BOEM-2011-059

MAG-PLAN Alaska Update

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Prepared under BOEM Contract

MO9PCOOO45

by

Northern Economics, Inc.

IMV Projects, Inc.

Eastern Research Group, Inc.

Published by

U.S. Department of the Interior

Bureau of Ocean Energy Management

Alaska Region

Anchorage

May 31, 2012

DISCLAIMER

This study was funded by the Bureau of Ocean Energy Management, U.S. Department of the Interior, Washington, D.C., under Contract Number M09PC00045

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CITATION

Suggested Citation:

Northern Economics, Inc., IMV Projects, and Eastern Research Group. 2012. MAG-PLAN Alaska Update. U.S. Department of the Interior, Bureau of Ocean Energy Management, Alaska Region, Anchorage, AK. BOEM study number BOEM 2011-059. 180 pp.

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ACKNOWLEDGMENTS

Northern Economics, Inc., IMV Projects, Inc., and Eastern Research Group, Inc. would like to thank Jerry Brian and Kim Coffman of BOEM for their helpful comments and assistance with preparing this report and their guidance during the project.

A number of firms, organizations, and individuals contributed a significant amount of confidential and proprietary data, without which this report would not have been possible. Although for confidentiality reasons we cannot name these contributors here, we offer our deepest thanks for their invaluable assistance.

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ABBREVIATIONS, ACRONYMS, SYMBOLS

AT	Activity Type (type of exploration, development, or production activity, such as drilling an exploration well)
AF	Activity Function (the spending necessary to create one unit of E&D activity, allocated among the relevant industry sectors and distributed among the onshore areas)
BOE	barrels of oil equivalent (barrels of oil, plus quantity of natural gas converted by Btu equivalent)
BOEM	Bureau of Ocean Energy and Management
CD	compact disk
COR	Contracting Officer's Representative
CWC	Concrete weight coating
EA	Environmental Assessment
E&D	Exploration & Development (For the purposes of this SOW, E&D Scenarios include Production Profiles and certain types of revenues)
EIS	Environmental Impact Statement
FBE	Fusion bonded epoxy
FTE	Full-time-equivalent (total count of full-time jobs, plus count of part-time jobs divided by the standard number of hours for a full-time job)
GOM	Gulf of Mexico
LNG	liquefied natural gas
MEG	Monoethylene glycol
MMS	Minerals Management Service
MRB	Economic Impact Modeling Review Board
NAB	North Aleutian Basin Planning Area
NAICS	North American Industry Classification System
NEPA	National Environmental Policy Act of 1969
NPS	Nominal pipe size
OCS	Outer Continental Shelf
OMA	Offshore Modeling Area (synonymous to OCS planning area)
OSA	Onshore Area (specified geographic areas that supply goods and services required for Activity Types)
PCE	Personal Consumption Expenditures
PDF	(Adobe's) portable document format

PDMP	Program and Data Management Plan
POP	period of performance
RE	Resource Evaluation
RT	Revenue Type (type of activity in an E&D Scenario that drives Government revenue levels in MAG-PIAN, such quantity of oil and gas produced, which helps determine total royalty payments)
RF	Revenue Functions (Government revenues received for use of public oil and gas resources, allocated among the relevant industry sectors and distributed among the onshore areas based on patterns of Government spending)
RFP	Request for Proposals
SIC	Standard Industry Classification
SOW	Statement of Work

1 STUDY SUMMARY

1.1 Objectives and Scope of Work

The Bureau of Ocean Energy Management (BOEM) continually seeks to improve and enhance decision-making tools for managing minerals and other resources on federal submerged lands. BOEM regularly evaluates potential economic impacts that may result from federal actions such as lease sales in OCS areas, and when it prepares a new 5-year OCS oil and gas program. MAG-PLAN Alaska is a region-specific economic impact model used by BOEM to estimate potential economic impacts (direct, indirect, and induced) of oil and gas development in OCS planning areas offshore Alaska.

BOEM commissioned this study to update MAG-PLAN Alaska, which was developed in 2005 using information that was gathered in the late 1990s and early 2000 for two earlier Alaska OCS models. Specific objectives of MAG-PLAN Alaska Upgrade Study are summarized in the following figure.

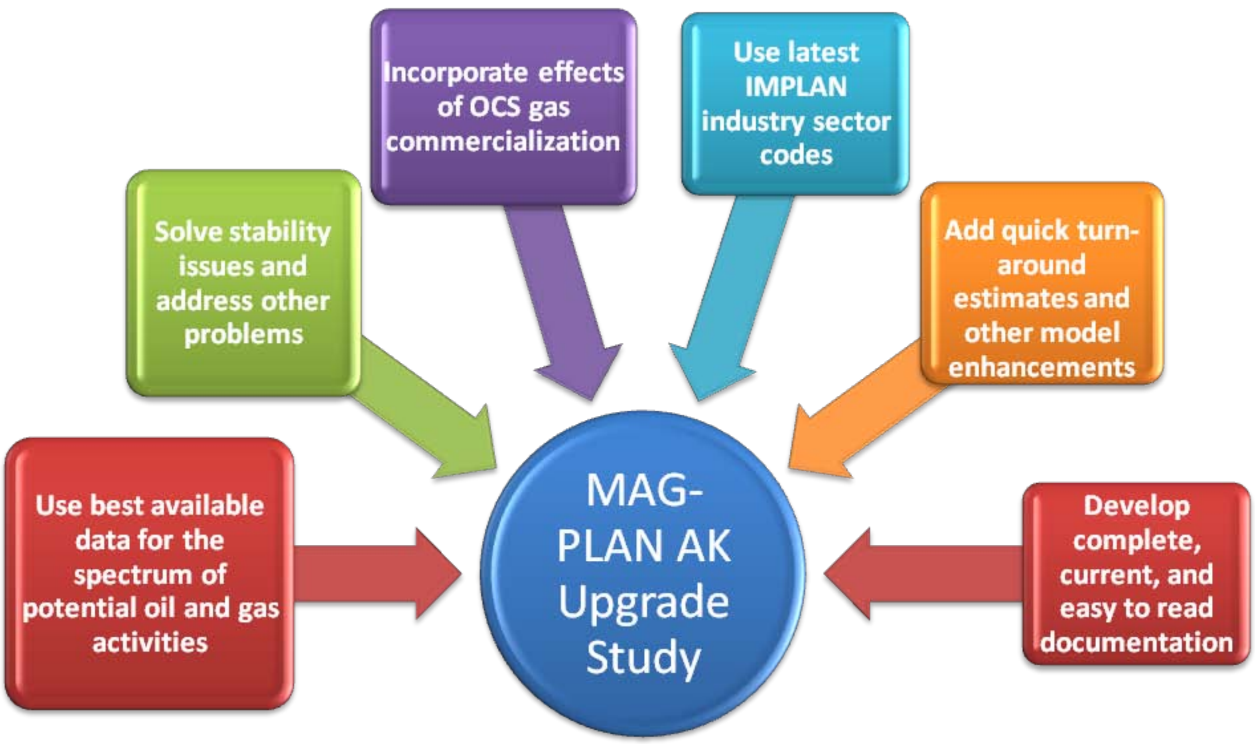

Figure 1. MAG-PLAN Alaska Upgrade Study Objectives

Source: Northern Economics adapted from BOEM Request for Proposal

The scope of work for this study is specified in the following list of 10 major tasks required to satisfy the objectives for the model update:

- **Task 1**: Conduct initial model testing for each Offshore Modeling Area (OMA) before revising the internal data gathered under other tasks in this section and identify needs for model improvement;

- **Task 2**: Collect/estimate industry expenditure data and update activity functions for Beaufort Sea and Cook Inlet activities;
- **Task 3**: Collect/estimate industry expenditure data and update activity functions for Chukchi Sea and North Aleutian Basin activities;
- **Task 4**: Collect/estimate data for revenue functions for all offshore modeling areas;
- **Task 5**: Extrapolate from data and activity/revenue functions from Tasks 2, 3, and 4 to model the effects of OCS activities in the other 11 planning areas;
- **Task 6**: Examine IMPLAN personal consumption expenditures (PCE) data and recommend alternate and/or supplementary data sources (if appropriate);
- **Task 7**: Revise MAG-PLAN sectors to match new IMPLAN sectoring scheme;
- **Task 8:** Minor enhancements: simplified start screen, FTE estimator, quick-turnaround employment estimator, and sector-code updater;
- **Task 9**: Conduct final MAG-PLAN revisions and testing;
- **Task 10**: Develop full documentation.

1.2 GEOGRAPHIC AREA AND OFFSHORE MODELING AREAS

MAG-PLAN Alaska has the ability to generate estimates of economic effects of OCS development in all of the Alaska OCS planning areas. The model has an offshore modeling area (OMA) developed for each of the fifteen OCS planning areas in Alaska (an OMA is therefore the same as an OCS planning area). Data collection efforts for this model update focused on 4 priority areas specified in the scope of work. These four priority areas include:

- Beaufort Sea
- Cook Inlet
- Chukchi Sea
- North Aleutian Basin

Information developed for these four OCS areas was used as the basis for extrapolating economic effects for the other eleven planning areas. (See section 3.2 for an explanation as to why these four areas were given priority.)

1.3 MODEL OVERVIEW

MAG-PLAN Alaska is a 2-stage, region-specific economic impact model used by BOEM to quantify potential economic impacts (direct, indirect, and induced) of oil and gas development in the 15 Alaska OCS planning areas. As part of this study, the original MS Access version of MAG-PLAN Alaska was updated. An Excel model version of MAG-Plan Alaska was also created. The basic data are the same in both versions, but the Excel-based model is more fully developed and is the focus of this report.

As in the previous model, the updated MAG-PLAN Alaska provides BOEM with an integrated model that provides estimates of Stage 1 and Stage 2 economic impacts of OCS exploration, development, and production. The model retains the two-stage process of the previous models. Stage 1 estimates the level and allocation of direct expenditures as well as direct manpower requirements resulting from OCS oil and gas activities specified in the exploration and development (E&D) scenarios, while Stage 2 estimates the multiplier effects of spending associated with OCS activities on potentially affected regions in Alaska. The model results are scenario-specific. The model requires an E&D scenario for a specified modeling area as an input. The E&D scenarios are developed by BOEM.

1.1.1 Approach and Data used in the Model

Figure 2 illustrates and summarizes the general approach used in updating MAG-PLAN Alaska.

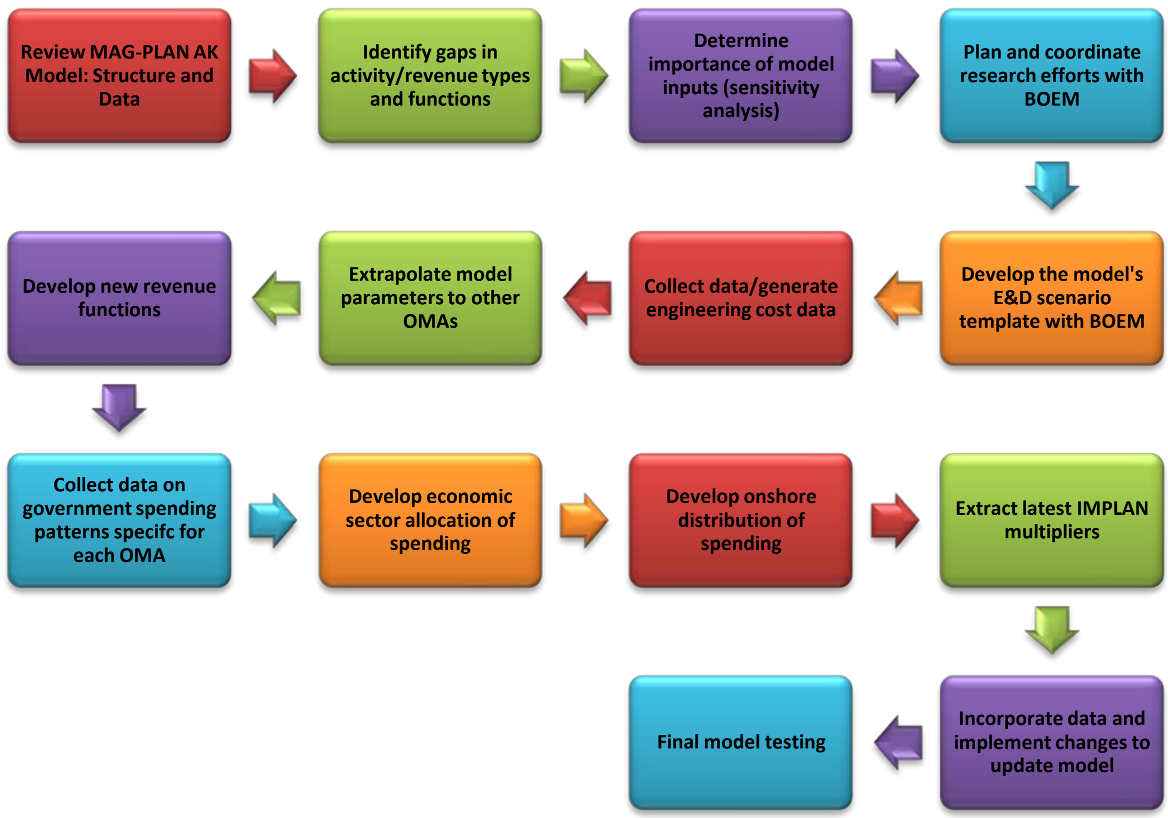

Figure 2. Study Approach

Source: Northern Economics, Inc.

The updated model is based on new planning area-specific data for the Beaufort Sea, the Chukchi Sea, Cook Inlet, and the North Aleutian Basin. The updated model incorporates new technologies and new industry practices since the completion of the prior version of MAG-PLAN, and includes concepts for working in deepwater Arctic areas that have not yet been explored. The data provide different costs for platform fabrication and installation or construction by platform type, and for operations and maintenance.

The cost estimates in the model are based on the expert engineering knowledge of the consultant team member IMV Projects, which is actively engaged in consulting and engineering work in Arctic regions around the globe, along with interviews by Northern Economics with contractors, suppliers, oil company officials, and other experts, and the latter firm's experience in other OCS-related studies for industry. A large research effort of secondary sources identified costs and manpower for the many specialized vessels and equipment that are included in the model. In many cases, these vessels and equipment operate around the globe and in some instances, markets exist with published spot rates. Where charter or lease costs were not available, published spot rates were used to reflect lease or charter costs to an operator. Mobilization and demobilization costs were added to the charter or spot rates to estimate the total cost to the operator.

For a number of activities, the model distinguishes between Arctic and subarctic regions due to the differences in equipment and vessel types required, the number of months that may be suitable for operations, and other factors. Thus, there are differences in manpower requirements and costs between the two regions. In addition, mobilization and demobilization costs for vessels and equipment are estimated separately for each planning area, resulting in variations in costs.

The model presently accounts for onsite (production) labor costs, offsite (non-production) labor costs, and fringe benefits, as in the prior model. The current model also estimates the percent of onsite labor that are residents of the relevant onshore area, the percent that are residents of the rest of Alaska, the percent that are residents of the rest of the U.S., and percent that are residents of the rest of the world.

With the exception of capital costs for production platforms and pipelines, which are assumed to be owned by the BOEM lessee, all other facilities, equipment, vessels, and services are assumed to be provided by a contractor, and appropriate contract, charter, or lease rates are used in the model. The data collection effort focused on large first round expenditures.

The E&D scenario will specify most of the Stage 1 results for the potential government revenues with the exception of property taxes on oil and gas facilities that will be imposed by the State of Alaska and shared with local jurisdictions. A revenue type and the corresponding revenue function was developed and incorporated into the model. Government spending patterns for the various regional governments associated with each offshore modeling area were also developed based on historical expenditure data from 2005 to 2009 reported in the state and local governments' Certified Annual Financial Reports. Stage 2 results are based on the latest available IMPLAN data (year 2010 data) (Minnesota IMPLAN Group, Inc. 2011).

1.1.2 Model Outputs

The model generates the following Stage 1 outputs:

- Direct employment estimates by offshore modeling area, by activity type, by year, and by location (local, rest of Alaska, rest of the U.S., and rest of the world);
- Direct industry spending (on labor and non-labor components) by offshore modeling area, by activity type, by year, and by location (local, rest of Alaska, rest of the U.S., and rest of the world);
- Direct government revenues[1] by offshore modeling area, by revenue type, by year, and by entity (regional, state, and federal government).

[1] The model calculates state corporate income taxes, property taxes, and additional state royalties resulting from OCS oil's contribution to TAPS throughput. Other direct government revenues such as rental revenues, bonus bids, and royalties are indicated in the E&D inputs.

The model generates the following Stage 2 outputs (multiplier effects of industry spending on non-labor costs, household spending of labor income, and government spending of OCS-related revenues):

- Indirect and induced employment estimates by offshore modeling area, by year, and by Alaska region;
- Indirect and induced labor income by offshore modeling area, by year, and by Alaska region;
- Indirect and induced economic output effects by offshore modeling area, by year, and by Alaska region.

2 INTRODUCTION

The Bureau of Ocean Energy Management (BOEM[2]) is the administrative agency responsible for leasing submerged federal lands. The Outer Continental Shelf (OCS) Lands Act, as amended, requires the preparation and maintenance of a current five-year schedule of proposed lease auctions ("5-year program"), and the National Environmental Policy Act (NEPA) of 1969 requires preparation of an environmental impact statement (EIS) prior to any major federal action, including a 5-year program or a lease auction ("lease sale").

BOEM uses a region-specific economic model called MAG-PLAN when preparing environmental assessments (EA) or environmental impact statements (EIS); and more broadly, the model is used in BOEM's decision-making process to guide the next 5-year OCS oil and gas program. MAG-PLAN estimates the potential employment, income, and economic output effects that could result from any alternative or exploration and development scenario being considered.

MAG-PLAN has evolved through the years in response to BOEM's analytical needs and in response to changing economic conditions and technological trends in oil and gas development. MAG-PLAN Alaska, the model specifically used for the Alaska OCS region, was developed to replace the original Alaska OCS Economic Impact Models, which grew out of a staff recommendation in 1999 to replace reliance on several unrelated regional models with a more consistent bureau-wide approach to estimating employment, personal income, and similar economic impacts from OCS activities. MAG-PLAN Alaska was largely based on data gathered in the Arctic IMPAK and Sub-Arctic IMPAK studies completed in 2002 and 2003 for MMS by Jack Faucett Associates (MMS 2002-066 and MMS 2002-060).

Since that time, certain events and significant changes have occurred—prevailing oil and gas prices; renewed industry interest in OCS development; particularly in the Chukchi Sea and more recently in the state waters of Cook Inlet; proposals to commercialize and transport stranded North Slope gas to markets; as well as changes in technology, specifically for arctic conditions—that warrant more than just routine changes to the data in MAG-PLAN Alaska.

This project was commissioned by BOEM to update MAG-PLAN Alaska.

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[2] The Bureau of Ocean Energy Management (BOEM) is an agency under the United States Department of the Interior, established by Secretarial Order # 3299. The agency exercises the oil, gas, and renewable energy-related management functions formerly under the *Minerals Management Service* (MMS), including activities involving resource evaluation, planning, and leasing.

2.1 Objectives and Scope of Work

The purpose of the MAG-PLAN Alaska Upgrade Study is to provide an updated and improved version of MAG-PLAN Alaska such that the model:

1. Is problem-free and stable, allowing users to open, run, and close the same model file repeatedly with full confidence that the results will be valid and that no errors will be introduced by heavy use of the file;
2. Contains the best available data to date for the spectrum of potential OCS Alaska oil and gas projects in the Beaufort Sea, Chukchi Sea, North Aleutian Basin, and Cook Inlet/Shelikof Strait planning areas, with analytically defensible extrapolations of such data to potential operations in the other Alaska OCS planning areas;
3. Incorporates the ability to estimate the effects of producing and transporting natural gas produced from any Alaska OCS planning area estimated to have gas resources;
4. Uses the latest IMPLAN industry sector codes;
5. Provides the ability to make quick turnaround employment and labor income estimates based on simple multipliers and/or other rules of thumb, along with other minor enhancements; and
6. Is accompanied by complete, current, and easy-to-read documentation.

The Request for Proposals specifically listed 10 major tasks that would be required to satisfy the objectives for this effort. The scope of work includes the following tasks:

- **Task 1:** Conduct initial model testing for each Offshore Modeling Area (OMA) before revising the internal data gathered under other tasks in this section and identify needs for model improvement;
- **Task 2:** Collect/estimate industry expenditure data and update activity functions for Beaufort Sea and Cook Inlet activities;
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- **Task 10:** Develop full documentation.

2.2 GEOGRAPHIC AREA

Figure 3 shows the OCS planning areas in Alaska. MAG-PLAN Alaska has the ability to generate economic effects of OCS development in any of the 15 Alaska OCS planning areas.

The RFP for this model update identified four priority areas for data collection: i) the Beaufort Sea; ii) the Cook Inlet; iii) the Chukchi Sea; and iv) the North Aleutian Basin. This contract requires not only the replacement of existing data in the previous model, which was based on information available for the Cook Inlet and theoretical concepts regarding exploration and development technology in the Beaufort Sea, but also requires the development of entirely new planning area-specific data for the Chukchi Sea and the North Aleutian Basin, as well as extrapolation from the new data for the four areas to obtain “rule-of-thumb” estimates for the other eleven planning areas.

These 4 priority OCS planning areas have a high potential for future OCS development given resource assessments and historical industry interest. The Beaufort Sea (65 million acres), Chukchi Sea (63 million acres), and the Cook Inlet (5 million acres) combined have a total of 133 million acres leased. Only the Beaufort Sea (183 active leases) and the Chukchi Sea (487 active leases) have active leases to date.

BOEM has held several lease sales for the Beaufort Sea, including Beaufort Lease Sales 186, 195, 202, and 209. The Beaufort Lease Sale 202, held in April 2007, was one of the most successful Beaufort lease sales in which the most intense bidding was around the Hammerhead offshore discovery. Hammerhead is located 20 miles north of the onshore Point Thomson gas and condensate field. The near shore of the Beaufort has an extensive history of exploration with several oil and gas field discoveries including the Northstar field (partially OCS but mostly in state waters), Oooguruk (state waters), and Liberty (an offshore discovery in federal waters).

The Chukchi Sea Planning Area is viewed to have a high potential for natural gas occurrence given its similar geology to confirmed plays on the North Slope. The Chukchi Sea Lease Sale 193 held in February 2008 was the biggest lease sale, onshore or offshore, in Alaska’s history. The lease sale collected $2.66 billion in high bids for 488 tracts. There has been no petroleum development in the Chukchi Sea to date. There are five prospects on the Chukchi shelf that have previously been drilled and have shown favorable geology—Burger, Klondike, Crackerjack, Popcorn, and Diamond. Shell Exploration, Statoil, BP Exploration, and ConocoPhillips are anticipated to engage in exploratory efforts in the Chukchi Sea.

BOEM conducted a lease in the North Aleutian Basin in 1985 in which over 5.6 million acres were offered for bid, accounting for 17 percent of the North Aleutian Basin planning area. In 1988, 23 lease blocks covering 121,757 acres were leased. Since then, the area has been the subject of several moratoria and has not had any recent lease sales. The planning area encompasses all of Bristol Bay and adjacent waters out to Unimak Pass. On March 31, 2010, the Secretary of the Interior Ken Salazar announced that as part of the Obama Administration’s plan for the protection of special areas like the Bristol Bay in Alaska, the planning area (North Aleutian Basin) would be withdrawn from consideration for oil and gas development through 2017 (U.S. Department of the Interior, 2010). Despite this development, the North Aleutian Basin is still considered important to the MAG-PLAN update in that current information on technology and operating conditions in this region is used as the basis for extrapolating Stage 1 economic effects in a number of other Alaska OCS regions that are not considered highly prospective at the moment.

There have been four lease sales offered in the Cook Inlet Basin since 1977. Subsequent lease sales in the area have not been successful. The most recent lease sale held in 2004 did not generate any bids from industry. Cook Inlet Sale 219 was cancelled in 2011 due to lack of industry interest at the time. There are several producing projects in state waters in the Cook Inlet Basin that provide good information for costs and manpower requirements for production activities. Interest in exploring for oil and gas in the region has been sparked recently by exploration incentives offered by the State of Alaska. The Cook Inlet information is used as a basis for extrapolating MAG-PLAN Stage 1 results for the other South Alaska OCS planning areas.

Figure 3. Alaska OCS Planning Areas

Source: Bureau of Ocean Energy Management

2.3 MAG-PLAN ALASKA MODEL OVERVIEW

Economic impacts are generated by industry spending for exploration, development, and production of oil and gas in OCS areas. Industry brings money into the local or state economy when it explores, develops, and produces oil and gas. Industry pays businesses located in Alaska and elsewhere to supply goods and services for exploration, development, and production activities; and industry also pays governments—local, state, and federal—for rent/lease payments, taxes (property and corporate income tax), and royalties.[3] These payments to businesses (and their employees) and governments generate additional employment, labor income, and business sales (also called multiplier effects).

MAG-PLAN Alaska is a regional economic impact model used by BOEM to generate estimates of the potential economic effects of OCS development in Alaska. The E&D scenarios drive the model. E&D scenarios are forecast for oil and gas exploration, development, and production activities anticipated to result from every proposed lease sale or proposed 5-year program in an OCS planning area. Specific E&D scenarios are developed by BOEM's Resource Evaluation (RE) offices.

MAG-PLAN uses a 2-stage process:

Stage 1: Using a specific forecast of exploration, development, and production activities as inputs, the Stage 1 process generates estimates of direct employment, direct industry spending on labor and non-labor components, and direct industry payments to the federal state, and local governments (government revenues).

Information developed under Tasks 2, 3, and 5 are used in the Stage 1 process. This includes the amount and category of initial industry spending, in what economic sector it is spent (sectors supplying the goods & services), and where it is spent (onshore regions supplying the goods & services).

Stage 2: The Stage 2 process involves using IMPLAN multipliers to estimate the indirect and induced effects of industry spending, labor income spending, and government spending in a particular economic region. IMPLAN provides region-specific employment, income, and output multipliers for 440 economic sectors (each corresponding to an SIC/NAICS sector). Generally, the multiplier effects are estimated by multiplying the estimated local spending on each economic sector (from Stage 1) by the appropriate IMPLAN multiplier for that sector and for the region.

It should be noted that unlike the previous model, this revised version of MAG-PLAN Alaska does not use IMPLAN data to estimate direct employment. Instead, direct employment is determined using information on manpower requirements for specific OCS activities obtained primarily from industry and secondary sources. To generate the indirect and induced employment effects, the model uses IMPLAN multipliers.

3 DESCRIPTION OF MAG-PLAN ALASKA INPUTS

3.1 EXPLORATION AND DEVELOPMENT SCENARIOS

An E&D scenario contains estimates of the level of OCS activity anticipated to result from a proposed OCS lease sale or set of lease sales. BOEM bases each E&D Scenario on analyses of existing geologic data and assumptions about the extent to which new resources will be discovered and produced under specified price scenarios, given market and equipment

[3] Bids, rentals, and royalties for OCS leases are paid to the Federal Government. However, under Section 8(g) of the OCS Lands Act amendments of 1978, the Federal Government shares 27 percent of all revenues it receives from leases within 3 miles of State waters.

constraints. For MAG-PLAN Alaska, an E&D template was developed in collaboration with BOEM.

The E&D template was developed in MS Excel as a matrix: the rows correspond to the year when the activity occurs and the columns show values for the following activities/revenues:

- Marine Seismic Survey (*# of survey teams*)
- Geohazard Survey (*# of survey teams*)
- Geotechnical Survey (*# of survey teams*)
- Exploration/ Delineation Wells (*# of wells*)
- Offshore Exploration Platform (*# and type of platform*[4] *for water depths of less than 10 meters, 10 to 25 meters, and greater than 25 meters*)
- Offshore Production Platform (*# and type of platform*[5] *for water depths of less than 15 meters, 15 to 100 meters, and greater than 100 meters*)
- On-Platform Production Wells *(# of wells*)
- Sub-Sea Wells (*# of wells*)
- Oil Offshore Pipelines or Export Lines (*# of miles*)
- Gas Offshore Pipelines or Export Lines (*# of miles*)
- Oil Onshore Pipelines (*# of miles*)
- Gas Onshore Pipelines (*# of miles*)
- LNG Plant & Marine Terminal (*% of facility cost*)
- Oil Terminal (*% of facility cost*)
- Exploration Base (*% of facility cost*)
- Production Base (*% of facility cost*)
- Supply Boat Terminal (*% of facility cost*)
- Air Support Base (*% of facility cost*)
- Gas Production/Sales (*billions of cubic feet per field*[6])
- Oil and Condensate Production/Sales (millions of barrels of oil)
- Gas Production/Sales Total 8(g) (billions of cubic feet)
- Oil and Condensate Production/Sales 8 (g) (millions of barrels of oil)
- Rental Revenues Non 8(g) (millions of $)
- Rental Revenues 8(g) (millions of $)
- Bonus Bids Non 8(g) (millions of $)
- Bonus Bids 8(g) (millions of $)
- Royalties non 8(g) (millions of $)
- Royalties 8(g) (millions of $)

3.2 MODELED AND EXTRAPOLATED OFFSHORE MODELING AREAS

The prior version of MAG-PLAN Alaska was based on theoretical projects in two planning areas: the Beaufort Sea and the Cook Inlet. The model used extrapolations and rules of thumb to allow users to estimate the impacts of activities in other areas. The current model is based on

[4] See Table 2 for the list of exploration platform types included in the model.

[5] See Table 3 for the list of production platform types included in the model.

[6] The E&D template provides columns for up to 10 oil/gas fields.

new planning area-specific data for four areas: the Beaufort Sea, Chukchi Sea, Cook Inlet, and the North Aleutian Basin. Prior exploration, development, and production in the Beaufort Sea and Cook Inlet areas provide historic data for the model. Recent exploration plans and permit applications in the Beaufort Sea and Chukchi Sea also provide data on current activities and manpower estimates. The North Aleutian Basin was selected for modeling analysis even though exploration activity in the area is limited, because it represents a better analog to Bering Sea and remote Gulf of Alaska planning areas than any of the other three planning areas.

At the onset of the project, it was envisioned that factors based on a specific parameter or parameters could be used to estimate costs in the 11 planning areas that were not modeled directly. These potential parameters include:

- Metocean and ice conditions
- Regional or basin-specific seabed/soil conditions
- Water depth
- Reservoir features (oil or gas prone)
- Distances from support infrastructure

It became apparent that other approaches would be needed to generate costs for certain technologies in the 11 planning areas that were not modeled. The primary reasons or challenges that supported this conclusion are:

- Granularity/complexity of some of the cost estimating approaches (e.g. pipelines and associated trenching and multi-year construction season considerations).

- Several technologies (e.g. gravel, ice islands, caisson-retained islands, jacket, gravity based structures) are largely infeasible for a significant portion of the 11 planning areas due to much deeper water depths.

- For Alaskan OCS regions of deepwater, ultra-deepwater, and beyond (~10,000ft+), (e.g. Aleutian, Basin, Bowers Basin, Aleutian Arc), temperate region production structures/technologies such as spars, tension leg platforms, or semi-submersibles, which will not be required for exploration or production in the Beaufort Sea, Chukchi Sea, Cook Inlet, or the North Aleutian Basin for the foreseeable future, needed to be considered.

- Based on resource assessments for the Alaskan OCS regions of deepwater, ultra-deepwater, and beyond (e.g. Aleutian, Basin, Bowers Basin, Aleutian Arc), pipeline export solutions do not appear to be economically feasible and may not even be technically feasible. For these remote deepwater Alaskan OCS regions, pipeline lengths would generally be well in excess of several hundred miles and boosting stations would be likely be required

- In areas with water depths in excess of the ultra-deepwater range (i.e. ~10,000 ft+), the technology/capability to install structures and infrastructure (e.g. platforms, pipelines, subsea equipment) does not currently exist—exploration structure capability in such water depths is very limited if not non-existent.

Several methodologies for creating and updating MAG-PLAN cost data were employed in the cost estimating procedures for the 11 planning areas that were not modeled:

- Parametric scaling and extrapolation (e.g., water depth, distance, production rate, etc.)
- Modifying and or extending cost functions and calculations from the modeled areas

- Basing costs on data collected for new structures/technologies (e.g., deepwater floaters)
- Developing cost functions for new structures/technologies (e.g., deepwater Arctic floaters)

Additional information on the extrapolation methods is presented in Section 3.5.

3.3 REVISIONS TO ACTIVITY TYPES AND FUNCTIONS

The essential inputs for MAG-PLAN estimates are activity levels for the various Activity Types (ATs) (e.g., number of exploration wells drilled) contained in BOEM-developed E&D scenarios and the associated oil and gas production profiles. A number of changes were made in the E&D scenario template that is used by the Resource Evaluation group to describe future oil and gas activities in a planning area or region. Table 1 summarizes the changes in ATs that were made.

Table 1.

Changes of Activity Types in the Exploration and Development Scenarios

Activity Type	Unit of Measure
~~Geo Survey~~	~~Months~~
Seismic Survey	**Number of surveys**
Geohazard/Bathymetry Survey	**Number of surveys**
Geotechnical Survey	**Number of surveys**
Exploration/Delineation Wells	Number of wells
~~Exploration Ice Islands~~	~~Number~~
~~Drill Ships for Calm Water Exploration~~	~~Number~~
~~Drill Ships for Rough Water Exploration~~	~~Number~~
~~Mobile Bottom Founded Structures (MBFS) for Exploration~~	~~Number~~
Exploration Platform	
<10 Meters	**Number**
10 to 25 Meters	**Number**
>25 Meters	**Number**
Production Wells	Number
~~Gravel Production Islands~~	~~Number~~
~~MBFS for Production~~	~~Number~~
Production Platform	
<15 Meters	**Number**
15 to 100 Meters	**Number**
>100 Meters	**Number**
Production Wells	Number
Sub-Sea Production Well Completions	Number
~~Offshore Pipeline~~	~~Miles~~
~~Onshore Pipeline~~	~~Miles~~
Offshore Oil Pipeline	**Miles**
Offshore Gas Pipeline	**Miles**
Onshore Oil Pipeline	**Miles**
Onshore Gas Pipeline	**Miles**
~~Landbase Operations~~	~~Percent of Total~~
LNG Plant & Marine Terminal	**Percent of Capital Expenditures in each year**
Oil Terminal & Tank Farm	**Percent of Capital Expenditures in each year**
Exploration Base	**Percent of Capital Expenditures in each year**
Production Base	**Percent of Capital Expenditures in each year**
Supply Boat Terminal	**Percent of Capital Expenditures in each year**
Air Support Base	**Percent of Capital Expenditures in each year**

Note: A strike-through indicates that the AT was removed from the E&D template. Bold ATs indicate ATs that were added to the template.

The original Geo Survey was a marine seismic survey which was replaced with the three types of site surveys that are undertaken: marine seismic (which also includes an ocean bottom cable technology that is used in shallow water areas), geohazard/bathymetry, and geotechnical.

Ice islands, drill ships, and mobile bottom-founded structures (MBFS) were replaced with a set of exploration platform types that were suitable in different water depths and in different planning areas of the Alaska OCS, as shown in Table 2. Each planning area has a default structure for each water depth, as shown in Table 3.

Table 2.

Exploration Platform Types

Water Depth		
< 10 m	**10 - 25 m**	**>25 m**
Ice Islands	Mobile Drilling Structure (MDS)	Drill Ship
Extended Reach Drilling (ERD)	Jack-up	Semi-submersible
Mobile Drilling Structure (MDS)		Tripod Arctic Floater (TAF)
Jack-up		Jack-up

Table 3.

Default Exploration Platform Types by Water Depth for each OCS Planning Area

Offshore Modeling Area/OCS Planning Area	**Water Depth**		
	< 10 m	**10 - 25 m**	**>25 m**
Aleutian Arc	n/a	Jack-up	Drill Ship
Aleutian Basin	n/a	n/a	Drill Ship
Beaufort Sea	MDS	MDS	Drill Ship
Bowers Basin	n/a	n/a	Drill Ship
Chukchi Sea	MDS	MDS	Drill Ship
Cook Inlet	Jack-up	Jack-up	Drill Ship
Gulf of Alaska	Jack-up	Jack-up	Drill Ship
Hope Basin	MDS	MDS	Drill Ship
Kodiak	n/a	Jack-up	Drill Ship
Navarin Basin	Jack-up	Jack-up	Drill Ship
North Aleutian Basin	n/a	n/a	Drill Ship
Norton Basin	Jack-up	Jack-up	Jack-up
Shumagin	n/a	Jack-up	Drill Ship
St George Basin	n/a	Jack-up	Drill Ship
St Matthew-Hall	n/a	n/a	Drill Ship

Gravel island and MBFS for production were also replaced with a set of production platform types as shown in Table 4. The current model also provides for natural gas production, and oil and gas production can be modeled at the same time. Table 5 shows the default production platform types by water depth for each of the Alaska OCS planning area.

Table 4.

Production Platform Types

Water Depth		
< 15 m	**15 - 100 m**	**> 100 m**
Gravel Island	Tower	Drill Ship
Extended Reach Drilling	Gravity Based Structure (GBS)	Semi-submersible
Tower	Jack-up	Tripod Arctic Floater (TAF)
Gravity Based Structure		Floating Liquefied Natural Gas (FLNG)
		Floating Production Storage and Offload (FPSO)
		Spar
		Tension Leg Platform

Table 5.

