAA 2012b).

One danger during the operational phase of spill cleanup is a lack of data, which can cause a delay in action, or inappropriate actions being taken which increase the overall damage. There is likely room for improvement in oil spill trajectory and subsea plume modeling, even beyond ADIOS capabilities, which is a concern cited by OSR-JIP for future research and development (OSR-JIP 2012).

In general, the current practice used in tracking spills is region specific. In some areas, the range of advancing technology may not be fully employed and oil spill response requires cross-functional imagery and geospatial data (OSR-JIP 2012).

Many groups, both government based and private corporation conglomerates, have been formed to plan and prepare for oil spills. One such group is the Joint Industry Oil Spill Preparedness and Response Task Force (JITF). This task force is made up of member companies and associates of the American Petroleum Institute (API), International Association of Drilling Contractors (IADC), Independent Petroleum Association of America (IPAA), National Ocean Industries Association (NOIA), and the U.S. Oil and Gas Association (USOGA). The goal of this group is to improve the oil spill response system in a number of areas: planning and coordination, optimization of each response tool, research and development, technology advancement and training, education of all parties preparing for or responding to a spill. The Oil Spill Preparedness and Response Subcommittee (OSPRS) was formed to respond to recommendations made in the original JITF report (JITF 2011).

NOAA has implemented a monitoring program for in situ burning and dispersant use: special monitoring of applied response technologies, or SMART (NOAA 2012c). This program uses small, highly mobile teams who collect real-time data during oil spill response, specifically dispersant and in situ burning operations. This program is a joint venture with numerous organizations including NOAA, the U.S. Coastguard, U.S. Environmental Protection Agency, Centers for Disease Control and Prevention, and the Bureau of Safety and Environmental Enforcement.

Once a spill occurs, a Unified Command is established: representatives of the responsible party and governmental agents (both state and federal) who are in charge of the spill. Data are channeled through the Unified Command so that they can track important concerns and questions regarding particulate concentration and effectiveness of dispersants (NOAA 2012c). This real-time data is vital for the successful application of in situ burning and dispersants, and assists with decision-making for these operations.

The Marine Spill Response Corporation (MSRC) is the largest standby oil spill response company in the U.S. It is a nonprofit organization which was founded in 1990, funded by the Marine Preservation Association through its member oil companies (Oil and Gas Journal 2012). MSRC started a program known as “Deep Blue” to improve response to oil spills and decrease response time for spills in the GOM. MSRC organized contracts with Edison Chouest Offshore and Hornbeck Offshore Services to modify five platform supply vessels and multipurpose support vessels for potential use as OSRVs (Dittrick 2012). Also, MSRC moved one of its large 210 foot OSRVs from the Atlantic Coast to Port Fourchon, Louisiana and named it the “Deep Blue Responder”. OSRVs are vital for spill response because they can store recovered oil temporarily and then can separate oil and water. The recovered oil will be transferred to boats and barges for sustainable cleanup efforts (Dittrick 2012). MSRC has expanded its fleet to seven vessels that can reach the deepwater area of the GOM and five storage barges dedicated as skimming barges from Ingleside, Texas to Tampa, FL (Dittrick 2012).

#### **4.5.1 Regulatory Changes**

As one of the agencies responsible for oil and hazardous waste spills, the EPA has published a number of regulations to mitigate the impact of such accidents (USEPA 2012a). The most extensive regulations and their descriptions are taken from the EPA’s website on emergency management for oil spills, but those taken from elsewhere are cited accordingly. All are listed below:

##### ***Facility Response Plan (FRP) Rule***

Certain facilities that store and use oil must submit a worst-case scenario response plan in the event that an oil spill or substantial threat of spill occurs. This rule is defined under the Clean Water Act, and was amended by the Oil Pollution Act. FRP was enacted in July of 1994.

##### ***National Contingency Plan (NCP) Subpart J***

Grants the EPA the responsibility of compiling a schedule of spill mitigating devices and substances that may be authorized for use on oil discharges including: dispersants, oil spill mitigating devices such as surface washing or collecting agents, and other chemicals useable in the control or removal of spilt oil. Subpart J is a component of the National Oil and Hazardous Substances Pollution Contingency Plan.

The purpose of the NCP Product Schedule is not to endorse or recommend products for use in spill situations, but is merely to compile the information into one easily located place. There is a separate recognition system, the EPA's Design for the Environment (DfE) Program, which tests products based on human health and environmental safety and then designates "safer" treatments for oil spills. The EPA is revising the NCP Subpart J to clarify the regulation, adding consideration for effectiveness and toxicity of products, and to update procedures for submitting products to be included in the schedule.

The National Contingency Plan Product schedule includes products authorized for use on oil discharges such as: dispersants, surface washing and collecting agents, bioremediation agents, sorbents, and miscellaneous oil spill control agents (USEPA 2012a). Sorbents, however, are not required to be on the schedule, but instead manufacturers can apply for EPA sorbent classification. Therefore, the manufacturer can share the letter as chemical composition proof for the on-scene coordinator at the site of a spill. On the NCA Product Schedule, chemical sorbents are classified as Miscellaneous Oil Spill Control Agents (MOSCA), but in use of oil spills they must be removed and disposed of properly (USEPA 2012a).

#### ***Spill Prevention, Control and Countermeasure (SPCC) Rule***

Facilities are required to prepare, amend, and implement SPCC Plans to address any likelihood or chance of an oil spill or leak. In some instances, the SPCC also requires spill reportage when a spill actually occurs. SPCC is a part of the Oil Pollution Prevention regulation and was signed into law in December 2006.

#### ***Discharge Oil Regulation***

Also known as the "sheen rule," the Discharge Oil Regulation requires individuals or organizations to report an oil spill if there is a visible sheen as a result of the spillage, and not based on the actual quantity released.

As discussed earlier in this chapter, the EPA also has notification regulations in the event that an organization or individual discovers a hazardous substance or oil leak.

## **4.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

As stated earlier, a number of companies existing in the Mid-Atlantic impact region provide oil spill response. Oil spills have occurred on the Mid-Atlantic OCS, usually from deliveries to refineries or other industrial activities that receive water-borne shipments. The oil spill response industry is knowledge-based and is highly mobile. Therefore assets from other producing areas would more than likely be utilized in the event of a catastrophic accident. If the oil and gas industry were to expand to the Mid-Atlantic OCS, it is unlikely that new oil spill response investments would be undertaken or even necessary in the area.

#### **4.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

There are a number of oil spill response companies located in the Mid-Atlantic impact region, including companies that respond to marine situations. The Mid-Atlantic coast has a number of refineries that receive cargo from water-borne suppliers. Spills from these imports and other industrial activities are likely to be greater than those associated with OCS development.

While oil spill response does not utilize capital-related equipment, this is mostly a knowledge-based industry that is highly mobile and assets from other producing areas could be utilized if a catastrophic accident were to occur. It is unlikely that new oil spill response investments will be needed in the region.



## 5 OIL FIELD WASTE DISPOSAL

### 5.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED

Waste management plays a critical role in drilling and production operations. There are a number of different types of waste generated at drilling sites and production platforms. Some wastes are common to any manufacturing or industrial operation, while others are unique to the oil and gas industry. The different types of waste generated as a result of offshore exploration and production activity include:

- Solids, such as drill cuttings, pipe scale, produced sand, and other solid sediments encountered during drilling, completion, and production phases.
- Drilling muds--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.
- Naturally Occurring Radioactive Materials (NORM), such as tank bottoms, pipe scale, and other sediments that contain naturally high levels of radioactive materials.
- 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.
- Non-hazardous industrial oily waste streams generated by machinery operations and maintenance, such as used compressor oils, diesel fuel, lubricating oils, pipeline testing, and pigging fluids.
- Municipal solid waste generated by the industry's personnel on offshore rigs, platforms, tankers, and workboats.

During the drilling process, the largest waste stream is used drilling fluids and cuttings (NPC 2011a). Drilling fluids or "drilling muds" a special mixture of clay, water, and chemical additives that are pumped down-hole through the drill pipe to facilitate the drilling process. These fluids serve a number of purposes. Drilling fluids help reduce friction and lubricate and cool the drill bit. During the drilling process, cuttings are created in the well (ground rock and earth), so drilling fluids act as a carrier, keeping the cuttings suspended in the mud until they are carried up the well to the surface. These fluids also help control pressure and aid in stabilization. Weighting agents are added to drilling fluids to keep pressure on the walls of a well, and additives are also used to ensure that the drilling fluids are not absorbed by the rock formation and that the pores of the rock formation do not become clogged (Rigzone 2012c).

There are three categories of drilling fluids: water-based mud (WBM), oil-based mud (OBM) and synthetic-based mud (SBM). WBMs are just as they sound, drilling fluids with water used as a base. OBMs use petroleum products as the base fluid, such as diesel fuel. OBMs are used when there is a need for higher levels of lubrication and viscosity. OBMs also withstand higher levels of heat before breaking down. SBMs have synthetic oils as the base fluid. These are often used offshore where there is a need for increased viscosity, but less toxicity.

The onshore infrastructure network needed to manage the variety of waste generated by offshore exploration and production activities 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 waste management facilities that are dedicated to handling particular types of waste; and,
- Generic waste management facilities that receive waste from a broad spectrum of U.S. industry, of which waste generated in the oilfield is only a small part.

This chapter presents a description of waste management techniques for the first two categories: these two categories are unique and important to the handling of offshore drilling waste. A specific analysis of generic waste management facilities has not been included as generic waste management facilities have unique permit terms that render physical capacity only a small factor in a site's longevity, and solid waste landfills would receive only a small fraction of their total loading from offshore oil and gas activities. Generic waste facilities will be discussed, but only in a general fashion as they relate to general waste disposal.

## **5.2 TYPICAL FACILITY CHARACTERISTICS**

The characteristics of drilling waste vary by location as different sites have varying conditions, environments, infrastructure and regulatory requirements. Therefore, no single waste management technique is used at all locations (NPC 2011a). The Argonne National Laboratory identifies three major categories of management technologies and practices for the management of drilling wastes: (1) Waste Minimization; (2) Recycle/Reuse; and (3) Disposal (DWMIS 2012a).

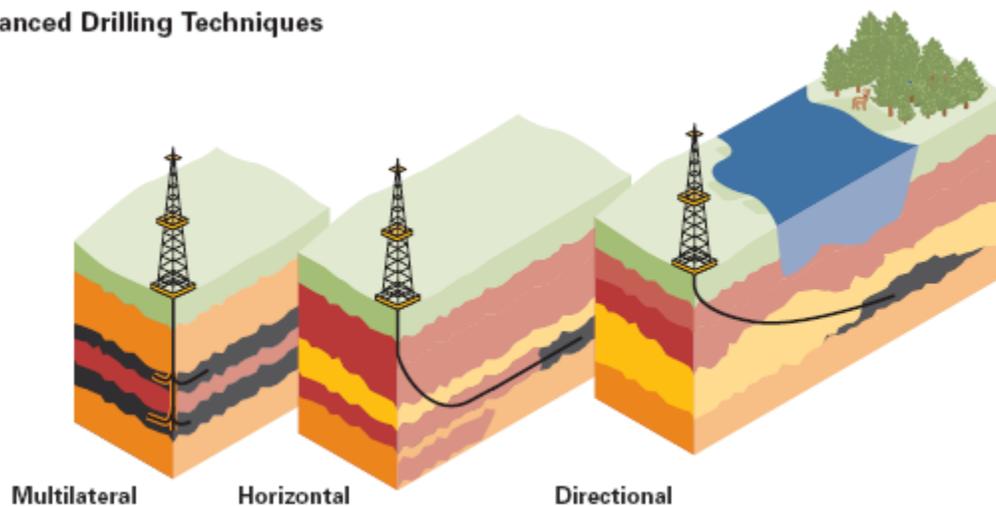
### **5.2.1 Waste Minimization**

In the waste minimization category, efforts are made to minimize the volumes of waste produced. Practices in this category include directional drilling, the drilling of smaller diameter holes, and the use of drilling techniques that use less drilling fluid.

- a) Directional drilling is the process of drilling at angles off of vertical, enabling producers to reach reservoirs that are not located directly beneath the drilling rig. This technique is particularly useful in avoiding sensitive environmental features, both above and below the surface. Environmental benefits to directional drilling include, but are not limited to, fewer production wells, less waste, and a lesser impact on sensitive environments (USDOE, OFE 1999).

There are three major types of directional drilling: Horizontal, Extended-Reach and Multi-Lateral. Horizontal drilling was developed to access hydrocarbon formations that extend over a large area. This enables producers to reach more of the reservoir, so that more resources can be pulled from a single well. In Mississippi's Black Warrior Basin, horizontal wells provide six times as much natural gas deliverability as some conventional vertical wells (USDOE OFE 1999). Extended reach drilling (ERD) is the directional drilling of long horizontal wells. With ERD technology a wellbore can be drilled several miles away to reach deposits that may lie under sensitive areas (Baker Hughes 2012). This is particularly useful when it is impractical or too costly to drill from directly above the target formation (DWMIS 2012a). And, multilateral drilling employs multiple offshoots from a single wellbore that extend in different directions, reaching deposits at various depths (USDOE OFE 1999).

### Advanced Drilling Techniques



**Figure 45. Advanced drilling techniques.**

Source: USDOE, OFE 1999.

- b) The volume of drill cuttings from a well is directly related to the diameter of the hole being drilled. A number of technologies can be employed to drill wells with smaller diameters. One example is the spacing of casing strings. With technological advancements in case milling, there is a larger variation in casing available for use, allowing for closer spacing of successive casing strings, and subsequently a lower volume of drill cuttings. Also, slimhole drilling, defined as a wellbore six inches (15 cm) or less in diameter, will reduce the volume of mud, casing, cement, water, and fuel used, and will produce smaller volumes of cuttings (Schlumberger 2012; Zhu and Carroll 1995). Slimhole drilling also reduces the operational footprint and area cleared for the drilling location (since equipment is smaller) (USDOE, OFE 1999). Coiled tubing drilling is a type of drilling that uses a continuous length of tubing rather than individual sections of drill pipe (DWMIS 2012a). The tubing is smaller in diameter than drill pipe, so like the slimhole drilling, the volume of waste is reduced.

- c) In some locations, wells can be drilled using pneumatic drilling, either reducing or eliminating the need for drilling fluids. Pneumatic drilling uses air, natural gas, mist or foam (Azar and Samuel 2007). With pneumatic drilling, only drill cuttings are generated which significantly reduces the waste management and disposal requirements (USDOE OFE 1999). This technology has limited applications, but can be used in fluid sensitive formations or formations with low pressures.

Drilling waste may also be minimized by using drilling muds and additives that have lower environmental impacts. Synthetic Based Muds (SBMs) combine the higher performance of Oil-Based Muds (OBMs) and the environmentally friendly qualities of Water-Based Muds (WBMs), making them ideal for complex and remote offshore drilling environments. SBMs are recycled while WBMs can generally be discharged on-site (DWMIS 2012).

### **5.2.2 Reuse / Recycle**

While most WBMs are disposed of once drilling is completed, many OBMs and SBMs are recycled. After use, recyclable drilling wastes are processed through a series of vibrating screens called shale shakes. The screens get finer and finer after each pass to collect smaller and smaller cuttings. The liquid mud that passes through the series of screens is stored in a holding tank and can be reused. Once these muds have degraded past the point of recycling, they can be discharged to the sea or disposed on shore.

While most drill cuttings are disposed of, some may be reused. Reusable cuttings however, must have the appropriate hydrocarbon content, moisture content, salinity and clay content for the intended use of the cuttings (DWMIS 2012a). One use of drilling cuttings is for surfaces such as roads or drilling pads. Cuttings can also be reused as construction material for fill, cover material and landfills, or aggregate or filler in concrete, brick or block manufacturing (DWMIS 2012a).

Drilling wastes may potentially be used as a substrate for restoring coastal wetlands. Research has shown that, in general cleaned drill cuttings have low levels of toxicity and may support wetlands vegetation (DOE 1999). However, no permits to conduct field demonstrations have been granted, and this application has not been tried in the U.S. (DWMIS 2012a).

### **5.2.3 Disposal**

For offshore drilling and production sites, there are a number of options for disposal of drilling fluids and cuttings. While each option has advantages and disadvantages with regard to environmental impact, primary considerations also include operational circumstances and costs (NPC 2011b). The three main options for waste produced offshore are offshore discharge, re-injection and onshore discharge.

#### ***Offshore Discharge***

This is the most operationally effective and safest method of disposal. It is also, the least expensive since the cost of transporting waste is essentially eliminated. WBMs consist primarily of water and have been demonstrated to have a limited effect on the environment (NPC 2011b). The EPA has evaluated the environmental impacts from WBMs and established guidelines for the discharge of WBMs and associated cuttings (CFR 2012a).

The discharge of SBMs is prohibited. However, cuttings coated with SBMs (up to 6.9 percent) may be discharged once the cuttings have been separated from the mud (DWMIS 2012b). This can be critical for the efficient operation of deep water exploratory drilling because of the long distance from shore and limitations on other disposal options (NPC 2011b). Extended guidelines have been formed in relation to SBMs (see Table 16). OBMs may not be discharged offshore.

**Table 16. Summary of U.S. offshore requirements for drilling wastes.**

<p><b>Baseline Requirements</b></p> <ul style="list-style-type: none"> <li>• No discharge of free oil (using a static sheen test) or diesel oil</li> <li>• Acute toxicity must have a 96-hour LC50 &gt; 30,000 ppm (using EPA's mysid shrimp toxicity test)</li> <li>• Metals concentrations in the barite added to mud must not exceed 1 mg/kg for mercury; or 3 mg/kg for cadmium</li> <li>• No discharge of drilling wastes allowed within 3 miles (5 kilometers) of shore*</li> </ul> <p><b>Additional Requirements for Synthetic-Based Muds (SBMs)</b></p> <ul style="list-style-type: none"> <li>• SBMs themselves may not be discharged</li> <li>• Cuttings coated with up to 6.9 percent SBMs may be discharged <ul style="list-style-type: none"> <li>○ Ester SBMs can have up to 9.4 percent SBM on cuttings</li> </ul> </li> <li>• Ratio of Polynuclear aromatic hydrocarbon mass to mass of base fluid may not exceed <math>1 \times 10^{-5}</math></li> <li>• Biodegradation rate of chosen fluid shall be no slower than that for internal olefin <ul style="list-style-type: none"> <li>○ Base fluids are tested using the marine anaerobic closed bottle test</li> </ul> </li> <li>• Base fluid sediment toxicity shall be no more toxic than that for internal olefin base fluid <ul style="list-style-type: none"> <li>○ Base fluid stocks are tested by a 10-day acute solid-phase test using amphipods (<i>Leptocheirus plumulosus</i>)</li> <li>○ Discharged cuttings are tested by a 4-day acute solid-phase test using amphipods (<i>Leptocheirus plumulosus</i>)</li> </ul> </li> <li>• No discharge of formation oil <ul style="list-style-type: none"> <li>○ Whole muds are tested onshore by GC/MS analysis</li> <li>○ Discharged cuttings are tested for crude oil contamination by fluorescence method</li> </ul> </li> <li>• Conduct seabed survey or participate in industry-wide seabed survey</li> </ul>
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Source: DWMIS 2012b.

***Re-injection***

The re-injection process involves pumping used fluids and cuttings into an underground formation. An underground formation with the appropriate geologic characteristics can be the actual well being drilled, or a separate dedicated disposal well. Often, depleted production wells can be converted into injection disposal wells. Cuttings or solids are ground into small particles, mixed with water or some other liquid to form slurry, and injected into the well (DWMIS 2012c).

Sub-surface injection is complicated and the right geologic formation is required. The injected slurry must not be able to migrate into other formations, or back to the surface. Also, the types and volume of waste, surface equipment and well design must be considered before injection is performed (NPC 2011b). If re-injection can be used, it can have a number of advantages (Guo and Geehan 2004):

- It can achieve zero discharge as no waste is left on the surface.
- It eliminates transportation risks, as there is not transportation to another facility or temporary storage.
- It eliminates future clean-up liabilities once the disposal well is plugged.
- It ensures the operator total control over the waste management process.
- It is not limited by location and it has been operated from the GOM to Alaska, from the North Sea to the Sakhalin Islands.
- It often has favorable economics.

During the production process, produced water creates the largest volume of waste and re-injection is the primary method of disposal (NPC 2011a; and GPRID 2012).

### ***Onshore Disposal***

Transportation back to shore is the third option of disposal of drilling fluids and cuttings from offshore operations. This option, however, requires extensive use of support vessels, and it increases safety, environmental risks, and costs. Once onshore however, there are numerous options for disposing of drilling waste. These options are listed below. The practicality of each of these options depends on environmental conditions, components of the drilling waste, regulations, operational limitations and economic factors (NPC 2011b).

**Pits and Landfills:** Pits are used for the disposal of cuttings at many onshore drilling sites. The pit is lined and is not intended to be used for any chemicals, refuse, debris, or other materials. Once drilling has completed, the cuttings are covered with soil and the site is graded to prevent water from accumulating. Vegetation is often planted in the area to reduce erosion and promote recovery of the area's ecosystem (DWMIS 2012c).

A landfill is an engineered facility with protective liners and caps to isolate waste from the surrounding environment. Landfills are used for the disposal of municipal, industrial, and hazardous wastes. Landfill waste is covered daily by a layer of soil other non-decomposing cover material. Drilling waste and other oil field wastes can be disposed of at landfills and may even be used as a daily cover (DWMIS 2012c).

Non-hazardous solid waste generated on offshore drilling rigs includes general trash and garbage that is transported to shore for disposal in landfills. Many companies now separate some solid waste for recycling (NPC 2011b). Hazardous and combustible wastes such as oil, oily rags, spent solvents, paint cans and used oil filters are placed in approved hazardous material containers, sealed, labeled and brought onshore for disposal in an approved hazardous waste handling facility (NPC 2011b).

**Land Application:** Drilling muds, produced sand and other fine solids are candidates for land application, also called “land farming”. Land farming can be a low-cost method for managing oily waste. With this method, the waste is spread over pasture or farmland, allowing the waste to be diluted or break down naturally (Annis 2008). Some studies indicate that land farming does not adversely affect the soil and may even benefit some soils by adding water-retaining capacity and reducing fertilizer losses (DWMIS 2012d). However, it may also add salts or heavy metals to the soil and water run-off from the property may create environmental concerns (Annis 2008).

**Bioremediation:** Bioremediation uses microorganisms to biologically decompose hydrocarbon-contaminated waste (Puder and Veil 2006). The goal is to accelerate the natural decomposition process by controlling oxygen, temperature, moisture and nutrients. This topic was discussed in the Oil Spill Response chapter.

**Thermal treatment:** Thermal technologies use high temperatures to destroy or remove hydrocarbons from waste materials. Incineration is a technology that heats hydrocarbons to very high temperatures, thereby destroying them. The other technology, thermal desorption, applies heat to the waste, vaporizing volatile and semi-volatile hydrocarbons. In both cases, additional treatment may be needed for metals and salts. Waste streams high in hydrocarbons, like OBMs are treated with thermal technologies (Puder and Veil 2006).

**Salt Cavern Disposal:** Salt caverns are used for a variety of underground storage purposes and can be used for the disposal of drilling wastes. Salt cavern disposal may be used for drilling muds, cuttings, produced sands, tank bottoms, contaminated soil and completion and simulation wastes. Wastes are transported to the cavern site and are combined with water or brine to make slurry. When the waste slurry is pumped into the cavern it displaces the brine used to create the cavern. The brine is either sold, or injected into another disposal well. The waste within the cavern will separate into layers: solids sink to the bottom, oily waste and other hydrocarbons rise to the top, and any remaining brine or watery fluids stay in the middle (DWMIS 2012f).

### **5.3 GEOGRAPHIC DISTRIBUTION**

The Argonne National Laboratory collected information on commercial exploration and production waste disposal companies in different states in 1997. In 2005 and 2006 this information was updated with a focus on the availability of offsite commercial disposal companies and prevailing disposal methods (Puder and Veil 2006). The researchers found that the availability of offsite commercial disposal companies and facilities falls into three categories:

1. States with high oil and gas production typically have a dedicated network of offsite commercial disposal companies and facilities in place.
2. In other states, such infrastructure does not exist and often, commercial disposal companies only focus on produced water services.
3. About half of the states do not have any industry-specific offsite commercial disposal infrastructure. If there is any oil and gas produced waste in these states, operators transport that waste to local municipal landfills (if permitted) or haul the waste to other states (Puder and Veil 2006).

Considering that there is little exploration and production activity in the impact region states (with the exception of Pennsylvania), we would expect there to be a minimal number offsite commercial disposal companies. In fact, Pennsylvania is the only state to have commercial disposal companies and facilities.<sup>8</sup>

The five companies located in Pennsylvania dispose of produced water through a “National Pollutant Discharge Elimination System” (NPDES) permit or “Publicly Owned Treatment Works” (POTW). The NPDES is a permit program authorized by the Clean Water Act and controls water pollution by regulating point sources that discharge pollutants into U.S. waters. In general, authorized states administer the NPDES permit program and industrial facilities must be permitted to discharge directly to surface waters.

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<sup>8</sup> The Argonne survey contacted the Pennsylvania Department of Environmental Protection for a list of commercial disposal companies. The state agency provided a list of eight facilities; and five responded to the survey.

POTWs are municipal wastewater treatment plants and are generally designed to take domestic sewage (residential, commercial) only. However, POTWs can also receive wastewater from industrial users. The General Pretreatment Regulations under the Clean Water Act establish the responsibilities of federal, state, and local governments; industry; and the public to implement pretreatment standards to control pollutants from industrial users (USEPA 2012b).

Table 17 presents a summary of these companies and their services.

**Table 17. Waste management facilities in the Mid-Atlantic impact region (Pennsylvania).**

Company Name	Disposal Method*	Type of Waste	Disposal Cost	Comments
Castle Environmental Inc.	Discharge (POTW)	Produced water	\$0.025-\$0.050/gal	Facility operates a nonhazardous wastewater processing facility. Treatment involves chemical precipitation and filtration.
Hart Resource Technologies	Discharge (NPDES)	Produced water	\$0.0525/gal	Treatment involves chemical precipitation and removal of oils and heavy metals.
Moshannon Valley Sewer Authority	Discharge (POTW)	Produced water	\$0.015/gal	Facility receives mostly gas field frack water and occasionally brines.
Pennsylvania Brine Treatment	Discharge (NPDES)	Produced water	\$0.055/gal	Facility uses chemical precipitation and generates a nonhazardous residual sludge that is land-filled offsite at a PA DEP-permitted facility. The treated water is then discharged to surface waters.
Tunnelton Liquids Co	Discharge (NPDES)	Produced water or Pit water	\$0.045/gal	Facility uses an innovative process to treat pit water (containing some OBMs and cuttings). It combines acid mine drainage from an abandoned coal mine with the produced water. Sulfates in the mine drainage help remove contaminants from the produced water. Following several treatment steps, the treated wastewater is discharged to a river under an NPDES permit. Any solids are sent to a landfill. Tank bottoms are heated and the oil is reclaimed.

Source: Puder and Veil 2006.

The Argonne survey identified three companies in Pennsylvania that discharge under NPDES authority. Hart Resources Technologies and Pennsylvania Brine Treatment Company use a process called chemical precipitation to generate a nonhazardous residual sludge that is then land-filled offsite at a Pennsylvania Department of Environmental Protection-permitted facility (Puder and Veil 2006). As described in the table Tunnelton Liquids Co. uses an innovative process to treat produced water, combining acid mine drainage from an abandoned coal mine with the produced water to remove contaminants.

The other two Pennsylvania companies, Moshannon Valley Sewer Authority and Castle Environmental, discharge produced water to a POTW. In both cases, the companies treat the produced water prior to discharge.

Disposal of produced water is the only type of disposal service identified in the Mid-Atlantic impact region states. There are no companies that offer bioremediation, burial (landfill or pit), salt cavern disposal, evaporation, injection, land application, recycling, or thermal treatment. Most of these companies are located in the Gulf region, California, Wyoming, Utah, New Mexico, Colorado, Nebraska and Oklahoma. There are a few companies listed in nearby states such as Ohio and West Virginia.

#### **5.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY**

Though a few companies have been identified in Pennsylvania, there is no drilling activity off of the Mid-Atlantic Coast, and it is likely these companies are mostly serving oil and gas operations in the Appalachian region.

Similarly, there are no useful NAICS codes or industry data to use to analyze the contribution of the support economy to the area. Waste disposal for oil and gas operations is likely a very small portion of the general waste disposal industry. Therefore, the economic contribution of this sector has not been estimated.

#### **5.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY**

Several factors drive demand for commercial disposal companies, including the supply, demand and pricing of oil and gas commodities which drive exploration and production drilling and development activity. Demand for most services is related to the level, type, depth and complexity of oil and gas drilling (SEC 2011d).

Commercial disposal companies face competition with each other, primarily on the basis of price, and their own customers who are continually re-evaluating their decision to use a third-party disposal company rather than their own internal disposal methods (SEC 2011d).

The waste disposal industry is also highly dependent upon environmental laws and regulation. The more stringent the regulations, the more demand for waste services as exploration and production companies take steps to comply with the more stringent regulations. In addition, the specific regulatory requirements of an area often dictate the technologies that can be used and materials (if any) that can be discharged (NPC 2011a).

Numerous companies within the waste management industry have developed innovative methods to handle waste. For example, PROwaste built a hydrocarbon recovery and recycling facility that is located in Baytown, Texas and “processes off-spec refinery products, hydrocarbon streams, lube oils and tank pipeline clean out materials” (PROwaste 2008).

Another example is R360 Environmental Solutions’ R3 Technology. R3 is an application of the ideas of reducing, reusing and recycling exploration and production waste. Their land treatment process decreases soluble salt content, reduces oil concentration through recovery or degradation, and can clean cuttings or reuse materials stored in onsite stockpiles. The stock piles can be safely eliminated through two new reuse programs to make the waste usable as road base or levee fill.

The R3 road base program converts stockpile materials as an environmentally safe road base material. Tests have proved that the material is cleaner, more affordable and has more comparative strength than asphalt (R360 2012). In fact, regulatory agencies have approved R3 road base to be used in building both public and private roads (R360 2012).

Challenges continue to evolve and be resolved with both traditional and new technology (NPC 2011b). Efforts to be environmentally conservative are an important driver in all exploration and production activities and these efforts will continue to include evaluation of existing drilling fluids, solids control and waste management practices.

### **5.5.1 Regulatory Changes**

Several different types of wastes are generated through oilfield activities and the removal and disposal of these wastes are governed by a variety of state and federal statutes, rules, and regulations.

The federal government utilizes two main agencies to regulate specific aspects of offshore oil and gas waste disposal operations. These agencies are the EPA and BOEM. On the state level, regulations for the disposal of oil and gas waste vary widely from state to state. Detailed information for specific states is listed on the Argonne National Laboratory’s Drilling Waste Management Information System (DWMIS) web site.

The EPA oversees the major federal laws governing waste materials and management activities which include the Resource Conservation and Recovery Act (RCRA), the Clean Water Act (CWA), and the Safe Drinking Water Act (SDWA). Table 18 provides a summary of the major federal laws governing waste materials and management activities. Within the Outer Continental Shelf, BOEM regulates waste disposal, injection criteria, and encapsulation criteria. These regulations are detailed at 30 CFR Part 250 (Oil and Gas and Sulphur Operations in the Outer Continental Shelf).

**Table 18. Federal laws governing waste materials and management activities.**

<b>Law</b>	<b>Material Subject of Regulation</b>	<b>Activity Subject to Regulation</b>
Clean Water Act	Aqueous waste streams	Surface discharge
Resource Conservation and Recovery Act	Solid and hazardous wastes (unless excluded or exempted)	Generation, transportation and treatment, storage and disposal
Safe Drinking Water Act	Waste fluids or slurries	Underground injection

Source: Puder and Veil 2006.

In 2002, EPA issued a publication entitled *Exemption of Oil and Gas Exploration and Production Wastes*. The document explains the exemption of certain oilfield wastes from regulation as hazardous wastes under RCRA Subtitle C. The report includes background on the exploration and production exemption, basic rules for determining the exempt or non-exempt status of wastes, examples of exempt and non-exempt wastes, the status of waste mixtures, and clarifications of several misunderstandings about the exemption. A subsequent analysis summarizing the findings of the Report noted:

With respect to petroleum production, primary field operations include activities occurring at or near the wellhead or production facility, but before the point where the custody of the petroleum is transferred from an individual field activity or centrally located facility to a carrier for transport to a refinery. Without a transfer of custody, the primary field operation ends at the last point of separation. Crude oil stock tanks are considered separation devices (Puder and Veil 2006).

In addition to specific oilfield waste regulations, the report noted that wastes that are a product of treatment of an exempted waste usually remain exempt, and the exemption is not negated by offsite transportation. However, wastes that are not specifically associated with primary field operations are not exempted. Any waste that is not associated with primary field operations is subject to further inspection for purposes of classification (USEPA 2002). The EPA also noted in the report:

In general, the exempt status of an E&P waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic. For example, some exempt E&P wastes might be harmful to human health

and the environment, and many non-exempt wastes might not be as harmful (USEPA 2002).

Table 19 presents examples of exempt and non-exempt E&P wastes.

**Table 19. Examples of exempt and nonexempt exploration and production waste streams.**

Exempt E&P Waste Streams	Nonexempt E&P Waste Streams
<ul style="list-style-type: none"> <li>• Caustics if used as drilling fluid additives</li> <li>• Cement slurry returns and cement cuttings</li> <li>• Debris, crude-oil soaked, crude-oil stained</li> <li>• Drill cuttings and solids</li> <li>• Drilling fluids and muds</li> <li>• Drilling fluids and cuttings from offshore operations disposed of onshore</li> <li>• Liquid hydrocarbons removed from the production stream</li> <li>• Liquid and solid wastes generated by crude oil and tank bottom reclaimers</li> <li>• Pit sludges and contaminated bottoms from storage or disposal of exempt wastes</li> <li>• Produced sand</li> <li>• Produced water</li> <li>• Produced water constituents removed before disposal</li> <li>• Soils, crude-oil contaminated</li> <li>• Tank bottoms and basic sediment from storage facilities that hold product and exempt waste (including accumulated materials such as hydrocarbons, solids, sand, and emulsion from production separators, fluid treating vessels, and production impoundments)</li> <li>• Volatile organic compounds from exempt wastes in reserve pits or impoundments or production equipment</li> <li>• Well completion, treatment, and stimulations, and packaging fluids</li> <li>• Workover wastes (blowdown, swabbing and bailing wastes)</li> </ul>	<ul style="list-style-type: none"> <li>• Batteries (lead-acid and nickel cadmium)</li> <li>• Caustic or acid cleaners</li> <li>• Cement slurries, unused</li> <li>• Chemicals, surplus/unusable</li> <li>• Compressor oil, filters, and blowdown waste</li> <li>• Debris, lube oil (contaminated)</li> <li>• Drilling fluids (unused)</li> <li>• Drums or containers, containing chemicals or lubricating oil</li> <li>• Drums, empty and rinsate</li> <li>• Hydraulic fluids (used)</li> <li>• Sandblast media</li> <li>• Scrap metal</li> <li>• Soil, chemical-contaminated, lube oil-contaminated and mercury contaminated</li> <li>• Solvents, spent (including waste solvents)</li> <li>• Thread protectors, pipe dope-contaminated</li> <li>• Vacuum truck rinsate (from tanks containing nonexempt waste)</li> <li>• Well completion, treatment and stimulation fluids (unused)</li> </ul>

Source: Puder and Veil 2006.

### ***30 CFR Part 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf***

This code lays out BOEM's disposal practices for dealing with offshore oil and gas exploration and production wastes. The U.S. allows operators in offshore areas to inject exempt exploration and production wastes into injection wells or encapsulated in well bores of wells that will be abandoned. This is applicable to wastes that come from the Outer Continental Shelf (OCS) and are subject to specific injection and encapsulation criterion. BOEM authorizes each proposal for underground waste disposal on a case-by-case basis (CFR 2012b).

If waste is to be injected, the formation that receives the waste must be below the deepest underground source of drinking water, isolated by shale layers on top and bottom, and cannot contain producing wells (BOEM 2012). And, the injection well must have complete mechanical integrity. On the other hand, two types of encapsulation are available for wastes. The first type places the waste directly in the well bore of a well that is being abandoned. The second type places the waste in a section of pipe then caps both ends and places that pipe within the well bore. The top of the encapsulated waste must be at least 1,000 feet (305 meters) below the mudline. Additional cement and cast-iron plugs are added to the well bores as a final step (BOEM 2012).

## **5.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

Five produced water treatment operators have been identified in Pennsylvania and all provide service to operations in the Appalachian region. Pennsylvania Brine for instance, operates two commercial wastewater treatment facilities in western Pennsylvania. According to the company, in the 12 month period from November 2008 to October 2009, one facility processed about 53 million gallons of water (Veil 2010).

Another company, Tunnelton Liquids is actually a remnant of Pennsylvania's coal industry. The Pennsylvania Department of Environmental Protection helped to create this company with the purpose of cleaning an abandoned mine (Puko 2011). Now the Tunnelton plant operates as a commercial wastewater facility, with an average discharge of one million gallons per day. Of this volume however, only 100,000 gallons are oil and gas flowback and produced water, the rest is acid mine drainage (Veil 2010).

Hart Resource Technologies (HRT) services 250 customers in the Western Pennsylvania region and processes over 23 million gallons of fluids annually. Like the Tunnelton facility, the Hart facility was originally constructed to treat acid mine drainage (Veil 2010). HRT notes that disposal of these fluids in an economical and environmentally safe manner has been problematic for the natural gas industry in Pennsylvania (HRT 2012). This is because of the presence of salts, metals and other pollutants that may be harmful if discharged before being treated.

As gas production in the Marcellus shale region continues to expand, so will the need for these waste disposal services. However, new policies and environmental regulations will keep the industry on its toes as state agencies attempt to manage and regulate the growing number of wells. In May 2010, the Pennsylvania Environmental Quality Board adopted new and more-stringent discharge requirements for oil and gas flowback and produced waters (Veil 2010). These requirements state that no discharge of oil and gas wastewater can be made directly to surface waters. Wastewater can be sent to a commercial industrial wastewater treatment plant, or to a POTW. Commercial disposal companies that already had discharge permits are grandfathered to discharge at their current levels. New dischargers however, will face much more restrictive limits (Veil 2010).

## **5.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

Few oil field waste disposal operators and facilities are in the Mid-Atlantic impact region states. The facilities that do exist support Appalachian drilling activities and currently only deal with produced water. Development in the Mid-Atlantic impact region will require expanded oilfield waste disposal capacity. The capacity will be a direct function of the level of drilling and production activity anticipated in the Mid-Atlantic OCS as more drilling and production will result in expanded capacity requirements.

New oilfield waste capacity is likely to arise in two different manners: (1) expansion of existing locations; and (2) development of new locations. Factors influencing capacity expansion at existing locations include:

- a. Availability of surface or subsurface storage capabilities.
- b. Costs relative to new development at alternative site.
- c. Proximity and transport costs of wastes to existing site.
- d. Local permitting and regulatory issues.

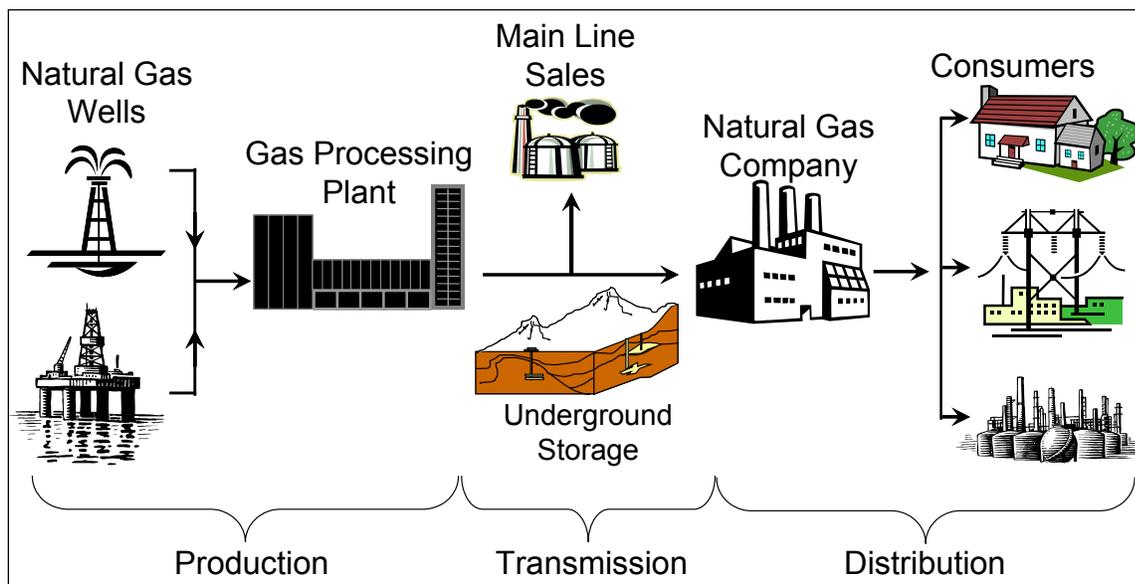
Factors influencing new capacity development at a new location include:

- a. Proximity of location to oilfield waste users (i.e. producers).
- b. Competition with existing facilities (if any).
- c. Surface and subsurface availability.
- d. Leveraging and expanded commercial opportunities.
- e. Other commercial considerations including project finance.
- f. Local permitting and regulatory issues.

## 6 PIPELINES

### 6.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED

The primary purpose of natural gas pipelines is to move gas from one location to another. Generally, natural gas is transported from (1) the wellhead (production location) to an intermediate natural gas processing facility; (2) from producing areas to transportation ‘hubs’, which distribute gas to other locations such as consuming areas; (3) or between consuming areas. Pipeline systems in the U.S. can also move gas that is transported, either from Canada or from offshore locations that import gas to U.S.-based liquefied natural gas (LNG) regasification facilities. A schematic of the natural gas value chain is provided in Figure 46.

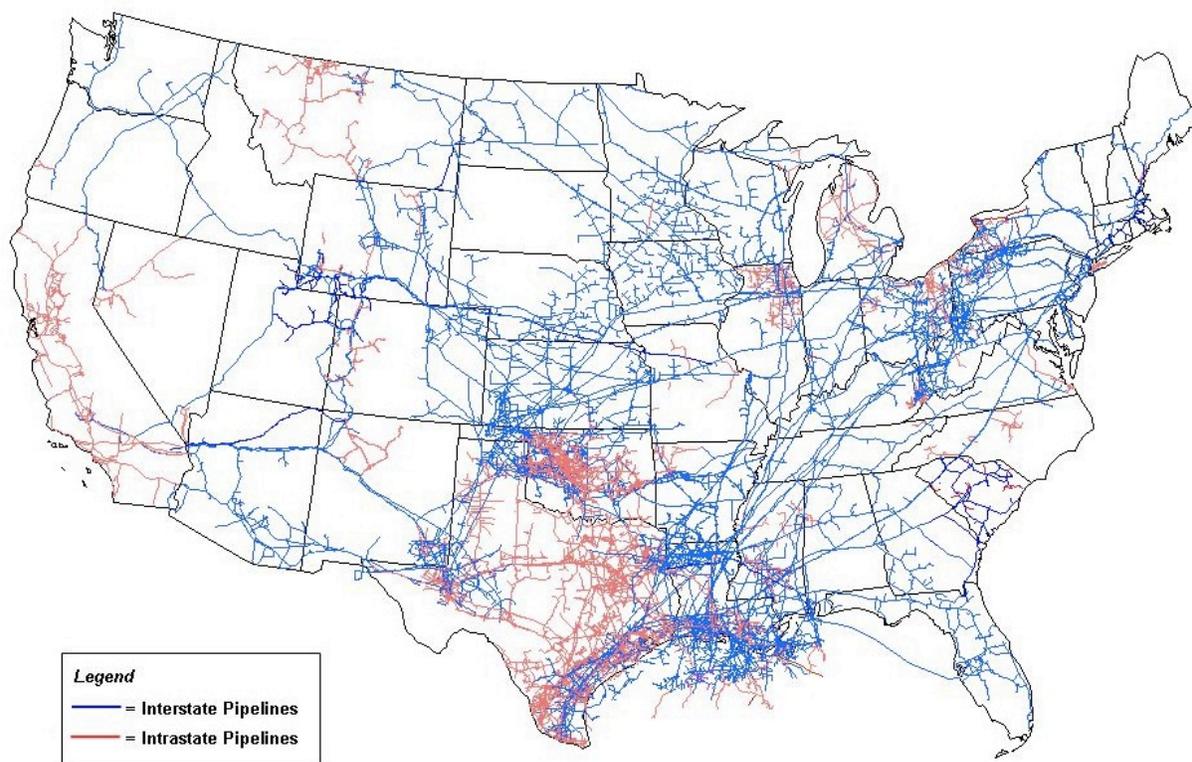


**Figure 46. Natural gas industry components.**

Natural gas extracted from a geological formation can often be raw and include a host of impurities, moisture, inert gases, and other hydrocarbons that must be separated from what is referred to as the raw natural gas stream. Thus, natural gas processing is one of the first steps that produced natural gas undergoes prior to transportation into the long-haul pipeline system. Most major natural gas pipeline systems cannot handle, and typically have strict regulations against, the injection of large quantities of raw natural gas into their systems since the impurities, moisture, and other inert gases can compromise pipeline material integrity (causing corrosion), or the uniformity and quality of the gas delivered to end users.

According to the U.S. Department of Energy, there are over 305,000 miles (490,850 kilometers) of major, large pipelines used to transport natural gas that range in size from a diameter of 20 inches (51 cm) to as large as 42 inches (107 cm). These large pipes serve as the “interstate highway” system for natural gas since they transmit natural gas at relatively high pressures in order to reduce volumes and provide a source of propulsion with limited off-ramps for lower level distribution (USDOE, EIA 2012a). Transportation system pressures range anywhere from 200 to 1,500 pounds per square inch gauge (psig) and are created by over 1,400 compressor stations located along the main trunklines moving natural gas across the U.S. (USDOE, EIA 2012a; and USDOE, EIA 2007a).

Pipelines can be characterized as being primarily interstate or intrastate in nature, where the designation refers to the areas over which natural gas is transported (Figure 47). Interstate natural gas pipelines, for instance, carry natural gas across state boundaries, whereas intrastate pipelines transport natural gas within a particular state. The distinction between inter- and intrastate pipeline systems is usually important for regulatory and pricing purposes and typically has little impact on the nature of the pipeline systems themselves since many intrastate pipeline systems, particularly those located along the Gulf Coast, can be made up of intricate systems of large diameter pipelines, much like their interstate counterparts.



**Figure 47. U.S. natural gas pipeline network.**

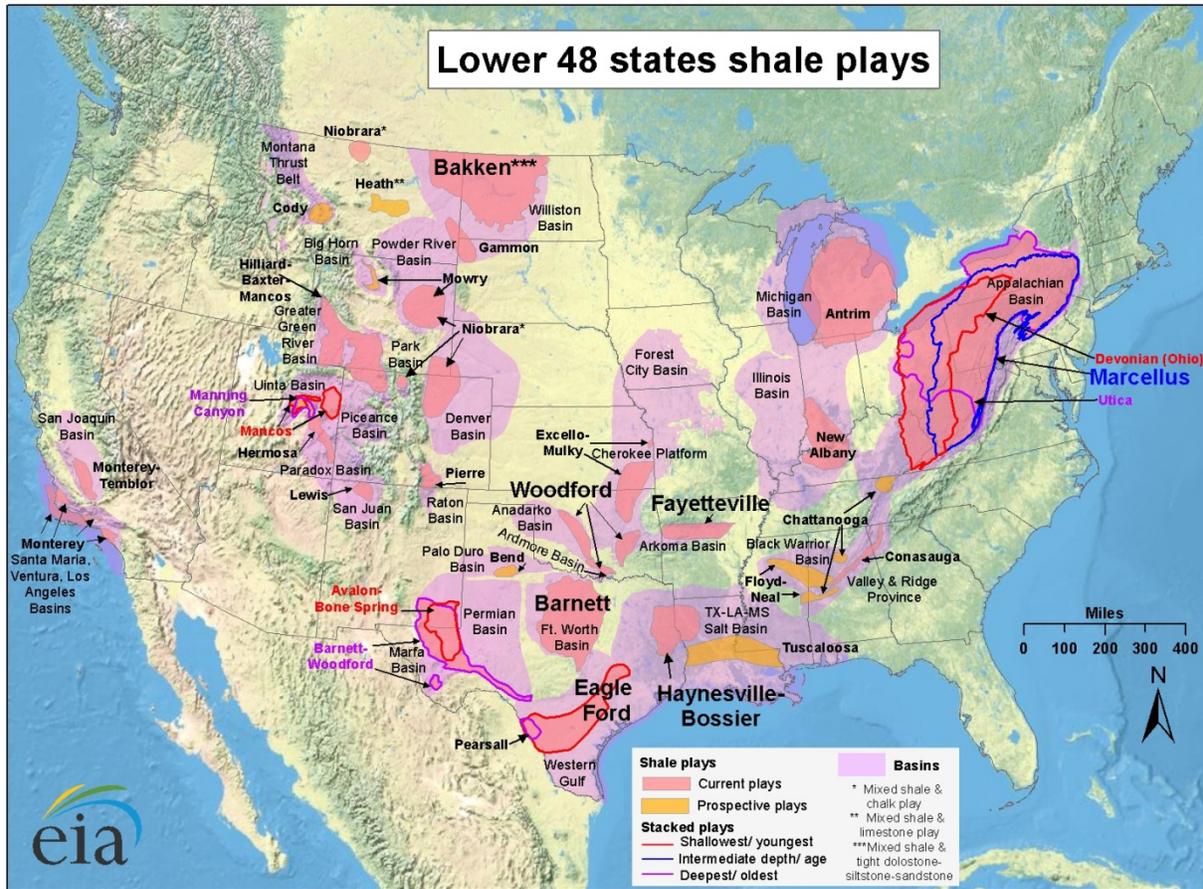
Source: USDOE, EIA 2012a.

Most U.S. natural gas producers are dependent upon the interstate pipeline system to move their supplies to consuming areas throughout the country. Large diameter (20 to 42 inch) pipelines with high capacities transport most of the gas on the national network. Some of the systems with the highest capacity are those originating in U.S. producing basins (i.e., midcontinent region, onshore Texas and Louisiana, offshore Louisiana) and terminating in large metropolitan consuming areas. Historically, the interstate natural gas transportation system was configured to move natural gas production originating in the GOM or midcontinent region, into the consuming areas of the upper mid-west, the eastern seaboard, or the southeastern U.S.

For instance, Figure 47 shows a number of pipelines originating along the GOM and moving natural gas into the southeastern U.S. (particularly Florida), along the Atlantic seaboard, and directly east-ward through the eastern mid-western U.S. (Ohio, Pennsylvania) and terminating in the northeast (New York City). Likewise, natural gas originating in the Hugoton and other mid-continent basins (Kansas, Oklahoma) move natural gas into the upper mid-west and Great Lakes regions. Gas originating in Alberta, Canada, a major non-U.S. (but North American) source of natural gas has historically moved gas south into the upper mid-west consuming areas terminating at what is called the Chicago hub.

Many of these traditional pipeline linkages and configurations, however, have been challenged as natural disasters and the development of new unconventional shale have created large pricing differentials that have sent signals to pipeline developers to plan, design, engineer, and construct a new series of large pipeline segments linking new production opportunities to traditional consuming regions in the U.S. Changes in natural gas production, particularly the development of new natural gas shale plays are also significantly changing the nature of pipeline systems since these resources are proving to be more ubiquitous, being located in very close proximity, if not directly in a number of very large consuming areas that have traditionally not possessed their own (or very little) local natural gas sources.

Figure 48 shows the location of those new natural gas shale plays and highlights the fact that while many are located in traditional producing areas (Barnett, Fayetteville, Haynesville), others are located directly, or very near, large northeastern or mid-western consuming areas (i.e., Marcellus, Atrium, Utica). The development of these new resources is challenging the continued importance of big long-lines from traditional conventional production, particularly those along the GOM, and leading to billions in new investments to link these new supplies to existing transportation lines and directly to various different distribution systems.



**Figure 48. U.S. shale gas and oil plays.**

Source: USDOE, EIA 2011a.

## 6.2 TYPICAL FACILITY CHARACTERISTICS

The natural gas pipeline system in the U.S. comprises a number of components including: (1) the gathering or field services systems in the producing areas; (2) the interstate or long-haul transportation facilities; and (3) the intrastate, or shorter-haul systems that move natural gas between various consuming areas. Each component of the system has a unique role in moving gas from the wellhead to retail consumers that are categorized as being residential, commercial, industrial, or power generation customers.

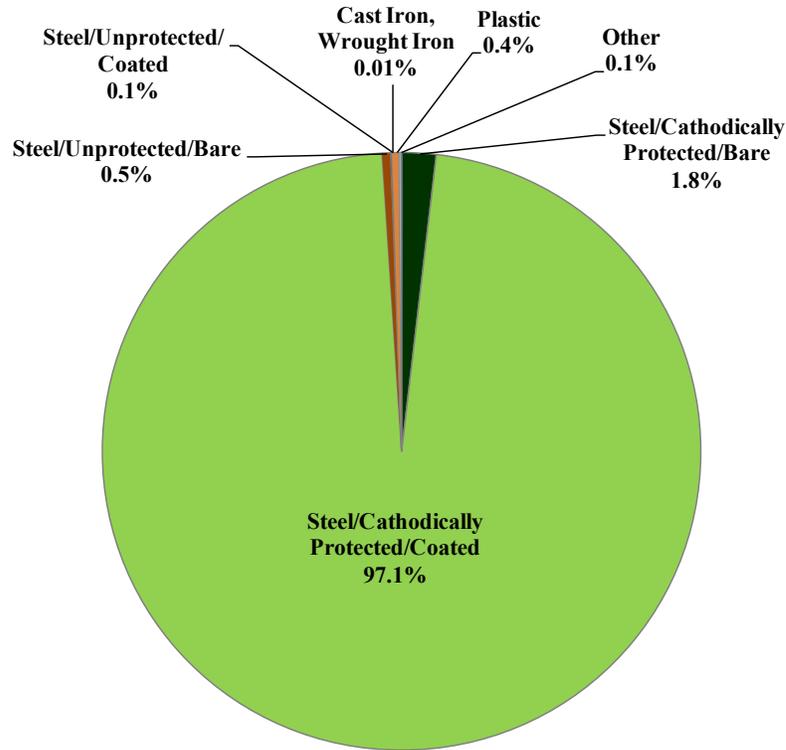
The natural gas transportation process typically starts with gathering or the collection of natural gas from various different wells and production units. In mature areas, gathering systems will typically use low-pressure, small diameter pipelines to move raw natural gas from the wellhead to the processing plant. However, many larger gathering systems, particularly those in the offshore GOM, can be as large in diameter (and under equally high pressure ratings) as the longer-haul transportation systems that move gas to market. While natural gas gathering can be thought of as the initial component of a broader transportation system that moves gas from producers to consumers, gathering is exempted from Federal Energy Regulatory Commission (FERC) jurisdiction under the Natural Gas Act of 1938 (15 U.S.C. § 717(b) (2000)). The distinction between a pipeline being gathering, or transportation is important and one not without controversy, since defining where gathering ends and transportation begins, can be problematic, particularly for offshore production.<sup>9</sup>

Transportation systems can be classified as being either interstate or intrastate in nature. The interstate transmission system is the traditional, and commonly-thought of part of the natural gas interstate highway system that moves gas over very long distances from producing areas to consuming areas. For instance, the Tennessee natural gas system originates in the GOM (offshore) and terminates at the Canadian border: some 1,400 miles (2,253 kilometers) away (Tennessee Gas Pipeline 2011a). The Transcontinental Pipeline System (or “Transco” system) also originates in the offshore GOM, and terminates in New York City. The Transco system totals 10,000 miles (16,093 kilometers) of transportation pipe (Williams 2011). One of the more recent pipeline systems to be developed over the past several years, the Rockies Express, links natural gas production from the Rocky Mountain region in northwestern Colorado to eastern Ohio, stretching 1,679 miles (2,702 kilometers) (Kinder Morgan 2011).

Most interstate natural gas transmission systems are made up of pipes that range from 6 inches to 48 inches (15 cm to 122 cm) in diameter, with the majority of the segments being larger-diameter pipes (i.e., 12 inches (30 cm) and above). These systems are built with protected steel pipe, although some older unprotected portions of the system (bare steel and cast iron) still exist in some parts of the country. A breakdown of the materials composition of the U.S. transportation system is provided in Figure 49.

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<sup>9</sup> In 1995, the Sea Robin Pipeline Company petitioned FERC for a declaration that Sea Robin's facilities perform a "gathering" function rather than a "transportation" function, thus exempting them from FERC jurisdiction. The Commission denied the petition stating that Sea Robin was engaged in jurisdictional transportation activities, not gathering. FERC also denied Sea Robin's petition for rehearing. Sea Robin petitioned the U.S. 5th Circuit Court of Appeals. The Court decided that FERC did not give adequate attention to Sea Robin's physical and operational facilities. It granted the petition for review, vacated FERC's order and remanded the case back to FERC. On remand, FERC concluded that Sea Robin's system was comprised of two distinct components: a jurisdictional transportation system from the Vermilion 149 Station to Erath, the onshore processing facility, and a non-jurisdictional gathering system upstream of the Vermilion 149 Station.



**Figure 49. Composition of U.S. natural gas pipeline transportation network.**

Source: USDOT, OPS 2011.

Intrastate pipelines are similar to their interstate counterparts since they are also composed of large diameter pipe (i.e., 12 inches [30 cm] and greater). Generally, intrastate pipelines are owned by smaller transportation companies that specialize in moving natural gas from an in-state hub location, to large end users like power plants, industries, and manufacturing facilities. The definition of intrastate transportation, as opposed to distribution, can often be muddled and can often be a function of how a pipeline company or utility classifies a particular line segment or series of line segments. These classifications can often be influenced by property tax or ad valorem tax definitions that treat public utility and other types of pipelines in differing fashions.

Typically, intrastate pipelines are corporate affiliates of a larger interstate pipeline company, or alternatively, a local distribution company (LDC or distribution utility) that specializes in moving gas from interstate systems to and between various local consuming areas, often delineated by what is referred to as the “city-gate” (i.e., the point at which gas is stepped-down in pressure to levels more suitable to various types of end-use). Gas is typically stepped down once it enters an LDC’s distribution system (at the city gate or main meter station) and moved through what are referred to as “distribution mains” and “service lines” to end users.

### **6.2.1 Compressors and Compression Stations**

Compression is the workhorse or engine of the natural gas transmission system that creates pressure on the system to maximize the flow of gas along various different line segments, and along the system as a whole. Compression stations are composed of a compressor, or series of compressors, and supporting equipment with the sole purpose of maintaining system pressure and integrity. Compressor stations are usually, but not always, automated, and are installed approximately every 40 to 100 miles (64 to 161 kilometers) along a pipeline route, depending on the size of the pipe and volume of gas (INGAA 2011a). All systems have a control center or series of control centers that monitor system performance and remotely increase or reduce pressure, and in some instances, shut-off valves or compressors along the transmission system. Pipeline operators have continuous and detailed operating data on each compressor station, and will make adjustments to maximize efficiency and safety on the system (AGA 2005).

When transmission pipelines deliver gas to utilities, the fuel passes through what is commonly referred to as a gate station or city gate at which point the LDC takes control of the natural gas and its further distribution. The pressure in the transmission segment of the pipeline, which usually operates between 200 to 1,500 pounds per square inch (psi) is typically reduced at the city gate to levels well below 200 psi to as low as  $\frac{1}{4}$  psi at the distribution mains and service line level (AGA 2005). Meters at the gate measure how much gas is being received by the utility, and a sour-smelling odorant (usually t-butyl mercaptan or thiophane) is added to help customers smell even small quantities of leaked natural gas. The local utility then uses distribution pipes, or mains, to bring natural gas service to homes and businesses.

### **6.2.2 Pipeline Monitoring and Maintenance**

Pipeline transportation companies of all types make a series of large investments in a variety of equipment and assets that include pipes, pumps, compressors, drivers, dehydration units, meters, control systems, and other equipment. Large amounts of potentially-explosive natural gas, moving at very high pressures, are mandated to have a high degree of monitoring for safety purposes. The large capital investments associated with this equipment and these assets also require periodic and unexpected maintenance. Natural gas transmission companies often use a combination of preventative maintenance (such as cathodic protection and pipeline coating, discussed further in the next chapter), planned and scheduled maintenance, along with frequent inspection to ensure pipeline asset integrity.

Traditionally, pipelines were inspected visually by traveling the pipeline route on the ground or patrolling the pipeline route in aircraft (USEPA 1997). Aerial inspection is still done today, but inspections are more likely to be conducted through digital and computerized instrumentation and measurement, and through the use of direct monitoring equipment that rests or travels within or through the pipe itself and can provide more rapid and precise identification of leaks, potential leaks, or other operational problems (USEPA 1997).

Electronic data systems, the most common of which are referred to as Supervisory Control and Data Acquisition systems, or SCADA systems, allow pipeline operators to keep accurate, real-time information about various sections of pipeline (Folga 2007). These SCADA systems allow operators to retrieve real operational information from remote sections of pipeline. Natural gas flows and volumes can also be controlled by these systems, and the coordination of flows with interconnecting pipeline systems, through the use of the Internet, satellite communication, and other telecommunication systems. SCADA systems not only allow pipeline operators to get timely information, but in some instances can allow producers (or pipeline shippers) to have access to delivery information in order to efficiently schedule pipeline deliveries (Yoon, et al. 2007).

An important piece of equipment used in pipeline inspection and maintenance is an intelligent robotic inspection device, known as a pipeline inspection guide, or PIG, that physically travels through a pipeline, inspecting the wall of the pipe for corrosion and defects, measuring the interior diameter of a section of pipe, and removing any accumulated debris (USDOE, NETL 2010). The size of the PIG is determined by the diameter of the pipeline being inspected. The PIG is carried through the pipe by the flow of the liquid or gas (USEPA 1997).

PIGs can travel and perform inspections over very large distances. In 1997, a PIG completed an inspection of the Trans Alaska crude oil pipeline, covering a distance of 1,055 km in one run (NDT Resource Center 2011). A PIG uses sensors to take thousands of measurements that can later be analyzed by computers to show possible problems, particularly those associated with pipeline integrity and development of corrosion. Magnetic-flux leakage PIGs are used to detect metal loss (from corrosion) in pipeline walls thereby locating potential problems without the cost and risk of using other methods (Nestleroth and Bubenik 1999).

If a PIG, or other form of inspection identifies an integrity problem, leading to a leak or high probability of future leaks, repairs or replacements are usually initiated. In some instances, a leak repair can be conducted by inserting a short length of pipe, or “pup joint,” into a leaking or leak-prone area (Kennedy 1993). In other instances, the entire pipeline segment may be replaced. During repair operations, a pipe segment may also be plugged temporarily on either side of the repair section, redirecting natural gas flows around the work area until the repair has been completed (Kennedy 1993).

Plugging and redirects are usually methods restricted to onshore pipeline repairs. The repair of offshore pipelines differs and can be considerably more complex and costly. A number of factors influence offshore pipeline repair methods including: pipeline diameter; rupture location and gas volumes being transported; water depth; rupture coverage; pipeline segment age; and other special hazards (i.e., mud slides, unusual currents, severe weather conditions, etc.) (Woods 1982). Pipe repair methods attempt to balance the economics of the repair, particularly the timing for conducting the repairs, against the safety-related challenges of the damage.

Offshore repair activities can be partitioned into three distinct categories (Woods 1982):

- **Surface repair:** A process that requires the damaged offshore pipeline segment to be lifted to the surface for repair. Once the pipe is at the surface, the damaged section is removed and a new section is welded into place. The repaired pipe is then lowered back to the sea floor and carefully reconnected to its original longer segment. This approach can be highly contingent upon offshore weather conditions because most of the work is done on the surface of offshore repair vessels.
- **Underwater hyperbaric welding:** Some repairs may require only simple welds that do not require a pipeline segment to be lifted to the ocean surface. Underwater welding is then conducted by a welder-diver who works in either (a) a completely enclosed dry habitat or (b) underwater with the pipe section under repair being enclosed in an entirely dry environment through the use of an environmentally-controlled chamber. Though underwater repairs are less weather sensitive, they do require highly skilled diver-welders that must meet specific professional qualifications for performing various types of welding work at various different water depths.
- **Mechanical connectors:** Mechanical repair options include a wide range of connectors and seals that attempt to contain a problematic section of pipe. These options do not require operators to remove a pipe segment and lift it to the surface for repair. Instead a variety of couplings, seals, and or gaskets are used to seal relatively small leaks. Mechanical connection options can range from the containment of a pin-hole leak with a simple split-sleeve clamp, to something as elaborate as a complete spool-piece repair in deepwater through the use of a diver or remote-operated equipment. Mechanical repair approaches are also less sensitive to the weather, and have somewhat less sensitivity to skill-specific professional resources than underwater welding, but are dependent on vendor inventory or manufacturing lead time, particularly as the type of mechanical repair becomes more unique.

## 6.3 GEOGRAPHIC DISTRIBUTION

### 6.3.1 U.S. Natural Gas Pipeline System

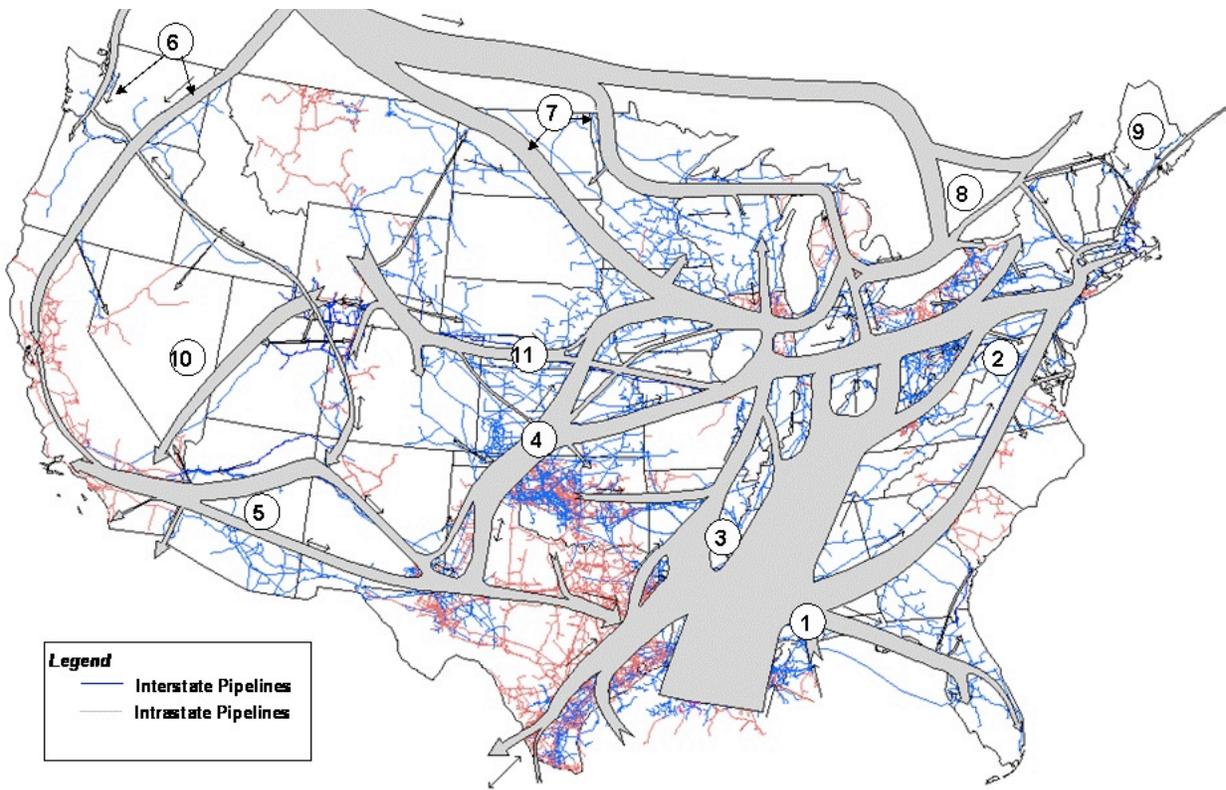
The U.S. has a complex and extensive pipeline system for transporting natural gas from production areas to consumers. However, most of the major transportation routes are categorized into 11 corridors or flow patterns (USDOE, EIA 2012b). Figure 50 shows these major corridors, and Figure 51 shows the estimated region-to-region natural gas pipeline capacity.