Default Production Platform Types by Water Depth for each OCS Planning Area

Offshore Modeling Areas/OCS Planning Area	Water Depth		
	< 15 m	**15 - 100**	**> 100**
Aleutian Arc	n/a	GBS	FPSO
Aleutian Basin	n/a	GBS	FPSO
Beaufort Sea	GBS	GBS	TAF
Bowers Basin	n/a	GBS	FPSO
Chukchi Sea	GBS	GBS	TAF
Cook Inlet	Tower	GBS	FPSO
Gulf of Alaska	n/a	GBS	FPSO
Hope Basin	GBS	GBS	TAF
Kodiak	n/a	GBS	FPSO
Navarin Basin	GBS	GBS	FPSO
North Aleutian Basin	n/a	GBS	TAF
Norton Basin	GBS	GBS	n/a
Shumagin	n/a	GBS	FPSO
St George Basin	n/a	GBS	FPSO
St Matthew-Hall	n/a	GBS	TAF

Offshore and onshore pipelines were replaced with offshore and onshore oil and gas pipelines, since the costs are different for each type of pipeline.

Landbase operations were removed and replaced with six different onshore ATs to be able to identify the onshore facilities that may or may not be needed in different planning areas. In areas with existing infrastructure, there may be no need for additional onshore infrastructure but in frontier areas, all six facilities may be needed.

In addition to the new ATs in the E&D scenario, the model includes a new AT entitled environmental management, which includes permitting, environmental monitoring, and oil spill contingency. This new AT and the associated activity functions are shown Table 6. Note that with the inclusion of the three site survey methods and permitting, which includes preparing environmental impact statements, the model now incorporates a major part of the pre-bid activity which was not included in the previous model.

Table 6.

Environmental Management Activity Type and Related Activity Functions

Activity Type	Activity Function
Environmental Management	• Permitting • Ice Reconnaissance • Spill Contingency • Oil Spill Response Vessels • Marine Mammal Observers (MMOs) • Oil Spill Tug & Barge • Oil Spill Tanker • Fixed Wing MMO Aircraft

Another change was the addition of a number of new vessel types to the activity functions to more accurately depict the work that is ongoing during the exploration, development, and production phases. For example, ice management vessels (icebreakers), anchor handling tug supply (AHTS) boats, subsea installation vessels, and derrick barges are examples of new vessel types that were added.

A major change to MAG-PLAN Alaska was providing the user with the capability of estimating the effects of oil and gas activities in any of the 15 Alaska OCS planning areas shown in Figure 3, based on specific attributes of the planning area. The model is based on analysis of oil and gas activities in the Beaufort Sea, Chukchi Sea, Cook Inlet, and conceptually, the North Aleutian Basin. Using these four planning areas as analogs and adjusting for such factors as water depth and location of shore bases enables the model to estimate effects for the other planning areas.

The model now incorporates new technologies and new industry practices, and includes concepts for working in deepwater Arctic areas that have not yet been explored. The data provide different costs for platform fabrication and installation or construction by platform type, and for operations and maintenance. The various platforms and technologies each require different amounts and types of support activities, and the model incorporates current and anticipated support activities for each platform type and technology. For example, there is only one Jones Act-compliant ice management vessels at this time, so cost estimates and crewing estimates have been developed to reflect the recent announcement by the U.S. Coast Guard that foreign-flagged icebreakers and AHTS vessels will not be permitted as of 2017. Vessels that will operate in Arctic ice conditions will be much larger than vessels used in subarctic conditions, and the supply boat terminals reflect this difference in terms of the deeper depth alongside a pier that will be required, larger crew sizes, and the resulting increase in cost.

The cost estimates in the model are based on the expert engineering knowledge of the consultant team member IMV Projects, which is actively engaged in consulting and engineering work in Arctic regions around the globe, along with interviews by Northern Economics with contractors, suppliers, oil company officials, and other experts, and the latter firm's experience in other OCS-related studies for industry. A large research effort of secondary sources identified costs and manpower for the many specialized vessels and equipment that are included in the model. In many cases, these vessels and equipment operate around the globe and in some instances, markets exist with published spot rates. Where charter or lease costs were not available, published spot rates were used to reflect lease or charter costs to an operator. Mobilization and demobilization costs were added to the charter or spot rates to estimate the total cost to the operator.

For a number of activities, the model distinguishes between Arctic and subarctic areas due to the differences in equipment and vessel types required, the number of months that may be suitable for operations, and other factors. Thus, there are differences in manpower requirements and costs between the two sub-regions. In addition, mobilization and demobilization costs for vessels and equipment are estimated separately for each planning area resulting in variations in costs.

The model presently accounts for onsite (production) labor costs, offsite (non-production) labor costs, and fringe benefits, as in the prior model. The current model also estimates the percent of onsite labor that are residents of the relevant onshore area, the percent that are residents of the rest of Alaska, the percent that are residents of the rest of the U.S., and percent that are residents of the rest of the world.

With the exception of capital costs for production platforms and pipelines, which are assumed to be owned by the BOEM lessee, all other facilities, equipment, vessels, and services are assumed to be provided by a contractor, and appropriate contract, charter, or lease rates are used in the model.

3.4 Summary of OCS Activities

In addition to the Activity Types identified in the previous report subsections, there are associated Activity Functions. The first stage of an AF consists of an estimate of per-unit industry manpower and expenditures necessary to produce a given unit of each AT. For example, one exploration well drilled from a drillship in the Chukchi Sea will require one ice-class offshore supply vessel with an onboard crew of 24, total employment of 48 counting the crew that is off-duty but on a rotation schedule, and a cost that is calculated in the model based on the duration of the activity and the required mobilization and demobilization time multiplied by the estimated day rate of $45,000, based on interview data. The stage 1 estimates also provide information on the percent of the crew and expenditures that are local, State of Alaska, other U.S. states, and rest of the world.

Figure 4 and Figure 5 illustrate the activities types associated with the exploration and production phases, respectively. As mentioned earlier, the model has the new AT "environmental management," which includes the AFs listed in the box on the left side of the figures, and some of the support vessels used in exploration and production activities are noted in the box on the right side of the figures.

MAG-PLAN Alaska contains both primary and secondary AFs. Examples of primary AFs would be drilling exploration wells and operating the production platform. Secondary AFs are contributing sub-functions. For example, most Arctic oil and gas activities require the housing, feeding, and transportation of workers to work sites, and helicopter transportation supports a variety of activities. Therefore, in contrast to the structure of MAG-PLAN Gulf of Mexico, ATs and AFs can have many-to-many relationships. Thus, accommodations facilities are required to support any Arctic onshore facilities with the size of the accommodations facility varying with the number and size of onshore facilities. The AFs of helicopter crew and helicopter support are related to a number of offshore activities, including the site survey ATs, exploration drilling, platform installation, operating the production platform, subsea completions, and decommissioning.

The AFs required to support the ATs vary depending on water depth, type of platform, and Arctic or subarctic. For example, a gravel island production platform would be supplied via an ice road by trucks in the winter, while a floating platform in the southern Bering Sea would be supplied by an offshore supply vessel at the same time of year. During the open water season in the Beaufort Sea, tugs and barges would replace the truck to resupply the gravel island, while the offshore supply vessel or vessels would continue to supply the floating platform.

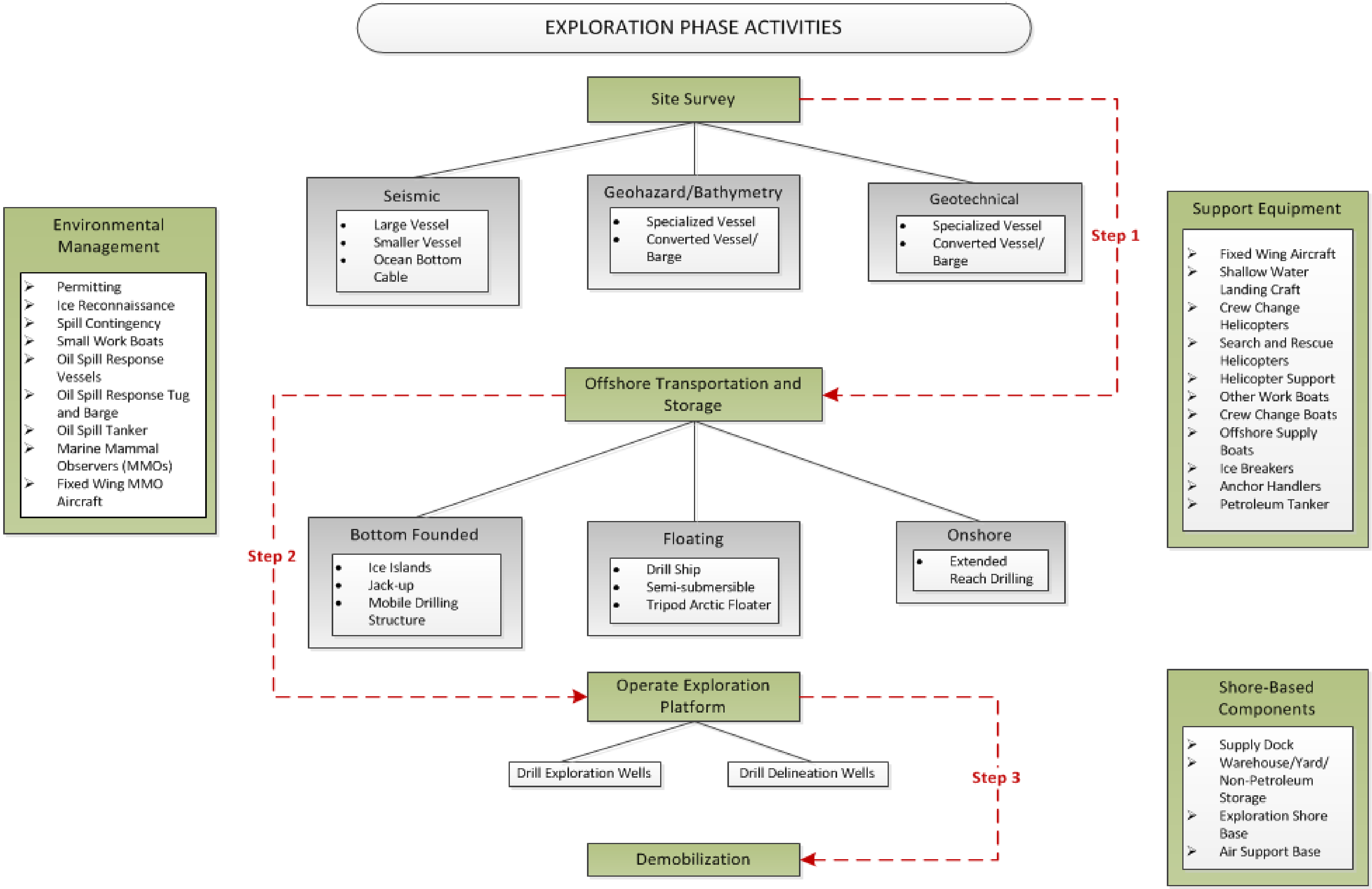

Figure 4. Exploration Phase Activities

Source: Northern Economics, Inc.

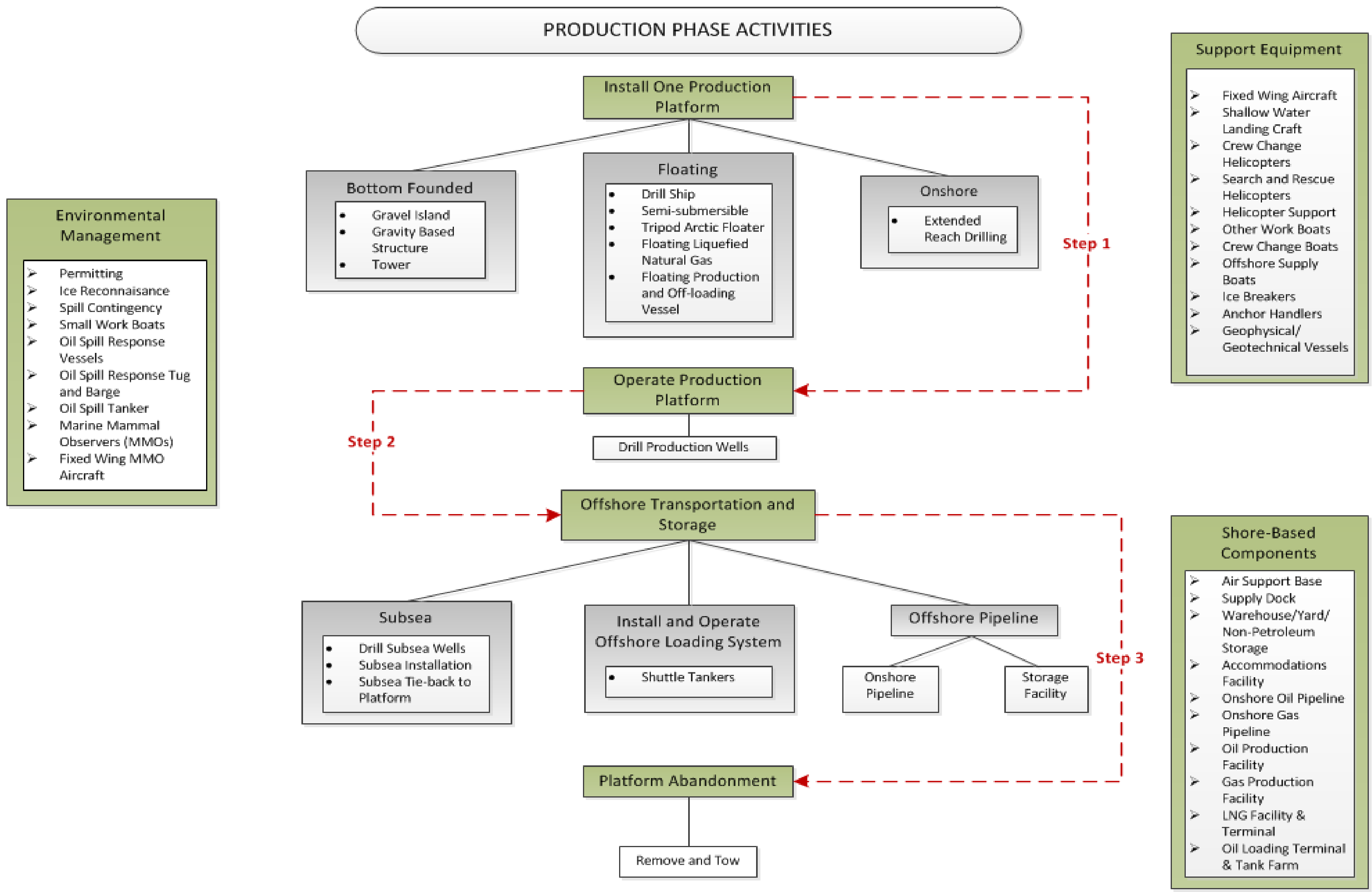

Figure 5. Production Phase Activities

Source: Northern Economics, Inc.

3.5 ACTIVITY COSTS AND MANPOWER REQUIREMENTS FOR MODELED OFFSHORE MODELING AREAS

This section provides information on costs and manpower requirements for the four planning areas, Beaufort Sea, Chukchi Sea, Cook Inlet, and the North Aleutian Basin for which data collection and engineering efforts were undertaken. It describes the major activity, the data sources, manpower requirements, equipment and vessels, and costs. The major activities addressed in this section include environmental support activities, site surveys, exploration drilling, development, production, and abandonment.

3.5.1 Environmental Support Activities

Environmental Support Activities include several types of activities that support OCS exploration, development, and production. These support activities include permitting and environmental monitoring, and oil spill contingency or response.

3.5.1.1 Data Sources

The data sources for this activity included interviews with several firms that have provided much of the permitting services for OCS activities in the Beaufort and Chukchi Seas during the last five years, and interviews with the firms that provide oil spill contingency services and oil spill responders throughout Alaskan waters. Interviews were also held with subcontractors that provide trained responders to these oil spill contingency services firms in the event of an oil spill, as well as firms that provide the vessels for oil spill contingency and for oil spill events. This report only addresses oil spill contingency since BOEM has another model which estimates the effects of oil spills.

In addition to the interviews, a number of secondary sources were reviewed including the oil spill contingency plans of firms seeking to explore in the Beaufort and Chukchi Seas, and other documents that were found during an extensive data collection effort.

3.5.1.2 Permitting and Environmental Monitoring

Permitting activities occur prior to any significant exploration or development activities, and are required on an ongoing basis during production to keep the permits current and reflecting the current level of activity. Environmental monitoring is required during most exploration activities and is anticipated to be required by various agencies during development and production as these OCS activities expand in the future. Environmental monitoring activities encompass a wide range of activities from marine mammal observers on vessels and platforms, to conducting airborne surveillance for marine mammals, to conducting acoustic monitoring of marine mammals and fishes, ice forecasting, weather forecasting, and a host of other monitoring activities of the environment.

3.5.1.3 Manpower

The manpower requirements for environmental monitoring vary greatly depending on the activity that is being conducted. Conducting oceanographic and biological surveys from a vessel can have a crew plus scientists of 16 to 30 people. Airborne surveillance of marine mammals has typically been conducted for the ice-free season and typical manpower requirements are two to six marine mammal observers plus two aircraft crew. Marine mammal observers have also been required on vessels, with the number of observers ranging from two to four on larger vessels. Observers are not required on smaller vessels, which do not have space for them.

Weather and ice forecasting requires several meteorologists. Weather forecasting is conducted year-round, while ice-forecasting is undertaken as required for marine operations that are being conducted in support of exploration activities. It is expected that ice forecasting would be conducted throughout the year if production activities began. This report assumes that these services are provided by a contractor, but some oil and gas firms have their own weather and ice forecasting staff.

Creating an environmental impact statement can require a large amount of baseline research and data collection and can involve 50 to 100 or more people for a period of several years; shepherding the document through the review period can require 15 to 20 full-time equivalent staff for a period of 6 months to a year or more.

Approximately 20 to 40 people can be required to obtain the initial permits for OCS drilling. Obtaining these permits can take a year or two, and sometimes longer as witnessed by recent events. Keeping the permits current requires four to six full-time equivalent positions on an annual basis. Regulatory field compliance contractors are also employed on the drilling rig and support vessels to ensure compliance with stipulations of the various permits and two to four persons may be on the rig and vessels while operations are ongoing. Two to four contractors working for a 90-day period may be required to obtain the permits for site surveys (i.e., seismic surveys, geophysical or geotechnical surveys).

Subsistence advisors and Inupiaq-speaking communicators have also been employed during exploration activities in the Beaufort Sea and the Chukchi Sea to provide information to subsistence hunters and the industry to minimize conflict between these activities. The persons in these positions are typically employed for 60 to 90 days.

3.5.1.4 Equipment

Permitting and environmental monitoring does not require an extensive number of vessels and aircraft equipment since much of the work is conducted in Anchorage or takes place on the rig and support vessels, which are discussed later in this report. The two primary activities that require capital equipment are oceanographic and related marine research, and airborne marine mammal observations. The vessels employed in conducting baseline marine research and other activities to obtain information for environmental impact statements and OCS permits can vary substantially in size depending on the suite of activities that are being conducted. Information obtained from interviews and secondary sources indicates that these vessels can range from 80 to 230 feet in length. The R/V Mt. Mitchell (see Figure 6) has been used for hydrographic research in the Chukchi Sea and elsewhere in Alaska waters. Airborne marine mammal operations are typically conducted far from shore over water, so to improve safety, twin-engine airplanes such as a DeHavilland Twin Otter (DHC-6) are used for this activity.

Figure 6 R/V Mt. Mitchell

Source: Global Seas Corporation, 2010.

The R/V Mt. Mitchell is a 231 foot hydrographic research vessel first commissioned in 1967 as a survey ship with NOAA. The vessel has a beam of 42 feet and has 60 berths for the ship's crew of 11 and 49 others.

Figure 7 DeHavilland Twin Otter

Source: National Oceanic and Atmospheric Administration, 2011.

The Twin Otter is a high-winged, unpressurized, twin-engine turboprop aircraft that is often used for marine mammal surveys offshore of Alaska's coast. The aircraft has two crew and marine mammal observers can range from two to six persons.

3.5.1.5 Contract Costs

The costs of permitting and environmental monitoring can have a very wide range depending on permit stipulations, the program that is being implemented by the OCS lease holder, and a number of other factors. The following information should be considered as representative of costs that may be incurred, but actual costs could be outside of the ranges presented here. Costs for the major activities are presented here; the costs of smaller activities described above are incorporated in the model.

Table 7.

Range of Contract Costs for Major Permitting and Environmental Monitoring Activities

Activity	Low Range	High Range
Baseline Research and EIS	7,000,000	14,000,000
Permit Acquisition for Site Surveys	250,000	1,000,000
Permit Acquisition for Drilling	5,000,000	10,500,00
Annual Permit Maintenance	2,000,000	4,000,000
Annual Airborne Marine Mammal Surveys	5,000,000	10,000,000

Source: Northern Economics, Inc. estimates based on interviews.

The total contract cost for permitting and environmental monitoring to a company proposing to conduct exploration drilling in the OCS could range from $22.5 million ($7.0 million for baseline research and EIS; permit acquisition for site surveys and drilling $5.25 million, and two years of airborne marine mammal surveys at $5.0 million each) to approximately $45 million ($14.0 million, plus $1.0 million, plus $10.5 million, plus two years at $10.0 million). In addition to the contract costs, the exploration company will incur "owner's costs" that will increase the cost of these activities above the contract price. Owner's costs include such items as employee costs for those persons managing the various contractors, travel for these persons, training, other overhead items for these individuals, insurance, and a number of other items. Owner's costs can also include such items as fuel for the drilling rig and all support vessels and aircraft, search and rescue helicopter, and accommodations and travel for crew and others to and from Anchorage or other place of origin. These items are generally not included in the contract price and are provided by the exploration company or reimbursed directly to the contractor. The level of owner's costs depends on the activity, the manner in which the exploration company manages its contractors, and the specifics of the contractual arrangement. Discussions with several companies operating in the North Slope and others conducting exploration activities in the OCS suggest that owner's costs can range from 15 percent to as high as 50 percent for certain activities. Using an estimate of an average 25 percent owner's costs for all activities combined results in total costs of $28 million to $56 million for permitting the necessary site surveys and an exploration well.

3.5.1.6 Oil Spill Contingency

Oil spill contingency activities include training of oil spill response workers and vessel crews, maintaining equipment and supplies so that it is ready in the event of a spill, and providing trained oil spill responders and persons capable of preventive monitoring on platforms while drilling is ongoing. The following descriptions of the manpower requirements and contract costs do not include oil spill cleanup activities, which are addressed in another BOEM model.

3.5.1.6.1 Manpower

Oil spill contingency services are provided in the Beaufort Sea and Chukchi Sea OCS planning areas on a seasonal basis for petroleum exploration activities and the state waters of Cook Inlet for oil and gas production on a year-round basis. However, oil spill contingency services are also required for vessels and tank barges that transport petroleum products in Alaska waters, and service providers operate in every coastal planning area in the state. As a result, if OCS activities were to occur in these regions, it is anticipated that current service providers would be available.

In addition to the employees of the oil spill contingency service providers, there are numerous other personnel that are trained as oil spill responders. These include the crews and oil spill technicians on the dedicated oil spill response vessels (8 to 40 positions; 16 to 60 persons), the oil spill tug and barge (15 to 17 positions; 30 to 34 persons), and the oil spill tanker (15 to 18 positions; 30 to 36 persons), as well as the crews of the platform supply vessels (8 to 19 positions; 16 to 38 persons), anchor handling tug supply (19 to 29 positions; 38 to 58 persons), and ice management vessels (25 to 37 positions; 50 to 74 persons). The lower numbers of positions and persons are more representative of subarctic manpower requirements, while the larger numbers are more representative of manpower requirements in the Arctic planning areas. Berthing capacities of some vessels are greater than shown here and during spill events a substantially larger number of persons would be onboard. The estimates shown here are indicative of the number of people onboard during normal operations when a spill has not occurred.

Marine operations in the Beaufort and Chukchi seas presently require 11 positions (22 persons) and future exploration drilling activity could require the oil spill contingency firm to provide an additional 20 to 78 employees and contractor personnel depending on the number of wells being drilled, the length of the drilling program, and the number of drilling rigs operating in a given season.

The manpower estimates noted above are for offshore spill contingency and response. In addition to these requirements, there would be additional personnel staged on shore for nearshore and coastal spill response if necessary. These nearshore contingency and response activities would likely be in state waters and are not included in this analysis.

3.5.1.6.2 Equipment

The equipment discussed in this section describes the major vessels that are dedicated to oil spill contingency training and cleanup in offshore and nearshore waters. Other vessels that can participate in such efforts but which have a different primary role in OCS waters are discussed later in the report. Dedicated oil spill contingency includes the following types of vessels:

- Oil spill response vessel (offshore)
- Tug and oil spill barge (nearshore)
- Tug and oil spill containment system barge (offshore)
- Vessels of Opportunity (offshore)
- Oil spill tanker (offshore)

Oil spill response vessels vary in size and capacity, with those vessels operating in Arctic waters being larger and with greater spill cleanup capacity, greater holding capacity for recovered petroleum products, and a greater number of crew berths for a larger number of spill responders. Figure 8 shows the M/V Nanuq, a 300-foot oil spill response vessel that is the only ice-class response vessel in Alaska.

Figure 8. M/V Nanuq

Source: Shell.com, 2011.

The M/V Nanuq, which was built for Shell by Edison Chouest (EC) is also capable of filling the role of an anchor handling tug supply boat (AHTS). EC has a contract to operate the Nanuq for Shell. The Nanuq is capable of accommodating 120 people, but approximately 40 people are onboard during normal operations. Per Shell's Offshore Inc.'s Exploration Plan for Camden Bay, the Nanuq is approximately 300 feet in length and has 12,000 barrels of holding capacity. It is large enough to carry three 34-foot workboats and a number of skimming technologies and containment boom.

In addition to the Nanuq, Shell identified the use of hull 247, a 360-foot ice management/anchor handler or an equivalent vessel as vessels of opportunity with 3,200 barrel holding capacity that could operate in conjunction with the Nanuq in the event of an oil spill. These vessels would also provide berths for crews operating off the oil spill response barge. Construction of Hull 247 was recently completed by EC and the vessel was named the Aiviq.

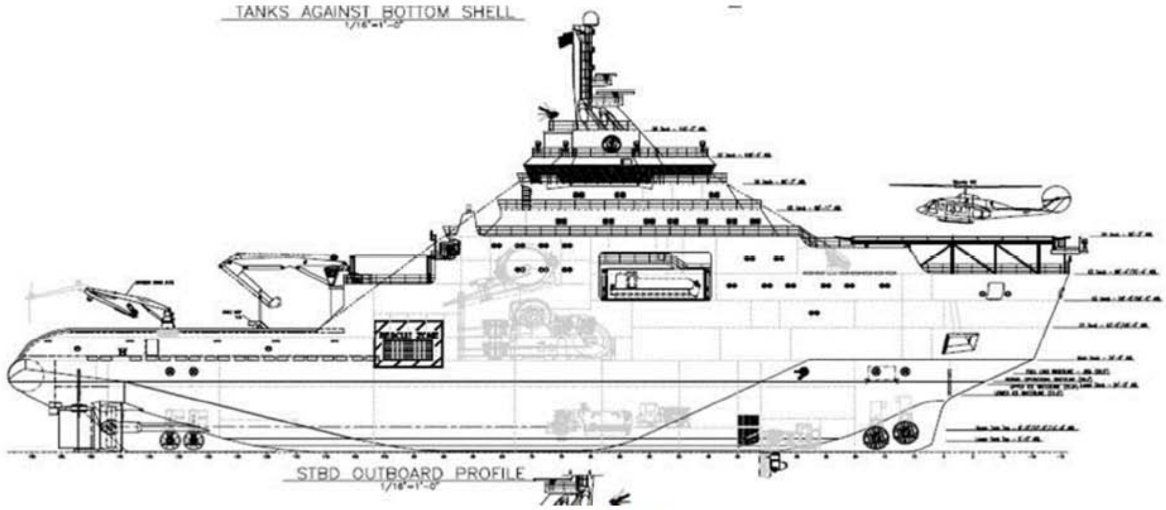

Figure 9. Hull 247 (Ice Management/Anchor Handler)

Source: Shell Offshore, Inc., 2011.

The M/V Perseverance is a 206-foot long platform supply vessel that was converted to an oil spill response vessel. The vessel operates in Cook Inlet providing contingency services to the oil and gas platforms in Cook Inlet, for tanker loadings that occur in the Inlet, and as the tow vessel for oil spill cleanup barges.

Figure 10. M/V Perseverance

Source: Ocean Marine Services, Inc., 2011.

The Arctic Endeavor is a 205-foot long, ice strengthened oil spill response barge in the Beaufort Sea that has a holding capacity of 16,800 barrels. The barge also has a suite of skimmers, workboats, containment booms, and other equipment for use in the event of a spill.

The barge is towed by available tugs such as the Point Barrow (see Figure 12), which is 85-feet long with 2,100 horsepower.

Figure 11. Arctic Endeavor Barge

Source: Shell, 2011.

Figure 12. M/V Point Barrow, a Point Class Tug/Tow Boat

Source: Crowley.com, 2011.

Barge 141 is a 260 x 68-foot, 60,000 barrel petroleum products barge customized for quick response to oil spills that operates in Cook Inlet. The vessel is fully self-contained and can rapidly deploy containment booms and skimmers to recover and transport product for final disposal. A picture of Barge 141 was not available.

In addition to the Arctic Endeavor, Shell has proposed the use of a second tug and barge set that would accommodate an oil spill containment system, similar to that deployed in the Gulf of Mexico to stop the flow of oil from the Macondo well (see Figure 13). The tug is proposed as an Invader Class vessel that is 136 feet in length with 7,200 horsepower, and capable of storing approximately 3,700 barrels (see Figure 14). The barge is 100-feet wide and 400-feet long and capable of storing 80,000 barrels of liquids. An AHTS has also been proposed but not identified to provide support to the containment barge.

Figure 13. Alaska Arctic Cap and Containment System

Source: Shell, 2011.

Figure 14. Invader Class Tug/Tow Boat

Source: Crowley.com, 2011.

Shell Offshore has proposed the use of a tanker to act as fuel supply vessel as well as a storage facility for recovered crude oil, emulsion, and free water that may be recovered in the event of an oil spill. Several vessels have been identified in Shell's exploration plans including the M/V Mikhail Ulyanov, an ice-capable tanker of 70,000 dead weight tons with a double hull and capable of breaking through 1.2 meter (4-feet) thick ice at a steady speed of not less than three knots when moving stern forward and not requiring an icebreaker escort. The vessel is 257 meters in length with a beam of 34 meters and a draft of 14 meters.

Figure 15. M/V Mikhail Ulyanov

Source: Aker Arctic Technology, 2010.

3.5.1.6.3 Contract Costs

The contract costs for oil spill contingency services, including the associated manpower and equipment can vary substantially based on the seasonal nature or duration of the activity; the contingency, exploration, and development plans of the companies that are conducting these activities; and agency requirements or stipulations that must be met by the companies. In addition, mobilization and demobilization of vessels and equipment, some of which are from the Gulf of Mexico or distant international waters, also affects the duration of these activities and the manpower requirements and costs. The following paragraphs describe the range of contract costs, day rates, or other costs for oil spill contingency vessels and services.

Dedicated oil spill response vessels are few in number and limited information is available from which to estimate day rates for these vessels. As noted above, the Nanuq was purpose-built by EC for Shell Offshore and EC operates the vessel for Shell. Several vessel operators, other than EC and Shell, suggested that potential day rates for a vessel as capable as the Nanuq could range from $40,000 to $50,000 per day. This rate would cover all costs except fuel. In comparison, the M/V Perseverance has a day rate of $10,000 per day for members of the Cook Inlet spill response organization and $20,000 per day for non-members, also excluding fuel. Hull 247 is still under construction and final costs are not well known, but one person interviewed indicated that the cost of such a vessel could be as high as $150 million.

The Arctic Endeavor is on charter to Shell, which outfitted the barge with oil spill supply equipment at a cost thought to lie between $5 million and $10 million. Used barges in good condition of the size range noted for these oil spill response barges can be purchased for as little as $300,000 on the West Coast. Conversion costs and ice-strengthening the barges can easily exceed the purchase cost, but still result in a reasonable day rate. However, amortizing the much larger equipment cost would result in a much larger day rate, and the labor costs for the crew that train on the equipment also increase the day rate. Day rates for such barges are thought to range from $10,000 to $25,000 per day with the lower end of the range in subarctic waters and the higher end of the range in Arctic waters.

As noted earlier, the M/V Perseverance is also the tow vessel for Cook Inlet oil spill barges while Point Class tugs are used in Arctic waters to move the Arctic Endeavor. The day rate for the M/V Perseverance was noted earlier at $10,000 to $20,000 per day while the day rates for Point Class and similar tugs operating in the Beaufort and Chukchi seas are thought to range from about $8,000 to $10,000 per day.

The day rates for tugs and barges operating in Arctic waters is high in comparison to vessels used in subarctic waters because the operating season in the Arctic is much shorter and the capital and annual operating and maintenance costs must be recovered in fewer operating days.

As noted earlier, Shell has proposed the use of an oil spill containment system in the Arctic that would be housed on a dedicated barge with an accompanying tug. The barge would also be used to store recovered oil and other liquids in the event of a spill. The Invader class and similar tugs have an estimated day rate ranging from $15,000 to $20,000 per day. These larger Invader Class tugs have historically not wintered over in the Arctic but have been demobilized at the end of the open water season to ice-free ports on the West Coast and elsewhere, where they continue to work throughout the remainder of the year, thus resulting in a relatively low day rate compared to the smaller Point Class tugs.

Tanker rates can vary significantly depending on the size of the vessel and whether a vessel is on a long-term charter or a spot rate. Spot rates are very volatile and can vary substantially over short periods of time. For example spot rates for Aframax crude carriers, which are in the size range of the M/V Mikhail Ulyanov, have ranged from an average of about $22,000 per day in 2010 to $9,000 per day in early October 2011. The icebreaking attributes of the M/V Mikhail Ulyanov would likely result in higher charter or spot rates for that vessel, but the information was not discovered or disclosed. Long-term charter rates are generally set at rates sufficient to cover all costs of the vessel owner and are between the troughs and peaks of spot rates, which can be below break-even costs and well above full cost recovery at times. For example, in 2010 Shell signed a 3-year charter for an Aframax tanker similar in size to the M/V Mikhail Ulyanov for $20,000 per day. Long-term charter rates are typically for multi-year periods and would not be applicable to shorter seasonal charters during the open water season in the Arctic. Long-term charter rates might be appropriate for multi-year production drilling activities.

3.5.2 Site Surveys

Prior to exploration drilling, oil and gas companies conduct marine seismic surveys to evaluate whether prospective leases might contain oil and gas resources and then, if successful in bidding for the leases, the companies conduct additional surveys to determine the geophysical and geotechnical conditions at various sites where the exploration drilling may occur and where pipelines or subsea developments might be located. The following paragraphs provide additional detail on these surveys. The typical schedule for these surveys would have the marine seismic survey completed in year 1. Based on the information from the seismic survey, the exploration company would then contract for a geophysical survey of four to five potential drill sites that were identified by the exploration company for the prospect. Based on the geophysical information, the exploration company might identify two or three sites for a geotechnical survey in year 3. The geotechnical survey would be used to select the specific exploration platform that would be used for the exploration drilling.

3.5.2.1 Marine Seismic Surveys

A review of exploration plans and environmental documents submitted to agencies indicated that three types of marine seismic surveys have been conducted in Alaska in recent years. These include three-dimensional (3-D) surveys conducted by large vessels that are specially designed to efficiently conduct these data intensive seismic surveys, two-dimensional (2-D) surveys that are more often conducted by smaller seismic vessels, and ocean bottom cable programs that use a fleet of shallow draft vessels to conduct both 2-D and 3-D information in shallow, nearshore waters and tidal areas. While the larger 3-D vessels can also conduct 2-D survey programs, it is generally more cost effective to use smaller vessels for those programs.

3.5.2.1.1 Data Sources

An interview was conducted with a major international seismic survey provider that has conducted recent 3-D and 2-D seismic surveys in Alaska waters including the Beaufort and Chukchi seas. This firm provided detailed information on the programs that were conducted, including contract costs. This information was corroborated with information provided in permitting applications submitted by the companies that retained this contractor. Interviews were held with two major international firms that provide marine geophysical and geotechnical surveys to companies exploring in Alaska waters, and who have conducted a number of recent surveys. This information was also corroborated by reviewing the permit applications for these surveys. An interview with the firm that provided a recent ocean bottom cable survey could not be arrange, but a review of the permit application for this survey provided information on the names of the vessels involved or descriptions of the smaller vessels that were involved. Using this information, research was undertaken to find the crew sizes, day rates, and other information for these vessels or for vessels of similar size and capabilities. In most cases, the seismic survey vessels are homeported in the Gulf of Mexico or conduct operations in distant international waters. As a result, mobilization and demobilization costs for these expensive vessels are substantial. Some of the smaller, shallow water vessels used in the ocean bottom cable survey were trailered from the Gulf of Mexico to the North Slope and the estimated costs for these landside mobilization and demobilization costs are included.

3.5.2.1.2 Large Seismic Survey Program Vessel

As noted above, mobilization and demobilization costs are very high for seismic vessels and the short open water season and the possibility of ice movements that reduces the time available for the vessel to conduct the surveys appear to have caused current leaseholders to select large, modern vessels that can conduct three dimensional (3-D) and four dimensional (4-D) surveys in much shorter time than even slightly older vessels. Two dimensional (2-D) surveys are more often conducted by less capable vessels.

3.5.2.1.2.1 Equipment

Modern, large seismic vessels operate around the globe and are in high demand due to their improved seismic equipment (12 to 16 streamers) and the ability to operate in remote waters for long periods of time. They can also operate in a wider window of weather conditions and mobilize to distant waters at high speeds. These large vessels operate in water depths of 20 fathoms (120 feet) or more. It is possible for them to operate in shallower water by shortening the length of the streamers, but it may be more cost effective to use smaller vessels for nearshore surveys. The M/V Boa Galetea (pictured below) is an example of a modern, large seismic vessel and similar to some of the vessels that have recently operated in the Beaufort Sea and Chukchi Sea. Seismic vessels operating in Arctic waters are required to have support vessels to monitor for marine mammals, survey ice conditions, and re-supply the seismic vessel if necessary. Photographs of some of the vessels that have participated in this role are shown after the seismic vessel that they operated with.

Figure 16. M/V Boa Galatea

Source: EMGS, 2011a.

The vessel is 80 meters (262 feet) in length and 20 meters in beam (62 feet) and has accommodations for 57 crew members. Other seismic vessels of similar size have up to 80 berths for crew and others.

Recent permit applications for seismic surveys have indicated that CGGVeritas and Fugro have conducted seismic surveys in Alaska Arctic waters. Examples of the modern vessels that are operated by these firms are shown in the following figures, followed by selected information about these vessels.

Figure 17. M/V Oceanic Vega

Source: CGGVeritas, 2011.

The Oceanic Vega has a overall length of 106 meters (348 feet) and a beam of 28 meters (79 feet) with a 70-person capacity.

Figure 18. M/V Geo Celtic

Source: Fugro-Geoteam, 2011.

The Geo Celtic was noted in Statoil’s permit application as the seismic survey vessel for its 3-D seismic program in 2010. The Geo Celtic was supported by the M/V Thor Alpha, which handled marine mammal monitoring, support, and supply duties, and the M/V Gulf Provider, which was used for marine mammal monitoring, crew transfer, support, and supply duties. The Geo Celtic 101 meters (331 feet) in length with a beam of 28 meters (92 feet), and is registered as an ice-class vessel although the class is for limited ice conditions. The vessel has accommodations for 69 persons.

Figure 19. M/V Thor Alpha

Source: Thor Offshore and Fisheries

The M/V Thor Alpha has a crew of eight and reclining seats for 34 persons. The vessel is 55 meters in length (180 feet) and has a beam of 12.6 meters (41 feet). The Thor Alpha is registered under the Faroese flag (Faroe Islands) and the U.S. Coast Guard has announced that as of 2017 no foreign flagged vessels will be permitted to operate as icebreakers or anchor handlers in U.S. waters. As a result, the Thor Alpha and other foreign-flagged vessels of these vessel types will not be operating in Alaska waters after that date.

Figure 20. M/V Gulf Provider

Source: LGL Alaska Research Associates, Inc. et al, 2009.

The overall length of the Gulf Provider is 57.8 meters (190 ft) and the vessel is 11.6 meters (38 feet) in width. In addition to its service to the Geo Celtic in 2010, the Gulf Provider was the Gilavar's primary supply vessel and also served as monitoring vessel during the 2008 seismic surveys in the Chukchi and Beaufort seas. The Gulf provider has berths for 52 persons.

Figure 21. M/V Gilavar

Source: LGL Alaska Research Associates, Inc. et al, 2009.

The Gilavar conducted seismic surveys in the Beaufort and the Chukchi seas in 2008. Its overall length is 84.9 m (279 ft) with a mean draft of 5.9 m (19 ft). The vessel has 50 berths.

Figure 22. M/V Torsvik

LGL Alaska Research Associates, Inc. et al, 2009.

The Torsvik was one of the two primary monitoring vessels for the Gilavar during seismic exploration activities in the Chukchi and Beaufort seas in 2008. The overall length of the Torsvik is 39.2 m (129 ft), with a beam of 8.5 m (28 ft), and it has berths for 31 persons. The Torsvik is also registered under the Faroe flag.

Figure 23. M/V Norseman II

LGL Alaska Research Associates, Inc. et al, 2009.

The Norseman II was built in Seattle at the Marco Shipyard in 1979 for the Bering Sea crab fisheries. In 2007 the Norseman II underwent major modifications, adding a new dining, work area and lounge along with 4 staterooms and bathrooms. The vessel measures 115 ft in length, 27 ft wide and draws 13 ft when loaded. The Norseman II operated as a chase/monitoring vessel for the Gilavar, and was involved in the deployment and retrieval of acoustic equipment in both the Chukchi and Beaufort seas in 2007.

In addition to the support vessels a search and rescue (SAR) helicopter has been located at Barrow during the open water season when exploration activity and research have been undertaken. This SAR helicopter is shared between companies that are sponsoring the activities and shared between the activities being undertaken by each company. Since the SAR helicopter is not applicable to any one activity, it has been included as part of the owner's costs described earlier.

3.5.2.1.2.2 Manpower Requirements

Large seismic vessels can have about 60 to 90 persons onboard the vessel at any given time. In addition to the vessel crew and the technical (survey) crew, there would typically be one to two owners' representatives onboard the vessel and two to four marine mammal observers. There would be another crew of similar size that would be at home awaiting the next rotation cycle. A normal rotation for many of these vessels is three weeks, but according to one source, the long distance and cost of travel to and from Alaska waters is such that the companies have negotiated with the unions for a rotation cycle of four to five weeks. Large seismic vessels are generally homeported in the Gulf of Mexico or are foreign-flagged vessels. As a result, most of the vessel crew and a large number of the technical crew are from those regions. Several of the major companies that operate globally have offices in Anchorage and some of the technical crew positions may be filled by Alaska residents, but according to one respondent, the number of

Alaska residents on board these vessels is limited. Marine mammal observers in Arctic waters generally consist of one to three local (North Slope Borough) residents and the same number of Alaska residents who reside elsewhere in the state. In subarctic waters the marine mammal observers are most often from Southcentral Alaska where the major environmental consulting firms are located.

During mobilization and demobilization to Alaska waters, the large seismic vessels may travel with only the vessel's crew onboard. The technical crew meets the vessel at Dutch Harbor/Unalaska or Nome or Kotzebue, depending on the survey plan.

Guard boats and supply boats generally have a crew of 12 to 14 persons and are generally on the same rotation schedule as the large seismic vessel. Guard boats can accommodate a much larger number of passengers than the vessel crew because they are often used to transfer crews to and from the large seismic vessel as well as their normal guard duties. Two to four marine mammal observers are typical on the guard boats and supply boats. Guard boats may not be involved in supply activities, and thus can be foreign-flagged vessels until 2017, when the U.S. Coast Guard will require such boats to be U.S. vessels. Supply boats are considered to be engaged in coastwise trade and are required to be U.S. vessels under the Jones Act. MAG-PLAN assumes that all guard and supply vessels will be U.S.-flagged vessels in the future and generally from Alaska or the Pacific Northwest. Crews will be residents of those regions with marine mammal observers being the primary source of employment for residents of the primary onshore areas.

In some instances, companies have retained crew transfer boats to shuttle crews at rotation time. The crews of these boats have ranged from two persons operating small boats between West Dock on the North Slope and vessels anchored offshore a few miles offshore in deeper water, to larger boats with 14 crew that are engaged in overnight travel between a vessel's location in the Chukchi Sea and Kotzebue. The smaller boats operating in the Beaufort Sea are generally crewed by Alaska residents, while the larger crew boats have been from elsewhere in Alaska or the Pacific Northwest, and crews are generally residents of those regions. Generally seismic vessels operating in Alaska do not use helicopters for crew changes because the cost is much greater than the cost for a crew transfer vessel.

In addition to this onsite manpower, there are additional jobs created elsewhere for planning the survey, data processing, and report writing. In general, most of these jobs are located either in the Anchorage office of the company conducting the survey or in an office located elsewhere in the U.S. if a firm does not have an Anchorage office. Two to three full-time equivalent positions can be required for several months to complete this work both before and after the actual survey.

3.5.2.1.2.3 Costs of Activity

EMGS (2011b) reported a contract with Petrobas for a seismic survey charter offshore Brazil for a period of approximately one year with a value of $90 million. This suggests a day rate for a fairly long charter of almost $250,000 per day.

Offshore Shipping Online (2010) reported that Fugro-Geoteam entered into an agreement with Statoil USA E&P Inc. for the acquisition and data processing of a 2,400 square kilometer 3-D marine seismic program around Statoil's leases in the Chukchi Sea. The project valued was reported at approximately $26 million, with an estimated duration up to three months. The survey was to have taken place from approximately early August into October 2010. Using a 60-

day duration for the survey (early August into early October according to the article), the day rate for this effort would be about $450,000 per day. This cost likely includes extensive mobilization and demobilization costs, which would account for the longer project duration. The day rate may also include costs for one or both of the support vessels, but the day rate for seismic surveys in Alaska does not include fuel costs for the vessels. MAG-PLAN assumes a day rate range of $250,000 to $300,000, but estimated mobilization and demobilization days are charged at the same rate, so the effective day rate using the actual survey time is considerably higher than the range. The day rate does not include data processing costs, which can range up to several hundreds of thousands of dollars depending on the amount of data to be processed.

Day rates for guard, supply, and crew change boats range from $25,000 to $45,000 per day, with larger crew change boats being at the lower end of the range. Smaller crew change boats used near Prudhoe Bay can range from $6,000 to $8,000 per day. The guard and supply boats are generally hired for the duration of the survey plus mobilization and demobilization time. Crew change boats are only used during the crew rotation, which may occur once or twice during the survey. The smaller crew change boats used in the Beaufort Sea are located at Prudhoe Bay and do not incur any mobilization costs, but the larger crew change boats may incur mobilization and demobilization costs from Southcentral Alaska or the Pacific Northwest that are larger than the costs of the actual crew change activity.

3.5.2.2 Smaller Seismic Survey Program Vessel

Smaller seismic surveys are undertaken where the survey is of limited geographic scope and shorter duration. The seismic vessels used in these programs have less endurance (i.e., ability to stay at sea for extended periods of time) than their larger brethren and are typically less capable in terms of the number of streamers they can deploy, and data acquisition and processing capacity. These vessels are generally used for smaller 3-D and 2-D seismic surveys, and in shallower water depths.

3.5.2.2.1 Equipment

The M/V Polar Princess shown in Figure 24 is an example of the type of vessel used for smaller seismic surveys. The vessel is not considerably smaller than the larger vessels described above (e.g., the M/V Polar Princess is 250 feet in length compared to the Geo Celtic at 331 feet), but the vessel's seismic acquisition capabilities (shown with four streamers) are much less than more modern vessels that can handle 12 to 16 streamers.

Figure 24. M/V Polar Princess

Source: Fugro.com, 2011.

The M/V Polar Princess was built in 1985 and has a beam of 46 feet and accommodations for 60 persons. The vessel is operated by Rieber Shipping AS of Norway and charters the vessel to major seismic survey firms around the world.

The vessels used for these smaller seismic surveys are also accompanied by guard vessels similar to those described above for the larger seismic survey program. However, they typically do not have supply vessels since the programs are of shorter duration.

3.5.2.2.2 Manpower Requirements

As noted above, the Polar Princess can accommodate 60 persons, so the vessel crew is likely about 50 with the balance of the berths available for owners' representatives, marine mammal observers, and others. One respondent indicated that smaller seismic survey vessels can have crews ranging from 30 to 40 persons. The rotation for the crews is similar to those described earlier for the larger vessels.

The manpower requirements for the guard boats would be the same as described for the larger survey program.

3.5.2.2.3 Costs of Activity

The costs for chartering smaller seismic survey vessels can range from $50,000 to $60,000 per day for the vessel, but the total cost for a 30-day, 2-D single streamer survey can exceed $6 million or $200,000 per day according to one respondent. This $6 million cost would include substantial mobilization and demobilization costs in addition to the 30-day survey project.

The $25,000 to $45,000 per day costs for the guard boat are similar to those reported above for the large seismic survey programs.

3.5.2.3 Ocean Bottom Cable Seismic Survey Program

Ocean bottom cable (OBC) is a relatively new technology that is being used in nearshore, very shallow waters of the Beaufort Sea or where the water depths are too deep to have static (shorefast or bottom-fast) ice. The technology was used by BP Alaska to obtain more detailed information to be used in its drilling program for the ultra-extended reach wells at Liberty (BP

Exploration (Alaska) Inc., 2007). The technology reportedly provides better data than over-ice or through-ice seismic survey programs that were used in the past.

3.5.2.3.1 Equipment and Material Requirements

The OBC seismic survey requires the use of multiple vessels—typically two or more vessels for cable layout/pickup, one for recording, one or more for shooting, and several additional vessels for crew change, accommodations, and survey management/safety. According to the permit application filed by BP for their OBC program, the following vessels were to be used for their 2008 program:

- Source vessels: M/V Peregrine and M/V Maxime
- Recorder boat/barge: M/V Hook Point and the Alaganik barge
- Cable boats: F/V Canvas Back, F/V Cape Fear, F/V Rumple Minze, And F/V Sleep Robber
- Health, safety, and environment (HSE): M/V Weather or M/V Knot
- Crew transport: M/V Qayak Spirit and M/V Arctic hawk
- Crew housing and fuel: M/V Arctic Wolf

The following figures show some of the vessels used in BP's OBC seismic survey. The M/V Peregrine shown in Figure 25 is 90 feet in length with a beam of 24 feet, and the vessel is homeported in Homer Alaska. The vessel has berths for up to 13 people, but for the OBC seismic survey accommodated nine persons (LGL Alaska Research Associates, Inc., et al, 2008).

Figure 25. M/V Peregrine

Source: mvperegrine.com

The M/V Hook Point and the barge Alaganik are primarily used for commercial fish tendering and providing ice to fishing vessels. The combination has oceanographic research certification. The Hook Point is a tugboat that is used to power the Alaganik barge. The Alaganik barge was equipped for this seismic survey to be used for recording and equipment staging. The Alganik barge is 80 feet in length with a beam of 24 feet and the M/V Hook Point is 32 feet in length with a beam of 15 feet.

Figure 26. M/V Hook Point and Alaganik Barge

Source: LGL Alaska Research Associates, Inc., et al, 2008.

Figure 27 shows some of the vessels used in the OBC; from left to right: Qayaq Spirit, Mariah B, Cape Fear, Rumple Minze, Canvasback, and Sleep Robber. The M/V Qayaq Spirit is 42 feet in length with a beam of 14 feet and was used as a crew transfer vessel. It has a beachable aluminum hull with seating for 34 people. The F/V Mariah B was used as HSE support and as a backup for crew transfers. The vessel is 34 feet in length with a beam of 13 feet. The four cable boats are similar commercial fishing vessels of the bowpicker style from the Bristol Bay fishery with a length of 32 feet and beams of 12 to 14 feet.

Figure 27. Subset of Vessels Used in Ocean Bottom Cable Seismic Survey

Source: LGL Alaska Research Associates, Inc., 2008.

The M/V Arctic Wolf is a multipurpose, shallow-draft, ice strengthened landing craft with a steel hull. The staterooms generally accommodate 24 people; however, the staterooms were modified for this survey to house more than 30 as the vessel was used primarily to accommodate seismic crew (LGL Alaska Research Associates, Inc., et al, 2008).

Figure 28. M/V Arctic Wolf

Source: LGL Alaska Research Associates, Inc., et al, 2008.

3.5.2.3.2 Manpower Requirements

The number of persons on the vessels ranges from two persons on the cable boats to seven persons on the source vessels during operations. Several vessels were used to house the survey crew and others, so the number of persons onboard may have been greater than that needed for the vessel to operate. Marine mammal observers were on several of the larger vessels. In total, about 50 persons are engaged in the OBC activity and if the program exceeds 4 weeks in duration, slightly less than this number of persons would rotate to the site to replace the existing crew. Marine mammal observers are typically hired for the season and do not rotate with other seismic survey staff.

3.5.2.3.3 Costs of Activity

Information on specific ocean bottom cable seismic surveys was not obtained from interviews, nor were costs for such programs found during research efforts, so the estimated costs are derived from the day rates for the vessels, which were obtained from interviews or from the internet for the same or similar vessels, and increasing the day rates by about twice to more closely reflect the total seismic survey costs. The number of vessels and the subsequent vessel cost in the OBC is much greater than for the marine seismic surveys, so the ratios noted for those programs were not used for this type of seismic survey. Including owner's costs, a 30-day OBC program could cost about $6 million.

3.5.2.4 Geophysical Surveys

When any structure is placed on the seabed, a geohazard assessment has to take place; this assessment aids the engineering design and planning for platform installation and infrastructure. Geohazard assessments consist of geophysical surveys, discussed in this report subsection, and geotechnical surveys, which are discussed in the following subsection.

Bathymetry data are used to identify features on the seabed that may be of concern, such as sand waves, signs of mass movement and large obstructions. This bathymetry mapping is complemented with data gathered using other instruments such as side-scan sonar, which generally offers a higher resolution of the seabed and is used to identify smaller items of debris or obstructions that may impact directly on infrastructure. High resolution seismic surveys are also used to identify hazards or constraints in the top-hole section of a well, and to identify potential areas of shallow gas and any other geological limitations to drilling such as faulting or channeling.

3.5.2.4.1 Data Sources

Two global companies that provide geophysical and geotechnical services in Alaska provided information on this activity, supplemented by internet research for permit applications for this activity and of the vessels that are used for geophysical research.

3.5.2.4.2 Geophysical Program Vessel

Interviews and a review of permit applications revealed that some of the geophysical programs were carried out by vessels that were specifically designed for such research, while other vessels were retrofitted to conduct this activity. The vessels and programs varied in duration and cost, so this subsection provides information on vessels designed for such research as well as information on vessels retrofitted for geophysical research.

3.5.2.4.2.1 Equipment and Material Requirements

The R/V Alpha Helix is an oceanographic research vessel built in 1966 (see Figure 29). Its overall length is 40.5 m (133 ft) and the width is 9.4 m (31 ft), and the vessel has an ice-class hull. The vessel operates with a crew of 8 to 10 depending on the mission, and can accommodate 19 to 21 other persons. After operating the R/V Alpha Helix for 27 years, the University of Alaska Fairbanks sold the vessel in August 2007 to Stabbert Maritime, which currently charters the vessel for work in Alaska and elsewhere. As noted earlier, the vessel has also been used for environmental research in addition to geophysical surveys.

Figure 29. R/V Alpha Helix

Source: Stabbert.maritime.com, 2011.

StatOil, Inc. used the R/V Alpha Helix to assist the M/V Henry Christoffersen to conduct shallow hazard surveys in the Beaufort Sea in 2007. The Alpha Helix later assisted the Cape Flattery during shallow hazards surveys in the Chukchi Sea.

The Mt. Mitchell was used in a geophysical survey for Shell in 2009 (see Figure 30). The vessel is 231 feet in length, has a beam of 42 feet, and has an ice-class hull.

Figure 30. R/V Mt. Mitchell

Source: Global Seas Corporation, 2010.

Formerly a NOAA survey ship, the Mt. Mitchell was completely refurbished in 2003 with upgrades to electronics, machinery, and safety equipment. The Mt. Mitchell has been used for oceanographic research and mapping, sub bottom surveys, fiber-optic cable route surveys, remotely operated vehicle support, geophysical research, and biological surveys in Alaska and elsewhere in the Pacific.

The Cape Flattery (See Figure 31) was originally built as an offshore supply vessel, and has been converted to conduct bathymetry and sidescan sonar surveys and other research activities. The vessel has an overall length of 56.7 m (186 ft) and a width of 12.2 m (40 ft). The Cape Flattery conducted shallow hazards and site clearance surveys for Shell Offshore Inc. in the Chukchi Sea in 2008.

Figure 31. R/V Cape Flattery

Source: LGL Alaska Research Associates, Inc. et al, 2009.

The M/V Henry Christoffersen (Figure 32) is a combination pusher – tower Canadian tug vessel that primarily operates on Great Slave Lake and the MacKenzie River to the Beaufort Sea. The vessel is 153 feet in length with a beam of 52 feet (Northern Transportation Company Limited, 2011). The Henry Christoffersen conducted shallow hazards and site clearance surveys in the Beaufort Sea during the 2007 open-water season.

Figure 32. M/V Henry Christoffersen

Source: LGL Alaska Research Associates, Inc. et al, 2009.

3.5.2.4.2.2 Manpower Requirements

As noted earlier, the Alpha Helix has a crew of eight to ten persons depending on the type of voyage that is being undertaken, and can accommodate 19 to 21 other persons for a total of 29 individuals.

The Mt. Mitchell can provide for up to 49 survey crew and associated staff, and ship's crew of 11 for a total berthing compliment of 60, fully occupied. In the 2009 survey, the vessel had 15 crew, 14 survey technicians, 6 marine mammal observers, and 3 owner's representatives for a total of 38 persons.

The Cape Flattery has a berthing capacity of 10 crew and 30 passengers (expandable to 48) (pacific4u.homestead.com, 2011).

The Henry Christoffersen has accommodations for 13 crew and 5 other persons (Northern Transportation Company Limited, 2011). The limited berthing capacity is likely the reason that the Alpha Helix assisted the Henry Christoffersen in conducting the survey in 2008.

Manpower requirements for geophysical operations were reported to range from 25 to 39 persons including the ship's crew, the technical survey crew, marine mammal observers, and owner's representatives, with a 4-weeks on and 4-weeks off rotation schedule for all except the marine mammal observers, who are hired for the season.

3.5.2.4.2.3 Costs of Activity

The day rates for these vessels were reported from several different sources, and the varying rates that were reported likely reflect changes in supply and demand for these vessels over time. The reported day rates for the vessels ranged from about $25,000 to $35,000 for surveys conducted over different years. For a 60-day geophysical program, this would result in a vessel cost of about $1.5 million to $2.1 million plus mobilization and demobilization costs. Based on interview information, the total cost for a 60-day geophysical program, which would clear about four drill sites, is estimated to range from about $5 million to $6 million. The cost for a 30-day program, which would clear two drill sites, could range from about $3 million to $4 million.

3.5.2.5 Geotechnical Surveys

Geotechnical surveys are generally the last of the site surveys to be conducted prior to exploration drilling. Soil characteristics can be determined using coring and cone penetrometer testing equipment deployed from vessels or barges. The sampling program can be designed in the field to "ground truth" the interpreted acoustic data, and assist in establishing a more accurate model of sea bottom conditions. This information is used to establish design and engineering parameters for projects such as platform installation and pipeline or cable installation. Geotechnical soil investigations are performed to collect detailed data on seafloor sediments and geological structure to a maximum depth of 100 m. These data are then evaluated to help determine the suitability of the site as a drilling location. According to one global geotechnical firm, it takes about one week to complete a geotechnical investigation for one drill site.

3.5.2.5.1 Data Sources

Two global companies that provide geophysical and geotechnical services in Alaska provided information on this activity, supplemented by internet research for permit applications for this activity and of the vessels that are used for geophysical research.

3.5.2.5.2 Geotechnical Program Vessels

Vessels that are originally designed as geotechnical vessels are permanently equipped with a full suite of drilling, sampling, and in-situ testing equipment. These vessels are also typically equipped with a geotechnical laboratory for onboard testing of soil samples, analysis, and report production. They have an opening in the hull, giving access to the water and seabed below.

Barges and other multipurpose vessels are also used for geotechnical investigations in some situations, and these vessels are often retrofitted to enable the use of a drill rig and other equipment. In some locations, geotechnical programs have been conducted over the ice when shorefast or bottomfast ice is present. This section focuses on vessels since most nearshore prospects have already been explored and industry is moving into deeper waters offshore Alaska.

3.5.2.5.2.1 Equipment Requirements

This subsection describes some of the vessels that have been used for geotechnical investigations in Alaska during the past few years. Statoil contracted with Fugro who planned to use the vessel M/V Fugro Synergy to complete a geotechnical program in 2011. Three to four bore holes were to be drilled at each of up to five prospective drilling locations on Statoil's leases and up to three boreholes were planned to be completed at each of up to three potential drilling locations on leases jointly owned with ConocoPhillips Alaska, Inc. This would result in a maximum total of 29 bore holes to be completed as part of the geotechnical soil investigation program (USDOC, 2011).

Figure 33. M/V Fugro Synergy

Source: Fugro Well Services, Ltd., 2011.

Fugro Synergy, which was built in 2009, is 103 meters (338 feet) in length and is 20 meters (66 feet) in width. The vessel is capable of doing geotechnical investigations as well as top hole drilling, installing conductor and surface casing (sometimes intermediate casings), installation of subsea templates, pilot hole drilling, construction work, pulling and connecting flowlines, handling Christmas trees, and well abandonment services.

The R/V Seaprobe, another Fugro vessel, transited from the Gulf of Mexico to the Chukchi Sea to conduct a geotechnical program for Shell Offshore, Inc. in 2009. The vessel is 190 feet in length with a beam of 40 feet.

Figure 34. R/V Seaprobe

Source: Fugro.com, 2011.

3.5.2.5.2.2 Manpower Requirements

The Fugro Synergy has berths for 70 people while the R/V Seaprobe has accommodations for 25 persons including 9 ship's crew and 16 other persons. Discussions with two firms that conduct these geotechnical programs suggests that manpower requirements for typical geotechnical programs can vary from 21 persons, including ship's crew, to about 45 persons. The duration of the programs was cited as lasting from two weeks to two months in Arctic waters, depending on the number of drill sites to be cleared and miles of pipeline routes to be investigated. In subarctic waters the geotechnical programs could extend for longer periods of time if needed.

3.5.2.5.2.3 Costs of Activity

Activity costs vary substantially depending on the type of geotechnical investigation being conducted. Over-the-ice investigations were cited as costing less than $2 million since there are no vessel costs, particularly no mobilization and demobilization costs. All of the equipment necessary for an over-the-ice geotechnical investigation are staged on the North Slope and are similar to the equipment used for onshore geotechnical investigations. In contrast, sources indicated that the costs for marine geotechnical investigations can range from about $240,000 to approximately $450,000 per day, depending on the vessel and mobilization and demobilization costs. Shorter duration investigations are generally at the high end of the range due to the fact that there are fewer days over which to cover the mobilization and demobilization costs, and longer duration investigations are near the low end of the range. Total costs for a 30- to 60-day program can range from approximately $5 million to over $7 million.

3.5.2.6 Onshore Support Activities

Seismic survey and site survey vessels typically stage from Dutch Harbor/Unalaska to conduct work in the Chukchi and Beaufort Seas. If necessary, vessels operating in the Chukchi Sea may be resupplied by another vessel from Dutch Harbor/Unalaska or Nome. The cost for these supply vessels was cited earlier in the report. Vessels operating in the Beaufort Sea may be resupplied and refueled by another boat operating from one of several docks in the Prudhoe Bay area. Seismic and site clearance vessels typically have drafts that are deeper than the water depths at the Prudhoe Bay dock, so a shallower draft vessel or tug and barge must be used to lighter fuel and supplies to the seismic and site clearance vessels. Some seismic and site clearance programs have a supply boat, as reported earlier in the document, while other purchase necessary fuel and supplies from vendors at Prudhoe Bay. These refuel and resupply activities are minimal in terms of the total level of activity and sales that occur at the Unalaska/Dutch Harbor or Prudhoe Bay docks and do not require additional manpower or facilities at the existing support facilities.

3.5.3 Exploration Activities

This report section describes the various exploration platforms that have been used, or may be used in Alaska OCS waters and also provides information on the vessels, other equipment, and onshore facilities that are used to support the exploration platforms.

Exploration drilling for oil and gas in the Beaufort Sea began from gravel islands in shallow Alaskan State Waters in the late 1960s and similarly in the Canadian Beaufort Sea in the early 1970s. With time, activities progressed into deeper waters. In 1976, ice reinforced drillships were first utilized in Canadian waters, followed in 1981 by the first use of a bottom-founded caisson system. Exploration activities commenced in Beaufort OCS regions in 1982 using gravel islands, ice islands, bottom-founded structures and drillships.

3.5.3.1 Exploration Platforms by Water Depth

MAG-PLAN has three water depth ranges, less than 10 meters, 10 to 25 meters, and greater than 25 meters. Specific platform types have been identified for each of these ranges for modeling purposes, but it should be recognized that each of these platform types might be used in two or even all three of these water depth ranges.

3.5.3.1.1 Data Sources

The primary source of information for these platform types is derived from secondary sources, particularly exploration plans and permit applications that have been submitted over the past few years. Other secondary sources, such as IMVPA's 2008 report for BOEM, have been used to develop information for platform types that have not been cited in recent exploration plans or permit applications. Information on drilling costs and labor requirements is based on an interview with a major drilling company that operates on the North Slope and offshore.

3.5.3.1.2 Less Than Ten Meters

Four platform types have been modeled for water depths of less than 10 meters. These include extended reach drilling, ice islands, jack-up rigs, and other mobile drilling structures, which can be either floating or gravity based. Each of these platform types is described in the following subsections along with manpower requirements and the costs of these structures.

3.5.3.1.2.1 Platform Types

Extended reach drilling (ERD) is directional drilling of very long horizontal wells. The aims of ERD are to reach a larger area from one surface drilling location, and to keep a well in a reservoir for a longer distance in order to maximize its productivity and drainage capability. The most publicized example of extended reach drilling in Alaska is the Liberty field in the Beaufort Sea, which is being developed by BP Alaska, Inc. The Liberty field is located about five miles off the Alaska coast, but will be accessed from BP's Endicott satellite drilling island, a man-made gravel island that was enlarged to accommodate the drilling activities and production facilities for the Liberty field. The ERD used to develop the Liberty field will extend the reach of the wells to distances of 34,000 to 44,000 feet, distances which are sometimes noted as ultra-extended reach drilling or uERD. While the use of ERD at Liberty is for development, ERD can also be used for exploration in nearshore waters although the cost of an ERD exploration well can be very high. ERD is similar to any land based drilling operation in Alaska with the primary exception that ERD requires very powerful drilling rigs that can turn the drill pipe that extends long distances and under great pressures. The Liberty drilling rig has a top drive rated at 105,000 foot-pounds of torque—a typical North Slope rig has a top drive rated at around 40,000 foot-pounds (Greeningofoil.com, 2010).

Nearshore oil and gas exploration activities from ice islands started in the Beaufort Sea in the1970s. The first grounded ice island in Alaska waters was built by Union Oil in Harrison Bay, Alaska in the winter of 1976/1977 by flooding the ice with a thin layer of seawater, letting the ice freeze, continuing the flooding process until the ice thickness grounded on the seafloor, and then continuing until the necessary vertical height above sea level was achieved. Grounded ice islands have generally been constructed in less than 9m water depth. Spray ice systems were used to form protection structures around grounded drilling structures such as the CIDS platform offshore Alaska in the mid 1980s. The development of ice island construction in the Arctic has clearly shown that the use of spray ice provides substantial productivity advantages over flooding techniques, and Figure 35 shows Amoco's Mars ice island, which was the first use of an island built completely from spray ice for exploratory drilling in Harrison Bay in 1986. Ice islands cost about half of the cost of a gravel island (C-Core, Inc., 2005) and are now the platform of choice for exploration wells in shallow, nearshore waters of the Beaufort Sea.

Figure 35. Amoco's Mars Ice Island

Source: Minerals Management Service, 2011.

Jack-up rigs are popular exploration platforms and are used globally, although jack-ups have not been used in the Beaufort Sea to date. ConocoPhillips proposes to use a jack-up rig similar to the GustoMSC – CJ50 shown in Figure 36 for its proposed 2012 exploration program in the Chukchi Sea. This particular version is capable of operating in 400-foot water depths in moderate environments and 300-feet in harsh environments (such as the Chukchi Sea).

Figure 36. GustoMSC – CJ50 Jack-up Rig

Source: GustoMSC, 2011.

Jack-up rigs are popular exploration platforms because the platform can be towed or transported to a drilling location and the three legs can then be lowered to the sea bed and within one to two days after arrival the platform can begin drilling operations. A jack-up rig is the only exploration platform described in this section that is not suitable for operations in ice conditions. Therefore, if substantial ice sheets were noticed moving toward the location of a drill site, the drilling operations could be discontinued, the legs raised and the AHTS vessel and potentially the ice management vessel could tow the platform to a safe location within 24 to 48 hours.

A jack-up rig is currently being used to drill exploration wells in Cook Inlet. Escopeta has transported the Spartan 151 drilling rig (See Figure 37) from the Gulf of Mexico to Cook Inlet this summer and is drilling a well in the fall of 2011. Ice conditions also exist in upper Cook Inlet, and the regulatory agencies are requiring the platform to be moved offsite and stored for the winter in a safe location. If needed, the well will be reentered in the spring of 2012 and drilling completed in late spring or early summer.

Figure 37. Spartan 151 Drilling Rig

Source: Spartan Offshore Drilling, 2011.

The Spartan 151 can operate in as little as 12 feet of water or in up to 150-feet of water.

As noted earlier, mobile drilling systems (MDS) can be bottom founded (gravity-based structures) or floating platforms. The two examples described in this section are designed for water depths greater than ten meters but are shown here to provide an example of the concepts that may be used in the future. The Kulluk, which Shell is proposing to use in its 2012 exploration program in the Beaufort Sea, is an example of a floating system (See Figure 38), while the concrete island drilling structure (CIDS) exemplifies a gravity based structure.

Figure 38. Conical Drilling Unit Kulluk

Source: Shell, 2011.

The Kulluk was designed to extend the drilling season available to more conventional floating vessels by enabling drilling operations to be carried out during the spring breakup, open water conditions, and well into early winter ice conditions in Arctic waters. Kulluk can maintain its location for drilling operations in moving first-year ice with a thickness of four feet. With ice management support vessels, the Kulluk can maintain location in more severe conditions. The Kulluk maintains its position with a 12-point anchoring system.

Gravel islands and bottom-founded structures have accounted for more offshore wells in the Beaufort Sea than other platform types. Gravel islands have already been discussed in this report section, and bottom-founded structures are described here. In total, five separate bottom-founded structures have been deployed in the Beaufort Sea:

- Tarsiut Caisson-Retained Island or Tarsiut Caissons (concrete caissons)
- Single-Steel Drilling Caisson (SSDC) (steel structure with later addition of steel MAT)
- Caisson-Retained Island or CRI (steel caissons)
- Molikpaq Mobile Arctic Caisson or MAC (steel caisson)
- Beaufort Sea I Concrete Island Drilling System or CIDS (steel-concrete structure).

These structures were conceived primarily to extend the depth capability of artificial islands. The caisson-retained islands were formed by building an underwater berm and then backfilling the caisson systems with a core of dredged material. Compared to conventional island-building up to that time, the amount of fill required to achieve stability was significantly reduced. As well, the effects of wave and current erosion during the open-water season were reduced. However, these structures still required significant field operations to construct the berms, deploy, backfill, densify the core (Molikpaq requirement), decommission, and move. Although touted as mobile structures, the caisson structures were not true mobile offshore drilling units (MODUs).

The SSDC was the first MODU-type structure in the Beaufort Sea, coming into service in 1982, and with the addition of the MAT remains the only active bottom-founded exploration structure in the arctic offshore. The SDC, as it is now known, has drilled eight arctic wells in total, with 2 occurring in the last decade—the McCovey well (2002-03) season, and the Paktoa well (2005-06).

The industry's first caisson-retained island was installed by Canadian Marine Drilling Ltd. (CANMAR) at the Tarsiut location in the Canadian Beaufort Sea. The Tarsiut Caissons comprised four concrete caissons (see Figure 3 54) set down on an underwater sand berm in 69 ft (21 m) of water, and then infilled and backfilled with dredged material. The structure was used for only one drilling season, 1981 – 82, although the structure did serve as an ice engineering research platform the following season. The Tarsiut Caissons were decommissioned near Herschel Island in the mid-1980s, where they remain.

Figure 39. Tarsiut Concrete Caissons during Installation and in Service

Source: IMV Projects, 2011

The experience with the Tarsiut Caissons led CANMAR to develop a fully-mobile, water-ballasted concept for year-round drilling. The SSDC was fabricated by modifying the forward half of a very large crude carrier (VLCC) and the name Single-Steel Drilling Caisson (SSDC) was adopted to differentiate it from the multiple concrete caissons used at Tarsiut. In 1986, the SSDC was modified to prepare it for deployment in the U.S. Beaufort Sea. It was mated with a steel MAT substructure to eliminate the need for foundation preparation (subsea berms) and functioned as a single unit called the SSDC/MAT. In recent years, with a change of ownership, the structure (including MAT) has been renamed the SDC. The structure is a MODU and all drilling and topsides facilities are permanently affixed to the deck, resulting in simpler and faster mobilization for drilling operations. Of the 19 deployments of bottom-founded structures in the U.S. and Canadian Beaufort Sea, eight were those of the SDC.