- Five major routes originate in the producing areas of the Southwest<sup>10</sup> and include about twenty major interstate pipelines. The Southwest region exports about 45 percent of the natural gas it produces, which is 47 percent of the total natural gas consumed in the lower 48 States. The pipelines leaving this region account for over 45 Bcf per day of capacity with 62 percent going to the Southeast Region, 20 percent to the Central Region, 13 percent to the Western Region, and the remaining 5 percent exporting natural gas to Mexico (USDOE, EIA 2012a).<sup>11</sup> (see Figure 50)
- Four routes enter the U.S. from Canada including pipelines that flow from (1) western Canada to western markets in the U.S. (mainly California, Oregon, and Washington); (2) western Canada to the mid-west; (3) western Canada to the northeast; and (4) offshore eastern Canada (Sable Island) to New England markets (USDOE, EIA 2012b).
- There are two routes, made up of two main pipeline systems that start in the Rocky Mountain area (central region). The first is the Kern River Transmission Company that extends from the producing areas of southwestern Wyoming, through Utah and Nevada to Southern California (Kern River 2011). The second is the Rockies Express Pipeline that links natural gas production from northwestern Colorado to eastern Ohio (Kinder Morgan 2011). The other routes operate primarily within the region, or come from other regions (USDOE, EIA 2012b).

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<sup>10</sup> The Southwest Region is defined as Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

<sup>11</sup> These regions are defined as follows: Southeast Region - Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee; Central Region - Iowa, Kansas, Missouri, Nebraska, Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming; and Western Region - Arizona, California, Nevada, Idaho, Oregon, and Washington.

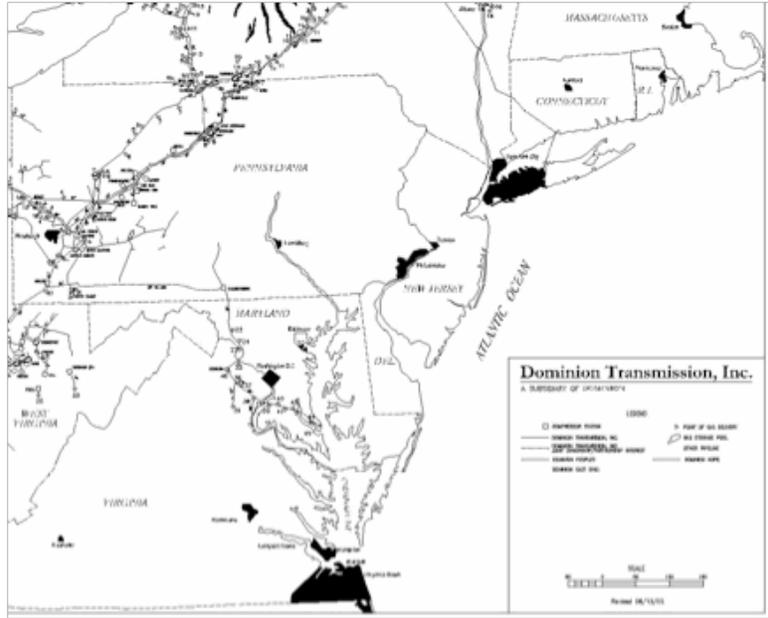


**Figure 50. Major U.S. natural gas transportation corridors.**  
 Source: USDOE, EIA 2012b.



***Dominion Transmission System***

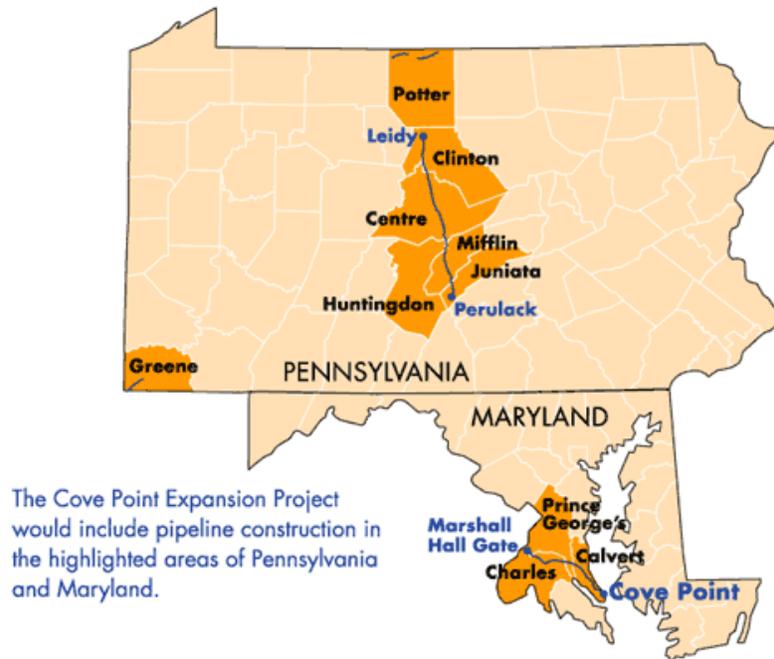
Dominion Transmission maintains 7,800 miles (12,553 kilometers) of pipeline in six states: Ohio; West Virginia; Pennsylvania; New York; Maryland; and Virginia. Dominion also operates one of the largest underground storage systems in the U.S. and links to other major pipelines and markets in the Midwest, Mid-Atlantic, and Northeast regions.



**Figure 52. Mid-Atlantic impact region natural gas pipelines – Dominion Transmission, Inc.**

Source: Dominion Transmission 2011.

In March 2009, Dominion Transmission completed its expansion of the Dominion Cove LNG facility, which is located on the Chesapeake Bay in southern Maryland. The expansion included a 48-mile, 36-inch natural gas pipeline that extends west from the marine terminal to connections with interstate pipelines in Virginia as shown in Figure 53.



**Figure 53. Mid-Atlantic impact region natural gas pipelines – Dominion Transmission, Inc.**

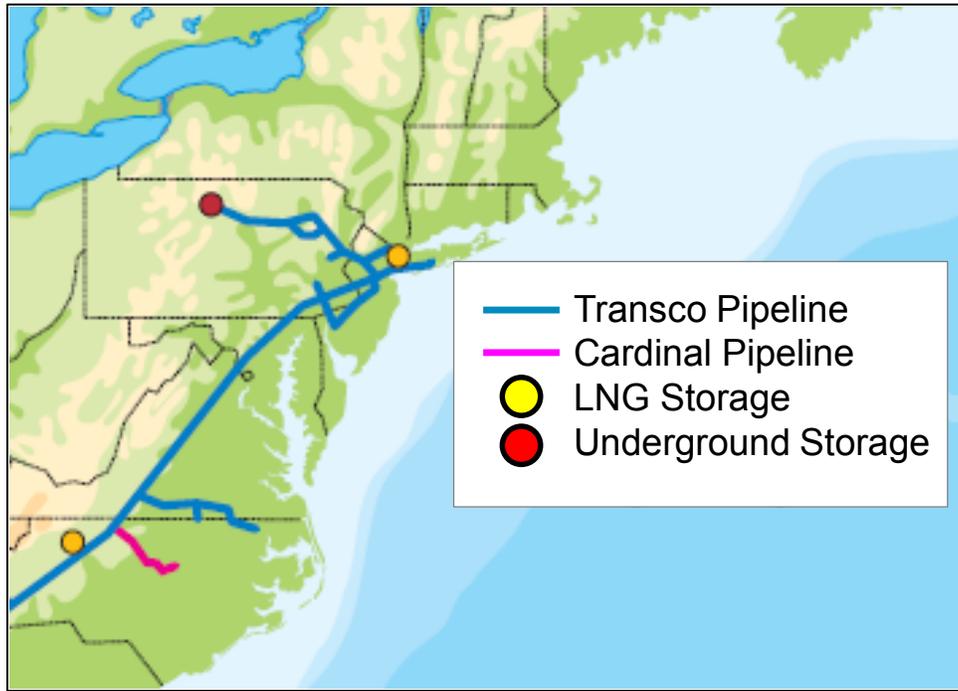
Source: Dominion 2011.

The Dominion Transmission, Inc., is the interstate gas transmission subsidiary of Dominion, a publicly-traded company headquartered in Richmond, Virginia and one of the largest energy producers and transportation companies in the U.S. Dominion, and its component subsidiaries, has a portfolio of over 28,142 MW of electric generation capacity, 6,300 miles (10,139 kilometers) of electric transmission lines, 56,800 miles (91,411 kilometers) of electric distribution lines, and 11,000 miles (17,703 kilometers) of natural gas transmission, gathering, and storage pipeline. Dominion also has natural gas LDC (utility) operations in Ohio and West Virginia and owns the nation’s largest underground natural gas storage system (SEC 2011e).

In 2011, Dominion’s natural gas transportation and storage revenues accounted for just 10 percent of Dominion’s total revenues. Dominion’s regulated electric sales accounted for the greatest share of total revenue, 49 percent, while unregulated electric sales accounted for 23 percent. Natural gas LDC operations only account for two percent of total company revenues (SEC 2011e).

***Transcontinental Pipeline System***

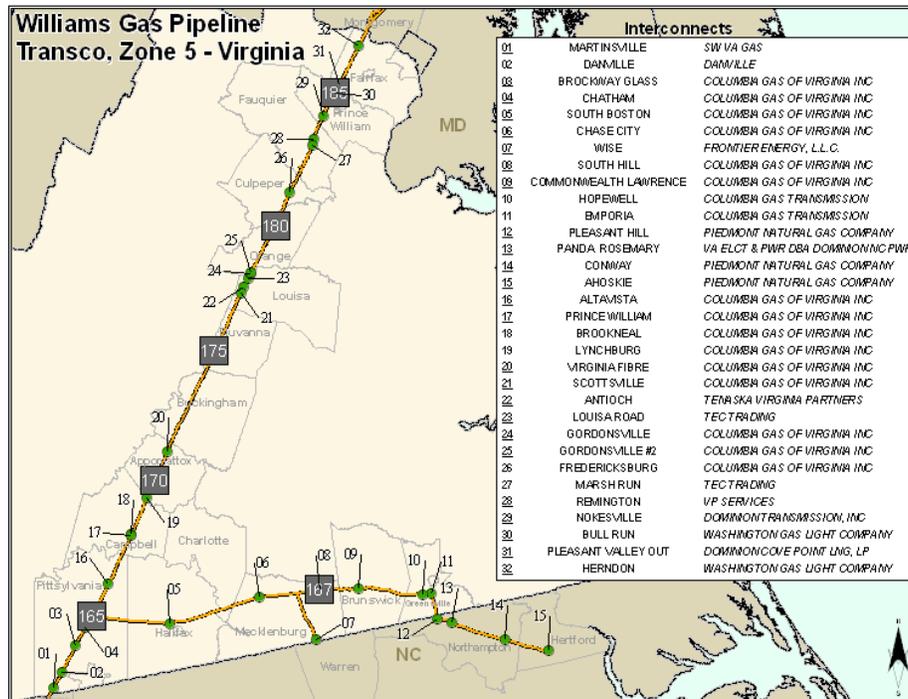
Figure 54 shows the Williams’ Transco Pipeline system which includes 9,800 pipeline miles (15,772 kilometers) that originates in the GOM and moves gas through 11 southeastern and Mid-Atlantic states, including major markets in Georgia, the District of Columbia, New York, New Jersey, and Pennsylvania (SEC 2011f). The pipeline’s major customers include public utilities and municipalities that provide service to retail end users. The Transco system also has natural gas storage capacity in four underground fields, and capacity in an LNG storage facility that it owns and operates (SEC 2011f).



**Figure 54. Mid-Atlantic impact region natural gas pipelines – Transco.**

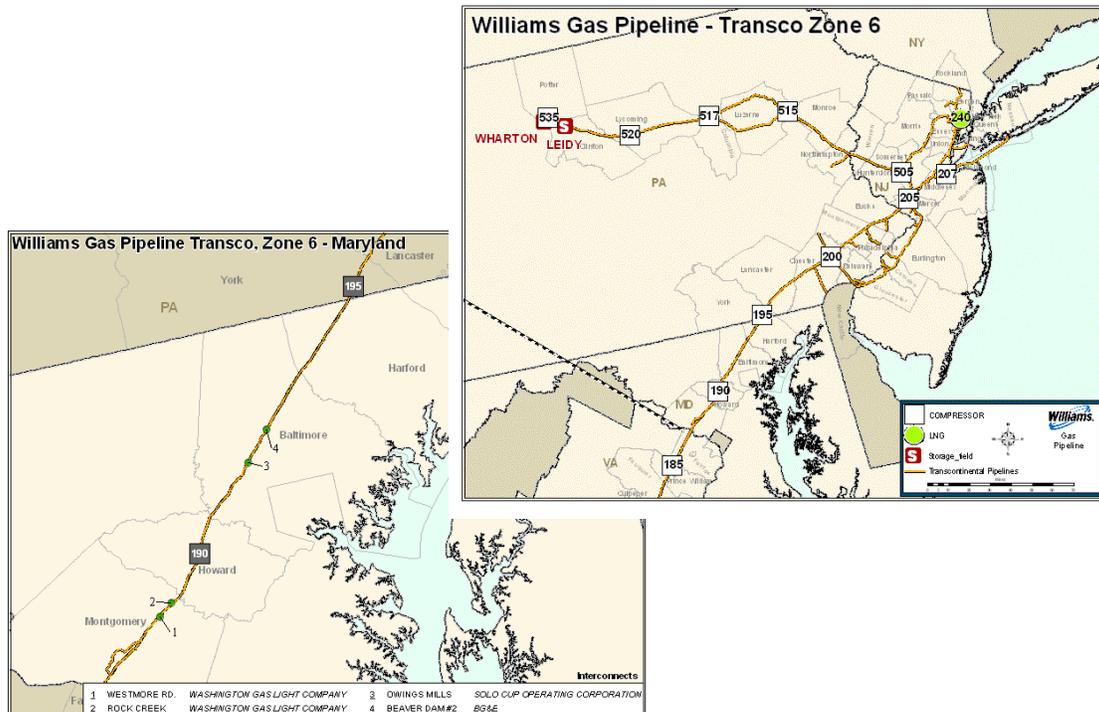
Source: Williams 2011.

While most of the Transco system is further inland, Figure 55 shows Transco’s Zone 5, which stretches east from Virginia to Hertford County in North Carolina, just miles from Albemarle Sound and the Atlantic Coast.



**Figure 55. Mid-Atlantic impact region natural gas pipelines – Transco Zone 5, Virginia.**  
Source: Williams 2011.

Transco’s Zone 6 (Figure 56) cuts through Maryland, near the Chesapeake Bay and up into New Jersey, near the Delaware Bay and New Jersey Harbor.



**Figure 56. Mid-Atlantic impact region natural gas pipelines – Transco Zone 6.**

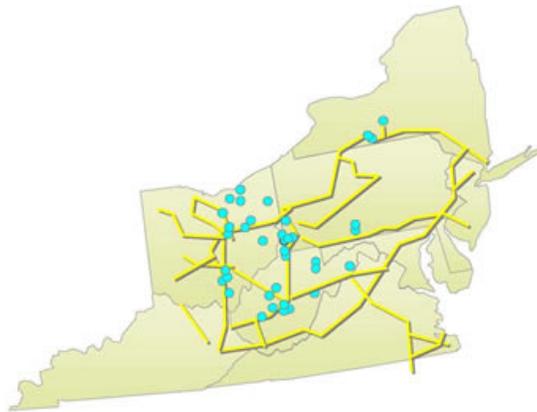
Source: Williams 2011.

The Transco transmission system is owned by The Williams Companies, Inc., a publicly-traded company headquartered in Tulsa, Oklahoma. The Williams subsidiaries include Williams Partners, which operates the Transco transmission system and two other interstate pipelines and includes a midstream business that provides natural gas gathering, treating and processing services; NGL production, fractionation, storage, marketing and transportation; and deepwater production handling and crude oil transportation services (SEC 2011f). Other Williams subsidiaries include an exploration and production company, and conduct other activities such as Canadian midstream investments and domestic olefins operations. In 2010, Williams Partners' revenues accounted almost 53 percent of The Williams Companies' total revenues. The exploration and production operations accounted for 37 percent of total revenues, and other operations accounted for 10 percent (SEC 2010a).

In February 2011, the Company announced it was splitting the company into two separate, publicly-traded corporations. The exploration and production business, WPX Energy, became its own publicly-traded company through an initial public offering and is one of the largest independent producers of natural gas in the U.S. (PR Newswire 2011). WPX Energy already has undeveloped positions in the Marcellus Shale and North Dakota's Bakken oil play, and also has investments in the Rockies, Barnett Shale, and Arkoma Basin (PR Newswire 2011).

### ***Columbia Gas Transmission System***

Columbia Gas Transmission (Figure 57) is a 12,000-mile transmission network that averages 3 Bcf per day and moves natural gas throughout the Mid-Atlantic states. It also owns and operates 37 storage fields in four states with over 650 Bcf of total capacity (NiSource 2011). Columbia Gas customers include LDCs, energy marketers, electric power generators and numerous industrial and commercial end users (NGTS 2011).



**Figure 57. Mid-Atlantic impact region natural gas pipelines – Columbia Gas Transmission.**

Source: NGTS 2011.

The Columbia transmission system is owned and operated by NiSource Gas Transmission & Storage (NGTS). In addition to the Columbia transmission system, NGTS owns and operates three other interstate pipelines (Columbia Gulf, Crossroads, and Central Kentucky) and has interest in a fourth (Millennium Pipeline) (NGTS 2011).

In August 2010, NGTS and UGI Corporation announced that they were partnering to develop a new natural gas pipeline to increase access between producers in the Marcellus Shale of Pennsylvania and high-value markets. About 500 MMcf/d of capacity will be accessible to producers along the Columbia Gas Transmission pipeline system to interconnections with Transcontinental Gas Pipeline, Tennessee Gas Pipeline, Dominion Gas Transmission, and Millennium Pipeline Company (Downstream Today 2010).

NGTS is a subsidiary of NiSource, Inc., a publicly traded company headquartered in Merrillville, Indiana. In addition to NGTS, NiSource, Inc., has natural gas distribution operations in seven states: Ohio, Pennsylvania, Virginia, Kentucky, Maryland, Indiana, and Massachusetts (NiSource 2011). It also has electric operations in Northern Indiana that include generation, transmission, distribution, and wholesale transactions (NiSource 2011). In 2011, NGTS operations accounted for about 23 percent of NiSource, Inc. total revenues. The NiSource LDC operations accounted for 50 percent, and the electric operations accounted for just over 24 percent (SEC 2011g).

## 6.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY

The pipeline transportation sector for the impact area is relatively small in comparison to (a) each state's overall GDP and (b) the economic contribution made by the U.S. natural gas transportation sector to total U.S. GDP. Pennsylvania's pipeline transportation GDP makes the largest contribution to its state's overall economy of any in the Mid-Atlantic impact area at just 0.12 percent.

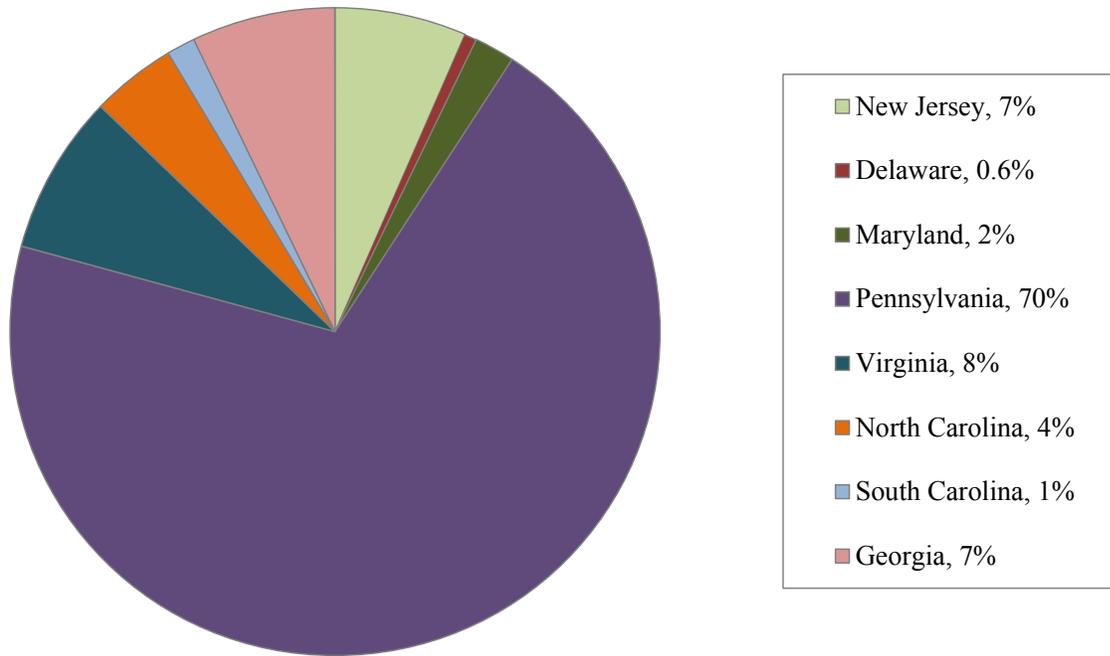
The contributions each Mid-Atlantic state makes to total U.S. pipeline transportation GDP is consistent with the size and location of pipelines along the Mid-Atlantic seaboard. Pennsylvania's share of U.S. pipeline transportation GDP is far greater than any other state in the impact region.

**Table 20. Regional and national GDP contribution, pipeline transportation, 2010.**

	GDP		Pipeline Transportation GDP as a Percent of Total State GDP	Pipeline Transportation GDP as a Percent of U.S. Water Transportation GDP
	Pipeline Transportation (millions of current \$)	Total State	----- (%) -----	-----
New Jersey	\$ 65	\$ 480,446	0.01%	0.4%
Delaware	\$ 6	\$ 64,010	0.01%	0.0%
Maryland	\$ 20	\$ 293,349	0.01%	0.1%
Pennsylvania	\$ 696	\$ 558,918	0.12%	4.6%
Virginia	\$ 79	\$ 419,365	0.02%	0.5%
North Carolina	\$ 42	\$ 424,562	0.01%	0.3%
South Carolina	\$ 14	\$ 160,374	0.01%	0.1%
Georgia	\$ 71	\$ 403,230	0.02%	0.5%
<b>Total Region</b>	<b>\$ 993</b>	<b>\$ 2,804,254</b>	<b>0.04%</b>	<b>6.5%</b>
<b>U.S.</b>	<b>\$ 15,287</b>	<b>\$ 14,416,601</b>	<b>0.11%</b>	<b>100.0%</b>

Source: USDOC, BEA 2012.

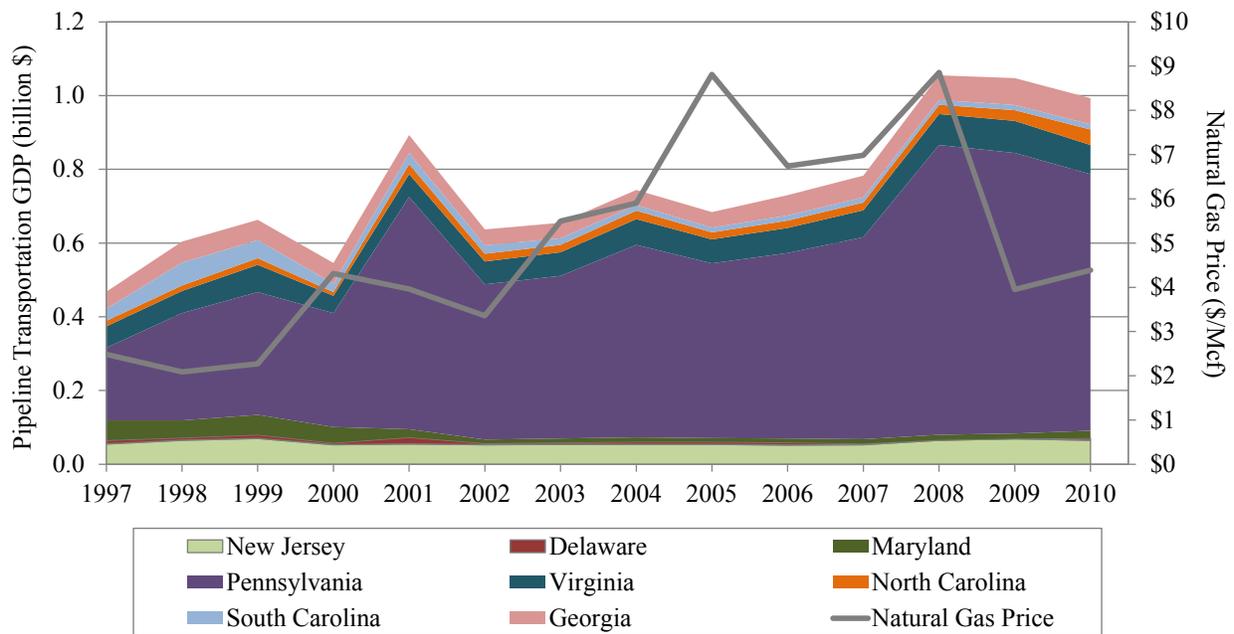
Figure 58 highlights the relative share of each Mid-Atlantic state's pipeline transportation GDP shares to the regional pipeline transportation total. Pennsylvania, with \$696 million in the annual value of its pipeline transportation output, comprises 70 percent of the value of the region's pipeline transportation output. Virginia, accounts for eight percent of the economic value of the region's pipeline transportation output (\$79 million per year). Georgia and New Jersey both account for seven percent of the region's pipeline transportation output, both around \$70 million. The remaining states comprise smaller shares of the region's pipeline transportation output with shares between 0.6 percent and 4 percent.



**Figure 58. Mid-Atlantic impact region pipeline transportation GDP shares, 2010.**

Source: USDOC, BEA 2012.

The economic value of the region’s pipeline transportation output has followed trends closely associated with the price of natural gas. Figure 59 compares the trends in pipeline transportation GDP for each Mid-Atlantic impact state since the mid-1990s. Regional pipeline transportation GDP increased at an average annual rate of close to 10 percent between 2002 and 2008, increasing by 36 percent in 2008 alone. Pipeline transportation GDP decreased by over 20 percent in 2009 however, as natural gas commodity prices fell to relatively low levels compared to the previous six year period.



**Figure 59. Trends in Mid-Atlantic impact region pipeline transportation GDP.**

Source: USDOC, BEA 2012; and Federal Reserve Bank of St. Louis 2012.

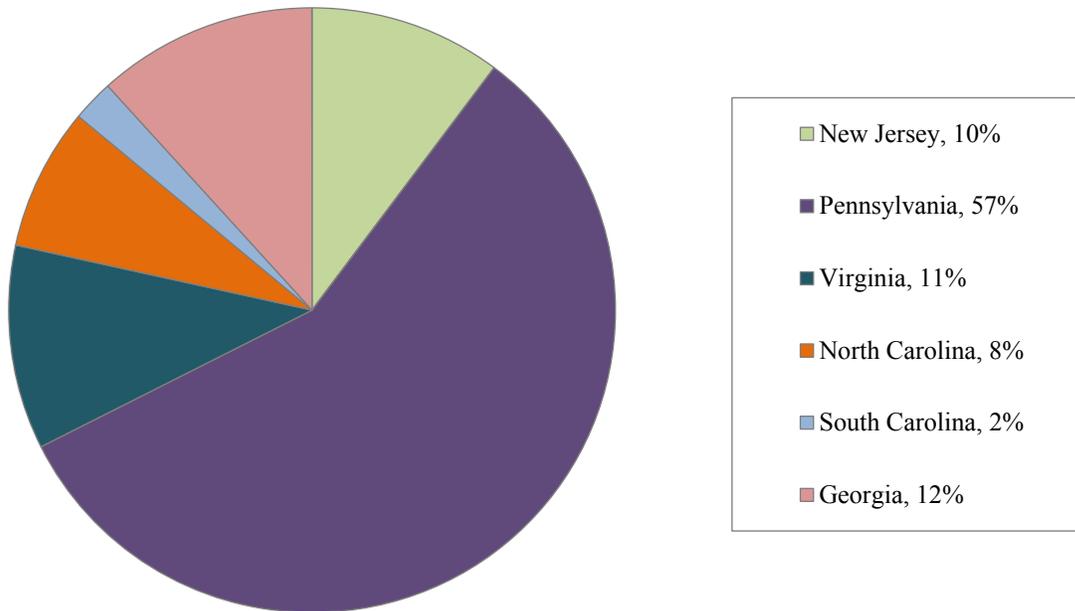
Table 21 shows that each state’s total pipeline transportation employment contributions are relatively small in comparison to the total employment in each of the states in the Mid-Atlantic impact region. None of the states in the Mid-Atlantic impact region have pipeline transportation employment totals that are over one-tenth of one percent of the overall statewide employment totals.

Pennsylvania has the overwhelming majority of pipeline transportation employment in the impact region (see Figure 60). Likewise, it also has the highest employment contribution to total U.S. pipeline transportation employment. Overall, the region accounts for eight percent of total U.S. pipeline transportation employment.

**Table 21. Regional and national employment contribution, pipeline transportation, 2011.**

	Number of Jobs		Pipeline Transportation Employment as a Percent of Total State Employment	Pipeline Transportation Employment as a Percent of Total U.S. Pipeline Transportation Employment
	Pipeline Transportation	Total State	----- (%) -----	----- (%) -----
New Jersey	350	3,156,538	0.01%	0.81%
Delaware	n.a.	342,585	n.a.	n.a.
Maryland	n.a.	1,991,055	n.a.	n.a.
Pennsylvania	1,960	4,825,064	0.04%	4.56%
Virginia	373	2,889,435	0.01%	0.87%
North Carolina	260	3,158,293	0.01%	0.60%
South Carolina	76	1,450,840	0.01%	0.18%
Georgia	401	3,135,735	0.01%	0.93%
<b>Total Region</b>	<b>3,420</b>	<b>20,949,545</b>	<b>0.02%</b>	<b>7.95%</b>
<b>U.S.</b>	<b>43,010</b>	<b>108,184,795</b>	<b>0.04%</b>	<b>100.00%</b>

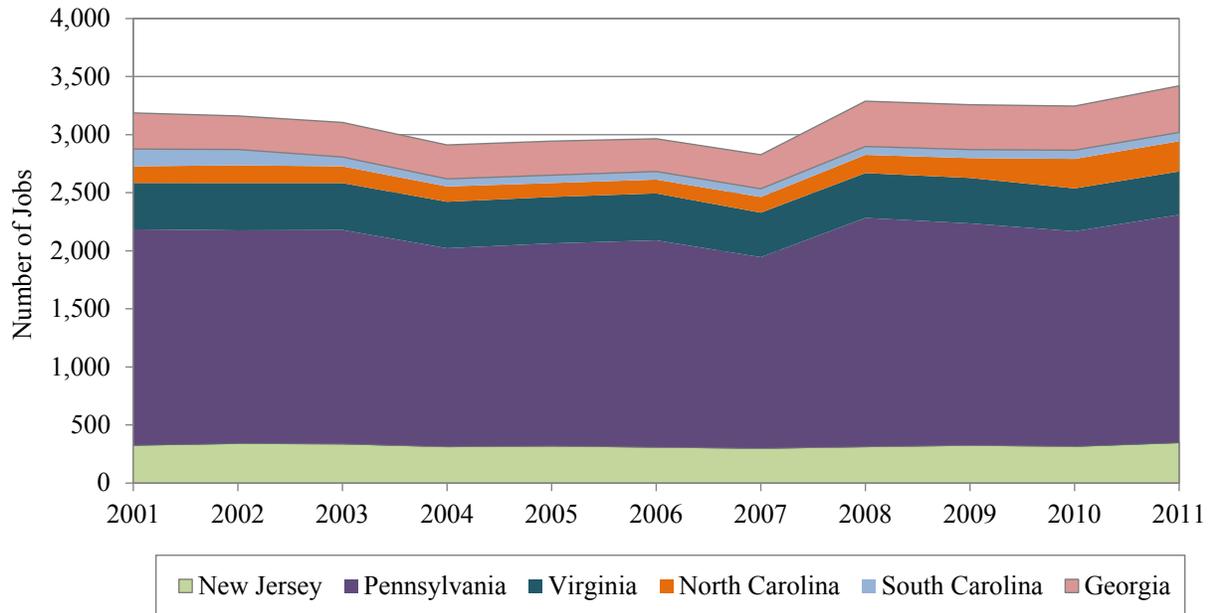
Note: n.a. is “not available.”  
 Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 60. Mid-Atlantic impact region pipeline transportation employment shares, 2011.**

Note: n.a. is “not available.”  
 Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.

Pipeline transportation employment in the Mid-Atlantic impact region has been relatively stable over the past decade. The region reported a high of 3,420 pipeline transportation jobs in 2011. This is an increase of seven percent since 2001. Between 2007 and 2008, pipeline transportation employment increased the most, by over 16 percent. This was mostly due to increases in Pennsylvania, North Carolina, and Georgia.



**Figure 61. Trends in Mid-Atlantic impact region pipeline transportation employment, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

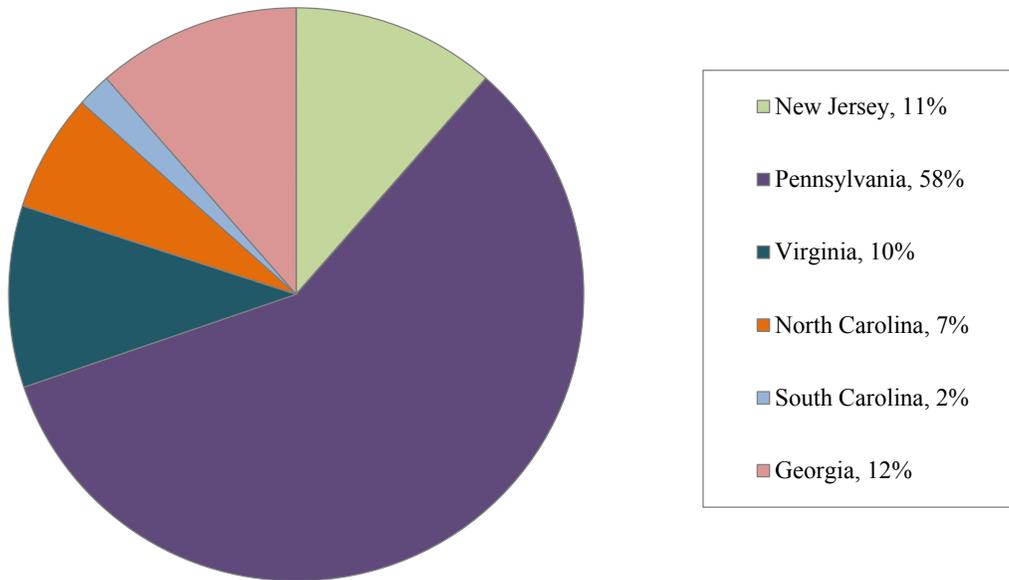
Source: USDOL, BLS 2012.

Regional wage contributions follow trends similar to employment levels discussed earlier with the regional totals dominated by the state (Pennsylvania) with the largest share of transportation pipeline miles (see Table 22). Regional shares of total wages paid by Mid-Atlantic coast pipeline transportation companies are provided in Figure 62.

**Table 22. Regional and national wage contribution, pipeline transportation, 2011.**

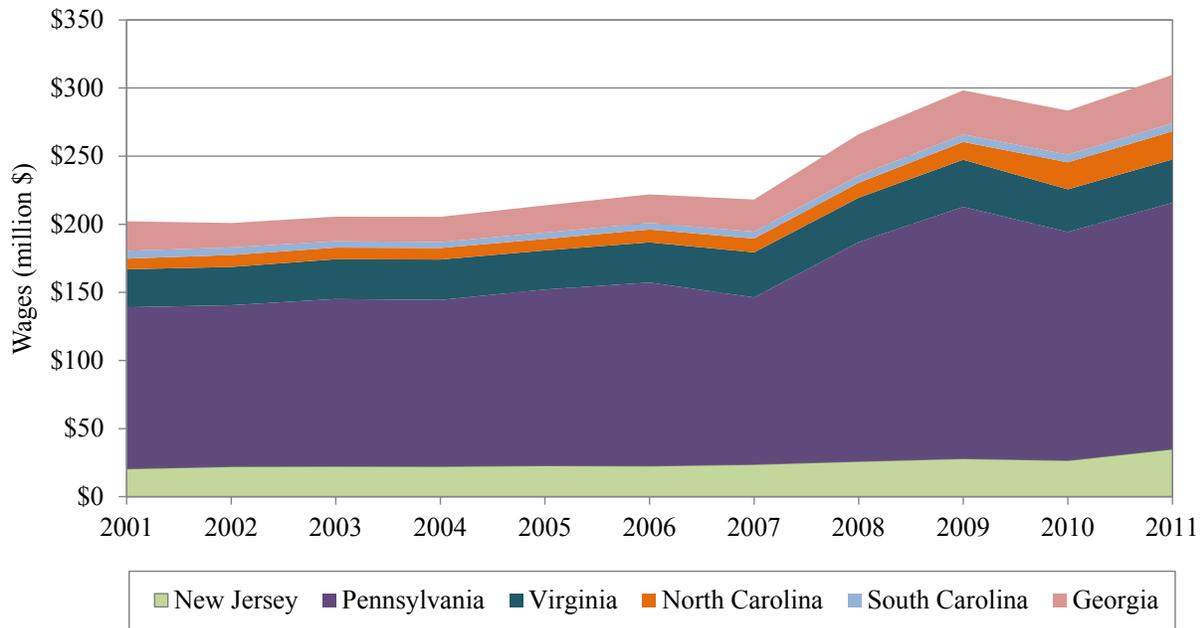
	Wages		Pipeline Transportation Wages as a Percent of Total State Wages	Pipeline Transportation Wages Percent of Total U.S. Pipeline Transportation Wages
	Pipeline Transportation	Total State		
	----- (million \$) -----		----- (%) -----	
New Jersey	\$ 35.5	\$ 179,559	0.02%	0.74%
Delaware	n.a.	\$ 17,313	n.a.	n.a.
Maryland	n.a.	\$ 100,787	n.a.	n.a.
Pennsylvania	\$ 180.8	\$ 225,147	0.08%	3.78%
Virginia	\$ 31.8	\$ 145,225	0.02%	0.67%
North Carolina	\$ 20.6	\$ 132,436	0.02%	0.43%
South Carolina	\$ 5.9	\$ 54,746	0.01%	0.12%
Georgia	\$ 35.5	\$ 142,928	0.02%	0.74%
<b>Total Region</b>	<b>\$ 310.1</b>	<b>\$ 998,140</b>	<b>0.03%</b>	<b>6.49%</b>
<b>U.S.</b>	<b>\$ 4,777.5</b>	<b>\$ 5,172,844</b>	<b>0.09%</b>	<b>100.00%</b>

Note: n.a. is “not available.”  
 Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 62. Mid-Atlantic impact region pipeline transportation wage shares, 2011.**

Note: n.a. is “not available.”  
 Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 63. Trends in Mid-Atlantic impact region pipeline transportation wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Table 23 compares the average annual wages paid to employees in the pipeline transportation sectors of the Mid-Atlantic impact area. The annual wages for pipeline transportation sector employees in each state in the region are considerably higher, in fact orders of magnitude higher than the average in-state wage. This is not surprising and consistent with industry trends in other parts of the country. The comparisons differ, however, when average annual pipeline transportation wages to the U.S. average annual pipeline transportation wage.

New Jersey, for instance, reports the highest average annual wage in the region: almost \$100,000 per year for a pipeline transportation company employee. In Pennsylvania, the average annual wage for pipeline transportation is \$92,250, which is almost double (198 percent) the average annual wage for Pennsylvania in general. In South Carolina, pipeline transportation wages in North Carolina are over 200 percent higher than the state average. However, average annual pipeline transportation wages in the region are below the U.S. pipeline transportation average of roughly \$111,000 per year.

**Table 23. Regional and national average annual wage contribution, pipeline transportation, 2011.**

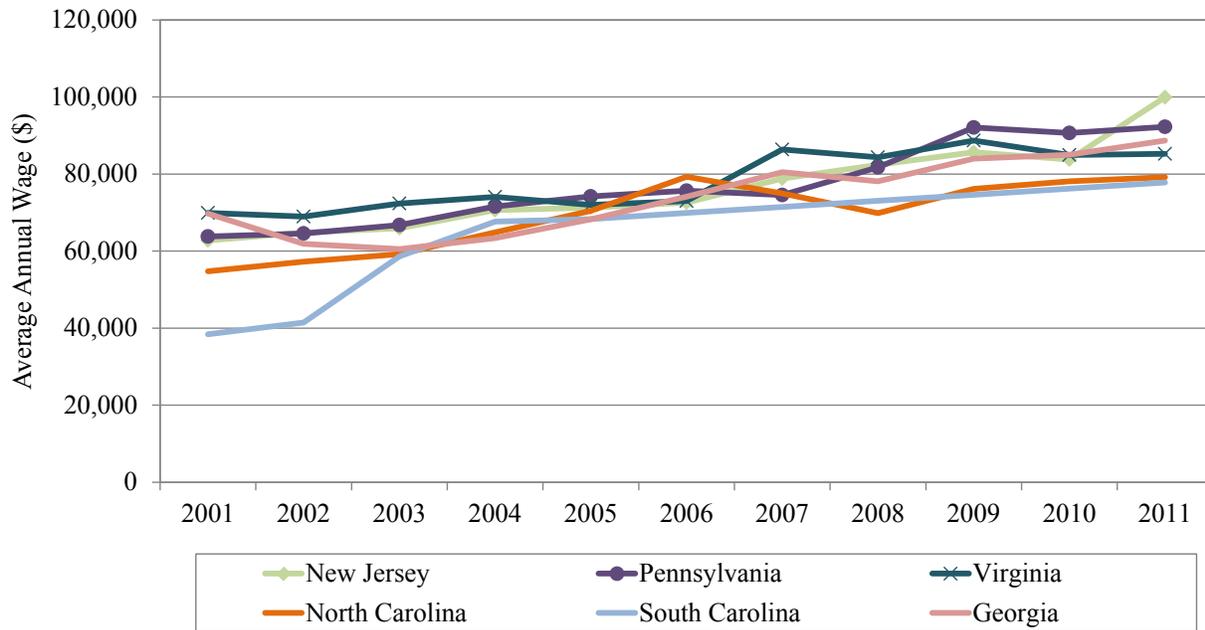
	Average Annual Wage		Pipeline Transportation Average Annual Wage as a Percent of Total State Average Annual Wage	Pipeline Transportation Average Annual Wage as a Percent of Total U.S. Pipeline Transportation Average Annual Wage
	Pipeline Transportation	Total	Percent of Total	Percent of Total
	----- (\$)	----- (\$)	----- (%)	----- (%)
New Jersey	\$ 99,949	\$ 56,885	175.7%	90.0%
Delaware	n.a.	\$ 50,535	n.a.	n.a.
Maryland	n.a.	\$ 50,620	n.a.	n.a.
Pennsylvania	\$ 92,250	\$ 46,662	197.7%	83.0%
Virginia	\$ 85,236	\$ 50,261	169.6%	76.7%
North Carolina	\$ 79,208	\$ 41,933	188.9%	71.3%
South Carolina	\$ 77,799	\$ 37,734	206.2%	70.0%
Georgia	\$ 88,681	\$ 45,580	194.6%	79.8%
<b>Total Region</b>	<b>\$ 87,187</b>	<b>\$ 47,526</b>	<b>183.5%</b>	<b>78.5%</b>
<b>U.S.</b>	<b>\$ 111,080</b>	<b>\$ 47,815</b>	<b>232.3%</b>	<b>100.0%</b>

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Trends in regional average annual wages for regional pipeline transportation employees are provided in Figure 64. The trends show that average annual wage have been increasing at an average annual rate of 4.2 percent, with the greatest increases in 2009 (6.6 percent) and 2011 (5.0 percent). In 2009, Pennsylvania and North Carolina showed the largest increases in average annual wages, with increases of 12.6 percent and 8.9 percent.



**Figure 64. Trends in Mid-Atlantic impact region pipeline transportation average annual wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

## 6.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

Between 2005 and 2010, over 14,000 miles (22,531 kilometers) of pipeline, totaling 136,806 million cubic feet per day of capacity, were added to the U.S. network (USDOE, EIA 2006a; USDOE, EIA 2008a; and USDOE, EIA 2009.). The period immediately following Hurricane Katrina (2005) to the year before the most recent economic recession (2008) was marked by significant capacity development, most of which were added in the southeastern and southwestern U.S. (see Table 24). Pipeline capacity development has stalled during the course of the last recession and current economic recovery (2009-2010), and is modest, given relatively lackluster growth in natural gas demand over the past two to three years.

**Table 24. Recent natural gas pipeline additions and expansions.**

	Additional Capacity (MMcf/day)					
	2005	2006	2007	2008	2009*	2010*
Central	272	3,873	4,280	6,515	2,558	3,655
Midwest	519	478	460	311	3,049	-
<b>Northeast</b>	<b>573</b>	<b>1,082</b>	<b>1,749</b>	<b>4,987</b>	<b>2,382</b>	<b>2,491</b>
<b>Southeast</b>	<b>795</b>	<b>430</b>	<b>430</b>	<b>10,092</b>	<b>3,403</b>	<b>9,911</b>
Southwest	5,537	6,792	6,971	22,553	19,684	6,283
Western	502	50	723	70	671	345
to Mexico/Canada	-	-	245	60	105	1,920
<b>Total Capacity</b>	<b>8,198</b>	<b>12,705</b>	<b>14,858</b>	<b>44,588</b>	<b>31,852</b>	<b>24,605</b>
	Additional Miles					
	2005	2006	2007	2008	2009*	2010*
Central	19	550	619	1,088	243	871
Midwest	26	56	13	42	606	-
<b>Northeast</b>	<b>33</b>	<b>116</b>	<b>134</b>	<b>491</b>	<b>112</b>	<b>249</b>
<b>Southeast</b>	<b>110</b>	<b>32</b>	<b>184</b>	<b>891</b>	<b>260</b>	<b>601</b>
Southwest	869	822	700	1,382	2,113	293
Western	94	6	13	-	309	27
to Mexico/Canada	-	-	-	-	-	29
<b>Total Miles</b>	<b>1,151</b>	<b>1,582</b>	<b>1,663</b>	<b>3,894</b>	<b>3,643</b>	<b>2,070</b>
	Estimated Cost (Million \$)					
	2005	2006	2007	2008	2009*	2010*
Central	\$ 62	\$ 823	\$ 1,607	\$ 2,452	\$ 470	\$ 1,820
Midwest	\$ 86	\$ 127	\$ 27	\$ 102	\$ 3,694	\$ -
<b>Northeast</b>	<b>\$ 78</b>	<b>\$ 166</b>	<b>\$ 784</b>	<b>\$ 1,952</b>	<b>\$ 1,194</b>	<b>\$ 1,276</b>
<b>Southeast</b>	<b>\$ 238</b>	<b>\$ 42</b>	<b>\$ 304</b>	<b>\$ 3,497</b>	<b>\$ 845</b>	<b>\$ 2,006</b>
Southwest	\$ 733	\$ 1,124	\$ 1,471	\$ 3,307	\$ 4,855	\$ 577
Western	\$ 78	\$ 11	\$ 39	\$ 41	\$ 821	\$ 107
to Mexico/Canada	\$ -	\$ -	\$ 70	\$ 1	\$ 37	\$ -
<b>Total Cost</b>	<b>\$ 1,275</b>	<b>\$ 2,293</b>	<b>\$ 4,302</b>	<b>\$ 11,352</b>	<b>\$ 11,916</b>	<b>\$ 5,786</b>
	Estimated Cost per Mile (Million \$)					
	2005	2006	2007	2008	2009*	2010*
Central	\$ 3.26	\$ 1.50	\$ 2.60	\$ 2.25	\$ 1.93	\$ 2.09
Midwest	\$ 3.31	\$ 2.27	\$ 2.08	\$ 2.43	\$ 6.10	\$ -
<b>Northeast</b>	<b>\$ 2.36</b>	<b>\$ 1.43</b>	<b>\$ 5.85</b>	<b>\$ 3.98</b>	<b>\$ 10.66</b>	<b>\$ 5.12</b>
<b>Southeast</b>	<b>\$ 2.16</b>	<b>\$ 1.31</b>	<b>\$ 1.65</b>	<b>\$ 3.92</b>	<b>\$ 3.25</b>	<b>\$ 3.34</b>
Southwest	\$ 0.84	\$ 1.37	\$ 2.10	\$ 2.39	\$ 2.30	\$ 1.97
Western	\$ 0.83	\$ .83	\$ 3.00	\$ -	\$ 2.66	\$ 3.96
to Mexico/Canada	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
<b>Total Cost/Mile</b>	<b>\$ 1.11</b>	<b>\$ 1.45</b>	<b>\$ 2.59</b>	<b>\$ 2.92</b>	<b>\$ 3.27</b>	<b>\$ 2.80</b>

Note: \*Figures for 2009 and 2010 are scheduled or proposed.  
Source: USDOE, EIA 2006a; USDOE, EIA 2008a; and USDOE, EIA 2009.

The areas relevant to the Mid-Atlantic impact area, highlighted in Table 24, include parts of the northeast region (primarily New Jersey, Delaware, Maryland, Pennsylvania, and Virginia) and the southeast region (primarily North Carolina, South Carolina and Georgia).

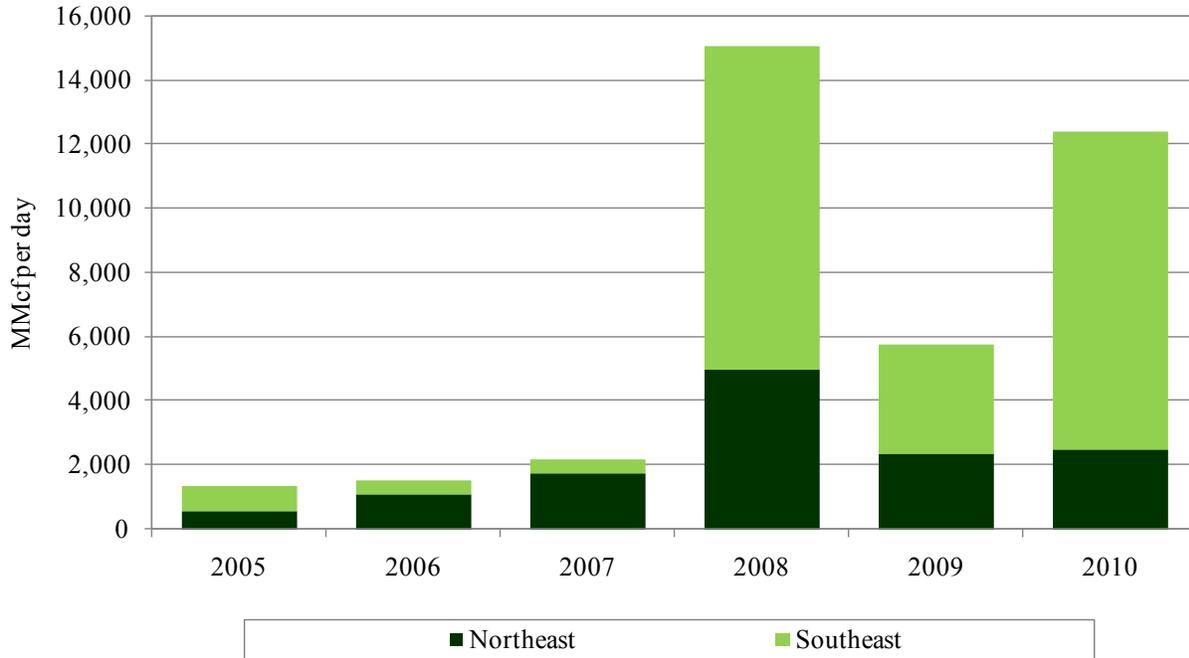
The number of pipeline construction projects completed in 2008 was remarkable: 84 projects completed, adding 44.6 Bcf per day of capacity (USDOE, EIA 2009). The southeast saw 19 different pipeline expansions completed in 2008, adding 891 pipeline miles (1,434 kilometers), and over 10.0 Bcf per day of transportation capacity. Much of this capacity was added to accommodate capacity coming out of the Southwest region, where production from unconventional resources (i.e., Haynesville, Barnett) has been growing (USDOE, EIA 2009).<sup>12</sup> These expansions are a good example of the new infrastructure requirements that are necessary to move gas from new production areas (unconventional) to growing consuming markets, particularly Florida in the southeastern region. Much of this transportation development moves gas from west to east, effectively bypassing the traditional long-haul lines that have moved gas from south to east, coming from the GOM.

Northeast pipeline capacity development over the past several years has been based on a number of factors, but more on the development and expansion of LNG import terminals than unconventional gas development. For instance, in 2009, Dominion completed the addition of 48 miles (77 kilometers) of new pipeline from its Cove Point LNG terminal in Maryland to interstate pipeline connections in Virginia (Dominion 2011). And, 81 miles (130 kilometers) were added in central Pennsylvania to allow imported LNG to be transported to natural gas markets in the Northeast (Dominion 2010).

Figure 65 and Figure 66 show the total capacity and mileage additions in the Northeast and Southeast regions of the U.S.

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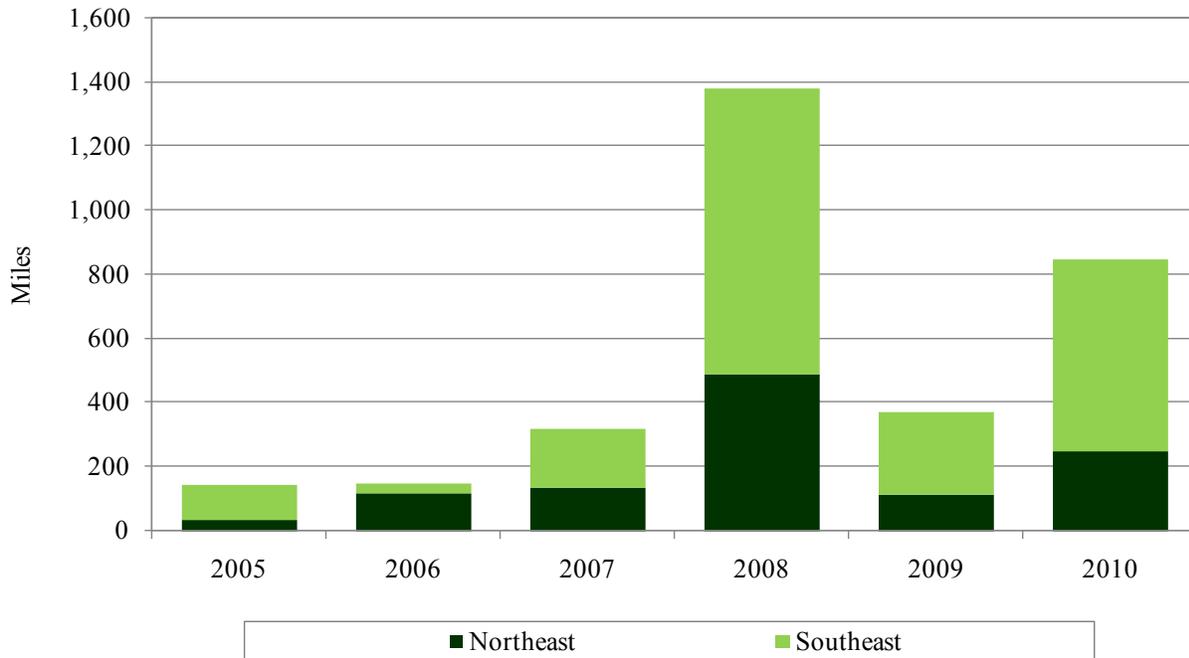
<sup>12</sup> This includes developments in the Barnett Shale (Texas) and the Fayetteville and Woodford Shales in Oklahoma and Arkansas.



**Figure 65. Natural gas pipeline capacity additions, Northeast and Southeast regions.**

Note: \*Figures for 2009 and 2010 are scheduled or proposed.

Source: USDOE, EIA 2006a; USDOE, EIA 2008a; and USDOE, EIA 2009.



**Figure 66. Natural gas pipeline capacity additions, Northeast and Southeast regions.**

Note: \*Figures for 2009 and 2010 are scheduled or proposed.

Source: USDOE, EIA 2006a; USDOE, EIA 2008a; and USDOE, EIA 2009.

According to FERC, natural gas production and transportation re-alignment trends are anticipated to continue as developers move into other new unconventional resource plays, particularly those in the northeast-Atlantic seaboard (Marcellus) and the upper mid-west-Great Lakes (Atrium, Utica) (FERC 2010a). Historically, consuming areas of the northeast have been served by Canadian imports; however, these imports are down by over 50 percent from prior year levels (2009 to 2010). Supply to the northeast is now being met by conventional and unconventional Rockies production through the Rockies Express Pipeline (REX), and increasingly through the rapid build-up of Marcellus (unconventional) production in the Mid-Atlantic-Appalachian region. Marcellus Shale gas production has doubled from 2009 to 2010, to around 700 MMcfd and is expected to increase by as much from 2010 to 2011 (FERC 2010a).

## **6.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

The Mid-Atlantic impact area should see some of the more dramatic changes in gas markets of any area in the U.S. given its proximity, and likely exposure, to such a wide range of natural gas resources. Historically, the region has been served primarily by sources from the GOM, and to a lesser extent, from Canada; these resources will likely continue to be available, albeit at much lower volumes, on a forward-going basis. A third new source of supply, discussed earlier from the Rocky Mountains region, will continue to provide the region significant volumes from both conventional and unconventional resources that were historically “stranded” in the Rockies, but have now found economic delivery opportunities in the northeast through the REX. A fourth area of opportunity is the exponentially growing production volumes that are “intra-regional” and produced in the Mid-Atlantic region itself in the broadly expansive Marcellus shale. A fifth set of resources is now emerging in the Great Lakes area (Atrium [Michigan]; and Utica [Ohio]) that could interconnect with the REX and provide even greater supply diversity and lower prices.

These are the natural gas resources against which offshore Mid-Atlantic production will have to compete. In fact, FERC reports that 2010 capacity flows on some major pipeline systems have changed direction and natural gas from the U.S. is now being exported to Canada via backhaul and, a number of Northeast pipeline projects have been proposed (FERC 2011). These opportunities have led to the announcement of a number of projects within the region to link emerging unconventional production with the various end-use markets of the Mid-Atlantic and northeastern region.

For instance, the Tennessee Gas Pipeline, a subsidiary of El Paso Corporation, recently proposed to develop what it is designating as the Northeast Upgrade Project, which will increase the capacity of Tennessee’s 300 Line in Pennsylvania by over one-half of a Bcf per day (636 MMcf per day) of incremental transportation capacity. This new intra-regional upgrade project will consist of an upgrade to Tennessee’s existing 24-inch diameter 300 Line by adding five, 30-inch diameter pipeline loops, in addition to a undefined upgrade of compression capacity at least four different existing compressor stations in the region. Tennessee anticipates making over a \$400 million investment to complete the Northeast Upgrade Project, and when complete, the new project is anticipated to greatly expand the company’s existing transmission capacity to meet the growing west-to-east gas flow discussed earlier (Tennessee Gas Pipeline 2011b).

Likewise, Dominion Transmission, in June 2010, announced that it entered into a 15-year firm transportation agreement with the gas production subsidiary of CONSOL. This new contract will help support, and provide some degree of longer term financial support, for Dominion's Northeast Expansion Project. The new contract will support over 200 MMcfd of capacity on the project and will collect CONSOL-produced natural gas from a variety of receipt points in the central and southwestern Pennsylvania areas of the Marcellus play to interconnections and storage facilities in Leidy, Pennsylvania. The project is expected to cost \$97 million, and will include new compression facilities at three stations in central Pennsylvania. Dominion filed its application with FERC in November 2010 and had a projected in-service date of November 2012 (SEC 2010b).

In 2010, Dominion Transmission announced a ten-year lease agreement with Tennessee Gas Pipeline for firm capacity on both its 300 Line system (under upgrade per above) and its 200 Line system. The 300 Line system brings gas into the Mid-Atlantic from western Pennsylvania, while the 200 Line system branches off and sends deliveries into New England. Dominion will construct a 150 MMcfd interconnection (Ellisburg-to-Craigs Project) that will connect the two systems increasing the amount of Marcellus-based natural gas that can enter into the system (PR Newswire 2010).

Lastly, FERC's 2011 State of the Market report noted that TransCanada has filed for a reduction in its long-haul rates in order to remain competitive with shorter-haul customers bringing gas from the Marcellus rather than the GOM or Canada (i.e., long-haul customers) (FERC 2011). FERC also noted in the same report that both Columbia Gulf Transmission and Tennessee Gas Pipeline have filed rate increase proposals, citing increased Marcellus production and the need to offer discounted long-haul rates from the Gulf Coast to compete (FERC 2011).

## **6.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

Production from the Mid-Atlantic OCS region will need to be transported to either an intermediate processing point or ultimately an end-use market depending on unknown gas quality issues from this new area. Most of the interstate natural gas transportation system along the East Coast has been developed to facilitate the movement of natural gas from its primary producing area (GOM) to market areas along the eastern seaboard. A number of the existing interstate natural gas lines, run along the Appalachian Mountain range and then progress northwards and eastward to New York. Currently, there are no natural gas interstate pipelines that run directly along the Atlantic seaboard, although Transco does have at least one line segment that runs from Mid-Virginia down close to the North Carolina coast and another that runs up to the northern New Jersey coast.

Future pipeline development along the Mid-Atlantic OCS is likely to be based on a series of line segment extensions from future coastal producing areas to the existing major trunk lines running along the Appalachian range. The overall investment level needed to link this production into the existing long-haul system will be a function of a variety of factors that include the volumes and economics of the gas production from the offshore Mid-Atlantic relative to production coming from the other five areas discussed earlier (i.e., GOM, Canada, Rockies, Marcellus, Great Lakes) in addition to imported sources by LNG regasification facilities

New natural gas transportation systems developed to accommodate new Mid-Atlantic OCS natural gas production are likely to be made up of a major trunk-line type segment for a large diameter pipeline (at or greater than 24 inches [61 cm]) that will directly connect into an existing major trunk line; more than likely the existing Transco system. The beginning of this system (upstream, production side) is likely to be interconnected into a series of smaller diameter pipes that connect individual offshore wells and structures to the new system. The size of the individual gathering lines, or gathering systems, will be a function of anticipated production from the area. The number of major trunklines and individual gathering systems will be determined, generally, by the scope and scale of Mid-Atlantic OCS production. Larger volumes produced in a concentrated geographic region are likely to see a fewer number of large trunk or gathering system configurations. Larger volumes produced over a broad geographic region will have a tendency to be smaller in capacity (diameter) but more numerous in terms of trunk and gathering segments.

As noted earlier, the likely configuration for new natural gas transportation systems along the Mid-Atlantic OCS will include (1) a major trunkline, and (2) a series of smaller gathering lines connected to the trunkline. This new configuration, in turn, will likely be connected into an existing long-haul transportation system that delivers to major end use markets. A new production to consuming area pipeline from the Mid-Atlantic production area to either the northeast, or even southeastern U.S., while possible, is unlikely.

Future pipeline development decisions can be thought of as having two components. First, where and at what point along an existing natural gas pipeline, will a major trunkline connection be developed? Second, where, and at what point will a gathering system be developed to connect the producing wells arising from Mid-Atlantic OCS development. The exact size, location and nature of this development cannot be answered at this time, but each component of a future development has a number of factors that will have to be considered before any infrastructure development scenarios.

There are a number of factors that will influence one, or a series of major trunkline developments that connect coastal production to the existing interstate system. These factors include:

1. Production location: pipeline developments cannot ignore their primary purpose of moving gas from point A to point B. Major pipeline segments generally tend to move from production areas to transportation segments moving gas to consumption areas. These systems' connections to the major interstate system can vary and are often influenced by many of the other considerations discussed below.
2. Distance: is related to location, but does differ and can be influenced by a number of factors such as geography, topology, bathymetry, and available right of way. The geography along the eastern seaboard, and its population density, differs considerably from the GOM, which is likely to lead to different prioritization of factors and pipeline siting outcomes.
3. Deliverability: an important commercial consideration in developing pipeline projects is maximizing its ability to facilitate a wide range of transactions across a range of different shippers (which can be producers or consumers, or both). Generally, pipeline companies will attempt to maximize the number of shippers on its system. In addition to linking new production to the interstate system, some new trunk line developments may also attempt to link new Mid-Atlantic OCS production to large, intermediate purchasers like power generations, manufacturing and industrial plants, and municipal gas systems and local distribution companies.
4. Supporting infrastructure: new line segments will also have to consider the degree to which supporting infrastructure such as compression, processing, and storage will be needed. Compression requirements are likely to be a function of the size and scope of the configuration and deliverability factors impacting development. Processing and storage considerations will be discussed in a later section of his memo.
5. Potential competition from other supply resources: as noted earlier, since 2008 there has been a dramatic paradigm-shifting development in gas production from shale-based geological formations. One of the more prolific opportunities for shale development is in the region referred to as the Marcellus shale play. This area spans the Appalachian region and runs as far north as New York State. A significant amount of production from this area is anticipated to arise and will compete with Mid-Atlantic OCS production for incremental pipeline capacity and access to northeastern markets. In addition, over the past five years, pipeline developments linking western (Rockies) production to eastern markets have materialized. This new source of additional production will also create some new market opportunities for Mid-Atlantic OCS gas production. Further, new shale resources in the Great Lakes region are likely, at some point in the future, to see development and transportation into the Northeast. Last, there are a large number of LNG regasification facilities that have seen development or expansion over the past several years. These facilities will also be a source of competition with Mid-Atlantic natural offshore gas production.

Figure 67 presents a preliminary analysis of the distance an offshore pipeline would need to traverse to facilitate production identified in the Five Year Lease Plan released in August 2006. Figure 22 provides a similar analysis, but assumes a hypothetical interconnection further south, into the high growth markets of the southeast (particularly Florida) and as a way to avoid shale production competition. Both diagrams are presented for illustrative purposes, and are not intended to represent the paths future transmission lines will take.