Figure 40. SSDC (left), MAT Substructure (Top Right), SSDC/MAT (Bottom Right)

Source: IMV Projects, 2011

Similar to the Tarsiut Caissons, but built with steel instead of concrete, the Caisson-Retained Island (CRI) was conceived and built by Esso Resources Canada and first deployed in 1983. The CRI was developed to reduce the amount of dredged material and was comprised of eight individual hinged steel caissons placed in a ring and held together with steel wire cables. Like the Tarsiut Caissons, the core of the CRI was filled with dredged material to provide the base for drilling operations and provide resistance to wave and ice loads. The CRI was deployed three times in the Canadian Beaufort Sea from 1983 to 1987. The structure has not been active since that time.

Figure 41. Esso's Caisson-Retained Island (CRI)

Source: IMV Projects, 2011

The Molikpaq, developed by Gulf Canada Resources, took the Esso steel caisson-retained island concept one step further. The structure is a monolithic, water-ballasted steel annulus with a self-contained deck for drilling and topsides facilities, but unlike the fully water-ballasted SSDC and CIDS, Molikpaq relied on a densified sand core to provide the bulk of its resistance to environmental loads. Like the Tarsiut Caissons and the CRI, Molikpaq is not a true MODU. The unit began operations in 1984 and drilled four locations in the Canadian Beaufort Sea. It was mothballed in 1990 and later modified and redeployed in 1997 as a permanent production facility in the Sea of Okhotsk off Sakhalin Island, Russia. The only Beaufort Sea production was from Amauligak with Molikpaq, when during extensive well testing they loaded a tanker and it offloaded in the south.

Figure 42. Molikpaq in the Beaufort Sea and as Modified for Sakhalin

Source: IMV Projects, 2011

The CIDS, also known as the Glomar Beaufort Sea 1, was a steel-concrete hybrid structure consisting of a steel base topped by a concrete mid-section at the ice belt and two steel deck sections. Like the SDC, the unit was a MODU and was ballasted with water only. It was designed and fabricated at the Nippon Kokan K.K. shipyard in Japan at a total cost of $75 million. In 1984, the platform was delivered to the Beaufort Sea in Alaska to drill shallow-water exploration and appraisal wells. The CIDS platform was leased to Exxon Mobil for $45 million per year (Yee Precast Design Group Ltd., 2010).

The CIDS was deployed at three locations in the US Beaufort Sea, the last in 1997. In 2001, the structure was towed to Russia for refurbishment, renamed the Orlan, and, like the Molikpaq, now operates as the permanent production platform Orlan in the Sea of Okhotsk, offshore Sakhalin Island.

Figure 43. CIDS in the Beaufort and Under Tow to Sakhalin Island

Source: IMV Projects, 2011

The Canadian east coast operating environment is harsh—characterized by high winds and waves, icebergs, and seasonal sea ice. Located in the Jeanne d'Arc Basin, approximately 350 kilometers southeast of St. John's, Newfoundland and Labrador, field developments in this region are remote.

Presently, the only permanent bottom-founded structure employed offshore Newfoundland and Labrador is the Hibernia platform. However, the Hebron gravity-based structure is scheduled to produce first oil in 2017 (ExxonMobil Properties, 2011).

The Hibernia field was discovered in 1979 and first oil was achieved in November 1997. Recoverable reserves for Hibernia are estimated to be 1.244 billion barrels (Department of Natural Resources, 2007). Hibernia field development capital expenditures amounted to $5.8 billion (Howell, 2007).

Shown in Figure 44, the Hibernia gravity-based structure weighs 1.2 million tonnes (HMDC, 2007), and is equipped with topside production and drilling facilities. The platform has a design production capacity of approximately 230,000 barrels of oil per day and has an oil storage capacity of 1.3 million barrels (HMDC, 2007). The platform is situated in approximately 80 meters of water.

The Hibernia gravity-based structure is a one-off design. To allow year-round production, the Hibernia platform is designed to withstand impact from sea ice and icebergs (HMDC, 2007). Although the probability of an iceberg colliding with the platform is low, Hibernia still employs an aggressive ice management strategy (HMDC, 2007).

Figure 44. Hibernia Platform

Source: HMDC, 2007

Located within water depths of 88 to 102 meters and located approximately 340 kilometers from St. John's, Hebron project area oil was first discovered in 1980 (ExxonMobil Canada Properties, 2011).

The Hebron platform (Figure 45) will be of post-tensioned reinforced concrete design, and will be built to withstand environmental loads associated with sea ice, icebergs, and metocean conditions. The platform will be equipped with production and drilling topside facilities, and will have a production capacity in the range of 150-180 thousand barrels of oil per day (kbopd) (ExxonMobil Canada Properties, 2011). Crude oil storage capacity of the platform will be approximately 1.2 Mbbl (ExxonMobil Canada Properties, 2011).

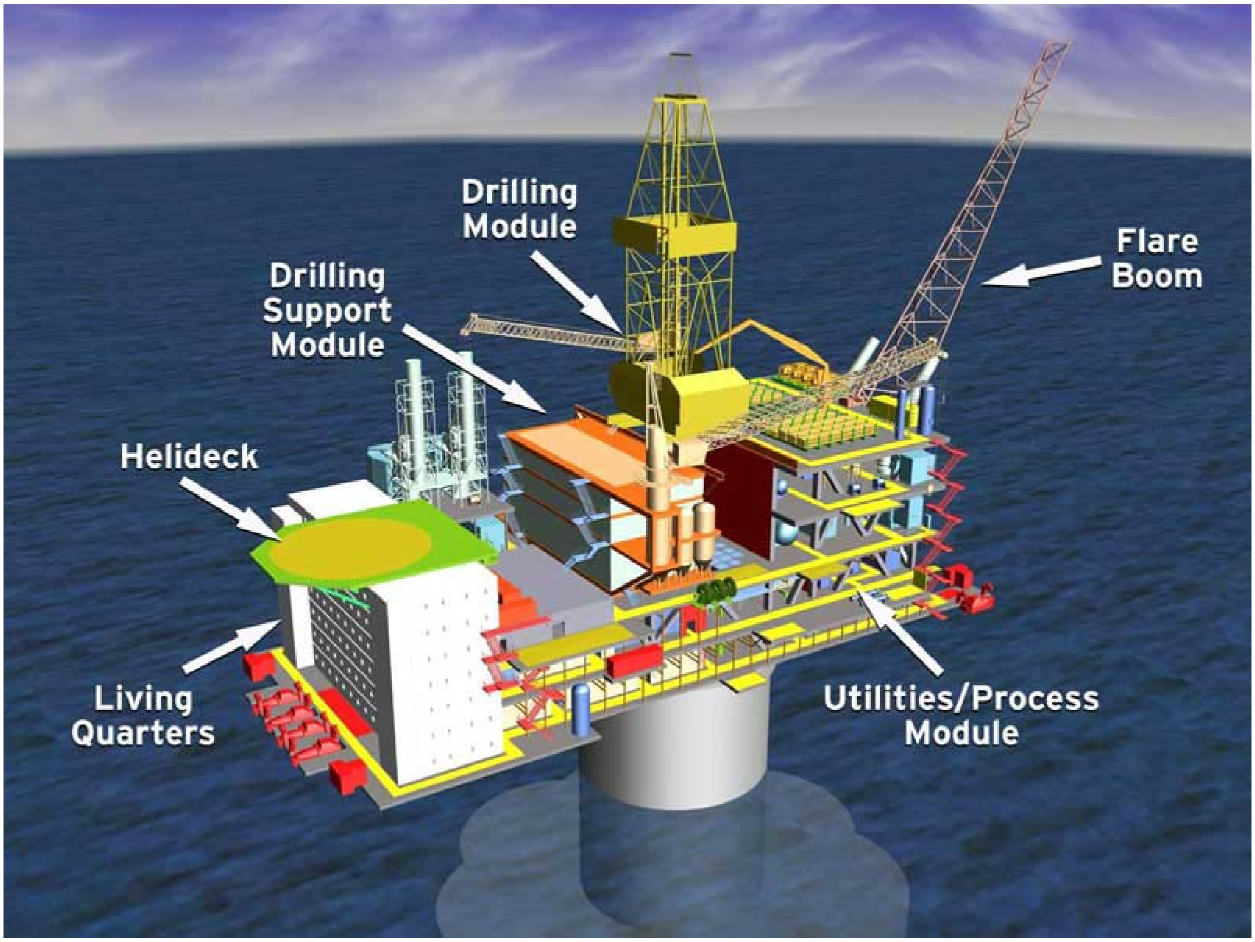

Figure 45. Hebron Platform

Source: ExxonMobil Canada Properties, 2011

Russian offshore oil and gas development has been focused in two areas, the sub-arctic region of Sakhalin Island and the Arctic Barents and Pechora Seas.

Offshore Sakhalin Island has seen significant oil and gas activity in the last decade with the development of Sakhalin I and Sakhalin II projects. Sakhalin I project employed the refurbished CIDS platform (now Orlan) as noted above, and as shown in Figure 46, the Sakhalin II project utilizes several gravity-based platforms for development.

The permanent offshore infrastructure installed for Sakhalin 2 includes a network of offshore pipelines and three bottom-founded production structures; the Piltun Astokh-A (PA-A) or Molikpaq, the Piltun Astokh-B (PA-B), and the Lunskoye A (Lun-A). These gravity-base platforms are designed to operate in six-month frozen seas, severe storms, significant seismic loading, and a combination of first-year sea ice, wind and wave loads.

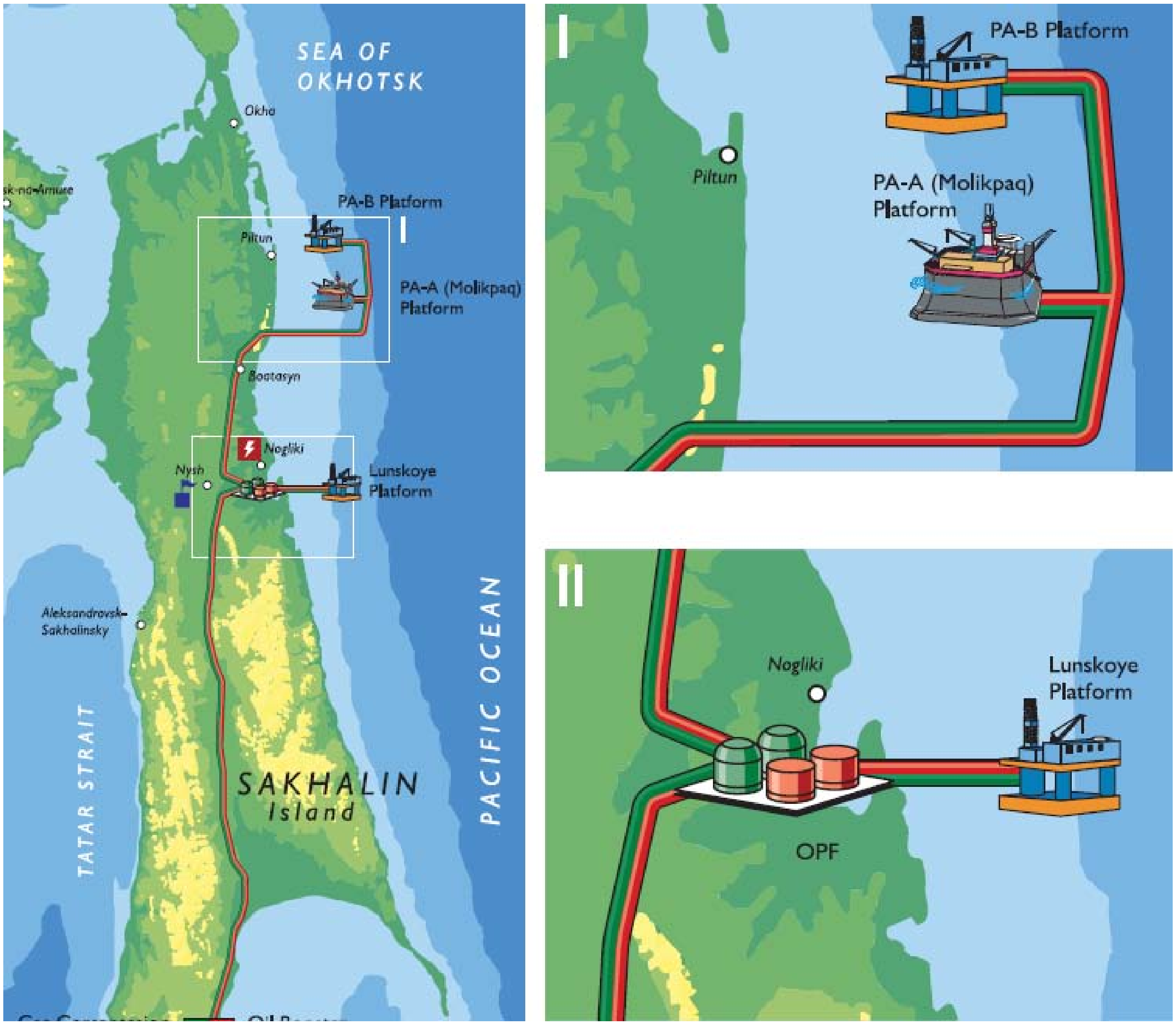

Figure 46. Sakhalin Island, PA-A, PA-B and Lun-A

Source: Sakhalin Energy, 2007

The Prirazlomnoye oil field contains oil reserves of 525 millions of barrels of oil, and lies approximately 60km offshore on the Pechora Sea shelf (Pennwell, 2009). The Prirazlomnoye gravity-base platform (Figure 47) is situated in approximately 20 meters of water, and is equipped for drilling, production oil storage services, and export. The target for annual field oil production is 43.8 million barrels or greater, while the platform will utilize associated gas production (PennWell, 2009).

For year-round operation, the Prirazlomnoye platform has been designed to withstand "severe climatic conditions and high loads." It is the first Russian-designed/built structure of its kind (Pennwell, 2009). The platform has an unballasted weight of 117,000 tons, measures 126 m wide by 126 m long, and can accommodate a crew of up to 200 (Pennwell, 2009). A special environmental feature of this platform is that it has a "zero discharge system for drilling and production waste" (Pennwell, 2009).

Figure 47. Prirazlomnoye Platform at Tow-out

Source: Pennwell, 2009

3.5.3.1.2.2 Manpower Requirements

While the total number of accommodations is reported for these platform types, the crew sizes reported in this section are for the crew that is required to maintain the drilling platform and support the drilling and production operations. The crew would include such positions as catering staff to prepare meals, maintenance staff for the platform and platform equipment, and maritime crew for ships and other vessels that can travel under their own power. The crew size does not include exploration drilling crews or ancillary crews that support drilling activities. Those persons are reported and modeled separately as part of exploration drilling activity. The drilling crew labor requirement is modeled separately in MAG-PLAN and would need to be added to the platform labor requirements described in this section to arrive at the total labor requirements on the rig.

Ice islands can be designed and built to accommodate the facilities, including accommodations that the operator believes will be necessary to handle the manpower needed at the drill site. Thus, the number of persons is not constrained as it is with the other platform types. The number of persons that can be accommodated is estimated to range from 120 to 150 depending on the operations that are ongoing. The crew size necessary to maintain the camp and related facilities is estimated to range from 24 to 30 persons. This crew size is similar to the crew estimated for the CIDS and the Kulluk, which have accommodations for 100 persons and 108 persons, respectively. The CIDS and the Kulluk were built in the 1980s when less technology was employed in drilling operations and fewer people were needed. The result of having a limited number of beds results in more helicopter flights to move people to and from the platforms as their specific services are required.

A review of secondary sources indicates that jack-up rigs can have crew sizes ranging from about 12 to 40 persons. The GustoMSC – CJ50 has accommodations for 150 persons, while other versions of this jack-up rig have accommodations for 120. In contrast, the Spartan 151 has accommodations for 57 persons.

The platform crew normally works 12-hour shifts, so half of the onboard crew would be on duty at any given time. The rotation schedule on these platforms is typically two weeks on and two weeks off, so the total number of persons employed for the platform crew would be double the onboard crew size. Approximately 48 to 60 persons might be employed as platform crew on ice islands or the CIDS or the Kulluk, and 24 to 80 persons might be employed as platform crew on jack-up rigs.

3.5.3.1.2.3 Costs of Activity

Typically, marine exploration platform costs are quoted as day rates that are the daily cost to the operator of renting the platform with the drilling rig and the associated costs of personnel and routine supplies. This cost may or may not include fuel, and usually does not include capital goods, such as casing and wellheads, or special services, such as logging or cementing. The cost for the drilling crew is typically in the day rate. In much of the world the day rate times the number of operating days and mobilization/demobilization days represent roughly half of the cost of the well. Similarly, the total daily cost to drill a well (spread rate) is roughly double the exploration rig day-rate amount. However, in Alaska, fuel is generally not included in the day rate and the lack of existing infrastructure and the high cost to support drilling operations results in total daily well costs being much greater than twice the day rate.

Estimating the cost for some of the platforms described here is difficult due to the fact that the Kulluk and the Liberty ERD drilling rig are owned by Shell and BP Alaska, respectively, and the fact that these are unique platforms and drilling rigs makes it difficult to estimate the day rates costs for this equipment with costs reported in other information sources.

For example, it is reported that BP is spending $1.5 billion to develop the Liberty field and that BP contracted Parker Drilling to construct the drill rig at a total cost of $215 million (GreeningofOil.com, 2010). In contrast, a more typical North Slope land-based drill rig capable of horizontal drilling, but not ultra-extended reach drilling, might have costs of about $72 million (Alaska Journal of Commerce, 2009). Exploration drilling on the North Slope is typically conducted from ice pads, which melt and have little effect on the environment. However, constructing an ice pad and ice road can take three to four weeks to complete, after the regulatory agencies have indicated that snow cover and freeze depth are sufficient for off-road travel, which can range from mid-December to mid-January. Then the drill rig, camp, and all other equipment and facilities and supplies are transported to the ice pad where set up and such can take several weeks before drilling operations commence. The drill rig and other equipment and facilities must be transported off the ice pad by mid-April to assure that the ice road is useable. Thus the exploration window is roughly 60-75 days for drilling activity. MAG-PLAN assumes that a 60-day drilling window is available for ERD activities on the North Slope. ERD in areas where gravel pads may be permitted for exploration activities could extend the drilling season to 90 days or more, but the costs for lengthy ERD exploration wells could exceed the cost of drilling from other platforms.

Interview responses from a major drilling company on the North Slope indicated that total daily costs for drilling a production well in Prudhoe Bay range from about $200,000 to $250,000 including owner's costs. Without owner's costs it is estimated that the total daily costs could range from about $150,000 to $200,000. Land-based exploration wells are more expensive because of the logistics required. Day rates for a complete ERD drilling rig and associated exploration camp facilities and equipment, but not labor, is estimated to range from about $240,000 to $290,000. Including mobilization and demobilization and owner's costs, an ERD exploration well with these estimates and a 60-day drilling period could exceed $25 million.

As noted earlier, ice islands have a significant capital cost advantage over gravel islands for exploration (See Figure 48). The historic cost for ice islands has been below $10 million, while costs for gravel islands are approximately double the ice island costs at similar water depths.

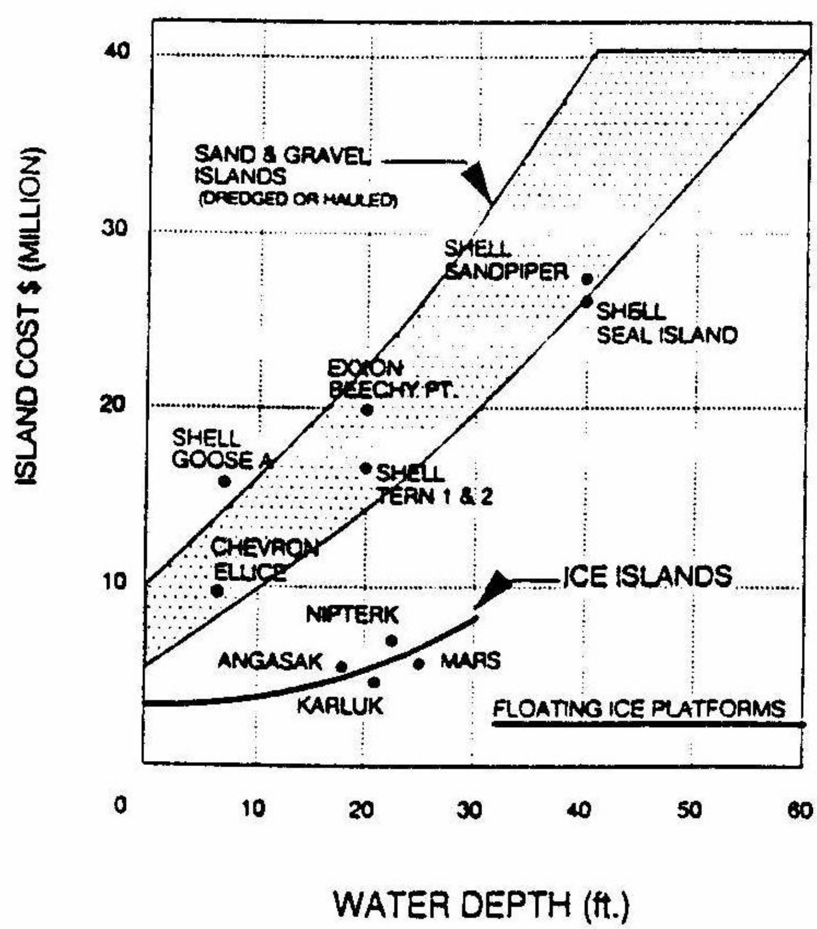

Figure 48. Capital Cost for Gravel Islands and Ice Islands by Water Depth

Source: C-Core, Inc., 2005.

MAG-PLAN is based on 2010 dollars, so the ice island construction cost information from the C-Core report was updated to 2010 dollars and results in the following capital cost curve.

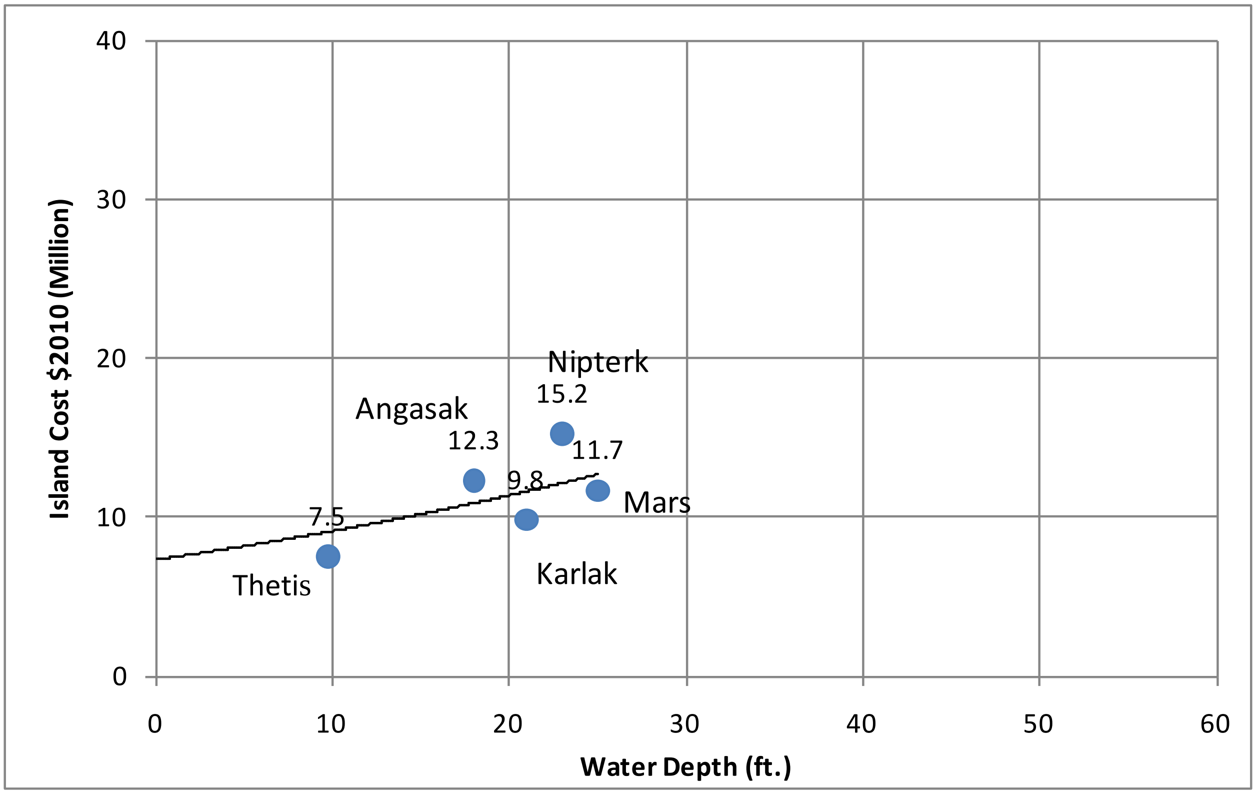

Figure 49. Ice Island Capital Cost in 2010 Dollars

Source: Northern Economics, Inc. estimates.

The cost of building the ice island and the associated ice road must also be added to the cost of the day rates for the drill rig, camp, and other facilities and equipment needed for drilling the well. Since the potential water depth is unknown, MAG-PLAN uses the average of the costs shown in Figure 49 ($11.3 million) for the ice island costs. The costs for the ice road are presented later in Section 3.5.3.3.

Cost information for jack-up rigs is readily available on the internet at the RigZone website, which provides daily quotations for average day rates for platforms including drill ships, jackups, and drill barges. The day rates for jackups depend on the type of equipment and the water depth that it is capable of operating in. The GustoMSC rig and the Spartan 151 are both independent-leg cantilevered platforms, or IC designation in the RigZone website. The average day rate for a jack-up rig capable of operating in less than 250 feet of water (Spartan 151) was noted as $63,000 per day, while those capable of operating in water depths greater than 300 feet (GustoMSC rig) were quoted at an average day rate of $141,000 per day (RigZone, 2011). For a 60-day drilling program, the costs for the jack-up rig could range from about $4 million to $8.4 million. However, mobilization and demobilization costs could double these costs, and these costs also do not include the costs for necessary support vessels and helicopters that are presented later in this subsection.

As mentioned above, the costs for other mobile drilling structures besides jack-up rigs that can operate in less than 10 meters of water are difficult to estimate since the current examples of such structures (i.e., the Kulluk and the CIDS) are designed for greater than 10 meters water depth and are older technologies and unique platforms with few comparables around the world.

In addition, the Kulluk is owned by Shell, so there are no public data on a day rate for the platform. However, the Kulluk has undergone extensive refurbishment to incorporate newer technologies and new equipment, which will result in a capital cost that is larger than the original purchase price, which is also not known. The unique capabilities of the Kulluk to operate in open water seasons and ice conditions also would contribute to a higher day rate for the platform.

It is anticipated that if initial exploration activities in the Beaufort and Chukchi Seas are successful, a new, modern ice-resistant mobile platform would be built for further exploration. The cost of such a platform is thought to be comparable to the cost of new modern deep water semi-submersibles, or about $500 million to $600 million in capital cost with a resulting day rate (capital amortization and operating costs) of about $460,000. With this cost as a marker, it is estimated that if the Kulluk were chartered on a day rate to a third party, the day rate might be in the vicinity of $310,000 per day, plus costs for the drilling crew and consumables. This range incorporates the present and future day rates for gravity-based platforms in the Arctic planning areas. In subarctic areas, ERD and jack-up rigs are considered the most likely exploration platforms now and in the future.

3.5.3.1.3 Between 10 Meters and 25 Meters

For water depths between 10 and 25 meters, MAG-PLAN anticipates that mobile drilling structures and jack-up rigs would be the preferred platforms. The mobile drilling structures (i.e., the Kulluk and the CIDS) described in the previous subsection of this report are examples of the type of structures that might be employed in this water depth of 10 to 25 meters. Similarly, the information for jack-up rigs mentioned above would be applicable to jack-up rigs operating in these water depths. As a result this report subsection does not report information for these platform types since it would be redundant.

3.5.3.1.4 Greater Than 25 Meters

In water depths greater than 25 meters, MAG-PLAN anticipates that jack-up rigs would still be used out to the design water depths for such platforms (400 to 500 feet) and the Kulluk mobile drilling structure could be used out to its rated water depth of 400 feet. Those platforms were described previously, so information for them is not repeated in this subsection. The additional platform types that are described in this subsection include drill ships, semi-submersibles, and a tripod Arctic floater (TAF), a conceptual mobile drilling structure that can operate in greater water depths than the Kulluk.

3.5.3.1.4.1 Platform Types

Shell has proposed to use the M/V Noble Discoverer (See Figure 50) for its proposed 2012 drilling program in the Chukchi Sea. The Noble Discoverer is owned and operated by Noble Drilling, but the drill ship is under a long-term charter to Shell. The Noble Discoverer is a single hull vessel that has been converted to an ice-class vessel by adding sponsons at the waterline to provide ice protection and stiffen the hull, internally strengthening the bow, and adding heat tracing and insulation to exposed lines. The vessel has undergone other refurbishment to reduce air pollution from the ship's engines. The Noble Discoverer is turret-moored, with a symmetric, eight-point anchor pattern. Thrusters allow the ship to rotate around the turret and face the bow into ice or weather. Even though the vessel is an ice-class vessel, it is only expected to operate in the summer open water season. If ice conditions suddenly became too severe, the ship can quickly disconnect the anchoring system and move off site.

Figure 50. Drill Ship Noble Discoverer

Source: Shell, 2011.

Semi-submersibles are another option for water depths greater than 25 meters. A number of new semi-submersibles are capable of dynamic positioning by the use of thrusters and can also move at 6 to 8 knots per hour with the use of the thrusters. As a result, modern semi-submersibles can avoid severe ice conditions, but they are more likely to operate in subarctic waters where ice is not as prevalent. Older semi-submersibles that operate in shallower water depths are more likely to be anchored and towed by several vessels if necessary to avoid ice. Figure 51 shows the West Alpha, a semi-submersible owned by Seadrill. The West Alpha is rated to 2,000 feet water depth and it operates in the North Sea, which is considered a harsh-environment operating area. Most of the newer semi-submersibles that are being built are rated to 10,000 feet or more in order to operate in the deep waters of the Gulf of Mexico, Brazil, and Angola.

Figure 51. West Alpha Semi-Submersible

Source: Seadrill, 2011.

3.5.3.1.4.2 Manpower Requirements

The Noble Discoverer has accommodations for 124 persons. West Alpha has accommodations for 114 persons. The crew size for drillships and semi-submersibles was found to range from 30 crew onboard an older semi-submersible to 63 persons onboard a new modern drillship. More frequently, the crew size was in the 40 to 50 person range, with drill ships typically having more crew than semi-submersibles.

3.5.3.1.4.3 Costs of Activity

The Noble Discoverer is rated to operate in water depths to 2,500 feet with its current anchoring system. Rig Zone noted that the average day rate for drillships rated for less than 4,000 feet was $241,000 while the average day rate for drillships that can operate in more than 4,000 feet water depth was $452,000 (Rig Zone, 2011).

Rig Zone reported average day rates of $241,000 for semi-submersibles that are rated up to 1,500 feet of water depth, $302,000 for those that can operate from 1,500 feet to 4,000 feet, and $419,000 for those capable of operating in waters greater than 4,000 feet (Rig Zone, 2011).

3.5.3.2 Well Drilling

While exploration platforms will be conducting drilling activity as part of the exploration program, production platforms may not have any significant drilling activity after development drilling is completed. In order to be able to model this cessation of drilling activity, the labor requirements and labor cost for the drilling crew and related drilling support staff (e.g., logging and cementing) are estimated separately and added or removed from the estimates as appropriate.

3.5.3.2.1 Equipment and Material Requirements

As noted earlier, ice islands use traditional land-based drill rigs for drilling exploration wells and ERD uses more powerful land-based drilling rigs to extend the reach of horizontal wells. Since these platform types do not have day rates that include the drilling rig, the cost of the drill rig and the labor requirements must be estimated. The other platform types that are described in this section have drilling rigs incorporated into the platform, and the day rate for the platform includes the capital and operating cost of the drilling rig including labor. However, drilling labor requirements for these latter platform types are estimated separately to be added to the crew responsible for operating and maintaining the platform.

3.5.3.2.2 Manpower Requirements

Based on interviews with a major drilling company that operates on the North Slope and offshore, a typical crew for a drill rig will consist of 22 to 24 crew, with an equal number of support staff for logging, cementing, and other necessary activities, and several camp personnel for each shift. Approximately 50 people will be on duty at any given time, with a similar number off duty at the time. These 100 persons are generally on a two-week on and two-week off rotation, although some firms reported a three-week rotation; a total of 200 persons may be engaged in the drilling activities. Offshore drilling activities will require more support positions than land-based drill rigs.

There are a number of short-duration activities that can occur while drilling a well, and small crews are brought in to conduct those activities and may be on the platform for only a few days. Thus, the number of people can fluctuate around the 50 persons on duty noted above.

In addition, a six-month planning period to plan the drilling program is normal and can involve several dozen people per well, although not full time. Logistics for moving the equipment to and from Dutch Harbor/Unalaska can also involve several people for a month or two prior to and after the drilling program.

3.5.3.2.3 Costs of Activity

Labor costs for the drilling crew were reported as approximately $24,000 per day for the two drilling crews that are onsite. Drilling support crews were noted as having substantially higher wages than drilling rig crews, but camp and platform support crews had lower wages. Total daily labor costs to conduct drilling activity are estimated to range from about $55,000 to $65,000 per day. The daily cost for the drill rig and other equipment can vary substantially depending on the capital cost of the drill rig, whether the rig is capable of horizontal drilling and if directional drilling capabilities are required for the well, and other factors. Using the $72 million cited earlier for a typical North Slope land-based drill rig and assuming that the owner attempts to recapture its capital cost in the first five years would result in a daily cost of about $50,000 for the drill rig. Other specialized equipment can add $5,000 to $10,000 per day to the drilling cost, for a total daily drilling cost of about $110,000 to 125,000, prior to owner's costs. Assuming owner's costs of 25 percent suggests that total daily drilling costs could range from $138,000 to $156,000.

It should be noted that much of this specialized equipment is put onboard the drilling platform in Dutch Harbor/Unalaska if the platform is destined to the Chukchi Sea or the Beaufort Sea and is not taken off until the platform returns to the port several months later. The equipment costs are incurred for the entire voyage time period and not just the time the equipment is being used in drilling activity. The equipment costs for this extended period are not included in the total daily costs noted above, since not all platforms will require equipment mobilization to and from Dutch Harbor/Unalaska.

3.5.3.3 Marine and Onshore Support Activities

A number of vessels, aircraft, and onshore facilities are required to support exploration platforms and drilling activity. This subsection identifies the various types of vessels, aircraft and other equipment, and facilities that have been proposed or used in the Alaska OCS, and describes their role in the exploration program, the labor requirements, and cost for each.

3.5.3.3.1 Vessels

At a minimum, several vessels will be required to support exploration drilling platforms operating in Alaska waters. In remote areas of western and Arctic Alaska, the industry will need to independently provide much if not all of its necessary support and infrastructure, while in Cook Inlet much of the infrastructure and services are in place to support drilling activities. Shell has identified examples of the types of vessels that might be used in its exploration plans, while ConocoPhillips has only provided the number and types of vessels that might be used without specifically identifying the vessels. Thus, the examples shown in this section are those identified by Shell or other vessel examples known to the consultant team if Shell does not anticipate using the same vessels as ConocoPhillips.

3.5.3.3.1.1 Heavy Lift Vessel

Prior to an exploration platform arriving in Alaska waters, it may be towed or transported from the Gulf of Mexico or other basins if it is not self-propelled. Heavy transportation vessels, similar to the M/V Blue Marlin shown in Figure 52, can move semi-submersibles as well as jack-up rigs over long distances. Heavy transportation vessels are typically used to transport new built platforms to their initial drilling operation and to move platforms between basins. Within a basin, it is often more cost-effective to have the floating platforms towed between locations. Semi-submersible platforms that have anchoring systems are accompanied by one or more AHTS and those are typically used for towing when needed. Jack-up rigs do not need anchor handlers, but some anchor handlers have high horsepower engines and are designed to tow platforms. ConocoPhillips is proposing to use one AHTS and two supply vessels to tow its proposed jack-up rig from the site where the jack-up will be offloaded from the heavy lift vessel to the drill site. The Kulluk would be moved by Hull 247 or another AHTS.

The Blue Marlin is 225 meters (738 feet) in length with a beam of 63 meters (206 feet). It is shown transporting the Thunder Horse production and drilling quarters semi-submersible from Korea to Corpus Christi Texas prior to its later installation onsite in the Gulf of Mexico.

Figure 52. M/V Blue Marlin Heavy Transport Vessel and BP's Thunder Horse Semi-submersible

Source: Dockwise, Inc., 2011.

The M/V Kang Sheng Kou (See Figure 53) was used to move the Spartan 151 jack-up rig from the Gulf of Mexico to British Columbia, where the jack-up rig was then towed by tugs to Cook Inlet. The Kang Sheng Kou is 156 meters (511 feet) in length and has a beam of 36 meters (118 feet).

Figure 53. M/V Kang Sheng Kou

Source: Vuyk Engineering Rotterdam B.V., 2011.

3.5.3.3.1.2 Ice Management Vessels

Shell has identified the M/V Nordica (See Figure 54) or a similar vessel as the primary ice management vessel in support of the Kulluk. Hull 247 (Figure 9) will provide anchor handling duties, serve as the berthing (accommodations) vessel and will also serve as a secondary ice management vessel.