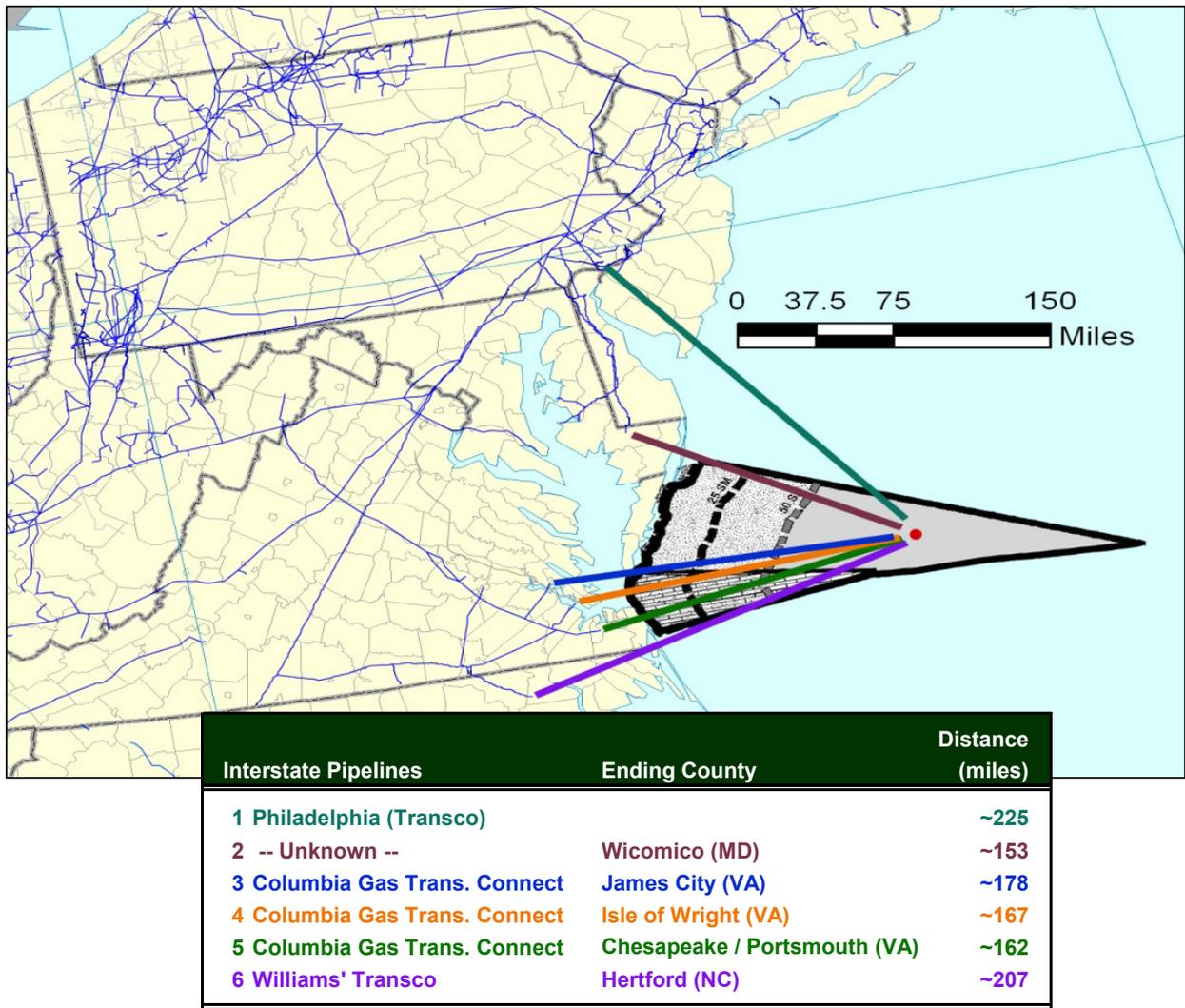
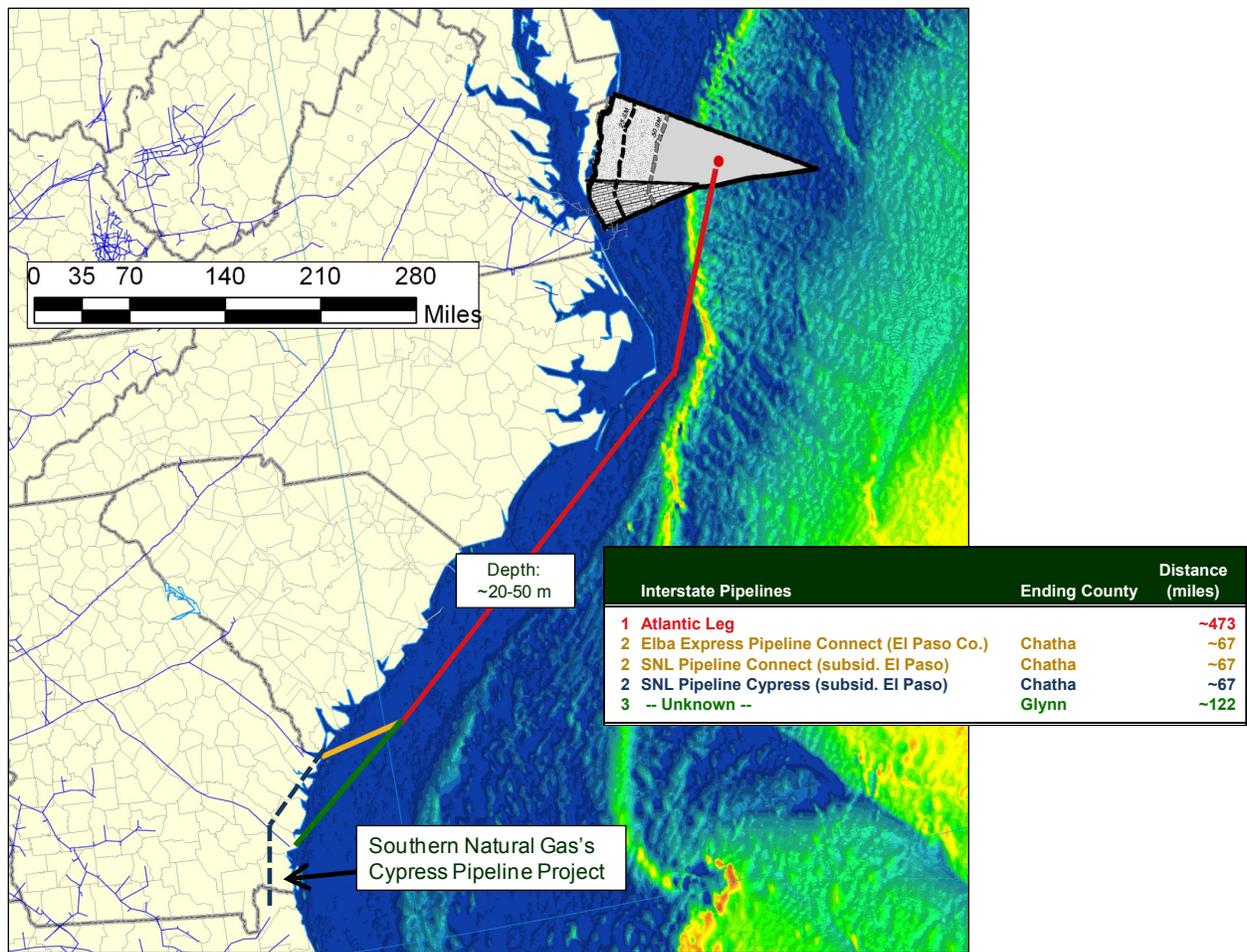


Figure 67. Mid-Atlantic coast interstate natural gas pipelines, location analysis.



**Figure 68. Mid-Atlantic coast interstate natural gas pipelines, location analysis, Southeast focus.**



## **7 PIPE COATING**

### **7.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED**

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

Pipeline integrity may be compromised by corrosion, natural forces (earthquakes, landslides, lightning, heavy rain, floods, mudslides, frost heave, frozen components), excavation, material defects or equipment malfunctions (OPS 2011). The most common threat is corrosion. Corrosion occurs when an electrical current flows from a pipe into the surrounding soil, causing metal loss, or corrosion. One way to arrest the corrosion process is to insulate the metal from the soil, or coat the pipe (Folga 2007). Because coatings are the first line of defense in protecting pipes from corrosion, they must be well bonded, continuous, and able to resist the effects of their environment.

To be effective, pipe coating must have several properties, including (Kennedy 1993):

- ease of application;
- adheres well to pipe;
- resistant to impact
- flexible;
- resistant to soil stress;
- resistant to water;
- resistant to electricity;
- chemically and structurally stable; and
- resistant to bacteria, marine organisms and cathodic disbondment.

### **7.2 TYPICAL FACILITY CHARACTERISTICS**

Pipe coatings are usually applied before the pipe is delivered to the installation site. Coating mills apply pipe coatings to protect the line pipe from corrosion once it is laid in the ground. Coating mills are often located adjacent to the pipe mill, so line pipe moves straight from the manufacturing line to the coating facility (INGAA 2012). At the construction site, the coating is rechecked for imperfections or damage that could occur during transportation. When pipe lengths are coated and wrapped at a coating yard, a short length at each end of the pipe is left bare so the joints can be welded together. A new coating is then applied at the welded joints by sandblasting the weld and applying a new layer of coating (Folga 2007).

Pipe coating can also be done at the job site. Individual lengths of pipe are first welded together and the pipeline is suspended over a trench. Special machines then move along the pipe to apply coating to the pipe and welds. Tape is wrapped over the coating by a tape machine in a spiral. The wrapping machine maintains tension on the tape so that it fits tightly over the coating (Kennedy 1993).



**Figure 69. Pipeline coating applied over the installation site.**

Source: Protection Engineering 2012.

### **7.2.1 Coatings**

Several different types of pipe coatings are available to protect pipe. In the past, pipeline companies coated pipe with a variety of different coatings such as coal tar enamels, asphalt enamels or an enamel tape wrap (INGAA 2012). Today, the most widely used coating is a fusion bond epoxy (FBE) coating or an extruded polyethylene (Guan et al. 2005; and Folga 2007). FBE coating is light blue in color and can often be seen on pipe being transported by rail or truck.

#### ***Fusion bonded epoxy***

Fusion bonded epoxy coating is also known as powder coating or FBE coating and has been one of the primary coatings chosen for pipelines because of its durability, corrosion protection properties and ease of application (CCSI 2012).

To prepare for FBE coating, the external surface of the pipe is cleaned with a shot-blast process. The pipe is then heated to a set temperature (450°F-500°F). Three heating methods can be used: (1) electrical induction; (2) gas fired forced air; or (3) a combination of high velocity direct flame impingement and infrared (Thermacor 2008). After the pipe is heated, it passes through a powder coating machine where the epoxy powder is electrostatically applied (Bayou Companies 2012a). The powder melts onto the heated pipe forming a water tight barrier. Before the pipe is transported to the job site, it is both visually inspected and tested with high voltage electricity to evaluate the coating's insulating effectiveness (CCSI 2012; and Folga 2007).

### ***Three-layer polyolefin (3LP)***

Second in use to FBE applications, the three-layer polyolefin coating consists of an FBE primer, a polyethylene (PE) or polypropylene (PP) adhesive layer and a top coat of PE or PP. During the 3LP process, first a primer of FBE is applied to protect the integrity of the steel. Then, adhesive is applied the PE or PP to the FBE (Bayou Companies 2012b).

One disadvantage of 3LP is the possibility of disbondment. Disbondment of 3LP applications can hinder the current of cathodic protection and expose the pipeline to environmentally induced cracking (Guan 2010).

### ***Internal diameter coatings***

Internal diameter (ID) coatings create a smooth, defect free surface on the inside of a pipe and are used to improve the flow of gas through the pipeline. ID coatings also: (1) help to reduce wax and hydrate formation; (2) act as an insulator on electrically heated pipe-in-pipe to reduce pipe maintenance and make pipeline inspection easier; (3) are used in potable water applications (Bayou Companies 2012c).

### ***Concrete weight coating***

Concrete weight coating (CWC) is coating used to provide negative buoyancy (a weight greater than the buoyant force of the water) for offshore pipelines or for river or road crossing applications (Bayou Companies 2012d). A mix of cement, iron ore and wire wrap is used in combination with other coating systems, such as FBE.

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

1. 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 GOM in the late 1940s.
2. 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.
3. Protection of anticorrosion coating: All presently used techniques of anticorrosion coating are subjected to damage when exposed to trawl gear or trailing cables.

### **7.2.2 Cathodic Protection**

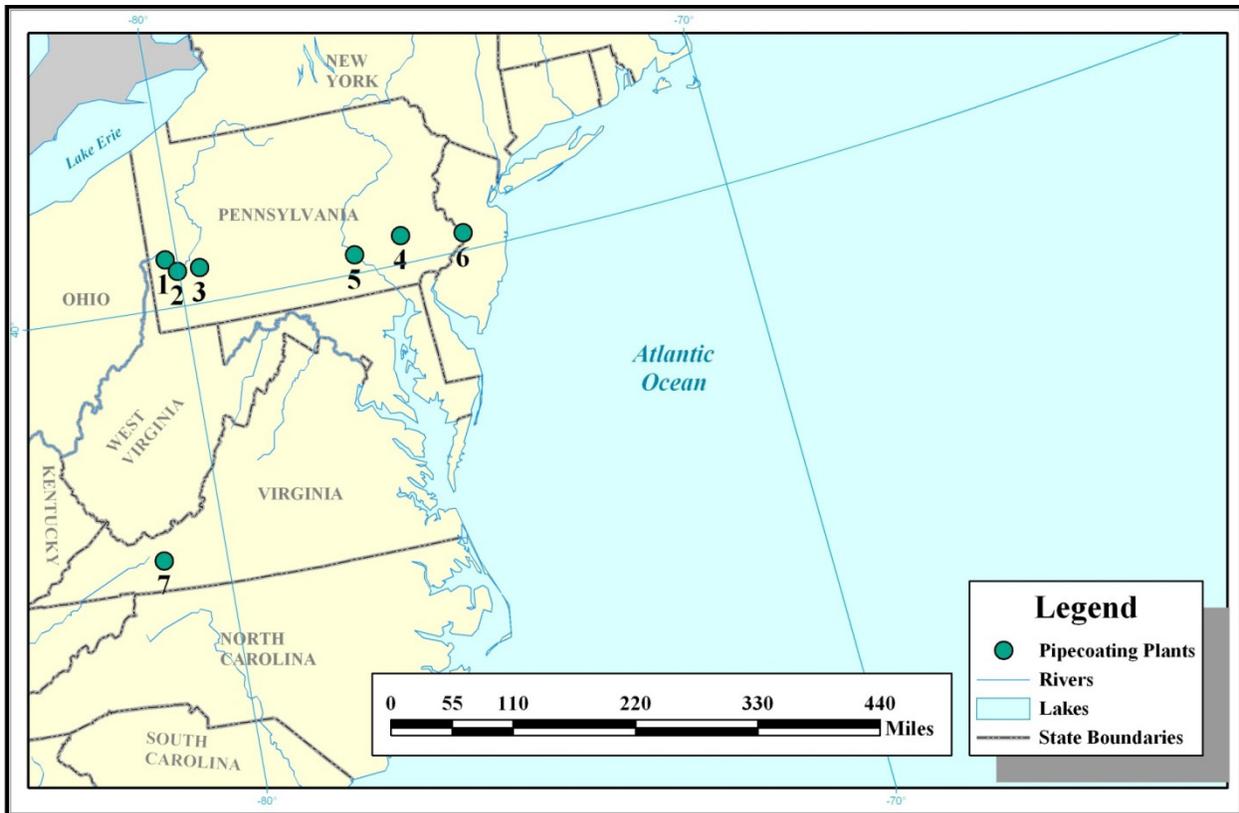
Cathodic protection is a method for preventing corrosion in metal by using electric voltage to prevent or slow the corrosion process. It is used along pipelines, underground storage tanks, ship hulls, water treatment facilities, bridges and steel pilings. In a cathodic protection system, anodes are installed and an electric current flows through the soil between the pipe and the anodes. The pipeline becomes the cathode of the system and corrosion is decreased. The anodes are the part of the system that is corroded, or sacrificed.

The magnitude of the currents in a cathodic protection system depends on several factors including: the temperature, moisture content and concentration of salts in the soil; the chemical constituents of the soil; distance between anode and cathode; and surface areas of the anode and cathode (Kennedy 1993).

Pipeline coatings today are routinely supplemented with cathodic protection. In fact, in 1971, the Department of Transportation passed Federal legislation requiring that all oil, gas and gas products pipelines be cathodically protected. The Code of Federal Regulations (CFR 2012c) requires all buried metallic pipe installed after July 31, 1997 must be coated and have a cathodic protection system designed to protect the pipe in its entirety. A system with cathodic protection must also be monitored and tested annually for effectiveness.

## **7.3 GEOGRAPHIC DISTRIBUTION**

Seven companies have been identified in the Mid-Atlantic impact region states (six in Pennsylvania, one in Virginia). However, all of these facilities are located inland in the Appalachian region, not along the coast or port facilities.



Company	City	State
1 Liberty Coating Company	Morrisville	PA
2 Dura-Bond Coating Inc	Export	PA
3 Dura-Bond Coating Inc	McKeesport	PA
4 Dura-Bond Coating Inc	Steelton	PA
5 IPSCO Tubulars Inc	Ambridge	PA
6 Rohm and Haas Chemicals LLC	Reading	PA
7 Rohm and Haas Chemicals LLC	Wytheville	VA

**Figure 70. Mid-Atlantic impact region pipe coating facilities.**

Liberty Coating Company, LLC provides industrial coatings for the oil, gas and water industries. It is located on 35 acres with six coating buildings that cover over 110,000 square feet (10, 219 square meters). The Company offers a number of coating options, including a proprietary coating system called Pritec®. This is a dual layer coating system that uses butyl rubber adhesive and polyethylene. The two materials are heated and applied through a dual-extrusion process. Pritec® protects pipe with a firmly bonded, damage resistant coating and can be applied to pipe ranging in diameter from ¾" to 144" (Liberty Coating 2012).



**Figure 71. Liberty Coating storage yard.**

Source: Liberty Coating 2012.

Durabond Coating has three locations in Pennsylvania. Durabond's focus is on the Marcellus Shale region and offers a number of products for corrosion protection: fusion bond epoxy; X-Tec extruded polyethylene; dual layer fusion bond; Powercrete® abrasion resistant overcoating; tape systems; and internal linings (Durabond 2012). Dura-Bond also uses protective paint and coating systems to non-fabricated structural steel such as pipe piling, steel piling and H-Beams for the construction market (Durabond 2012).

TMK IPSCO is on the Ohio River, adjacent to both rail lines and river barge facilities. It is one of the largest producers of welded and seamless pipe and premium connections in North America. The Ambridge, Pennsylvania plant is responsible for manufacturing IPSCO's seamless tubular products. The facility has an annual capacity of 260,000 tons (TMK IPSCO 2012).



**Figure 72. IPSCO Tubulars, Ambridge, Pennsylvania.**

Source: IPSCO 2012.

Rohm and Haas is a subsidiary of the Dow Chemical Company. The Company was founded over 100 years ago and was originally established to sell Rohm's invention that created a superior leather bate. Rohm and Haas products include not only pipe coatings, but plastic additives (bottles, window frames, car bumpers), other acrylic coatings (soft drink cans, structural steel and cabinets), emulsion products (for paints and polishes), and monomers and acrylates (a foundation of products used in resins, coatings, floor care and aircraft windows) (Dow 2012).

#### **7.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY**

Though a few companies have been identified in Pennsylvania and Virginia, there is no drilling activity off of the Mid-Atlantic Outer OCS, and it is likely these companies are mostly serving oil and gas operations in the Appalachian region.

Similarly, there are no useful NAICS codes or industry data to use to analyze the contribution of the support economy to the area. Pipe coating services are likely included under NAICS code 332812, "Metal Coating, Engraving (except Jewelry and Silverware), and Allied Services to Manufacturers." This sector includes establishments primarily engaged in one or more of the following: (1) enameling, lacquering, and varnishing metals and metal products; (2) hot dip galvanizing metals and metal products; (3) engraving, chasing, or etching metals and metal products (except jewelry; personal goods carried on or about the person, such as compacts and cigarette cases; precious metal products (except precious plated flatware and other plated ware); and printing plates); (4) powder coating metals and metal products; and (5) providing other metal surfacing services for the trade (USDOD, CB 2002). Therefore, the economic contribution of this sector has not been estimated.

#### **7.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY**

The pipe coating industry is dependent on the oil and gas industry, and changes within the pipe coating industry are often spurred by changes and needs in oil and gas exploration and production. Pipe coatings have evolved from simple coal-tar applications to sophisticated fusion-bonded epoxies and polypropylene coatings. Companies continue to try new, cost-effective methods and materials in the battle against corrosion and extreme environmental effects. The advantages and disadvantages of each type of coating need to be considered in the development of different coating products.

According to the industry, technology and environmental trends are pushing product innovation to meet client needs. For instance, when selecting pipe materials for deepwater installations, fatigue is a critical element that must be considered. Also, the installation of export lines and flowlines is an expensive and risk-intensive procedure. One company uses a double jointing facility, where line pipe is pre-assembled at the mill, then coated with anti-corrosion or thermal insulation. The pipe and materials arrive at the site ready to be installed, which decreases offshore welding time significantly. Even the anti-corrosion anode pads can be attached before applying protective coatings, thereby reducing installation time even further (Tenaris 2012a).

As the oil and gas industry continues to push the boundaries of exploration, the pipe coating industry will need to be able to adapt and innovate to changing needs. Most of the developments in pipe coating technologies are found through a specific company's research and development. The largest companies have the greatest amount of capital and funds to conduct this type of research. For example, Tenaris is one of the world's leading suppliers of pipe and has research centers in Argentina, Italy, Japan and Mexico (Tenaris 2012b).

The outlook for the pipe coating industry is strong, yet also competitive because companies vie for market share while trying to keep pace with advances in technology. The market for steel pipe is highly competitive, with primary competitive factors being price, quality, services and technology (Tenaris 2011). Industry participants must focus on timely and efficient applications and offer solution-based services. Research and development will continue to play a major role in the pipe coating industry, particularly as environmental regulations become more stringent and the oil and gas industry moves into deeper waters.

### **7.5.1 Regulatory Changes**

Pipe coating industry is not economically regulated like other segments of the natural gas industry, but pipe coating techniques have to meet industry standards and specifications as established by the Department of Transportation and recommended by the National Association of Pipe Coating Applicators (NAPCA).

Sections 195.557 through 195.561 of the Code of Federal Regulations (CFR) list the requirements for external coatings for pipelines:

- Each buried or submerged pipeline must have an external protective coating for external corrosion if the pipeline is:
  - Constructed, relocated, replaced or otherwise changed after the applicable date;
  - Has an external coating that substantially meets allowable coating before the pipeline is placed in service;
  - Is a segment that is relocated, replaced, or substantially altered.
- 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.
- Allowable coating materials for external corrosion control include material that is:
  - Designed to mitigate corrosion of the buried or submerged pipeline
  - Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
  - Sufficiently ductile to resist cracking;
  - Has enough strength to resist damage due to handling and soil stress;
  - Supportive of any supplemental cathodic protection;
  - If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

Regulations for cathodic protection systems are also included in Sections 195.563 and 195.567. A cathodic protection system must be installed for all buried or submerged facilities to mitigate corrosion that might result in structural failure. A cathodic protection system must be installed not later than 1 year after completing the construction. Except for offshore pipelines, electrical test leads used for corrosion control is required for all buried or submerged pipeline or segment of pipeline. Requirements for how to test are described in the code.

### ***External Corrosion Control***

According to the CFR, every pipeline operator must conduct tests annually on any pipe that is buried, in contact with the ground, or submerged, to determine whether the cathodic protection is adequate. Also, operators must inspect any bare pipe that is not cathodically protected and study leak records for that pipe to determine if additional protection is needed. This needs to be done every three years. Whenever buried pipe is exposed for any reason, the operator must examine the pipe for evidence of external corrosion. If active corrosion is found, the area should be reviewed for leak and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

### ***Internal Corrosion Control***

Pipeline operators may not transport hazardous liquid or carbon dioxide that would corrode a pipe or other components of a 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, these inhibitors should be used in sufficient quantity to protect the entire part of the system. Monitoring equipment must be examined twice a year to determine the effectiveness of inhibitors or the extent of any corrosion.

If any pipe is removed from the pipeline, the internal surface must be inspected 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 adjacent pipe must also be inspected. 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.

Corrosion control information must be maintained and maps must be kept of cathodically protected pipelines, for cathodic protection facilities installed after January 28, 2002. The required information includes a stated number of anodes, records of each analysis, inspection, investigation, review, survey, and test required by the statute in sufficient detail to demonstrate the adequacy of corrosion control measures or to indicate that corrosion requiring control measures do not exist.

## **7.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

Business is strong for some of the pipe coating facilities in the Mid-Atlantic impact region states. Dura-Bond Industries for instance, cut its staff by 30 percent during the recession, but is now hiring 75 workers for a new planned facility in Duquesne, Pennsylvania (Davidson and Hansen 2012). The company was recently awarded the entire pipe manufacture and corrosion coating responsibilities for the Marc 1 Pipeline (DuraBond 2012). The pipeline, owned by Inergy Midstream, L.P. is a 39 mile, 30 inch bi-directional gas pipeline connecting Inergy's Stagecoach South Lateral pipeline interconnect at Tennessee Gas Pipeline's (TGP) 300 line to Transco's Leidy Line (Inergy 2012).

As gas production in the Marcellus shale region continues to expand, so will business for these facilities. The probable increase in unconventional natural gas production from the Marcellus Shale areas will likely increase the amount of gas transported in this area, potentially to levels that rival (conventional) prolific supply basins like the GOM. In addition, the undeveloped eastern portion of the Marcellus Shale could extend as far east as parts of Virginia, eastern Pennsylvania, and Maryland, possibly creating new onshore resources and pipeline investments.

## **7.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

All existing pipe coating facilities in the Mid-Atlantic impact region states are in the Appalachian region. Under a limited or moderate development scenario, it is likely that coated pipe would come from these existing facilities, or the GOM region.

Under a limited offshore development scenario, it is most likely that pipe coating services would be provided by the GOM region. Coated pipe would be shipped or delivered by rail or truck to Mid-Atlantic impact regions. Industry consolidation and economy of scale associated with large coating operations may offer further support for this outcome. At this point, we do not anticipate any new pipecoating or fabricating facilities being developed along the Mid-Atlantic. It is likely that existing regional facilities may see some expansion, some are showing indications of increased orders given the rise in Marcellus production, and new pipeline projects bringing gas from the Rockies into the Midwest and Appalachian area.

## 8 NATURAL GAS PROCESSING AND STORAGE

### 8.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED

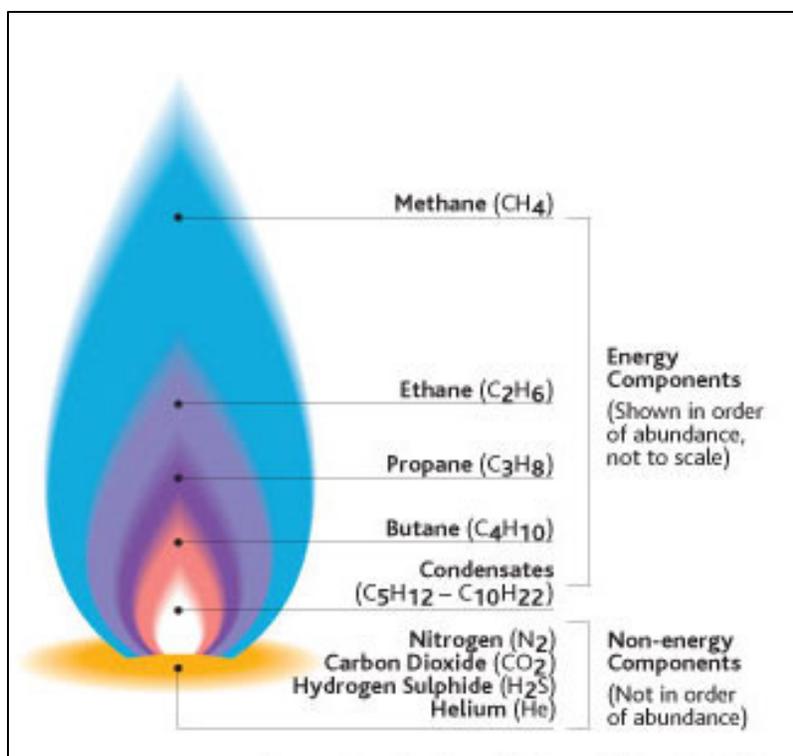
#### 8.1.1 Natural Gas Processing

Natural gas, typically produced from a reservoir rock, is a mixture of light hydrocarbon gases, impurities and liquid hydrocarbons. Natural gas processing is used to remove the impurities and separate 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. This type of gas is produced along with crude oil from oil wells 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. As of 2004, this gas-well gas or dry gas is about 75 percent of all U.S. natural gas (USDOE, EIA 2006b).
- *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 the 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 made up of methane (the lightest hydrocarbon component) and ethane. Figure 73 shows the common components of a natural gas production stream.



**Figure 73. Common components of natural gas.**

Source: Canadian Centre for Energy Information 2009.

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 found in this liquid has no value; however, the remaining portion of the wet gas may contain five or more gallons of recoverable hydrocarbons per thousand cubic feet (Berger 1992). When natural gas does not contain enough of the heavier hydrocarbon molecules to form a liquid at the surface, it is classified as 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 or even fatal to breathe (Berger 1992).

Hydrocarbons have distinctive weights, boiling points, vapor pressures and other physical properties that make their separation from each other possible.<sup>13</sup> 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 (Berger 1992). Processing cleans natural gas so that it is in a useable form, but also provides numerous hydrocarbons to other distinct markets for use.

<sup>13</sup> A boiling point occurs at a combination of temperature and pressure, where the vapor pressure of a liquid is equal to the pressure being exerted on it.

### 8.1.2 Natural Gas Storage

In order for the natural gas market to operate efficiently, there must be some capability to store natural gas. Gas storage provides three services to facilitate this efficiency: base-load storage to meet seasonal demand; peaking storage to meet short-term demand peaks; and price arbitrage (hedging) to take advantage of changes in volatile natural gas prices between peak and non-peak usage periods. There is generally a cyclical up and down pattern in the volume of gas being stored throughout the year. This occurs as gas is withdrawn during peak periods of high utilization (winter) and gas is stored during low utilizations periods (April through October).

The two principal functions of natural gas storage are: base-load storage and peaking storage. Base-load storage is used to meet seasonal demands for gas, while peaking storage is utilized to meet short-term peaks in demand. Natural gas demand commonly has peaks which can range from a few hours to a few days. Specifically, the injection season typically occurs between April and October, when natural gas demand is low and underground natural gas storage facilities are filled to prepare for and meet seasonal base-load requirements during the fall and winter peak usage from November to March. This withdrawal season, uses natural gas that has been in storage to supplement domestic production and imports during this high demand period. Note, however, that, in addition to the traditional withdrawal season, recent increases in the amount of gas fired power generation have caused significant daily variance in the amount of natural gas being used, even during summer months.

In the absence of underground storage, there would be a need for larger capacity investments in pipeline systems, to the detriment of customers. Pipeline operators would need to construct additional pipelines, or larger pipelines, to meet peak localized demands during winter months. Market participants, shippers for example, would have to pay capacity fees to utilize these assets, which would likely be idle for large periods of time throughout the year. Storage provides a great benefit passed along to customers, as opposed to increased pipeline capacity, of lower rates and more reliable service.

Another benefit of underground storage comes from the ability to meet new regulatory and market requirements. Natural gas markets are very competitive and storage facilities have evolved to be varied and complex value-added services that create opportunities for competitive sales revenues. The historic regulatory functions of storage to offer simple back-up and balancing services on a cost-of-service basis are no longer the only norm. Today, underground storage services also facilitate (FERC 2004):

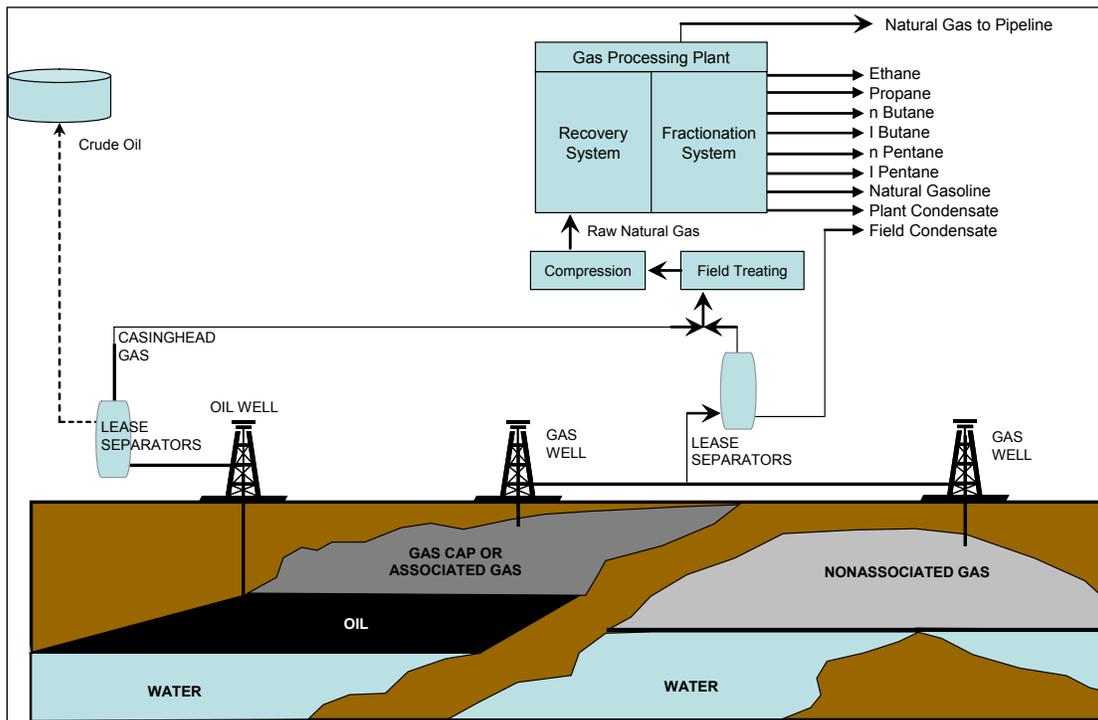
- Daily nomination changes, parking and lending services, and simultaneous injections and withdrawals.
- Avoidance of imbalance penalties.
- Liquidity at market centers to limit price volatility.
- Arbitrage gains from seasonal and regional differences in gas prices, thus creating trade opportunities.
- Price risk management for regulated natural gas and electric utilities, and large industrial customers that can contract directly with storage operators or indirectly through marketers.

- Competitive electric generation markets by providing quick service to natural gas-fired generation facilities that provide power during load fluctuations in any given day, hour, or season.

## 8.2 TYPICAL FACILITY CHARACTERISTICS

### 8.2.1 Natural Gas Processing

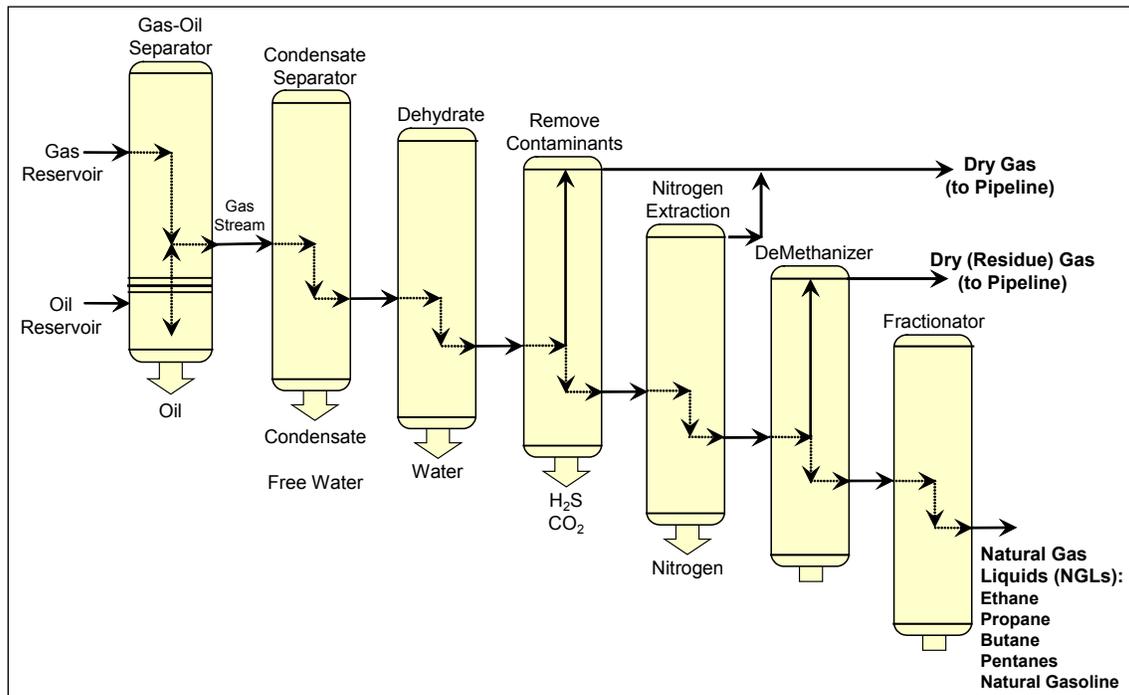
Natural gas must be processed to remove water vapor, solids, and other contaminants that would interfere with pipeline transmission or marketing of the gas. The most common contaminants are water, hydrogen sulfide, carbon dioxide, nitrogen, and helium. In general, natural gas processing plants are centrally located so that they can serve multiple fields. Processing plants provide two main services: to remove essentially all impurities and to separate the gas into its useful components for eventual distribution to consumers. This general process is depicted in Figure 74.



**Figure 74. Natural gas processing.**

Source: GPA 2004.

Because the composition of the raw natural gas depends on the characteristics of the underground deposit and area geology, the number of steps and exact methods used to create pipeline-quality natural gas differ across different processing facilities. The general steps in processing are presented in Figure 75; however, in some cases, some steps may be combined, performed in a different order, or not at all.



**Figure 75. General natural gas processing schematic.**

Source: USDOE, EIA 2006b.

Figure 75 depicts the multiple stages involved in the processing and treatment of natural gas (USDOE, EIA 2006b):

- *Gas-Oil Separators:* Natural gas is often found with crude oil, and, while sometimes pressure relief at the wellhead naturally separates the gas from oil (using a conventional closed tank where gravity separates the gas hydrocarbons from the heavier oil), at other times a multi-stage gas-oil separation process is necessary. Generally these gas-oil separators are formed from closed cylindrical shells which are mounted horizontally with inlets at one end and outlets on the top and bottom for removal of gas and oil, respectively. The process separates gas from the flow stream through multiple steps of compression heating and cooling. If there is water or condensate, some of this is also removed during this separation process.
- *Condensate Separator:* In most circumstances condensates are removed from the gas stream at the wellhead by using mechanical separators. Because the gas-oil separation process is often unnecessary, gas generally flows directly from the wellhead and enters the processing plant at very high pressure (600 pounds per square inch gauge (psig) or greater). This highly pressurized gas enters through an inlet slug

catcher where free water is removed from the gas and sent to a condensate separator. From here, the gas is routed to storage tanks on site.

- *Dehydration:* The dehydration process is the removal of water from produced natural gas, and is required to eliminate water which may cause hydrates to form. Hydrates form under certain temperature and pressure conditions if there is free water present in a gas or liquid. There are several available methods to dehydrate the natural gas such as ethylene glycol systems or adsorption dehydration. Ethylene glycol (glycol injection) systems can be used as an absorption mechanism to remove water and other solids from the gas stream. The adsorption method uses dry-bed dehydrator towers, which contain desiccants (such as silica gel or activated alumina), to extract water. The distinction between adsorption and absorption is an important one: adsorption is the binding of molecules or particles to the surface of a material, while absorption is the filling of the pores in a solid. The binding to the surface is weak with adsorption, and therefore, usually easily reversible (USDOE, EIA 2006b):.
- *Contaminant Removal:* The gas stream can contain many contaminants, such as hydrogen sulfide, carbon dioxide, water vapor, helium, and oxygen. The most common technique used for contaminant removal directs the flow of gas through a tower containing an amine solution. Amines are useful because they can be reused and they absorb sulfur compounds from natural gas. The next processing step utilizes the different gravities of contaminants and gas. As the gas flows more slowly through a series of filter tubes, the remaining contaminants separate into individual tubes. For instance, the smaller particles fall out as the gas passes through, combine to become larger components and then flow into the lower section of the unit. As the stream of gas moves through the series of tubes, a centrifugal force is generated which removes any remaining water and small solid particulate matter.
- *Nitrogen Extraction:* After contaminant removal, the gas stream is sent to a Nitrogen Rejection Unit (NRU). The NRU further dehydrates the natural gas using molecular sieve beds. After passing through a brazed aluminum plate fin heat exchanger, the nitrogen is cryogenically separated and vented from the stream. There is another NRU method which separates methane and heavier hydrocarbons from nitrogen using an absorbent solvent. Then, the pressure on the processing stream is reduced in multiple decompression steps to flash off the methane and heavier hydrocarbons. Last, the liquid from this flash regeneration step is returned to the top of the methane absorber as lean solvent. If helium is present, it can be extracted by using membrane diffusion in a Pressure Swing Adsorption (PSA) unit.
- *Methane Separation:* Methane separation can occur as part of the NRU operation or independently within the gas plant. Demethanizing the gas stream from natural gas liquids (NGLs) can be done by cryogenic processing and absorption methods. Cryogenic methods, lowering the temperature of the gas stream to around -120 degrees Fahrenheit, are better at extracting lighter liquids such as ethane. The quick temperature drop condenses the hydrocarbons while still maintaining methane's gaseous form. Alternatively, the absorption method uses a "lean" absorbing oil to separate the methane from the NGLs when the gas stream passes through an absorption tower. The enriched absorption oil with the NGLs is disposed through the

bottom of the tower, fed into distillers and heated to above the boiling point of the NGLs, but to a point where the oil remains in liquid form. The oil is recycled while the NGLs are cooled and sent to the next phase of processing. One other methane separation method of absorption refrigerates the lean oil instead of heating it, which actually increases recovery rates.

- *Fractionation:* The final stage presented in Figure 75, fractionation, is the process of separating the remaining NGLs present in the gas stream into their respective components. In the same way as methane separation, the stages of fractionation use the different boiling points of individual hydrocarbons to separate them. The gas stream is sent to multiple towers with heating units to heat and then siphon off the various liquids into specific holding tanks as they are turned to gas. The liquids contained in the separate holding tanks can be sold as individual commodities for energy feedstock purposes along the Gulf coast.

The natural gas processing industry includes a range of companies: fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-regulated affiliates, financial institutions with trading platforms, and independent processors (SEC 2011h). Each company type has varying levels of financial and personnel resources. Competition in the market generally revolves around the quality of customer service, price and fees, and location (SEC 2011h). These factors are also important in the storage market, with the addition of the number of pipeline connections available and operational dependability.

Enterprise Products Partners (EPP) is an integrated midstream company with many diverse assets that include natural gas gathering, processing, transportation and storage; NGL fractionation (or separation), transportation, storage; crude oil transportation; offshore production platform services; and petrochemical pipeline and services. EPP is one of the largest natural gas processors in North America and owns 24 processing plants located in Colorado, Texas, Louisiana, Mississippi, New Mexico, and Wyoming (SEC 2011h). Figure 76 depicts one such plant. They process natural gas and sell the NGL byproducts, but state “when operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, the recovery levels of certain NGL products, principally ethane, may be reduced or eliminated” (SEC 2011h). This is problematic because it will likely lead to a reduction in NGL volumes available for fractionation and transportation. EPP also owns 14 Bcf of natural gas storage capacity in salt dome caverns.



**Figure 76. Enterprise natural gas processing plant.**

Source: USDOE, OFE 2006.

The largest NGL producer in North America and another large integrated midstream company is DCP Midstream. DCP Midstream collects natural gas through 62,000 miles (99,779 kilometers) of pipe, where it is processed at 61 owned or operated plants in Colorado, Kansas, Oklahoma, Texas, Louisiana, and New Mexico. They also own or operate 12 fractionating facilities and a 9 Bcf storage facility. The storage facility is used for residue gas before it is sold to marketers and end users (large industrial customers and natural gas and electric utilities) (DCP Midstream 2012). DCP Midstream's equity interests also consist of a 50 percent ownership interest of Spectra Energy and its Affiliates, 50 percent ownership interest of ConocoPhillips and its Affiliates, and DCP Midstream Partners, LP (DCP Midstream 2012).

Targa Resources is another significant provider of midstream natural gas and NGL services such as gas gathering, processing, treating, fractionation, storage terminaling, and transportation. The processing facilities owned or operated by Targa Resources are located in Louisiana and Texas. In fact, the majority of Targa Resources' assets are located throughout producing basins in the those states, primarily in the Permian Basin in west Texas and southeast New Mexico, the offshore region of the Louisiana Gulf Coast, and, through the Partnership, the Fort Worth Basin in north Texas, the Permian Basin in west Texas, and the onshore region of the Louisiana Gulf Coast. Terminal assets are located throughout the United States, even in the north east, with one in Maryland, New Jersey, and Massachusetts. Targa's processing plants include 22 facilities that it owns or operates. In 2011, they processed an average of approximately 2.16 Bcf per day of natural gas and produced an average of approximately 124 million barrels per day of NGLs (SEC 2011i).

## 8.2.2 Natural Gas Storage

Natural gas is stored under pressure in three types of underground storage facilities (Figure 77):

1. Depleted reservoirs in oil or gas fields;
2. Aquifers; and
3. Salt cavern formations.

A small amount of natural gas is also stored above ground in tanks in liquid form. All three types of underground natural gas storage need access to a transportation pipeline, but beyond this similarity there are major differences even within a category. The geological and engineering properties of underground sites are the most important considerations when developing or expanding underground storage. A few examples of relevant characteristics are size, cushion gas requirement, access to transportation pipeline, markets, and gas production sources. In addition, each type of storage facility has its own physical characteristics that include porosity, permeability and retention capability. Each type of storage facility also has its own economic characteristics that include capacity development costs, location, deliverability rates and cycling capability.

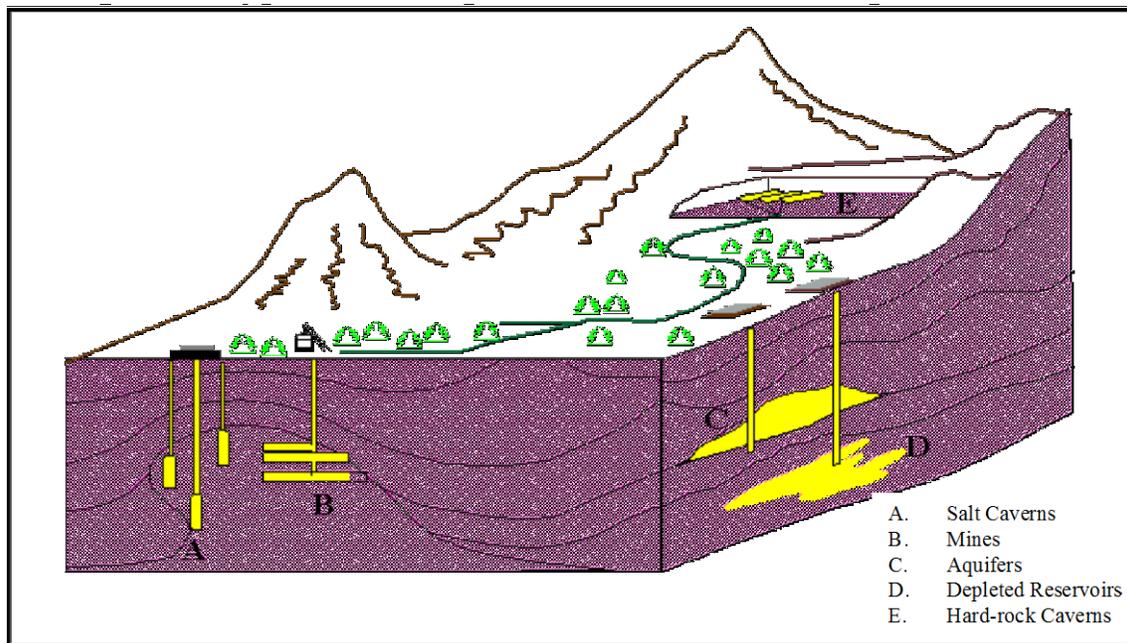
Cushion gas is the term used to describe the minimum amount of gas necessary to maintain operating pressures in an underground storage facility. The higher the cushion gas requirement, the more expensive the facility, due to the amount of valuable gas which is not useable outside of storage. In this regard, salt caverns have an advantage in having the lowest cushion gas requirement of all underground storage types, as can be seen in Table 25. This advantage persists even though cushion gas is also required to maintain the integrity of salt caverns. However, reservoir storage is significantly cheaper on a capacity-developed basis due to the higher start-up cost of salt caverns. All characteristics should be considered in determining which option is the best in any given situation.

The flexibility of injections has become an important characteristic to consider when developing an underground storage facility. Since today's markets are increasingly competitive and fast paced, in some situations the ability to quickly withdraw and deliver stored gas translates into higher revenue. In the past, this was less important because the main function of the storage market was to provide gas during times of high seasonal demand. The needs of today still include seasonal demand; however, there are frequent needs which should be addressed immediately: like an injection request to a LNG tanker arriving to offload supplies. The complement to injection capacity is deliverability: the amount of gas that can be withdrawn daily from a storage facility. High deliverability is also vital in today's market environment (USDOE, EIA 2004).

**Table 25. Characteristics of underground storage.**

Storage Facility Type	Number of Active Fields*	Cushion Gas Ratio	Injection Period (days)	Withdrawal Period (days)	Injection / Withdrawal Flexibility
Depleted Reservoir	331	50% to 80%	200 to 250	100 to 150	Low
Aquifer	43	50%	200 to 250	100 to 150	Low
Salt Cavern	37	20% to 30%	20 to 40	10 to 20	High

Note: \*Number of active fields is as of 2010.  
 Source: USDOE, EIA 2012d; and FERC 2004.



**Figure 77. Types of underground natural gas storage facilities.**

Source: USDOE, EIA 2004.

While salt cavern storage provides considerable advantages in today’s market, most gas is stored in depleted oil and gas reservoirs. In fact, salt caverns make up the smallest number of underground storage types in the U.S. More detailed descriptions about each type of facilities are provided below.

### ***Depleted Reservoir***

Depleted reservoirs make up 81 percent of natural gas storage facilities in the U.S., making this the most commonly used form of underground natural gas storage (USDOE, EIA 2012d). Depleted reservoirs are geological formations that once held oil or natural gas, but have since been tapped out, or depleted. These formations can take advantage of surface facilities, gathering systems and pipeline connections that are already on site. In general, approximately 50 percent of depleted reservoir contents are working gas. Depleted reservoirs are the cheapest, easiest to develop and operate, and the easiest to maintain (FERC 2004, NaturalGas.org 2012b).

In order for a reservoir to be suitable for gas storage it must have the appropriate geographical and geological characteristics. Two geological characteristics are important for a depleted reservoir to be effective in natural gas storage: high permeability and porosity. Permeability is the rate at which gas flows through the formation, and as such determines the rate of injection and withdrawal of working gas. High porosity equates to higher amount of gas that can be held (NaturalGas.org 2012b).

Most depleted reservoirs are near regions which consume natural gas and have well-developed pipeline and transportation infrastructure (USDOE, EIA 2004). Most important is proximity to trunk pipelines and large diameter lines for local distribution companies if service is being developed to serve local needs. Depleted reservoirs are generally found in producing regions in the U.S., and other storage options must be used for areas like New England where there are no naturally occurring reservoirs (NaturalGas.org 2012b).

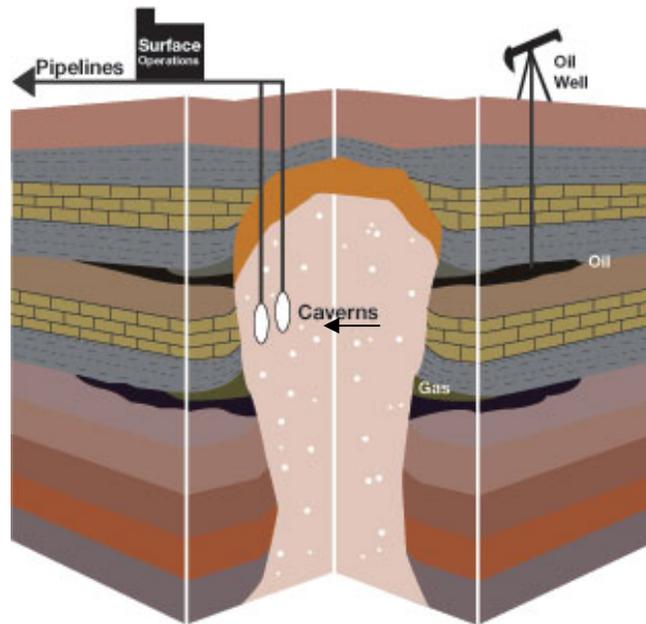
### ***Aquifer Storage***

Aquifers are underground natural water reservoirs that can also be used for natural gas storage. They are porous, permeable rock formations found below the ground and can be used for natural gas storage if the formation is capped with an impermeable rock (USDOE, EIA 2004). The geology of aquifers is similar to depleted reservoirs; however they require higher levels of base gas (between 50 and 80 percent base gas) and greater monitoring of injection and withdrawals than depleted fields (FERC 2012a; and USDOE EIA 2004). Before an aquifer is used for storage, extensive time and money is spent to determine if its geological characteristics are suitable for storage. Due to their expensive nature, aquifers tend to be used mostly in areas without depleted reservoirs, and are commonly found in the Midwest U.S. Their main purpose is for the single winter withdrawal period, but can also be used to meet peak load requirements.

Aquifer storage is the most expensive underground storage option, due to the additional geological research requirements and the infrastructure which must be built. Since they are often full of water, dehydration equipment must be used to create storage space for the natural gas. Similar to other storage facilities, wells must be drilled along with inter-facility pipelines, compression systems to move the gas from the facility into the long-line pipeline system. Uniquely, aquifers tend to leak natural gas and require “collector” wells which capture any gas which escapes from the aquifer (NaturalGas.org 2007b).

### ***Salt Cavern Storage***

The internal integrity and strength of salt formations (as structurally sound as steel) make formed caverns an ideal type of natural gas storage (see Figure 78) (NaturalGas.org 2007b). Salt caverns have very high withdrawal and injection rates and require lower levels of base gas (in comparison to reservoirs and aquifers). In general, 20 to 30 percent of the gas held in salt caverns is cushion gas and the remaining is working gas, which can be recycled 10-12 times a year in this type of storage facility (FERC 2004). Salt caverns are typically used for peak-day deliverability like fuel for electric power plants. The Gulf Coast region holds most salt cavern storage facilities that are in use, developed from salt dome formations, but caverns have also been leached from bedded salt formations in Northeastern, Midwestern, and Southwestern states (USDOE, EIA 2004).

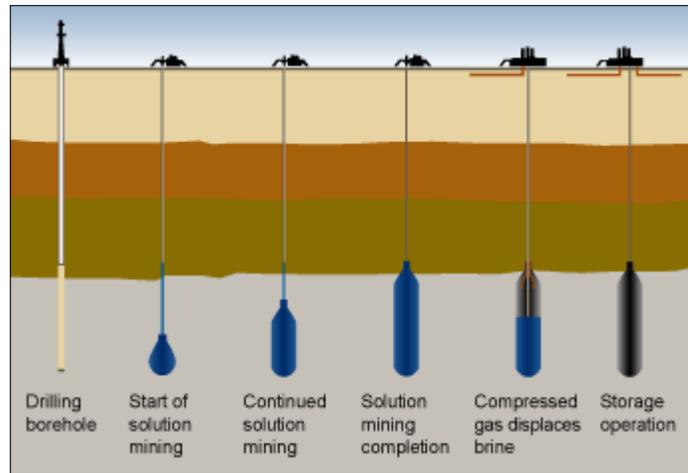


**Figure 78. Salt dome used in underground storage.**

Note: Figure is not drawn to scale.

Source: JISH 2012.

A salt cavern must be developed within a salt dome or salt bed by drilling into the formation and pumping water into the deposit to dissolve the salt. Then the salty water, or brine solution, is pumped out leaving an empty space in the salt formation. This salt cavern leaching or solution mining process is illustrated in Figure 79.



**Figure 79. The solution mining process.**

Source: JISH 2012.

Salt cavern leaching, though expensive, creates an extremely valuable underground storage facility with very high deliverability. Salt caverns have an additional advantage of a very low base (or cushion) gas requirement, as compared to the amount necessary in reservoir and aquifer storage. One negative aspect of salt caverns, however, is that they are generally smaller than depleted gas reservoirs and aquifers, resulting in smaller gas storage capacity. For this reason, the main purpose of salt cavern storage is cycling or peaking as opposed to meeting base-load storage requirements. They are particularly attractive for emergency periods or periods of unexpectedly high demand because of their higher deliverability.

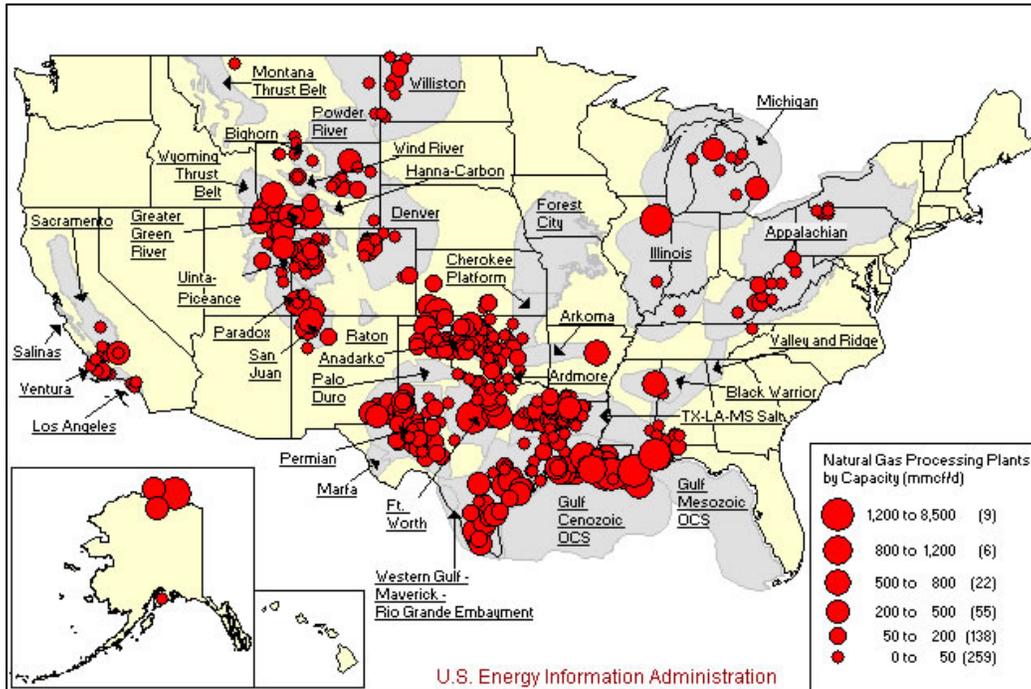
A major drawback to salt caverns as storage facilities is their high capital cost of development. Additional capital investments are required to complete the leaching and mining process, including the development of a brine handling system (pipes, pumps, electrical), an injection well first used in brine handling (mining) operations, and then converted to facilitate storage service. Before the cavern can be used as a storage facility, a number of tests are required to ensure the integrity of the cavern and well. For these reasons, creating salt cavern storage sites is more expensive than converting depleted oil fields into storage facilities in terms of dollars per thousand cubic feet of working gas capacity. However, salt caverns provide the ability to run multiple withdrawal and injection cycles each year, thus reducing the per-unit cost of each volume of gas injected and withdrawn (USDOE, EIA 2004).

## 8.3 GEOGRAPHIC DISTRIBUTION

### 8.3.1 Natural Gas Processing

As of 2011, there were 585 operational natural gas processing plants in the United States (Oil & Gas Journal 2011). The majority of processing plants are in areas of the country that produce natural gas: Alaska, the Rocky Mountain region, and the GOM. As shown in Figure 80 and Table 26, Texas and Louisiana accounted for nearly half of the total U.S. processing capacity (45 percent) with Oklahoma in third.

Table 26 illustrates the large variation in processing capacity across states. For example, Texas has 194 gas processing plants and Louisiana has only 70, however, Louisiana's gas processing capacity is 14 percent higher than Texas. Total U.S. gas processing capacity is almost 75 Bcf per day and current throughput is about 61 percent of capacity (Oil & Gas Journal 2011).



**Figure 80. Concentrations of natural gas processing plants.**

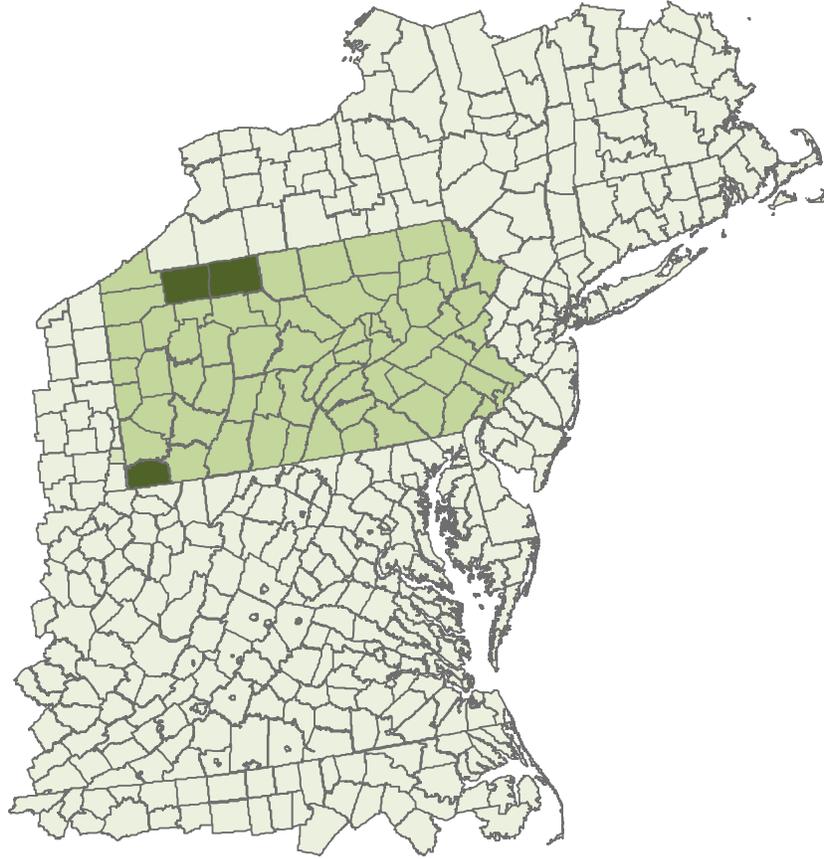
Source: USDOE, EIA 2011b.

**Table 26. Natural gas processing plants in the U.S. as of January 1, 2011.**

<b>State</b>	<b>Number of Plants</b>	<b>Gas Capacity ----- (MMcf/d) -----</b>	<b>Gas Throughput</b>
Texas	194	15,904.3	11,088.1
Louisiana	70	18,180.3	8,790.3
Oklahoma	60	3,944.0	2,691.5
Colorado	44	4,332.7	1,651.7
Wyoming	38	6,145.2	3,424.8
California	31	1,106.9	755.2
New Mexico	26	3,194.0	2,364.9
Michigan	22	1,549.4	625.7
Alabama	14	1,358.0	475.3
Utah	14	531.0	243.2
Kansas	12	2,828.5	889.6
West Virginia	10	825.0	304.0
Pennsylvania	9	73.0	32.5
North Dakota	8	298.0	202.3
Alaska	5	9,525.0	9,298.0
Arkansas	5	873.8	507.4
Kentucky	5	290.0	106.1
Mississippi	4	1,603.4	900.1
Ohio	4	25.0	10.0
Montana	4	15.4	7.8
Tennessee	2	8.0	1.5
Illinois	1	2,200.0	1,426.0
Florida	1	32.0	4.0
Nebraska	1	10.0	8.0
Wisconsin	1		
<b>U.S. Total</b>	<b>585</b>	<b>74,852.9</b>	<b>45,808.0</b>

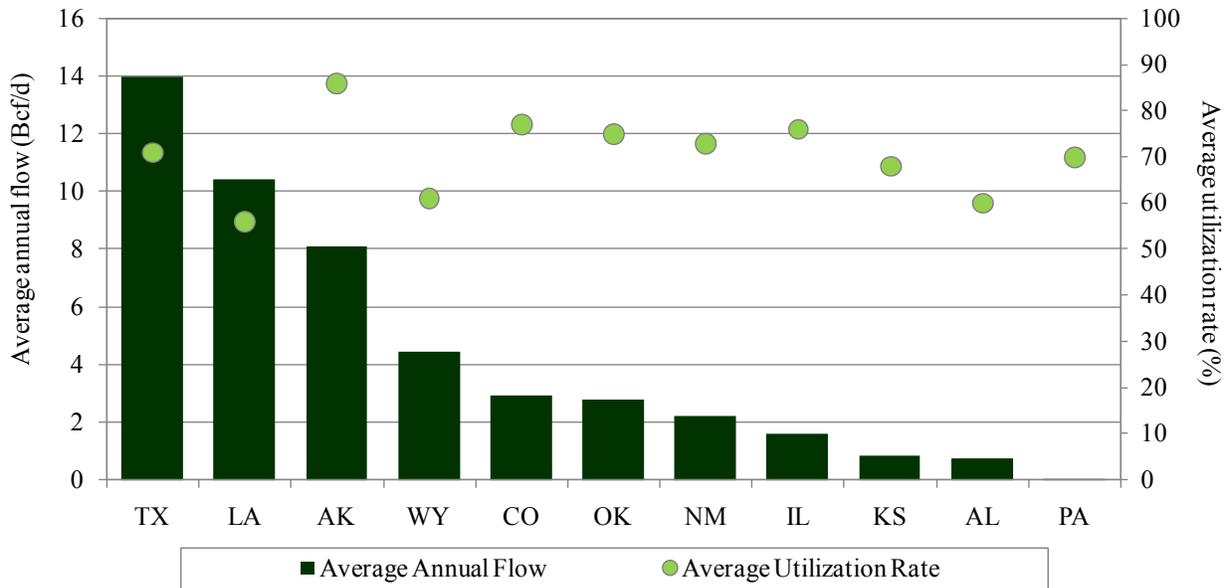
Source: Oil & Gas Journal 2011.

Within the Mid-Atlantic impact region states, there are just nine processing facilities. Figure 81 shows that all of these are located in the western part of Pennsylvania.



**Figure 81. Mid-Atlantic impact region natural gas processing facilities.**

Figure 82 presents the average annual processing flows for the ten states with the highest capacity and Pennsylvania. In terms of throughput, Texas leads the U.S., with about 12.6 Bcfd of natural gas processed in 2010, and the highest average utilization rate of any state at 71 percent (USDOE, EIA 2011b). Louisiana and Alaska follow closely behind. Together, Louisiana and Texas account for 47 percent of natural gas processing capacity in the United States (USDOE, EIA 2011b). To get a comparative idea of the Mid-Atlantic region contribution, along with the top ten processing states, Pennsylvania is included. Pennsylvania has approximately 36 Bcf of processing capacity, which accounts for about one tenth of one percent of the capacity of the entire U.S. (USDOE, EIA 2011b).



**Figure 82. Average annual processing flows and utilization rates for top 10 states and Pennsylvania.**

Source: USDOE, EIA 2011b.

### 8.3.2 Natural Gas Storage

Nearly half of all storage capacity is in the Midwest. Specifically, Ohio, Michigan, Illinois, and the Gulf Coast areas have the highest concentrations of underground storage, as a result of conducive geology and location of depleted oil and gas reservoirs. The Mid-Atlantic region accounts for about 14 percent of the number of natural gas storage sites and about 10 percent of working capacity in the U.S. However, like natural gas processing, most of these sites are located in western Pennsylvania (Table 27). In fact, of the three states in the Mid-Atlantic region that have storage facilities, Pennsylvania accounts for 94 percent of facilities (51 out of 54) and 95 percent of working gas capacity. All of the Pennsylvania storage sites are depleted fields. Maryland has one depleted field with 18.3 Bcf of working gas capacity. And, Virginia has one depleted field and one salt cavern, totaling 5.4 Bcf of working gas capacity.

**Table 27. Mid-Atlantic impact region natural gas storage fields, 2010.**

	Number of Fields				Working Gas Capacity			
	Depleted		Salt		Depleted		Salt	
	Field	Aquifer	Cavern	Total	Field	Aquifer	Cavern	Total
Maryland	1	-	-	1	18.3	-	-	18.3
Pennsylvania	51	-	-	51	431.1	-	-	431.1
Virginia	1	-	1	2	1.4	-	4.0	5.4
Total Mid-Atlantic Region	53	-	1	54	450.8	-	4.0	454.8
U.S. Total	331	43	37	411	3,734.0	364.2	312.0	4,410.2

Source: USDOE, EIA 2012d.

Consistent with the overall pattern of storage location, a large percentage of depleted reservoirs is located near major consuming regions in the Northeast and Midwest to serve peak winter heating demand. Table 28 lists the breakdown of storage type by region. In the U.S., depleted reservoirs account for 85 percent of working gas capacity. The Midwest, Southwest, and Northeast have the highest depleted reservoir capacities at 28 percent, 26 percent, and 19 percent, respectively. Similarly, these areas account for the highest daily delivery capacities. The Midwest also has the most aquifer storage sites accounting for 72 percent of the sites and 65 percent of capacity. Salt caverns present a different picture: the majority are located in the Southwest, accounting for 70 percent of the sites and 74 percent of capacity. The Southeast holds 16 percent of salt cavern sites, 23 percent of working gas and 32 percent of daily delivery capacity (USDOE, EIA 2012d).

**Table 28. Underground natural gas storage by region, 2010.**

	Central	Midwest	Northeast	Southeast	Southwest	Western	Total
<b>Number</b>							
Depleted Field	41	87	110	28	45	20	<b>331</b>
Aquifer	8	31	-	3	-	1	<b>43</b>
Salt Dome	1	2	2	6	26	-	<b>37</b>
<b>Total</b>	<b>50</b>	<b>120</b>	<b>112</b>	<b>37</b>	<b>71</b>	<b>21</b>	<b>411</b>
<b>Working Gas Capacity (Bcf)</b>							
Depleted Field	476.8	994.2	839.1	180.3	916.6	327.0	<b>3,734.0</b>
Aquifer	96.0	237.6	-	6.6	-	24.0	<b>364.2</b>
Salt Dome	0.4	2.2	5.5	73.1	230.9	-	<b>312.0</b>
<b>Total</b>	<b>573.2</b>	<b>1,233.9</b>	<b>844.5</b>	<b>260.0</b>	<b>1,147.6</b>	<b>351.0</b>	<b>4,410.2</b>
<b>Maximum Daily Delivery (MMcf)</b>							
Depleted Field	5,208	24,664	16,390	4,170	13,895	8,575	<b>72,882</b>
Aquifer	1,733	4,734	-	68	-	1,150	<b>7,685</b>
Salt Dome	1	85	470	7,487	15,570	-	<b>26,613</b>
<b>Total</b>	<b>6,942</b>	<b>29,464</b>	<b>16,680</b>	<b>11,725</b>	<b>29,465</b>	<b>9,725</b>	<b>104,180</b>

Source: USDOE, EIA 2012d.