The M/V Nordica and its sister ship M/V Fennica are classified by Des Norske Veritas (the Norwegian verification company which provides services similar to the American Bureau of Shipping for vessel classification) as icebreaker tug supply vessels. The vessels are also capable of anchor-handling duties. Both vessels are undergoing upgrades in Finland to meet the U.S. Environmental Protection Agency's air emission standards in the event that exploration drilling activity will occur in 2012. The vessels are 116 meters (380 feet) in length overall and 26 meters (85 feet) wide (Arctia Offshore, 2011).

Figure 54. M/V Nordica

Source: Arctia Offshore, 2011.

Shell chartered the Tor Viking II, a sister ship to the Vidar Viking shown operating in ice conditions in Figure 55, for its anticipated drilling program in 2010. The Tor Viking II and its sister ships are 83.7 meters (275 feet) in length and 18 meters (59 feet) wide (Transatlantic, 2011).

Figure 55. M/V Vidar Viking

Source: TransAtlantic, 2011.

The Tor Viking II responded to a disabled ship, the M/V Golden Seas in December 2010, while the Tor Viking was berthed in Dutch Harbor/Unalaska. With its 18,000 horsepower, it was able to take the Golden Seas under tow and bring it safely to refuge in Dutch Harbor. The Tor Viking II then transited the Northern Sea Route with a Russian icebreaker support to arrive back in Sweden where it went immediately to ice breaking for the Swedish Maritime Administration (Offshore Shipping Online, 2011).

Figure 56. M/V Tor Viking II Towing M/V Golden Seas to Safety

Source: Unalaska Community Broadcasting, 2010.

Ice management vessels are not used in Cook Inlet, but the platform supply vessels operating in Cook Inlet are ice strengthened and designed to operate in temperatures well below freezing.

3.5.3.3.1.3 Platform Supply Vessels

Shell has identified the M/V Harvey Spirit (see Figure 57) or similar vessel as a supply vessel for its 2012 exploration program. The Harvey Spirit is a 280 foot offshore (or platform) supply vessel (OSV) with a 60 foot beam. The vessel was built in 2007. The vessel has 2 engines that provide 6,140 horsepower each for a total of over 12,000 horsepower (Harvey Gulf International Marine, 2011). The horsepower is much higher than most OSVs, which have 3,000 to 5,000 horsepower total but will be useful in towing the Kulluk to drill sites.

Figure 57. M/V Harvey Spirit

Source: Shell, 2011.

The Carol Chouest was also identified as a potential offshore supply vessel that could participate in Shell's 2012 exploration program. The vessel (See Figure 58) is 79 meters (260 feet) in length and has a beam of 18 meters (60 feet).

Figure 58. M/V Carol Chouest

Source: Marinetraffic.com, 2011.

Supply vessels used in Cook Inlet are ice strengthened and designed to operate in temperatures down to -35 degrees Fahrenheit during the winter in Cook Inlet, but the vessels are smaller than those proposed for use in the Chukchi Sea and the Beaufort Sea. The M/V Champion, M/V Resolution (See Figure 59), and the M/V Discovery provide Cook Inlet production platforms transportation of supplies for ongoing operations and assist in backup spill response operations. The Champion is 175 feet in length, the Resolution is 190 feet in length, and the Discovery is 200 feet in length.

Figure 59. M/V Resolution

Source: Ocean Marine Services, Inc., 2011.

3.5.3.3.1.4 Other Vessels

Both Shell and ConocoPhillips have identified other vessels that will assist with the exploration program. These include vessels or barges to handle wastes other than recovered oil, and to hold supplies that will be required for drilling activities, and shallow draft vessels or landing craft to access shoreside facilities.

The M/V Arctic Seal (Figure 60) was identified by Shell as a potential vessel that could handle resupply efforts from West Dock at Prudhoe Bay. The Arctic Seal, operated by Bering Marine Corporation, was built in 1978 to transport material and bulk oil to remote Alaska villages. The vessel is 134 feet in length and has a beam of 32 feet with a draft of 7 feet. The Arctic Seal would transport supplies from West Dock to the Harvey Spirit or similar vessel, which would then transport the material to the drilling platform.

Figure 60. M/V Arctic Seal

Source: Shell Offshore, Inc., 2011.

The M/V Ocean Ranger was identified by Shell as a potential vessel to support the Ocean Provider deck barge, or a similar barge, which would be used for waste storage and transport once the exploration program is complete. The Ocean Ranger is a twin screw tug with a length of 117 feet and a beam of 32 feet.

Figure 61. M/V Ocean Ranger

Source: Western Towboat Company, 2011.

3.5.3.3.1.5 Manpower

Crew sizes can vary substantially by vessel, even within the same vessel type. For example, the Blue Marlin has accommodations for 60 while the Mighty Servant 2, a smaller heavy transportation vessel owned by the same company, has accommodations for 20. Loading of massive loads onto vessels would require a number of persons in addition to the vessel's crew to ensure that the loads are safely brought aboard and offloaded. Some of those persons could be employees of the vessel owner, while others could be employees of the cargo or platform owner. Some of those individuals who travel with the vessel to ensure the safety of the load could be considered “ship’s crew.”

Ice management vessels also have differences in crew sizes. The Nordica has a crew of 30 and accommodations for an additional 47 passengers, for a total of 77 persons. In contrast, the Tor Viking has accommodations for 23, which includes the crew.

The Harvey Spirit has a crew of 22 and accommodations for an additional 4 passengers for a total of 26 berths. The Carol Chouest has berths for 29 persons.

The Champion has berths for 9 people, the Resolution has 18 berths, and the Discovery has 20 berths with standby seating for 100 persons. All three vessels are crewed with 7 people and the boats have a different rotation than found on the North Slope, so only 12 people are needed to operate a boat year-round in Cook Inlet.

Information regarding crew sizes for the Arctic Seal and the Ocean Ranger were not discovered during research efforts, but interview information indicates that large tugs generally have a crew of seven people, and a similar size crew is anticipated for the Arctic Seal.

If a platform is being supported by two ice management vessels and two supply boats in Arctic waters, it could result in 80 to 100 people onboard the vessels with a similar number of people rotating in with a crew change.

3.5.3.3.1.6 Charter Costs

Fairstar (2011) provided charter estimates for three different classes of heavy transportation vessels. The largest of such vessels can transport loads of 60,000 tons or more, and can have day rates of $100,000 to $130,000. The smallest class of heavy transportation vessels has day rates of $30,000 to $50,000, and the middle segment has day rates of $80,000 to $110,000. Jack-up rigs are typically transported by the smaller or medium size vessel classes.

Based on interviews with vessel operators and internet research on ice-class AHTS and offshore supply boat day rates, it is estimated that the ice-management vessels can be chartered for $50,000 to $75,000 per day depending on supply and demand. Ice-class AHTS day rates are estimated at $40,000 to $70,000, and charter rates for ice-class supply boats are estimated to range from $40,000 to $50,000 per day.

AHTS and supply boats that are not operating in Arctic waters can be chartered for $10,000 to $20,000 per day, but if vessels need to be mobilized to Alaska, the mobilization and demobilization costs can add $200,000 to $700,000 to the cost depending on whether the vessel comes from the West Coast or the Gulf of Mexico, respectively.

It should be noted that during the time period this study was conducted, spot rates for AHTS vessels in the Gulf of Mexico have ranged from less than $10,000 to over $100,000 per day, so there can be significant volatility in vessel rates from those estimated here.

Charter costs for large tugs (Invader Class) are estimated at $15,000 to $20,000 per day, while smaller Point Class tugs are estimated to cost $8,000 to $10,000 per day. Day rates for barges can vary considerably depending on the size of the barges that are being used. Rates of $10,000 to $25,000 per day were cited.

Small work boats, crew change boats, and similar size vessels (<50 feet) are estimated to charter at $9,000 to $14,000 per day, while day rates of $20,000 to $30,000 were identified for larger work boats.

3.5.3.3.2 Aircraft

Offshore operations will be serviced by helicopters operated out of onshore support base locations. Several types of helicopter have been identified in the various exploration plans including Sikorsky S-92, Eurocopter EC225, and AugustaWestland 139. These aircraft are capable of transporting 10 to 12 persons plus luggage, and will be used to transport crews between the onshore support base and the drillship. The helicopters will also be used to haul small amounts of food, materials, equipment, and waste between vessels and the shorebase.

Figure 62. Sikorsky S-92

Source: Sikorsky, 2011.

Figure 63. EuroCopter 225

Source: American Eurocopter, 2011.

Figure 64. AugustaWestland 139

Source: AugustaWestland, 2011.

The exploration companies will also have a search and rescue helicopter staged at Barrow or Deadhorse as noted earlier in the report. This SAR helicopter may be similar to those shown above.

A fixed wing propeller or turboprop aircraft, such as Saab 340-B 30-seat, Beechcraft 1900 19-seat, or DeHavilland Dash 8 30-seat, will be used to transport crews, materials, and equipment between the Wainwright and hub airports such as Barrow, Kotzebue, Fairbanks, and Anchorage. Deadhorse has several jet flights per day, and existing commercial carrier schedules can likely meet the demand for passenger travel and cargo movements for Beaufort Sea exploration programs.

3.5.3.3.2.1 Manpower

There are slight differences between helicopter companies operating on the North Slope in terms of manpower requirements, but in general, for a single helicopter with 24-hour availability, a crew consisting of four pilots, two mechanics, two ramp hands, a supervisor, and one dispatcher would be required. If only one shift is required, then a crew would consist of two pilots, one mechanic, one ramp hand, a supervisor, and a dispatcher. SAR helicopters would have three to four positions in addition to the pilots to assist in rescue efforts. A program that has one SAR helicopter standing by and one active helicopter operating with two crew shifts would have 23 to 24 people on site and the same number of people rotating in with the next crew change. The rotation schedule is generally two weeks on and two weeks off, but that can change depending on the contracted workload.

3.5.3.3.2.2 Contract Costs

The cost to contract for a helicopter and crew is estimated to range from about $560,000 per month for exploration in the Beaufort Sea, which is closer to infrastructure, to $1.05 million per month for the Chukchi Sea, where the distances are much greater. These estimates include fuel costs.

The cost for a dedicated SAR helicopter is estimated to range from $25 million to $35 million per year, and is shared between a consortium of companies. This cost is modeled as part of owner’s costs as noted earlier in the report.

Fixed wing air transportation to and from the North Slope or any remote exploration program is part of owner’s costs as noted earlier, so the costs for these charters or air fares are not estimated separately.

3.5.3.3.3 Other Onshore Facilities

Air support would be necessary to meet manpower and supply needs once the drilling platform is operational. Helicopter operations to and from the drill rig would require adequate staff and refueling throughout the drilling season, facilities and land use for temporary staging, a helicopter landing site, a fuel containment site, and camp accommodations. Existing facilities at Barrow and Deadhorse would be used for helicopter operations and temporary facilities would be constructed at Wainwright.

Infrastructure associated with helicopter activities would be constructed of a simple fabric with a metal frame similar to those typically used on the North Slope. The temporary helicopter landing pads would be constructed of metal or composite mats.

Fuel would be stored in approved tanks or containers. Fuel would be barged to the shorebase and relocated to the designated refueling area by way of local fuel transporters.

Fixed wing transport would carry crews from Anchorage or another hub airport directly to the shorebase. Wainwright has limited navigational aids, so in the event of inclement weather, alternative accommodations are available in Barrow. Existing lodging may house the displaced change-out crew until conditions are favorable for helicopter transfer to the drill rig.

In the event that an ice island or ERD platforms are used, an ice road may need to be constructed and maintained to provide access to these platforms.

3.5.3.3.4 Manpower

Exploration plans have noted the need for about 30 people working onshore at shorebases to support the exploration programs primarily through logistics support and communications. At Deadhorse, the plans indicate that no new facilities will be needed; existing facilities will be used to meet the needs of the exploration program. At Wainwright, a combination of existing facilities and temporary facilities would be used to support the exploration activities in the Chukchi Sea. It is anticipated that these 30 persons would rotate with another 30 persons on a two-week on and two-week off schedule for the duration of the exploration drilling program.

Support for Cook Inlet exploration activities can be met through existing facilities. In more remote areas of the state, at least some temporary facilities would be required to support exploratory drilling.

3.5.3.3.5 Contract or Construction Costs

Costs for building temporary facilities and renting existing facilities where available at Wainwright or renting/leasing facilities at Deadhorse are estimated to be roughly the same order of magnitude with a range of $900,000 to $1.2 million for the drilling season. Temporary facilities at Wainwright would be relatively inexpensive, but mobilization and demobilization costs would be higher than at Deadhorse, and rents at existing facilities in Wainwright could be higher than Deadhorse, particularly if more than one exploration drilling program is occurring in the region. Conversely, total rent costs at Deadhorse would be higher than Wainwright due to the fact that all facilities are being rented.

Onshore exploration can be conducted in Cook Inlet from existing facilities and based on telephone interviews, the costs for renting facilities for an onshore support base would be considerably less than either Wainwright or Deadhorse, at roughly $200,000 to $400,000 for a 60-day exploration drilling program. If the drilling program extended for a longer period, then costs would increase. It is anticipated that slightly higher costs could be experienced in other Southcentral and Southeast Alaska regions, but costs in more remote areas of western Alaska could approach those of the Arctic regions due to the mobilization and demobilization costs and inadequate support infrastructure.

3.5.4 Development Activities

This section discusses those activities that are necessary to build or install the infrastructure that is necessary to begin production of an oil or gas field. This includes onshore facilities and platforms, including pipelines (shuttle tankers are discussed in Section 3.5.5.5).

3.5.4.1 Construction of Offshore Pipelines

Capital cost estimates have been prepared for the pipeline portion of a wide range of oil and gas development scenarios in the Beaufort and Chukchi Seas, the Cook Inlet and the North Aleutian Basin. These estimates include funds to cover shore crossings and tie-ins to an offshore structure.

For each selected oil or gas production rate, a cost estimate has been generated for pipeline lengths of 25, 50, 75 and 100 miles from shore. The cost estimates are expressed in 2010 US dollars using cost information developed from previous arctic experience and by adjusting available industry cost data from projects in other parts of the world. For the purposes of sizing the pipelines running from the offshore structure to shore, a number of assumptions had to be made. For the gas development cases, it has been assumed that a dehydrated gas is being transported to shore. Oil pipelines are assumed to be handling oil with free water and gas removed.

Assumptions are necessary in developing capital cost estimates for projects in the two arctic regions because of the limited data available on the seabed materials that exist, the depth of ice scour that occurs, and the maximum depth of water in which scouring can occur. Some geophysical and geotechnical data are available as a result of surveys conducted in preparation for exploratory well drilling; however, this information is widely scattered and is generally single point sources of data. It is not possible to extrapolate this information for use along the entire length of a pipeline with appreciable confidence. It is also outside the scope of this study to analyze available data as an input to estimating the cost of trenching and burying pipelines in the Beaufort and Chukchi Seas. Another assumption/factor that significantly impacts the cost for these regions is the complex logistical effort that is necessary in shipping and storing materials, erecting temporary construction camps for personnel, and mobilizing marine vessels capable of working in the harsh conditions that exist.

In the cost estimates, trenches for Beaufort and Chukchi Sea pipelines have been assumed to be prepared and backfilled using cutter suction dredges out to 100 feet of water depth and trailing suction hopper dredges in deeper water. United States law requires the use of dredges that are Jones Act compliant, and it is unlikely that any existing American dredges can operate in open water (up to 5/10ths cover) ice environments in the Beaufort and Chukchi Seas. Based on the timeframe considered in the MAG-PLAN model (20-50 years into the future), and to avoid burdening single MAG-PLAN development scenarios, the costs for new Jones Act compliant dredges have not been accounted for in estimates; instead, it has been assumed that such dredges will be available in the future when developments occur in these regions.

In preparing cost estimates for developments in the four areas (Beaufort, Chukchi, NAB, and Cook Inlet), it is assumed that all marine equipment, with the exception of the pipelay vessel and ice-breaking freighters used in transporting pipe to the Beaufort and Chukchi Seas, will meet the requirements of the Jones Act. This is a significant assumption, because there are essentially no Jones Act compliant vessels in existence capable of operating in these two areas. As a result, new vessels would have to be built in the United States of America, which would add significantly to the cost of manufacture. In developing the cost estimates it has therefore been necessary to use the best professional judgment as to what the day rates for the various dredges and other marine vessels would be, based on day rates for ice-capable vessels constructed in other countries.

The pipeline lay rates have been adjusted depending on both the type of pipelay vessel being used and the size of the pipeline being laid. For the large dynamically positioned vessel used in the Beaufort and Chukchi Seas and the North Aleutian Basin, the layrate ranges from 4 miles/day for an 8-inch diameter line down to 1.5 miles/day for a 38-inch line. For the smaller anchored barge used in the Cook Inlet, the layrate ranges from 2 miles per day down to 0.5 miles/day for the same range of pipeline sizes.

Engineering and permitting support has been included in all cost estimates at 10 percent of construction costs and 6 percent has been added for project management. A contingency of 30 percent has also been included in these Class V quality cost estimates. Because of the many unknowns associated with work in an arctic environment, a range of costs from –20 percent to +100 percent has also been shown. The probable need to build a number of vessels designed to work in harsh arctic conditions could add significantly to the cost, and ultimately affect economic feasibility of any project in the Beaufort and Chukchi Seas, particularly if such costs are absorbed by a single proponent.

For materials supply and transportation in the arctic areas, it is assumed that pipe will be purchased from Japan and sent to Kuantan, Malaysia for application of anti-corrosion coating (fusion bonded epoxy, or FBE) and concrete weight coating (CWC).

Standard freighters and barges are not able to withstand the forces involved when trapped in pack ice. With the risk of pack ice intrusions into the construction area at any time, and no safe havens into which marine equipment can take refuge in either the U.S. Beaufort or Chukchi Seas, vessels entering these areas must be able to deal with potential sea ice conditions encountered. Since there are no Jones Act compliant freighters capable of operating in these areas, it becomes necessary to use foreign flagged freighters, such as SA15's built in Finland, to transport the pipe. Because foreign flagged vessels are not allowed to transport material from one U.S. port to another, the assumption is made for the cost estimates that the pipe is purchased in Japan, coated in Malaysia and transported to the Beaufort or Chukchi Sea using ice-breaking freighters. Two ice-breaking pipe carriers will shuttle between these freighters and the pipelay vessel.

It is essential that the pipeline route be surveyed in detail prior to dredges being sent to the construction site. The cost estimate includes the cost of a survey vessel to conduct a survey prior to the commencement of dredging and pipelay. This survey would be conducted at least one year in advance of the start of construction. A survey vessel is also on site for the entire construction period to ensure that the trenching meets specifications and that the pipe is properly laid into the trench bottom.

Two shallow-draft icebreaking crew boats are included in the cost estimates. It has been assumed that these vessels can be chartered locally, but there may be no American vessels that meet the "coastwise passenger law" and also meet technical requirements. Funds could be required to fabricate new vessels for this service, but have not been included in the cost estimates.

Icebreaking workboat support is assumed through the entire construction period when dredges and the pipelay vessel are present. The cost of a dedicated icebreaker and a smaller ice management vessel to support each of the major activities of dredging and pipelaying has been included in the cost estimates.

3.5.4.1.1.1 Construction Camp

Because these cost estimates are intended to be generic and apply to any location, the cost for the camp is based on erecting the camp on two barges in the Lower 48 and then towing the barges to the construction site and sinking them onto a prepared pad next to shore. The camp is sized based on the estimated construction manpower required with a number of additional support units added for dining, kitchen, recreation, etc. The cost of building a 60-mile long ice road to serve the camp has also been included, but depending on the location of the development, this road could be either shorter or longer.

3.5.4.1.2 Winter Construction

For developments in the Beaufort Sea where shore-fast ice is available during the winter months, it is assumed that the first three miles of pipeline is built in the winter using the ice as a work surface. This opportunity is not available in the Chukchi Sea as the shore-fast ice is not stable and therefore not suitable as a work surface from which to lay a pipeline.

The costs for installing this three-mile section of pipeline have been developed by examining each activity and estimating the cost for the materials, equipment and personnel required, assuming an approach somewhat similar to that used for onshore pipelines. The costs also include creating a thickened ice pad along the route where the pipeline is to be laid and maintaining this work pad over the construction period.

3.5.4.1.3 Summer Construction

3.5.4.1.3.1 Trenching

Based on the limited information available, it appears that ice scour does not extend beyond a water depth of about 200 feet. Bathymetry data for the Beaufort Sea suggests that the distance from shore to reach this water depth is about 22 miles. The cost estimates have used this length as the distance requiring trenching for Beaufort Sea developments. The three-mile section of the line built in the winter is buried to a depth of 7.5 feet. The next two miles have cover of 8.5 feet and the remainder (17 miles) is buried with 16 feet of cover. In the Chukchi Sea, cover depths of 8.5 feet for the first 2.5 miles from shore, 17.5 feet for the next 13 miles, and 19 feet for the balance of the pipeline have been used in determining the volume of seabed material to be excavated.

Dredges were the only option considered in these cost estimates for preparing and backfilling the pipeline trench. Potentially a plow could be employed in some capacity, but with the limited geotechnical information available, it is not possible to determine if either a pre-lay or post-lay plow would be viable options for burying pipelines in these two areas.

Out to a water depth of 100 feet, a cutter suction dredge dredging at a rate of 3,000 cubic yards/hour is used. Beyond this depth, a trailing suction hopper dredge is employed with a dredge rate of 1,000 cubic yards/hour. It is assumed that the dredges only work 20 hours each day to allow for weather and maintenance downtime. As mentioned previously, the assumption has been made that Jones Act compliant dredges would be available and the cost of building new dredges has not been included in the cost estimates.

Because the water depth never exceeds 200 feet in the Chukchi Sea and it has been assumed that ice scour can occur out to this water depth, the entire pipeline must be buried for all of the cases considered. This large amount of dredging adds significant cost to a Chukchi development.

3.5.4.1.3.2 Shore Crossings

Because the pipeline shore crossings are undefined, it is not possible to provide detail on the approach to be used. In the Beaufort Sea estimates, the actual shore crossing is part of the first three miles of pipeline installed from the ice in the winter. Along much of the Alaskan Beaufort Sea coast the slope of the seafloor is relatively gradual and the resulting water depths close to shore are insufficient to accommodate large marine equipment. For this reason, it has been assumed that a further pipeline pull would still be required in order to lay pipe in water too shallow for a large pipelay vessel to operate. A tie-in barge is set up at the end of the pipeline section installed during the winter. A pipeline pull of 2500 yards is then executed between the tie-in barge and the pipelay vessel. Costs have been included for a tug and the tie-in barge plus four days of the pipelay vessel.

In the Chukchi Sea a shore pull is also executed. The pull is assumed to be 2,500 yards and the cost estimates include four days of the pipelay vessel to execute the pull. The distance of 2,500 yards was selected as a reasonable distance from shore to provide adequate water depth for the pipelay vessel. These are large pieces of marine equipment with a working draft in the range of 40 to 50 feet of water.

3.5.4.1.3.3 Pipeline Installation

It is assumed that a dynamically positioned pipelay vessel would be required for pipelaying in the Beaufort and Chukchi Seas. It is anticipated that another requirement would be that the vessel have a ship-shaped hull to avoid having large ice blocks trapped in the structural legs and support members of a semi-submersible type of lay vessel.

Using an anchored barge would also be problematic. Ice blocks could snag on the anchor wires and pull the barge out of alignment and if an ice incursion were to occur, there could be insufficient time to lay down the pipe and pick up the anchors.

There are currently no pipelay vessels that are designed for operating in arctic environments. Either a significant amount would have to be spent winterizing an existing vessel and reinforcing its hull to withstand ice or a completely new vessel designed specifically to operate in the conditions that would be experienced in the Beaufort and Chukchi Seas. No funds have been included in the cost estimates to either upgrade or build a new vessel. The pipelay vessel also executes the tie-in of the pipeline to the offshore structure in the cost estimates. A duration of five days has been included in the cost estimates.

For developments in the Cook Inlet and North Aleutian Basin, pipe is sourced in the United States with FBE and CWC applied in the Houston, Texas area. The coated pipe is then transported via the Panama Canal to the construction site using tugs and barges. This approach has been chosen because there is no need for concern about the presence of ice in either the Cook Inlet or the North Aleutian Basin and therefore no need for special freighters. This is not to suggest that ice is not present in these areas, but that the open water period is long enough each year that ice can be avoided during both shipment of materials and installation of the pipeline.

Arrival at the construction site of the tugs and barges being used to transport the coated pipe is timed to match the arrival of the pipelay vessel in order to avoid having to store the pipe onshore and then reload onto barges to supply the lay vessel.

The cost of a survey vessel is included to conduct a preconstruction survey and then to be present during the entire pipeline installation period.

In the Cook Inlet cost estimates an anchored barge has been used with mobilization out of the Gulf of Mexico. For the North Aleutian Basin it is assumed that a larger dynamically positioned pipelay vessel would be required because of the possible weather conditions that could arise. An amount has been included in each estimate to cover the mobilization and demobilization of the personnel working on the lay barge. The anchored barge is assumed to have 250 persons with 350 on the DP vessel.

3.5.4.2 Construction of Onshore Facilities

Onshore facilities may not be needed near Prudhoe Bay and Cook Inlet, where existing infrastructure already exists. Onshore facilities will be required in other areas where sufficient infrastructure does not exist, or where there is insufficient capacity in current facilities to handle additional demand. The exploration and development scenario has the following types of onshore facilities:

- Construction Camp/Accommodations
- Air Support Base
- Supply Boat Terminal
- Oil Export Terminal
- LNG Export Plant & Terminal
- Production Base

The exploration and development scenario identifies if these facilities will be built and the year or years of construction activity. MAG-PLAN then estimates the capital and operating costs of the facility based on oil and gas production volumes. The following subsections describe the data sources used in this section, and define the type of infrastructure associated with each facility, the manpower requirements, and the operating or contract cost.

3.5.4.2.1 Data Sources

Several interviews of firms that operate air support bases on the North Slope and firms that construct and operate construction camps or other accommodations provided reference points for capital cost and operating cost estimates for these facilities. The capital and operating costs for the other facilities are derived from secondary sources and previous work that Northern Economics has done related to such facilities (e.g., deep draft docks, LNG plants, export terminals for natural gas liquids, accommodation facilities in Deadhorse). A proprietary report on capital costs for a dock in heavy ice conditions which would be suitable for a supply boat terminal was also available to Northern Economics. In some cases, the secondary sources reported capital costs for similar facilities recently built, or proposed to be built in the Gulf of Mexico or the Pacific Coast. In these cases, the costs were first increased to account for the construction cost differentials between Houston or Seattle and Anchorage, and then depending on the OMA, a geographic cost differential study prepared for the State of Alaska (McDowell

Group, 2009) was used to change the costs between Anchorage and the hub community noted in the study that was the closes to the OMA.

3.5.4.2.2 Types of Onshore Facilities

The facilities mentioned in this section are conceptual in nature and only the major infrastructure components for each facility are described.

3.5.4.2.2.1 Construction Camp/Accommodations

Except in OMAs where there is existing and sufficient infrastructure, a construction camp/accommodations will be required to support one or all of the other facility types. It is assumed that the construction camp will be constructed prior to any other facilities to house and feed the construction workers, and that the camp will evolve into the final accommodations facility. This facility would have sufficient beds to house the construction and operations crews with one person per room per rotation; during the period of a month, two individuals would occupy the room for alternating two-week periods. The facility would also provide meals and recreation areas for the workers. Warehouses, storage yards, and laydown areas would be part of this facility, although the warehouses would be separate structures. This facility would have sufficient generating capacity to supply electricity to the supply boat terminal and the air support base if those are part of the exploration and development scenario. Other facilities would provide their own power. Sewer and water treatment facilities would be included in the camp and accommodation facilities.

3.5.4.2.2.2 Air Support Base

We assume that the air support base would be located at an existing airstrip. The air support base would be large enough to accommodate three large helicopters and provide a maintenance area for them. The base would function as a terminal for workers arriving via fixed wing aircraft and those transiting to or from the platforms via helicopter. The air support base also provides housing for the helicopter crews and support personnel that work at the air support base. The accommodations facility provides meals for the air support base workforce and provides utilities for the base.

3.5.4.2.2.3 Supply Boat Terminal

MAG-PLAN assumes that if a supply boat terminal needs to be built, it will be within a reasonable distance of the accommodations facility and air support base so that personnel working at the supply boat terminal can commute to and from the terminal for their work schedule. The supply boat terminal is assumed to provide its own utilities rather than access the utilities available at the accommodations facility. The terminal is comprised of a large sheet pile pier or dock which can resist ice forces where needed. Several warehouses, an office/accommodations structure, utility buildings, and a large laydown yard are located onshore in the immediate vicinity of the pier or dock. A large tank farm is located further inland to provide fuel for the vessels and the platforms operating in the planning area. A helicopter landing pad is also located in proximity to the terminal. The accommodations features in the office structure would be sufficient to support the on-duty crew in the event that they were forced to remain at the terminal due to inclement weather.

3.5.4.2.2.4 Oil Export Terminal

If the exploration and development scenario identifies that an oil export terminal is needed to export the oil, this facility is assumed to be built in a location that deep-draft ships can access. Thus, the oil export terminal is assumed to be built in a different location than the supply boat terminal location and the accommodations/air support base. The oil terminal is assumed to consist of a large deep draft pier or dock sufficient to handle shuttle tankers with a 45-foot draft, a very large tank farm, a construction camp/accommodations facility, utilities, warehouses for maintenance equipment and supplies, office building, a large laydown yard, and a helicopter landing pad. We assume that the facility will be located close enough to an existing air strip that helicopters can transport personnel, food, and light cargo on a daily basis. The shuttle tankers would be ice reinforced or capable of independent icebreaking operations if necessary, and would transport the oil to a location in the state where the oil would be offloaded for eventual export via very large crude carriers to the West Coast of the U.S.

3.5.4.2.2.5 LNG Export Plant and Terminal

An LNG export terminal, if identified in the exploration and development scenario, would consist of a series of liquefaction units or trains depending on the maximum gas production levels in the planning area. The plant would also include storage tanks to hold the LNG between vessel loadings. A dock similar to the oil export terminal dock is built to handle LNG tankers. Due to the water depth requirements of the vessels, the LNG plant and terminal is assumed to be built either near the oil export terminal or, if only gas is produced in the planning area, at a location distant from the accommodations facility and the air support base. The terminal also includes a construction camp/accommodations facility, utilities, warehouses for maintenance equipment and supplies, an office building, a large laydown yard, and a helicopter landing pad.

3.5.4.2.2.6 Production Base

Most OCS oil and gas production is assumed to be handled on the production platforms. However, for ERD and some nearshore fields, it may be more cost-effective to bring the raw oil and gas stream onshore for treating and then exporting the desired product or products and reinjecting the remainder of the stream into the reservoir. In many cases, it is anticipated that an onshore facility would be less expensive than an offshore facility. The production base would consist of a set of modules to process the produced fluid and separate into oil, water, and gas. The oil must be free of dissolved gas before export and the gas, if being exported, must be stabilized and free of liquids and unwanted components such as hydrogen sulfide and carbon dioxide. Any water and components not being exported are assumed to be reinjected to maintain reservoir pressure. If noted in the exploration and development scenario, the production base is assumed to be located in proximity to the accommodations and air support base. The production base would generate its own power, but use the sewer and water utilities provided by the accommodations facility.

3.5.4.2.3 Manpower Requirements

Manpower requirements to operate the construction camp/accommodations facility are estimated at 15 percent of the total number of persons estimated for the production base, the supply boat terminal, and the air support base. Total employment for these facilities, including the crew that is not onsite at the time, would be twice the number estimated of beds needed for camp staff. The assumption for camp support crews and other onshore facilities workers is that they work a two-week on/two-week off rotation.

The air support base manpower requirements range from 6 to 12 persons onsite for security and logistics plus the SAR crew and support staff for the SAR helicopter (total of 18 persons onsite for SAR). Total employment would range from 48 to 60 persons. The helicopter crews and the support staff for the crew changes and platform support activities are counted separately and are not included in the air support base employment.

The number of crew at a remote supply boat terminal is estimated to range from 15 to 20 persons onsite at a time, with total employment at 30 to 40 persons with a two-week on/two-week off rotation schedule. In Cook Inlet the crew does not rotate since they live nearby, so the total employment for a supply boat terminal in that planning area is 15 to 20. A similar manpower requirement could be applicable where a supply boat terminal might be located at a coastal community.

Secondary research identified the smallest employment at an oil tank farm and terminal to be 15 employees and for larger terminals employment was about 15 employees per one million barrels of storage capacity. The model uses the maximum annual oil production over the study period to estimate the amount of storage, in millions of gallons, that would be required, assuming a maximum of 10 days of storage at the terminal, and multiplies that storage volume by 15 employees to arrive at the manpower requirements.

The manpower requirements for an LNG export plant and terminal are based on a range of 63 to 96 employees per one million tons of LNG per year, which is based on secondary research of planned and recently built LNG plants around the globe and previous proprietary work completed by Northern Economics. If an LNG plant is identified in the exploration and development scenario, MAG-PLAN uses the maximum annual gas production over the study period to estimates LNG production in terms of million tons per year that would be produced, and calculates the number of employees associated with the tonnage.

The production base manpower requirements are estimated using a regression equation that was derived from crew sizes for floating production and storage offload vessels (FPSOs) with different production volumes (in terms of 1,000 barrels per day), and adding manpower for logistics support and camp facilities.

3.5.4.2.4 Operating or Capital Cost

Construction camp and accommodations contract costs are based on secondary research which provided recent sales prices for camps in the lower 48 states and enabled the calculation of a capital cost per person or bed. This cost was then increased to account for the construction cost differences between the lower 48 and Anchorage, and increased again depending on the planning area that is being modeled using the geographic differential study cited earlier (McDowell Group, 2009). The cost per bed for a complete camp in the lower 48 is about $25,000 and the cost for a bed on the North Slope is estimated at $52,500. Thus, a 280 bed camp that costs $7 million in the lower 48 would cost approximately $14.7 million on the North Slope. The total cost of the camp is based on the total number of persons estimated for the production base, the supply boat terminal, and the air support base, plus 15 percent for camp staff. Operating costs are based on a range of operating costs for camps on the North Slope. These costs are thought to be comparable to the costs that would be experienced in any remote Alaska location, though Cook Inlet and some other areas in the state with adequate infrastructure have lower costs.

The air support base cost estimates are based on the capital costs for an air support facility that was recently built on the North Slope. Estimates of the cost per square foot for a similar facility on the Chukchi coast were also obtained in the interview. The facility is 70,000 square feet and has room for two S-92 helicopters or three smaller helicopters, plus accommodations for 60 people. The facility does not provide meals. The cost is adjusted for the planning area based on the interview information and the geographic cost differentials between the planning areas. The facility was not operating at the time the interviews were conducted, so operating costs are estimated using an estimated annual operations and maintenance cost of 10 percent of capital cost and an annual return on capital of 12 percent plus annual debt amortization.

The supply boat terminal costs are based on a proprietary study that Northern Economics had access to from previous work on the North Slope and on several other dock studies that the firm has worked on in other areas of the state. The North Slope report is used as the cost estimate for Arctic planning areas, and the other dock studies are used for the subarctic planning areas. In all areas, a large sheet pile dock with gravel backfill is the construction method. The total operating costs are estimated in a manner similar to the air support base, including an estimated annual operations and maintenance cost of 10 percent of capital cost, annual debt amortization, and an annual return on capital of 12 percent.

The oil terminal includes a deep-draft dock to handle a vessel with 45-foot draft and an uplands area to site the tank farm and other ancillary equipment and facilities. The tank farm cost is based on recent construction costs for very large jet fuel tanks that were recently built at the Ted Stevens Anchorage International Airport. Those costs were increased to the appropriate planning area with the geographic differential cost estimates (McDowell Group, 2009). The volume of the tanks is based on 10 days of storage at the maximum production volume indicated in the exploration and development scenario. The cost for the terminal is based on a new marine terminal for very large ships that was built in Corpus Christi Texas, which has a 45-foot ship canal that abuts the terminal. This cost was escalated to Anchorage prices and then increased to the appropriate planning area. An additional $15 million is added to the cost to account for the accommodations facility, warehouses, office building, lay down yards, and other features. Note that when building in areas requiring large amounts of fill or in areas of steep terrain, the removal of large volumes of rock to create land for the tank farm could vastly increase these costs for the oil terminal. Proprietary information that Northern Economics obtained access to revealed a range of operating costs for petroleum and other liquids terminals in the amount of $0.15 to $0.17 per barrel at those terminals with high volumes. This operating cost range is multiplied by the oil production volume in each year to arrive at the annual operating cost.

Construction costs for the LNG plant and terminal are based on based on secondary research of planned and recently built LNG plants around the globe and prior work by Northern Economics. The total cost for a planned LNG plant and terminal in the Gulf of Mexico was converted into the total cost per train, then increased to Anchorage prices, and then escalated based on the geographic differential study (McDowell Group) for the appropriate planning area. An additional $15 million is added to the cost to account for the accommodations facility, warehouses, office building, lay down yards, and other features. The note in the prior paragraph regarding the potential for cost increases is also applicable to the LNG plant and terminal. The operating costs for the LNG plant are based on previous proprietary work conducted by Northern

Economics, and are multiplied by the appropriate geographic differential factors (McDowell Group, 2009) to arrive at an operating cost estimate for each planning area.