#### **8.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY**

Neither natural gas processing nor natural gas storage has a unique NAICS code. Natural gas processing is included in the category for oil and gas extraction activities (NAICS Code 2111). This classification code also includes exploration for crude petroleum and natural gas; drilling, completing and equipping wells; operation of separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment (USDOC, CB 2002).

Similarly, natural gas storage is included along with a number of related services in the natural gas transportation industry: booster pumping station, natural gas transportation, natural gas pipeline operation and transportation, and natural gas transmission (processing plants to local distribution systems). This is all identified under the main NAICS code 486210 for Pipeline Transportation of Natural Gas. Note that this will inherently make this section of this chapter identical to the same section in the Natural Gas Pipelines Chapter. The U.S. Census explains the reason for this combined coding as, “the storage is usually done by the pipeline establishment and because a pipeline is inherently a network in which all the nodes are interdependent.” (USDOC, CB 2002) The GDP, employment and wage statistics reported in the next two sections should be interpreted with this caveat in mind.

### 8.4.1 Natural Gas Processing

The oil and gas extraction sector for the impact area is minute in comparison to (a) each state's overall GDP and (b) the economic contribution made by the U.S. natural gas transportation sector to total U.S. GDP. Pennsylvania's oil and gas extraction GDP makes the largest contribution to its state's overall economy of any in the Mid-Atlantic impact area at just 0.264 percent.

The contributions each Mid-Atlantic state makes to total U.S. oil and gas extraction GDP is also small, totaling just 1.2 percent of the U.S. total for oil and gas extraction.

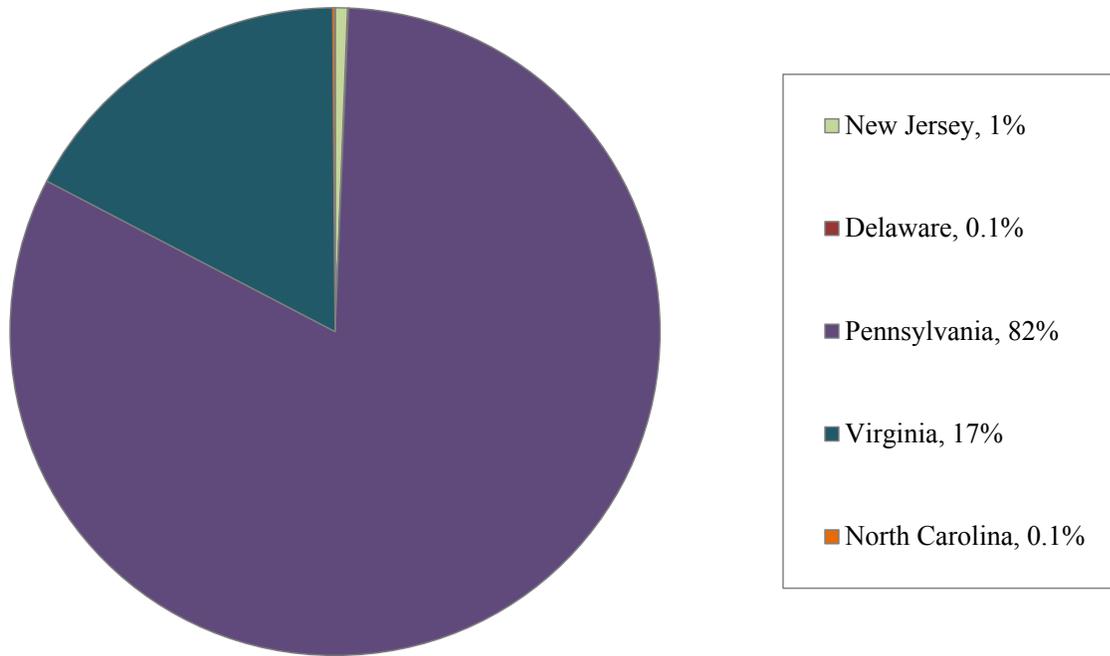
**Table 29. Regional and national GDP contribution, oil and gas extraction, 2010.**

	GDP		Oil and Gas Extraction GDP as a Percent of Total State GDP ----- (%) -----	Oil and Gas Extraction GDP as a Percent U.S. Oil and Gas Extraction GDP -----
	Oil and Gas Extraction (millions of current \$)	Total State		
New Jersey	\$ 11.0	\$ 480,446	0.002%	0.007%
Delaware	\$ 1.0	\$ 64,010	0.002%	0.001%
Maryland	n.a.	\$ 293,349	n.a.	n.a.
Pennsylvania	\$ 1,474.0	\$ 558,918	0.264%	0.999%
Virginia	\$ 309.0	\$ 419,365	0.074%	0.209%
North Carolina	\$ 2.0	\$ 424,562	0.000%	0.001%
South Carolina	n.a.	\$ 160,374	n.a.	n.a.
Georgia	n.a.	\$ 403,230	n.a.	n.a.
<b>Total Region</b>	<b>\$ 1,797</b>	<b>\$ 2,804,254</b>	<b>0.064%</b>	<b>1.218%</b>
<b>U.S.</b>	<b>\$ 147,505</b>	<b>\$ 14,416,601</b>	<b>1.023%</b>	<b>100.0%</b>

Note: Maryland, South Carolina and Georgia report less than \$500,000 in nominal or real GDP.

Source: USDOC, BEA 2012.

Figure 83 highlights the relative share of each Mid-Atlantic state's pipeline transportation GDP shares to the regional pipeline transportation total. Pennsylvania far outweighs the other states, accounting for 82 percent of oil and gas extraction GDP. Virginia accounts for 17 percent. The remaining three states contribute smaller shares of the region's oil and gas extraction output, with shares between 0.1 percent and 1 percent.

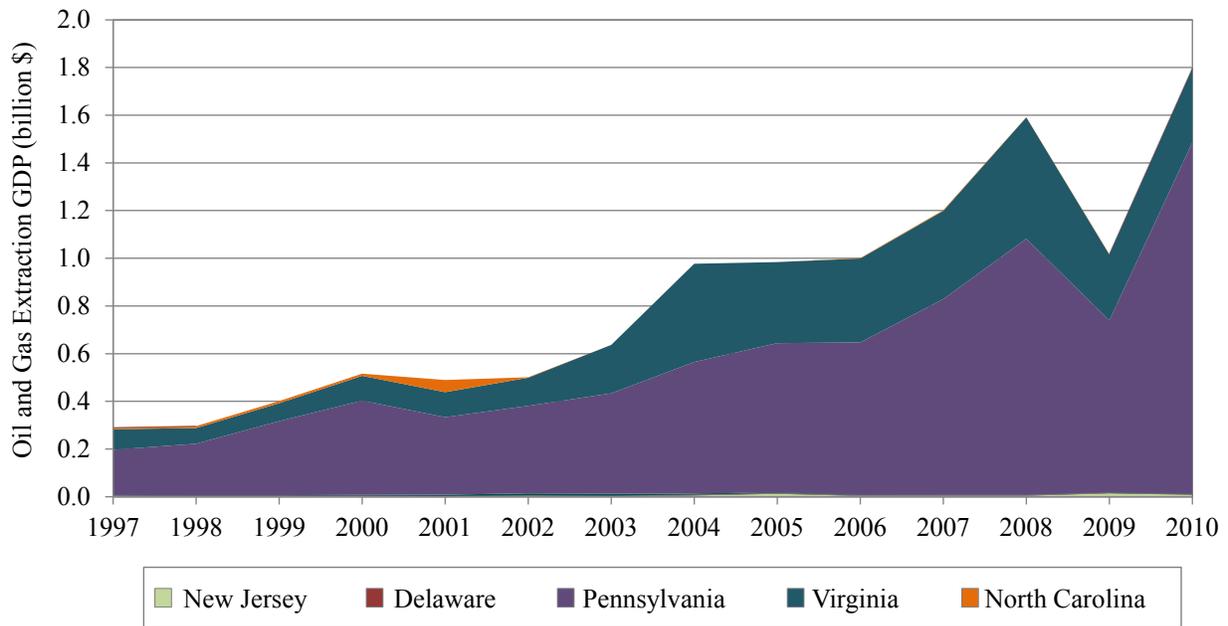


**Figure 83. Mid-Atlantic impact region oil and gas extraction GDP shares, 2010.**

Note: Maryland, South Carolina and Georgia report less than \$500,000 in nominal or real GDP. Delaware's oil and gas extraction GDP is large enough to be reported, however it is too small to be visible on this graph.

Source: USDOC, BEA 2012.

Figure 84 compares the trends in oil and gas extraction GDP for each Mid-Atlantic impact state since the mid-1990s. Oil and gas extraction GDP in Pennsylvania and Virginia shadow any value reported by the other impact region states. In Pennsylvania, oil and gas extraction GDP has increased at an average annual rate of 20.9 percent. Though this sector has grown steadily over the period, much of this increase is attributable to 2009 and 2010, when oil and gas extraction GDP increased from \$722 million to almost \$1.5 billion, an increase of 104 percent. Similarly, but on a lesser scale, in Virginia, oil and gas extraction GDP has increased at an average annual rate of 16.3 percent. Virginia's largest increase was in 2003 and 2004 when GDP increased from \$203 million to \$412 million, or 103 percent.



**Figure 84. Trends in Mid-Atlantic impact region oil and gas extraction GDP.**

Delaware and New Jersey oil and gas extraction GDPs are large enough to be reported, however they are too small to be visible on this graph.

Source: USDOC, BEA 2012.

Table 30 lists gas and oil extraction employment statistics for the Mid-Atlantic region in 2011. Oil and gas extraction activities are an extremely small portion of employment for the Mid-Atlantic region, only about .02 percent. The region accounts for 2.94 percent of total oil and gas extraction employment in the U.S., with the largest number of people employed in Pennsylvania. This is consistent with the previous sections in this chapter, because Pennsylvania has the most activity in this sector (in the Mid-Atlantic region).

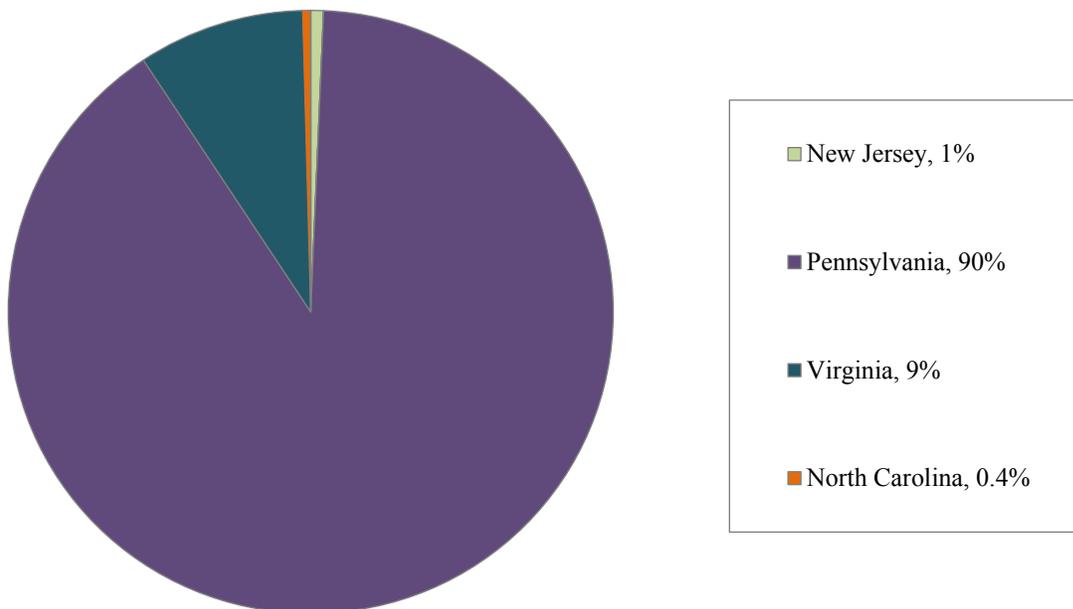
Figure 85 depicts the employment shares for the Mid-Atlantic region's oil and gas extraction employment. Again, Pennsylvania plays the largest role, comprising 90 percent of the region's number of jobs in this sector in 2011. Virginia accounts for only 9 percent of oil and gas extraction employment in the region, and the two remaining states with reliable data account for less than one percent each.

**Table 30. Regional and national employment shares, oil and gas contribution (processing of natural gas included), 2011.**

	Number of Jobs		Oil and Gas Extraction Employment as a Percent of Total State Employment ----- (%) -----	Oil and Gas Extraction Employment as a Percent of Total U.S. Oil and Gas Extraction Employment ----- (%) -----
	Oil and Gas Extraction	Total State		
New Jersey	34	3,156,538	0.00%	0.02%
Delaware	n.a.	342,585	n.a.	n.a.
Maryland	n.a.	1,991,055	n.a.	n.a.
Pennsylvania	4,517	4,825,064	0.09%	2.65%
Virginia	445	2,889,435	0.02%	0.26%
North Carolina	22	3,158,293	0.00%	0.01%
South Carolina	n.a.	1,450,840	n.a.	n.a.
Georgia	n.a.	3,135,735	n.a.	n.a.
<b>Total Region</b>	<b>5,018</b>	<b>20,949,545</b>	<b>0.02%</b>	<b>2.94%</b>
<b>U.S.</b>	<b>170,735</b>	<b>108,184,795</b>	<b>0.16%</b>	<b>100.00%</b>

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

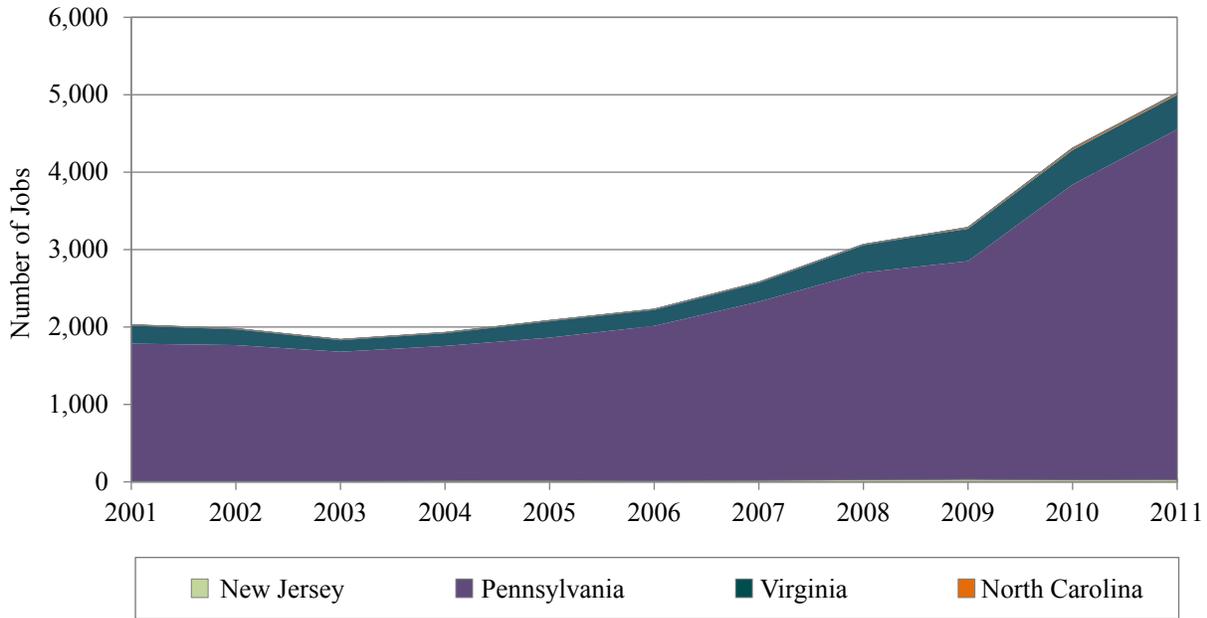


**Figure 85. Regional oil and gas extraction employment shares, 2011.**

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Figure 86 depicts the trend in oil and gas extraction employment in the Mid-Atlantic region states since 2001. The increase in employment in recent years in Pennsylvania likely corresponds to the increase in attention on the Marcellus Shale region (Caiman Energy 2012). Employment in Virginia has also been rising, with large increases in 2007 through 2009. Employment figures for New Jersey and North Carolina are dwarfed by Pennsylvania and Virginia and are thus not visible in the graph. Also, data for North Carolina’s employment contribution was disclosed only for 2009 through 2011.



**Figure 86. Historic trends in Mid-Atlantic impact region oil and gas extraction employment, 2001-2011.**

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards. Although employment figures for New Jersey and North Carolina are large enough to be reported, they are too small to be visible on this graph.

Source: USDOL, BLS 2012.

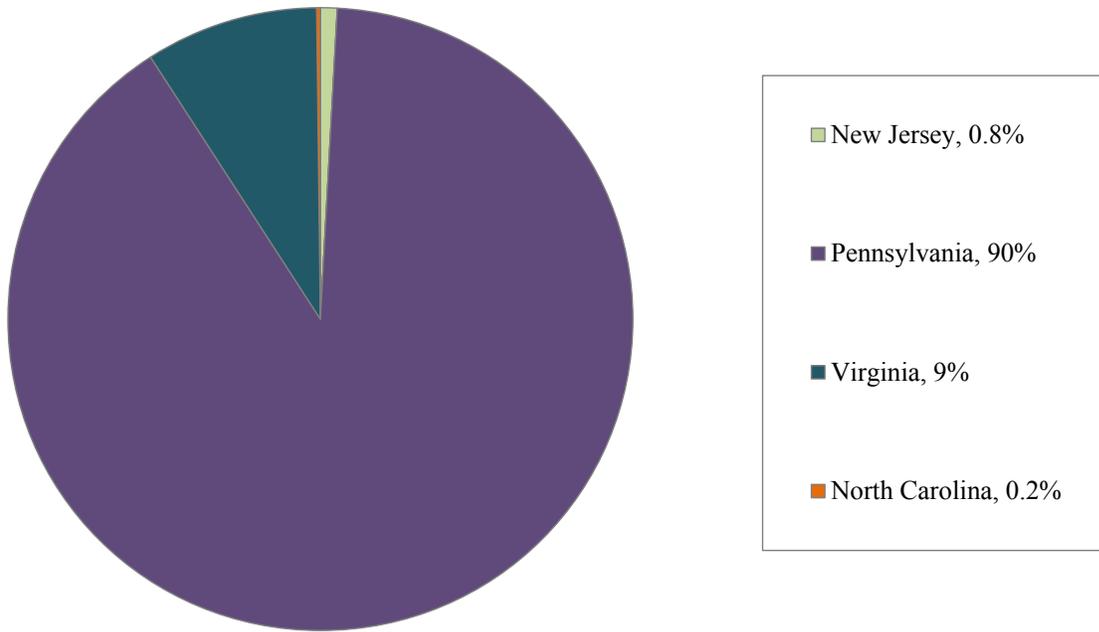
Table 31 provides 2011 wage contribution data for the Mid-Atlantic region and the United States. This table is consistent with Table 30: the wages of the Mid-Atlantic region are a very small proportion of U.S. wages in oil and gas extraction. Pennsylvania accounts for the majority of wage contributions within the area (Figure 87). However, wage contributions of all Mid-Atlantic states are small compared to the total state wages and the total U.S. oil and gas sector. Trends in wages are shown in Figure 88.

**Table 31. Regional and national wage contribution, oil and gas extraction (processing of natural gas included), 2011.**

	Wages		Oil and Gas	Oil and Gas
	Oil and Gas	Total	Extraction	Extraction Wages
	Extraction	State	Wages as a	Percent of Total U.S.
	(million \$)		Percent of Total	Oil and Gas
			State Wages	Extraction Wages
			(%)	
New Jersey	\$ 4.4	\$ 179,559	0.00%	0.02%
Delaware	n.a.	\$ 17,313	n.a.	n.a.
Maryland	n.a.	\$ 100,787	n.a.	n.a.
Pennsylvania	\$ 451.2	\$ 225,147	0.20%	1.74%
Virginia	\$ 44.9	\$ 145,225	0.03%	0.17%
North Carolina	\$ 0.9	\$ 132,436	0.00%	0.00%
South Carolina	n.a.	\$ 54,746	n.a.	n.a.
Georgia	n.a.	\$ 142,928	n.a.	n.a.
<b>Total Region</b>	<b>\$ 501.4</b>	<b>\$ 998,140</b>	<b>0.05%</b>	<b>1.93%</b>
<b>U.S.</b>	<b>\$ 25,969.0</b>	<b>\$ 5,172,844</b>	<b>0.50%</b>	<b>100.00%</b>

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards.

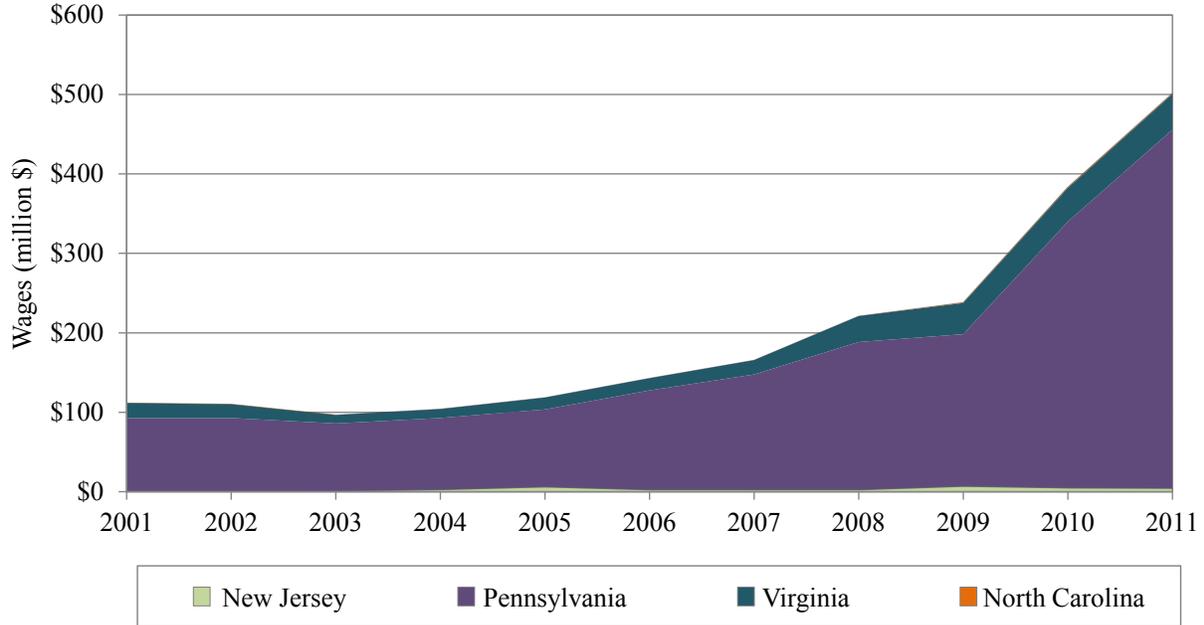
Source: USDOL, BLS 2012.



**Figure 87. Mid-Atlantic impact oil and gas extraction wage shares, 2011.**

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.



**Figure 88. Trends in Mid-Atlantic impact region oil and gas extraction wages, 2001-2011.**

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards. Although wage figures for New Jersey and North Carolina are large enough to be reported, they are too small to be visible on this graph.

Source: USDOL, BLS 2012.

Table 32 lists average annual wages for the Mid-Atlantic impact region in 2011. New Jersey has the highest average annual wage by a significant amount, \$129,013. Virginia paid an average wage of \$100,862, followed by Pennsylvania at \$99,891. All average annual wages in this region were higher than the average annual wage for this sector in the entire United States. When considered as a whole, a worker in the Mid-Atlantic received an average annual wage of about 318 percent higher than the average oil and gas extraction worker in the U.S.

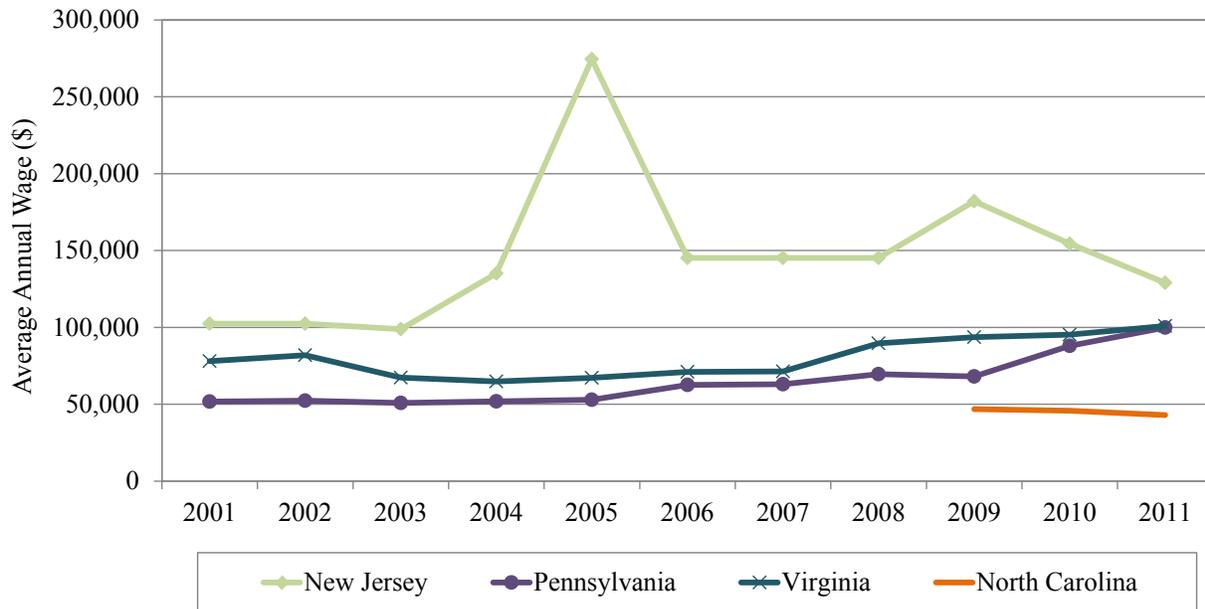
**Table 32. Regional and national average annual wage, oil and gas extraction (processing of natural gas included), 2011.**

	Average Annual Wage Oil and Gas Extraction ----- (\$)		Oil and Gas Extraction Average Annual Wage as a Percent of State Total State Average Annual Wage ----- (%)	
				Oil and Gas Extraction Average Annual Wage as a Percent of Total U.S. Oil and Gas Extraction Average Annual Wage ----- (%)
New Jersey	\$ 129,013	\$ 56,885	226.8%	84.8%
Delaware	n.a.	\$ 50,535	n.a.	n.a.
Maryland	n.a.	\$ 50,620	n.a.	n.a.
Pennsylvania	\$ 99,891	\$ 46,662	214.1%	65.7%
Virginia	\$ 100,862	\$ 50,261	200.7%	66.3%
North Carolina	\$ 43,015	\$ 41,933	102.6%	28.3%
South Carolina	n.a.	\$ 37,734	n.a.	n.a.
Georgia	n.a.	\$ 45,580	n.a.	n.a.
<b>Total Region</b>	<b>\$ 93,195</b>	<b>\$ 47,526</b>	<b>196.1%</b>	<b>61.3%</b>
<b>U.S.</b>	<b>\$ 152,101</b>	<b>\$ 47,815</b>	<b>318.1%</b>	<b>100.0%</b>

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

The trend in average annual wage growth over time is quite different among Mid-Atlantic states. Again, data is available only for New Jersey, Pennsylvania, and Virginia, but each state presents a unique pattern of wage growth. New Jersey wages are quite volatile, likely resulting from the very small size of the employment force in this sector. There are also a few years of missing data due to reporting inconsistencies. Pennsylvania and Virginia seem to follow a relatively similar path to one another, though Virginia annual average wages are consistently higher (USDOL, BLS 2012).



**Figure 89. Trends in regional average oil and gas extraction wages.**

Note: Data for Delaware, Maryland, South Carolina, and Georgia data do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

#### 8.4.2 Natural Gas Storage

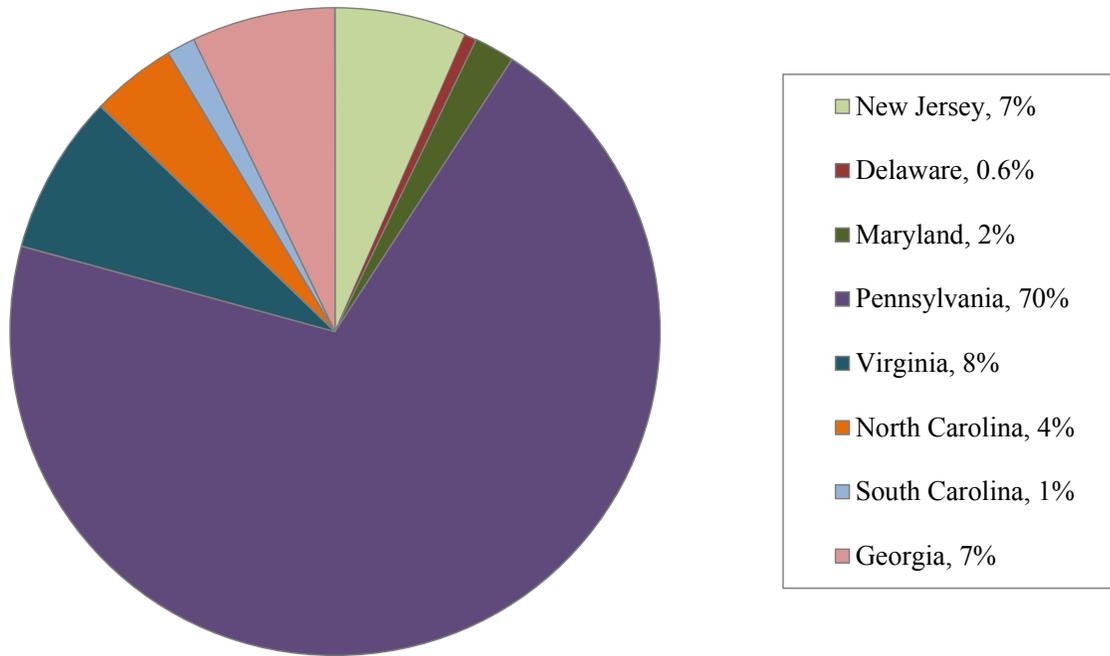
The pipeline transportation sector for the impact area is small in comparison to (a) each state's overall GDP and (b) the economic contribution made by the U.S. natural gas transportation sector to total U.S. GDP. Pennsylvania's pipeline transportation GDP makes up the largest contribution to its state's overall economy of any in the Mid-Atlantic impact area at just 0.12 percent. Pennsylvania's share of U.S. pipeline transportation GDP is far greater than any other state in the impact region. Every other state's share of U.S. pipeline transportation GDP is less than one percent.

**Table 33. Regional and national GDP contribution, pipeline transportation, 2010.**

	GDP		Pipeline Transportation GDP as a Percent of Total State GDP ----- (%) -----	Pipeline Transportation GDP as a Percent of U.S. Water Transportation GDP -----
	Pipeline Transportation (millions of current \$)	Total State		
New Jersey	\$ 65	\$ 480,446	0.01%	0.4%
Delaware	\$ 6	\$ 64,010	0.01%	0.0%
Maryland	\$ 20	\$ 293,349	0.01%	0.1%
Pennsylvania	\$ 696	\$ 558,918	0.12%	4.6%
Virginia	\$ 79	\$ 419,365	0.02%	0.5%
North Carolina	\$ 42	\$ 424,562	0.01%	0.3%
South Carolina	\$ 14	\$ 160,374	0.01%	0.1%
Georgia	\$ 71	\$ 403,230	0.02%	0.5%
<b>Total Region</b>	<b>\$ 993</b>	<b>\$ 2,804,254</b>	<b>0.04%</b>	<b>6.5%</b>
<b>U.S.</b>	<b>\$ 15,287</b>	<b>\$ 14,416,601</b>	<b>0.11%</b>	<b>100.0%</b>

Source: USDOC, BEA 2012.

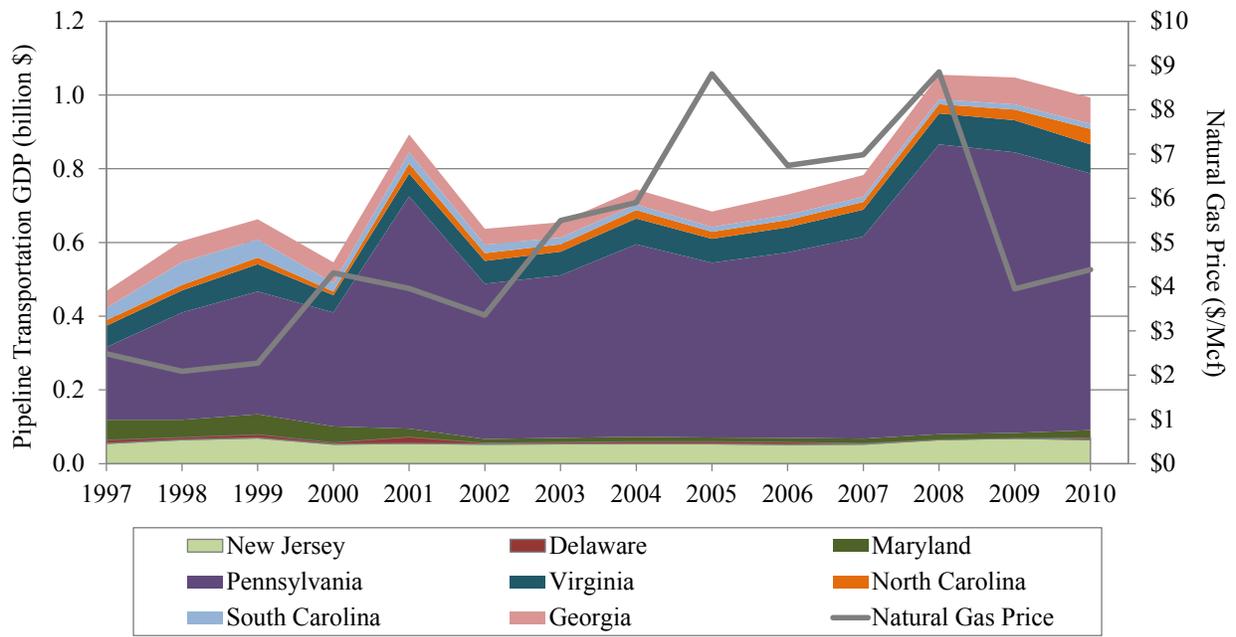
Figure 90 highlights the relative share of each Mid-Atlantic state's pipeline transportation GDP shares to the regional pipeline transportation total. Pennsylvania, with \$696 million in the annual value of its pipeline transportation output, accounts for 70 percent of the value of the region's pipeline transportation output. Virginia accounts for eight percent of the economic value of the region's pipeline transportation output (\$79 million per year). Georgia and New Jersey both account for seven percent of the region's pipeline transportation output, both around \$70 million. The remaining states possess smaller shares of the region's pipeline transportation output with shares between 0.6 percent and 4 percent.



**Figure 90. Mid-Atlantic impact region pipeline transportation GDP shares, 2010.**

Source: USDOC, BEA 2012.

The economic value of the region’s pipeline transportation output has followed trends closely associated with the price of natural gas. Figure 91 compares the trends in pipeline transportation GDP for each Mid-Atlantic impact state since the mid-1990s. Regional pipeline transportation GDP increased at an average annual rate of close to 10 percent between 2002 and 2008, increasing by 36 percent in 2008 alone. Pipeline transportation GDP decreased by over 20 percent in 2009 however, as natural gas commodity prices fell to relatively low levels compared to the previous six year period.



**Figure 91. Trends in Mid-Atlantic impact region pipeline transportation GDP.**

Source: USDOC, BEA 2012; and Federal Reserve Bank of St. Louis 2012.

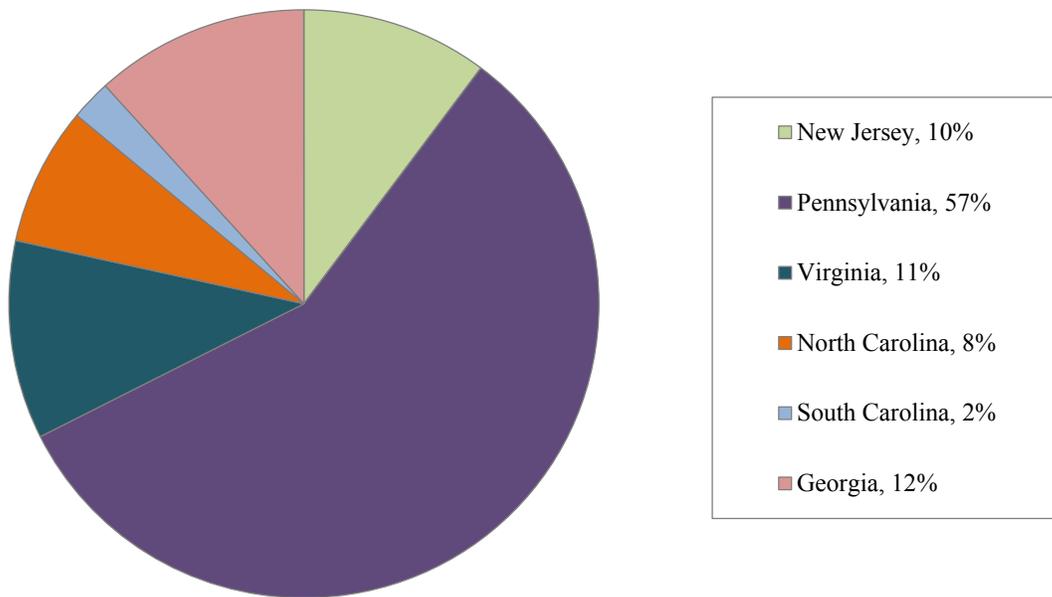
Table 34 shows that each state's total pipeline transportation employment contributions are relatively small in comparison to the total employment in each of the states in the Mid-Atlantic impact region. None of the states in the Mid-Atlantic impact region have pipeline transportation employment totals that are over one-tenth of one percent of the overall statewide employment totals.

Pennsylvania has the overwhelming majority of pipeline transportation employment in the impact region (see Figure 92). Likewise, it also has the highest employment contribution to total U.S. pipeline transportation employment. Overall, the region accounts for just eight percent of total U.S. pipeline transportation employment.

**Table 34. Regional and national employment contribution, pipeline transportation, 2011.**

	Number of Jobs		Pipeline Transportation Employment as a Percent of Total State Employment	Pipeline Transportation Employment as a Percent of Total U.S. Pipeline Transportation Employment (%)
	Pipeline Transportation	Total State	----- (%) -----	----- (%) -----
New Jersey	350	3,156,538	0.01%	0.81%
Delaware	n.a.	342,585	n.a.	n.a.
Maryland	n.a.	1,991,055	n.a.	n.a.
Pennsylvania	1,960	4,825,064	0.04%	4.56%
Virginia	373	2,889,435	0.01%	0.87%
North Carolina	260	3,158,293	0.01%	0.60%
South Carolina	76	1,450,840	0.01%	0.18%
Georgia	401	3,135,735	0.01%	0.93%
<b>Total Region</b>	<b>3,420</b>	<b>20,949,545</b>	<b>0.02%</b>	<b>7.95%</b>
<b>U.S.</b>	<b>43,010</b>	<b>108,184,795</b>	<b>0.04%</b>	<b>100.00%</b>

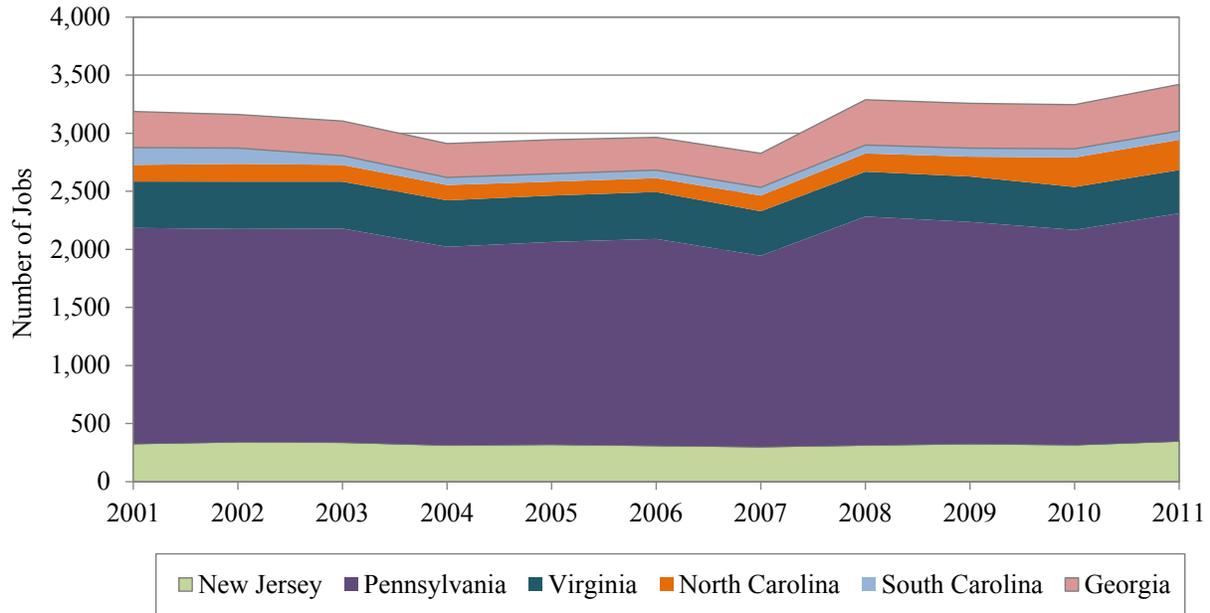
Note: n.a. is “not available.”  
 Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 92. Mid-Atlantic impact region pipeline transportation employment shares, 2011.**

Note: n.a. is “not available.”  
 Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.

Pipeline transportation employment in the Mid-Atlantic impact region has been relatively stable over the past decade. The region reported a high of 3,420 pipeline transportation jobs in 2011. This is an increase of seven percent since 2001. Between 2007 and 2008, pipeline transportation employment increased the most, by over 16 percent. This was mostly due to increases in Pennsylvania, North Carolina, and Georgia.



**Figure 93. Trends in Mid-Atlantic impact region pipeline transportation employment, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Regional wage contributions, provided in Table 35, follow trends similar to employment levels discussed earlier with the regional totals dominated by the state (Pennsylvania) with the largest share of transportation pipeline miles. Regional shares of total wages paid by Mid-Atlantic coast pipeline transportation companies are provided in Figure 94. Trends in pipeline transportation wages are presented in Figure 95.

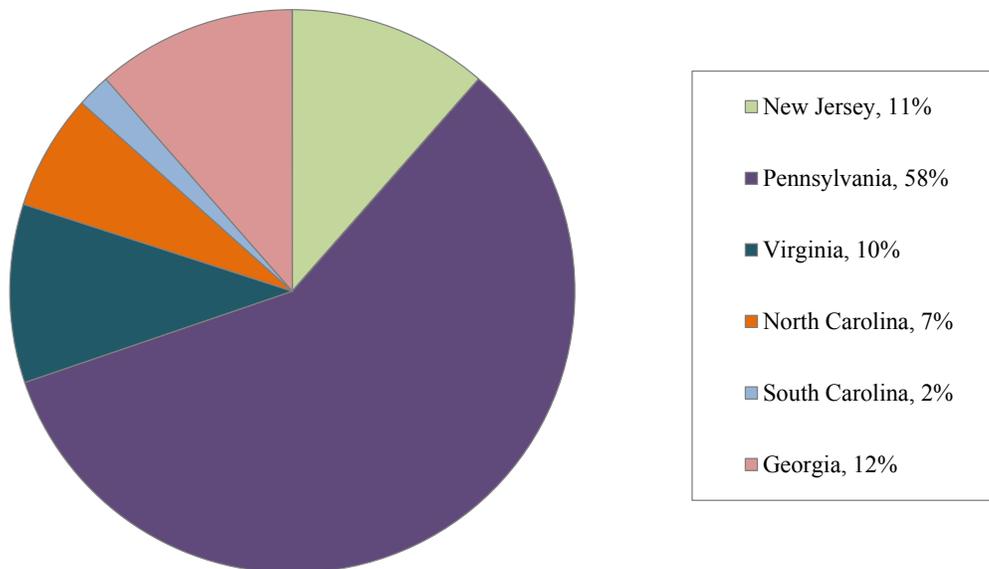
**Table 35. Regional and national wage contribution, pipeline transportation, 2011.**

	Wages		Pipeline	Pipeline
	Pipeline	Total	Transportation	Transportation
	Transportation	State	Wages as a	Wages
	(million \$)		Percent of Total	Percent of Total U.S.
	-----	-----	State Wages	Transportation Wages
			-----	-----
			(%)	(%)
New Jersey	\$ 35.5	\$ 179,559	0.02%	0.74%
Delaware	n.a.	\$ 17,313	n.a.	n.a.
Maryland	n.a.	\$ 100,787	n.a.	n.a.
Pennsylvania	\$ 180.8	\$ 225,147	0.08%	3.78%
Virginia	\$ 31.8	\$ 145,225	0.02%	0.67%
North Carolina	\$ 20.6	\$ 132,436	0.02%	0.43%
South Carolina	\$ 5.9	\$ 54,746	0.01%	0.12%
Georgia	\$ 35.5	\$ 142,928	0.02%	0.74%
<b>Total Region</b>	<b>\$ 310.1</b>	<b>\$ 998,140</b>	<b>0.03%</b>	<b>6.49%</b>
<b>U.S.</b>	<b>\$ 4,777.5</b>	<b>\$ 5,172,844</b>	<b>0.09%</b>	<b>100.00%</b>

Note: n.a. is "not available."

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

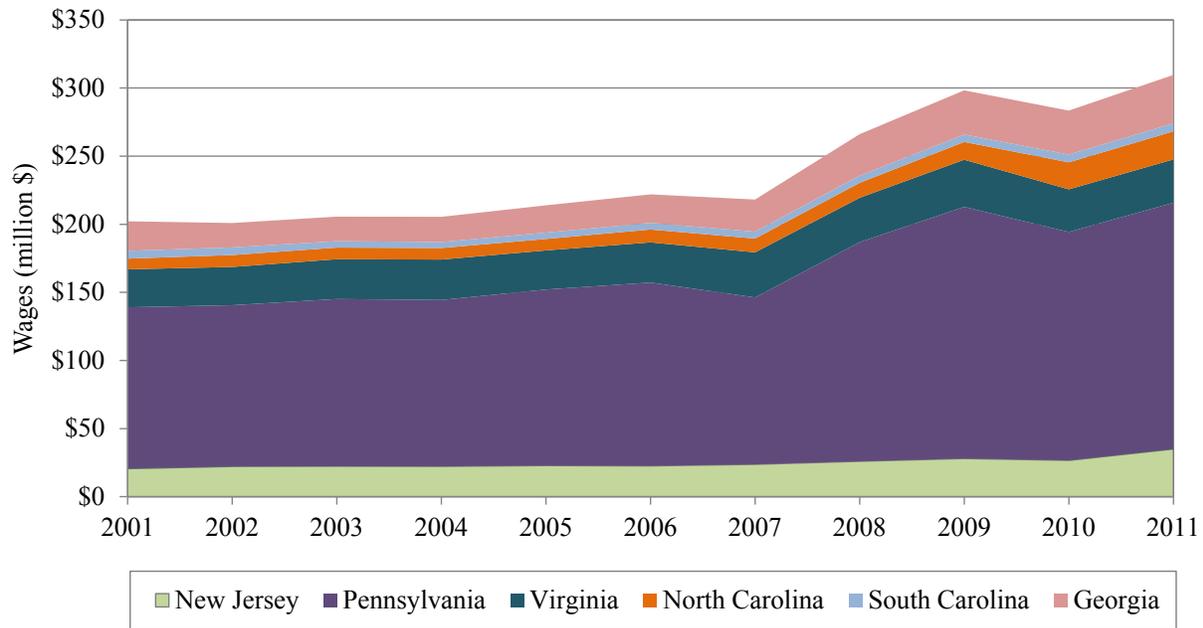


**Figure 94. Mid-Atlantic impact region pipeline transportation wage shares, 2011.**

Note: n.a. is "not available."

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.



**Figure 95. Trends in Mid-Atlantic impact region pipeline transportation wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Table 36 provides a comparison of the average annual wages paid to employees in the pipeline transportation sectors of the Mid-Atlantic impact area. The annual wages for pipeline transportation sector employees in each state in the region are considerably higher, in fact orders of magnitude higher than the average in-state wage. This is not surprising and is consistent with industry trends in other parts of the country. The comparisons differ, however, when average annual pipeline transportation wages to the U.S. average annual pipeline transportation wage.

New Jersey, for instance, reports the highest average annual wage in the region at almost \$100,000 per year for a pipeline transportation company employee. In Pennsylvania, the average annual wage for pipeline transportation is \$92,250, which is almost double (198 percent) the average annual wage for Pennsylvania in general. In South Carolina, pipeline transportation wages in North Carolina are over 200 percent higher than the state average. However, average annual pipeline transportation wages in the region are below the U.S. pipeline transportation average of roughly \$111,000 per year.

**Table 36. Regional and national average annual wage contribution, pipeline transportation, 2011.**

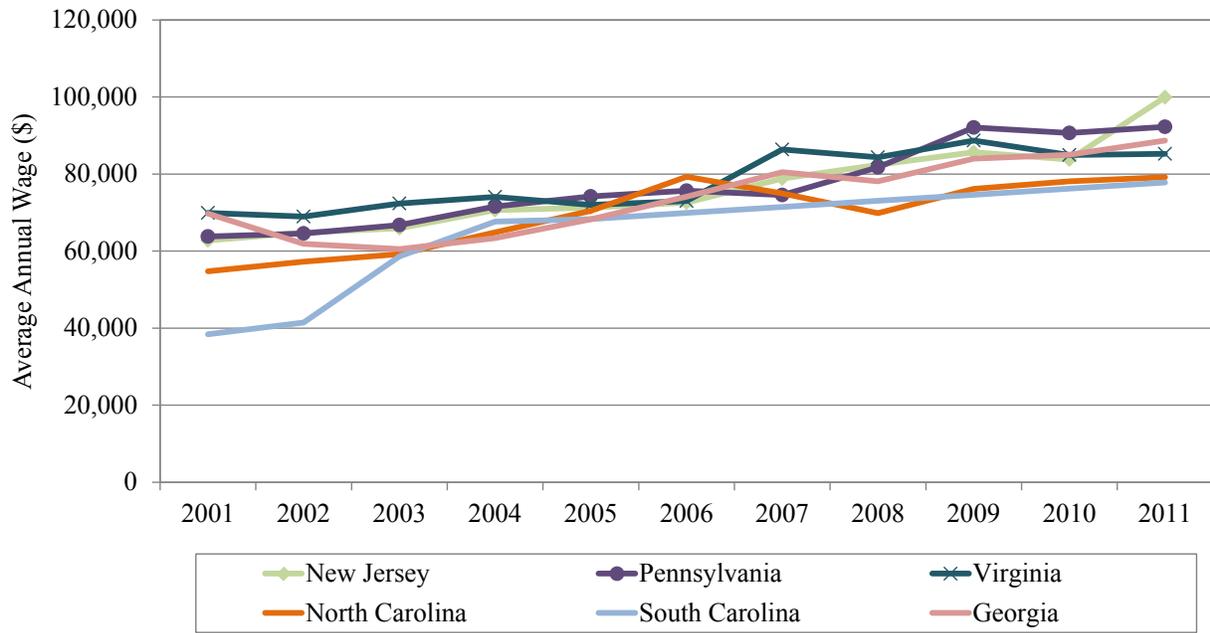
	Average Annual Wage		Pipeline Transportation Average Annual Wage as a Percent of Total State Average Annual Wage	Pipeline Transportation Average Annual Wage as a Percent of Total U.S. Pipeline Transportation Average Annual Wage
	Pipeline Transportation	Total	Percent of Total	Percent of Total
	----- (\$)	----- (\$)	----- (%)	----- (%)
New Jersey	\$ 99,949	\$ 56,885	175.7%	90.0%
Delaware	n.a.	\$ 50,535	n.a.	n.a.
Maryland	n.a.	\$ 50,620	n.a.	n.a.
Pennsylvania	\$ 92,250	\$ 46,662	197.7%	83.0%
Virginia	\$ 85,236	\$ 50,261	169.6%	76.7%
North Carolina	\$ 79,208	\$ 41,933	188.9%	71.3%
South Carolina	\$ 77,799	\$ 37,734	206.2%	70.0%
Georgia	\$ 88,681	\$ 45,580	194.6%	79.8%
<b>Total Region</b>	<b>\$ 87,187</b>	<b>\$ 47,526</b>	<b>183.5%</b>	<b>78.5%</b>
<b>U.S.</b>	<b>\$ 111,080</b>	<b>\$ 47,815</b>	<b>232.3%</b>	<b>100.0%</b>

Note: n.a. is “not available.”

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

Trends in regional average annual wages for regional pipeline transportation employees are provided in Figure 96. The trends show that average annual wage have been increasing at an average annual rate of 4.2 percent, and the greatest increases were in 2009 (6.6 percent) and 2011 (5.0 percent). In 2009, Pennsylvania and North Carolina showed the largest increases in average annual wages, with increases of 12.6 percent and 8.9 percent.



**Figure 96. Trends in Mid-Atlantic impact region pipeline transportation average annual wages, 2001-2011.**

Note: n.a. is "not available."

Data for Delaware and Maryland do not meet BLS or state agency disclosure standards.

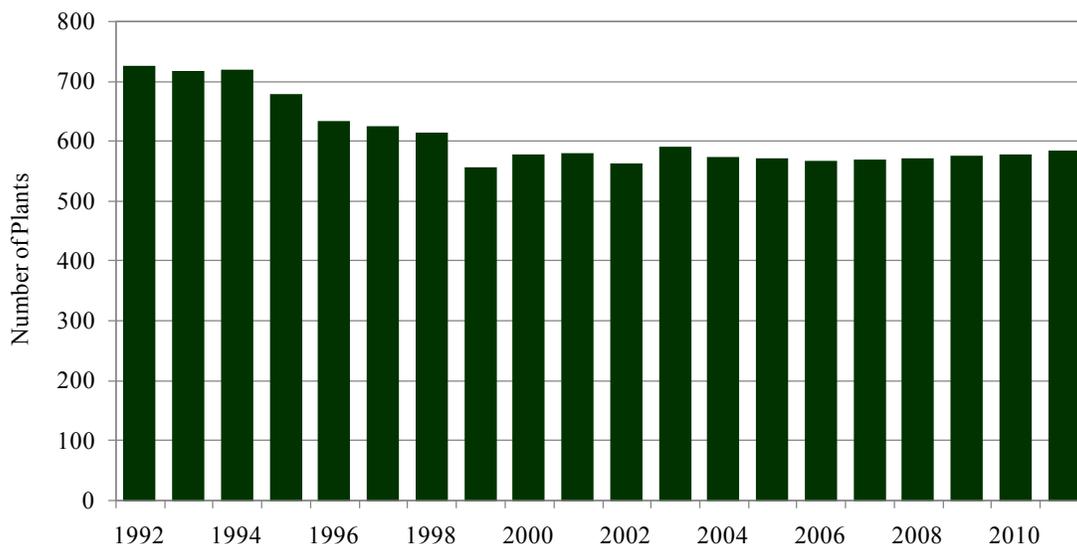
Source: USDOL, BLS 2012.

## 8.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

### 8.5.1 Trends

As of 2011, there were 585 operational natural gas processing plants in the U.S. (Oil & Gas Journal 2011). Operating capacity overall has increased since 2004, despite a reduction in the number of processing plants, where combined it is approximately 77 billion cubic feet (Bcf) per day. The majority of processing plants are located in areas of the U.S. that produce natural gas: Alaska, states in the Rocky Mountain region, and states along the GOM (USDOE, EIA 2006b).

As seen in Figure 97, the total number of gas processing plants operating in the U.S. has been declining over the past several years as companies merge, exchange assets, and close older, less efficient plants. From 1995 to 1999 the number of gas processing plants decreased overall, with a downward and near constant trend after that (USDOE, EIA 2006b). Despite the decrease in the number of processing plants, daily processing capacity has actually increased significantly, by about 49 percent. For example, Texas has seen an increase in average capacity per plant, but a decrease in the number of plants and overall processing capacity. The reason for this productivity improvement is the opening of newer plants while older plants which were less efficient have been shut down. Pennsylvania however, has seen an increase in both the number of processing plants and capacity. The past several years have shown a clear trend of movement towards efficiency and economies of scale in the processing industry.



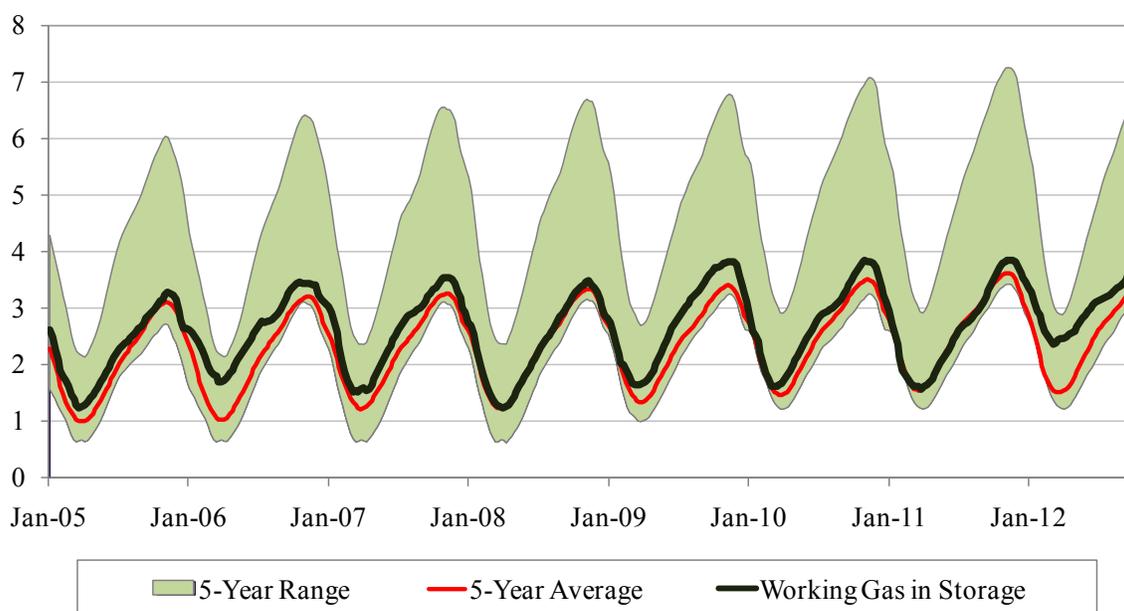
**Figure 97. U.S. natural gas processing plants.**

Note: The number of plants for 1992 through 1996 are estimated from the figure provided in True 2000.

Source: True 2000; and Oil & Gas Journal 1997 through 2011.

There are 411 active underground storage facilities in the lower 48 states (USDOE, EIA 2012d). The aggregate peak capacity for the U.S. is 4,239 Bcf as of April 2012, which is a three percent increase over the previous year's capacity (USDOE, EIA 2012e).

Injections into, and withdrawals out of, natural gas storage facilities is usually seasonal; storage is filled during low utilization periods (April through October) and withdrawn during high utilization periods (November through March). This results in a cyclical up and down pattern in the amount of stored gas. Figure 98 below shows these cycles since 2005. The total amount of gas in storage, though cyclical, has increased over time, while remaining fairly stable over the last three years. Note that the volume of base gas is fairly consistent because its quantity varies with changes in the amount of available storage facilities over time as opposed to being driven by seasonal variations.



**Figure 98. Working gas in underground storage.**

Source: USDOE, EIA 2012b.

A number of new natural gas storage facilities have been certificated by FERC in the past few years. Table 37 provides a list of facilities certificated since 2010 along with their capacities. The majority of these recent projects are located in the Midwest and Gulf Coast regions, consistent with existing infrastructure.

One project of significant size located in a Mid-Atlantic impact state is the UGI Storage Company project certified in 2010. This project is three reservoirs totaling 14.7 Bcf of natural gas storage and pipeline wheeling services in the Marcellus Shale Region of Pennsylvania.

**Table 37. Underground natural gas storage facilities certificated since 2010.**

<b>Company/Project</b>	<b>State</b>	<b>Working Gas Capacity (Bcf)</b>	<b>Year Certificated</b>
<b>Northeast</b>			
Arlington Storage Company	NY	1.4	2010
UGI Storage Company	PA	14.7	2010
<b>Southeast</b>			
MoBay Storage Hub, LLC	AL	9.6	2010
Mississippi Hub LLC	MS	15.0	2010
Petal Gas Storage, LLC	MS	5.0	2010
<b>South Central</b>			
BCR Holdings, Inc.	LA	15.0	2010
Cadeville Gas Storage LLC	LA	16.4	2010
Perryville Gas Storage, LLC	LA	15.0	2010
Petrologistics Natural Gas Storage, LLC	LA	5.3	2010
Port Barre Investments, LLC d/b/a Bobcat Gas Storage	LA	9.3	2010
Petrologistics Natural Gas Storage, LLC	LA	4.6	2010
Tres Palacios Gas Storage, LLC	TX	2.4	2010
Tallulah Gas Storage, LLC	LA	24.0	2011
CenterPoint Energy- Mississippi River Trans. Corp.	LA	1.2	2011
Pine Prairie Energy Center, LLC	LA	32.0	2011
Perryville Gas Storage, LLC	LA	5.0	2011
Golden Triangle Storage, Inc.	TX	16.6	2012
<b>Midwest</b>			
Texas Gas Transmission, LLC	KY, IN	4.1	2010
Southern Star Central Gas Pipeline	KS	1.4	2010
Natural Gas Pipelines of America LLC	IA	0.5	2010
Southern Star Central Gas Pipeline	KS	2.6	2010
Northern Natural Gas Storage, LLC	IA	2.0	2011
<b>Western</b>			
Colorado Interstate Gas Company	CO	0.9	2010
East Cheyenne Gas Storage, LLC	CO	18.9	2010
Magnum Gas Storage LLC	UT	42.0	2011
Ryckman Creek Resources, LLC	WY	35.0	2011
Leader One Energy	CO	11.0	2011
Tricor Ten Storage Hub, LLC	CA	22.4	2011

Notes: Numbers are as of February 1, 2011.  
Source: FERC 2012d.

The natural gas market has become more responsive in recent years, with the ability to quickly inject or withdraw from storage translates into more revenue. This, as mentioned previously, is one reason for the increase in the number of salt caverns in use since the 1980s. Table 38 depicts this trend and describes the average amount of withdrawals and injections from storage over the past 60 years.

**Table 38. History of average storage withdrawals and injections.**

Period	Average Storage Activity		Net Withdrawals
	Withdrawals	Injections	
	----- (Bcf) -----		
1950 to 1959	384	507	(123)
1960 to 1969	1,001	1,122	(121)
1970 to 1979	1,759	2,009	(250)
1980 to 1989	2,170	2,156	14
1990 to 1999	2,703	2,753	(50)
2000 to 2009	3,042	3,088	(46)

Source: USDOE, EIA 2011a.

### 8.5.2 Outlook

The natural gas processing and midstream industries are experiencing rapid technological improvements, and it is likely that the processing industry will continue to be more efficient in production (GPA 2011). Demand for processing services is related to production activity, and more processing facilities (particularly fractionation) will be needed soon given today's market production activity in areas rich in oil, condensate and NGLs. Shale gas will likely play a large role in this demand for services as well (SEC 2011i).

As is evident in Chairman Kelliher's statement about the issuance of Order 678, natural gas storage development is a top priority. FERC is taking action "to facilitate the development of [natural gas] storage (Magill 2008)." The development of new LNG import capacity has had the ripple effect of encouraging the construction of nearby storage projects, particularly in the Gulf Coast region (Magill 2008). Like production, natural gas imports will come year round, while demand is cyclical. Therefore, gas from LNG imports during the injection season when demand is low will need to be injected into storage.

The newly-certificated projects listed in Table 37 are not the only new additions to underground gas storage; applications have been filed or will be filed with FERC for a number of pending or pre-filed projects. These projects are listed in Table 39 along with their status. These new projects total 102.2 Bcf in storage capacity; however, none are located in the Mid-Atlantic region.

The two largest recently announced natural gas storage projects are in Louisiana and Oklahoma. The Sawgrass Storage project in Louisiana will be a depleted natural gas reservoir conversion with a deliverability rate of 300 MMcf per day (Sawgrass Storage, LLC 2011). The Unigas Corporation project in Oklahoma is also a storage facility converted from a depleted natural gas reservoir. Though the Oklahoma facility will have the same working gas capacity as the Sawgrass project, the expected daily delivery is twice that of the Louisiana facility. This storage facility is part of a larger project to develop a system of pipelines and storage in Okfuskee county Oklahoma (Unigas 2007).

**Table 39. Upcoming major storage projects.**

<b>Project / Company</b>	<b>State</b>	<b>Working Gas Capacity (Bcf)</b>	<b>Status</b>
PetroLogistics Natural Gas Storage, LLC	LA	10.7	Pending
Sawgrass Storage, LLC	LA	30.0	Pending
UNIGAS Corporation	OK	30.0	Planned
Tres Palacios Gas Storage, LLC (Extension Project)	TX	9.5	Planned
Picacho Peak Gas Storage	AZ	8.0	Planned
Wabash Gas Storage LLC	IL	14.0	Pre-Filing

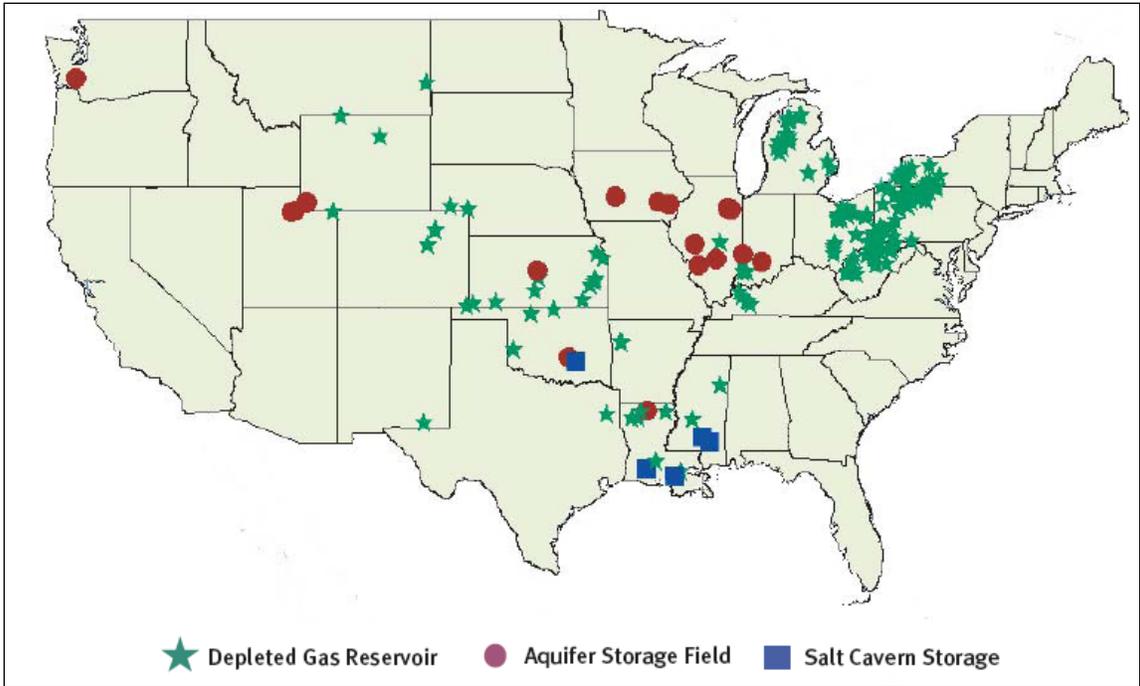
Note: Pending projects are those in which an application has been submitted, but a final FERC decision has not yet been reached; Planned projects are those that have been reported in the trade press, but an application has not yet been filed with FERC; and Pre-Filing projects are working with interested stakeholders to identify and resolve issues before an application is filed with FERC.

Source: FERC 2012b; FERC 2012c; and FERC 2012d.

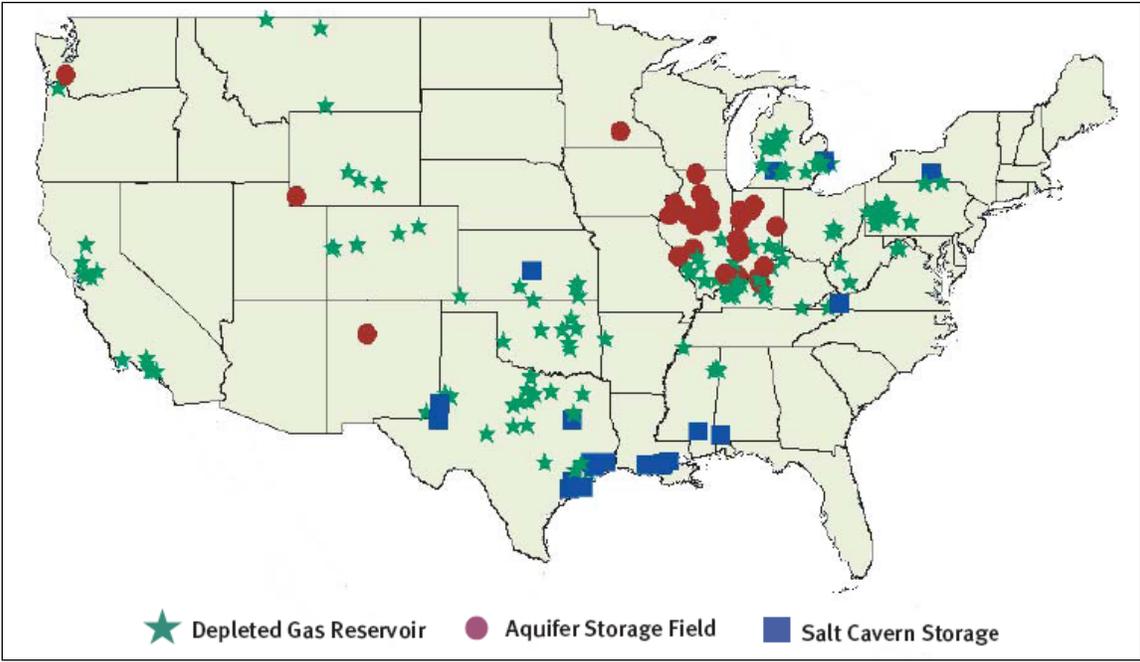
### **8.5.3 Regulatory Changes**

The main regulatory changes regarding processing are generally also related to the production process as a whole. For example, there has been a recent push of regulations regarding safety. In the Mid-Atlantic region, Pennsylvania’s Department of Environmental Protection fined one oil and gas company for contaminating groundwater, and another to suspend drilling following a blowout. Production and processing continue regardless of these changes which have increased the costs associated with production of natural gas (USDOE, EIA 2011c).

State and federal regulation covers almost all natural gas storage facilities. FERC does not have jurisdiction over all underground storage facilities (Figure 99 and Figure 100), but those owned by an interstate pipeline or integrated into the interstate pipeline network and independently operated storage projects that offer storage services in interstate commerce are under FERC’s jurisdiction (FERC 2004).



**Figure 99. FERC jurisdictional U.S. storage by type.**  
 Source: FERC 2004.



**Figure 100. Non-jurisdictional U.S. storage by type.**  
 Source: FERC 2004.

Storage facility operators who are subject to FERC jurisdiction are generally required to operate on an open-access basis by providing available storage capacity to third-parties without discriminating. Before Order 636, the storage owner was usually an interstate pipeline company and had the ability to make decisions regarding capacity allocation.

FERC issued Order 636 in 1992 to complete deregulation of the natural gas commodity market. This also marked the end of the majority of traditional pipeline merchant services. FERC focused specifically on pipeline's access to storage in the making of Order 636, because they believed that ownership of storage by pipelines generated an unfair competitive advantage in that the transportation component of firm pipeline sales would be superior to service offered to unaffiliated shippers who may not have similar storage access (Cates 2001).

Since Order 636 was enacted, competitive storage service pricing at market-based rates has become a noticeable trend. Under market-based rates, a storage developer has more freedom to better craft rates and terms of service to meet specific customer needs.

In June 2006, FERC issued Order 678, which made it significantly easier for storage providers to get market-based rate treatment for natural gas storage (Culotta 2006). This regulation was intended to encourage the development of new storage facilities. Further motivation behind the regulation was explained by FERC Chairman Joseph T. Kelliher:

Since 1988, natural gas demand in the United States has risen 24 percent. Over the same period, gas storage capacity has increased only 1.4 percent. While construction of storage capacity has lagged behind the demand for natural gas we have seen record levels of price volatility. This suggests that current storage capacity is inadequate. Further, this year, what storage capacity exists may be full far earlier than in any previous year. According to some analysts, that raises the prospect that some domestic gas production may be shut-in.... My hope is that reform of market based pricing for gas storage and flexibility on cost based pricing will help expand gas storage capacity, which in turn will help reduce the price volatility that has characterized gas markets in recent years. There is significant potential for near term expansion of natural gas storage. I hope that potential is realized (FERC 2006b).

Order 678 also expanded FERC's market-power analysis methodology to allow storage providers to include non-traditional storage alternatives, such as local production, availability of LNG, and pipeline capacity as competing sources in its market-power analyses (Culotta 2006). FERC chose this as one major focus because of the diversification occurring in the natural gas market since the 1990s.

The Commission finds it is appropriate to adopt a more expansive definition of the relevant product market for storage to explicitly include close substitutes for gas storage services, including pipeline capacity and local production and LNG supplies. As explained below, this modification to our market-power analysis better reflects the competitive alternatives to storage and is supported by changes in the natural gas markets that have occurred since the mid-1990s. In today's markets, these non-storage products may well serve as adequate substitutes for gas storage in appropriate circumstances (FERC 2006c).

The second major focus of Order 678 was to implement NGA Section 4(f), which gives FERC the authority to grant market-based rates to new storage facilities, even if they cannot demonstrate that they lack market power. Thus, as long as it is in the public interest and is necessary to encourage needed storage capacity development, new storage facilities will be able to charge market based rates (Culotta 2006). This provision applies to both greenfield storage and expansions of current facilities because of the useful potential capacity available at said existing locations.

Since 2006, the only major regulations regarding natural gas storage was Order No. 757, which eliminated the semi-annual storage reporting requirements for Interstate and Intrastate Natural Gas Companies.

## **8.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

The Mid-Atlantic region does not play a significant role in gas processing, with the exception perhaps of Pennsylvania which only has 9 processing facilities (USDOE, EIA 2006b). This could change in the future however, depending upon production in the area resulting from shale gas.

There are 54 underground natural gas storage sites in the Mid-Atlantic impact region; the majority are depleted gas reservoirs found in Pennsylvania. In all, these facilities provide ten percent of the working gas capacity of underground storage for the U.S. as a whole (USDOE, EIA 2012d).

The Marcellus Shale is the likely site of the majority of near-term development in the Mid-Atlantic region because of its potential to bring very large quantities of natural gas to the market. It is estimated to be the second largest known natural gas play in the world, and the largest geographic gas-producing area in the U.S. (Caiman 2012). The Marcellus Shale extends across parts of West Virginia in the northern Appalachian Basin and into Pennsylvania and New York. Historically, coal has been the most depended-upon resource in this region. However, with the discovery of the Marcellus Shale in 2009, and the progressively optimistic outlook of its contents since, state and regional leaders are enthusiastic about the development of the region's natural gas resources as the new fuel (particularly eastern Pennsylvania and northwestern West Virginia) (Caiman 2012).

Caiman Energy LLC has built a cryogenic plant in the Marcellus Shale in West Virginia as of 2011, and has planned two additional plants based on drilling projections. These plans incorporate plans for additional large-diameter pipelines and gathering lines. Mark West Liberty Midstream & Resources LLC along with Sunoco Logistics LP are also working on a project, the Mariner West project, which is designed to deliver Marcellus shale-produced ethane to Ontario with pipelines beginning in Pennsylvania (Oil and Gas Journal 2011).

Earlier in this chapter major businesses involved in processing and storage were discussed. DCP Midstream, for example, has no processing plants in operation in the northeast. Instead, they operate wholesale propane terminals in this area to ease facilitation of delivery to natural gas customers in the area (DCP Midstream 2012). The underlying reason there are no major processing plants in this region is due to their location near producing areas. If shale gas is further used where it has been found then it will make sense to develop processing plants near that gas production (Oil and Gas Journal 2011).

## **8.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

The need for gas processing along the Mid-Atlantic OCS will be a function of the degree to which wet and sour gas volumes are anticipated to be produced from offshore areas. Assuming gas processing is needed, which is likely given the increased use of shale gas, for example, many of the same factors influencing gas transportation will be important, including:

- a. Location: gas processing facilities will be located as close to production as economically feasible;
- b. Volumes: production volumes will influence the processing capacity; and
- c. Commercial factors: the ability to store, transport, and market the natural gas liquids processed from the gas stream will be important in determining facility configuration.

The development of new storage infrastructure could help customers maintain service reliability while at the same time managing commodity price volatility (FERC 2004). A number of natural gas storage facilities have been identified in the Mid-Atlantic states; the majority of them are depleted reservoirs. Gas storage will likely be developed in this area in the future to support new production volumes. Some characteristics that will be important in future development include:

- a. Location: gas storage will likely be located in proximity to new areas of production, but exact location decisions will be a function of both the ultimate location of production and the geological capabilities of creating underground storage.
- b. Capacity: the size of a storage facility will be a function of the perceived volumes available to be stored from the Mid-Atlantic OCS and the commercial consideration of the developer. There could be trade-offs between a single large storage facility and a larger number of smaller facilities.
- c. Deliverability: type of cavern and size of injection well will be driven by deliverability goals and the location and number of proximate pipelines and potential storage customers.

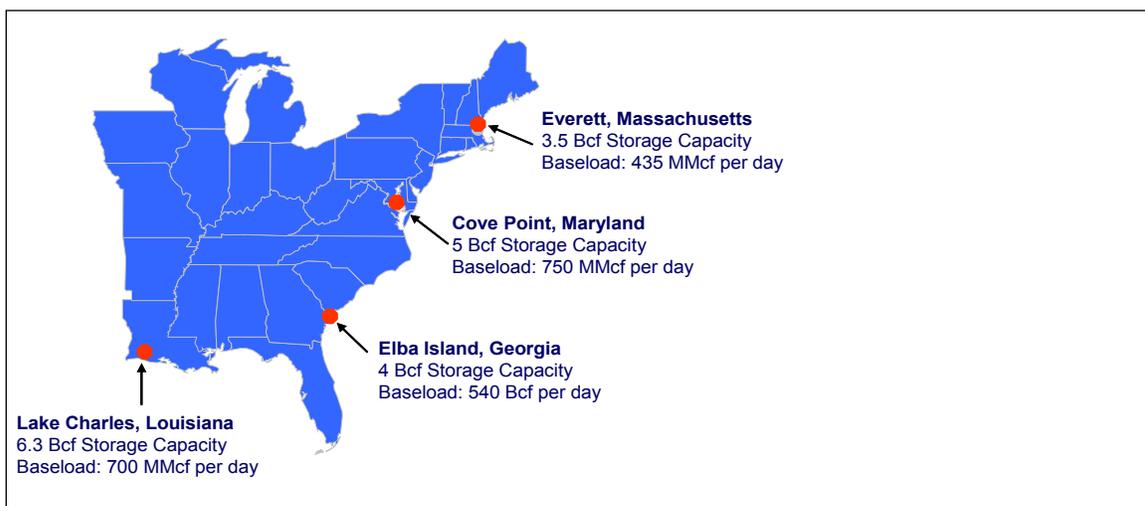
The majority of storage facilities currently located in the Mid-Atlantic region are depleted reservoirs. It is likely that reservoir-based storage will continue to be the more common facility used to support offshore production given its base-load nature. However, a salt-based facility is not unlikely and one has been developed recently in the Virginia area (i.e., Saltville).

## 9 LIQUIFIED NATURAL GAS

### 9.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED

Liquefied natural gas (LNG) is natural gas converted to liquid form by cooling it to a temperature of  $-256^{\circ}\text{F}$ , the point at which gas becomes liquid. Once liquefied, natural gas can be transported from an area of abundance to an area where it is needed. After the LNG arrives at its destination, it is either stored as a liquid, or converted back to natural gas and delivered to end-users. Liquefying gas is not a new process or technology, it is simply a process by which the physical properties of natural gas, primarily methane, are altered in order to transport the commodity from markets where it is abundant to those more limited in supply (Dismukes 2008).

The natural gas price controls and production shortages of the late 1960s led many U.S. energy planners to look at alternative sources of natural gas to meet domestic energy needs. The energy crisis of the 1970s provided the impetus for the first generation of LNG regasification facilities in the U.S. During this period, four LNG facilities were developed in the eastern U.S., as shown in Figure 101, for the express purpose of importing natural gas. Two of these LNG regasification facilities (Cove Point, Maryland and Elba Island, Georgia) are within the potential impact area for future East Coast oil and gas activity.



**Figure 101. Initial U.S. LNG terminals and original capacity.**

Source: FERC 2012.

Despite the growth of LNG regasification in the late 1970s, policies, markets, and the underlying economics of natural gas production changed relatively quickly and left these newly developed facilities economically stranded for almost 20 years. In fact, two of the facilities shut down (Cove Point and Elba Island), while the other two suffered low use (Everett and Lake Charles) (Tusiana and Shearer 2007). It was not until the early part of 2000 that the dynamics of natural gas supply and demand led to renewed interest in natural gas imports and re-activation of these legacy LNG regasification facilities. In 2002, FERC issued what became known as the Hackberry Decision granting preliminary approval for the construction of the first LNG regasification facility in over 20 years. The facility, originally developed by Dynegy, is located in Hackberry, Louisiana (USDOE, EIA 2012f).

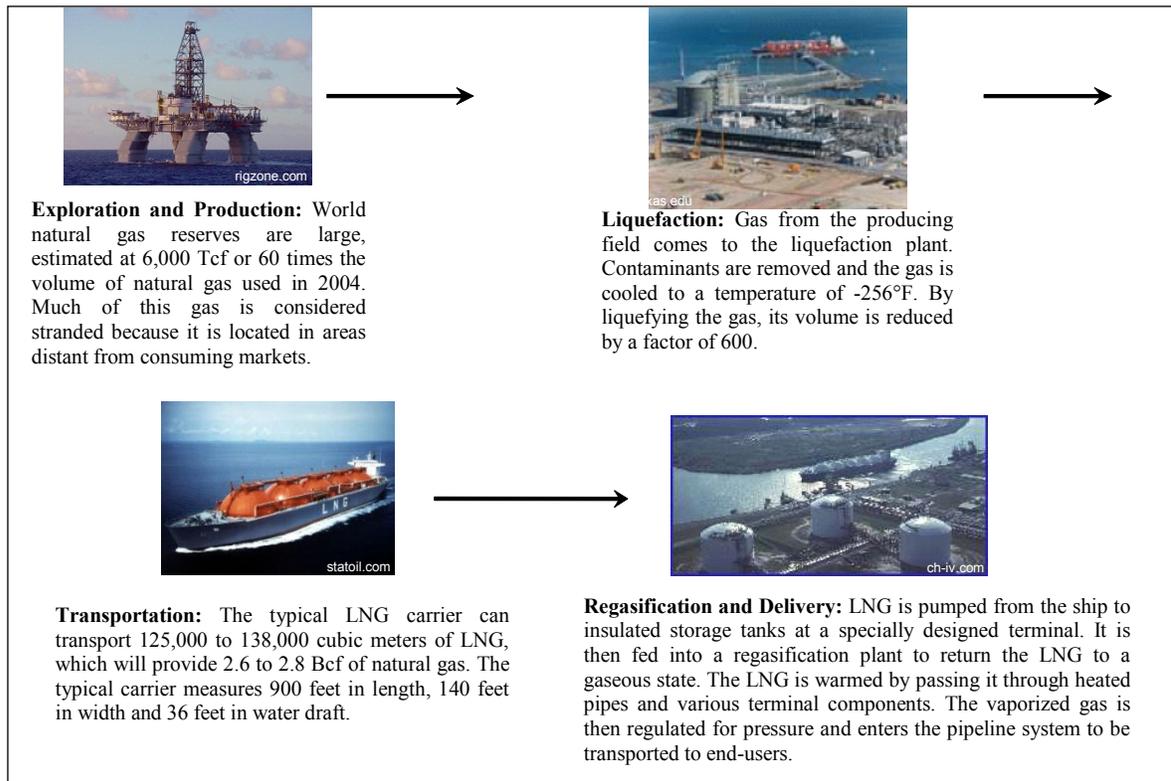
Forecast growth in natural gas usage, with limited domestic supply capabilities, was the factor motivating developers into the construction of new LNG regasification facilities. By the early to mid-2000s, the size of the U.S. natural gas market was anticipated to increase substantially. At the time, DOE forecasted that U.S. natural gas imports (primarily through LNG regasification) would need to grow by as much as 50 percent by 2030 (USDOE, EIA 2007b). The source of this imported natural gas was anticipated to come from the prolific conventional reserves around the world which were estimated to be around 6,200 trillion cubic feet (Tcf), at the time many of these second generation LNG regasification facilities were being developed (USDOE, EIA 2007b).

The renaissance of LNG regasification, however, was short lived. High natural gas prices and supply disruptions created by the tropical activity during the 2004 and 2005 hurricane seasons along the Gulf coast, led to significant natural gas drilling activity, particularly exploratory drilling for unconventional natural gas resource found in various shale plays in Texas, Louisiana, and the mid-continent areas of the U.S. Natural gas from proven and unproven shale resources totals as much as 542 Tcf. Today, U.S. technically recoverable reserves are estimated to be 2,214 Tcf (USDOE, EIA 2012g).

This immediate change in the future natural gas outlook has changed U.S. domestic interest away from the importation of natural gas, and towards being an exporter to other places in the world. Both the legacy and recently-developed LNG regasification facilities, are proposing to change their configuration from one focused on imports, to one focused on exports. Considerable new investments will need to be made at the facilities proposing to export natural gas produced, primarily from unconventional shale resources. Any increase to U.S. natural gas supplies, either unconventional, or conventional (like production likely to arise from any future lease sales off the Atlantic seaboard), will increase the opportunities for U.S. natural gas exports.

## 9.2 TYPICAL FACILITY CHARACTERISTICS

The LNG value chain, shown in Figure 102, is made up of the various stages of natural gas conversion, transportation, and delivery. The first part of the value chain is the exploration and production process, during which natural gas wells are drilled, reserves are developed, and production begins. Natural gas production is delivered, usually by pipeline, to a facility dedicated to the second part of the value chain: liquefaction. Liquefaction is a process that converts natural gas to a liquid through a super-cooling process. On-site insulated tanks are used as intermediate storage facilities before the gas is transported internationally. This intermediate storage helps to regulate the flow of natural gas since it cannot be transported in its liquid form in a continuous state.



**Figure 102. LNG Schematic – production to end-user.**

Source: Dismukes 2008.

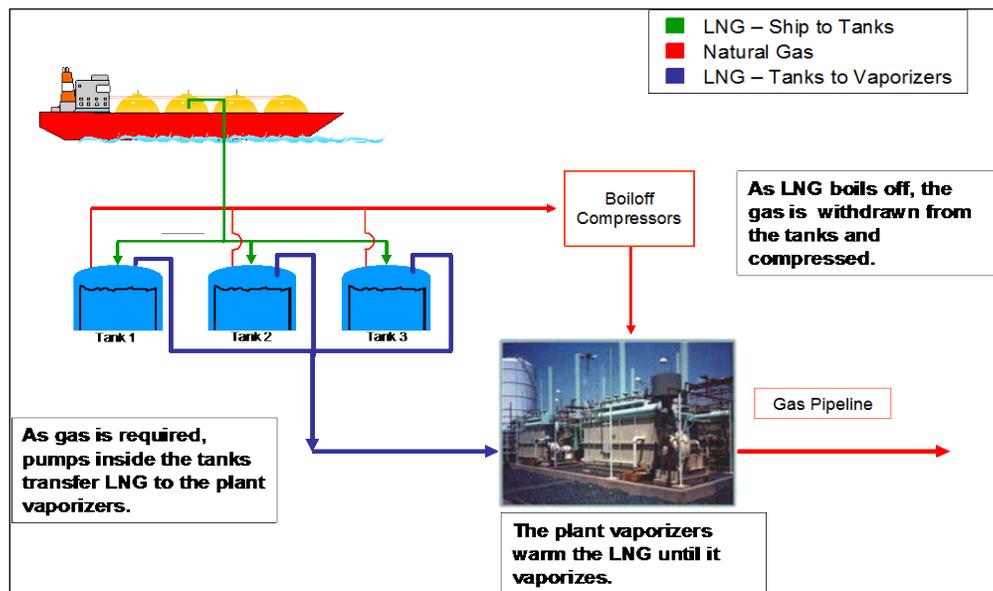
The third part of the LNG value chain is transportation, usually through specialized ships that have their own insulated storage to keep the gas in its cooled and liquefied state until it is delivered to its destination market. Any gas that naturally regasifies during the transport process (known as boil-off) is used as transportation fuel during the trip. Tankers can typically hold as much as 2.9 Bcf of natural gas (USDOE, EIA 2003). Today, tankers are being constructed to move as much as 3.7 Bcf of natural gas (Colton Company 2012b).

A typical 2.9 Bcf tanker can hold enough natural gas to fuel: (1) a typical natural gas-fired steam electricity plant for one to two months, (2) serve over 50,000 typical residential customers for a year; or 5 moderately-sized industrial facilities (Dismukes 2008). As of February 2012, there were 361 LNG carriers worldwide and 58 under construction (Colton Company 2012b).

The last step in the LNG value chain is the regasification process, which gradually heats the imported LNG on a steady and controlled basis and then delivers that natural gas to local destination markets or intermediate storage for future delivery to end-users. On-site insulated tanks can also serve as intermediate storage facilities at the regasification location to regulate the potentially intermitted flow of imported LNG.

To date, all of the LNG facilities developed along the Eastern seaboard or the Gulf Coast are regasification facilities. The other three components of the LNG value chain (production, liquefaction, and transportation) originate in other locations depending upon the source of the natural gas. As will be discussed later, several facilities originally developed as regasification locations are now considering additional investments to give the facilities full liquefaction capabilities. These types of investments will allow facilities to import or export gas based upon U.S. and global market conditions.

Figure 103 presents a general schematic of the LNG regasification process. The process does not differ much between onshore and offshore receiving terminals used across the U.S. The first step of the regasification process consists of unloading LNG from ships into a series of intermediate storage tanks. The physical process of offloading the LNG cargo usually takes about 10 to 12 hours, but depends on the capacity of the regasification facility (Cheniere 2012). The typical capacity for an onshore facility ranges between 1 Bcf per day to 3 Bcf per day. For an offshore facility, the typical capacity ranges from 0.5 Bcf per day to 1.5 Bcf per day.



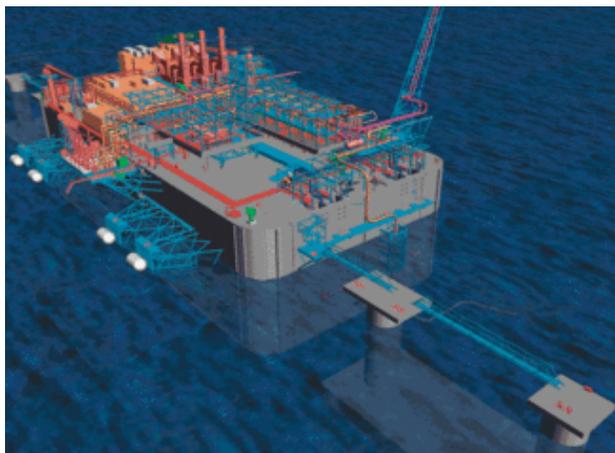
**Figure 103. Receiving terminal – LNG gas flow.**

Source: Dismukes, et al. 2004.

The next step in the regasification process is to heat and vaporize the LNG. The primary method is to use heat treaters or vaporizers to warm the gas and convert it from a liquid to a gaseous state. From there, the gas is injected into large interstate or intrastate pipelines for delivery to markets (end-users) or intermediate storage facilities that are commonly used for domestic natural gas production.<sup>14</sup> Any boil-off associated with the liquid natural gas in storage is captured, compressed, and then combined with gas from the vaporizers to feed into pipelines for delivery to end-users or intermediate storage facilities.

Two types of regasification facilities, offshore and onshore facilities, are currently in operation or development along the GOM. Onshore regasification facilities have existed for over 40 years. The primary difference between onshore and offshore facilities tends to be the capacity levels of the facilities. Onshore LNG regasification facilities are typically located at or near major ports, where LNG tankers arrive and unload their cargoes. Because of their port locations, these LNG regasification facilities are referred to as “marine” facilities. Homeland security concerns, however, have led to greater interest in locating these regasification facilities further offshore away from what are usually densely-populated areas around coastal and port areas.

Offshore are newer types of facility that have had little historic application even though they tend to use many of the same types of technologies and equipment facilitated by their onshore counterparts. The following lists some of the various types of offshore LNG regasification facilities proposed over the past several years.

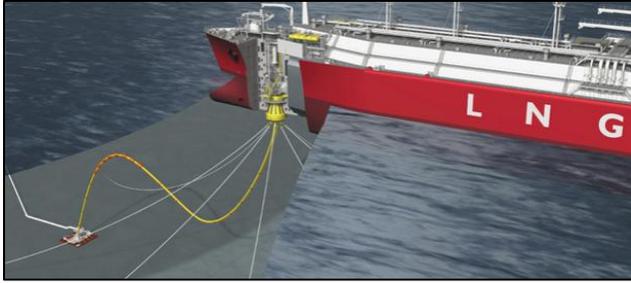


A **Gravity-Based Structure (GBS)** has two large concrete caissons that are towed to the site and lowered to rest on the sea floor. LNG carriers offload their cargoes into storage tanks on the GBS. The topside of the GBS houses vaporizers and other equipment to warm the LNG and return it to its gaseous state. The gas is then transported by pipeline to onshore processing facilities for delivery to end-users.

Source: True and Sen 2007.

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<sup>14</sup> These intermediate storage facilities are typically underground natural gas storage facilities which are developed from various geological formations such as abandoned aquifers, oil and gas reserves, and salt caverns.



Source: Excelerate Energy 2014.

At a **Buoy or Energy Bridge**, specially designed regasification vessels dock with a subsurface buoy that is permanently anchored offshore. The LNG is returned to its gaseous state onboard the regasification vessel and delivered to the buoy. The natural gas is then sent through the buoy and flexible rise to a subsea pipeline. The offshore pipeline brings the gas onshore and delivers it to end-users.



Source: AMOG Consulting 2008.

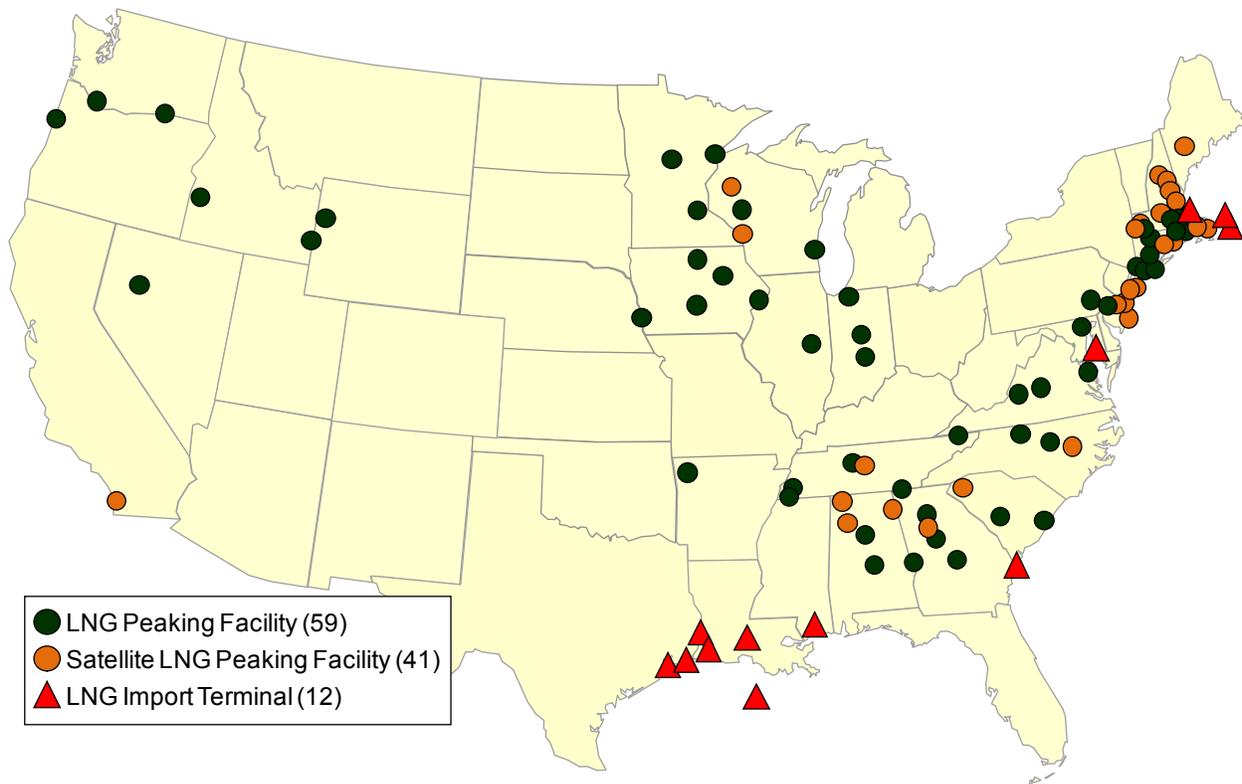
**Floating Storage and Regasification Units (FSRU) or Floating Production, Storage, and Offloading (FPSOs)** are floating regasification systems where the vaporizer, storage, and other equipment is housed on the vessel itself. The vessel tethers to a buoy-based system during the regasification process. The tether connects the ship and vaporization equipment to the subsea pipeline system. Regasified LNG (natural gas) is then delivered to end-user markets or intermediate storage. When the offload is complete, the ship can leave the system to get additional cargoes. The FSRU system would be permanently moored to a tether system and would serve as an intermediate station for offloading LNG.

### **9.3 GEOGRAPHIC DISTRIBUTION**

LNG is not a new means for transporting natural gas from, within, and to the U.S. In addition to the large, recently-developed marine terminals developed for importing LNG, there are numerous small LNG liquefaction and regasification facilities throughout the U.S. These small facilities have been in operation for several decades and have been used by LDCs as a form of storage that can be tapped during peak winter use periods to shaving very high weather-related surges in natural gas demand usage (also known as a peak shaving resource).

Most, LDC peak-shaving facilities have a regasification unit attached, but not all have a liquefaction unit. Facilities without regasification equipment are known as “satellite” facilities and must rely upon tank trucks to deliver LNG from other producing or transportation terminal areas. Figure 104 provides a map with the location of several different types of LNG facilities located throughout the country. As shown in the figure, about half of the LNG facilities in the U.S. are peak-shaving facilities, and well over half of the total LNG capacity around the country is associated with the larger marine terminals.

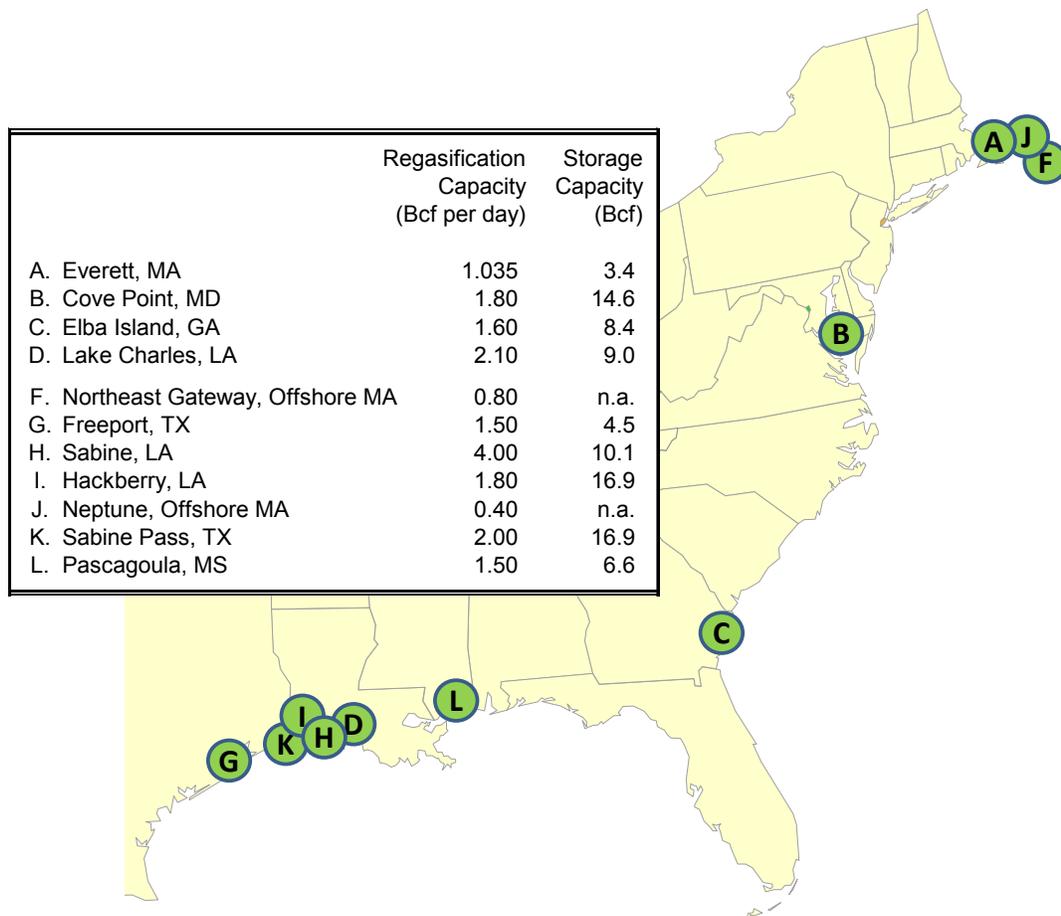
New facility investment and development over the past several years has focused almost exclusively on the large marine terminals located primarily along the GOM and the eastern seaboard, including the potential Mid-Atlantic impact area for future offshore oil and gas activities. Four of the original LNG import facilities, developed in the late 1970s and early 1980s, are located along the Atlantic and GOM coasts. And three of the four legacy LNG regasification facilities are along the East Coast; two of which are located in the Mid-Atlantic impact area (Cove Point, Maryland and Elba Island, Georgia). The last remaining legacy LNG asset is in Lake Charles, Louisiana.



**Figure 104. U.S. LNG facilities.**  
 Source: USDOE, EIA 2008b; and FERC 2012e.

Figure 105 provides an expanded view of the currently active LNG facilities located in the U.S. All four legacy LNG facilities are still active, and each has had significant capacity expansions and upgrades over the past five years. An additional seven facilities are now also in operation. These facilities are included in the figure below. Approximately 12 Bcfd of capacity has been developed at these new greenfield LNG facilities.

Last, there is also one formerly operational facility, the Gulf Gateway Energy Bridge that was retired in 2011. The Gulf Gateway Energy Bridge, developed in 2005, was the world’s first deepwater LNG port and was located 116 miles (187 kilometers) off the south coast of Louisiana in 298 feet (91 meters) of water with the capability to deliver approximately 3 Bcf of regasified LNG into the pipeline grid through the Sea Robin and Blue Water subsea systems at a rate of about 500 MMcf per day (Excelerate Energy 2008a). However, citing changing market conditions, Excelerate Energy announced it would retire this facility in April 2011 (Oil & Gas Journal 2011). In addition, Excelerate Energy noted that in 2008, Hurricane Ike had caused significant damage to both pipeline systems that serviced the Energy Bridge and that neither pipeline had been able to return to its prior level of service or provide adequate capacity. The Gulf Gateway Energy Bridge was not damaged by Hurricane Ike (Excelerate Energy 2011).



**Figure 105. Current U.S. LNG import terminals.**

Source: FERC 2012e.

Combined, these eleven active LNG regasification facilities account for 18.5 Bcfd of import capacity, which, if fully used, could supply up to 30 percent of total U.S. natural gas demand of 61 Bcfd, on average. LNG facilities located along the GOM were originally developed to take advantage of the unique infrastructure. Large users, Atlantic-based LNG regasification facilities, were developed almost exclusively as a needed source of supply for large residential and commercial end-use markets.

Five of the eleven facilities are on the Atlantic coast. These facilities total 5.6 Bcfd, or 30 percent of total U.S. LNG regasification capacity. Of these five facilities, only two are located within the potential impact area for future East Coast oil and gas activity. These two (Cove Point, Maryland and Elba Island, Georgia) total 3.4 Bcfd of import capacity, which represents 60 percent of the capacity on the Atlantic coast; and 18 percent of total U.S. capacity.

The Cove Point, Maryland facility is located on the Chesapeake Bay just south of Baltimore. Built by Consolidated Natural Gas Company and Columbia Gas System in the 1970s, it received its first LNG shipment in 1978 (Downstream Today 2012). The facility had an original peak send out capacity of 750 MMcf per day and storage capacity of five Bcf. However, after just two short years of operation, in 1980 the terminal was shut down due to unfavorable market

conditions (CEC 2012). In 1988 Consolidated sold its interest in Cove Point to Columbia who in turn sold the terminal to Williams in 2000. Dominion purchased Cove Point from Williams in 2002 for \$217 million (PR Newswire 2002). At the time, the facility was used for storage (five Bcf) and employed 25 people (PR Newswire 2002). Dominion reactivated the facility and received its first LNG shipment at Cove Point in the summer of 2003. In 2006 Dominion began construction on an expansion of the facility. The expansion was finished in 2009 and increased the facility's output capacity from 1 Bcfd to 1.8 Bcfd. Storage capacity at the facility was also increased from 7.8 Bcf to 14.5 Bcf (Downstream Today 2012).

Today, Cove Point receives LNG from various locations including Trinidad, Nigeria, Norway, Venezuela, and Algeria. A single ship typically delivers 34 million gallons of LNG, which, according to Dominion, is enough to supply more than 10 million homes (Dominion 2012). In addition to serving the natural gas markets of the Mid-Atlantic, the facility also serves a number of Dominion Energy's natural gas-fired electric generation facilities including Possum Point, Remington, Ladysmith, and Fairless Works (Dominion 2012).

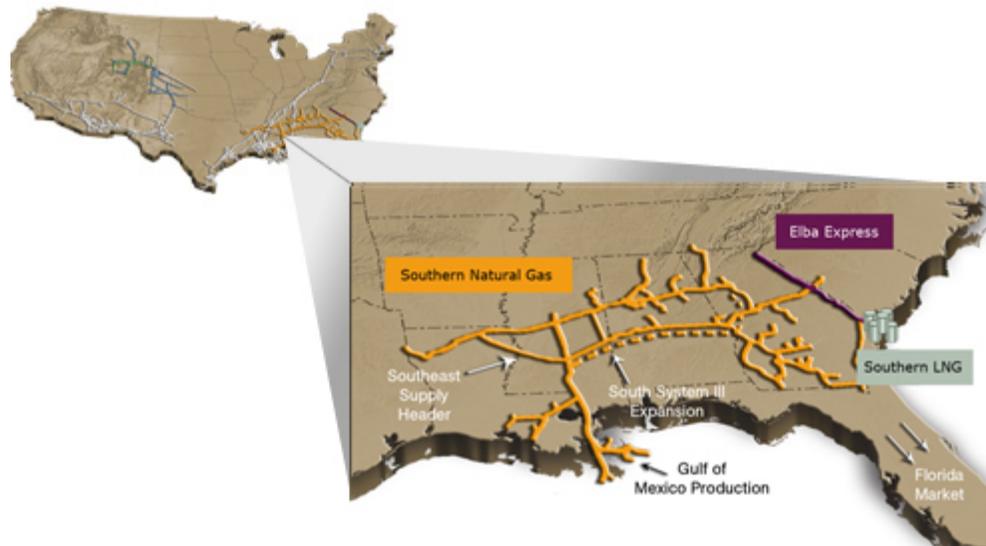


**Figure 106. Cove Point LNG.**

Source: LNG World News 2012.

Elba Island is the other LNG import terminal located within the potential impact area. Located near Savannah, Georgia, the terminal was built by Southern LNG, a part of the El Paso Corporation, to supply natural gas to the growing population and industrial base of the southeastern U.S. The facility was brought online in 1978 with a peak send out capacity of 540 MMcf per day and storage capacity of 4 Bcf (Sen 2001). And, like Cove Point, the Elba Island facility was shuttered in 1982. After almost 20 years, in 2001 market conditions had turned enough that the terminal was reopened (CEC 2012). And, in 2003, Southern received approval to expand Elba Island's sendout capacity. This expansion increased the peak sendout capacity by 540 MMcfd and the base load send out capacity by 360 MMcfd and was expected to cost \$157 million (SEC 2004). Southern announced plans for further expansion of the terminal in December 2005. The Elba Island Phase III expansion added storage capacity, which now totals

11.5 Bcf (El Paso 2012). Send out capacity was also increased by 0.9 Bcfd and unloading docks at the terminal were upgraded to accommodate new and larger LNG ships (El Paso 2005).



**Figure 107. Elba Island LNG.**

Source: El Paso 2012.

Though these facilities still represent a significant source of potential natural gas supply, recent development and production of natural gas in the various shale-producing regions of the U.S., has changed the importance and attractiveness of LNG imports. In fact, as will be discussed later, many large LNG regasification facilities are now seeking licenses to export what is becoming a glut of relatively affordable domestically-produced natural gas supplies for foreign market consumption.

## 9.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY

LNG regasification facilities tend to be very capital intensive and employ relatively few workers. Research has found that on average, approximately 33 workers are employed per Bcfd of regasification capacity. Given this limited number of employees, and the fact that employment data for LNG facilities tends to not be released due to data disclosure purposes, an estimate based on this average is provided in Table 40.

**Table 40. Estimated number of employees by LNG facility.**

<b>Facility</b>	<b>Capacity (Bcfd)</b>	<b>Estimated Employees</b>
Everett, MA	1.035	34
Cove Point, MD	1.80	59
Elba Island, GA	1.60	52
Lake Charles, LA	2.10	69
Northeast Gateway, Offshore MA	0.80	n.a.
Freeport, TX	1.50	49
Sabine, LA	4.00	131
Hackberry, LA	1.80	59
Neptune, Offshore MA	0.40	n.a.
Sabine Pass, TX	2.00	65
Pascagoula, MS	1.50	49

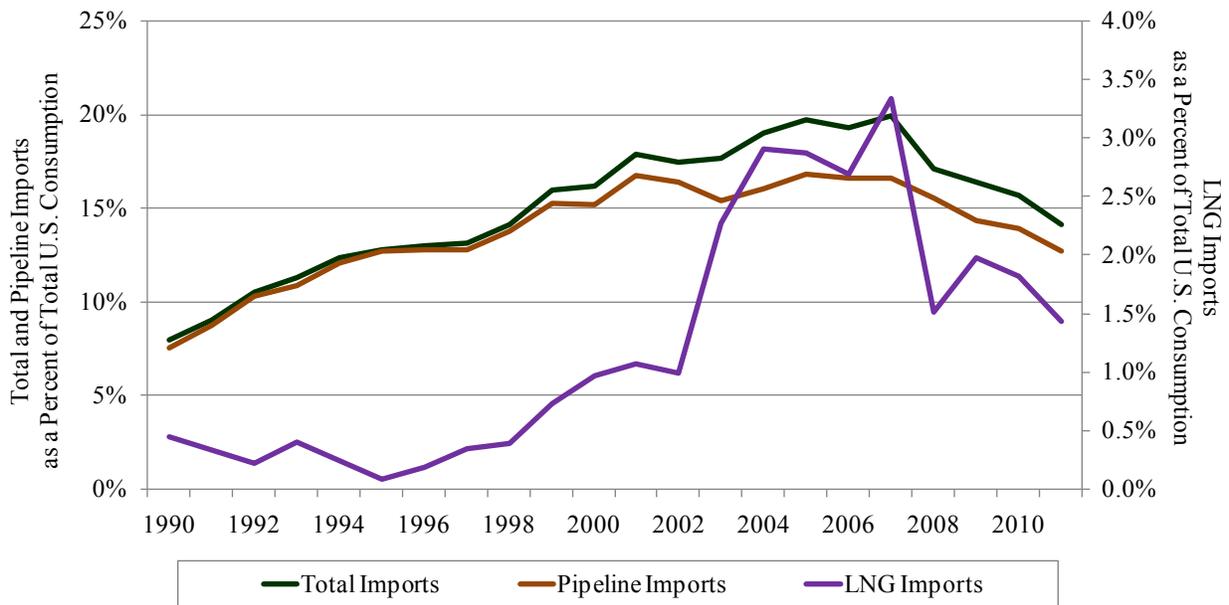
Source: FERC 2012e and Author's estimate using various resources.

## 9.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

### 9.5.1 Trends

Historically, LNG imports have represented a small share of overall U.S. natural gas supply. The overwhelming majority of U.S. gas supplies used to meet demand have come from producing fields in the lower 48 states. The limited amount of natural gas that has been imported into the country, outside of LNG, has been from pipeline imports from Canada. Figure 108 shows overall natural gas import trends over the past two decades.

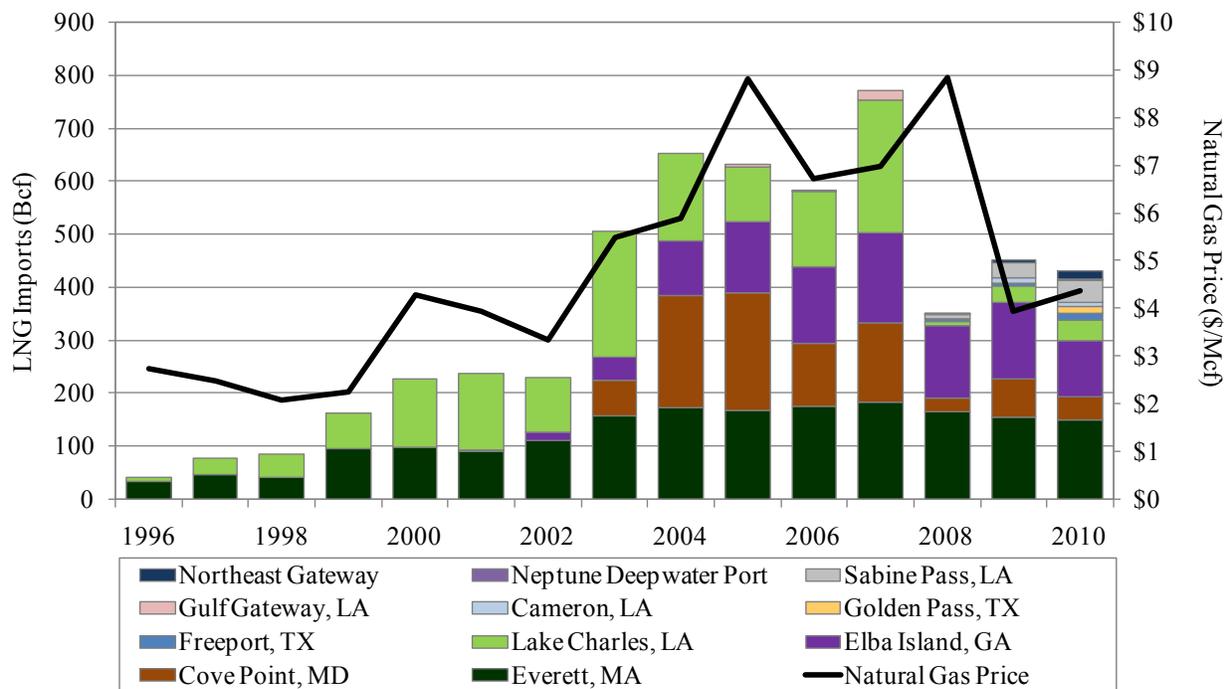
The left axis graphs total imports and pipeline imports (the difference between the two series being LNG). The right side of the figure shows the growing share of LNG as a percent of total consumption. LNG imports peaked in 2007 to a high of 17 percent of total imports and 3.3 percent of total U.S. consumption. This represents an increase of over 4,000 percent since the low of 1995 and almost 240 percent since 2002. However, those shares have fallen considerably since the 2007 peak and today, LNG imports have returned to levels comparable to the early 2000s before the era of the U.S. natural gas supply bubble.



**Figure 108. U.S. natural gas imports as a percent of total consumption, 1990-2011.**

Source: USDOE, EIA 2012d.

Figure 109 shows historic LNG imports per facility since the mid-1990s. The left side of the graph measures total LNG imports (in Bcf) and the right side compares those imports to trends in Henry Hub natural gas prices (i.e., wholesale prices). The graph shows the increase in imports from all three terminals starting in 2001, when Elba Island became operational. Clearly, the import trend has increased considerably since natural gas prices began their climb in 2000, though it actually slowed during 2005 and 2006 due to European and Asian competition. Today, imports from all facilities have decreased considerably; although the East Coast facilities have suffered less than those along the GOM. Today, collectively, the Atlantic-based facilities have seen LNG imports decrease by as much as 40 percent from their 2007 high.

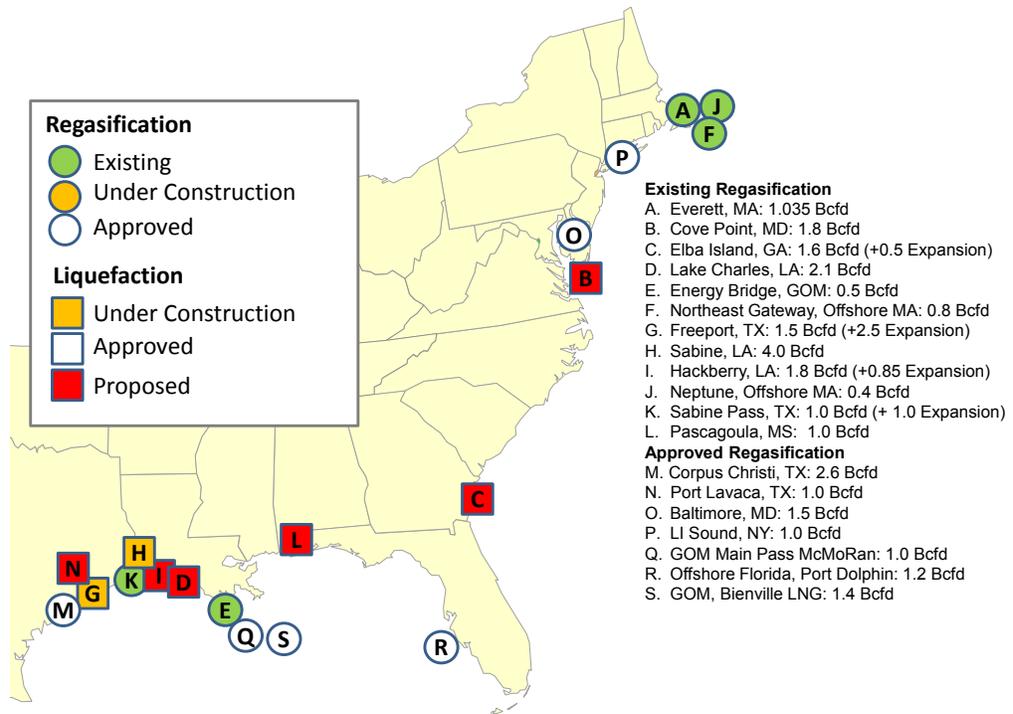


**Figure 109. LNG imports and natural gas price.**

Source: USDOE, EIA 2012d; and Federal Reserve Bank of St. Louis 2012.

In addition to the expansions at existing facilities, there has been a plethora of new facility announcements made since approximately 2005. At one time, there were well over 40 proposed LNG regasification facilities for location throughout the U.S. including the eastern seaboard, the GOM, the Florida coast, and the Pacific coast. Many facilities were announced for both onshore and offshore development. However, to date, very few of the announced new, greenfield facilities have actually reached commercial operation with one of these actually being prematurely abandoned (Energy Bridge) in 2011.

Figure 110 provides a map of the active LNG regasification facilities in the U.S. This map represents a change from other past LNG development representations since it includes several facilities that have requested the ability to export LNG in addition to their currently-authorized ability to import natural gas.



**Figure 110. Existing and proposed North American LNG terminals.**

Source: FERC 2012e.

Currently, there are 15 applications, totaling 18.7 Bcfd, requesting the ability to export natural gas (USDOE, OFE 2012a). The Natural Gas Act of 1938 requires a potential exporter to attain authorization from the U.S. Department of Energy’s Office of Oil and Gas Global Security and Supply, Office of Natural Gas Regulatory Activities. Section 3(a) of the Natural Gas Act, sets forth the statutory criteria for review of the instant export application:

[N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy]<sup>15</sup> authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary’s] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate. [USDOE, OFE 2011]

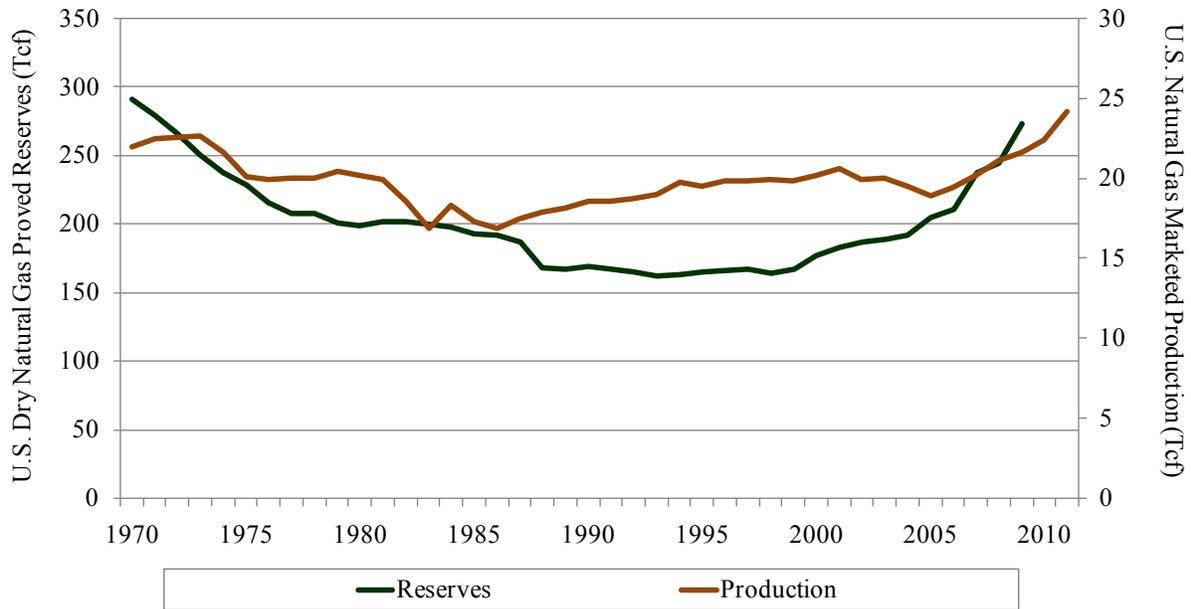
<sup>15</sup>The Secretary’s authority was established by the DOE Organization Act which transferred jurisdiction over imports and export authorizations from the Federal Power Commission.

The Department of Energy's review of export applications focuses on the domestic need for the natural gas to be exported and whether these exports pose a threat to domestic natural gas supply. The application must also be consistent with the Department of Energy's policy of "promoting competition in the marketplace by allowing parties to negotiate their own trade arrangements." (USDOE, OFE 2011) In addition, the National Environmental Policy Act requires the Department of Energy to consider any environmental effects of its proposed decision.

Nine facilities have requested authorization to export domestically produced LNG to both free trade agreement (FTA) and non-free trade agreement (non-FTA) countries. The other six have requested only authorization for FTA exports. Currently, the DOE has approved one facility, Cheniere Energy's Sabine Pass, for export to both FTA and non-FTA countries (USDOE, OFE 2012a). Most facilities have received approval to export LNG to FTA countries, but they have not yet received approval to export to non-FTA countries. As of June 2012, two East Coast facilities, Cove Point, Maryland and Elba Island, Georgia, have applied for export authorization.

Cheniere Energy's existing Sabine Pass regasification facility will be retrofitted to be used for liquefaction and export (USDOE, OFE 2012b). Project capital costs for liquefaction plants range from \$1.5 to \$10 billion dollars, and the Cheniere project is estimated to cost \$10 billion (USDOE, EIA 2012h; Wingfield and Carroll 2012). Cheniere expects that approximately 3,000 jobs will be created or continued during the design, engineering, and construction of the project, and 150 to 250 full-time positions will be required to maintain and operate the export project (Sabine Pass 2010). In addition, Cheniere estimates that the project will support another 30,000 to 50,000 new permanent jobs associated with natural gas upstream development (Sabine Pass 2010).

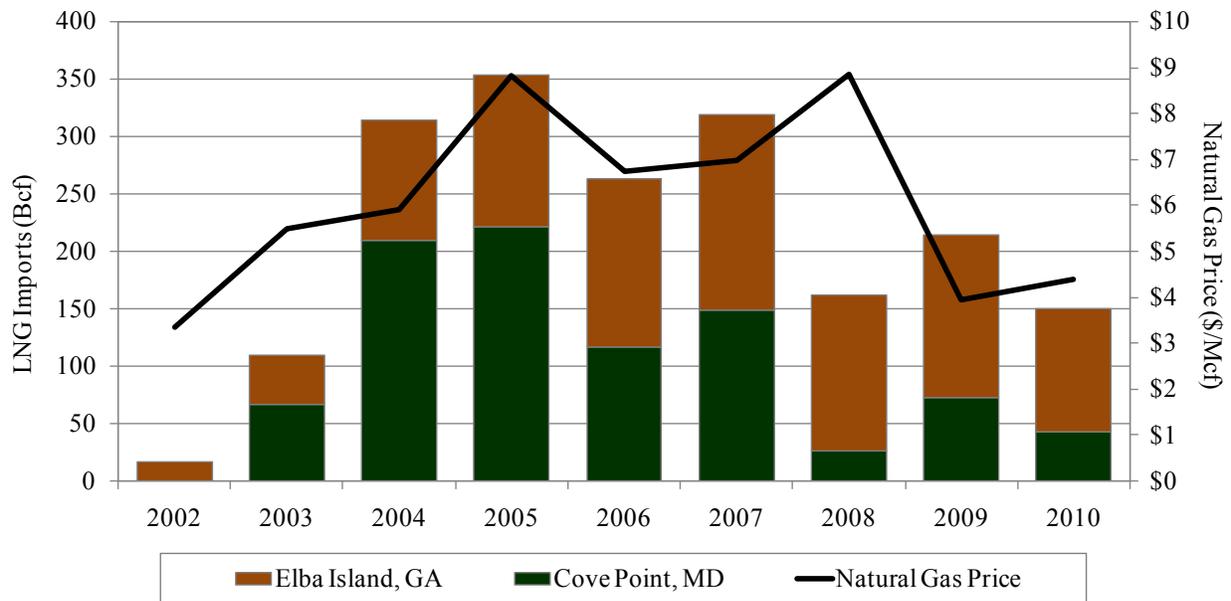
Current regasification facilities interested in exporting natural gas will likely be required to make significant capital investments primarily in the form of liquefaction facilities to convert domestically produced natural gas, primarily from the shale formations developing throughout the U.S. The dramatic increase in natural gas reserves that has arisen over the past several years currently places the U.S. at 273 Tcf of proven resources (Figure 111). The Department of Energy's, Energy Information Administration (EIA) most recent Annual Energy Outlook, puts the estimated unproved technically recoverable resource (TRR) of shale gas for the U.S. at 482 Tcf.



**Figure 111. U.S. natural gas production and reserves.**  
 Source: USDOE, EIA 2012d.

## 9.6 CURRENT TRENDS AND OUTLOOK: EAST COAST

Two of the current LNG regasification facilities (Cove Point, MD and Elba Island, GA) are located within the potential impact area for future East Coast oil and gas activity. Figure 112 shows the significant decline in LNG imports for these two facilities, and imports have fallen even further since 2010.



**Figure 112. LNG imports and natural gas price.**  
 Source: USDOE, EIA 2012d; and Federal Reserve Bank of St. Louis 2012.

The decline in imports has been driven largely by the development of shale gas in the U.S. and demand for LNG and higher gas prices in other countries. Given this abundance of domestically produced, low-cost natural gas, at least two of the impact area facilities have applied for exportation authorization.

The Cove Point LNG terminal will operate as a bi-directional facility, allowing Dominion Energy to export LNG when natural gas prices in the U.S. are low and to import LNG if and when market conditions change. Dominion Cove Point LNG (DCP) is proposing to export up to the equivalent of 1 Bcfd and anticipates its liquefaction facility to come online in 2016 (DCP 2011). DCP also believes its facility is well positioned to export natural gas from the Marcellus Shale and the Utica Shale (DCP 2011). In addition, the facility is connected directly or indirectly to transmission lines that carry gas from the production regions of the Gulf Coast, and shale plays in the south (the Fayetteville in Arkansas, the Haynesville in Louisiana, and the Barnett in Texas).

The DCP application for export states that it expects construction and operation of the liquefaction project to create and support between 2,700 and 3,400 jobs, and 1,000 additional indirect jobs throughout Maryland.

## **9.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

There are currently two LNG regasification facilities located along the Atlantic coast. Imports through both of these facilities have decreased significantly in recent years. Given the surge in estimated reserves and domestic natural gas supply, it is likely imports will remain low and these facilities under-used.

Because of the development of shale and increased natural gas supply, a number of facilities have applied to the Department of Energy for authorization to export natural gas.

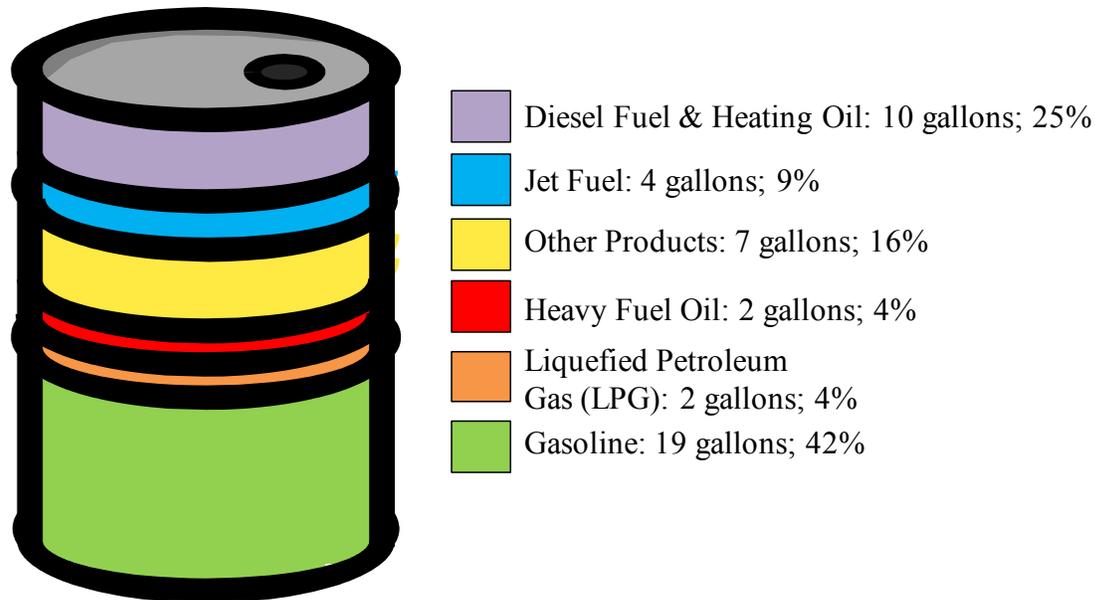
It is highly unlikely, given expected overall market conditions over the next several years, that any U.S. or East Coast LNG import facility would expand its current capacity.

## 10 REFINERIES

### 10.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED

The petroleum refining industry is dedicated to the processing of crude oil and other crude oil-based feedstocks into usable fuels and products. Refineries have been operating as long as crude oil has been produced, because crude oil has few uses in its raw and unprocessed form. The first refinery in the U.S. began production in 1861 near Titusville, Pennsylvania, adjacent to the site where Edwin Drake and W.A. Smith had discovered the first producing oil field. The wood-fired still worked on a batch method that took three days and produced only kerosene (Wisdom, Peer and Bonnifay 1998; and Uhl 1984).

The processing of crude oil into useable petroleum products requires a variety of physical and chemical changes that have been developed over the past hundred years at specialized manufacturing units known as petroleum refineries. Early refineries were most interested in producing kerosene from the crude, a process that simply involved heating or “boiling” the mixture to various temperatures to extract one product, kerosene, for clean burning, uniform-quality fuel for lighting purposes. Today, the refining process produces a large number of end products through a range of processes including heating, distilling, and catalytic conversions. In today’s refineries, a 42 U.S. gallon barrel of crude oil provides slightly over 44 gallons of different petroleum products such as gasoline, diesel fuel and heating oil, jet fuel, and liquefied petroleum gas.



**Figure 113. Products made from a barrel of crude oil (gallons).**

Source: Author’s construction from information in USDOE, EIA 2012i.

## 10.2 TYPICAL FACILITY CHARACTERISTICS

Differences in crude oil composition and consistency have led to the development of different types of refineries. Crude oil input quality can be an important factor in defining the scope of a refinery's operations and refining processes. Crude oil is not uniform or homogeneous in quality and can vary in gravity and sulfur content. Each characteristic will determine the degree of additional processing, treatment, capital investment, and profitability needed to develop a given slate of refined product yields.

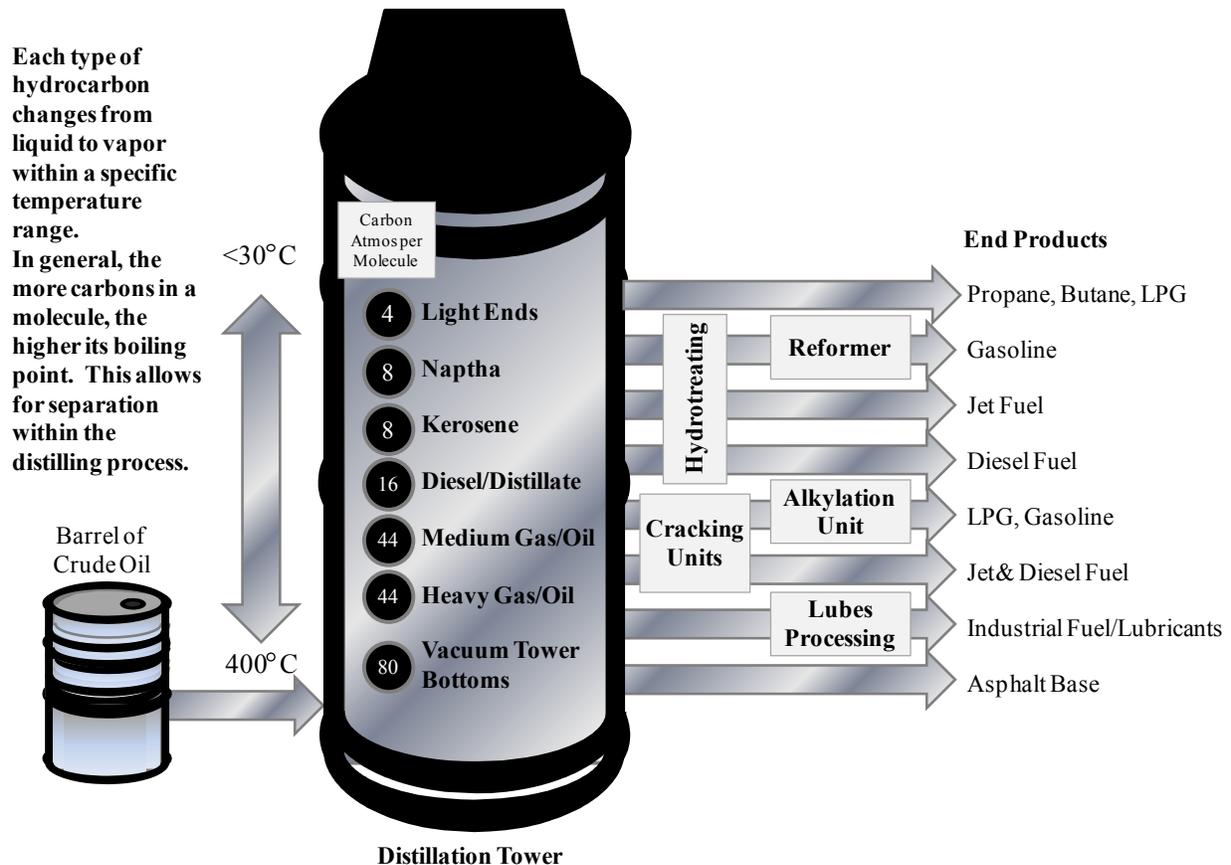
The gravity of any given crude oil stream is an important qualitative characteristic. A crude oil stream can be either heavy (low gravity) or light (high gravity), or somewhere in between. A heavy crude oil input, with relatively low gravity, is typically thicker, does not flow well, and is usually associated with a higher carbon to hydrogen ratio than a crude stream that is considered light. Heavier crude oils, typically produced and imported from such places as Venezuela and Saudi Arabia, are also known to contain a high level of carbon residues, asphaltenes, sulfur, nitrogen, and heavy metals (Lloyd Minster 2011).