The production base capital costs are derived from proprietary work developed by IMV Projects for offshore production islands in this report. The firm developed estimates for platforms in different water depths and different production volumes. A range of costs per barrels per day of oil equivalent production was derived by evaluating the difference in capital costs for different production volumes for platforms in the same water depth. The results were then multiplied by the maximum daily volumes as calculated from the exploration and development scenario. It is assumed that the costs of building production facilities of a certain size for a platform are similar to the costs of building production facilities onshore, and since the onshore production base is located in proximity to the accommodation facility and the air support base, the model assumes that there are limited other costs, beyond those estimated for the production facilities, that need to be included. Operating costs for this facility are based on an observation that operating costs for other facilities seemed to range around three to four times the labor costs for the facility. The operating costs for the production base are estimated at three times the labor cost.

It should be noted that the operating cost for all of these facilities also includes 25 percent for owner's costs.

3.5.5 Production Activities

This version of MAG-PLAN includes the cost of designing, constructing or fabricating, installing, operating, and decommissioning of a platform. A number of production platform types that are suitable for subarctic conditions have been built and operate around the world and in Cook Inlet. However, with the exception of gravel islands and extended reach drilling, no production platforms have been built than operate in multi-year ice conditions. Where construction or fabrication cost estimates were readily available, those costs have been employed with appropriate adjustments for mobilization and installation costs in Alaska. Cost estimates have been prepared for those platform types that were not readily available. Following the discussion of production platforms, this section addresses production drilling, workovers, and subsea drilling and completion.

3.5.5.1 Production Platforms

At present, the only offshore production platforms in the Alaska OCS are gravel islands, although an extended reach drilling production operation is being developed at Liberty. It is anticipated that gravel islands and extended reach drilling will continue to be used in shallower waters of the Beaufort Sea, but other structures will be needed in deeper water. The gravity-based structures presented herein are constructed of steel and have been sized according to the principles developed by project team member John Fitzpatrick, P.Eng., which are summarized in the technical paper "State-of-the-art of Bottom-Founded Arctic Steel Structures" (Fitzpatrick, 1994). These same principles were used to size, and effectively estimate gravity-based structure costs, in a recent BOEM-sponsored arctic offshore technology assessment (IMV Projects Atlantic, 2008). This assessment forms the basis for gravity-based structure cost estimation in the current study.

The following subsections summarize design and functional considerations that have been accounted for in structure cost estimates generated for this study. For further discussion/information on topics and considerations mentioned below, please refer to IMVPA's (2008) report.

There are many technical and economic advantages to steel structures, and the reader is referred to the aforementioned references for further details. One of the chief benefits, however, is that a steel structure can be mobilized (and, ultimately, demobilized) complete with topsides, and can be installed on location in basically a single day. Steel structures offer tremendous advantages over concrete options, which have inherent stability issues, deeper drafts, constructability concerns, greater costs, and unknown decommissioning issues.

It is the experience of the engineering consultant team members that in virtually all cases where ice is involved, concrete solutions end up being close to two or more times the cost of steel solutions.

3.5.5.1.1 Primary Design Considerations

There are three principal factors that govern the design of the structure:

1. Environmental loads (ice, waves, etc.);
2. Foundation resistance;
3. The functional requirements of the platform itself.

The combined effect of these factors drives the geometry and material quantities of the structure.

3.5.5.1.1.1 Environmental Loads

In arctic regions (i.e., Beaufort and Chukchi Seas) where substantial multi-year ice can impact a structure, the loads resulting from this interaction become the primary design condition and the structure shape and scantlings[7] are dictated by both local and global ice loading intensities. In such locations, wave loads are small by comparison and do not have any appreciable effect on the design. Where deck-cantilevers are involved, wave slam dynamics must be designed for, however.

In the deepwater, more southerly basin areas, where only first-year ice occurs, the platform design is primarily governed by wave loads. In these areas, it is still necessary to employ solid monolithic type structures, as ice loads are still too locally intensive to permit jacket or "water transparent" type structures. However, the use of a monolithic type structure in order to eliminate local ice load effects, bridging and vibrations, results in relatively high global wave loads (an unfortunate "Catch 22" effect). Avoiding this effect can be achieved by employing a stepped or necked structure as shown below in Figure 65.

[7] Scantlings are the interior framing members of the structure.

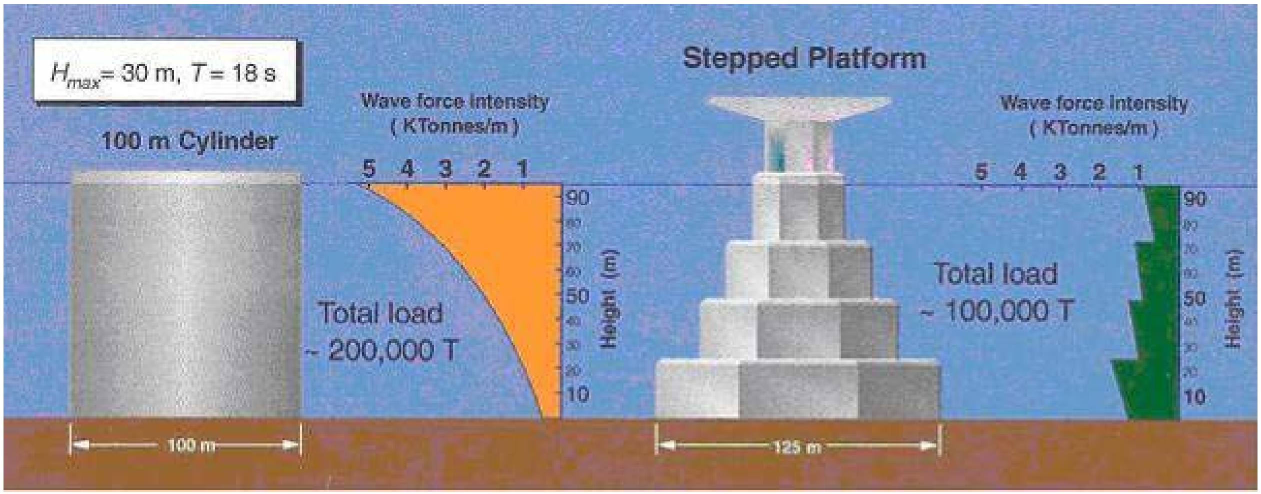

Figure 65. Wave Load Comparison of Hibernia-type GBS vs. Stepped-style GBS

Source: Fitzpatrick and Kennedy, 1997

After ice loads, there are two other parameters that have a major effect on the global structure size optimization: water depth and foundation conditions. Generally, multi-year ice loads increase as the water depth increases. Thus, water depth has a two-fold influence in that the deeper the water, the greater the horizontal design load, and the greater the structure height requirement, and hence cost.

Other design considerations such as earthquake, vibration (due to ice), fatigue, temperature, wind, etc. that do not have a significant effect on structure sizing/costs, have not been discussed here.

3.5.5.1.1.2 Foundation Resistance

Foundation conditions are very important to platform stability and, hence, overall platform costs. In some circumstances, providing adequate foundation resistance can be a very serious hurdle to overcome. Table 8 presents measures that may be required to achieve platform stability.

Table 8.

Achieving Platform Stability based on Foundation Conditions

Foundation Condition	**General Stability Solution**
Very stiff clay	Water ballast only
Sand or granular (friction type) material	Increase structure freeboard and/or adding solid ballast
Stiff clay	Increase platform base area
Weak clay	Foundation preparation by excavation and replacement with granular material

Source: IMV Projects, 2011.

3.5.5.1.1.3 Functional Requirements

In the most general terms, an offshore production platform is required to provide a safe and stable base of sufficient area for drilling and production, but there are other functional requirements that are inherent to working in cold and remote regions, and these do have an impact on the final size and shape of the platform.

Topsides Deck Area

Resupply to the arctic offshore is difficult and expensive, especially during the dark extended winter months. During the development drilling phase, large storage areas are required to ensure consumables are available, and resupply costs are minimized.

Storage and Transportation

Significant amounts of oil storage will be required to facilitate arctic shuttle tanker loading and to provide a “buffer” for tanker delays or, in the case of loading terminals, process upsets downstream of the terminal. Storage can be either “wet” (oil and/or water is present in the storage area at all times) or “dry” (segregated oil storage with no oil/water interface). Wet storage is more cost-effective, and is the preferred choice for most offshore production platforms (e.g., cold region projects like Hibernia and Hebron). Dry storage should be avoided as it can add upwards of 30 percent to the basic structure cost. The gravity-based platform cost estimates provided in this section assume that oil storage is not a requirement and that oil will be exported from the platform by pipeline.

Installation and Lift-off

Operations in the arctic are expensive, and therefore, ease and speed of installation (set-down) of the platform should be a priority. At the end of the useful life of the platform or field life, ease and speed of lift-off for decommissioning or relocation to another site is also an important consideration.

Environmental Protection

For environmental reasons, oil storage areas should not be immediately inside the outer walls of a structure. Double-walled construction is therefore an important consideration.

Draft

Access to many arctic sites is often restricted by tight weather-windows and bottom clearance. Conceptual designs must carefully consider bathymetry along towing routes and also any seasonal towing restrictions or “choke points”.

3.5.5.1.2 Technical Feasibility and Limits of Technology

In multi-year ice areas, there are gravity-based structure solutions that would be considered safe and economical up to around 250 feet (75 meters) water depths when foundation properties are good, and up to around 200 feet (60 meters) water depths when foundation properties are relatively weak. There are no known bottom-founded platform design solutions for the 330 feet (100 meters) plus water depth range that could be deemed workable or proven for multi-year ice areas.

In line with study requirements to consider plausible technologies and solutions for up to 20 or more years into the future, we have extrapolated gravity-based structure costs for Arctic planning areas (Beaufort and Chukchi) out to a water depth of 100m. This extension in range of application may be realistic if, for example, advances in gravity-based structure design or understanding of ice loadings are achieved. Notwithstanding the foregoing, it is important to note that to date there has been no gravity-based structure employed for production in the U.S. Arctic.

In the more southern areas, where multi-year ice is absent and only first-year consolidated ridge loadings are possible, bottom-founded solutions out to 425 feet to 500 feet (130 meters to 150 meters) water depths are potentially viable.

3.5.5.1.2.1 Arctic OMAs

In arctic regions (i.e., Beaufort and Chukchi Seas) where substantial multi-year ice can impact a structure, the loads resulting from this interaction become the primary design condition. Figure 66 presents an example of an arctic gravity-based substructure option, which has been used as cost basis for the current study.

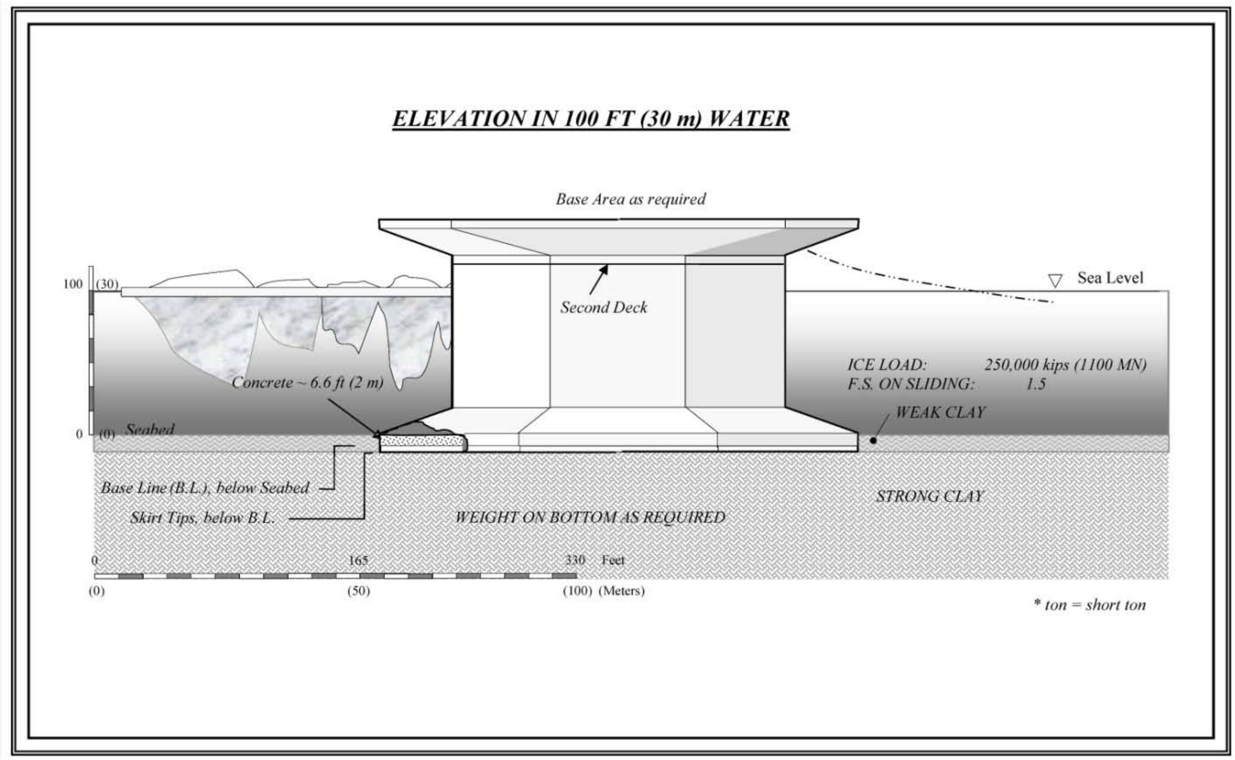

Figure 66. Example Arctic Gravity-base Substructure Option

Source: IMVPA, 2008

3.5.5.1.2.2 Sub-Arctic OMAs

In the deepwater, more southerly basin areas, where only first-year ice occurs, the platform design is primarily governed by wave loads. Figure 67 presents an example of a sub-arctic gravity-based substructure option, which has been used as cost basis for the current study.

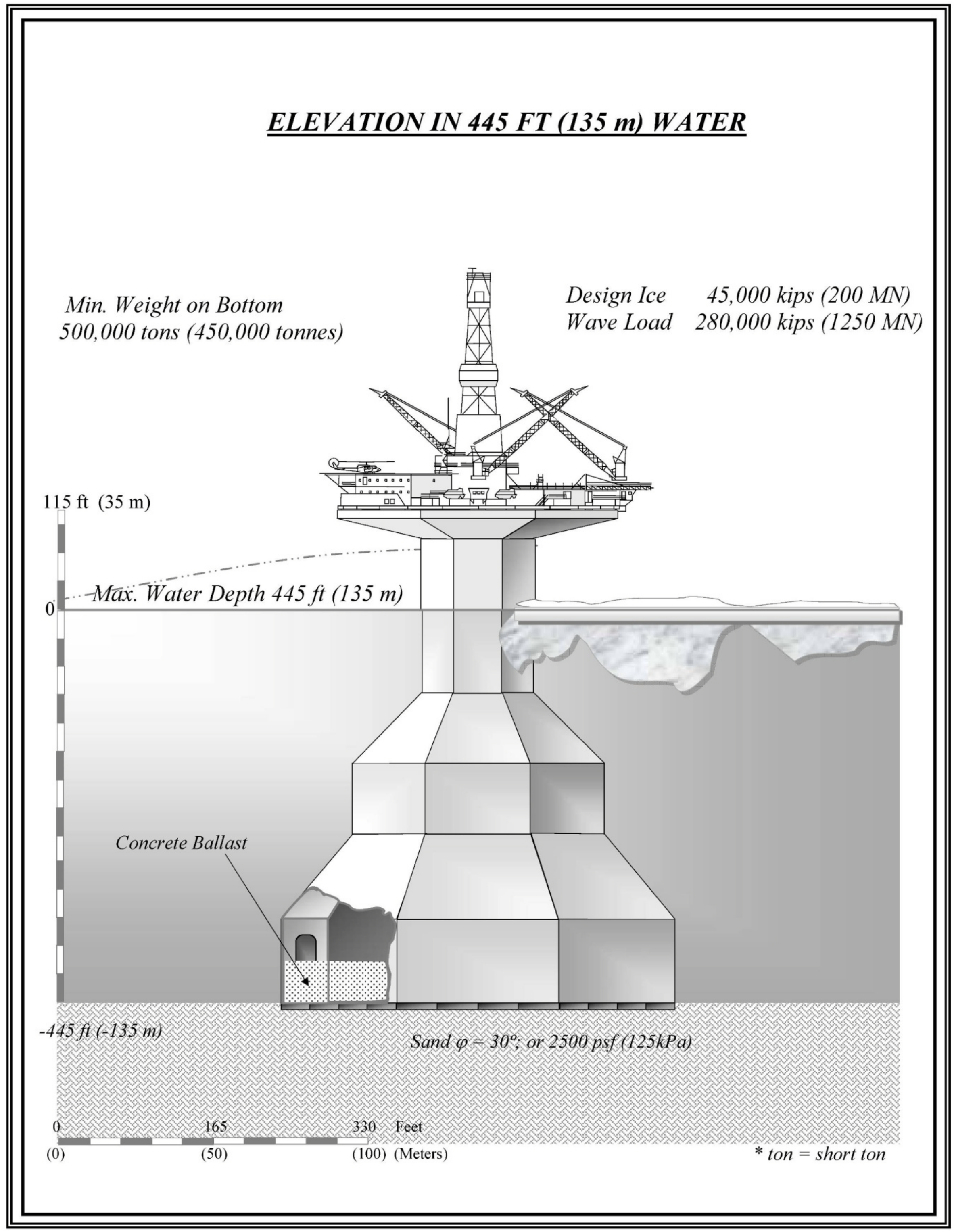

Figure 67. Example Sub-Arctic Gravity-base Substructure Option

Source: IMV Projects Atlantic, 2008)

3.5.5.1.2.3 Manpower Requirements

Manpower requirements for Alaskan OCS production platforms are likely to be similar to those of deepwater Gulf of Mexico platforms, which can range up to 200-250 persons onboard. For the purposes of providing input into MAG-PLAN Alaska, we have assumed that personnel on board have a linear relationship with topside tonnage as follows:

$$y = 0.0024x + 74.635,$$

where x = tonnage, which can range up to 40,000 tonnes or more.

3.5.5.1.2.4 Capital and Operating Costs

Gravity-based cost estimates present total installed costs (TIC) in 2010 U.S. dollars and include topside facilities. The estimates include costs associated with engineering and design through to installation, and commissioning/hook-up.

Estimates prepared for this study have not been based on a specific set of project criteria (location, environmental conditions, water depth, etc.), and therefore, a general approach and assumptions were required.

In line with the above, and approaches discussed below, overall costs prepared for this study are to be considered pre-appraisal or Class 5 level estimates at best; and, as such, have been generally provided with wide accuracy tolerances (e.g., -50% to +100%). It should be noted however, that while these tolerances have been included in an attempt to bound study cost estimates, due to the high-level nature of this study and broad geographic scope (i.e. arctic and sub-arctic areas of the Alaskan OCS), the accuracy tolerances provided will likely not bracket all conceivable scenarios.

Ultimately, cost estimates/information presented in this study will be used as input to the BOEM economic impact model (MAG-PLAN Alaska), and they are sufficient for this purpose. Current study cost estimate work should not be used as a basis for assessing the feasibility of a specific project. More definition and engineering and design work for the project would be required than is presented in the exploration and development scenario.

A Class 5 level estimate, as characterized by the Association for the Advancement of Cost Engineering International (AACE International, 2011), would be based on little to no (0%-2%) project definition.

Estimates prepared for this study have not been based on a specific set of project criteria (location, environmental conditions, water depth, etc.), and, therefore, generalities and assumptions were required to be made. In addition, estimates have been provided with accuracy tolerances in an attempt to bound estimate uncertainty.

Gravity-based structure cost estimates have been prepared for water depth ranges of 10-15m and 15-100m. Gravity-based substructure cost estimates for the primary planning areas of interest in this study (Beaufort Sea, Chukchi Sea, North Aleutian Basin, and Cook Inlet) have been based largely on interpolation/extrapolation of previous work conducted for BOEM (IMVPA, 2008). Gravity-based structure sizing and cost estimation work contained in IMVPA's report was based on assumed and general scenarios that could potentially be encountered in the Alaska OCS.

Based on the variety of seabed conditions that can be encountered in the various planning areas, or in a particular planning area, a minimum or 'typical' amount of foundation preparation and excavation work has been assumed in each cost estimate.

It has been assumed that the quay-side completed gravity-based structure will be towed from Korea to a location in the Alaskan OCS, and then set-down on a prepared foundation. The number of tugs required has been estimated based on the review of previous towing operations (e.g., CIDS, SDC, Hibernia).

Marine support equipment required for foundation preparation, cold region towing segments, installation, and equipment mobilization and demobilization has been accounted for. It should be noted however that it is assumed that a GBS structure will be installed in the same season the associated export pipeline installation finishes. As a result, and to avoid duplicating costs, consideration was given to the equipment which would already be employed during pipeline construction.

Typical marine support equipment would include ice-class work and crew boats, ice breakers, tug and fuel barge, weather and ice forecasting and monitoring services, etc.

Topside costs have been based on a range of oil or gas production rates, and are included in the overall costs presented below. All gravity-based platforms are assumed to be both production and drilling capable.

The following general notes should be considered in conjunction with the estimates provided below in Table 9:

1. Costs are inclusive of engineering and permitting support (10%), project management (6%) and contingency (30%)
2. Given the short open water season in certain planning areas, multiple years of construction and development may be required and the years of offshore and total construction are based on the expected cost estimates.
3. 0-construction years indicates that the gravity-based structure is assumed to be installed in parallel with completion of an export pipeline.

Table 9 is an example table that summarizes the capital cost estimates for a gravity-based structure in 15 meters of water in the Beaufort Sea. IMV Projects used proprietary data and methods in arriving at the capital costs and the detailed cost estimates are considered confidential and not provided in the report or the model. The detailed capital costs are, however, the basis for regression equations and other formulas that are employed in the model for the relevant ATs and AFs.

Table 9.

Summary Cost Table for Beaufort Sea Gravity-Based Structure

15m Water Depth					
Oil Production (kbopd)	Expected Cost (-20%) (2010 $)	Expected Cost (2010 $)	Expected Cost (+100%) (2010 $)	Offshore Construction Years	Total Construction Years
50	902,400,000	1,128,000,000	2,256,000,000	0	0
150	1,418,400,000	1,773,000,000	3,546,000,000	0	0
250	1,934,400,000	2,418,000,000	4,836,000,000	0	0

Source: IMV Projects, 2011.

Note: kbopd is thousands of barrels of oil per day.

Capital Costs for Topsides

The topsides cost estimating method is used to determine cost associated with an offshore production platform topsides to be installed offshore Alaska. The costs include the following components:

- Engineering and Design
- Structural Steel Materials and Fabrication
- Equipment
- Piping Materials and Fabrication
- Electrical Materials and Fabrication
- Instrument Materials and Fabrication
- Architectural Materials and Fabrication
- Drilling Rig and Equipment
- Transportation
- Offshore Installation
- Offshore Hook-up.

Topsides capital expenditure estimates do not include the cost of the substructure (jacket, GBS or hull) or account for potential synergies with other development components; however, such opportunities may be limited based on typical development execution strategies.

The topsides cost estimating approach relies on the assumption that topsides weight is proportional to the design production capacity in Barrels of Oil Equivalent (BOE). BOE is calculated as follows:

[Oil Rate in BPD] + [Gas Rate in MMSCFD / 6] + [Water Injection Rate in BPD / 3]

By trending known topsides weights against their design capacities, a linear trend line was determined. The data used for the known topsides weights were primarily based on Gulf of Mexico and North Sea topsides. In order to account for whether or not the topsides were designed to support a drilling package, multiple trend lines were created. A trend line was created for each of two platform types (see Figure 68 below):

- PDQ – Production Drilling and Quarters Topsides (e.g. GBS topsides)
- PQ – Production and Quarters Topsides (e.g. FPSO topsides).

Using BOE, the facility type, and the associated trend line, an estimated Gulf of Mexico / North Sea equivalent weight is established.

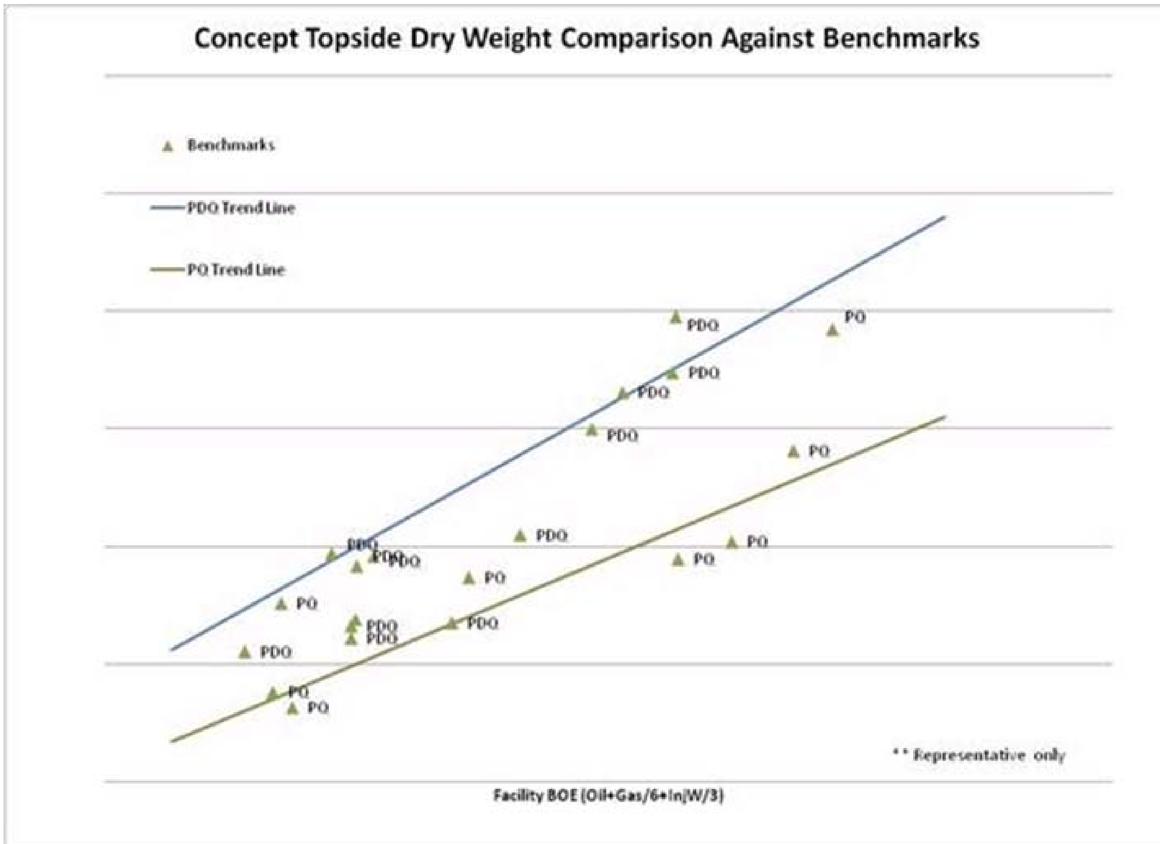

Figure 68. Estimated Topside Weight vs. BOE

Source: IMVPA, 2008

Note that the weight of the drilling equipment for the PDQ type platform is not represented in the trend line since the drilling rig weight and cost is not a function of BOE. The drilling rig weight and cost are accounted for separately, and added to the weight and cost of the base topsides cost. However, even excluding the drilling rig and equipment, the topsides weight for a drilling and production platform is normally higher than the weight of a dedicated production platform.

For the purposes of cost estimating, it is assumed that topsides weight is distributed consistently between material and equipment types. Hence, the weight is then distributed proportionally among the following categories:

- Structural Steel
- Equipment

- Piping
- Electrical
- Instrument
- Architectural
- Other

Once the weight is calculated for each category, it is adjusted from the Gulf of Mexico/ North Sea equivalent weight basis to an offshore Alaska weight basis—adjustments are made at the category level. In general, all platform weights will increase as a result of Alaska's harsh offshore arctic environment. The architectural category, for example, will be much higher.

Fabrication Costs

The above noted adjusted category weights are then used along with an assumed category-specific unit costs (per ton) to calculate category costs. The sum of the category costs equates to the total topsides fabrication cost. The fabrication cost includes engineering, equipment, materials and labor to build and prepare for loading the entire topsides.

Transportation Costs

Transportation costs are based on the assumption that the transportation spread size and associated cost per day, and the transportation time, are a function of the weight of the topsides. As the weight of the topsides increases, the spread size and number of transportation days also increases. Spread cost includes all cost associated with transportation including barges, tugs, fuel, labor, etc.

The above approach is applicable for gravel islands and Cook Inlet tower structures; however, it has been assumed that a shipyard will build the substructure and topsides for GBSs and FPSOs, and therefore transportation costs have been omitted for these options.

Installation Costs

Where topsides have to be installed on location (i.e. gravel islands), installation costs can be a significant cost component of an offshore development, especially for large and heavy topsides due to the very expensive equipment (e.g. derrick barges) required to perform the operations. The installation cost is based on two cost components:

1. Mobilization/demobilization cost
2. Spread day rate times number of installation days.

These components are a function of topsides weight, increasing as topsides weight increases. Spread cost includes all cost associated with installation including labor, accommodations, heavy marine lifting barges and support vessels.

The above approach is applicable to gravel islands and Cook Inlet tower structures only. For structures that will be fabricated in a shipyard/quayside (e.g. GBS, FPSO) topside installation costs are assumed to be accounted for in substructure and topside fabrication costs.

Hook-Up Costs

For gravel islands and Cook Inlet tower structures, hook-up includes the labor and materials required at the platform final location after the topsides is set on the substructure. Like installation cost, this cost can be very significant due to the remoteness of the operations and the expected low oil and gas activity offshore Alaska. The hook-up cost is based on spread day rate multiplied by the number of hook-up days. The number of days and crew day rate are a function of topsides weight, increasing as topsides weight increases. Spread cost includes all cost associated with hook-up including labor, accommodations, equipment and consumables.

3.5.5.2 Production Platform Support Operations

Other than the actual production costs, which are discussed in Section 3.5.5.2, the next largest cost items in platform-related operating costs for the ice-infested areas (Beaufort and Chukchi Seas) are the costs for building a dedicated icebreaker and an ice class multi-purpose vessel. The cost of these Jones Act compliant vessels has been included as an operating cost over a 20-year period.

Another significant cost is a marine survey of the pipelines conducted every year for the first five years and at five-year intervals thereafter. These surveys will be necessary to confirm that ice scour from ice keels is not to a depth where the pipeline is being contacted and possibly damaged. A further inspection cost is running intelligent pigs on the same frequency as the marine surveys.

In the Cook Inlet and North Aleutian Basin, the largest cost item is the two dedicated multi-purpose support vessels charged to the operating costs. Geotechnical marine surveys and intelligent pig runs are included every five years to confirm the integrity of the pipeline.

Because of the limited information available upon which to develop an estimate of operating costs, a contingency of 40% has been included in all of the estimates of operating costs

3.5.5.3 Production Drilling

Production drilling, often referred to as development drilling, occurs in the first few years after the production platform is installed to bring the field on line. As production peaks and then begins to decline, other wells may be drilled as sidetracks off existing wells to maintain production levels or to slow the decline rate. Sidetrack drilling is more sporadic than, and not as sustained as, the original development drilling program, but otherwise similar to the exploration drilling described in Section 3.5.3.2. Production drilling also has similar characteristics to the exploration drilling cited in Section 3.5.3.2, and the reader is referred to that section for information on manpower requirements and costs. In addition, the marine and onshore support for production drilling is similar to the vessels and equipment described in the prior section. The two production drilling-related items that are distinct from exploration drilling are workovers and subsea drilling and completions, which are described below.

3.5.5.4 Workovers

Oil and gas wells need maintenance over time, and some of this activity is conducted in the well or "downhole," and is called workover in the industry jargon. Workovers include such activities as conducting operations to reduce the amount of water that is produced with the oil and gas, or to reduce the amount of gas produced with oil, or if there are several producing intervals and a lower one is depleted, putting a plug above the depleted interval to seal off the lower reaches of the well. Workovers might be needed every 5 to 10 years, and the model assumes that workovers are conducted every fifth year after the production well is drilled. While directional production wells may take 30 to 60 days to drill and complete, workovers for a single well can be accomplished in one to two weeks. The model assumes a two-week period for each workover operation. Thus, if six production wells were completed in the first year of production drilling, 12 weeks would be required to complete the workovers in year six.

3.5.5.4.1 Manpower

After production drilling is completed the drilling crew would demobilize from the production platform. The drill rig would likely remain on an offshore platform although the drill rig could be demobilized from an onshore ERD platform. A portion of the specialized drilling equipment would also likely be demobilized, since the day rates for this equipment are very high as described for exploration drilling.

Thus, conducting workovers would require the mobilization of a drill crew and needed support services to the platform, along with any specialized equipment or supplies (e.g., wireline equipment, coiled tubing, cement) needed for the workover operations. A workover crew is much smaller than exploration or production drilling crews, with a typical range of 18 to 24 persons in the crew. If only one well on a production platform needed a workover, then the operation could be conducted by one crew within a normal two-week rotation period. However, if more than one workover were required, then it is likely that the platform operator would seek to minimize costs by having crews rotate to complete both workover operations as expeditiously as possible. The model assumes that all production wells drilled in the same year require workovers in the same future years and that they are conducted sequentially so that a second crew rotates in on a two-week schedule and the first crew rotates out. Total employment is 36 to 48 persons for the duration of the activity, which depends on the number of production wells identified in the exploration and development scenario for each year.

3.5.5.4.2 Contract Cost

One of the persons interviewed for this topic indicated that the price of workovers starts at approximately $1 million and increases depending on the work to be conducted and the time necessary to complete the job. Mobilization to an offshore platform increases the cost of workovers reported for onshore wells, although the model assumes that the drill rig is available on the offshore platform so that mobilization of a workover rig is not necessary, although specialized equipment will be mobilized. The model calculates the total contract cost for workovers at three times the total labor cost plus owner’s costs, or about $6 million for a two-week workover.

3.5.5.4.3 Data Sources

The data sources for workovers are primarily interviews with a major drilling company on the North Slope and a global provider of drilling support services and equipment. There is a substantial amount of secondary information available on subsea operations and equipment that was reviewed for modeling information. In addition, IMV Projects developed very detailed proprietary cost estimates for subsea completions, which included various types of equipment and vessels for completing this task.

3.5.5.5 Subsea Drilling and Completions

The exploration and development scenarios provide an option for subsea wells in addition to wells drilled from platforms. Subsea production systems can range in complexity from a single satellite well to several wells on a template or clustered around a manifold with a flowline linked to a fixed platform, a floating platform, or an onshore installation. Subsea production systems can be used to develop reservoirs, or parts of reservoirs, which require drilling of the wells from more than one location.

With production equipment located on the seafloor rather than on a fixed or floating platform, subsea processing can, in some situations, provide a less-expensive solution for offshore development and production. Originally designed as a way to overcome the challenges of deepwater discoveries, subsea processing has also become an economical solution for certain fields located in ice conditions where processing equipment on the water's surface might be at risk. Additionally, subsea processing can be employed to increase production from mature or marginal fields in some circumstances.

The main types of subsea processing include:

- water removal and re-injection or disposal
- single-phase and multi-phase boosting of well fluids
- sand and solid separation
- gas/liquid separation and boosting, and
- gas treatment and compression (RigZone, 2011b).

Subsea separation of water, sand, and gas reduces the amount of production necessary at the water's surface, thereby avoiding limitations of surface processing capacity that may exist. Also, by separating unwanted components on the seafloor, flowlines and risers are not lifting these ingredients to the surface facility just to direct them back to the seafloor for re-injection. Re-injection of produced gas, water and waste increases pressure within the reservoir that has been depleted by production. Also, re-injection helps to decrease unwanted waste, such as flaring, by using the separated components to boost recovery. Figure 69 shows the subsea production facility used at the Tordis field, which began operations in 2007 as the world's first full-field subsea separation, boosting and injection system. Through subsea processing, the mature Tordis oil field increased recovery by an extra 35 million barrels of oil and extended the life of the field by 15 to 17 years (RigZone, 2011b).

Figure 69. Tordis Subsea Production Facility

Source: RigZone, 2011b.

There are a number of reasons why operators may choose to install subsea processing equipment:

- Most subsea processing may increase the recovery from the field, thus increasing profits;
- By enhancing the efficiency of flowlines and risers, subsea processing contributes to flow management and assurance;
- Subsea processing may enable development of challenging and marginal subsea fields while reducing expenditures for surface production equipment.

Figure 70 illustrates the complexity of a major subsea development with subsea wellheads, subsea separation and production facilities, flowlines and risers, and a floating production, storage and offload (FPSO) vessel. Total's Pazflor project offshore West Africa is expected to come on-stream in 2011.

Figure 70. Total's Pazflor Subsea Development

Source: RigZone, 2011b.

3.5.5.5.1 Vessels and Equipment

The model assumes that the same platform used to drill the exploration wells is used for drilling the subsea wells. While the drilling platform can also be used to install the subsea production equipment, it is anticipated that the drilling platform would be moved to the next well site to maximize the number of wells drilled per open-water season with a specialized vessel used to install the subsea equipment. Information for exploration platforms was discussed in Section 3.5.3.1 and the information is not repeated here.