Sulfur content is a second and important qualitative difference in crude oil that can impact refining configurations. Generally, sweet crudes contain less than 0.5 percent sulfur by weight while high sulfur, or sour crudes, typically have a sulfur content of 0.5 percent or higher. High sulfur crudes are more corrosive than their "sweeter" counterparts making them more expensive to handle and process. Over the years, various regions' crude oil production has been named by its qualitative difference, such as Heavy Louisiana Sweet, West Texas Intermediate, and Wyoming Sour.

Unique product blends and regulatory requirements, such as those restricting the sulfur content of various types of fuels, can also impact the configuration of a modern refinery. The geographic needs for various refined products, the availability of inputs, export and distribution capabilities, input cost characteristics and historic evolution can also be important determinants that have led to the development of certain refineries in various locations of the country. Today, these factors tend to be more important in decisions associated with maintaining or expanding existing facilities, than it does in developing new ones since no new modern greenfield refinery has been developed since the Garyville, Louisiana refinery started operations in 1976 (Marathon Petroleum 2011).

While each individual refinery can differ, some common operations occur at most facilities. For instance, the initial phase of most refining processes begins with the heat separation of the crude oil components through a series of distillation towers. This distillation process is a modern variation of the boiling processes used by refineries over one hundred years ago. Today's modern distillation towers, however, are much more complicated and use individually calibrated temperatures and pressures to separate various unique types of fuels from crude oil inputs.

Crude oil entering the distillation tower is separated into various vapor and liquid mediums using heat generated from furnaces that can reach temperatures as high as 400 degrees Fahrenheit. The vaporized portion of the crude oil input rises through the tower condensing into different products as the temperature falls. The heavier, liquid portion of the crude remains at the bottom of the distillation tower (ExxonMobil 2006).



**Figure 114. Distillation process and yield schematic.**

Source: Author's construct from information in ExxonMobil 2006.

A schematic of how distillation towers separate products from gases at the top, to very heavy, viscous liquids at the bottom, is presented in Figure 114. The thick liquids remaining at the bottom of the distillation tower are considered unfinished and usually require further processing (ExxonMobil 2006). Yield refers to the relative percentage of each type of separated component, or product streams, produced through the primary distillation process. This percentage will vary depending on the composition of the crude being processed.

The heaviest hydrocarbons, having the highest boiling points, remain at the bottom of the distillation tower and can be further processed through an additional distillation process that takes place under vacuum. The resulting materials from vacuum distillation can be further processed into lubricating oils and other products through another process known as solvent extraction. Various types of solvents can also be used to separate impurities, non-lubricating types of oils, or various waxes from the various hydrocarbon mixes produced from the primary distillation process (AIP 2011).

An important and secondary form of refining is commonly referred to as the cracking process during which intermediate hydrocarbon blends, commonly from the distillation process, are exposed to various catalysts under controlled heat and pressure to produce various types of refined products. The most common refined products that arise from the cracking process include gasoline, liquefied petroleum gas (LPG), unsaturated olefin compounds, cracked gas oils, cycle oil, light gases, and solid coke. The cracking process can also lead to the separation of a class of liquid hydrocarbons known as naphthenes, often used as solvents and diluents, olefins (propylene and butylene), and paraffins (AIP 2011). With additional treatment (reformation), these intermediate refined products can be important building blocks for a wide range of petrochemical products, including:

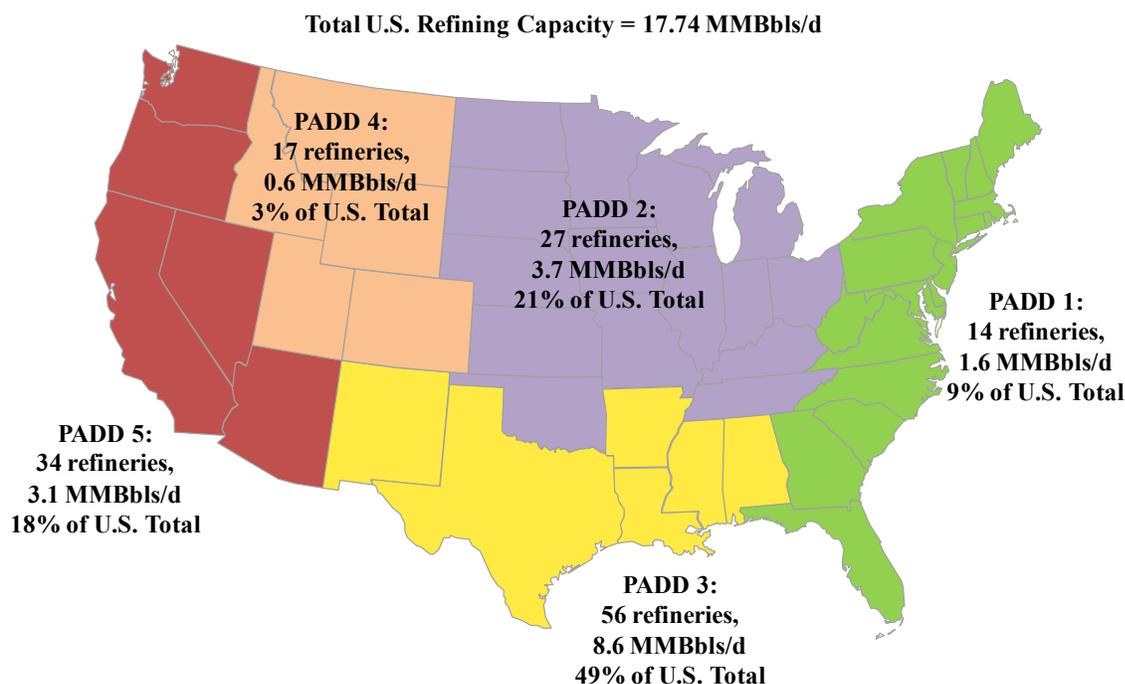
- Ammonia
- Antiseptics
- Bubble gum
- Crayons
- Denture adhesive
- Eyeglass frames
- Fertilizer
- Floor polish
- Guitar strings
- Heart valves
- Ice chests
- Insect repellent
- Life preservers
- Liquid detergent
- Mascara
- Paint
- Ping-Pong paddles
- Plastic beverage containers
- Roller-skate wheels
- Sneakers
- Synthetic fibers
- Telephones
- Tobacco pouches
- Volleyballs

Reforming is another important function that can occur during the refining process. The reformation process converts naphthenes into products that can be used as petrochemical inputs or components of high-octane gasoline. An additional refining process, known as isomerisation, separates paraffins or single-chained hydrocarbons, into isoparaffins to create a product more readily processed into other outputs and to be more effective in fuel blends (Earth Science Australia 2011). Alkylation is a refining function that produces isoparaffins from the bonding of olefins and isobutene (Fahim, et al. 2010). And, a process known as polymerization creates large hydrocarbon molecules from smaller, lighter, chains under exposure to heat, pressure, and catalysts to yield a high-octane gasoline component polymer gasoline (AIP 2011).

The varied transformations required at modern refineries depend on the quality and composition of the crude oil being processed and many of the additional supporting facilities that may be integrated at the refining location: for instance, the collocation of a downstream petrochemical plant that may take many of the refineries' byproducts as inputs for chemical manufacturing. The types of transformation that occur at a refinery are important in defining the rate of products that can be generated from the facility. The scope of refining processes can also be important determinants of the overall importance and profitability of a particular refinery because more transformation capabilities will tend to result in more value-added refined products.

### 10.3 GEOGRAPHIC DISTRIBUTION

The coastal region of the Atlantic is included in PADD District 1 as defined by the U.S. Department of Energy.<sup>16</sup> PADD District 1 is home to some 14 refineries with approximately 1.6 million barrels per day (MMBbls/d) of refining capacity. PADD District 1 is a relatively evenly-balanced refining region in that it accounts for nine percent of the total number of refineries and nine percent of total U.S. refining capacity. These relative shares differ from the Gulf Coast (PADD 3), which accounts for only 38 percent of the total refineries in the U.S., but close to 50 percent of total U.S. refining capacity. PADD 1 also differs from the western U.S. (PADD 5), which accounts for 23 percent of all U.S. refineries but only 18 percent of total U.S. refining capacity.



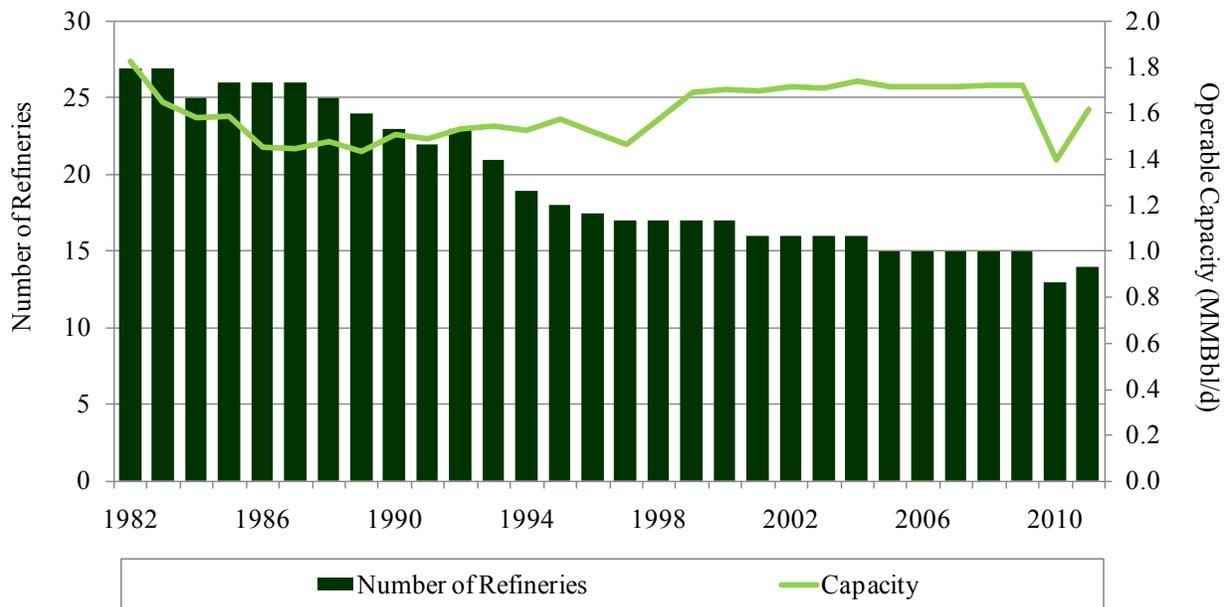
**Figure 115. Number and capacity of U.S. refineries, as of January 1, 2011.**

Source: USDOE, EIA 2012i.

Atlantic region refineries (PADD 1) are also relatively close to the average size for a typical U.S. refinery. The U.S. currently has over 17.7 MMBbls/d of total refining capacity located at over 148 refineries, for an average refinery size of almost 120 thousand barrels per day (MBbls) of capacity. PADD 1 refineries have an average size of about 116 MBbls/d of capacity, smaller than a large modern Gulf Coast facility of over 154 MBbls/d of capacity, but larger than a refinery in the western U.S. that averages about 92 MBbls/d of capacity.

<sup>16</sup> The five regions referred to as “Petroleum Administration for Defense Districts” or “PADDs” were created during World War II to facilitate oil allocation for defense purposes. Though the original PADDs were abolished in 1946, they were re-activated during the Korean War and taken over by the U.S. Department of the Interior (Oil and Gas Division) and then later by the U.S. Department of Energy.

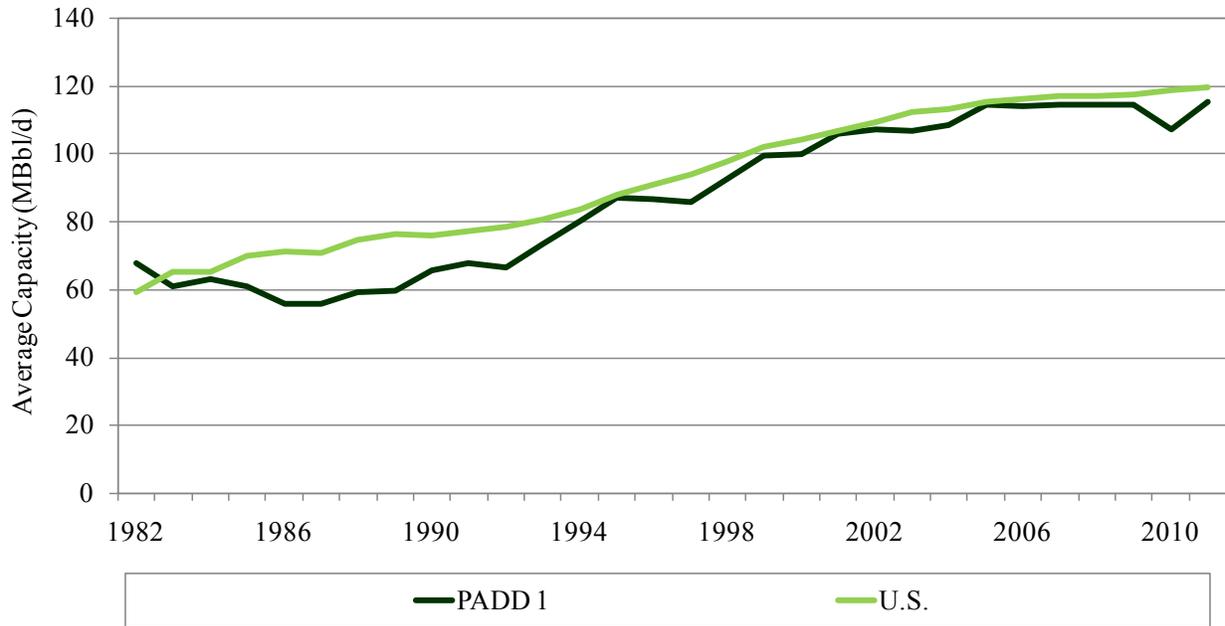
East Coast refineries have followed development and capacity trends similar to the overall U.S. industry. For instance, the number of refineries along the eastern seaboard has decreased from a high of 27 in 1982 to 14 in 2011. However, overall operable refining capacity for the region has remained relatively constant, at about 1.6 MMBbls/d, since the late 1990s.



**Figure 116. PADD 1 refineries.**

Source: USDOE, EIA 2012i.

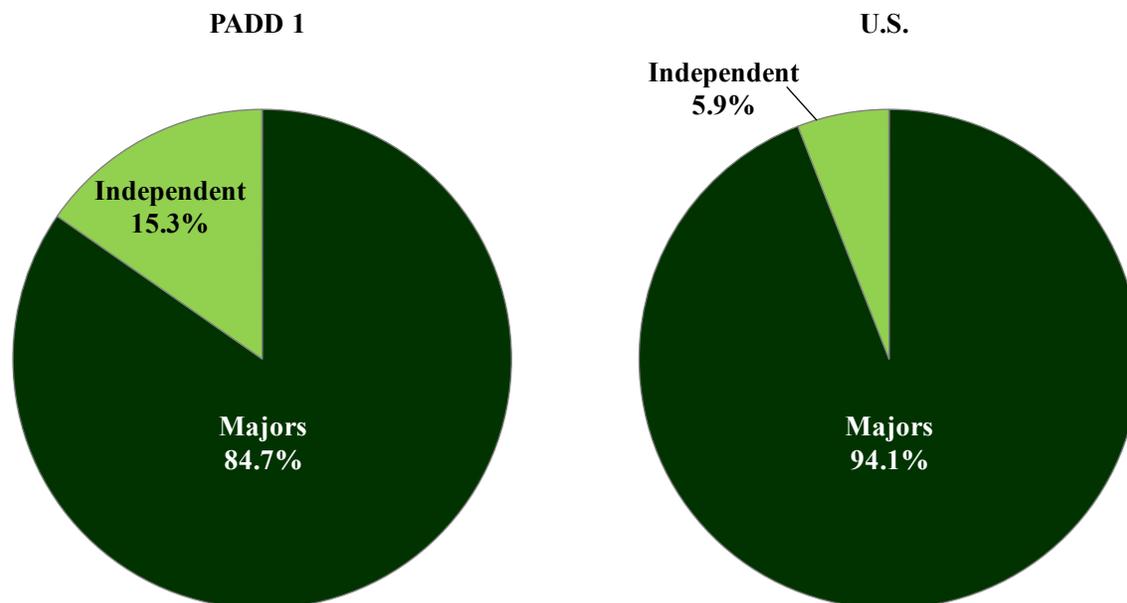
U.S. refineries in general and refineries along the eastern seaboard, have preserved total operating capacity, and met U.S. refined product needs through a trend often referred to in the industry as “capacity creep.” This arises through the concentration and expansion of refining capacity at existing facilities rather than the investment in new greenfield sites. Figure 117 shows the capacity creep and increased average refinery size for both refineries along the eastern seaboard and the U.S. average. In 1982, the year with largest number of refineries in both the East Coast and the U.S., an average-sized refinery was 68 MBbls/d (East Coast) and 59 MBbls/d (U.S.). Today, average refinery capacity is 116 MBbls/d (East Coast) and 120 MBbls/d (U.S.). In the U.S. average refinery capacity has increased 102 percent. Thus, capacity creep has led to the addition of close to 60 new refineries over the past three decades, even though the number for East Coast refineries is not as dramatic since most of these expansions have occurred in either the Gulf Coast or the Midwestern U.S. (PADD 2).



**Figure 117. Historic trends in average operable capacity (PADD 1 v. U.S.).**

Source: USDOE, EIA 2012i.

The ownership characteristics of East Coast refineries differ from other regions of the U.S. Generally, major oil companies, typically comprised of the super-majors that have integrated oil and gas operations from production to distribution, control a large majority of total U.S. refining capacity. In the U.S., major oil companies own approximately 94 percent of all refining capacity while independent oil refining companies own approximately six percent. This differs along the broader East Coast region (PADD 1) where majors control a lower-than-average 85 percent of all operable capacity and independents control as much as 15 percent of the region’s refining capacity; almost three times the U.S. average independent ownership share (see Figure 118).



**Figure 118. Average ownership shares.**

Source: USDOE, EIA 2012j.

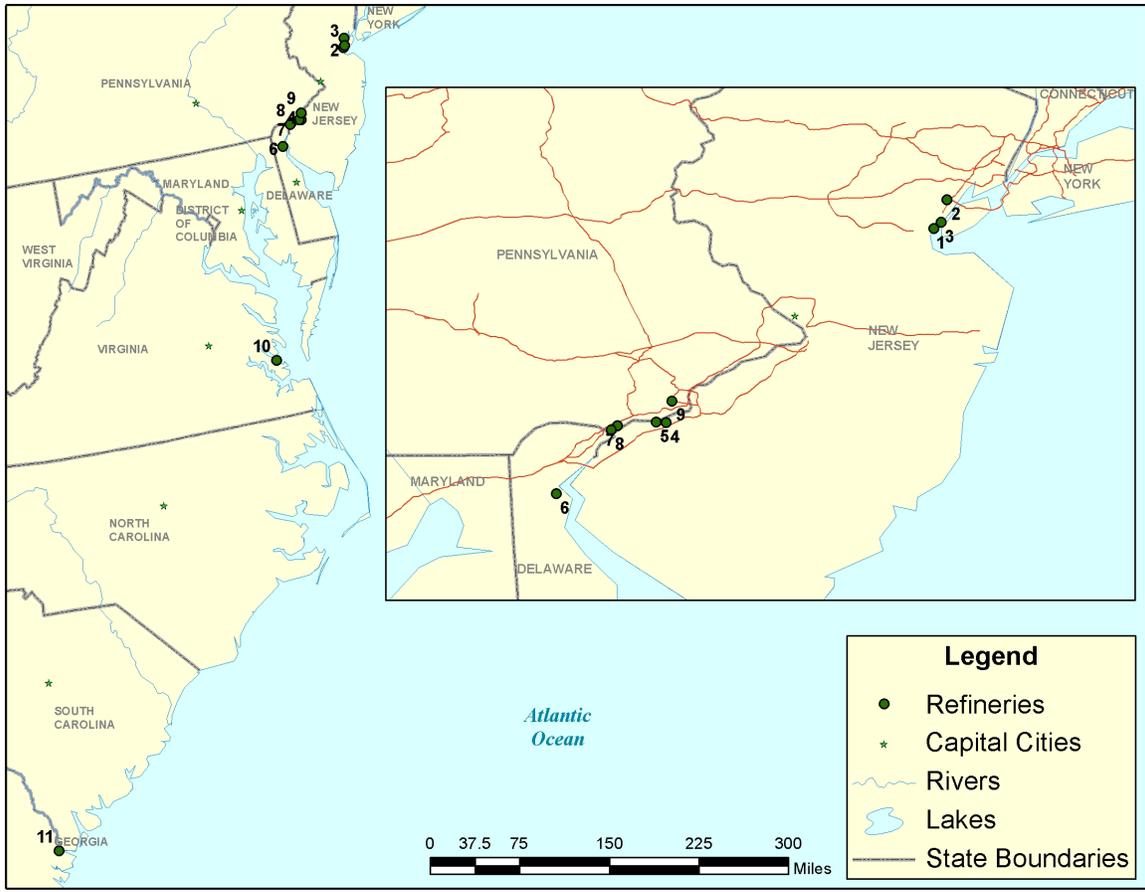
There are 11 refineries located in the Atlantic coast region which are listed, along with their operating capacities, in Table 41.<sup>17</sup> The geographic location of each of these refineries has been provided on a map in Figure 119. Nine of these refineries are operating, with a total capacity of 1.4 million barrels per calendar day; while the other two are currently “idle.” Of the nine refineries that are currently operating, four are located in New Jersey, one in Delaware, three in Pennsylvania and one in Georgia. One of the idle facilities is in New Jersey, and one is in Virginia.

<sup>17</sup> There are a total of 14 refineries in the PADD 1 district; one of these refineries is in West Virginia and two are in northwest Pennsylvania, and are not in the Atlantic coastal region.

**Table 41. Mid-Atlantic impact region refineries.**

		Bbls per Calendar Day		Bbls per Stream day	
		Operating	Idle	Operating	Idle
<b>New Jersey</b>					
1	Chevron USA Inc. (Perth Amboy)	-	80,000	-	83,000
2	ConocoPhillips Co (Linden)	238,000	-	250,000	-
3	Hess Corporation (Port Reading) Nustar Asphalt Refining LLC	65,000	-	70,000	-
4	(Paulsboro)	70,000	-	75,000	-
5	Paulsboro Refining Co LLC	160,000	-	166,000	-
<b>Delaware</b>					
6	Delaware City Refining Co LLC (Delaware City)	182,200	-	190,200	-
<b>Pennsylvania</b>					
7	ConocoPhillips Co (Trainer)	185,000	-	190,000	-
8	Sunoco Inc. (Marcus Hook)	178,000	-	194,000	-
9	Sunoco Inc. R&M (Philadelphia)	335,000	-	355,000	-
<b>Virginia</b>					
10	Western Refining Yorktown Inc. (Yorktown)	-	66,300	-	70,800
<b>Georgia</b>					
11	Nustar Asphalt Refining LLC (Savannah)	28,000	-	32,000	-
<b>Total Region</b>		<b>1,441,200</b>	<b>146,300</b>	<b>1,522,200</b>	<b>153,800</b>

Note: Data is as of January 2011.  
Source: USDOE, EIA 2012i; and Reuters 2011a.



**Figure 119. Mid-Atlantic impact region refineries.**  
 Source: Author’s construction; and USDOE, EIA 2012i.

The following summarizes the characteristics of each operating refinery.

- ConocoPhillips’ Linden, New Jersey facility was built by John D. Rockefeller in 1908 and has a total capacity of 238,000 barrels per day (ConocoPhillips 2011a; and USDOE, EIA 2012j). The facility reports 830 employees, is the second largest refinery on the East Coast, and fifteenth largest in the U.S. (Caroom 2010; and ConocoPhillips 2011a). The refinery has a railway container terminal and a heliport. It processes mainly light, low-sulfur crude from the North Sea, Canada, and West Africa and produces mostly transportation fuels, including gasoline, diesel fuel, and jet fuel. Other products include petrochemical feedstocks, heating oil, and residual fuel oil. In addition, an onsite petrochemical plant produces lubricants and additives; a polypropylene plant produces over 775 million pounds per year of polypropylene. Products are delivered to customers on the East Coast by pipeline transport, barges, railcars and tank trucks. This facility can process up to 238,000 barrels per day with naphtha or reformer feed and diesel fuel the main outputs at 97,000 and 108,000 barrels per day respectively (USDOE, EIA 2012i).

- Hess Corporation's Port Reading, New Jersey facility is a fluid catalytic cracking (FCC) unit located just ten miles (16 kilometers) from New York City. The facility has a total capacity of 70,000 barrels per day and primarily produces gasoline and heating oil which is distributed to local Hess retail outlets and industrial and residential customers in the area (Hess 2009; and SEC 2010c).
- The Paulsboro, New Jersey refinery is owned by PBF Energy has a total capacity of 160,000 barrels per day and approximately 540 employees (Valero 2010; and Valero 2009a). It is located on 950 acres in southern New Jersey on the Delaware River, 15 miles (24 kilometers) south of Philadelphia. The refinery receives feedstocks from its deepwater access on the Delaware River, including sour crudes such as Arab Light, Arab Heavy, Hamaca, Urals, and Kirkuk (Valero 2009a). It produces gasoline, mid-distillate products, petroleum coke, liquefied petroleum gases, fuel oil, and molten sulfur. In addition, it produces a variety of lube oil base stocks that are sold to an adjacent Exxon Mobil finished-lube blending and packaging plant and to other purchasers. Much of the jet fuel production supplies Philadelphia International Airport through a pipeline. Products from the Paulsboro refinery are moved out by docks, on-site truck racks, and through various pipeline connections, including a spur of the Colonial pipeline (Valero 2009a).
- The Nustar refinery also in Paulsboro, New Jersey has a total operating capacity of 70,000 barrels per day (USDOE, EIA 2012j). The facility is located on the Delaware River and has two petroleum refining units, a liquid storage terminal for petroleum and chemical products, three marine docks, a polymer-modified asphalt production facility and a testing laboratory. The refinery produces and supplies various grades of asphalt that are delivered to 12 different asphalt terminals in the northeastern U.S. by ship, barge, railcar, and tanker. Its location on the river allows for access to receipts and shipments (SEC 2010d).
- PBF Energy's refinery in Delaware City, Delaware has a total operating capacity of 182,200 barrels per day (USDOE, EIA 2012j). The facility is located on 5,000 acres on the Delaware River, is accessible by pipeline, barge, and truck-rack facilities and has approximately 570 employees (Valero 2009b). It refines primarily sour crude into conventional and reformulated gasoline, diesel, low-sulfur diesel, and heating oil. It also has the ability to produce ultra-low-sulfur diesel. The plant has an 1,800 tons per day petroleum coke gasification unit and a 160 MW cogeneration plant. PBF Energy purchased the facility from Valero Energy in 2010. Valero Energy had idled the facility in November 2009 as the company was losing an estimated \$1 million per day due to reduced gasoline demand (Reuters 2011b). PBF Energy restarted the facility in May 2011 (Reuters 2011a).

- The ConocoPhillips refinery in Trainer, Pennsylvania has a total capacity of 185,000 barrels per day (USDOE, EIA 2012j). It is located on Delaware River, 10 miles (16 kilometers) southwest of Philadelphia International Airport. The refinery processes mainly light, low sulfur crude oil that it receives from West Africa, Canada, and the North Sea. It produces mostly transportation fuels such as gasoline, diesel and jet fuel, but also heating oil, residual fuel oil and liquefied petroleum gas. Products from this facility are primarily distributed to customers in Pennsylvania, New York, and New Jersey by pipeline, barge, railcar and truck. Heating oil is distributed by tanker (ConocoPhillips 2011b).
- Sunoco's Marcus Hook refinery in Pennsylvania is strategically integrated with its Marcus Hook polymers plant (Sunoco 2011a). The refinery is located on the Delaware River, 20 miles (32 kilometers) south of Philadelphia and has a total capacity of 178,000 barrels per day. Both of Sunoco's Marcus Hook and Philadelphia refineries process crude oil imported from foreign sources delivered by ocean-going tanker (SEC 2010e).
- Sunoco's Philadelphia refinery in Pennsylvania has a total capacity of 335,000 barrels per day and over 900 employees (USDOE, EIA 2012j; and Sunoco 2011b). The facility is located on the Schuylkill River in Philadelphia and produces gasoline, aviation fuel, kerosene, heating oil, residual fuel, propane, and butane. The facility also produces petrochemical feedstocks that are shipped to Sunoco Chemicals' Frankford plant (Pennsylvania) to make phenol, which is used in the manufacture of plastics and synthetics (Sunoco 2011b). Other products are transported by pipeline to markets in New York, New Jersey, Pennsylvania, Ohio, and Michigan.
- The Nustar refinery in Savannah, Georgia has a total capacity of 28,000 barrels per day (USDOE, EIA 2012j). It is located adjacent to the Savannah River and includes two atmospheric towers, a tank farm, a marine dock, a polymer modified asphalt production facility, a testing laboratory and processing areas (SEC 2010d). The refinery produces and supplies various grades of asphalt that are delivered to nine different asphalt terminals in the southeastern U.S. by truck, rail, and marine vessel. Its location on the river allows for access to receipts and shipments (SEC 2010d).

#### ***Other Refining Capacity on the East Coast (Idled or Low Volume Operations)***

- Chevron's Perth Amboy facility in New Jersey is located near the New York-New Jersey border. Chevron purchased the refinery from Barber Asphalt Corporation in 1946. In 1983, the company discontinued gasoline and heating oil production as falling demand, excess refining capacity and inefficient refining processes made the facility uneconomic (Oil & Gas Journal 1983). Chevron continued to run its asphalt production and terminaling operations until 2008 when it was idled indefinitely (SEC 2010f). Today the facility is operated as a terminal (SEC 2010f).

- Western Refining’s Yorktown refinery is located on 570 acres on the York River with access to the Chesapeake Bay and has its own deep-water port access. Before it was idled in 2010, the facility had a capacity of 70,800 barrels per day and most of the facility’s feedstocks came from Canada, the North Sea, South America, and the Far East (Burkhardt 2010; and Western Refining 2009). Refining operations were temporarily suspended in September 2010 due to the “challenging refining margin environment experienced on the East Coast, the continued low price differentials between light and heavy crudes, and poor coking economics.” (Burkhardt 2010, SEC 2010g). Western Refining still operates the products terminal and supplies finished projects to the East Coast region.

The nine active refineries on the Atlantic coast have a total capacity of almost 1.4 MMBbls per day and are equipped to process light, sweet crude and certain grades of heavier, sour crude oil. They also each have the capability to manufacture a wide range of refined products. Currently, none of these refineries are connected to a major interstate crude oil pipeline and receive most of the crude oil they process from non-domestic sources by tanker. Crude oil refined at these facilities is primarily light, sweet crude originating from the North Sea, Canada, and West Africa with fewer imports from the Middle and Far East. The source of crude, and the products imported into each facility along the East Coast impact area, is provided in Table 42. The private companies involved in the oil spill response industry are extremely mobile; however, in that they may be stationed in one location, but offer their services across the entire U.S. or even internationally. For example, the Coast Guard lists the Marine Spill Response Corporation (MSRC) as an OSRO with ocean response capabilities in COTP zone five. MSRC is headquartered in Virginia, but provides oil spill response services throughout all Coast Guard COTP zones. Environmental Expert Online provides a list of oil spill response companies, many of which are located outside of the U.S., but others are on the East and West Coast and in the GOM region.

The Coast Guard also provides a listing of all classified OSPROs within their Response Resource Inventory System (USCG 2012b). This listing illustrates a similar pattern of widespread locations for OSPROs, with some concentration in the GOM and along the coasts.

Table 12 provides a list of these companies with physical locations in the Mid-Atlantic impact region.

**Table 42. Imported refinery inputs, 2010.**

<b>Product Imported</b>	<b>Country of Origin</b>
<b>New Jersey</b>	
ConocoPhillips Co (Linden) Crude Oil	Canada
Motor Gas Blending Components	Algeria, Canada, Georgia, Norway, UK
Reformulated Blendstock for Oxygenate Blending (RBOB)	Canada, Virgin Islands, UK
Hess Corporation (Port Reading) Gasoline Treated as Blendstock (GTAB)	India, Netherlands, Virgin Islands
Motor Gas Blending Components	Algeria, Estonia, France, India, Libya, Nigeria, Norway, UK, Venezuela
Unfinished Oils, Heavy Gas Oils	Belgium, Estonia, Israel, Italy, UK, Virgin islands
Nustar Asphalt Refining LLC (Paulsboro) Crude Oil	Mexico, Venezuela
Paulsboro Refining Co LLC Crude Oil	Brazil, Canada, Columbia, Iraq, Kazakhstan, Russia, Saudi Arabia,
Motor Gas Blending Components	France, Venezuela
Unfinished Oils, Heavy Gas Oils	Belgium, Syria, Virgin Islands
<b>Delaware</b>	
Delaware City Refining Co LLC (Delaware City) Motor Gas Blending Components	Canada
<b>Pennsylvania</b>	
ConocoPhillips Co (Trainer) Crude Oil	Algeria, Angola, Canada, Columbia, Congo, Gabon, Libya, Nigeria, Norway
Sunoco Inc. (Marcus Hook) Crude Oil	Angola, Azerbaijan, Brazil, Canada, Columbia, Congo, Gabon, Libya, Nigeria, Norway
Sunoco Inc. R&M (Philadelphia) Crude Oil	Angola, Azerbaijan, Brazil, Cameroon, Canada, Columbia, Congo, Gabon, Libya, Nigeria, Norway
Unfinished Oils, Naphthas & Lighter	Cote D'Ivoire, Netherlands, Norway, Portugal, Trinidad & Tobago, Venezuela
<b>Georgia</b>	
Nustar Asphalt Refining LLC (Savannah) Crude Oil	Venezuela
Unfinished Oils, Heavy Gas Oils	Canada, Taiwan

Source: USDOE, EIA 2012i.

## 10.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY

The refining sector for the impact area is relatively small in comparison to (a) each state's overall GDP and (b) the economic contribution made by the refining sector overall to the U.S. GDP. Delaware's refining GDP makes the largest contribution to its state's overall economy of any in the Mid-Atlantic impact area at 0.84 percent. This is an interesting outcome given the relatively small share of total regional refining capacity (12.6 percent) located in Delaware. By comparison, Pennsylvania refineries have the largest refinery operating capacity in region, but only contribute four-tenths of one percent to the state's overall GDP.

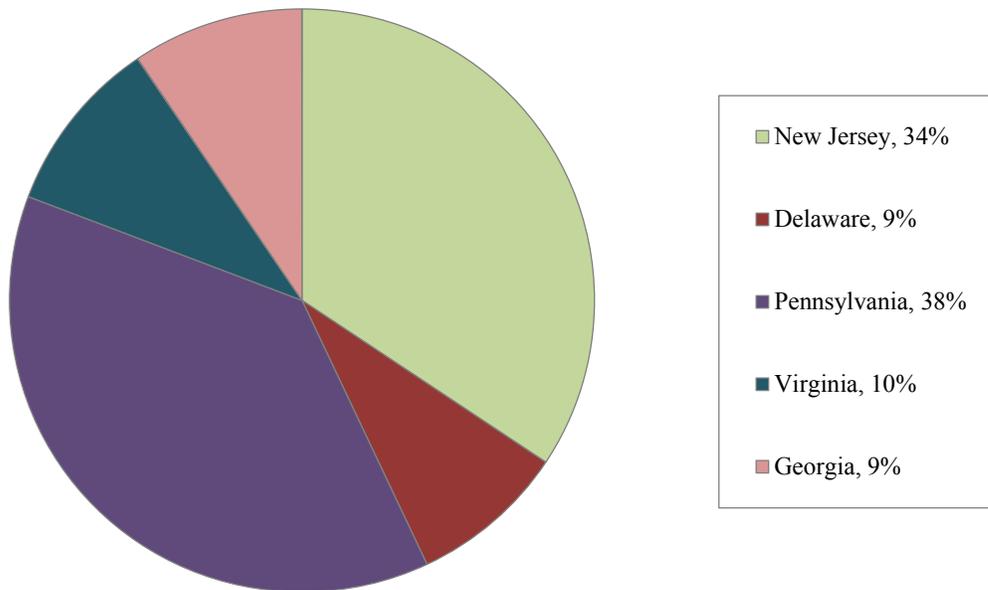
The contributions each state makes to total U.S. refining GDP, however, run more along the lines expected given each state's total refining capacity. New Jersey, with the second-largest regional refining share (37 percent), makes the second-largest contribution to the regional refining sector GDP of 34 percent; and total U.S. refining sector GDP of 1.2 percent. However, the state accounts for only three percent of total U.S. refining capacity. Similarly, Delaware, which makes a larger relative contribution to its own economy, makes a relatively smaller contribution to the economic output of the overall U.S. refining sector.

**Table 43. Regional and national GDP contribution, refinery sector, 2010.**

	GDP		Refining GDP as a Percent of Total State GDP ----- (%)	Refining GDP as a Percent of U.S. Refining GDP -----
	Refining (millions of current \$)	Total State		
New Jersey	\$ 2,137.0	\$ 480,446	0.445%	1.244%
Delaware	\$ 537.0	\$ 64,010	0.839%	0.313%
Maryland	n.a.	\$ 293,349	n.a.	n.a.
Pennsylvania	\$ 2,352.0	\$ 558,918	0.421%	1.369%
Virginia	\$ 605.0	\$ 419,365	0.144%	0.352%
North Carolina	n.a.	\$ 424,562	n.a.	n.a.
South Carolina	n.a.	\$ 160,374	n.a.	n.a.
Georgia	\$ 590.0	\$ 403,230	0.146%	0.343%
<b>Total Region</b>	<b>\$ 6,221</b>	<b>\$ 2,804,254</b>	<b>0.222%</b>	<b>3.621%</b>
<b>U.S.</b>	<b>\$ 171,795</b>	<b>\$ 14,416,601</b>	<b>1.192%</b>	<b>100.0%</b>

Source: USDOC, BEA 2012.

Figure 120 highlights the relative share of each Mid-Atlantic state’s refining GDP shares relative to the regional refinery total. New Jersey, with over to \$2.0 billion in the annual value of its refinery output, accounts for 34 percent of the value of the region’s refinery output. Pennsylvania, home to 48 percent of the region’s operating capacity, accounts for 38 percent of the economic value of the region’s refinery output (close to \$2.4 billion per year). The remaining states comprise a much smaller share of the region’s refinery output with values around \$500 to \$600 million per year.



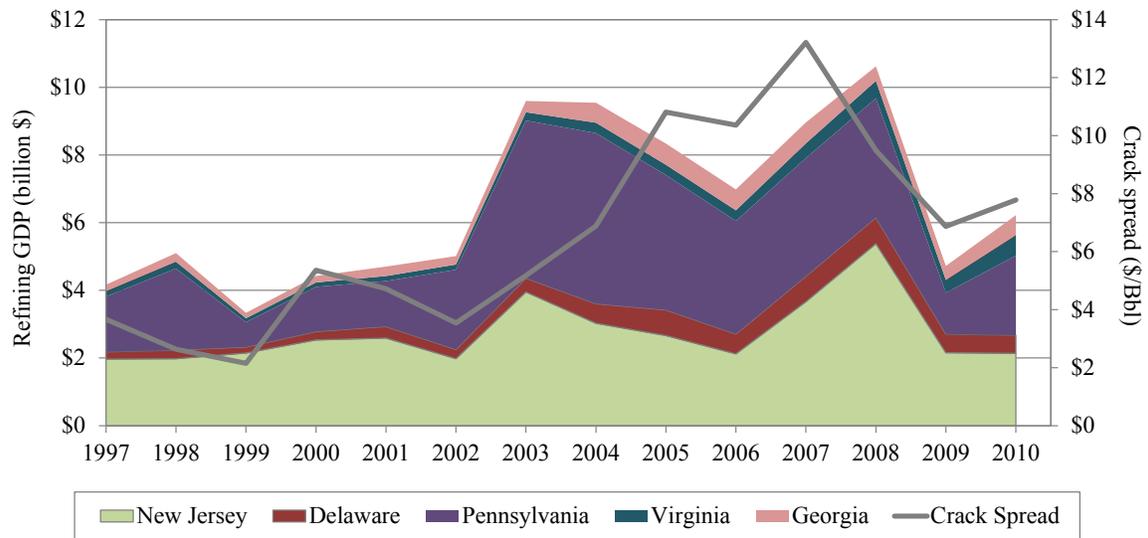
**Figure 120. Regional refinery GDP shares, 2009.**

Source: USDOC, BEA 2012.

Until 2003, the economic value of the region’s refinery output has followed trends closely associated with the price and profitability of its outputs. Figure 121 compares the trends in refining GDP for each Mid-Atlantic impact state since the mid-1990s and compares those trends to the “crack spread”<sup>18</sup> available in the market during a comparable time period. Regional refining GDP saw two relatively large and noticeable peaks in 2003 and in 2008 at over \$16 billion in constant 2009 dollars. Those fortunes have fallen considerably since 2003 with regional refining GDP now at a level less than half (\$6 billion) its prior high. Interestingly, this is also the same year that crack spreads started to increase leading to a short-lived renaissance in the refining industry. This graphs shows that eastern-based refineries did not take advantage of that renaissance that saw increased output and new capacity expansion plans. Most of these new opportunities were restricted to the Gulf Coast, and, as the chart shows, not the East Coast,

<sup>18</sup> A crack spread is a general measure of refined product profitability as reflected in the price of crude oil inputs relative to refined product outputs. A “3:2:1 crack spread” is one of the more commonly-reported forms of crack spreads and represents the commodity-priced cost of purchasing 3 barrels of crude oil and selling 2 barrels of gasoline and 1 barrel of distillates on futures markets.

despite the increasing overall profitability of selling refined product from a pure commodity-priced basis.<sup>19</sup>



**Figure 121. Trends in Mid-Atlantic impact region refining GDP.**

Source: USDOC, BEA 2012.

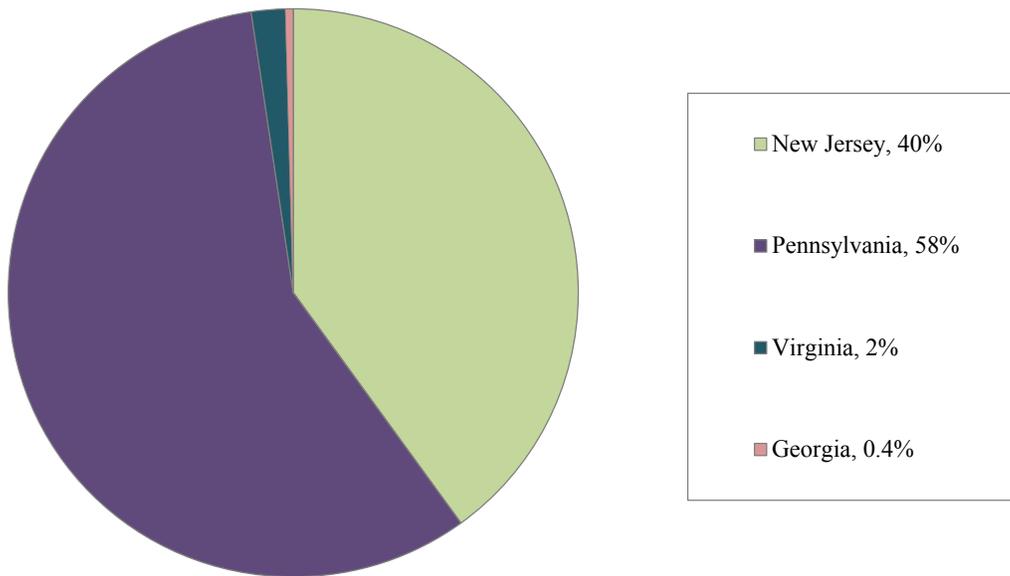
Table 44 shows that each state’s total refinery employment contributions are very small in comparison to the total employment in each of the impact region’s states. None of the states in the Mid-Atlantic impact region have refinery employment totals that are over one percent of the overall statewide employment totals. Refining employment in New Jersey and Pennsylvania represents the highest contributions, at 0.05 percent each. On a regional basis, both New Jersey and Pennsylvania have the highest share of total refinery employment.

<sup>19</sup> Crack spreads simply measure the profitability, broadly, of refining crude oil into end-use products given broad market dynamics. In the broadest terms, a crack spread can be thought of as a ratio of refined product inputs to outputs. These crack spreads do not reflect specific or individual refinery profitability opportunities which can be influenced by a variety of other factors than the simple ratio of inputs to outputs.

**Table 44. Regional and national employment contribution, refinery sector, 2011.**

	Number of Jobs		Refinery Employment as a Percent of Total State Employment	Refinery Employment as a Percent of Total U.S. Refinery Employment
	Refinery	Total State	----- (%) -----	----- (%) -----
New Jersey	1,588	3,156,538	0.05%	2.23%
Delaware	n.a.	342,585	n.a.	n.a.
Maryland	n.a.	1,991,055	n.a.	n.a.
Pennsylvania	2,286	4,825,064	0.05%	3.21%
Virginia	77	2,889,435	0.00%	0.11%
North Carolina	n.a.	3,158,293	n.a.	n.a.
South Carolina	n.a.	1,450,840	n.a.	n.a.
Georgia	17	3,135,735	0.00%	0.02%
<b>Total Region</b>	<b>3,968</b>	<b>20,949,545</b>	<b>0.02%</b>	<b>5.57%</b>
<b>U.S.</b>	<b>71,248</b>	<b>108,184,795</b>	<b>0.07%</b>	<b>100.00%</b>

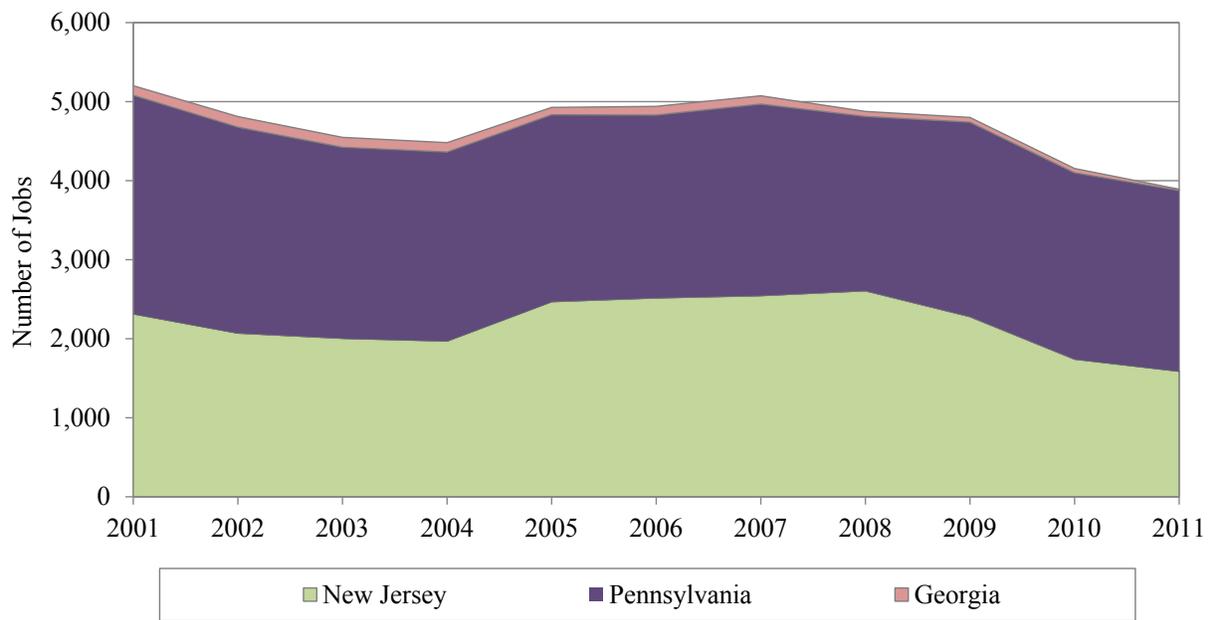
Note: n.a. is “not available.”  
 Data for Delaware does not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 122. Mid-Atlantic impact region refinery employment shares, 2011.**

Note: n.a. is “not available.”  
 Data for Delaware does not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.

Historic regional refinery employment has been relatively stable over the past decade along the Mid-Atlantic coast. The region reported a high of just over 5,000 refinery jobs in 2001. Though employment fell through the early part of the decade, it rebounded in 2004 and 2005, but has fallen again in recent years.



**Figure 123. Trends in Mid-Atlantic impact region refinery employment, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware does not meet BLS or state agency disclosure standards. Historic data for Virginia does not meet BLS or state agency disclosure standards and is not included in this figure.

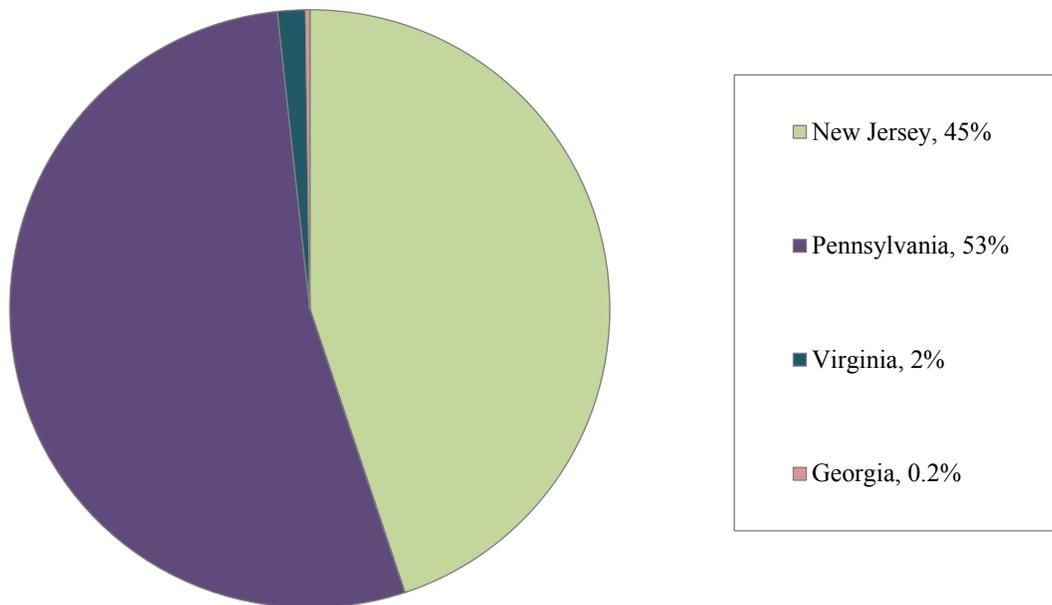
Source: USDOL, BLS 2012.

Regional wage contributions, provided in Table 45, follow trends similar to employment levels. The regional totals are dominated by the states with the largest shares of refining capacity (New Jersey and Pennsylvania). The regional shares of total wages paid by Mid-Atlantic coast refineries are provided in Figure 124.

**Table 45. Regional and national wages contribution, refinery sector, 2011.**

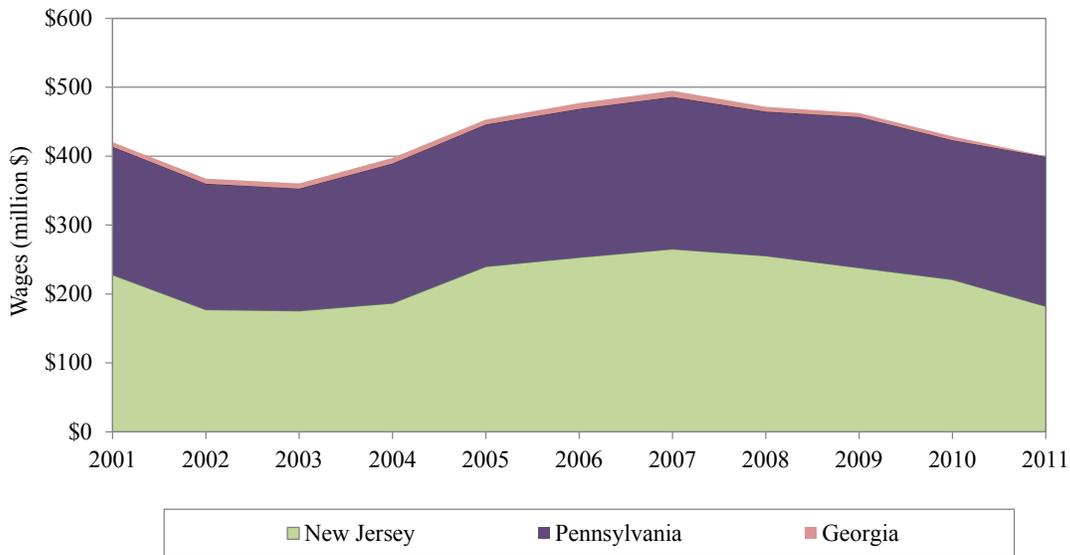
	Wages		Refinery Wages as a Percent of Total State Wages	Refinery Wages as a Percent of Total U.S. Refinery Wages
	Refinery (million \$)	Total State	(%)	
New Jersey	\$ 182.2	\$ 179,559	0.10%	2.06%
Delaware	n.a.	\$ 17,313	n.a.	n.a.
Maryland	n.a.	\$ 100,787	n.a.	n.a.
Pennsylvania	\$ 216.8	\$ 225,147	0.10%	2.45%
Virginia	\$ 6.1	\$ 145,225	0.00%	0.07%
North Carolina	n.a.	\$ 132,436	n.a.	n.a.
South Carolina	n.a.	\$ 54,746	n.a.	n.a.
Georgia	\$ 0.9	\$ 142,928	0.00%	0.01%
<b>Total Region</b>	<b>\$ 406.0</b>	<b>\$ 998,140</b>	<b>0.04%</b>	<b>4.58%</b>
<b>U.S.</b>	<b>\$ 8,857.2</b>	<b>\$ 5,172,844</b>	<b>0.17%</b>	<b>100.00%</b>

Note: n.a. is “not available.”  
 Data for Delaware does not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 124. Mid-Atlantic impact region refinery wage shares, 2011.**

Note: n.a. is “not available.”  
 Data for Delaware does not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.



**Figure 125. Trends in Mid-Atlantic impact region refining wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware does not meet BLS or state agency disclosure standards. Historic data for Virginia does not meet BLS or state agency disclosure standards and is not included in this figure.

Source: USDOL, BLS 2012.

Table 46 provides a comparison of the average annual wages paid to employees in the refining sectors of the Mid-Atlantic impact area. The annual wages for refinery employees in each state in the region are considerably higher, in fact orders of magnitude higher than the average in-state wage. This is not surprising and consistent with industry trends in other parts of the country. The comparisons differ, however, when average annual refinery wages are compared within the region and to the U.S. average annual refinery wage.

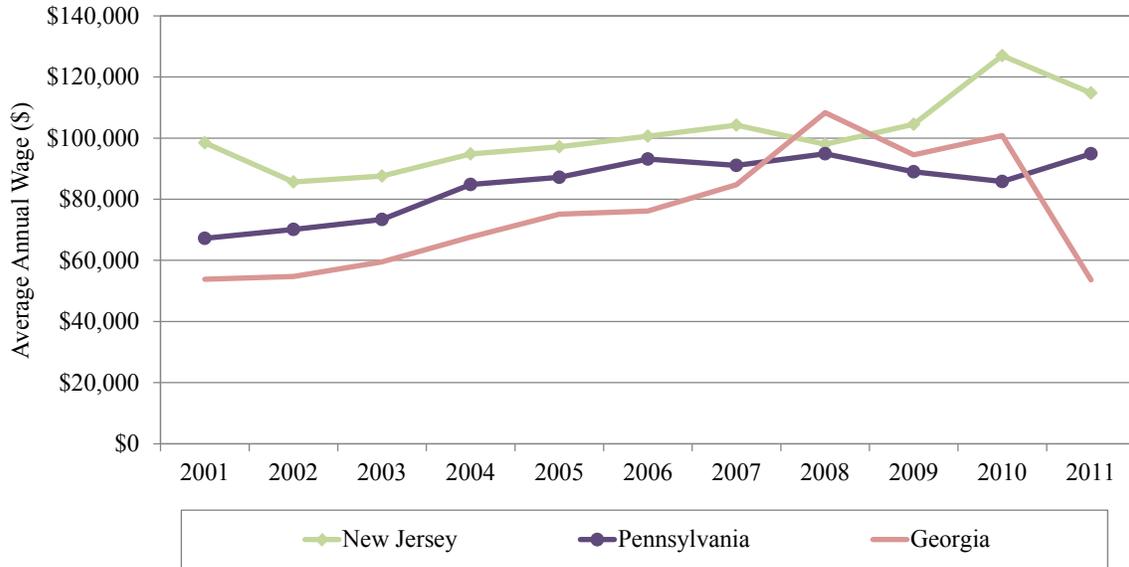
Generally, average annual refinery wages in the region are below the U.S. average. Pennsylvania, with the second highest share of refining capacity in the region, has considerably lower-than-average wages that are 76 percent of the U.S. average. New Jersey, while better, is also slightly lower-than-average.

**Table 46. Regional and national average annual wage contribution, refineries, 2011.**

	Average Annual Wage		Refinery Average Annual Wage as a Percent of Total State Average Annual Wage	Refinery Average Annual Wage as a Percent of Total U.S. Refinery Average Annual Wage
	Refinery ----- (\$)	Total State Average	----- (%)	----- (%)
New Jersey	\$ 114,755	\$ 56,885	201.7%	92.3%
Delaware	n.a.	\$ 50,535	n.a.	n.a.
Maryland	n.a.	\$ 50,620	n.a.	n.a.
Pennsylvania	\$ 94,843	\$ 46,662	203.3%	76.3%
Virginia	\$ 78,885	\$ 50,261	157.0%	63.5%
North Carolina	n.a.	\$ 41,933	n.a.	n.a.
South Carolina	n.a.	\$ 37,734	n.a.	n.a.
Georgia	\$ 53,641	\$ 45,580	117.7%	43.1%
<b>Total Region</b>	<b>\$ 85,531</b>	<b>\$ 47,526</b>	<b>180.0%</b>	<b>68.8%</b>
<b>U.S.</b>	<b>\$ 124,315</b>	<b>\$ 47,815</b>	<b>260.0%</b>	<b>100.0%</b>

Note: n.a. is “not available.”  
 Data for Delaware does not meet BLS or state agency disclosure standards.  
 Source: USDOL, BLS 2012.

Trends in regional average annual wages are provided in Figure 126. The trends show that, in general, average annual wages for refinery employees have been increasing for New Jersey and Pennsylvania, but fell in 2010 and 2011 for Georgia.



**Figure 126. Trends in Mid-Atlantic impact region refinery average annual wages, 2001-2011.**

Note: n.a. is “not available.”

Data for Delaware does not meet BLS or state agency disclosure standards. Historic data for Virginia does not meet BLS or state agency disclosure standards and is not included in this figure.

Source: USDOL, BLS 2012.

## **10.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY**

### **10.5.1 Trends**

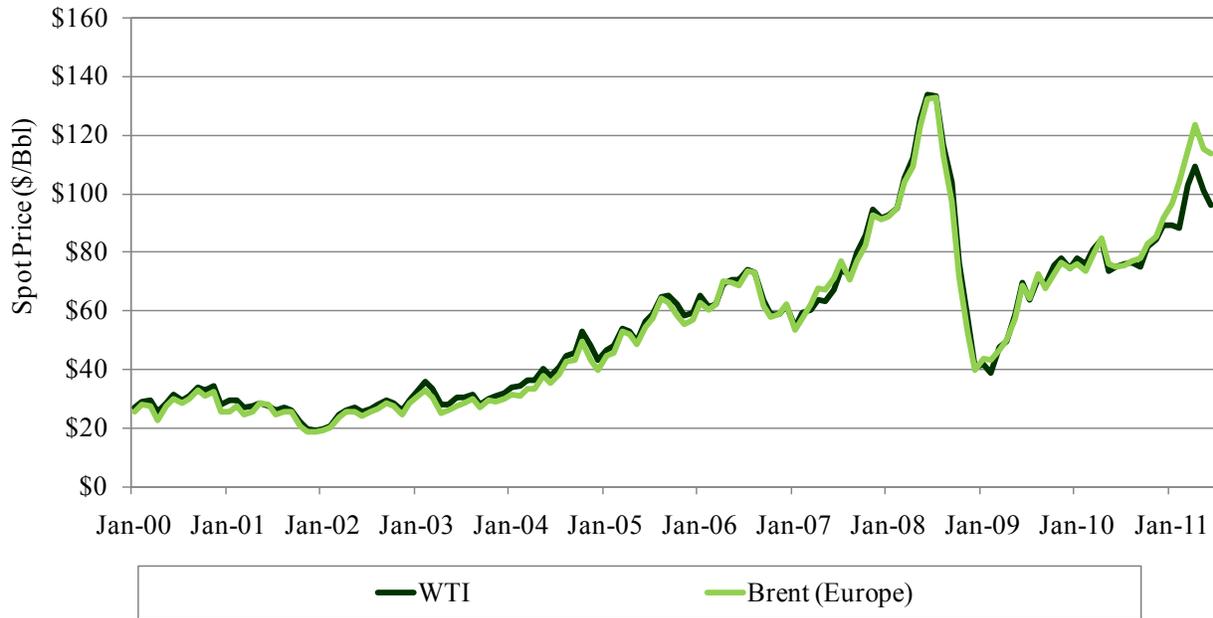
Refineries are undergoing one of the more challenging operational periods witnessed over the past three decades. The challenges are a stark reminder of the uncertainty associated with the refining business. In 2004, industry analysts and policy makers heralded the advent of the new “golden age of refining.” By 2010, that golden age had slipped away the industry is faced with a number of new simultaneous challenges including:

- High and volatile crude oil input prices;
- Decreased demand for refining product;
- Excess capacity development;
- Uncertain regulatory changes;
- Alternative transportation fuels; and
- Changes in industry composition and potential “de-integration.”

Sunoco, a major East Coast independent refiner, summed up these challenges recently in its annual report to investors by noting that “... the volatility of crude oil, refined product, and chemical prices and the overall supply and demand balance for these commodities should continue to have a significant impact on margins and the financial results of the Company” (SEC 2010e).

#### **10.5.1.1 Crude Oil Prices**

Crude oil prices, provided in Figure 127, have fluctuated dramatically over the past eight years. The more recent period of crude oil price increases began in earnest around January 2005 when increased U.S. refined product demand (gasoline, diesel, jet fuel, etc.), coupled with increasing refined product demand from developing countries like China and India, put increasing pressure on global spare production capacity, and, ultimately, price.

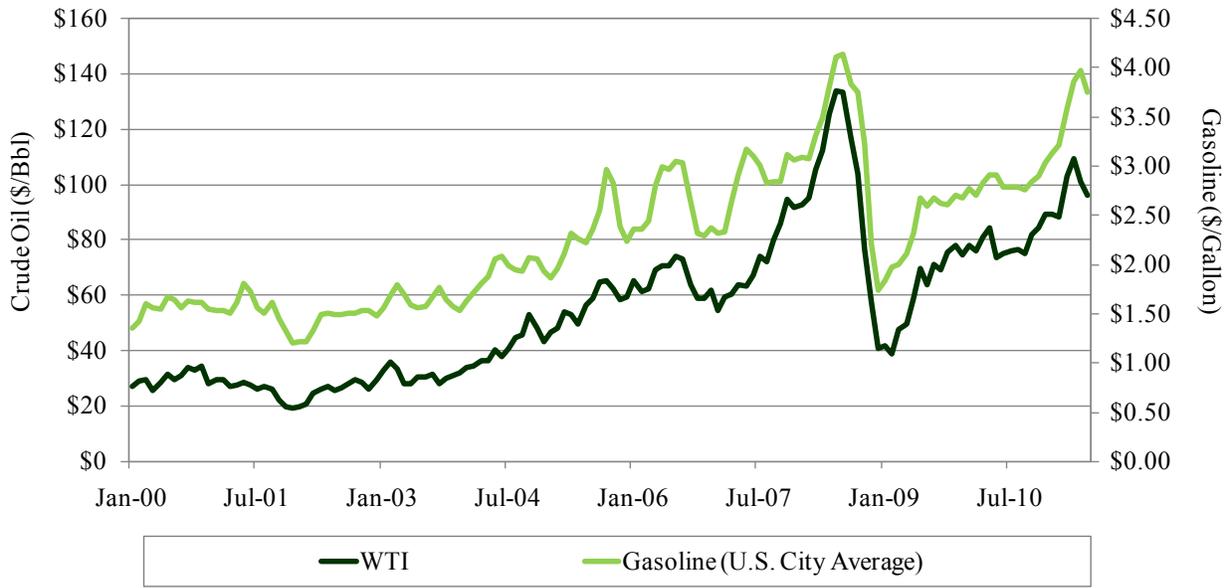


**Figure 127. Monthly crude oil spot prices.**

Source: USDOE, EIA 2012i.

Crude oil prices accelerated at an average monthly rate of 2.8 percent between January 2005 and June 2008, the point at which they hit their near-term peak. The U.S. financial market meltdown and subsequent global economic recession that began in December 2007 pulled the proverbial rug out from under crude oil prices almost overnight. Over the following nine months, world crude oil prices fell by 242 percent, one of the fastest and most precipitous decreases in recorded history. The decrease erased virtually three years of gains, and returned crude oil prices not seen since about January 2005.

The reduction in crude oil prices, however, was short-lived. Markets soon re-loaded their longer-run expectations about world petroleum demand, pushing crude oil prices up at an annual rate of 122 percent from January 2009 to January 2011, when crude once again broke the important psychological barrier of \$100 per Bbl. One of the more unique trends arising during this period has been the wide swing and variation in crude oil prices increasing from close to \$140/Bbl, then falling to around \$40/Bbl, and rising again to over \$100/Bbl: a high to low swing of 250 percent. This creates a number of challenges for refiners, particularly the independent refineries that dominate the eastern seaboard, because crude oil represents its single largest input and significantly impacts final refined product and margins.



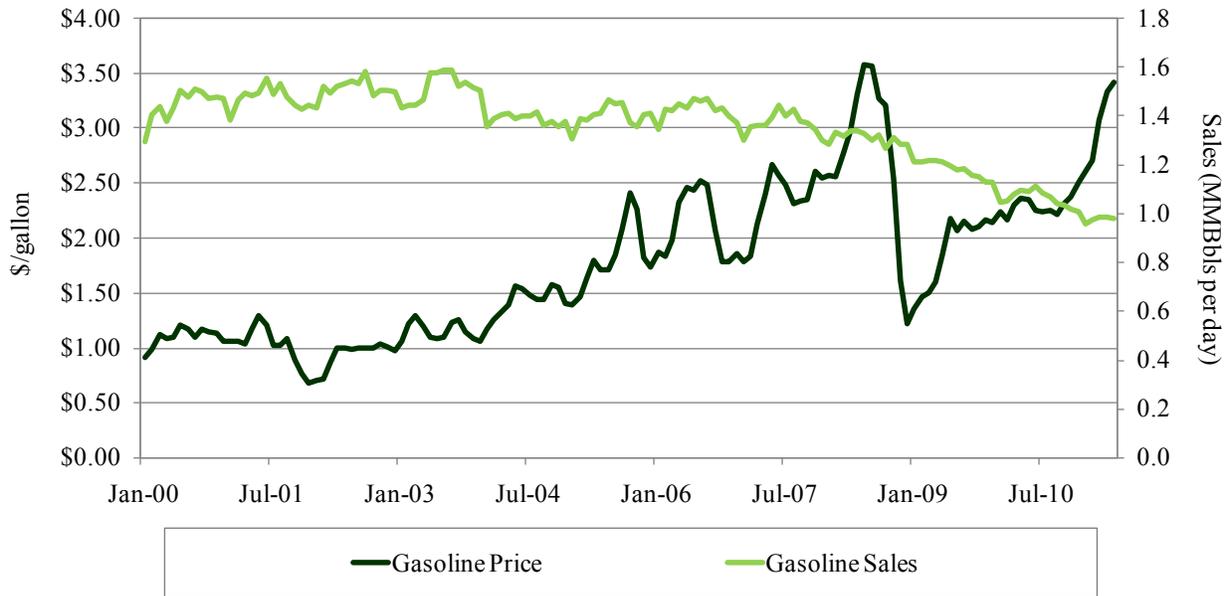
**Figure 128. Monthly crude oil spot and retail gasoline prices.**

Source: USDOE, EIA 2012i.