Subsea installation may require a small fleet of vessels to complete the operations as effectively as possible given relatively short open water seasons in many areas. The vessels may include the vessel actually installing the equipment on the seabed; supply vessels to deliver equipment, supplies, pipe, and other materials; dredges to bury the pipeline in areas where ice gouging may be prevalent; freighters if the pipe is brought from Asian suppliers; geophysical and geotechnical vessels to survey the installation site and the pipeline route; crew boats for crew rotations; other work boats, tugs and barges; and ice management boats if working in waters where ice conditions warrant their presence. Previous sections of this report have described supply vessels (Section 3.5.2.1.2), tugs and barges (3.5.1.6.2), ice management boats (Section 3.5.3.3.1), geophysical and geotechnical vessels (Sections 3.5.2.4.2 and 3.5.2.5.1), and crew boats and other work boats (Section 3.5.2.3). The following paragraphs describe the vessels that have not been previously discussed such as the subsea installation vessels, derrick barges, dredges, FPSO's, and freighters.

Figure 71 shows the M/V Boa Sub C, a multi-purpose vessel that is under long-term charter for subsea installation work. The vessel is 138.5 meters (454 feet) in length and 30.6 meters (100 feet) in width. It has two remotely operated vehicles, one on each side of the vessel that can operate to depths of almost 10,000 feet for subsea installation and maintenance. Note the cranes and large work deck that enable the vessel to move and install large units of subsea equipment.

Figure 71. M/V Boa Sub C

Source: Boa Group, 2011.

Other types of vessels may be required depending on the particulars of the subsea installation. For example, Figure 72 shows an unnamed derrick barge beginning to lower equipment to the seafloor for the Tyrihans project developed by Statoil in the North Sea. Derrick barges would be preferable to ships where equipment weights are significant.

Figure 72. Unnamed Derrick Barge with Subsea Equipment

Source: Rigzone, 2009.

Figure 73 provides another example of a derrick barge that can be used for subsea installation work. The large crane has a capacity of 800 metric tons and the barge has a moon pool that can be used for subsea installation and maintenance work. The barge is 394 feet in length and is 104 feet wide.

Figure 73. Derrick Barge Superior Performance

Source: Superior Energy Services, 2011.

Maintenance of subsea installations also requires specialized vessels. The M/V Fugro Synergy (Section 3.5.2.5.1) is one example of this type of vessel. A second example is the M/V Seawell, which pioneered vessel-based subsea wireline and coiled tubing services in the North Sea since 1987. The vessel and its crew have entered more than 650 wells, and decommissioned over 150 wells and 15 subsea fields. The vessel's two-bell saturation diving system is rated to 300 m and has capacity for 18 divers. The diving system, combined with the vessel's observation and work class ROVs, provides for full IRM and construction services. Overall length of the vessel is 114 m (374 feet) with a beam of 22.5 m (74 feet).

Figure 74. M/V Seawell

Source: Helix Energy Solutions Group, 2011.

Dredges and trenchers will be important to ensuring that the flowlines and pipelines are buried sufficiently deep to avoid damage by ice gouging in Arctic conditions, and to avoid exposure while transiting the shallow water and beach zones. Figure 75 shows the M/V Island Pioneer, a multipurpose vessel that is equipped with a ROV trencher to bury pipelines and flowlines (See Figure 76). The Island Pioneer is 93 meters in length (305 feet) with a beam of 20 meters (66 feet).

Figure 75. M/V Island Pioneer

Source: Canyon A Helix Energy Solutions Company, 2011.

Figure 76. T750 Trencher ROV

Source: Canyon A Helix Energy Solutions Company, 2011.

The Island Pioneer and the ROV trencher are particularly well suited for dredging or trenching in deep water. In shallower waters, a trailing suction dredge may be employed and in even shallower waters, a cutter head dredge may be used. These dredge types are described below.

The vessel shown in Figure 77 is a suction dredge with two 35-inch diameter trailing suction pipes to gather the dredge material and deposit it into the cargo hold of the vessel, and bottom doors of the hull that open to release the dredged material when the vessel is located over an approved dredge disposal area. The vessel is also capable of pumping the dredge spoils ashore via floating flexible pipes. It is 103 meters (338 feet) in length and 18 meters (59 feet) in width.

Figure 77. Unnamed Trailing Suction Hopper Dredge

Source: Dredge Brokers, 2011a.

In shallower waters a cutter head dredge (See Figure 78) may be employed. The length overall of the vessel is 86 meters (282 feet) in length, with a deck being 65 meters (213 feet) in length. The barge has a beam of 19 meters (62 feet). The vessel has two steel piles that are 150 meters (492 feet) in length that can effectively anchor the barge in place while dredging operations are ongoing. The 9-foot diameter cutter head is used to displace the seafloor material, which is then suctioned up to the barge via a 30-inch pipeline and then transported via floating flexible pipelines to an approved disposal area.

Figure 78. Unnamed Cutter Suction Dredge

Source: Dredge Brokers, 2011b.

A number of different types of fixed or floating platforms can be used with subsea completions. Most of these platform types have been described earlier in this report. FPSOs are one production platform that has not been previously described and are presented in this section.

A FPSO unit is an offshore production facility, typically ship-shaped, which processes raw oil from wells located on the seabed. FPSO units are connected to a wellhead platform or seabed wells through a series of flexible tubes called risers. An FPSO receives oil from the seabed, processes it to remove impurities, such as water, gas, sand and stones, and stores it on board before offloading to shuttle tankers. FPSOs are suitable for a wide range of field sizes and water depths and can be either purpose built—at a cost ranging from USD 100 million to over USD 1 billion—or converted from an existing oil tanker (Teekay Offshore Partners L.P., 2011).

Figure 79 shows the M/V Petrojarl Varg, a 214 meter (702 feet) long by 38 meter (125 feet) FPSO that is under long-term charter to Petrobas offshore Brazil. The vessel can handle up to 82,000 barrels of liquids per day including 57,000 barrels of crude oil per day. Crude oil storage capacity is 470,000 barrels. The ship is also capable of reinjecting seawater and natural gas back into the reservoir. The ship is arranged from forward to aft in the following arrangement (Teekay Offshore Partners L.P., 2011):

- Helicopter deck
- Accommodations area
- Turret area including crane (the vessel has a 10 point anchoring system and the turret enables the vessel to turn into the wind as needed to maintain station)
- Process area including two cranes
- General facilities including power generation
- Offloading area and flare.

In comparison to more traditional offshore platforms, which are typically manned by employees with experience in the onshore oil field and oil service companies, FPSOs, since they are ships, are crewed with vessel masters, ships officers, and a crew, which is typically made up of members of various seafarers unions. Thus, wage rates on FPSOs vary from other platform types.

Figure 79. M/V Petrojarl Varg

Source: Teekay Offshore Partners L.P., 2011.

Shuttle tankers are specialized ships built to transport crude oil and condensates from offshore oil field installations to onshore terminals and refineries. Highly trained crews and advanced onboard technology, including dynamic positioning and offshore loading systems, ensure the safe and reliable offloading of oil from offshore installations in both deepwater and harsh weather. Shuttle tankers can be either purpose-built or converted from existing conventional oil tankers.

Key features of newer shuttle tankers include:

- Dynamic positioning (DP), which monitors wind, currents, swells and tide changes to allow the vessel to position itself near an offshore installation and remain in position, without anchoring, when connected to offshore installations or a loading system, even in harsh weather
- Variable pitch propellers and lateral thrusters, which control the positioning of the vessel as determined by the DP
- Bow loading systems, which allows for the transfer of oil from a variety of fixed or floating offshore installations, even in extreme weather conditions
- High cargo pumping capability
- Reinforced hull design for fatigue prevention, which is particularly important in harsh weather environments.

Shuttle tankers use DP to remain in position rather than anchoring, making them suitable for areas with subsea equipment or in deepwater. Also, shuttle tankers can transport oil from offshore installations to numerous discharge locations rather than a single destination as is the case for pipelines.

Figure 80 shows the M/V Basker Spirit, a shuttle tanker capable of holding 686,263 barrels of crude oil. The vessel has an overall length of 256.8 meters (842 feet) and a beam of 41.1941 meters (135 feet) (Teekay Offshore Partners, L.P., 2011).

Figure 80. M/V Basker Spirit

Source: Teekay Offshore Partners, L.P., 2011.

Pipelay vessels and barges will also be required to install flowlines and pipelines. Given the short open water season in the Arctic, it is anticipated that modern pipelay vessels will be required if the distances involved are substantial. Figure 81 shows the M/V Solitaire, the largest pipelay vessel in the world at 300 meters (984 feet) excluding the stinger shown in the photo. The vessel can carry 22,000 tons of pipe and has achieved lay speeds of nine kilometers (5.6 miles) per day. While the Solitaire and similar ships are required in deep water, small modern pipelay ships can still attain good lay speeds in the relatively shallow waters of the Beaufort and Chukchi Seas.

Figure 81. M/V Solitaire

Source: Allseas, 2010.

In shallow waters closer to shore, pipelay barges similar to the Big Chief (See Figure 82) could be used. The Big Chief is 220 feet long and 74 feet wide and has two 70-foot steel piles that can be used to assist the barge in holding location during pipelay operations. In even shallower waters in Arctic planning areas, the pipeline may be installed during the winter using over-the-ice construction methods and large excavators to dig the trench lower the pipe into the trench and then backfill.

Figure 82. Big Chief

Source: Bisso Marine Company, Inc., 2011.

SA-15 is the project name for a series of icebreaking 15,000 dead-weight-ton cargo ships built in Finland for the Soviet Union in the 1980s. The ships, capable of independent operation in Arctic ice conditions, were the first merchant vessels designed for year-round operations in the Northern Sea Route. They have hulls that resemble those of polar icebreakers and powerful propulsion systems to move through ice conditions. Similar ships may be used to transport pipe and other materials to Arctic waters for development activities.

The M/V Norilsk (See Figure 83) was the first of the SA-15 class of cargo vessels to be built, and the Norilsk and its sister ships established the trade between the Norilsk nickel mine in Dudinka Russia and the rest of the world. The vessel's length was 176.85 meters (580 feet) with a beam of 24.5 meters (80 feet). The Norilsk was reportedly sold for scrap and recycling on November 3, 2010 (Mersey Shipping, 2010).

Figure 83. M/V Norilsk

Source: Wikipedia, 2011.

3.5.5.5.2 Manpower

Large ships typically have crews on 8-hour shifts to reduce human error and enhance safety, as compared to 12-hour shifts typically found on the North Slope and elsewhere in the Alaska oil and gas industry. Consequently, while the number of crew may seem large, the number of crew on duty is lower than might be expected given the total crew on board.

The M/V Boa Sub C has 105 single cabins and 10 of the cabins have Pullman beds, so the total number of people that can be accommodated is 135. The Seawell has accommodations for 122 people. A review of other subsea installation vessels suggested a range from 100 to 150 persons on board. With rotations, 200 to 300 people could be employed on these vessels during the time they are engaged in subsea installation or maintenance.

Derrick barges such as the M/V Superior Performance can accommodate 272 people. A review of other derrick barges indicates a potential range of 250 to 300 persons on board, or the potential for 500 to 600 persons to be employed on these vessels.

Dredging and trenching vessels and barges can have a wide range of accommodations. The M/V Island Pioneer has accommodations for 85 persons while the unnamed suction hopper dredge has 32 berths. A review of manpower requirements for other cutter suction head and suction hopper dredges indicates a range of 24 to 35 employees onboard at any time. Total employment would range from about 48 to 70 persons.

The staffing level, including catering, onboard the M/V Petrojarl Varg is 41 persons during normal operation. The vessel can accommodate 77 persons onboard if needed. A review of accommodations for other FPSOs and floating storage and offtake vessels (FSOs) indicates a range of 18 to 77, with the FSOs having crews at the lower end of the range since they do not have production facilities.

Information found for shuttle tankers indicates an onboard crew of about 27 persons and, with rotations, approximately 54 people employed for each vessel.

The M/V Solitaire has 420 berths as might be expected for such a large construction vessel. In comparison, the Big Chief pipelay barge has accommodations for 56 persons.

MV Norilsk had accommodations for 42 crew and 10 passengers (The Motor Ship, 1983). Newer cargo vessels are more automated than the Norilsk and would require fewer crew members. Staffing on newer vessels could be in the range of half to two-thirds of the Norilsk's crew.

Total manpower requirements for a subsea installation if all of the vessels were present at the same time could exceed 1,050 persons on site with total employment exceeding 2,100 people.

3.5.5.5.3 Capital, Operating, and Contract Costs

Capital cost estimates have been prepared for an eight mile-long subsea tie-back to an offshore structure for three different development scenarios:

1. Gas Tie-back in Arctic Areas (Beaufort and Chukchi Seas)
2. Gas Tie-back in Sub-Arctic Areas (Cook Inlet and NAB)
3. Oil Tie-back in Sub-Arctic Areas (Cook Inlet and NAB)

For the Arctic region tie-back, subsea facilities include a single eight-well drill center set in a cased glory hole with a multiphase gas pipeline, monoethylene glycol (MEG) pipeline and umbilical buried in a trench running to the offshore structure where the production facilities are located.

The other two cases are for oil or gas subsea developments in sub-arctic areas, where floating ice could be present in the winter, but would not impact the design of the facilities or the amount of time available in the construction season to install the needed subsea equipment, pipelines and umbilical.

All offshore construction for subsea tie-backs has been assumed to be conducted in the summer season/open water. For gas tie-backs, 12-nominal pipe size (NPS; approximately the inside diameter in inches) pipelines have been used, and for oil, 8-NPS pipelines have been used.

Considerations and assumptions pertaining to trenching/dredging, pipeline burial, logistics, and Jones Act compliance, are discussed in the Offshore Pipeline section.

Cost estimates are expressed in 2010 US dollars using cost information developed from previous arctic experience and by adjusting available industry cost data from projects in other parts of the world. Engineering and permitting support has been included in all cost estimates at 10 percent of construction costs and 6 percent has been added for project management. No contingency has been included in these cost estimates. Because of the many unknowns associated with work in an arctic environment, a range of costs from –20 percent to +100 percent has been shown.

Because of the small quantity of pipe required for a single subsea development tie-back and the relatively small pipe diameter needed, the cost estimate assumes that the pipe will be manufactured in the southern United States (Texas or Louisiana). The pipe will be coated with FBE anti-corrosion coating in the same area and then welded and spooled onto reels.

The production flowline, MEG pipeline and umbilical will be spooled onto reels mounted on a barge and then towed to the construction site.

All of the subsea equipment is manufactured in the Gulf of Mexico area and shipped by tug and barge from the GOM to the construction site. For the arctic gas tie-back, the steel caisson structure (i.e. cased glory hole) to be set in the dredged glory hole is assumed to be fabricated in one of the yards in the Seattle area and transported by tug/barge.

As far as marine support services are concerned, with the exception of aiding with setting the steel caisson into the glory hole that will contain the subsea wellheads and other equipment, survey vessel requirements will essentially be the same as discussed in the Offshore Pipeline section. A single crew boat is included in each cost estimate. It has been assumed that these vessels can be chartered locally, but there may be no American vessels that meet the "coastwise passenger law" and also meet technical requirements for operating in ice-infested waters. Funds could be required to fabricate a new vessel for this service but have not been included in the cost estimate. Certainly for the cases where development is in open water, vessels exist that could provide this service.

None of the specialized equipment described above for subsea installation is located in Alaska where interviews might have been conducted, so a large secondary research effort was necessary to identify contract costs or day rates for this equipment or similar vessels. Mobilization and demobilization costs were a major cost component for the vessels noted above since most of them operate globally or are located in the Gulf of Mexico. As was noted earlier for anchor handlers and platform supply vessels, the day rates or charter rates for oil and gas support vessels has shown wide ranges over the past few years and future rates could exceed the ranges noted here. The costs shown here are the costs to the operator or the field developer. These rates are not bareboat charters (without crew) from a vessel owner to the vessel operator. For some vessels and equipment, day rates were not found but information on new construction cost was found. In those cases, the day rate was constructed from debt service assumptions, crew costs, and operating costs excluding fuel. In instances where neither day rates or capital cost were found, estimates were made using information for analog vessels or equipment. For example, trenching vessels are considered to have day rates similar to the largest subsea vessels. Note that the rates presented below do not include owner's costs, estimated at 25 percent of the day rate or charter costs.

Subsea vessel rates are estimated to range from \$65,000 to \$175,000 per day depending on size and capability of vessel. The very largest subsea vessels could have day rates larger than this estimate.

Rates for derrick barges ranged from \$500,000 to \$600,000 per day, with smaller crane barge rates at \$35,000 to \$60,000 per day.

No information on day rates or charter rates was found for trenching vessels, but those rates may be similar to the high end of the subsea vessels' day rates given the similar nature of the vessels in many regards. Day rates for dredging barges and trenching barges ranged from \$25,000 to \$52,000, with the cutter suction head barges at the lower end of the range due to their inability to work in deeper water.

FSOs and FPSOs are typically on long-term charters with rates ranging from \$80,000 to \$263,000 per day, primarily depending on the production capacity of the vessel, and whether it was new-built or a converted oil tanker; conversions generally had lower rates.

Shuttle tankers also generally operate on long term charter rates and one source noted a long term charter rate of \$46,000 per day.

Pipelay vessels are chartered for a specific pipelay project, so they are not long-term charters, and the rates ranged from $151,000 to an estimated $400,000, depending on the vessel's capabilities.

The cost for the steel pipe is estimated in the model using a regression equation derived from a set of proprietary cost estimates prepared by IMV Projects. The model calculates the size of pipe required in the peak production year for oil and a similar estimate for gas and using this diameter and the distance in miles specified in the exploration and development scenario obtains an estimate of the metric tons of steel required for the oil pipeline and a separate estimate for a gas pipeline. A current cost of $2,300 per metric ton is applied to each tonnage estimate to arrive at the steel cost.

A spot rate of $10,000 to $15,000 was used in the model based on spot rates for Handysize bulk cargo carriers which are in the same general size class as the SA-15.

The current subsea cost estimates three drill centers, capable of supporting 8 wells each, and 1 hub/manifold center capable of 4 wells, for a total of 28 wells. Depending on production volume, the costs could range from $1.2 billion to $3.3 billion, although the expected cost range is from $1.5 to $1.7 billion. These total costs include all of the vessel and steel costs noted above.

3.5.6 Abandonment

Abandonment or decommissioning of wells and structures occurs after a platform stops production for five years or more. In some cases, platforms have been toppled to the seafloor to create habitat for marine life, while in other circumstances the platform and all wells are cutoff below the seafloor and the platform and all equipment on the seafloor is removed and disposed of elsewhere. The model assumes that removal of the platform and all appurtenances will be required in the future. No production platforms have been abandoned or decommissioned in Cook Inlet or the Alaska OCS as of late 2011, although decommissioning of several platforms in Cook Inlet has been discussed.

The model assumes that all onshore facilities remain in place to service other fields that are still in production.

3.5.6.1 Data Sources

While the costs of platform decommissioning in the Gulf of Mexico and other parts of the world are available, it was felt that these costs would not be representative of the costs for decommissioning in Alaska, so the costs of labor and each vessel or major of equipment that would be used in this activity were estimated separately. The vessels and equipment required for decommissioning have all been discussed in previous sections of this report, so this section identifies the vessels and equipment and provides a summary of total manpower requirements and the total cost for decommissioning, but does not repeat the manpower and cost for each vessel and piece of equipment.

3.5.6.2 Vessels and Equipment

The costs of operating in the Arctic are much higher than in subarctic areas of Alaska, and oil and gas production will need to be much greater to cover these costs. As a result, the production capacity and the platforms will need to be much larger than the typical platform in Cook Inlet.

Because of these differences, MAG-PLAN has different vessel and equipment requirements for Arctic and subarctic planning areas, and for different platform types.

Table 10 shows the number and types of vessels and equipment that are used in the model for decommissioning different platform types in Arctic and subarctic planning areas. The derrick and crane barges are assumed to have dive and ROV personnel onboard as necessary. For gravel islands, it is assumed that the gravel will remain in place and that natural forces will be allowed to shape the island into a natural form over time. On the other hand, the ERD pad is assumed to be reused and the land rehabilitated to bring it back to its former condition.

Table 10.

Number and Types of Vessels and Equipment for Decommissioning Platforms

	Arctic		Subarctic		Onshore
Vessel or Equipment Type	**Bottom-founded**	**Floating**	**Bottom-founded**	**Floating**	**ERD**
Derrick Barge & AHTS	1	1			
Crane Barge & AHTS	2	2	2	1	
Subsea Vessel		1			
Helicopter crew	1	1	1	1	
Helicopter support	1	1	1	1	
Icebreaking workboats	1	1			
Ice management boats	1	1			
Workboats/supply boats			1	2	
Crawler crane					1
Demolition crew					1
Trucks					8

3.5.6.3 Manpower

Total manpower requirements for decommissioning a platform range from about 70 persons for removal of an ERD facility and pad to a range of 800 to over 1,000 for deepwater OCS platforms in the Arctic.

3.5.6.4 Contract Cost

The estimated costs for decommissioning range from about $9 million for the ERD facility to over $130 million for deepwater Arctic platforms. Subarctic platform decommissioning costs are estimated to range from $22 million to $27 million. These costs exclude owner’s costs, which are estimated at 25 percent of total contract costs.

3.6 ACTIVITY COSTS FOR EXTRAPOLATED OFFSHORE MODELING AREAS

As described earlier, the prior version of MAG-PLAN was based on theoretical projects in two planning areas: the Beaufort Sea and the Cook Inlet. The model used extrapolations and rules of thumb to allow users to estimate the impacts of activities in other areas. The current model is based on new planning area specific data for four areas: Beaufort Sea, Chukchi Sea, Cook Inlet, and the North Aleutian Basin. Prior exploration, development and production in the Beaufort Sea and Cook Inlet areas provide historic data for the model. Recent exploration plans and permit applications in the Beaufort Sea and Chukchi Sea also provide data on current exploration activities and manpower estimates. Projects from analog areas such as Russia and eastern Canada have been considered in developing profiles of future production activity in the Alaska OCS. The North Aleutian Basin was selected as the basis for extrapolation even though exploration activity in the area is limited because it represents a better analog to Bering Sea and remote Gulf of Alaska planning areas than any of the other three primary planning areas.

At the onset of the project, it was envisioned that a specific parameter or parameters could be used to estimate costs in the 11 planning areas that were not modeled directly. These potential parameters include:

- Metocean and ice conditions
- Regional or basin-specific seabed/soil conditions
- Water depth
- Reservoir features (oil or gas prone)
- Distances from support infrastructure

After the MAG-PLAN structure was developed, it became apparent that other approaches would be needed to generate costs for certain technologies and equipment in the 11 planning areas that were not modeled. The primary reasons or challenges that supported this conclusion are:

- Complexity and differences between technologies (e.g. relatively shallow water buried pipelines versus deepwater pipeline installation).
- Several technologies (e.g. gravel, ice islands, caisson retained islands, jacket, gravity based structures) are largely infeasible for a significant portion of the 11 planning areas due to much deeper water depths.
- For Alaskan OCS regions of deepwater, ultra-deepwater, and beyond (~10,000ft+), (e.g. Aleutian, Basin, Bowers Basin, Aleutian Arc), temperate region production structures and technologies such as spars, tension leg platforms, or semi-submersibles, which will not be required for exploration or production in the shallower waters of the Beaufort Sea, Chukchi Sea, Cook Inlet, or the North Aleutian Basin for the foreseeable future, needed to be considered.
- Based on resource assessments for the Alaskan OCS regions of deepwater, ultra-deepwater, and beyond (e.g., Aleutian, Basin, Bowers Basin, Aleutian Arc), pipeline export solutions do not appear to be economically feasible and may not be technically feasible at this time. For these remote deepwater Alaskan OCS regions, pipeline lengths would generally be well in excess of several hundred miles and boosting stations may be required.
- In areas with water depths in excess of the ultra-deepwater range (i.e. ~10,000 ft+), the technology and capability to install structures and infrastructure (e.g., platforms, pipelines, subsea equipment) does not currently exist—exploration structure capability in such water depths is very limited if not non-existent.

Several methodologies for creating and updating cost data were employed in the cost estimating procedures for the 11 planning areas that were not modeled:

- Parametric scaling and extrapolation (e.g., water depth, distance, production rate, etc.)
- Modifying and or extending cost functions and calculations from the modeled areas
- Basing costs on data collected for new structures/technologies (e.g., deepwater floaters)
- Developing cost functions for new structures/technologies (e.g., deepwater floaters)

To help clarify the points mentioned above, Figure 84 has been included as it provides insight on the current state of the art for deepwater drilling, subsea tree, and floating facility installations. In considering the water depths associated with some of the more remote Task 5 OMAs, trends in deepwater technology advancement have been considered in proposing technologies, and providing rudimentary cost estimate functions.

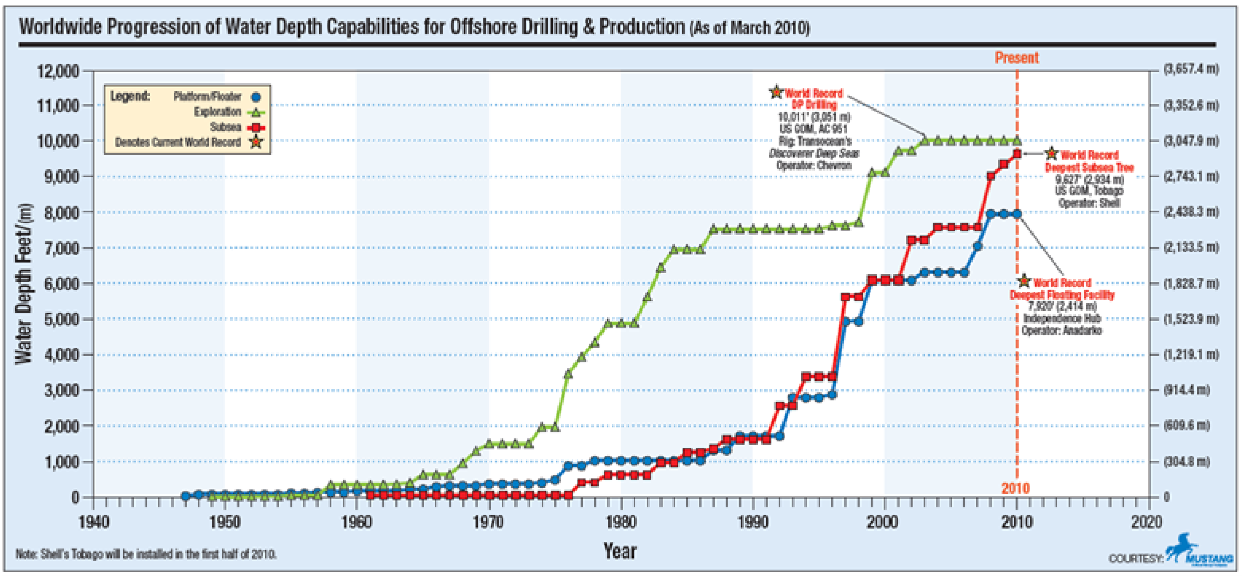

Figure 84. Deepwater Capabilities and Technology Records

Source: Mustang Engineering, 2010.

Similarly, Figure 85 below provides an overview of subsea tie-back records with respect to water depth and distance, and includes water depth range definitions as well.

In terms of technology advancement over time, the study team will consider figures such as those shown above. Another method of establishing a trend(s) for deepwater technology in the 11 planning areas would be to evaluate trends already established in the Gulf of Mexico. The effect of the recent oil spill in the Gulf of Mexico on deepwater technology advancement and development will also need to be considered.

Related to the above, addressing the potential future requirement for same-season relief wells should be considered by the BOEM resource evaluation team that prepares the exploration and development scenarios. Discussions with current lessees indicate that the economics of an exploration prospect are severely impacted if a exploration platform drill must be on standby to drill a relief well. If a same season relief well is required, an exploration drilling program involving two platforms located within reasonable proximity of each other, would be the most cost-effective approach.

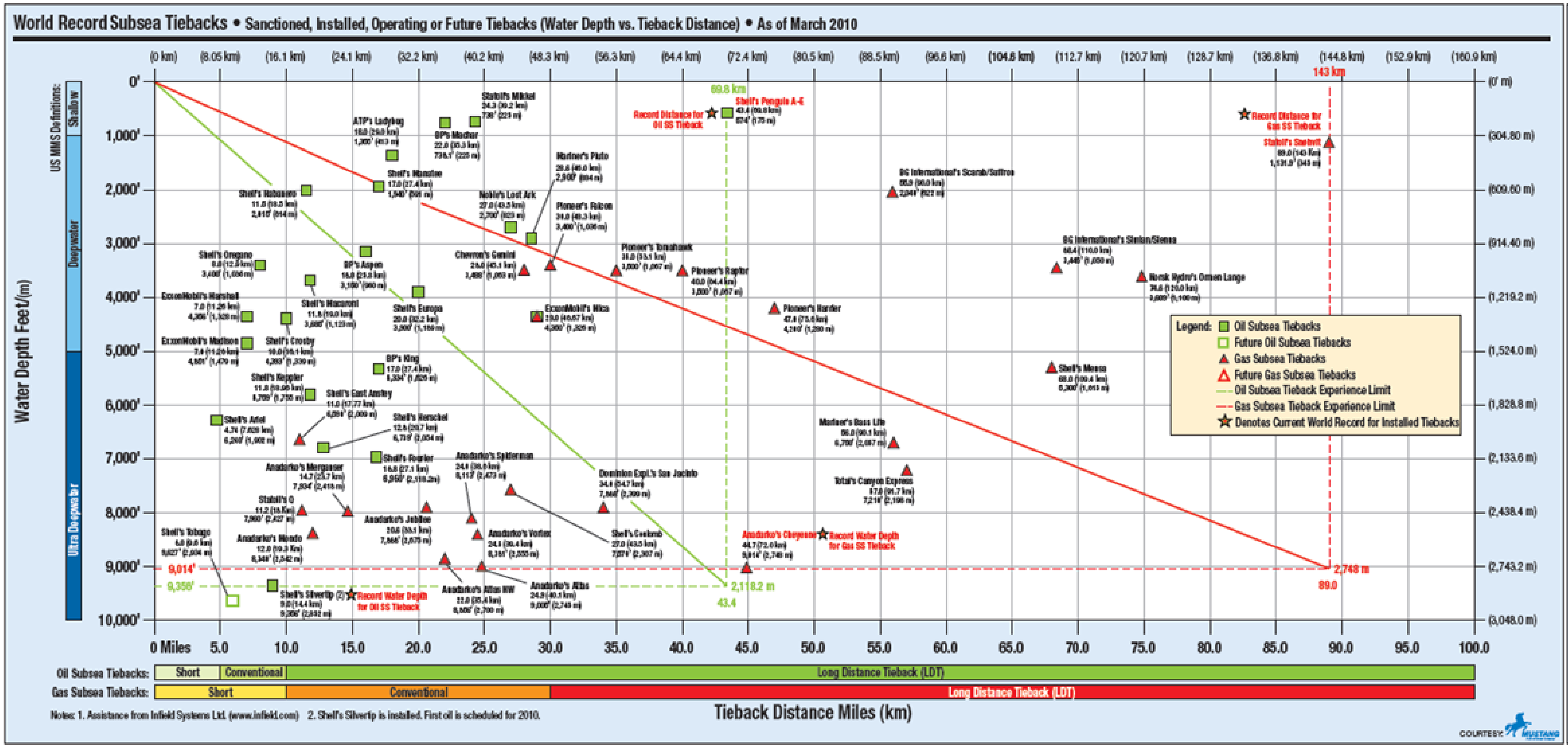

Figure 85. World Record Subsea Tiebacks

Source: Mustang Engineering, 2010.

Table 11 captures structures/technologies proposed for each of the 11 planning areas that were not modeled, along with notes on methodologies and bases for cost estimates. Structures and technologies were proposed based on considerations such as water depth, ice conditions, infrastructure, remoteness, input from BOEM resource evaluation regarding resource potential, etc. A separate table (Table 12) provides more detail on pipeline considerations and challenges.

Based on discussions between the consultant team and BOEM, exploration-related activities are the main concern in the foreseeable future for the majority of the planning areas there were not modeled; however, in line with the study scope of work, this report and MAG-PLAN maintain at least one production solution per planning area. Also, with the exception of the most remote planning areas with water depths largely beyond the ultra-deepwater range, each planning area has shallow-water and deepwater structures, as well as structures with and without storage.

Some examples of structure and technology costs are provided in the following tables.

In general, very remote and deepwater planning areas—Aleutian Basin, Bowers Basin, Aleutian Arc, Shumagin, and Kodiak will be very difficult to develop due to the limited resources anticipated in these basins and the cost of development. The model currently assumes subsea completions, FPSOs, and shuttle tankers are used to exploit oil and gas from these areas although water depths in these basins can exceed current technology.

Table 11.

Costing Methods and Cost Estimate Basis Considerations

Planning Area	**Structures/ Technologies**	**Notes on Costing Methodologies and Basis**
Hope Basin	Drillship	Based on modeled Chukchi cost function
	Gravity-based structure	Based on modeled Chukchi cost function; reduction factor to account for less severe ice environment
	Subsea Tie-back	Based on modeled Chukchi cost function; reduction factor to account for less severe ice environment
	Pipeline	Based on modeled Chukchi cost function; reduction factor to account for less severe ice environment
Norton Basin	Mobile Bottom- Founded	Based on modeled Chukchi gravity-based structure cost function
	Gravity-based structure	Based on modeled Chukchi cost function; reduction factor to account for less severe ice environment
	Artificial Island	Based on modeled Beaufort cost function; reduction factor to account for less severe ice environment
	Pipeline	Based on modeled Chukchi cost function; reduction factor to account for less severe ice environment
St. Matthew Hall	Semi	Based on modeled North Aleutian Basin cost function
	Gravity-based structure	Based on modeled cost function
	Tripod Arctic Floater	Based on modeled cost function
	Subsea Tie-back	Based on North Aleutian Basin cost function
	Pipeline	Based on North Aleutian Basin cost function
Navarin Basin	Semi	Based on North Aleutian Basin cost function
	Gravity-based structure	Based on modeled cost function
	Tripod Arctic Floater	Based on modeled cost function
	Subsea Tie-back	Based on North Aleutian Basin cost function
	Pipeline	Based on North Aleutian Basin cost function; cost increase factor to account for increased distance to landfall
St. George Basin	Semi	Based on North Aleutian Basin cost function
	Gravity-based structure	Based on modeled cost function
	Tripod Arctic Floater	Based on modeled cost function
	Subsea Tie-back	Based on North Aleutian Basin cost function
	Pipeline	Based on North Aleutian Basin cost function; cost increase factor to account for increased distance to landfall

Planning Area	Structures/ Technologies	Notes on Costing Methodologies and Basis
Aleutian Basin	Semi	Based on North Aleutian Basin cost function; deepwater cost increase factor
	Deepwater Floater	FPSO, TLP, or Spar; North Sea and Gulf of Mexico cost data with mobilization factor
Bowers Basin	Semi	Based on North Aleutian Basin cost function; deepwater cost increase factor
	Deepwater Floater	FPSO; North Sea and Gulf of Mexico cost data with mobilization factor
Aleutian Arc	Semi	Based on North Aleutian Basin cost function
	Deepwater Floater	FPSO; North Sea and Gulf of Mexico cost data with mobilization factor
Shumagin	Semi	Based on North Aleutian Basin cost function; deepwater cost increase factor
	Deepwater Floater	FPSO, TLP, or Spar; North Sea and Gulf of Mexico cost data with mobilization factor
	Pipeline	Based on North Aleutian Basin cost function; cost increase factor to account for increased distance to landfall and deepwater installation considerations
Kodiak	Semi	Based on North Aleutian Basin cost function; deepwater cost increase factor
	Deepwater Floater	FPSO, TLP, or Spar; North Sea and Gulf of Mexico cost data with mobilization factor
	Pipeline	Based on North Aleutian Basin cost function; cost increase factor to account for increased distance to landfall and deepwater installation considerations
Gulf of Alaska	Semi	Based on North Aleutian Basin cost function
	Gravity-based structure	Based on modeled cost functions for subarctic planning areas; reduction factor to account for no ice
	Deepwater Floater	FPSO, TLP, or Spar; North Sea and Gulf of Mexico cost data with mobilization factor
	Subsea Tie-back	Based on North Aleutian Basin cost function
	Pipeline	Based on North Aleutian Basin cost function

Source: IMV Projects.

Table 12.