Figure 128 highlights the direct relationship between crude oil prices and retail gasoline prices. Before January 2005, retail gasoline hovered between \$1.50 per gallon to \$2.00 per gallon. Retail gasoline prices surged during 2005, driven in part by the Gulf Coast refining interruptions created by Hurricanes Katrina and Rita that year. Retail gasoline prices see-sawed throughout 2005 to early 2007, when they began a steady crude oil-price induced rise. Average U.S. retail gasoline prices peaked at over \$4.00 per gallon before the global financial market crash and onset of the global economic recession. Retail gasoline prices have followed crude oil prices on its upward march to come close to re-establishing their pre-recessionary highs of around \$4.00 per gallon.

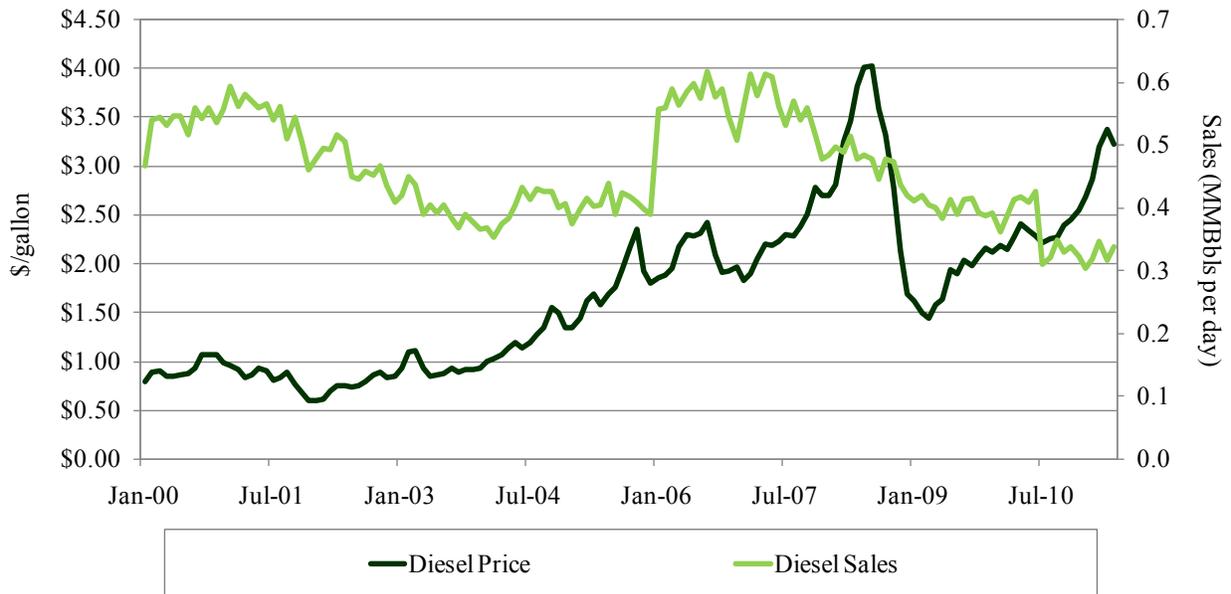
### 10.5.1.2 Refined Product Demand

Figure 129 and Figure 130 show the recent trends in refined product demand and prices for U.S. retail gasoline and diesel, respectively. The impact of high prices on the demand for each refined product is easily discerned.



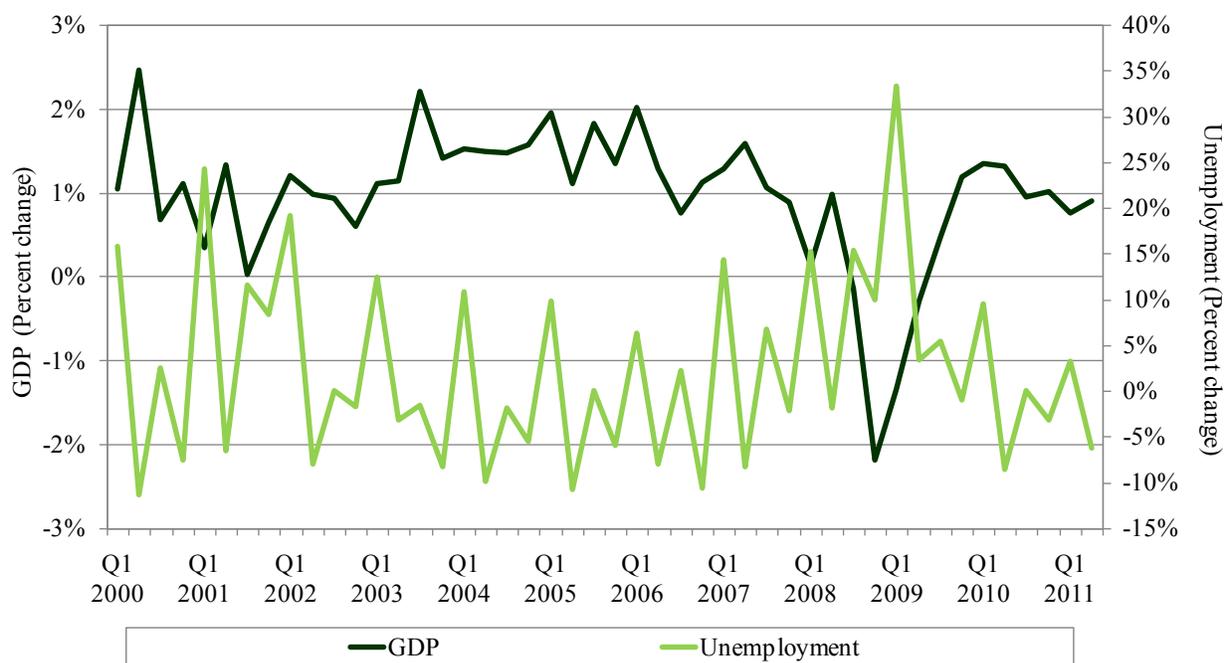
**Figure 129. Gasoline prices and demand.**  
 Source: USDOE, EIA 2012i.

Before 2005, U.S. retail gasoline demand remained steady at about 1.5 MMBbls per day, and then began to fall in 2007 as retail prices surged to new highs, reaching \$3.58 per gallon in June of 2008. Since June 2007, retail gasoline sales have decreased 32 percent. During the same period, prices have increased 33 percent.



**Figure 130. Diesel prices and demand.**  
 Source: USDOE, EIA 2012i.

Retail diesel prices and demand have followed a similar trend to gasoline as diesel demand has also decreased considerably over the past several years. Before 2005, U.S. diesel fuel was priced attractively relative to retail gasoline. Changes in fuel standards required the dramatic reduction of sulfur from 200 parts per million to less than 10 parts per million, which increased costs, and subsequently, prices. Like retail gasoline, diesel demand slowed in 2007 due to the onset of the global economic recession. Today, diesel demand is 45 percent lower than its high of 617,478 Bbls per day set in August 2006.



**Figure 131. Quarterly change in GDP and unemployment.**

Source: USDOC, BEA 2012; and USDOL, BLS 2012.

While refined product prices can be an important determinant of the quantities of refined product purchased in any given year, the economy and general economic activity can also have a significant impact on the demand for refined products. The global economic recession and its corresponding impacts on the U.S. economy have been important factors in influencing refined product demand. The sharp contraction in U.S. economic output helps explain the significant decrease in both U.S. refined product demand and prices (see Figure 126). The uncertainty associated with the domestic and global economic recovery and growth is an important factor influencing, and creating challenges, for all refiners, particularly independent refineries, many of which are concentrated along the East Coast.

### **10.5.1.3 Excess Refinery Capacity**

During the period before the 2008 recession, a number of factors arose that led to the belief that the U.S. was woefully short of refining capacity and needed to consider a more aggressive and expansive development of existing, if not new refineries. Price increases throughout 2004–2008 were one of the major factors motivating the call for new development. The refinery outages created by the tropical activity of 2005 (Katrina, Rita) and 2008 (Gustav, Ike) also raised questions about not only the amount of available refinery capacity, but the logic of its development along a potentially vulnerable part of the country. During this period, a number of different policymakers began to openly advocate policies that would facilitate, or directly encourage, the development of a new petroleum refinery.

In 2005, the state of Louisiana contacted members of OPEC in response comments made about the limitations of U.S. refining capacity. Michael Olivier, Secretary of Economic Development for the state of Louisiana, stated that “Louisiana is keen on attracting development at existing refineries or Greenfield and we want to send a strong message” (Taylor 2005). A solicitation of bids by the Louisiana Department of Economic Development requested a study for construction of a refinery with “world-class environmental performance” and the ability to use alternate feedstocks (Taylor 2005).

In June 2006 the House of Representatives passed H.R. 5254, the Refinery Permit Process Schedule Act, with support from the Bush Administration. H.R. 5254 included measures to expedite the permitting process for refinery construction and expansion and encouraged refinery siting on former military sites (Woolley and Peters 2006). Citing national security, the bill’s main advocate, Texas Representative Joe Barton stated, “[t]he message we hear from home is ‘America needs American energy.’ One part of that need is for more domestic refining capacity” (Johnson 2006).

The need and apparent political enthusiasm for the development of new refining capacity did not go unnoticed by industry. In 2004, Marathon Oil Company’s Chief Executive Officer, Clarence Cazalot, was reported as noting:

We believe at Marathon that we are reaching a golden age of U.S. refining. I certainly don't believe we are always going to see gasoline prices at the level that they are at today. There has not been a new refinery built in the U.S. since 1976, and that was our refinery in Garyville, La., just north of New Orleans on the Mississippi River," Cazalot said of the 245,000 b/d plant.

The industry is not investing in new refining capacity because it's spending massive sums to upgrade existing refineries to meet new clean fuel standards, he said.

Marathon alone will invest \$900 million over the 2002-06 timeframe. There is a little bit of additional capacity that we picked up in that, but most of that is just staying-in-business investment (Dittrick 2004).

Industry's enthusiastic response resulted in one of the largest announced refinery build-outs since the late 1960s. Table 47 provides a listing of some 15 refinery projects that were announced or commenced during this time period. The table shows that most projects were located in the Midwest or the GOM. None of these major projects was proposed for the Atlantic seaboard.

**Table 47. Refinery announcements.**

Refinery	Location	Project Type	Capacity (bbl/day)	Announced	Current Status
Arizona Clean Fuels LLC	Yuma, AZ	Greenfield	150,000	1999	in development
Flint Hills Resources	Rosemount, MN	Expansion	50,000	Jan-05	completed 2007
Chevron Global Refining	Pascagoula, MS	Expansion	15,750	Jun-05	completed
Tesoro Corporation	Anacortes, WA	Expansion	25,000	Jun-05	canceled
Frontier Oil	Cheyenne, WY	Expansion	n.a.	Jul-05	completed
Wynnewood Refining Co.	Wynnewood, OK	Expansion	15,000	Oct-05	completed
Marathon Oil Corporation	Garyville, LA	Expansion	180,000	Nov-05	completed
Frontier Oil	El Dorado, KS	Expansion	11,000	Dec-05	completed
Marathon Oil Corporation	Detroit, MI	Expansion	80,000	Jan-06	completed
Coffeyville Resources	Coffeyville, KS	Expansion	15,000	Jan-06	completed
Motiva Enterprises LLC	Port Arthur, TX	Expansion	325,000	Apr-06	under construction
BP America Inc.	Whiting, IN	Expansion	260,000	Sep-06	under construction
ConocoPhillips	Ferndale, WA	Expansion	25,000	2006	postponed
Connacher Oil and Gas	Great Falls, MT	Expansion	9,500	2007	canceled
Valero	Port Arthur, TX	Expansion	45,000	2008	delayed indefinitely

Source: Armistead and Evans 2006; Reuters 2007; and Reuters 2008.

Many refinery projects, however, did make it to commercial operation despite the equally significant number of project cancellations. Unfortunately, for most refineries, the capacity development came to the market much too late to take advantage of, or help alleviate, the high pre-recessionary refined product prices. These now-apparent mistimed additions have helped lead to a refining capacity glut that has squeezed margins and profitability, and had little to no impact on refined product prices given world crude oil prices. This glut has pressured refineries of all types, particularly independents, and those with lower profitability like the ones along the Atlantic seaboard. These challenges were recently emphasized by Sunoco, which advised investors:

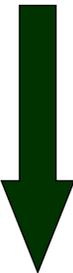
...the profitability of the Refining and Supply business will continue to be challenged in 2011 due to volatility in the global marketplace causing ongoing weakness in product demand and the general oversupply of refined products due to increases in worldwide production capacity. The absolute level of refined product margins is difficult to predict as they are influenced by extremely volatile

factors, including the absolute level of crude oil and other feedstock prices, changes in industry production capacity, the effects of weather conditions on product supply and demand and the status of the global economy. Furthermore, excess capacity, increasing biofuels mandates and environmental regulations continue to adversely impact the refining industry. These factors may prevent refiners, including Sunoco, from earning their cost of capital and may lead to industry plant closures in the future (SEC 2010e, emphasis added).

#### **10.5.1.4 Regulatory Changes**

Refineries have also been significantly impacted by changes in fuel standards and the use of various fuels to meet localized air emission requirements, particularly those that attempt to reduce smog and nitrous oxides (NO<sub>x</sub>). For instance, the Clean Air Act Amendments of 1990 tightened emissions standards for “tailpipe emissions.” (USEPA 1999) The new standard, called “Tier 1,” set NO<sub>x</sub> standards for cars at 0.6 gpm, which was a 40 percent reduction from the previous 1981 standard (USEPA 1999). Tier 1 standards were applicable to new light-duty vehicles, such as passenger cars, light-duty trucks, SUVs, minivans, and pick-up trucks, and were phased in between 1994 and 1997 (Dieselnet 2007).

Tier 2 standards were adopted in December 1999 with a NO<sub>x</sub> requirement of 0.07 gpm for both cars and light-duty trucks (USEPA 1999). Tier 2 was implemented from 2004 through 2009 and extended standards to include heavier vehicle categories (Dieselnet 2007). The Tier 2 standards also included regulations on sulfur levels in gasoline and diesel fuel quality. As shown in Figure 132, the regulations required an average gasoline sulfur standard of 120 parts per million (ppm) beginning in 2004. In 2005, this average standard was reduced to 30 ppm. The EPA has also established rules for highway diesel, non-road diesel, and locomotive and marine diesel. The 15 ppm specification is known as Ultra Low Sulfur Diesel (ULSD) and was phased in from 2006 to 2010.

	Gasoline	On-Road Diesel	Off-Road Diesel	Locomotive & Marine	
2004	120 ppm	500 ppm	500+ ppm		
2005	30 ppm				
2006		15 ppm			
2007			500 ppm	500 ppm	
2008					
2009				15 ppm	
2010					
2011					
2012				15 ppm	

**Figure 132. EPA regulations, sulfur fuel specifications.**

Source: Dieselnets 2007; and USEPA 2011a.

In April 2010 the EPA and the U.S. Department of Transportation’s National Highway Traffic Safety Administration (NHTSA) finalized a joint rule establishing a national program of new standards for model year 2012 through 2016 light-duty vehicles (USEPA 2011b). These rules are intended to reduce greenhouse gas emissions and improve fuel economy and cover passenger cars, light-duty trucks, and medium-duty passenger vehicles (Pew Center 2011).

A report from the Pew Center noted that proposed Federal standards will accelerate the fuel economy improvements required under the Corporate Average Fuel Economy or “CAFE” program, administered by the NHTSA, within the Department of Transportation. The new standards slightly modify those included in the Energy Independence and Security Act of 2007 (EISA) seeking average fuel economy of 35.5 miles per gallon by 2016. However, these standards were soon challenged by an executive memorandum ordering the EPA and the NHTSA to develop stricter standards. Though the memorandum did not cite specific fuel economy figures, it pushed for further improvements in fuel efficiency for cars and light trucks made in 2017 and beyond, and medium and heavy trucks made in 2014 through 2018 (Baker 2010). Automakers applauded President Obama’s efforts, and cited the need for a single national program for fuel economy and greenhouse gas emissions because it would be difficult to comply with a regulatory patchwork of standards from NHTSA, the EPA, and multiple states (Roland 2010).

Before the EPA and the NHTSA finalized their regulations, a group of 19 U.S. senators sent a letter to President Obama urging him to set the “maximum feasible” standard (Argus Media 2011). In addition, a proposal developed by the Environmental Protection Agency, the National Highway Traffic Safety Administration and the California Air Resources Board suggested an average of 56.2 miles per gallon for all new cars and trucks by 2025 (Mitchell and Terlep 2011). The Alliance of Automobile Manufacturers (AAM) responded and warned that “arbitrary new federal fuel economy and GHG standards could lead to higher car prices, less-safe vehicles and industry job losses” (Argus Media 2011).

In July 2011, President Obama and 13 different automotive manufacturers, who represented close to 90 percent of the auto sales in the U.S., reached a historic agreement to a new set of aggressive fuel efficiency standards for cars and light trucks (NHTSA 2011). The new fuel efficiency standards call for a reduction of five percent per year for cars, and 3.5 percent per year for light duty trucks over the next five years (Federal Register 2011). After five years, manufacturers will be required to increase car and light truck fuel efficiency, on fleet-wide basis, by five percent per year. These standards are set to reach an overall fleet-wide efficiency target of 54.5 MPG by 2025 (Federal Register 2011).

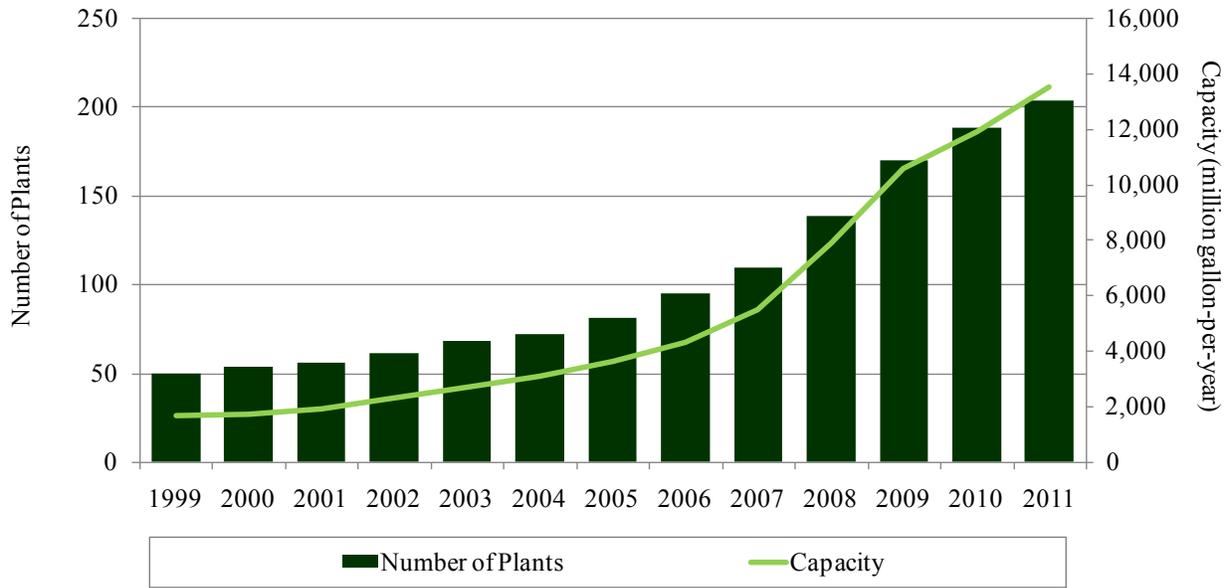
This is a significant increase in efficiency and will have important impacts on the refinery industry given the current glut of excess capacity in the marketplace. Current estimates by the Administration place total fuel savings at around 12 BBbls per year and the reduction of 6 billion metric tons of CO<sub>2</sub> (NHTSA 2011).

#### **10.5.1.5 Alternative Fuels Standards**

Another factor significantly impacting refineries across the U.S. are the new and increasing standards for alternative fuels and alternative fuel blends required under the Renewable Fuel Standard (RFS) program, established by the Energy Policy Act (EPAct) of 2005. The RFS program is managed by the EPA. The original EPAct requirements set a target fuel blend level for gasoline of 7.5 billion gallons (178 MMBbls) of renewable fuel by 2012. These standards were almost immediately modified by the EISA in the following ways:

- RFS eligibility was expanded to include diesel, in addition to gasoline;
- Renewable fuel blend requirements were increased from 9 billion gallons in 2008 to 36 billion gallons by 2022;
- New renewable fuel categories were established with separate volumetric requirements; and
- EPA was required to apply lifecycle greenhouse gas performance threshold standards so that each class of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces.

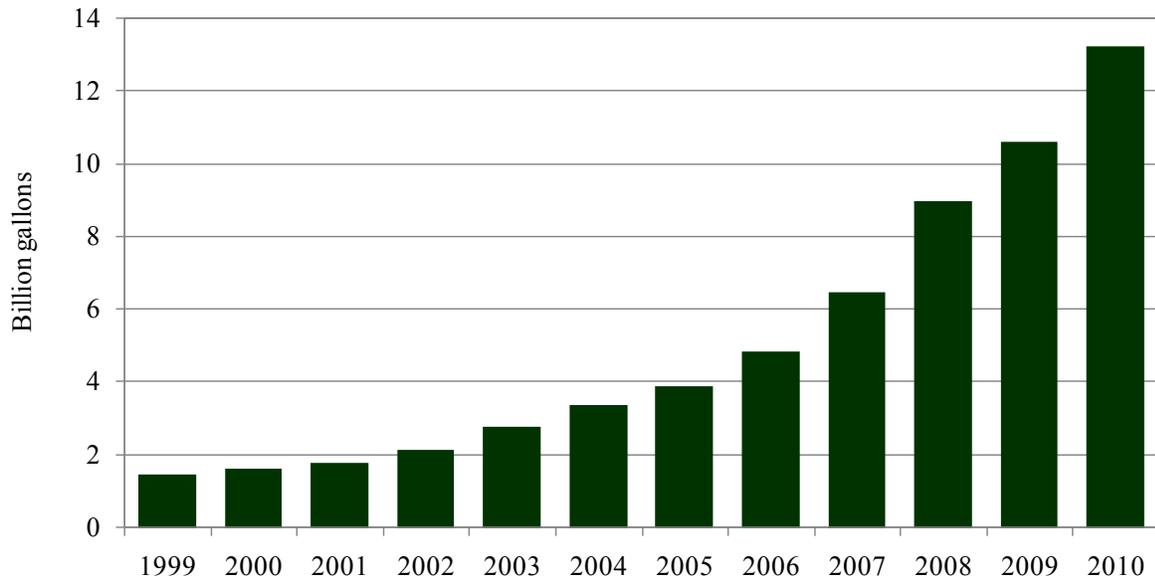
Figure 133 highlights the historic change in annual renewable fuel refining capacity and installations throughout the U.S. The chart shows a dramatic increase starting in 2007: at about the same time period, some of the initial petroleum refining additions were beginning to come online.



**Figure 133. U.S. fuel ethanol industry plants and production capacity.**

Source: RFA 2011.

Figure 21 highlights annual production of renewable fuels, in billion gallons, over the decade before the EPAct and EISA were adopted. These new fuel production levels had an immediate and important impact on traditional refining operations, particularly profitability, as more and more capacity was displaced by new biofuel capacity.



**Figure 134. U.S. fuel ethanol production.**

Source: RFA 2011.

Biofuels are not the only new transportation fuel competing with traditional petroleum-based fuels. The past several years has seen an increase in the advocacy and promotion of a wide range of other transportation fuel sources particularly electricity and natural gas vehicles. The American Recovery and Reinvestment Act (ARRA), commonly referred to as the “Stimulus Bill,” led to the funding of over \$2.4 billion for 48 projects for manufacturing electric vehicles, vehicle batteries and electric vehicle components. This funding included grants to:

- U.S. based manufacturers to produce batteries and their components and to expand battery recycling capacity (\$1.5 billion);
- U.S. based manufacturers to produce electric drive components for vehicles, including electric motors, power electronics, and other drive train components (\$500 million); and
- The purchase of plug-in hybrid and all-electric vehicles for test demonstrations in multiple locations; to deploy them and evaluate their performance; to install electric charging infrastructure; and to provide education and workforce training to support the transition to advanced electric transportation systems (\$400 million) (USDOE, EERE 2009).

The Stimulus Bill also included funding for programs of interest to natural gas vehicle (“NGV”) promoters, including a Department of Energy pilot program for alternative fuel, infrastructure, and advanced technology vehicles (\$300 million); a diesel emissions reduction program that will facilitate the use of natural gas vehicles (\$300 million); a Federal Transit Administration capital expenditures grant (\$8.4 billion); numerous community block grants for energy efficiency and conservation (\$3.2 billion); and a U.S. General Services Administration Federal Fleet acquisition of fuel efficient vehicles (\$300 million) (NGVAmerica 2009). The Stimulus Bill also included two important changes to the tax credits for natural gas vehicles and fueling infrastructure design to facilitate the use of NGVs (NGVAmerica 2009).

### **10.5.1.6 Industry Decomposition**

Historically, the two main participants in the refining industry have been integrated majors and independent refiners. The integrated majors have long held a dominant position in the refining business and were the original source of operations for the Standard Oil Company, the predecessor to what was historically referred to as the “seven sisters.” However, some major oil companies are in a historic position. Many are starting to find the economics of continuing refining operations as part of their overall operations to be challenging and have begun the process of “spinning-off” these downstream operations (refining, retail) into separate, non-affiliate companies.

In January 2011, Marathon Oil Corporation announced that it would spin off its downstream business into a stand-alone company (New York Times 2011). The exploration and production part of the company will keep the Marathon Oil Corporation name, while the new Marathon Petroleum Corporation would include the refining plants, pipeline transportation and the Speedway gas station chain (New York Times 2011; and Daily 2011). Marathon's president and CO stated that "the substantial improvement in the global business and financial environments over the last two years has created the conditions under which we believe it is now appropriate to move forward with the formation of two strong independent energy companies" (Fontevicchia 2011).

Similarly, in July 2011, ConocoPhillips announced it would separate its refining and production businesses into two publicly traded corporations (Ordonez 2011). Conoco Chief Executive James Mulva noted, in a conference call with investors, that "we came to the conclusion that [the split] was the best way to create value" for shareholders (Ordonez and Gilbert 2011). ConocoPhillips also plans to split its upstream and downstream business into two stand-alone, publicly traded corporations. According to the company, the resulting exploration and production company will focus on oil and gas worldwide, while the downstream company will focus on refining and marketing, primarily in the U.S., although ConocoPhillips has downstream operations in Europe (Ordonez and Gilbert 2011).

## **10.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

Despite their history and legacy as the originating locale for petroleum production and refining, facilities along the eastern seaboard are some of the lowest margin refineries in the U.S. Most serve in a relatively niche role and can be thought of as occupying the very upper end of the U.S. refinery supply curve. As such, these facilities will be some of the last to be utilized or expanded, and one of the first to be curtailed during periods of industry expansions or contraction, respectively.

East Coast refineries are also forced to compete with their Gulf Coast counterparts through regional product deliveries (imports) on the Colonial Pipeline system (see Figure 135 ). The Colonial system originates in Houston, Texas and carries a variety of refined products, including several grades of gasoline, kerosene, home heating oil, and diesel fuel up the entire East Coast, terminating 5,519 miles (8,882 kilometers) later at the New York harbor. The Colonial system, developed in the late 1960s and expanded several times, delivers an average of 100 million gallons per day (Colonial Pipeline 2011a). This is equivalent to 2.3 MMBbls per day, or a level comparable to the output of 165 percent of the capacity along the East Coast. This competitive alternative to regional refining helps to keep refined product processes lower for consumers, but also prevents existing regional refineries from expanding in any meaningful fashion. This differs from more geographically-isolated West Coast refineries which, though also somewhat less cost-effective, have no import capabilities other than through tankers.



**Figure 135. Colonial Pipeline system map.**

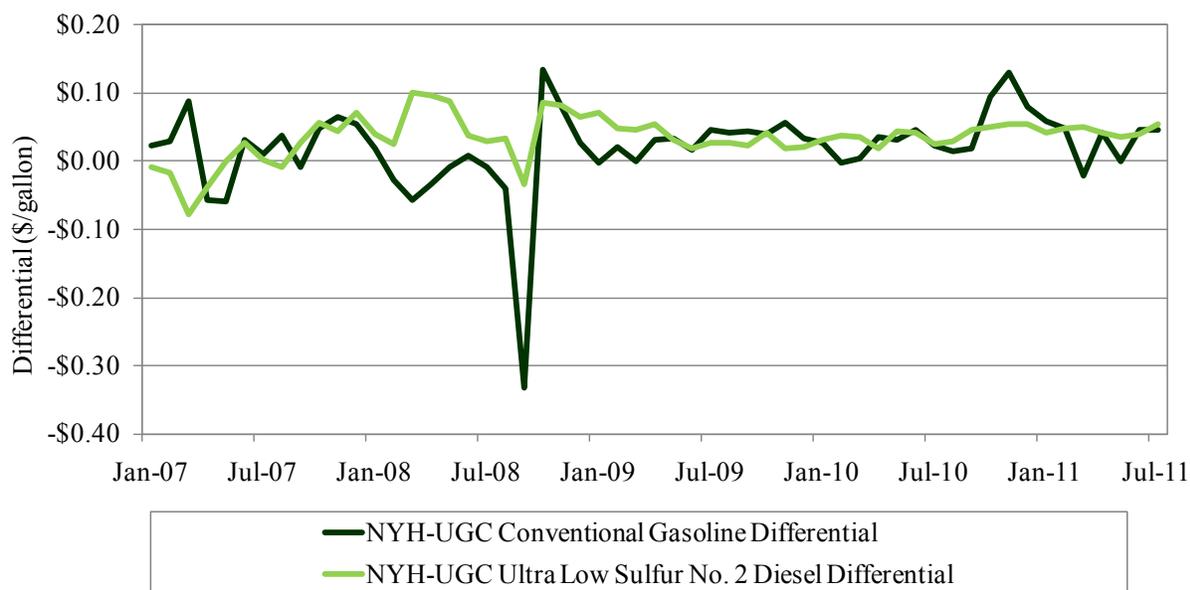
Source: Colonial Pipeline 2011b.

Over the past two years, the economic downturn has begun to have a noticeable effect on refineries in the Mid-Atlantic. In November of 2009, Valero closed the coker at its 180,000 barrel per day refinery in Delaware City due to economic conditions (Reuters 2011b). In April of 2010, Valero announced that it was selling the Delaware City refinery to PBF Energy Partners, a fund of Petroplus, Blackstone Group, and First Reserve. After investments of between \$125 and \$150 million, Petroplus reopened the facility in the spring of 2011 (Goldstein 2010). The \$220 million purchase price not only includes the refinery, terminal and pipeline, but also a 218 megawatt power plant complex.

Also in late 2009, Sunoco permanently shut down all processes at its Westville, New Jersey refinery (SEC 2009a). In the announcement Sunoco cited economic conditions, weak demand for refined products, and increased global refining capacity (Sunoco 2009). All production from this facility was transferred to the company's two nearby refineries in Marcus Hook and Philadelphia, Pennsylvania. This shutdown affected 400 employees (Sunoco 2009).

In August of 2010, the Western Yorktown, Virginia refinery was also idled due to the "poor outlook for East Coast refining margins" and low price differentials between light and heavy crudes. Although the plant will continue to operate its products terminal to supply final products to the East Coast 230 of the 260 employees lost their jobs (Burkhardt 2010, SEC 2010g).

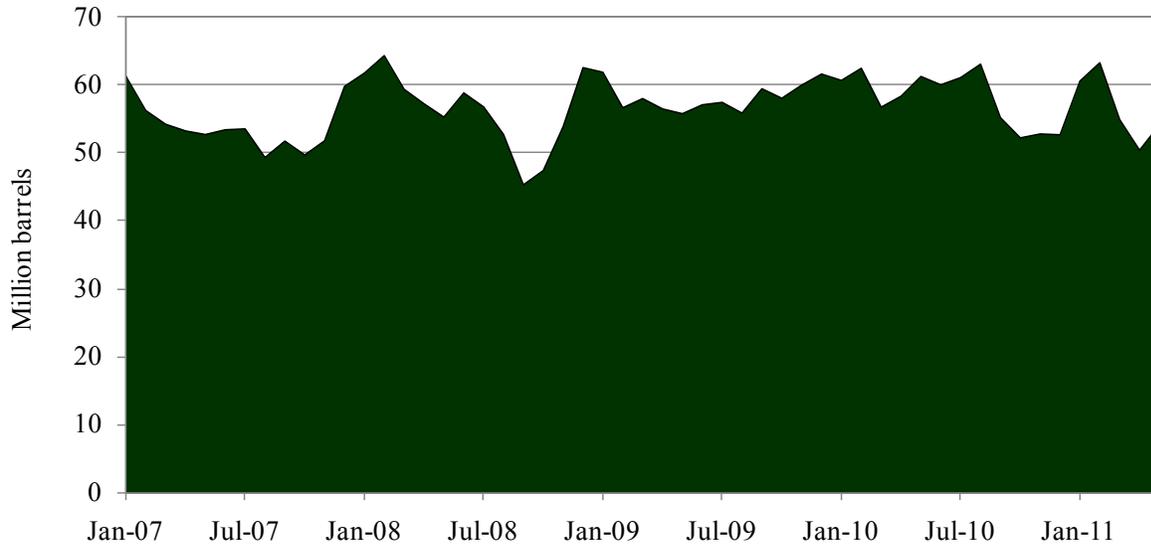
The recent shut-downs of these regional East Coast refineries, however, may be leading to a fundamental change in regional supply dynamics that may increase the profitability of these facilities, albeit only in the most limited fashion in the near-term depressed refined product market. For instance, recent decreases in regional refining capacity, coupled with maintenance outages and output idling, has helped tighten New York Harbor (NYH) to U.S. Gulf Coast (USG) conventional gasoline and distillate differentials as seen in Figure 136.



**Figure 136. New York Harbor – U.S. Gulf Coast price differentials.**

Source: USDOE, EIA 2012i.

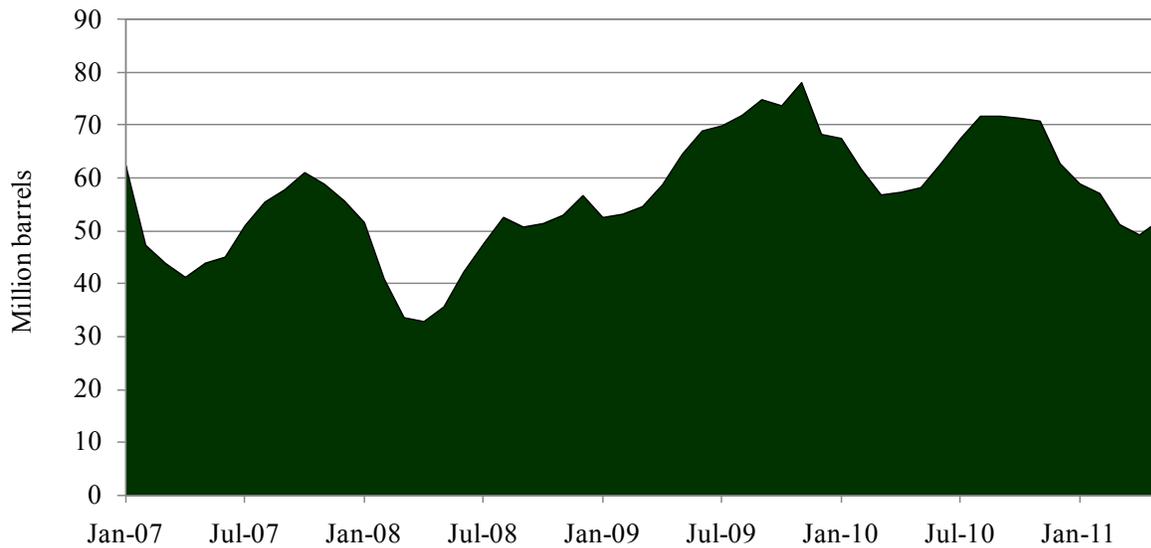
Another potential indicator of tighter Mid-Atlantic refined product markets resulting from this capacity realignment may be materializing in recent refined product stock information. Figure 137 shows historic PADD 1 gasoline stocks back to 2007, while Figure 138 provides comparable information for distillates over the same time period. PADD 1 gasoline stocks have been decreasing from their 62 MMBbls recent high reached around January 2009. By the summer 2011, those stocks were down to slightly over 50 MMBbls. Though the move is not as dramatic as the winter-summer 2008 inventory drop, regional inventories were relatively flat for an entire year before starting the more recent tightening in the summer of 2010.



**Figure 137. PADD 1 gasoline stocks (total motor gasoline).**

Source: USDOE, EIA 2012i.

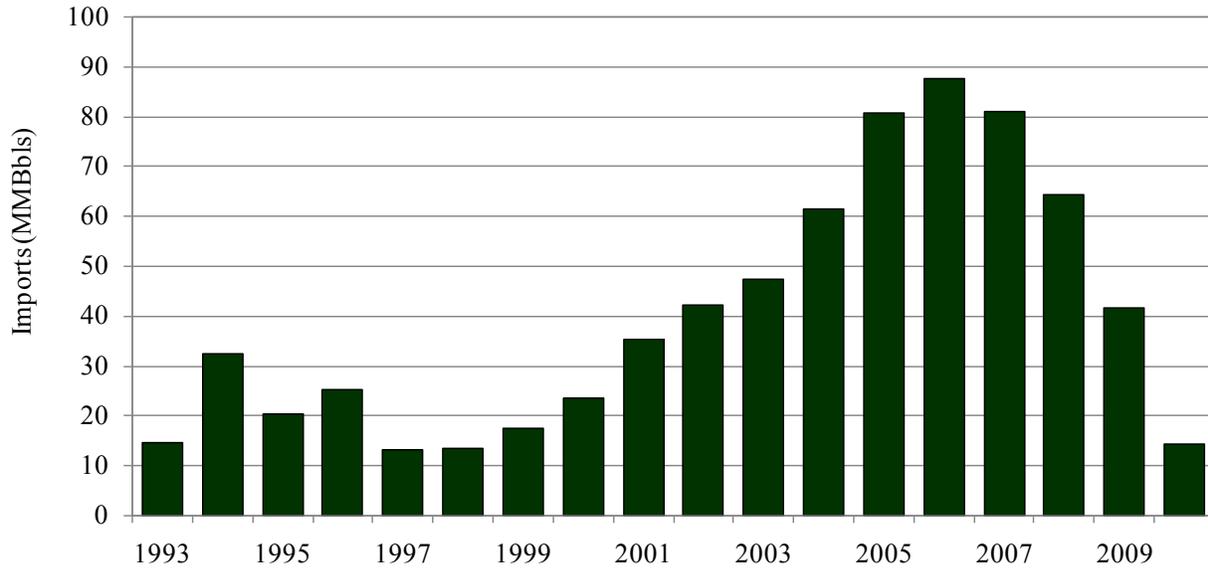
A similar trend can be seen in regional distillate stocks (Figure 138). Again, while the recent 2009 to 2011 regional tightening is not as dramatic as that seen in 2008, distillate stocks have held relatively steady for almost two years before starting its recent contraction. Summer 2011 regional distillate stocks are currently at levels not seen since prior to the recession.



**Figure 138. PADD 1 distillate fuel oil stocks.**

Source: USDOE, EIA 2012i.

The last potential indicator of potential regional market tightening can be reflected in regional gasoline imports. PADD 1 historically imports a considerable amount of gasoline from European refineries. Between 2005 and 2007, PADD 1 gasoline imports from Europe averaged about 83 MMBbbls per year. Figure 139 shows that those imports have fallen considerably in recent years, to 41.7 MMBbbls in 2009 and 14.3 MMBbbls in 2010.



**Figure 139. PADD 1 imports of finished motor gasoline.**  
Source: USDOE, EIA 2012i.

## 10.7 FACTORS IMPACTING EAST COAST DEVELOPMENT

As of mid-2012, 11 refineries were located along the Mid-Atlantic OCS. Of those, two are currently idle. The nine active refineries in the region are relatively large by East Coast standards; six have capacities of over 160,000 barrels per day. All have the ability to handle light, sweet and certain grades of heavier, sour crude oil. Most all produce a wide range of refined products from the high to lower end of the barrel. Most, if not all, of these facilities get their crude oil input supplies from imports and not from other producing basins in the U.S. None of these refineries are currently connected to a major interstate crude oil pipeline and obtain most of their crude oil supplies from tankers.

Clearly, existing refinery capacity could be used to process Mid-Atlantic OCS crude oil production. It is highly unlikely, given expected overall market conditions over the next several years, that any East Coast refinery would expand its current capacity without a high degree of certainty that offshore development was certain and imminent. Further, it would be nearly impossible to site a new greenfield refinery along the Mid-Atlantic OCS.

If Mid-Atlantic OCS oil production were to materialize in the near future, it is highly likely that East Coast refineries would substitute some of their current imports from Canada, the North Sea and Africa for Mid-Atlantic OCS production, provided the economics of doing so are favorable. These economics will be ultimately driven by a comparison of the total average cost of crude inputs produced offshore along the Mid-Atlantic OCS compared with the total average cost of imported crude inputs. Factors influencing these relative cost differentials include:

1. Crude oil quality: light, sweet crude is often priced at a premium relative to heavier sour crudes. The quality of Mid-Atlantic OCS production has not been identified and further input is needed from BOEM on this issue. Regardless, most East Coast refineries are processing the heavier inputs. Mid-Atlantic OCS production will have to be priced to this qualitative basis or transported elsewhere to earn a higher margin.
2. Transportation: the cost differential of transporting crude from the Mid-Atlantic OCS to nearby refineries needs to be considered. Pipeline alternatives, which currently do not exist, could be evaluated. Pipeline options are likely to be expensive and reduce producer flexibility in marketing crude output since an extensive system linking crude to multiple refineries, like that in the GOM region, does not exist. Further, most of the region's refineries now import crude oil via tanker, so continued tanker imports, via floating production, storage, and offloading (FPSOs) are likely to be the near term, if not longer term option.
3. Market conditions: the long run need for refined product in the U.S. is anticipated to decrease and not rise to 2007 highs for at least a decade. If refined products can be imported via pipeline or tanker from cheaper sources than East Coast refining operations, East Coast crude oil production may need to be exported to other refining location in the U.S. (GOM, Midwest) or abroad (Europe).

## **11 ELECTRIC POWER**

### **11.1 DESCRIPTION OF THE INDUSTRY AND SERVICES PROVIDED**

Electricity is an integral part of modern life in most developed countries. Electricity is used for lighting, running appliances, electronics, and for heating and cooling. It is essential to factories, commercial business, and some recreational facilities. As will be discussed later, electricity is also an essential input for the industries located in the Mid-Atlantic impact region states.

Electric utilities are responsible for ensuring a consistent and reliable source of electricity to the consumers in their service territories. Electric utilities can be investor-owned, publicly-owned, cooperatives or Federal utilities. Power marketers may also be considered electric utilities. These companies buy and sell electricity, but usually do not own or operate electric utility assets (generation, transmission, or distribution facilities).

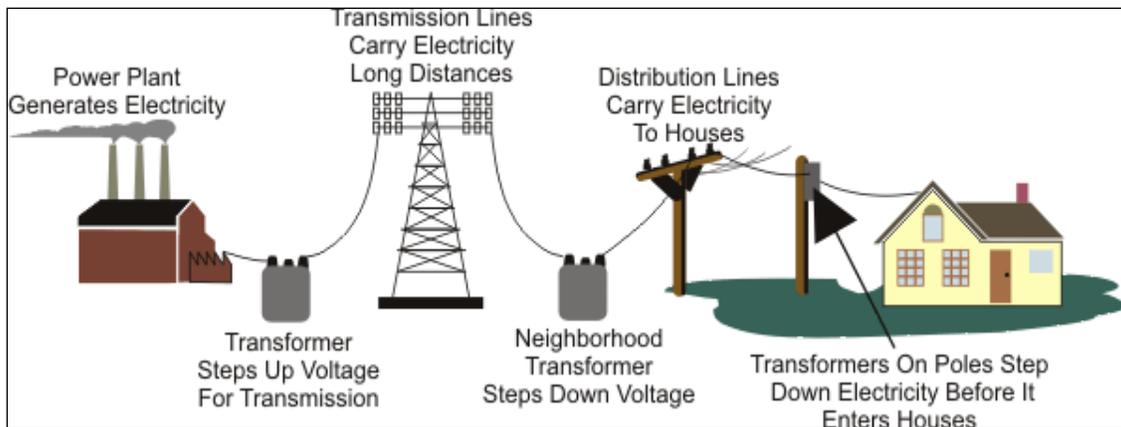
Over 1,700 nonutility power producers generate electricity in the U.S. These facilities are typically cogeneration facilities at industrial sites that produce electricity as a byproduct for efficiency and reliability purposes. Also included are independent power producers (IPPs) that produce and sell power on the wholesale market at non-regulated rates. The IPPs do not have franchised service territories and most are exempted from the regulatory requirements imposed on traditional utilities by FERC.

Electric utilities have historically been thought of as regulated monopolies and have pre-defined market service territories within which they are the exclusive providers of service. Electric utilities are regulated by the state in which they operate and are one of the more heavily regulated industries out of the various energy industries. Competition in the power generation sector and retail service has been introduced in some states and will be discussed in greater detail below. The introduction of retail competition, however, is a function of state determinations and policy. There are no federal mandates at this time for retail competition.

Electricity is a relatively homogeneous commodity and is typically differentiated only by customer type and, in some instances, on the type of service quality (i.e., firm or various types of interruptible service). Utility service territories are typically distinguished by restricted geographic locations, although this can vary across different states. Classes of service, or sectors, for electricity customers typically include residential, commercial, industrial, and others and are used for setting rates and for long-run capacity planning (i.e., load growth and peak demand).

### **11.2 TYPICAL FACILITY CHARACTERISTICS**

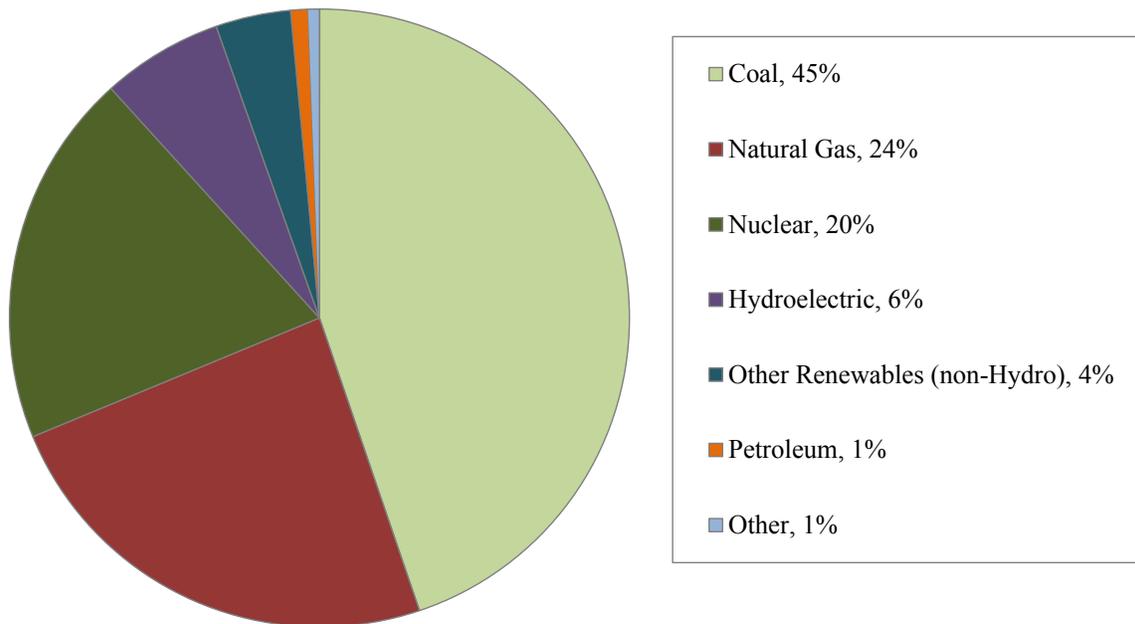
An electric power system is a group of generation, transmission, distribution, and communication facilities that are physically connected and operated as a single unit under one control (Figure 140) (USDOE, EIA 2008c). Dispatch centers are responsible for matching the supply and demand of electricity and maintaining the electricity flow.



**Figure 140. Electric power generation, transmission, and distribution.**

Source: USDOE, EIA 2008c.

Power plants use a number of different types of fuel to produce electricity: fossil fuels (coal, natural gas, or a refined oil product), nuclear energy, and renewable energy sources, such as water (hydroelectric power), biomass, waste-to-energy, geothermal, wind, and solar energy, and alternative fuels. Figure 141 shows the relative share of electricity generation in 2010 by fuel type.



**Figure 141. U.S. electric power industry net generation by fuel source, 2010.**

Source: USDOE, EIA 2012k.

In most areas, demand for electricity fluctuates daily. Demand is usually highest in the afternoon and early evening (on-peak). Seasonal demand reflects regional weather and climatic conditions; the highest demand occurs in the summer when air-conditioning use is greatest. Power plants tend to operate in two basic modes: base-load and peaking load. Base-load power plants are efficient generators that produce electricity around the clock at an even consistent level. These plants generally include nuclear, coal-fired, geothermal, and waste-to-energy plants. Peaking plants are used when demand increases above the normal base load or demand. For the most part, these plants are less efficient and expensive to operate.

Transmission lines are the large, high-voltage power lines that move electricity from generating plants, sometimes over long distances to substations located near population centers. The U.S. electric transmission grid totals more than 200,000 miles (321,869 kilometers) of high-voltage transmission lines (EEI 2012).<sup>20</sup> The voltage from these transmission lines is reduced to move power onto smaller, lower voltage distribution lines.

Local utilities deliver electricity to customers through a network of existing transmission and distribution lines. These are the lines that are seen along streets, supported by wood poles (Figure 142).

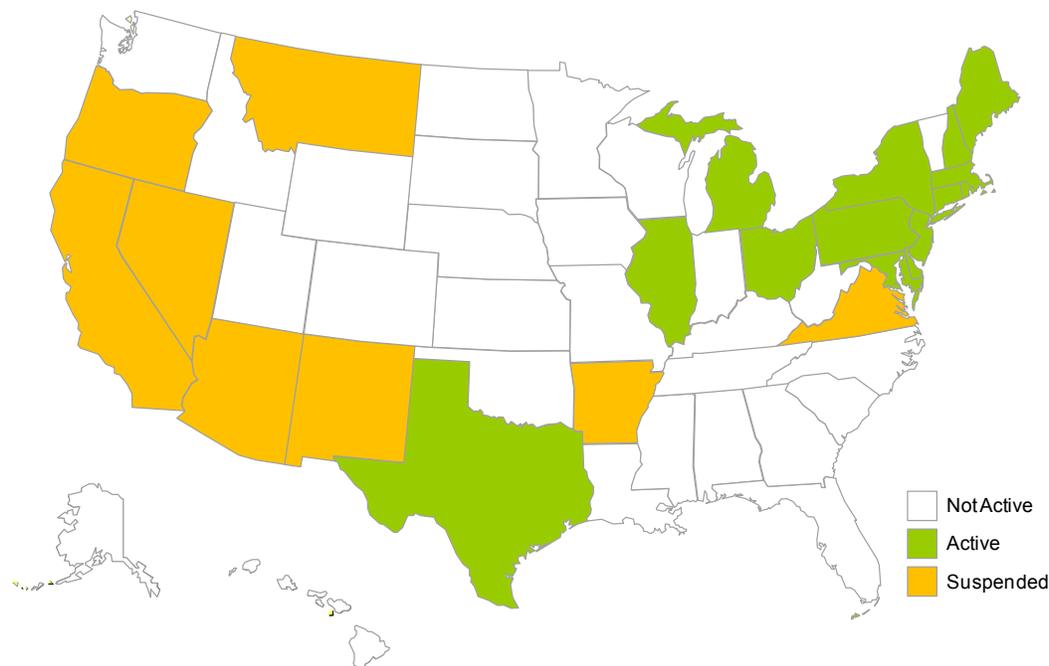


**Figure 142. Electric transmission: high voltage transmission and low voltage distribution.**  
Source: Clough Harbor and Associates 2008; FreeFoto.com 2008.

<sup>20</sup> This includes lines that are 230 kV or greater.

Often, a utility will generate excess electric power that it does not need to serve its customers. This power may be used as “sales for re-sale” and become part of the wholesale electricity market. This wholesale market is open to anyone who can generate power, connect to the transmission grid, and find another party to purchase their production. Sellers in the wholesale market include competitive suppliers and marketers, independent power producers, and those utilities with excess generation (EPSA 2010).

In the past, the electric utility was a regional monopoly, characterized by vertically-integrated companies that provided generation, transmission, and distribution service to customers. The utility owned its generation facilities, and the transmission and distribution lines through which power travels to customers. These utilities charged customers regulated cost-based rates, made up of the cost to generate, transport and distribute power. Though most states still use this model, a number of states have restructured their electric power industries. In these states, the generation of electric power is no longer done by the utility, but rather a number of competitive suppliers will compete to supply the electricity. Ownership or operation, or both, of generation, transmission, and distribution facilities are separated into independent entities. And, in these deregulated markets, prices for electric power are determined by competition in the market. In most cases, the utility that was once the regional monopoly still owns the transmission and distribution service, and rates for such are still regulated and cost-based. While a competitive supplier may be providing the electricity, the regulated utility still delivers that power through its distribution system. As shown in Figure 143, most states still have integrated-utilities, while others have restructured the market. Some states started the restructuring process and then suspended the effort.



**Figure 143. Electricity restructuring by state.**

Source: USDOE, EIA 2010.

More than 2,930 electric utilities in the U.S. are responsible for ensuring a reliable source of electricity to all consumers in their service territories (USDOE, EIA 2012m). Distribution utilities can generally be classified as into three categories by ownership type: (1) investor-owned; (2) publicly-owned; (3) cooperatives; and (4) federal utilities. There are 193 investor-owned electric utilities, 2,005 publicly owned electric utilities, 873 consumer-owned rural electric cooperatives, and nine Federal electric utilities operating in the U.S. (USDOE, EIA 2012n). Power marketers buy and sell electricity, but usually do not own or operate generation, transmission, or distribution facilities.

Investor-owned electric utilities are privately owned and operate much like private businesses, providing a service for their customers and a return for their investors. These utilities are assigned certain geographic areas where they must provide service. They are regulated and required to charge reasonable prices and fair service to all consumers. Most provide basic services for the generation, transmission, and distribution of electricity.

Nonprofit agencies operated by local governments, publicly owned electric utilities serve communities in their regions at cost. Excess funds are returned to consumers in contributions to the community, economic growth, efficient operations, and rate reductions. Examples of publicly owned electric utilities are municipals, public power districts, state authorities, irrigation districts, and other state organizations.

Most municipal electric utilities only distribute power; however, some larger municipalities may actually own generating facilities and transmission lines. These utilities obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sale of electricity. Voters in a public utility district elect commissioners or directors to govern the district independent of any municipal government.

Cooperative electric utilities are owned by their members and are typically established in rural areas with fewer consumers which are not as attractive to investors. Cooperatives are incorporated under state laws and are usually directed by an elected board of directors, which in turn selects a manager.

Federal electric utilities in the U.S. are part of several agencies in the U.S. Government:

- the Army Corps of Engineers in the Department of Defense,
- the Bureau of Indian Affairs and the Bureau of Reclamation in the Department of the Interior,
- the International Boundary and Water Commission in the Department of State,
- the Power Marketing Administrations in the Department of Energy (Bonneville, Southeastern, Southwestern, and Western Area), and
- the Tennessee Valley Authority (TVA).

There are also three federal agencies that operate generating facilities:

- TVA, the largest federal producer;
- the U.S. Army Corps of Engineers; and
- the U.S. Bureau of Reclamation.

The TVA markets its own power. Generation by the U.S. Army Corps of Engineers (except for the North Central Division, for example, Saint Mary's Falls at Sault Ste. Marie, Michigan), and the U.S. Bureau of Reclamation are marketed by the federal power marketing administrations: Bonneville, Southeastern, Southwestern, and Western Area.

## 11.3 GEOGRAPHIC DISTRIBUTION

### 11.3.1 Generation

There are 2,970 electric power generators in the Mid-Atlantic impact region states (USDOE, EIA 2012). The locations of these generating facilities are shown in Figure 144. Facilities in these states total 210,033 MW of generating capacity. Figure 145 shows the regional break-out of the capacity of these facilities. The most generation capacity is located in Pennsylvania, which totals almost 50,000 MW, or 24 percent of the regional total. Georgia is second, with 40,087 MW, or 19 percent of the regional total. The smallest share is Delaware's, with just 3,336 MW, or two percent of the regional total.

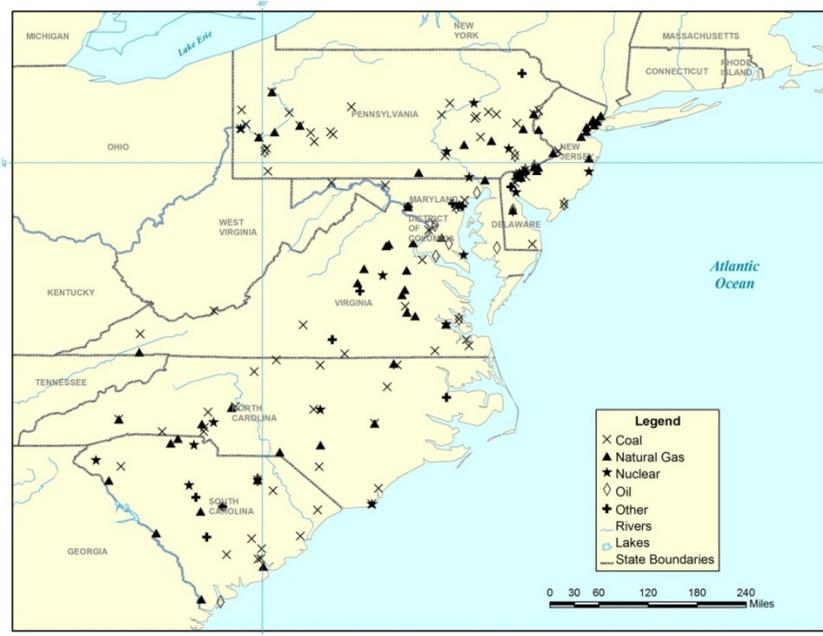
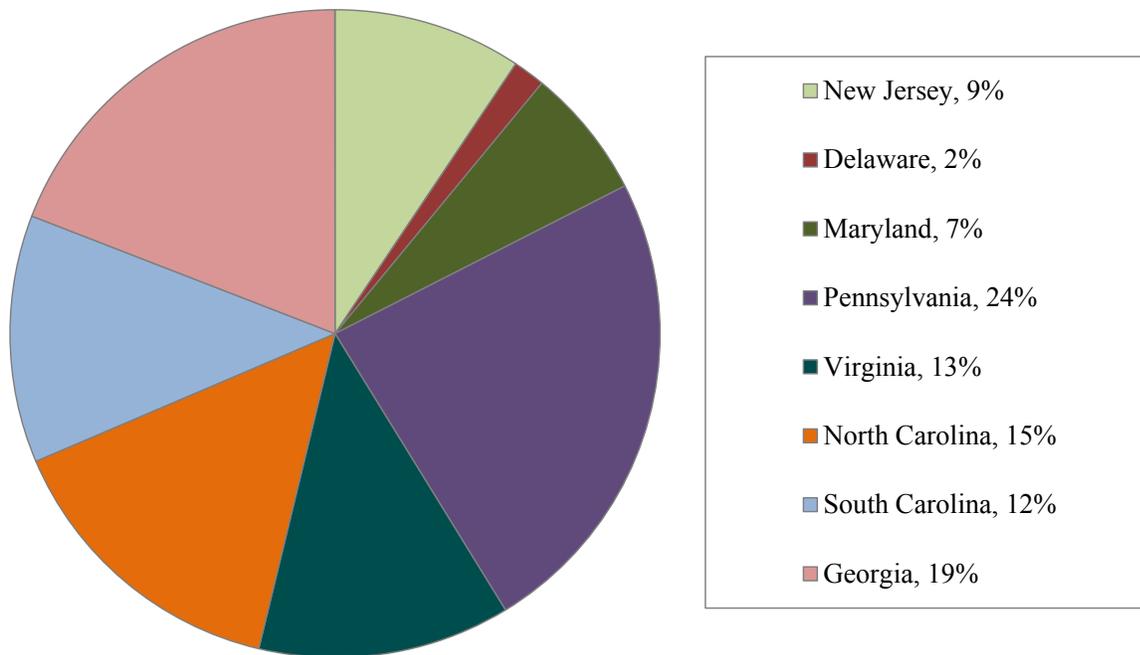


Figure 144. Mid-Atlantic impact region electric generators by fuel type.

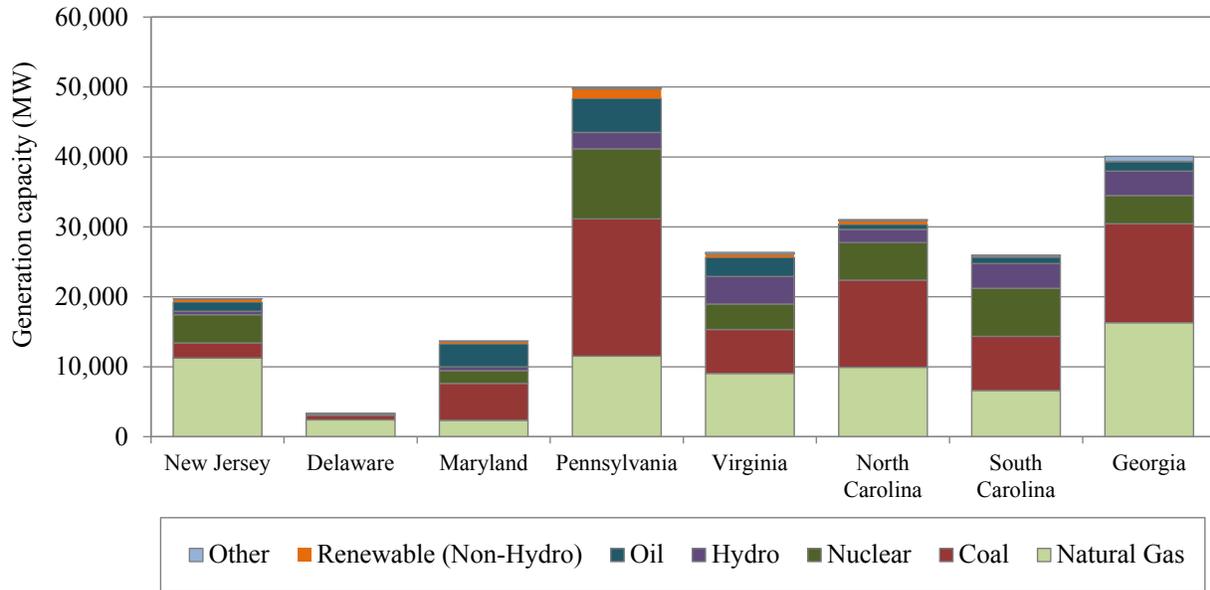


**Figure 145. Mid-Atlantic impact region share of electric generation capacity, 2011.**

Source: USDOE, EIA 2012I.

Figure 146 shows each state's generating capacity by fuel type. Natural gas is the primary fuel used in the region, fueling almost 70,000 MW of capacity, or 33 percent of the regional total. However, only four states use natural gas as the primary source: New Jersey, Delaware, Virginia, and Georgia. Coal-fired capacity makes up the majority in Maryland, Pennsylvania, North Carolina, and South Carolina. In total, coal provides 68,248 MW of capacity, or 32 percent of the regional total.

Some states also have significant amounts of nuclear capacity. In South Carolina, 26 percent of the state's generating capacity comes from nuclear-fueled units. Pennsylvania and New Jersey also have significant capacity fueled by nuclear (20 percent and 21 percent, respectively). In Virginia and South Carolina, hydroelectric fueled capacity is significant (15 percent and 14 percent of those state totals).



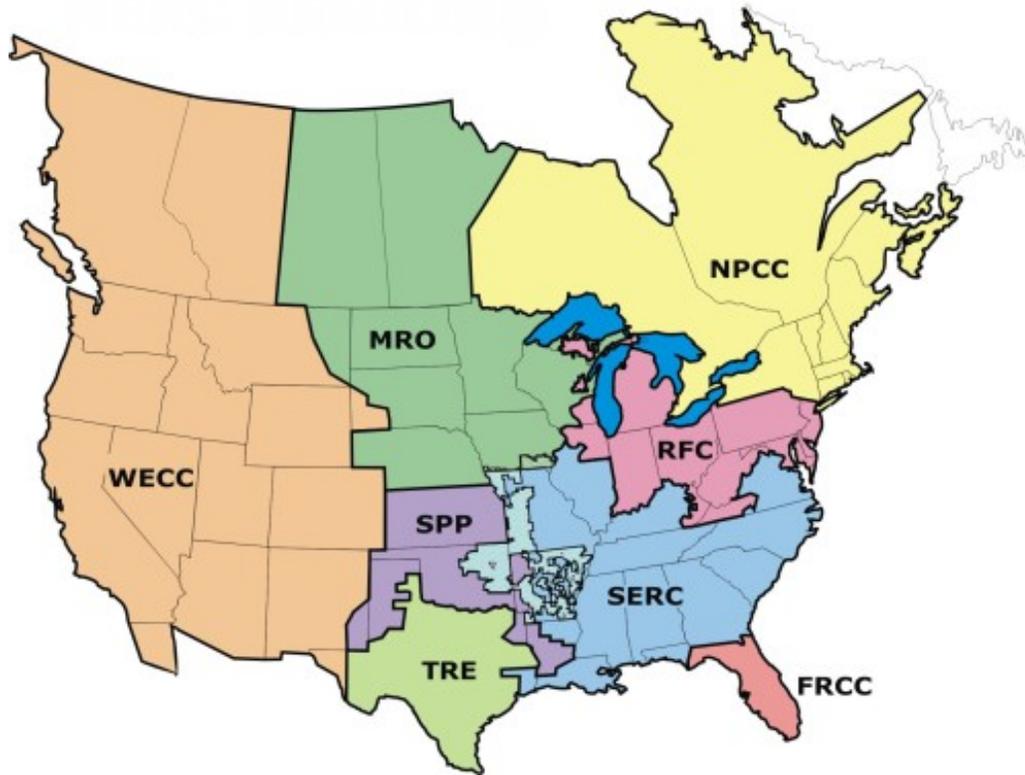
**Figure 146. Mid-Atlantic impact region share of electric generation capacity, 2011.**

Source: USDOE, EIA 2012I.

### 11.3.2 Transmission

The U.S. transmission system is the backbone of the U.S. electric power industry moving electric power over long distances, from generation source to local distributor. To better support competition in the electric power industry, the power transmission system in the U.S. has been reorganized from a fragmented system with many operators to one where a handful of organizations operate the system (USDOE, EIA 2000).

When interconnected, transmission lines become high-voltage transmission networks. In the U.S., these networks are referred to as grids. There are three major grids in the U.S.: The Eastern Interconnect, the Western Interconnect, and the Electric Reliability Council of Texas (ERCOT). As shown in Figure 147, these three regions are separated into eight regional entities:



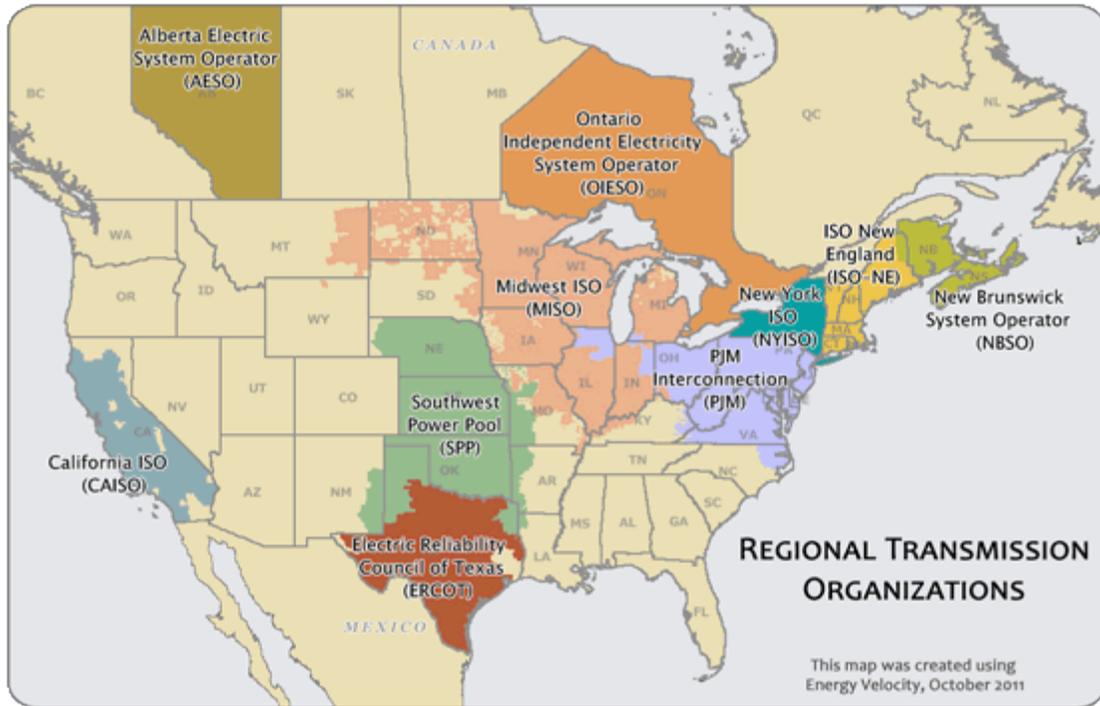
**Figure 147. Current NERC regions.**  
 Source: USDOE, EIA 2000.

Each of these regions is overseen by the North American Electric Reliability Corporation, or NERC. In 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S. users, owners, and operators of the bulk power system and made compliance with those standards mandatory and enforceable (NERC 2012). The regions are defined as:

1. Northeast Power Coordinating Council (NPCC);
2. Reliability First Corporation (RFC);
3. Midwest Reliability Organization (MRO);
4. SERC Reliability Corporation (SERC);
5. Florida Reliability Coordinating Council (FRCC);
6. Southwest Power Pool (SPP);
7. Texas Regional Entity (TRE); and
8. Western Electricity Coordinating Council (WECC).

Within each of these regions are Independent System Operators (ISOs), also known as Regional Transmission Organizations (RTOs). FERC created RTOs as a way to coordinate generation and transmission across each geographic region. These regional organizations operate wholesale electricity markets that allow participants to buy and sell electricity on a day-ahead or real-time spot market basis. The RTOs also provide non-discriminatory transmission access; facilitate competition among wholesale suppliers; and forecast demand and schedule generation to ensure that enough power is available at all times. All of these services are provided more efficiently on a regional basis rather than a small-scale utility-by-utility basis. As shown in Figure 148, there are seven RTOs in the U.S:

- ISO NE: operates in Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut.
- NY ISO: operates only in New York, but is regulated by FERC because the state's transmission grid is interconnected with the rest of the region.
- PJM: operates in all or parts of Delaware, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and District of Columbia.
- MISO: operates in all or parts of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Pennsylvania, South Dakota, Virginia, Wisconsin, and Manitoba, Canada.
- SPP: Operates in all or parts of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas.
- CAISO: operates only in California. This ISO is also regulated by FERC because the state's transmission grid is interconnected with the rest of the Western states.
- ERCOT: operates only in Texas. The ISO is entirely encompassed within the state and has its own intrastate transmission grid and is therefore subject only to state regulatory authority.



**Figure 148. U.S. regional transmission organizations.**

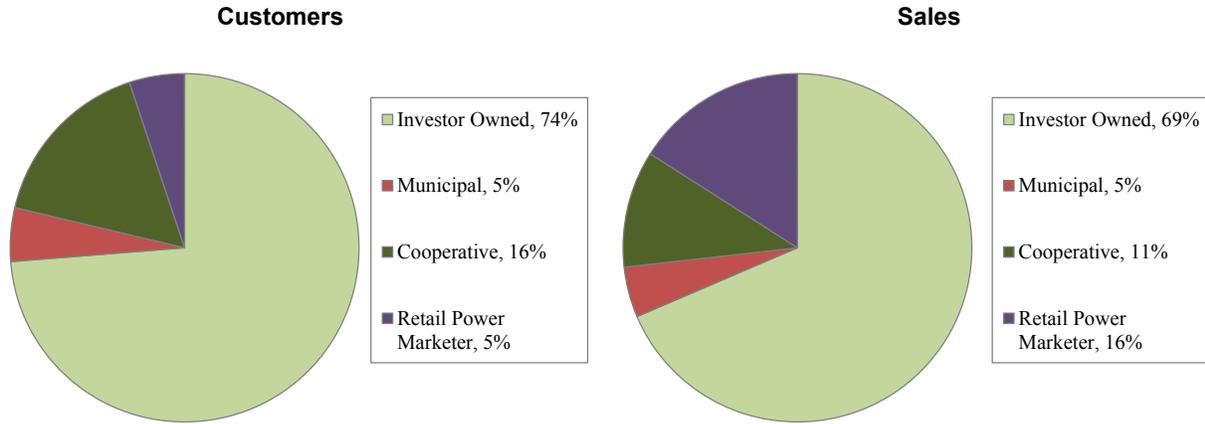
Source: FERC 2012f.

Because the trades in the wholesale market occur within these regional, multi-state interconnections, they are interstate sales and regulated by FERC. The one exception to this is ERCOT. The ERCOT region of Texas functions as its own, separate entity and is regulated by the Public Utilities Commission of Texas because the entire interconnection lies within the state.

Most of the Mid-Atlantic impact region is located within the PJM Interconnection. North Carolina, South Carolina, and Georgia, however, are not located within an RTO.

### 11.3.3 Distribution

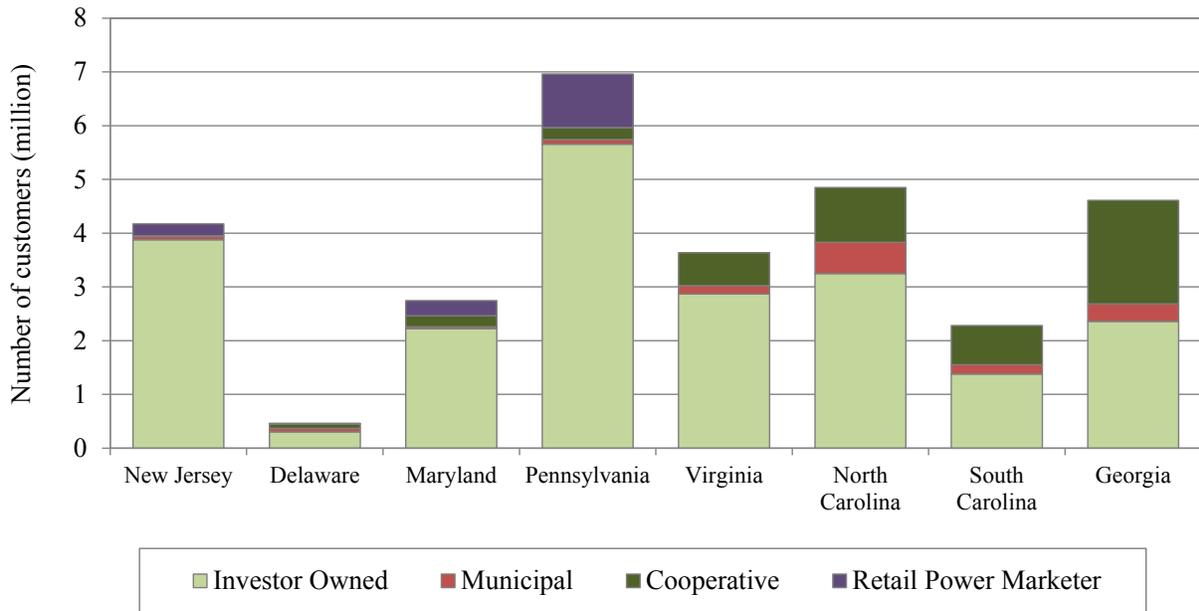
There are close to 30 million customers in the Mid-Atlantic impact region, consuming over 900 million MWh of electricity. Investor-owned utilities in this region serve 74 percent of the customers and provide 69 percent of electricity sales. Cooperatives serve an additional 16 percent of customers and deliver 11 percent of electricity sales. Municipalities only account for five percent. Retail power marketers serve five percent of customers, but sell about 16 percent of the MWh (see Figure 149).



**Figure 149. Mid-Atlantic impact region, customers and sales by utility type.**

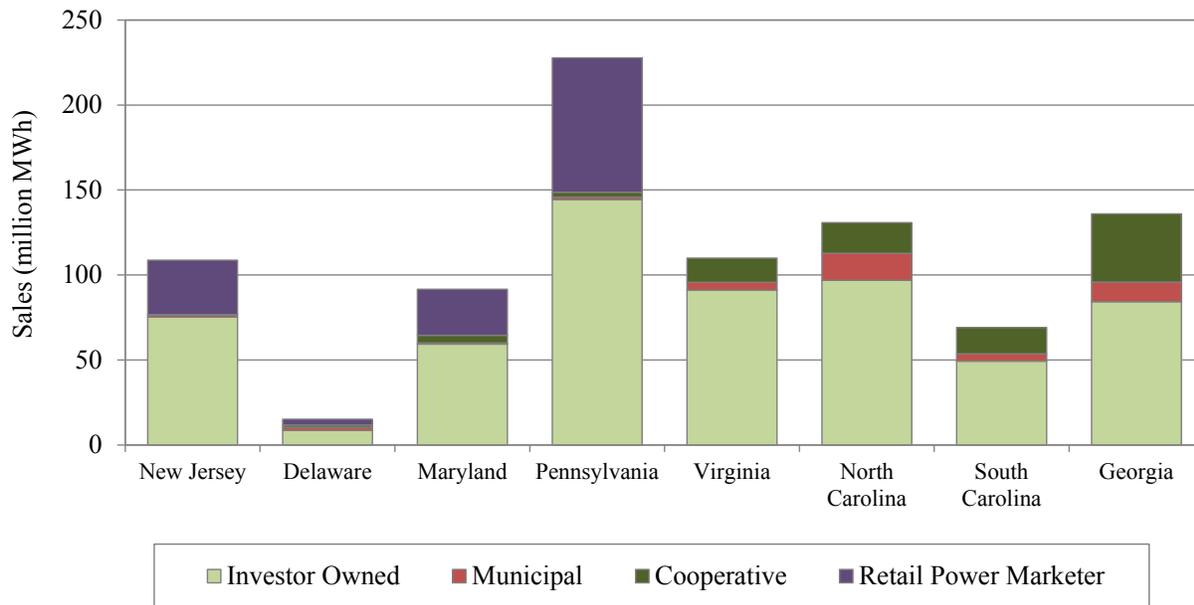
Source: USDOE, EIA 2012m.

Figure 150 and Figure 151 show the regional customers and sales by state and type of utility. Pennsylvania has the largest number of customers and utility sales and most of these are served by investor owned utilities (81 percent). Georgia has a significant number of customers served by cooperatives: 42 percent of customers are served by cooperatives; 51 percent served by investor-owned, and the remaining seven percent are served by municipalities. In general, municipalities and cooperatives have a larger role in electricity distribution in the southern part of the Mid-Atlantic impact region. Municipalities serve only one to two percent of customers in New Jersey, Maryland, and Pennsylvania.



**Figure 150. Mid-Atlantic impact region utility customers by state and type of utility.**

Source: USDOE, EIA 2012m.



**Figure 151. Mid-Atlantic impact region utility sales by state and type of utility.**

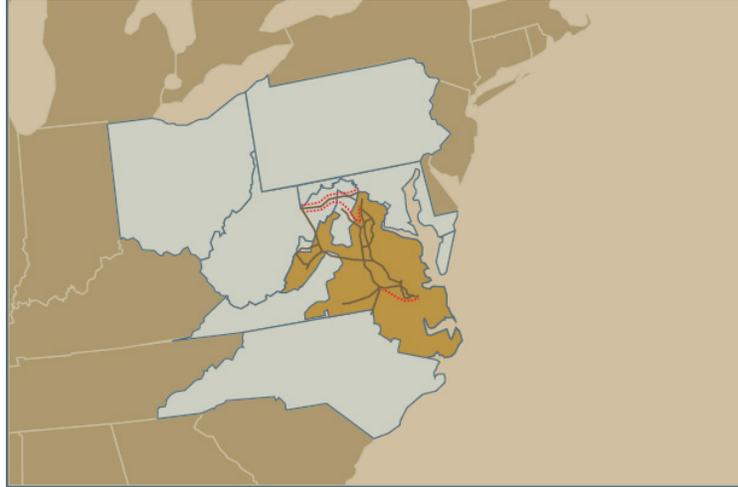
Source: USDOE, EIA 2012m.

Table 48 shows a list of major investor-owned electric utilities in the Mid-Atlantic coastal region. One large company in the area is Dominion, which has two separate electric distribution companies (Dominion Virginia Power and Dominion North Carolina Power) that distribute electricity in the states of Virginia and North Carolina. Together, these Dominion companies account for 11 percent of customers, 13 percent of sales, and 14 percent of revenues out of all investor-owned utilities in the Mid-Atlantic impact region states. Dominion comprises of thirteen separate subsidiaries engaged in many activities in the energy industry, including electric generation and transmission, and natural gas transportation and distribution. Dominion’s electricity distribution service territory is shown in Figure 152.

**Table 48. Investor owned utilities in Mid-Atlantic impact region states.**

	<b>Number of Customers</b>	<b>Sales (MWh)</b>	<b>Revenue (thousand \$)</b>
<b>New Jersey</b>			
Atlantic City Electric	547,763	9,683,043	1,034,324
Jersey Central Power & Light	1,099,194	21,481,810	2,219,024
Public Service Electric & Gas	2,157,077	42,516,023	4,285,190
Rockland Electric	72,470	1,665,455	209,828
<b>Delaware</b>			
Delmarva Power	301,543	8,360,863	599,684
MidAmerican Energy	177	268,029	17,708
<b>Maryland</b>			
Baltimore Gas & Electric	1,240,290	31,808,754	2,175,149
Delmarva Power	199,456	4,329,714	363,990
MidAmerican Energy	899	919,838	65,319
The Potomac Edison	252,769	6,954,244	485,700
Potomac Electric Power	531,189	15,332,821	1,178,333
<b>Pennsylvania</b>			
Citizens Electric	6,823	164,677	16,726
Duquesne Light	587,610	14,027,155	846,056
Metropolitan Edison	552,631	13,969,633	1,055,464
Pennsylvania Electric	582,091	14,072,672	912,124
PPL Electric Utilities	1,403,889	36,941,727	1,797,564
Pennsylvania Power	160,250	4,585,851	233,288
PECO Energy	1,574,521	39,369,235	3,039,841
Pike County Light & Power	4,662	75,242	6,036
UGI Utilities, Inc.	62,067	985,564	99,636
Wellsborough Electric	6,178	119,727	13,195
West Penn Power Company	717,269	20,104,093	1,029,315
<b>Virginia</b>			
Appalachian Power	521,923	15,845,232	1,203,709
Kentucky Utilities	29,250	936,229	71,866
Dominion Virginia Power	2,319,501	74,323,597	6,503,719
<b>North Carolina</b>			
Progress Energy Carolinas	1,277,207	37,353,311	3,235,956
Duke Energy Carolinas	1,853,838	55,430,896	4,171,486
Dominion North Carolina Power	118,724	4,176,834	300,719
<b>South Carolina</b>			
Progress Energy Carolinas	165,996	6,264,949	515,592
Duke Energy Carolinas	542,712	20,785,579	1,426,044
Lockhart Power	6,238	183,692	16,829
South Carolina Electric & Gas	663,433	22,151,222	2,263,198
<b>Georgia</b>			
Georgia Power	2,360,487	84,299,772	8,098,561

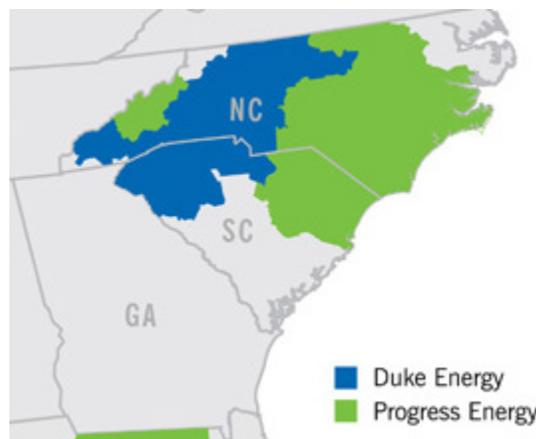
Source: USDOE, EIA 2012m.



**Figure 152. Virginia Electric & Power Company (Dominion) service territory.**  
 Source: Dominion 2010a.

Duke Energy and Progress Energy also have a significant presence in the Mid-Atlantic impact region through the subsidiary companies Duke Energy Carolinas and Progress Energy Carolinas.

Figure 153 shows these two companies' service territories. These two investor-owned utilities are vertically integrated utilities providing for electric generation, transmission, and distribution needs of the region. The two companies merged in 2011 and, though the resulting company is named Duke Energy, the utilities continue to operate as Duke Energy Carolinas and Progress Energy Carolinas. Combined, these companies account for 18 percent of customers, 20 percent of sales, and 19 percent of revenues of all investor-owned utilities in the Mid-Atlantic impact region states.



**Figure 153. Duke Energy Carolinas and Progress Energy Carolinas service territories.**  
 Source: Duke Energy 2011a.

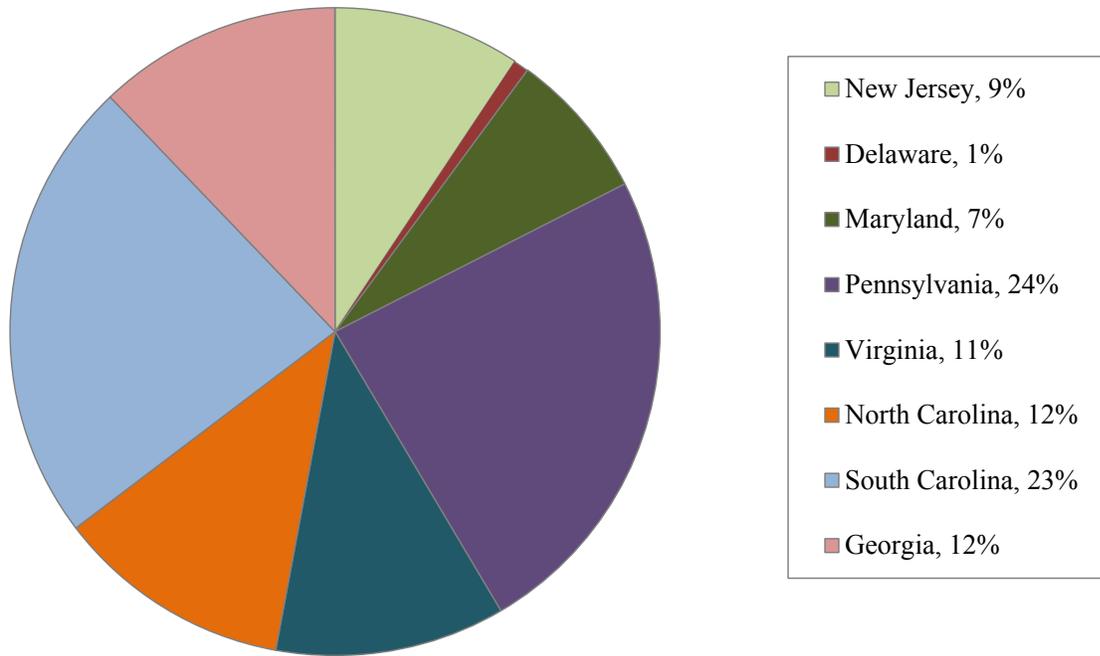
## 11.4 SCOPE OF ECONOMIC CONTRIBUTION TO REGIONAL ECONOMY

Electric power generation employment contributions are relatively small in comparison to the total employment in each of the impact region's states. None of the states in the Mid-Atlantic impact region have electric power generation employment totals that are over one percent of the overall statewide employment totals. On a regional basis, Pennsylvania and South Carolina have the highest share of total electric power generation employment. Notice though, that while the electric power generation employment makes up a relatively small portion of total state employment, the electric power generation employment in these states makes up over 21 percent of total electric power generation employment in the U.S.

**Table 49. Regional and national employment contribution, electric power generation, 2011.**

	Number of Jobs		Electric Power Generation Employment as a Percent of Total State Employment ----- (%) -----	Electric Power Generation Employment Percent of Total U.S. Electric Power Generation Employment ----- (%) -----
	Electric Power Generation	Total State		
New Jersey	3,293	3,156,538	0.10%	1.98%
Delaware	269	342,585	0.08%	0.16%
Maryland	2,621	1,991,055	0.13%	1.58%
Pennsylvania	8,488	4,825,064	0.18%	5.11%
Virginia	4,046	2,889,435	0.14%	2.44%
North Carolina	4,150	3,158,293	0.13%	2.50%
South Carolina	8,205	1,450,840	0.57%	4.94%
Georgia	4,293	3,135,735	0.14%	2.58%
<b>Total Region</b>	<b>35,365</b>	<b>20,949,545</b>	<b>0.17%</b>	<b>21.29%</b>
<b>U.S.</b>	<b>166,099</b>	<b>108,184,795</b>	<b>0.15%</b>	<b>100.00%</b>

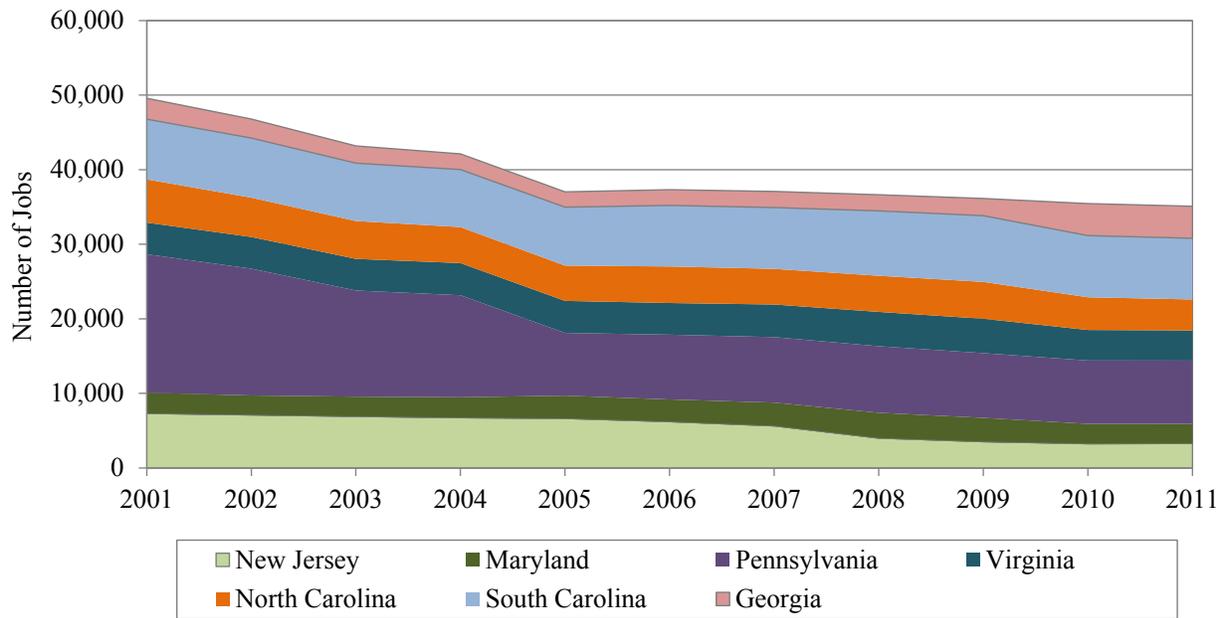
Source: USDOL, BLS 2012.



**Figure 154. Mid-Atlantic impact region electric power generation employment shares, 2011.**

Source: USDOL, BLS 2012.

Electric power generation employment in the Mid-Atlantic impact region has been falling. In 2001, electric power generation employed almost 50,000 workers. Now, that number is just over 35,000. This is an average annual decrease of 3.3 percent. Decreases in New Jersey’s electric power generation employment are the cause of most of this decrease.



**Figure 155. Trends in Mid-Atlantic impact region electric power generation employment, 2001-2011.**

Note: Historic data for Delaware does not meet BLS or state agency disclosure standards.

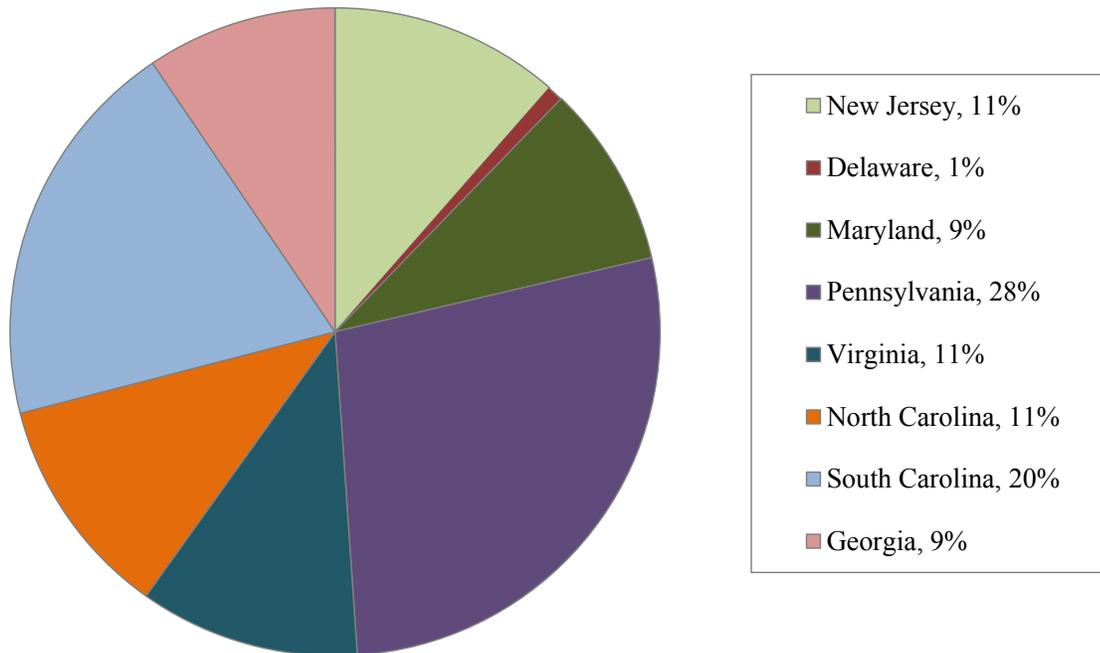
Source: USDOL, BLS 2012.

Regional wage contributions, provided in Table 50, corroborate the employment levels discussed above. Regional shares of total wages paid by Mid-Atlantic coast electric power generation have been provided in Figure 156. Again, Pennsylvania and South Carolina have the highest share of regional wages and total regional electric power generation wages account for 21 percent of total U.S. electric power generation wages.

**Table 50. Regional and national wage contribution, electric power generation, 2011.**

	Wages		Electric Power Generation Wages as a Percent of Total State Wages	Electric Power Generation Wages Percent of Total U.S. Electric Power Generation Wages
	Electric Power Generation	Total State		
	----- (million \$) -----		----- (%) -----	
New Jersey	\$ 408.2	\$ 179,559	0.23%	2.41%
Delaware	\$ 28.6	\$ 17,313	0.17%	0.17%
Maryland	\$ 324.2	\$ 100,787	0.32%	1.91%
Pennsylvania	\$ 985.0	\$ 225,147	0.44%	5.81%
Virginia	\$ 391.2	\$ 145,225	0.27%	2.31%
North Carolina	\$ 396.3	\$ 132,436	0.30%	2.34%
South Carolina	\$ 698.9	\$ 54,746	1.28%	4.12%
Georgia	\$ 337.9	\$ 142,928	0.24%	1.99%
<b>Total Region</b>	<b>\$ 3,570.3</b>	<b>\$ 998,140</b>	<b>0.36%</b>	<b>21.05%</b>
<b>U.S.</b>	<b>\$ 16,964.4</b>	<b>\$ 5,172,844</b>	<b>0.33%</b>	<b>100.00%</b>

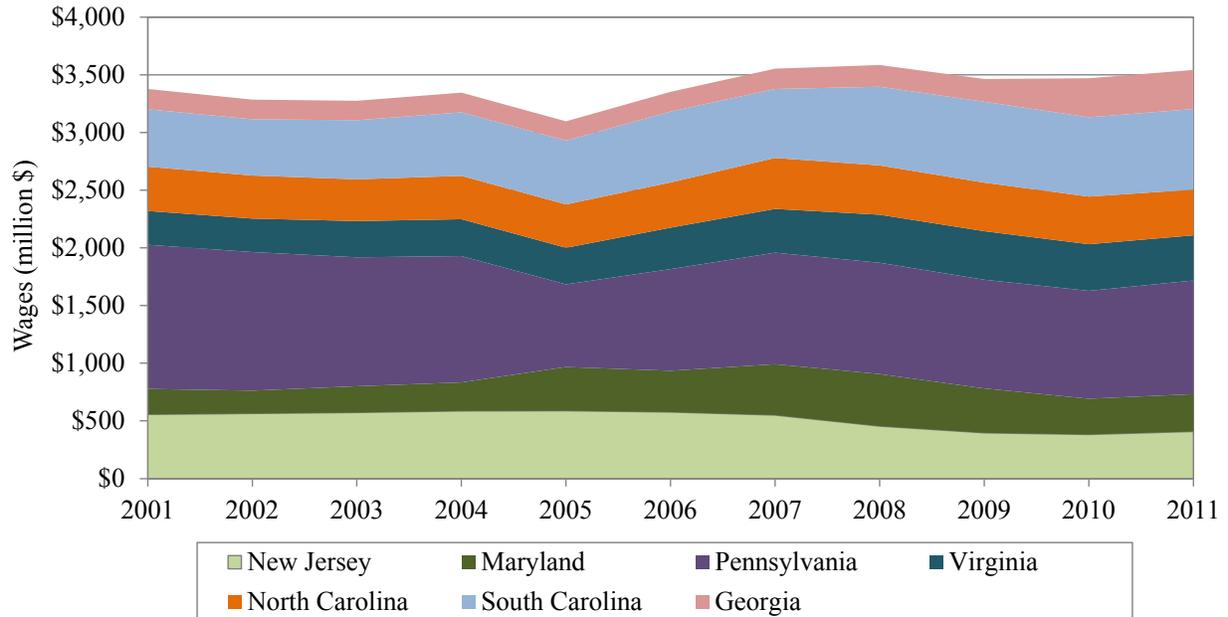
Source: USDOL, BLS 2012.



**Figure 156. Mid-Atlantic impact region electric power generation wage shares, 2011.**

Source: USDOL, BLS 2012.

Trends in electric power generation wages have followed trends in regional port employment.



**Figure 157. Trends in Mid-Atlantic impact region electric power generation wages, 2001-2011.**

Note: Historic data for Delaware does not meet BLS or state agency disclosure standards.

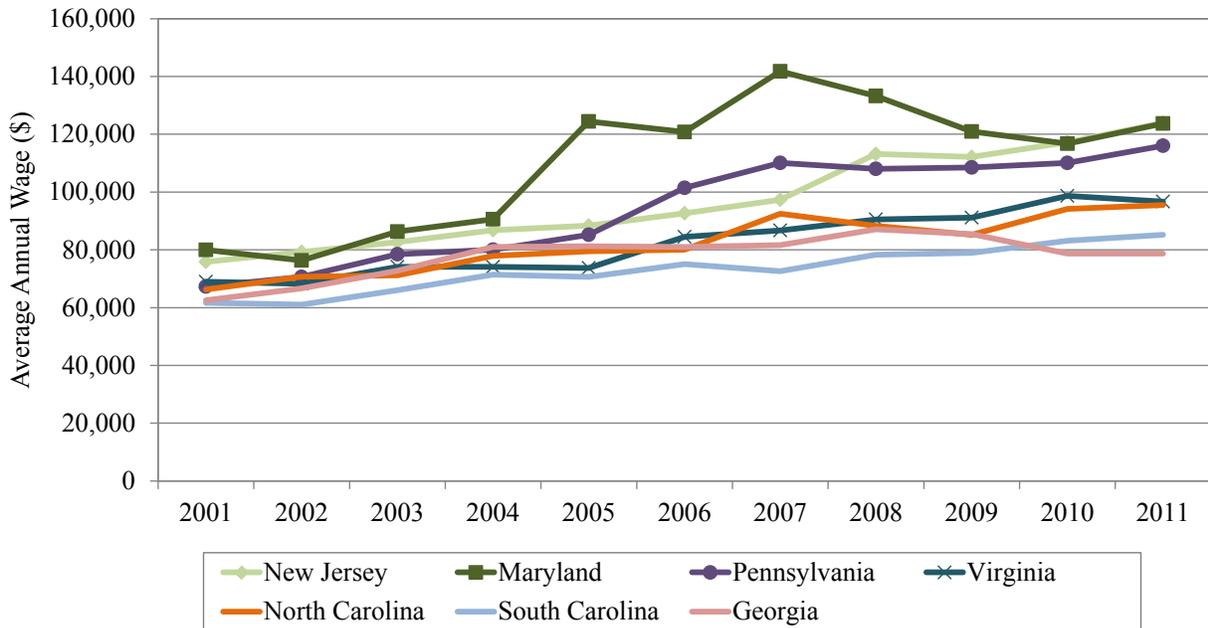
Source: USDOL, BLS 2012.

In each of the Mid-Atlantic impact region states, average annual wages for electric power generation are double the total state average annual wage. And, in comparison to the U.S. average annual wage for electric power generation, the wage difference is split. In four states, New Jersey, Delaware, Maryland, and Pennsylvania, the average annual wage for electric power generation is greater than the U.S. average. In North Carolina, South Carolina, and Georgia, however, the average annual wage for electric power generation is less than the U.S. average. Figure 158 shows the trend of average port wages by state.

**Table 51. Regional and national average annual wage contribution, electric power generation, 2011.**

	Average Annual Wage Electric Power Generation ----- (\$) -----		Electric Power Generation Average Annual Wage as a Percent of Total State Average Annual Wage ----- (%) -----	
		Total State Average	Wage as a Percent of Total State Average Annual Wage	Electric Power Generation Average Annual Wage as a Percent of Total U.S. Average Annual Wage
New Jersey	\$ 123,964	\$ 56,885	217.9%	121.4%
Delaware	\$ 106,320	\$ 50,535	210.4%	104.1%
Maryland	\$ 123,710	\$ 50,620	244.4%	121.1%
Pennsylvania	\$ 116,044	\$ 46,662	248.7%	113.6%
Virginia	\$ 96,706	\$ 50,261	192.4%	94.7%
North Carolina	\$ 95,484	\$ 41,933	227.7%	93.5%
South Carolina	\$ 85,180	\$ 37,734	225.7%	83.4%
Georgia	\$ 78,726	\$ 45,580	172.7%	77.1%
<b>Total Region</b>	<b>\$ 103,267</b>	<b>\$ 47,526</b>	<b>217.3%</b>	<b>101.1%</b>
<b>U.S.</b>	<b>\$ 102,134</b>	<b>\$ 47,815</b>	<b>213.6%</b>	<b>100.0%</b>

Source: USDOL, BLS 2012.



**Figure 158. Trends in Mid-Atlantic impact region electric power generation average annual wages, 2001-2011.**

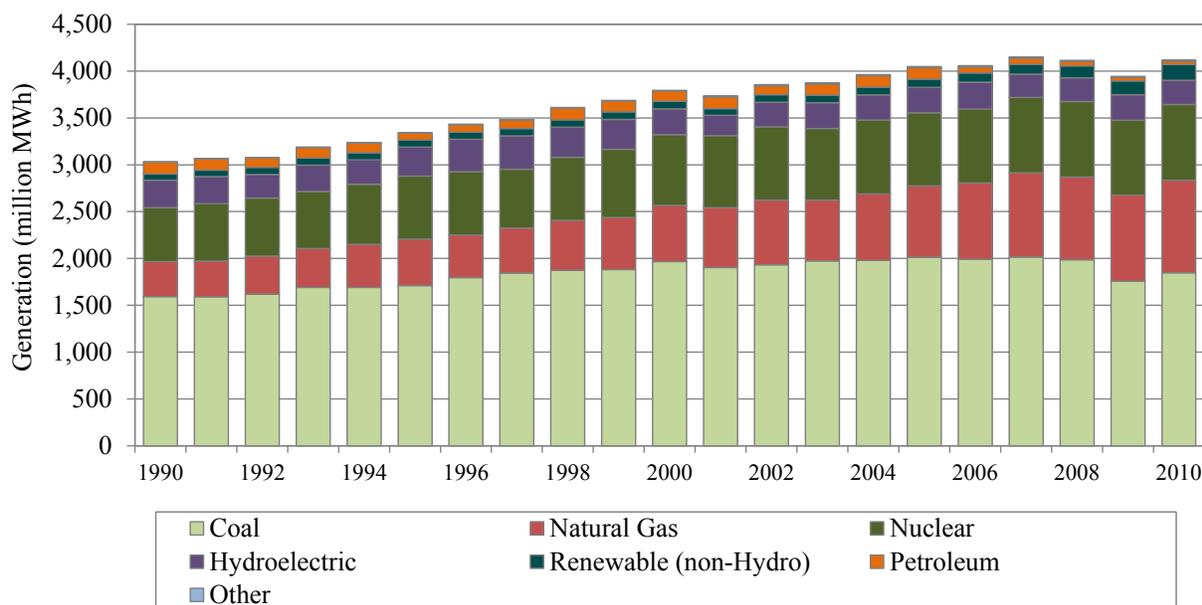
Note: Historic data for Delaware does not meet BLS or state agency disclosure standards.

Source: USDOL, BLS 2012.

## 11.5 CURRENT TRENDS AND OUTLOOK: INDUSTRY

### 11.5.1 Generation and Consumption

As shown in Figure 159, electric power generation in the U.S. has been increasing. Since 1990, electric power generation has increased at an average annual rate of 1.6 percent. Power generation fueled by coal has remained relatively stable (increasing at an average annual rate of 0.8 percent), while power generation fueled by natural gas has increased significantly. Natural gas fired-generation has increased at an average annual rate of 5.1 percent. These increases were highest 1998 through 2002, when natural gas fired-generation increased by 44 percent, and again in recent years. In 2009 natural-gas fired generation increased 4.3 percent and another 7.2 percent in 2010. Non-hydroelectric renewable generation (i.e., wind, solar, biomass) has also increased considerably, at an average annual rate of 5.1 percent (the same as natural gas). In the last three years, the use of these renewable has increased 20 percent (2008), 14 percent (2009) and 16 percent (2010).

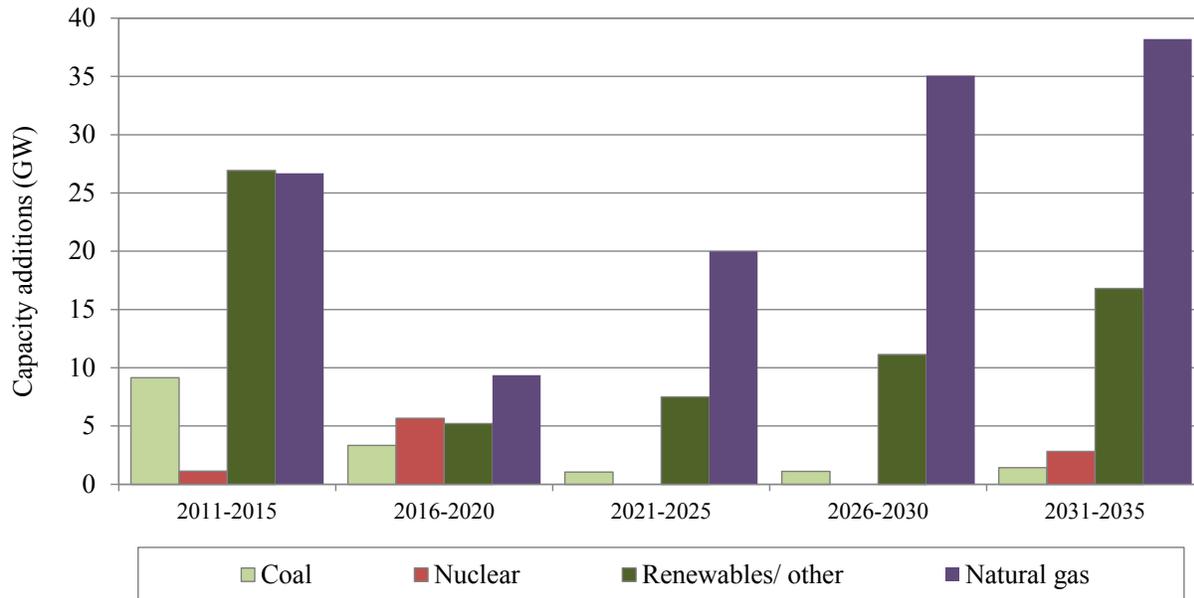


**Figure 159. U.S. electric power generation by fuel type.**

Source: USDOE, EIA 2012k.

The EIA expects this trend to continue. The Annual Energy Outlook (AEO) for 2012 shows that the natural gas share of electricity is expected to increase from 24 percent in 2010 to 28 percent in 2035. Similarly, renewables share of electric power generation is expected to increase from 10 percent to 15 percent. And the share of electric generation from coal is expected to fall to 38 percent by 2035, from 44 percent in 2010 (USDOE, EIA 2012g).

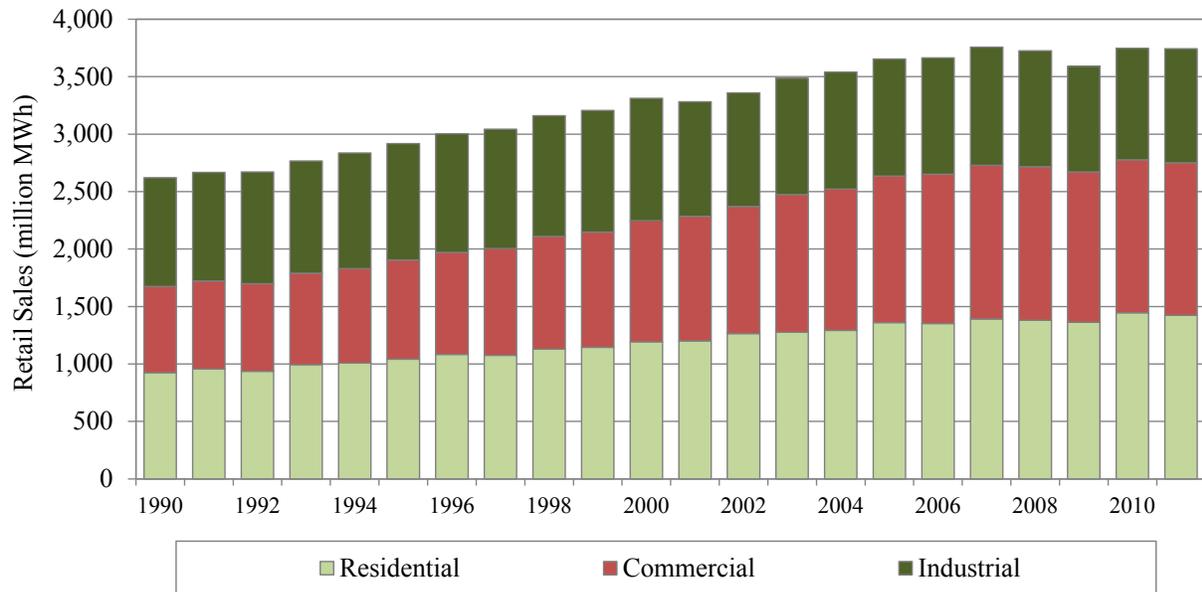
A number of factors influence decisions to add capacity and the type of capacity (fuel choice). These factors include an increase in electricity demand; the need to replace older, inefficient plants; the cost and operating efficiencies of different generation options; fuel prices; state mandates for renewable resources; and the availability of tax incentives for certain technologies (USDOE EIA 2012g). Figure 160 presents the expectations for capacity additions by fuel.



**Figure 160. Annual Energy Outlook, Capacity Additions by Fuel Type.**

Source: USDOE, EIA 2012g.

Figure 161 shows the trends in electric power consumption. Since 1990, electric power consumption increased for all sectors: residential 54 percent (or an average annual rate of 2.1 percent); commercial 77 percent (or an average annual rate of 2.8 percent); and industrial 5 percent (or an average annual rate of 0.3 percent). In recent years, however, the rate of increased consumption for each sector has slowed. On average, for each year since 2007, residential consumption has increased by just 1.1 percent, commercial by just 0.4 percent, and industrial consumption has actually decreased by 0.3 percent.



**Figure 161. Electric power consumption by customer class.**

Source: USDOE, EIA 2012k.

According to the EIA’s 2012 Annual Energy Outlook, electricity demand is expected to increase 22 percent from 2010 to 2035. Residential demand is expected to increase by 28 percent due to increases in population, disposable income, and population shifts to warmer climates with greater cooling requirements. Commercial demand is also expected to increase, by 28 percent, mostly due to demand in service industries. In the industrial sector, however, as noted with Figure 161, demand has slowed and has even been declining in recent years. However, the EIA projects industrial demand to increase slightly, by just 2 percent from 2010 to 2035 (USDOE, EIA 2012g).

The growth in demand for electricity should be somewhat offset by efficiency gains in both the residential and commercial sectors. In both sectors, continuing efficiency gains are expected for electric heat pumps, air conditioners, refrigerators, lighting, cooking appliances, and computer screens. In addition, federal and state policies will continue to drive energy efficiency.

### 11.5.2 Transmission

NERC assesses and reports on the reliability and adequacy of the North American bulk power system in North America. In its most recent Long-Term Reliability Assessment, it cites the ability to site, permit, and build new transmission assets as one of the highest risks facing the electricity industry over the next 10 years (NERC 2011).

The need for new transmission can be driven by reliability, resource integration, and the need to address congestion issues. Projected additions to the transmission system can indicate a strengthening of the bulk power transmission system. Over the next ten years, approximately 39,000 miles (62,764 kilometers) of new high-voltage transmission line are projected to be added to the U.S. transmission system. Of this, about 30,000 miles (48,280 kilometers) are either under construction or planned and the other 9,000 miles (14,484 kilometers) are considered conceptual (NERC 2011).

The PJM region is expected to increase by just 1,517 miles (2,441 kilometers), from 53,079 miles (85,422 kilometers) to 54,596 miles (87,864 kilometers). This is an increase of just under three percent. Most of this increase (1,192 miles, or 1,918 kilometers) is planned for the 2011-2015 timeframe.

**Table 52. Transmission line additions by assessment area.**

	Existing 2010	Under Construction 2011	2011-2015		2016-2021		Total Existing, Under Construction, and Planned Additions, 2021
			Planned	Conceptual	Planned	Conceptual	
ERCOT	29,107	486	5,666	-	496	-	35,755
FRCC	11,973	45	240	-	134	11	12,392
MI SO	50,144	33	805	141	255	1,050	51,237
MRO-MAPP	10,314	75	574	-	-	-	10,964
NPCC - New England (ISO-NE)	8,496	182	342	180	35	16	9,056
NPCC - New York (NYISO)	10,990	-	14	-	12	-	11,016
PJM	53,079	271	1,192	520	54	236	54,596
SERC-E	21,995	213	130	81	164	276	22,502
SERC-N	21,303	96	654	11	22	29	22,075
SERC-SE	27,316	114	263	69	336	34	28,029
SERC-W	13,604	127	114	33	70	41	13,915
SPP	32,857	181	1,961	264	216	180	35,215
WECC-US	103,371	495	5,879	2,089	2,404	2,900	112,149
<b>Total U.S.</b>	<b>394,549</b>	<b>2,138</b>	<b>17,833</b>	<b>3,388</b>	<b>4,199</b>	<b>4,773</b>	<b>418,900</b>

Source: NERC 2011.

### 11.5.3 Regulatory Changes

Electric utilities are regulated by local, state, and federal authorities. As with natural gas pipelines, in general, interstate activities are subject to federal regulation, while intrastate activities are subject to state regulation. Also, plant and transmission line construction issues and retail rates are state regulatory functions. Other issues, such as wholesale rates (sales and purchases between electric utilities), licensing of hydroelectric facilities, questions of nuclear safety and high-level nuclear waste disposal, and environmental regulation, are federal issues.

#### *Federal Regulation*

For many years, the focus of national policy has been to encourage competition in wholesale power markets. FERC is charged with regulating the prices, terms, and conditions of wholesale power sales and transmission services. FERC states that its core responsibility is to “guard the consumer from exploitation by non-competitive electric power companies” (FERC 2010b). To do this, FERC has attempted to maintain the appropriate balance between regulation and competition. Regulation is the primary approach for wholesale transmission service; competition is the primary approach for wholesale generation service. Although the commission’s views of this balance have changed over time, FERC’s goal is to find the best mix to protect customers from monopoly power (FERC 2010b).

#### *The Energy Policy Act of 2005 (EPAct 2005)*

EPAct2005 updated a number of federal laws that govern the electric power industry and made important changes to guarantee electric reliability for consumers. The Act strengthened the legal framework for encouraging wholesale competition (FERC 2010b). In addition, it gave FERC authority to review merger and acquisition activity by investor-owned electric utilities. Some of the important changes made by EPAct 2005 are detailed below (EEI 2007):

- Repeal of the Public Utility Holding Company Act (PUHCA): Enacted in 1935 to regulate the corporate structure and financial operations of utility holding companies. PUHCA was repealed by EPAct, which gave FERC more authority to protect consumers. By repealing PUHCA, Congress eliminated federal restrictions on the scope, structure, and ownership of electric companies (Southern Company 2010). This has encouraged investment in critical energy infrastructure by allowing new classes of non-utility investors and increasing the availability of capital (Southern Company 2010). However, the mandate was accompanied by new provisions allowing FERC and state regulatory authorities access to the books and records of most holding companies and their affiliates. FERC was also given the authority to approve cost allocation issues within holding company systems if requested by a utility or state commission (EEI 2007).
- Reform of the Public Utility Regulatory Policies Act (PURPA): Signed into law in November 1978 as part of the National Energy Act. In an attempt to expand the use of cogeneration and renewable energy sources, PURPA required utilities to purchase power from a qualified facility (“QF”) at their avoided cost regardless of whether

they needed the power.<sup>21,22</sup> PURPA also required electric utilities to sell requested energy and capacity to QFs.

This resulted in electricity prices that were above-market, so EPAct removed some of the requirements. It eliminated the mandatory purchase obligations and revised the criteria for new QFs that wanted to sell power. If an electric utility can prove that QFs in their region have full access to competitive wholesale power markets, then they do not have to follow the mandatory purchase obligation.

- Creation of the Electric Reliability Organization (ERO): EPAct also created an independent, self-regulating entity called ERO. ERO enforces reliability rules on the nation's transmission system. Unregulated utilities (cooperatives and government-owned utilities) are required to comply with reliability standards as well (Southern Company 2010). FERC has oversight authority for ERO. In July 2006, FERC certified the North American Electric Reliability Corporation (NERC) as ERO, which became operational in January 2007 (EEI 2007).

### ***FERC Orders 888, 890 and 1000***

In 1996, FERC issued Order 888, which required transmission providers to offer open-access transmission service on a nondiscriminatory basis to wholesale transmission customers. In 2007, FERC issued Order 890, which required public utility transmission providers to participate in open transmission planning processes at the local and regional level. Through this order, FERC encouraged greater coordination among neighboring transmission providers and interconnected systems, state authorities, and other stakeholders.

In July 2011, FERC built upon Order 890 by issuing Order 1000 in attempts to prevent undue discrimination and preferential treatment in transmission service. Through Order 1000, FERC has allowed each public utility transmission provider 18 months to comply with a series of planning, cost allocation, and non-incumbent developer reforms. Though Order 1000 provides a framework for cost allocation and requires certain considerations that need to be addressed, in terms of enhancing reliability, the potential benefit the order brings is in its inter-regional transmission planning reform. Specifically, Order 1000 requires public utility transmission providers to participate in regional transmission planning processes that consider, in part, the transmission needs of the region driven by public policy requirements of state and federal laws. Order 1000 also requires these same providers to participate in regional cost allocation discussions to determine cost allocation of new transmission facilities, while satisfying six regional cost allocation principles laid out by FERC (FERC 2012g). Though many regions within the U.S. electric grid already perform inter-regional planning as outlined by Order 1000, the order facilitates the acknowledgement of large, interconnection-wide issues by the federal government.

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<sup>21</sup> A qualifying facility, or QF, is a class of generating facility that receives special rate and regulatory treatment. These facilities are either small power production facilities with a capacity of 80 MW or less, and a renewable primary energy source (hydro, wind, solar, biomass, waste, or geothermal resources); or a cogeneration facility that sequentially produces electricity and another form of useful thermal energy (heat or steam) in a way that is more efficient than the separate production of both forms of energy.

<sup>22</sup> Avoided cost is the cost the utility would have paid to build or generate power on its own.

### ***Environmental Regulations***

Hundreds of environmental rules and regulations apply to the electric power industry. Two of the most significant are the Clean Air Act (CAA) and Clean Water Act. In addition, electric generators are subject to regulations that focus on air emissions from fossil fuel-based plants. In 1990, the Acid Rain Program made a series of amendments to the CAA and subsequent programs to address ozone transport. These changes have helped to significantly reduce emissions of sulfur dioxide (SO<sub>2</sub>) and nitrogen oxides (NOX) from electricity generation. Other noteworthy federal regulations include the Toxic Substances Control Act, which controls chemicals, and the Resource Conservation and Recovery Act, which controls hazardous waste. Electric companies are also subject to state issued environmental regulations (EEI 2007).

In 2005, the U.S. Environmental Protection Agency (EPA) issued three new major regulations to further reduce SO<sub>2</sub>, NOX, and mercury emissions: the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR). In 2008, however, CAIR was vacated by the U.S. Court of Appeals for the D.C. Circuit. The court decision kept the requirements of CAIR in place temporarily but directed the EPA to develop a new rule to implement CAA requirements (USEPA 2012c). In 2011, the EPA finalized the replacement rule: the Cross-State Air Pollution Rule (CSAPR). CSAPR would require 23 states to improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states (USEPA 2012d). However, the U.S. Court of Appeals for the D.C. Circuit vacated this rule as well, and sent the rule back to the agency for revision (WSJ 2012). In the interim, CAIR will remain in place.

CAIR applies to all fossil-fuel-fired units with capacity of 25 MW or greater that provide electricity for sale in 28 eastern states and the District of Columbia. It also includes combined heat and power units larger than 25 MW that sell at least one-third of their potential electrical output and supply more than 219,000 MWh of electricity to the grid. CAMR focuses on coal-fired power plants and establishes “standards of performance” to limit mercury emissions. The rule creates a market-based cap-and-trade program (USEPA 2012e). CAVR applies to all states and requires additional controls for SO<sub>2</sub> and NOX to reduce haze that affects National Parks and wilderness areas.

## **11.6 CURRENT TRENDS AND OUTLOOK: EAST COAST**

Both CAIR and CSAPR will have a major impact on companies’ decisions regarding new electric power generation capacity and fuels to fire that capacity. These rules are also likely to force many older coal-fired generation units to cease operations due to the investment cost needed to get these plants into compliance. This is especially the case when examining coal-fired power plants using bituminous coal without the use of a flu-gas desulfurizer (FDG) unit to remove SO<sub>2</sub> and NOX emissions from waste steam produced in the plant’s operations. In the U.S., subbituminous coal is mined predominately in the Powder River Basin region of the state of Wyoming; bituminous coal is mined predominately in the Appalachian region. Bituminous has a higher energy content than subbituminous coal, but it also has higher sulfur concentrations. The different locations of these mining operations cause a regional effect in the usage of bituminous compared with subbituminous coal, with Eastern States using primarily bituminous coal, and

Western States using primarily subbituminous coal.

Table 53 shows unscrubbed bituminous coal-fired electrical generation within the Mid-Atlantic impact region states. Within these eight states, 8.3 percent of annual electric generation is produced by older unscrubbed bituminous coal-fired electric power plants. Georgia has the highest percentage, by far, with 23.4 percent of the state’s generation coming from unscrubbed bituminous. In Maryland, 8.6 percent of generation is from unscrubbed bituminous coal. The remaining states have much smaller shares, ranging from 0.2 percent (North Carolina) to 2.8 percent (Delaware).

**Table 53. Unscrubbed bituminous coal-fired generation.**

	Generation		Percent Generation from Unscrubbed Bituminous Coal (%)
	Unscrubbed Bituminous Coal (MWh)	Total	
New Jersey	339,711	12,296,605	2.8%
Delaware	50,061,193	213,772,228	23.4%
Maryland	18,462,128	215,967,303	8.5%
Pennsylvania	181,744	107,969,381	0.2%
Virginia	1,003,056	122,602,911	0.8%
North Carolina	1,449,679	86,152,363	1.7%
South Carolina	561,498	37,371,254	1.5%
Georgia	1,258,661	86,135,211	1.5%
<b>Total</b>	<b>73,317,670</b>	<b>882,267,256</b>	<b>8.3%</b>

Source: USDOE, EIA 2012o.

Coal-fired generation is facing more stringent environmental regulations and increased cost for compliance; at the same time, the price of natural gas is falling and the fuel is becoming increasingly abundant. The EIA projects continued development of shale gas resources, and by 2035 it will account for 49 percent of total U.S. natural gas production. This is more than double shale’s current share of 23 percent (USDOE, EIA 2012g). Recently, the EIA announced that, for the first time since EIA began collecting data, generation from natural gas-fired plants is equal to generation from coal-fired plants (USDOE, EIA 2012p).

To take advantage of this abundant and low cost resource, a number of utilities have started to displace some of their coal-fired generation with natural gas. Some companies have started to use gas-fired generating units that were originally intended to serve peak-power demand more frequently. Other companies are operating plants that typically use a mix of coal and natural gas solely on natural gas. And new gas-fired units will be built to replace older, less efficient, and now uneconomical units (Katusa 2012). The CEO of one utility called the switch from coal to natural gas a “perfect storm” of economic and regulatory factors (Lipton 2012).

For example, Southern Company's (which operates Georgia Power) combined cycle gas turbine units ran at 70 percent of capacity in the beginning of 2012, which is double the plants' typical use (Katusa). The company stated in its first quarterly report for 2012 that "[a]s part of Southern Electric Generating Company's (SEGCO) environmental compliance strategy, the Board of Directors of SEGCO approved adding natural gas as the primary fuel source in 2015 for its 1,000 MWs of generating capacity and the construction of the necessary natural gas pipeline" (SEC 2012b).

Also, Progress Energy (Progress Energy Carolinas) announced that it intends to retire its coal-fired plants without environmental controls by the end of 2013. These retirements represent about 1,600 MW of capacity, or one-third of the utility's coal-powered units (Energy Policy Update 2012a). In September of 2012, Dominion Virginia filed an application with regulators to convert its Bremo Power Station from coal to natural gas. The cost of the conversion would be \$53.4 million, which is one-third of the estimated cost of continued operation on coal (\$155 million) (PR Newswire 2012).

## **11.7 FACTORS IMPACTING EAST COAST DEVELOPMENT**

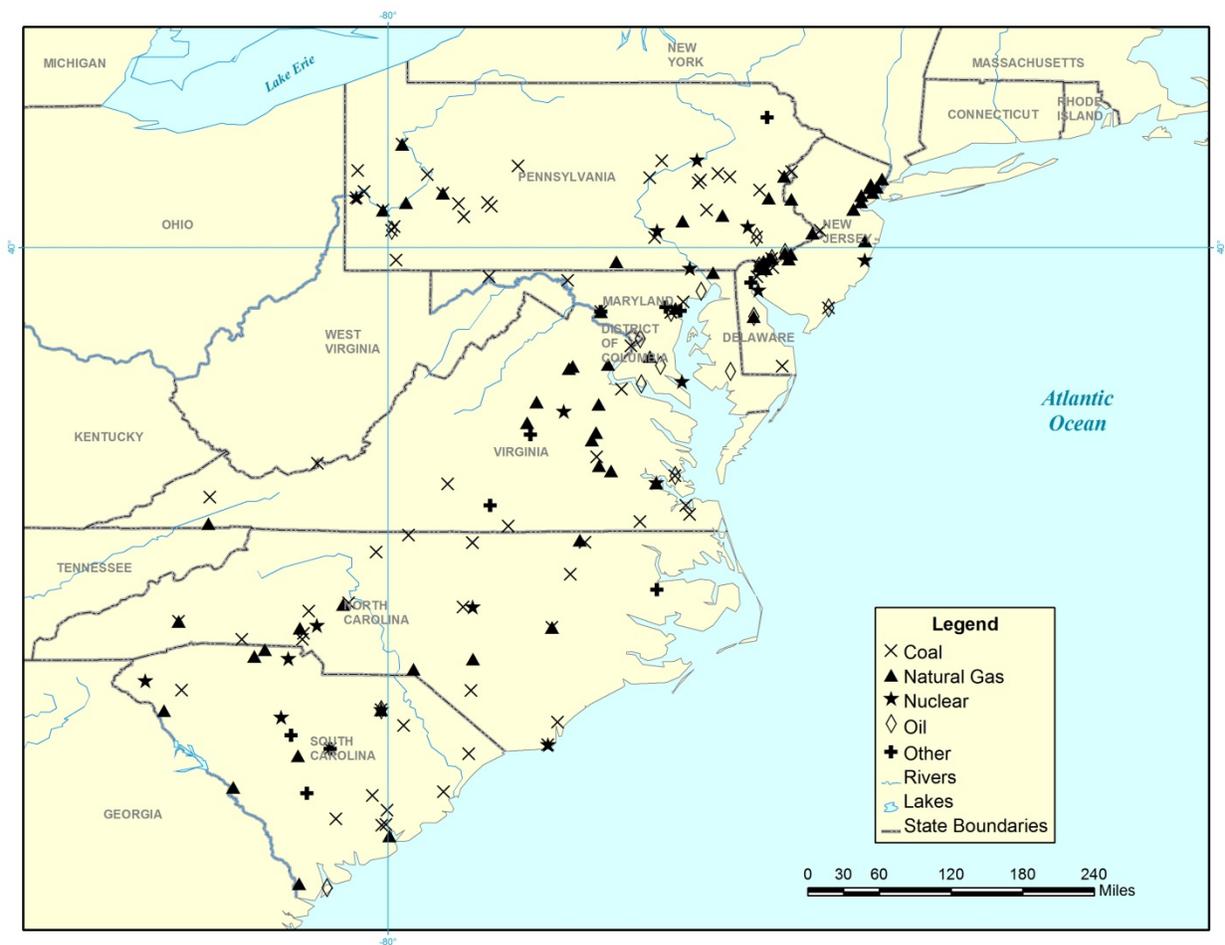
Electric power infrastructure in the Mid-Atlantic impact region is extensive with more than 856 power generation facilities located in these states. Many of these states are anticipating the development of considerable new offshore alternative energy assets that may have implications for offshore oil and gas production infrastructure.

The Upper Mid-Atlantic region (New Jersey, Delaware, and Pennsylvania) has 325 power generation facilities that total almost 80,000 MW of generating capacity. Most of this capacity (66 percent) is fueled by coal (31 percent) and natural gas (35 percent). About 19 percent of this capacity is nuclear powered. The remainder is fueled by oil (nine percent) and renewable generation (six percent). It is likely that new generation in the region will primarily be driven by natural gas (USDOE, EIA 2012l).

Some states in the upper Mid-Atlantic region are actively promoting offshore energy development, primarily offshore wind. For instance, regulators in New Jersey have approved plans for 350 MW of offshore wind, and are currently soliciting proposals to build more.

The Central Mid-Atlantic region (Maryland and Virginia) has 172 power generation facilities, accounting for over 40,000 megawatts of capacity. Most of this capacity (58 percent) is fueled by coal (29 percent) and natural gas (29 percent). About 14 percent of this capacity is nuclear power generation. The remaining generation is fueled by oil (15 percent), renewable (13 percent), and other resources (less than one percent) (USDOE, EIA 2012l).

The Lower Mid-Atlantic region (North Carolina, South Carolina and Georgia) has 359 power generation facilities, accounting for 97,000 megawatts of capacity. Most of this capacity (69 percent) is fueled by coal (35 percent) and natural gas (34 percent). About 17 percent of this capacity is nuclear power generation. The remaining generation is fueled by oil (3 percent), renewable (10 percent), and other resources (1 percent) (USDOE, EIA 2012l).



**Figure 162. Mid-Atlantic impact region electric generators by fuel type.**  
 Source: Author's construct using USDOE, EIA 2012l.

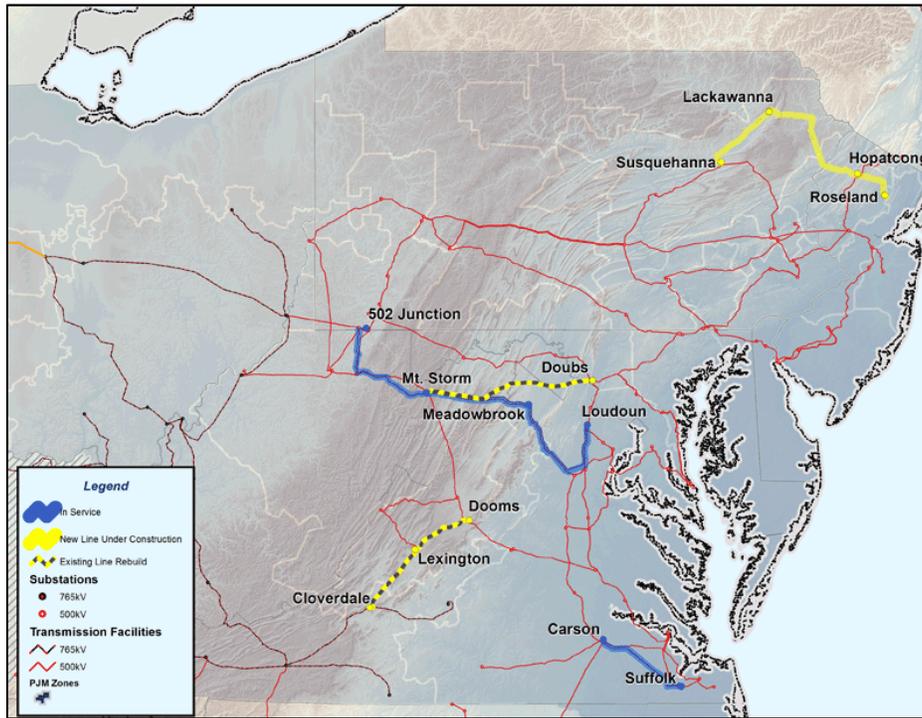
Most of the wholesale transmission of electricity throughout the U.S. is controlled by a number of Regional Transmission Organizations (RTOs). Most of the states in the Mid-Atlantic region, on which this report is based, are controlled by the PJM Interconnection. The PJM includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia (see Figure 163).



**Figure 163. PJM Interconnection.**

Source: PJM 2009.

To manage the electricity in this region, PJM dispatches 163,500 MW of generating capacity over 56,350 miles (90,687 kilometers) of transmission line (PJM 2009). PJM is responsible for maintaining the integrity of these transmission lines and for managing the additions or changes to the grid (i.e., new generating plants, substations or transmission lines). PJM also forecasts future electricity needs and develops a 15-year plan to ensure that reliability is maintained. Figure 164 shows some of the major transmission expansion projects that are currently ongoing.



**Figure 164. PJM Interconnection key upgrade projects.**

Source: PJM 2009.

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### **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 the 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 communities.

### **The Bureau of Ocean Energy Management Mission**

The Bureau of Ocean Energy Management (BOEM) works to manage the exploration and development of the nation's offshore resources in a way that appropriately balances economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development and environmental reviews and studies.