Pipeline Capital Cost Multipliers and Basis Considerations

Planning Area	Base Cost Estimate	Multiplier	Comments
Hope Basin	Chukchi Sea	0.65	Reduced burial depths in comparison to Chukchi Sea
Norton Basin	Chukchi Sea	0.60	Same trenching assumptions as for Hope Basin. Cost of temporary camp removed because town of Nome can serve as base for materials handling.
St. Matthew Hall	North Aleutian Basin	1.0	Pipelining conditions similar to North Aleutian Basin—no trenching required, pipelines will be of similar length, and open water season of sufficient length to install a pipeline.
Navarin Basin	North Aleutian Basin	3.0	Pipelines on the order of 300 miles long to nearest landfall but installation conditions similar to NAB.
Aleutian Basin	North Aleutian Basin	5.2	Pipelines extremely long, >500 miles to nearest landfall but installation conditions similar to NAB.
Bowers Basin	North Aleutian Basin	TBD	Water depths significantly exceed the limits of existing pipelay equipment. In 20 years technology pipelay equipment will likely exist but other components of the overall production system could be more challenging. More likely to use FPSO and shuttle tankers.
St. George Basin	North Aleutian Basin	2.8	Similar pipeline installation conditions as NAB but line length on the order of 280 miles to nearest landfall in the Aleutian Islands
Aleutian Arc	North Aleutian Basin	TBD	Water depths significantly exceed the limits of existing pipelay equipment. In 20 years, technology and pipelay equipment will likely exist but other components of the production system could be more challenging. More likely to use FPSO and shuttle tankers.
Shumagin	North Aleutian Basin	TBD	Water depths significantly exceed the limits of existing pipelay equipment. In 20 years, technology and pipelay equipment will likely exist but other components of the production system could be more challenging. More likely to use FPSO and shuttle tankers.
Kodiak	North Aleutian Basin	TBD	Water depths significantly exceed the limits of existing pipelay equipment. In 20 years, technology and pipelay equipment will likely exist but other components of the production system could be more challenging. More likely to use FPSO and shuttle tankers.
Gulf of Alaska	North Aleutian Basin	1.0	Similar pipeline installation conditions as NAB out to about 100 miles from shore. Beyond this distance water depth increases to the point where the capability of existing pipelay equipment is exceeded. More likely to use FPSO and shuttle tankers in deeper water.

Source: IMV Projects, 2011.

The following Figures and Tables capture examples of capital cost data/functions (exclusive of topsides, where applicable) for the 11 planning areas that were not modeled.

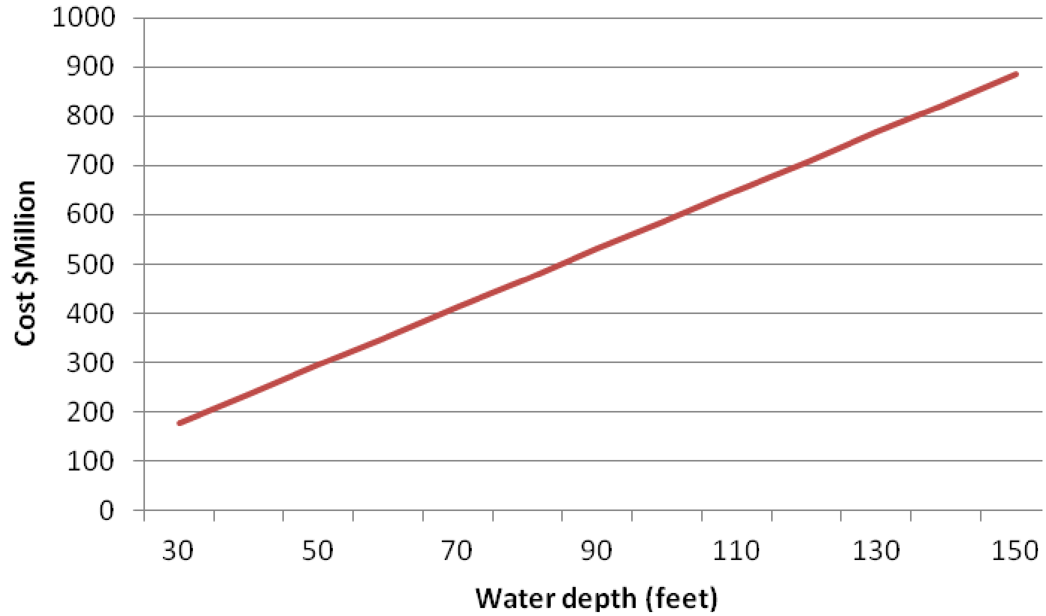

Figure 86. Cost of Norton Sound Gravity-Based Structure by Water Depth

Source: IMV Projects, 2011.

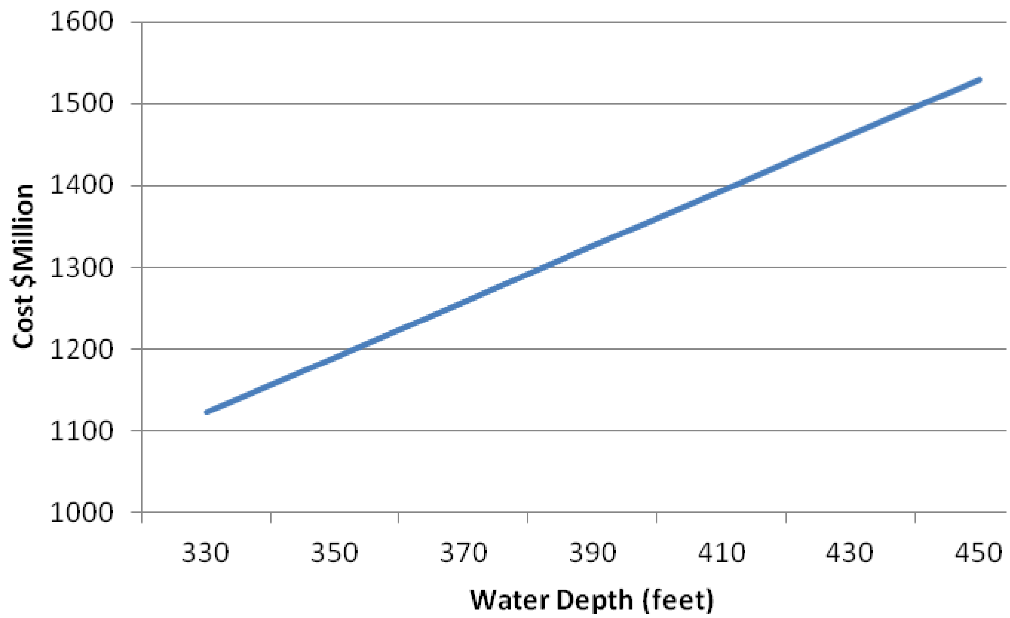

Figure 87. Cost of Navarin Basin Gravity-Based Structure by Water Depth

Source: IMV Projects, 2011.

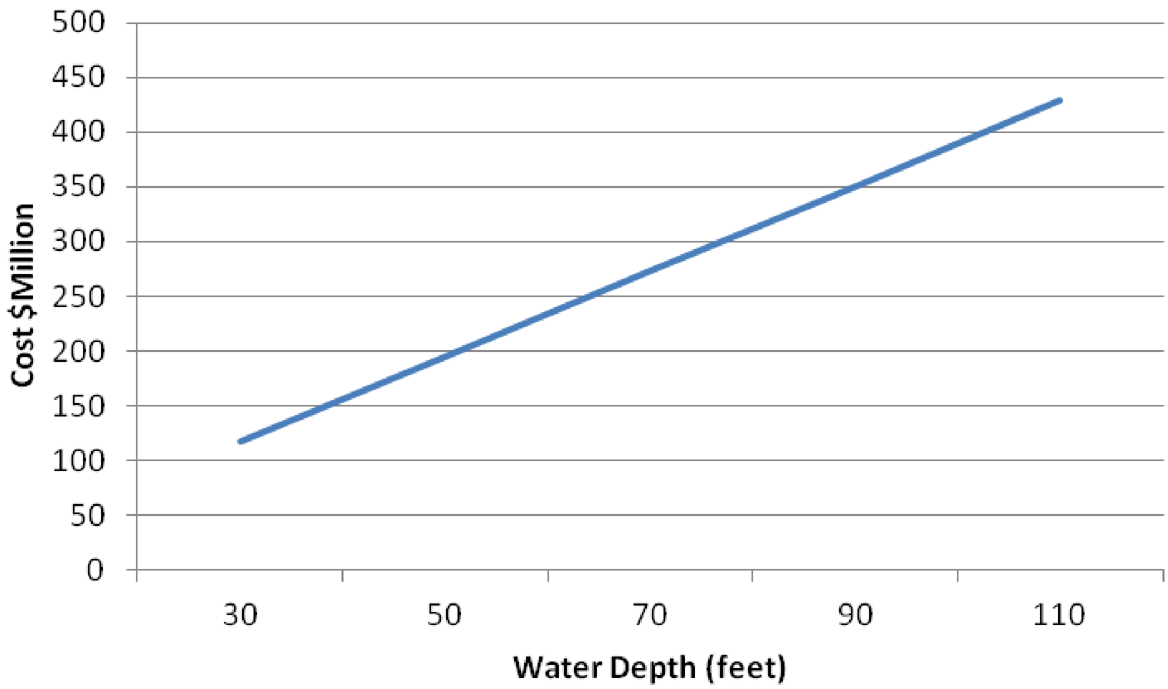

Figure 88. Cost of Mobile-Bottom Founded Exploration Platform by Water Depth

Source: IMV Projects, 2011.

Table 13.

Comparison of Pipeline Capital Costs for Chukchi Sea and Hope Basin

Chukchi Sea			Hope Basin (based on Multiplier)
Flowrate (MMscfd)	**Pipeline Diameter (Inches)**	**Pipeline Capital Cost (2010 MM $)**	**Pipeline Capital Cost (2010 MM $)**
167	12	1,970	1,281
356	16	2,040	1,326
1007	24	2,200	1,430
1780	30	2,370	1,541
2834	36	2,800	1,820

Source: IMV Projects, 2011.

3.7 ECONOMIC SECTOR ALLOCATIONS FOR EACH OCS ACTIVITY

The previous sections described the approach and data used in estimating the first stage results of MAG-PLAN. The first stage generates estimates of direct manpower requirements and industry spending for each of the activity types.

This section of the comprehensive report describes the approach used in generating the results of the second stage of the model. The second stage involves projecting the indirect and induced economic impacts (also referred to as multiplier effects) of the OCS activities on various Alaska regions affected by OCS activities.

The approach for projecting second-stage results involves the following:

- Allocating non-labor and labor spending among various economic sectors.
- Allocating non-labor and labor spending among various regions in Alaska.
- Applying the appropriate output, employment, and labor income multipliers from IMPLAN to generate Stage 2 results.

The following sections describe these steps in more detail.

3.7.1 Allocation of Non-Labor Spending by Economic Sector

The allocation of the non-labor component of industry spending associated with each Activity Type is summarized in Table 14. This allocation was specified based on a number of considerations. First, the study team identified the primary NAICS codes of the oil and gas field service companies that were interviewed for this project, as well as other companies not interviewed but known from secondary sources to be engaged in these activities, and mapped those to the corresponding IMPLAN sector.

Second was the consideration of the economic sectors most relevant for OCS activities in Alaska. The economies of the regions in Alaska that are going to be affected by OCS activities are not quite as diverse as the economies in other OCS areas in the United States, such as in the Gulf of Mexico. While there is significant industry spending on equipment and materials for fabrication of production platforms for example, the industries that manufacture these items do not exist in Alaska, and therefore these purchases are going to be made outside of Alaska and would not generate local multiplier effects. The IMPLAN sectors listed in Table 14 reflect those economic sectors that are going to be significantly affected by OCS activities in Alaska.

The study team reviewed the IMPLAN production functions (industry spending pattern) for each of the economic sectors identified in Table 14. The production functions show the average spending pattern of businesses in any given sector, and specify the intermediate inputs and the proportions needed to generate each dollar of output. The number of inputs specified in the production functions reviewed ranged from 100 to 208. However, the review was focused on the top 20 inputs in each of the production functions. For those activity types that have a 100 percent allocation to one IMPLAN sector, the spending patterns of these IMPLAN sectors are considered close approximations of industry spending for that particular OCS activity type. Hence, there was no need to modify the production function. A sensitivity test indicated that modifying the production function coefficients did not generate any significant difference in per million dollar impacts compared to the default IMPLAN spending pattern.

For those activity types (e.g. exploration drilling support; offshore production platform installation) that do not have a 100 percent allocation to one IMPLAN sector, the sub-allocation to various IMPLAN sectors reflects information gathered from the companies interviewed, from cost data provided by IMV, and from review of previous BOEM studies that looked into production functions specific to OCS activities (Saha et al., 2005, Dismukes et al., 2003). Finally, the production functions specified in the IMPLAN database for the relevant economic sectors were reviewed and if it was determined that certain economic sectors would be significantly more affected than what were reflected in the absorption coefficients in the IMPLAN production functions, these sectors were specifically identified in the sub-allocation as shown in the table. Most of these sectors are associated with logistics of OCS activities such as transport by water and transport by air. Generally, the goods and services that are locally purchased are captured in the production functions (backward linkages) of the major IMPLAN sectors identified for each OCS activity.

Table 14.

Allocation of Non-Labor Costs by Economic Sector

Activity Type	**Allocation**	**IMPLAN Sector**	**IMPLAN Sector Description**
Marine Seismic Survey	100%	375	Environmental and other technical consulting services
Geohazard Survey	100%	375	Environmental and other technical consulting services
Geotechnical Survey	100%	375	Environmental and other technical consulting services
Exploration/ Delineation Wells	100%	28	Drilling oil and gas wells
Offshore Exploration Platform	100%	29	Support activities for oil and gas operations
Exploration Drilling Support Activities	20%	332	Transport by air
	67%	334	Transport by water
	13%	29	Support activities for oil and gas operations
Offshore Production Platform CAPEX and Installation	67%	334	Transport by water
	33%	29	Support activities for oil and gas operations
Offshore Production Platform Production	100%	29	Support activities for oil and gas operations
Drill On-Platform Production Wells	100%	28	Drilling oil and gas wells
Workovers	100%	29	Support activities for oil and gas operations
Production Support	20%	332	Transport by air
	67%	334	Transport by water
	13%	29	Support activities for oil and gas operations
Subsea Wells Drilling	100%	28	Drilling oil and gas wells
Sub-Sea Wells Installation	67%	334	Transport by water
	33%	29	Support activities for oil and gas operations
Subsea Maintenance	50%	334	Transport by water
	50%	29	Support activities for oil and gas operations
Offshore Pipelines (Export Lines)	100%	36	Construction of other new nonresidential structures
Onshore Pipelines (Export Lines)	100%	36	Construction of other new nonresidential structures
LNG Plant & Marine Terminal Construction	100%	36	Construction of other new nonresidential structures
LNG Plant & Marine Terminal Operations	100%	141	All other chemical product and preparation manufacturing
Oil Terminal Construction	100%	36	Construction of other new nonresidential structures
Oil Terminal Operations	100%	29	Support activities for oil and gas operations
Exploration Base	50%	29	Support activities for oil and gas operations
	50%	36	Construction of other new nonresidential structures
Production Base Construction	100%	36	Construction of other new nonresidential structures
Production Base Operations	50%	20	Extraction of oil and natural gas
	50%	29	Support activities for oil and gas operations

Activity Type	Allocation	IMPLAN Sector	IMPLAN Sector Description
Supply Boat Terminal Construction	100%	36	Construction of other new nonresidential structures
Supply Boat Terminal Operations	100%	340	Warehousing and storage
Air Support Base Construction	100%	36	Construction of other new nonresidential structures
Air Support Base Operations	100%	29	Support activities for oil and gas operations
Construction Camp/Accommodations	100%	29	Support activities for oil and gas operations
Oil Spill Contingency	100%	380	All other miscellaneous professional, scientific, and technical services
Abandonment	75%	334	Transport by water
	25%	29	Support activities for oil and gas operations

Source: Northern Economics, Inc., 2011.

3.7.2 Allocation of Labor Spending by Economic Sector

BOEM's request for proposal (RFP) for this project identified the need to examine ways to improve the allocation of spending of labor income to different economic sectors to more accurately reflect household spending patterns in the different regions in Alaska. The previous model used personal consumption expenditure (PCE) data provided by IMPLAN that reflect typical household spending patterns for specific income groups based on information from the nationwide survey that is conducted by the Bureau of Labor Statistics.

To address this BOEM requirement, the study team considered a number of ways to modify IMPLAN PCE data to more closely approximate household spending patterns in Alaska. This effort included a review of the Consumer Expenditure Survey (CES) metadata developed by the Bureau of Labor Statistics for Alaska to determine whether the data could provide distinct spending patterns of rural versus non-rural areas in Alaska. The metadata for Alaska, however, only represented responses from "greater Anchorage" residents and none from the rural areas. While the CES data for Anchorage would be a better representation of Alaska household spending than the national average spending pattern, the differences in the spending were not significant enough to warrant the additional effort that would be needed to modify the default PCE data embedded in the IMPLAN database.

Table 15 shows a comparison of the household spending pattern between Anchorage and the national average based on the Bureau of Labor Statistics 2010 data. As the data show, the differences are relatively small. For example, the average Anchorage consumer spends 41.3 percent of expenditures on housing, versus 41.9 percent nationally (a 0.6 percent difference); or the 17.4 percent versus 16.7 percent spending on transportation (a 0.7 percent difference). The categories with marked differences are recreation,[8] with a 1.3 percent difference, and education and communications, with a 1.2 percent difference between Anchorage and the nation.

[8] The Alaska Department of Labor and Workforce Development noted that the difference in recreation is apparently due to Anchorage residents' higher spending on recreational vehicles and outdoor sports equipment.

Table 15.

Comparison of Household Spending Pattern between Anchorage and the Nationwide Average

Household Expenditure Category	Anchorage	Nationwide
	Percent	
Housing	41.3	41.9
Apparel	3.7	3.7
Transportation	17.4	16.7
Medical Care	6.4	6.5
Recreation	7.7	6.4
Other Goods and Services	3.8	3.5
Food and Beverage	14.5	14.8
Education and Communications	5.2	6.4

Source: Fried and Shanks, Alaska Economic Trends, May 2011.

In addition to reviewing the BLS data, a number of studies and survey data were also considered. A recent study conducted by the McDowell Group looked at geographic differential data to determine cost of living differences in different regions of Alaska, and in the process evaluated household spending levels in major categories such as food, housing, fuel, and others. There are other cost-of-living studies conducted for specific regions in Alaska, such as the one conducted by the University of Alaska Cooperative Extension. The City of Unalaska also has cost of living information based on a local survey. All potential sources of data were reviewed and compared to the PCE data provided in IMPLAN.

The review considered the following:

- how to localize/regionalize the PCE data (household spending pattern);
- whether the changes can be standardized across the different regions (corresponding to each OMA); and
- whether changes in the way household spending among income categories are specified in the model.

Based on discussions with the Minnesota IMPLAN Group and guidance from BOEM regarding the use of one-time survey data, it was concluded that "localizing" spending patterns by OMA will not be practical. The steps required to model the changes in IMPLAN so that the model's regional multipliers reflect the changes on household spending would require a significant effort.[9] In addition, spending pattern survey data for each of the regions will have to be generated in the future, since the secondary sources are not consistently available from year to year. Therefore, the updated MAG-PLAN uses the default IMPLAN PCE data without modifications.

The updated model is different from the previous version of MAG-PLAN, however, in the way household spending is specified among the different household income categories. The

[9] The modification will require the following, as stated by Doug Olson of MIG, Inc.: "… *need to RAS a matrix (iteratively force the ROW totals and the column totals to match controls until it closes). The column totals would be total household spending for each of the 9 income classes. The row totals would be total spending by all households for each of the 440 IMPLAN commodities. The control totals can be derived from the region's "Household commodity demand" under Explore>Study Area Data.*"

previous version of MAG-PLAN assumes that the distribution of OCS labor income in the region will follow the current household income distribution in the area. For example, looking at the income distribution in Anchorage (as shown in Table 16), the model will allocate 2.8 percent of the labor income going to Anchorage (from OCS-related direct and indirect jobs) to the household income category of less than $10,000, and will assume that those dollars will be spent according to the typical spending patterns of households with less than $10,000 of annual income (using IMPLAN PCE data for that same household income category). Table 16 shows both the values from the 2000 Census, which are used in the current model (also the basis for the latest IMPLAN data), and the updated values from the American Community Survey.

Table 16.

Household Income Distribution (in percent) for Selected Alaska Regions, Years 1999 and 2008 data from the U.S. Census Bureau

	Alaska		MOA		FNSB		KPB		MSB	
Income Category	**'99**	**'08**	**'99**	**'08**	**'99**	**'08**	**'99**	**'08**	**'99**	**'08**
Less than 10,000	5.6	3.8	4.2	2.8	5.6	4.2	7.3	5.5	6.8	4.5
$10,001 to $14,999	5.0	3.9	4.0	3.3	5.5	3.6	6.6	6.5	5.2	3.5
$15,000 to $24,999	10.3	7.7	9.4	6.3	10.4	7.1	12.1	10.7	10.5	6.4
$25,000 to $34,999	11.2	8.9	10.8	7.8	12.1	9.9	11.5	8.9	10.9	10
$35,000 to $49,999	16.0	12.9	16.0	13.2	17.2	11.9	15.9	13.3	15.3	11
$50,000 to $74,999	22.0	19.1	22.6	18.6	22.4	19	21.6	18.9	23.6	21.1
$75,000 to $99,999	13.7	15.6	14.3	16.4	12.7	16.3	12.1	12.4	13.9	16.8
$100,000to $149,999	11.5	17.8	12.9	18.5	10.6	19.6	10.0	17.4	10.2	17.2
Greater than $150,000	4.6	10.3	5.9	13.1	3.5	8.3	2.9	6.4	3.6	9.4

Source: 2000 Census information (based on 1999 data) and 2008 American Community Survey.

Notes: Values shown in the table reflect Borough-level data (except for Alaska, which reflects statewide data). Column heading definitions are as follows: 1) MOA= Municipality of Anchorage; 2) FNSB= Fairbanks North Star Borough; 3) KPB= Kenai Peninsula Borough; and 4) MSB= Matanuska-Susitna Borough.

The distribution of labor income in the revised model is different in that it reflects the anticipated level of OCS-associated wages. Based on ADOLWD data, oil and gas extraction workers currently earn an average of $152,840 per year and workers in "support activities for oil and gas" sector have an average annual wage of $89,839. Figure 89 shows annual average wages for other industries in Alaska.

While the model has the flexibility to allow the user to choose the appropriate household income category to generate the multiplier effects of labor spending, the default category in the updated model is set at $75,000 to $100,000 household income category. This approach would more closely approximate the workers' level of spending that would likely result from OCS activities, rather than assuming that the labor spending amount will be distributed according to historical income distribution in the region.

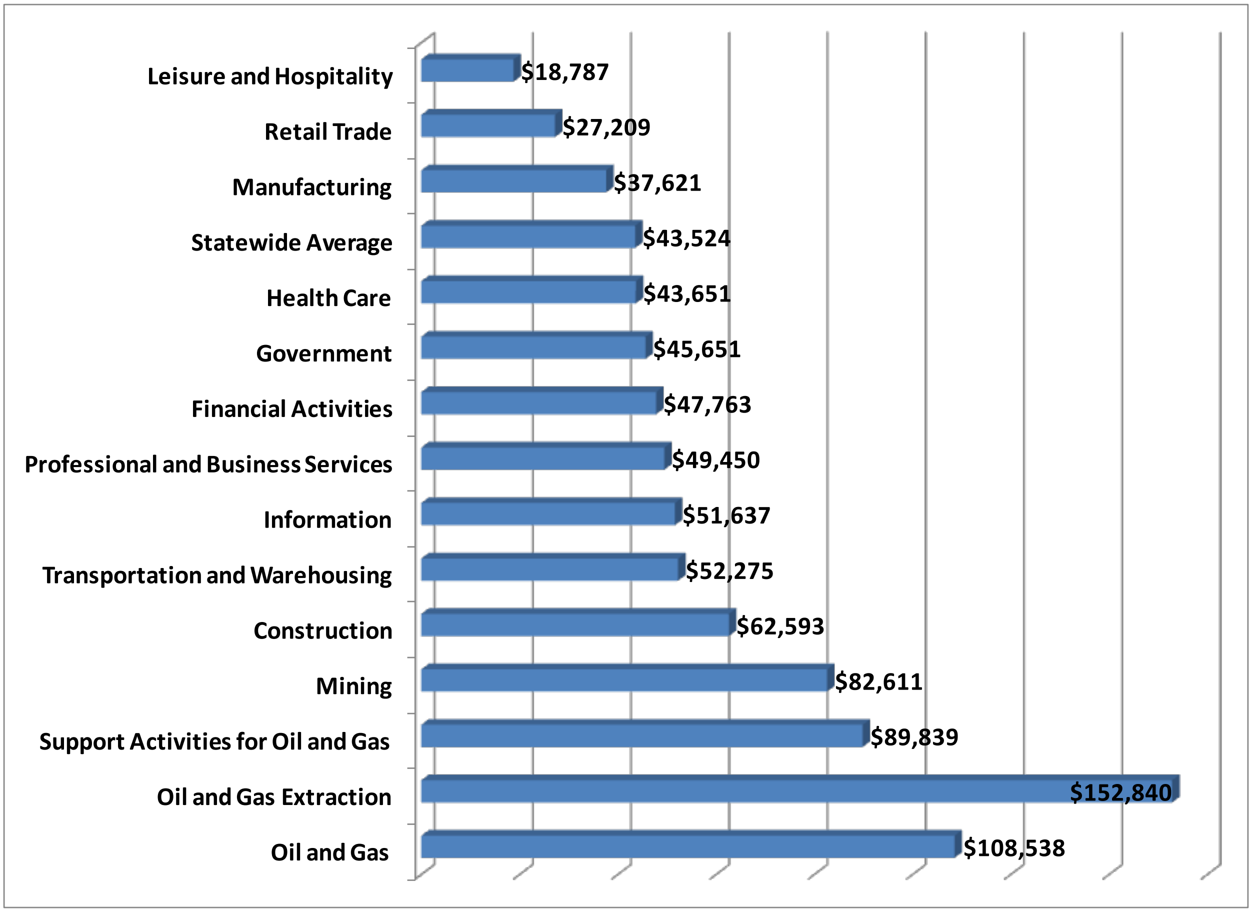

Figure 89. Average Annual Wages by Sector, Alaska

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section.

The sensitivity of IMPLAN results to assumptions regarding who is doing the spending (low versus high income earners) was tested. Three household income levels were tested: 1) $10,000 to $15,000; 2) $50,000 to $75,000; and 3) Greater than $150,000. Spending patterns of these three household income levels were then used to determine the induced effects of $1 million spending in the Municipality of Anchorage economy.

Table 17 shows that total output and employment effects are larger for the higher income category, but the labor income and value added effects don't necessarily follow this pattern, given an equal level of spending ($1 million) for each income group. The total labor income effects are smallest for the highest income category because of variation in the mix of sectors affected by the spending and the fact that these affected sectors differ in labor income and other value added components.

Table 17.

Estimated Per Million $ Output, Employment, Labor Income, and Value Added Effects of Household Spending by Income Category

Household Income Category	Output	Employment	Labor Income	Total Value Added
$10,000 to $15,000	$785,430	5.97	$261,942	$475,457
$50,000 to $75,000	$822,434	6.23	$265,844	$495,898
Greater than $150,000	$818,732	6.37	$261,128	$490,058

Source: NEI estimates based on IMPLAN results.

Table 18 shows the top ten sectors (ranked according to output effects) affected by household spending of the three income groups. The magnitude of effects differs by income category and there are slight variations in the ranking of sectors.

Table 18.

Top Ten Total Output Effects of $1 million Household Spending by Income Category

Description/Income Category	Output ($)
$10,000 to $15,000	
Real estate establishments	100,074
Private hospitals	86,613
Imputed rental activity for owner-occupied dwellings	73,509
Offices of physicians, dentists, and other health practitioners	59,359
Food services and drinking places	40,401
Monetary authorities and depository credit intermediation activities	31,158
Medical and diagnostic labs and outpatient and other ambulatory care services	28,078
Wholesale trade businesses	23,555
Telecommunications	22,310
Other state and local government enterprises	16,964
$50,000 to $75,000	
Imputed rental activity for owner-occupied dwellings	111,317
Real estate establishments	75,766
Private hospitals	62,820
Offices of physicians, dentists, and other health practitioners	53,179
Food services and drinking places	49,823
Wholesale trade businesses	47,169
Monetary authorities and depository credit intermediation activities	28,897
Telecommunications	19,770
Medical and diagnostic labs and outpatient and other ambulatory care services	16,147
Other state and local government enterprises	14,187
Greater than $150,000	
Imputed rental activity for owner-occupied dwellings	142,267
Private hospitals	52,199
Offices of physicians, dentists, and other health practitioners	48,160
Food services and drinking places	47,158
Real estate establishments	46,675
Wholesale trade businesses	28,207
Monetary authorities and depository credit intermediation activities	24,686
Funds, trusts, and other financial vehicles	19,008
Retail Stores - Food and beverage	17,625
Medical and diagnostic labs and outpatient and other ambulatory care services	17,300

Source: NEI estimates based on IMPLAN results.

3.8 ON-SHORE AREA DISTRIBUTION (OMA TO OSA MAPPING)

3.8.1 Non-Labor Costs

MAG-PLAN Stage I outputs identify the amount of non-labor spending that will be done locally, in the rest of Alaska regions, in the rest of the United States, and in the rest of the world. Only the amount estimated to be spent in Alaska regions are considered in generating the Stage 2 results.

The local (regional) onshore area/s identified for each of the offshore modeling areas are shown in Table 19. The main consideration in assigning the primary on-shore areas to each modeling area is logistics—the coastal region closest in distance to the OMA is assumed to be the region where onshore facilities will likely be located. As shown in the table, some of the OMAs have more than one primary onshore area. In this case, likely locations for the air support base and marine support base were also considered (these are shown in Table 20 and Table 21). These locations were a result of discussion with the Alaska Resource Evaluation Division staff at BOEM.

Table 19.

List of Primary Onshore Area/s by Offshore Modeling Area

Offshore Modeling Area	Primary Onshore Area/s
Aleutian Arc	Aleutians West Census Area
Aleutian Basin	Aleutians West Census Area
Beaufort Sea	North Slope Borough
Bowers Basin	Aleutians West Census Area
Chukchi Sea	North Slope Borough
Cook Inlet	Kenai Peninsula Borough
Gulf of Alaska	Kenai Peninsula Borough
	Yakutat City and Borough
	Sitka, City and Borough of
Hope Basin	Northwest Arctic Borough
	Nome Census Area
Kodiak	Kodiak Island Borough
Navarin Basin	Aleutians West Census Area
North Aleutian Basin	Aleutians East Borough
	Aleutians West Census Area
	Bristol Bay Borough
Norton Basin	Northwest Arctic Borough
	Nome Census Area
Shumagin	Aleutians East Borough
	Aleutians West Census Area
St George Basin	Aleutians West Census Area
St Matthew-Hall	Bethel Census Area
	Wade Hampton Census Area

Source: Northern Economics, Inc. and BOEM

Table 20.

Exploration Phase: Air Support Base and Marine Support Base Locations by Offshore Modeling Area

Offshore Modeling Area	Air Support Shore Base Location	Borough/CA Jurisdiction	Marine Support Shore Base Location	Borough/CA Jurisdiction
Beaufort	Prudhoe	NSB	Prudhoe	NSB
Chukchi	Barrow	NSB	Dutch Harbor	AWCA
Hope	Kotzebue	NWAB	Dutch Harbor	AWCA
Norton	Nome	Nome	Dutch Harbor	AWCA
Navarin	Nome	Nome	Dutch Harbor	AWCA
Matthew-Hall	Nome	Nome	Dutch Harbor	AWCA
Aleutian	Adak	AWCA	Adak	AWCA
St. George	Cold Bay	AEB	Dutch Harbor	AWCA
North Aleutian	Cold Bay	AEB	Dutch Harbor	AWCA
Cook Inlet	Kenai	KPB	Kenai	KPB
Bowers Basin	Adak	AWCA	Adak	AWCA
Aleutian Arc	Adak	AWCA	Adak	AWCA
Shumagin	Cold Bay	AEB	Dutch Harbor	AWCA
Kodiak	Kodiak	Kodiak	Kodiak	Kodiak
Gulf of Alaska	Yakutat	Yakutat	Yakutat	Yakutat

Source: Northern Economics, Inc. and BOEM

Table 21.

Production Shore Base Location by Offshore Modeling Area

Offshore Modeling Area	Production Shore Base Location	Borough/CA Jurisdiction
Beaufort	Prudhoe	NSB
Chukchi	Wainwright	NSB
Hope	Kivalina	NWAB
Norton	Nome	Nome
Navarin	Nome	Nome
Matthew-Hall	Nome	Nome
Aleutian	Adak	AWCA
St. George	Balboa Bay/Dutch Harbor	AEB/AWCA
North Aleutian	Balboa Bay	AEB
Cook Inlet	Kenai	KPB
Bowers Basin	Adak	AWCA
Aleutian Arc	Adak	AWCA
Shumagin	Balboa Bay	AEB
Kodiak	Kodiak	Kodiak
Gulf of Alaska	Yakutat	Yakutat

Source: Northern Economics, Inc. and BOEM

The actual direct industry spending on non-labor items in these primary onshore areas is anticipated to be limited given how small the economies in these coastal regions are. IMPLAN multipliers for each of the primary onshore areas are used in the model to generate Stage 2 results at the local or regional level. For OMAs that have more than one primary onshore area, IMPLAN multipliers for the aggregated region are used. For example, for local non-labor spending associated with development of the North Aleutian Basin OMA, multipliers for the aggregated region comprised of Aleutians East Borough, Aleutians West Census Area, and the Bristol Bay Borough are used in the model.

It is anticipated that most of the economic impacts of in-state spending by industry will actually occur in the Municipality of Anchorage, which is the considered the economic hub for the state of Alaska. In the model, non-local spending on non-labor items is generally assigned to the Municipality of Anchorage, with a few items allocated to the Kenai Peninsula Borough, Fairbanks North Star Borough, and the Matanuska-Susitna Borough, depending on the industry sector and the OCS planning area or OMA being modeled.

3.8.2 Labor Costs

In calculating estimates of economic impact of labor spending, it is necessary to consider both where the employee works and where the employee spends his or her income and pays taxes. While labor data are initially developed based on the location of the workplace (based on E&D scenario for each offshore modeling area), an important next step involves determining the primary place of residence of the workers. The assumption is that workers spend their income at their place of residence. This is especially true in the Alaska North Slope, where most of the workforce involved in the oil and gas operations commute to the area and stay at employer-provided hotel/camp type facilities, some of which are operated by contractors. To track labor spending effects, estimates of workers' wages by place of residence therefore need to be determined to more closely approximate where labor spending might occur.

The model distinguishes between place of income (place of work) and place of residence. The information used in the previous version of MAG-PLAN was based on data from the IMPAK model. The developers of the IMPAK model drew on expert project staff and interviews with industry to determine residency data. Generally, they determined that:

> …oil and gas related workers in existing or new production areas will be primarily drawn from existing pools of workers throughout Alaska and the lower 48 states. For projects in the Beaufort Sea area, labor will continue to be drawn from the various areas in the current percentages.

These percentages for the Beaufort model are shown in Figure 90. Native employment was also estimated based on expert opinion of project staff who had worked extensively in the NSB. They estimated that approximately 25 percent of the NSB Natives still live in the NSB and the rest are assumed to live in the rest of Alaska. The Hope Basin model assumes that the activities will draw labor from the existing areas in the same percentages as the Beaufort Sea model.

Exhibit 5-4: Percent of Production Employees By Ethnicity, Place of Residence and Activity

Activity	Native Workers				Non-Native Workers		All Workers		
	Percent Native	Percent Native Residing in NSB	Percent Residing in NSB	Percent Residing in Other Alaska	Percent Residing in Other Alaska	Percent Residing in Other U.S.	Percent Residing in NSB	Percent Residing in Other Alaska	Percent Residing in Other U.S.
1. Geological Survey	0%	25%	0.00%	0.00%	80%	20%	0.00%	80.00%	20.00%
2. North Slope Support	15%	25%	3.75%	11.25%	70%	15%	3.75%	81.25%	15.00%
3. General Personnel Transport	0%	25%	0.00%	0.00%	70%	30%	0.00%	70.00%	30.00%
4. Construct Ice Road	15%	25%	3.75%	11.25%	65%	20%	3.75%	76.25%	20.00%
5. Construct Ice Island	15%	25%	3.75%	11.25%	65%	20%	3.75%	76.25%	20.00%
6. Move Drill Ship/Bottom Founded Platform	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
7. Operate Drill Ship in Calm Waters	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
8. Operate Drill Ship in Rough Seas	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
9. Operate Mobile Exploration Platform	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
10. Helicopter Support	0%	25%	0.00%	0.00%	90%	10%	0.00%	90.00%	10.00%
11. Barge Support	5%	25%	1.25%	3.75%	80%	15%	1.25%	83.75%	15.00%
12. Drill Exploration Well	5%	25%	1.25%	3.75%	70%	25%	1.25%	73.75%	25.00%
13. Drill Production Well	5%	25%	1.25%	3.75%	70%	25%	1.25%	73.75%	25.00%
14. Well Workover	5%	25%	1.25%	3.75%	70%	25%	1.25%	73.75%	25.00%
15. Construct Gravel Island	5%	25%	1.25%	3.75%	80%	15%	1.25%	83.75%	15.00%
16. Protect Gravel Island	5%	25%	1.25%	3.75%	80%	15%	1.25%	83.75%	15.00%
17. Equip Production Island	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
18. Operate Production Island	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
19. Construct Gas Production Facility	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
20. Operate Gas Production Facility	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
21. Construct Offshore Pipeline	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
22. Construct Onshore Pipeline	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
23. Lay Sea Floor Pipeline	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
24. Land Base Operation	10%	25%	2.50%	7.50%	70%	20%	2.50%	77.50%	20.00%
25. Spill Contingency	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%
26. Abandon Production Island	5%	25%	1.25%	3.75%	75%	20%	1.25%	78.75%	20.00%

Figure 90. Screenshot of IMPAK model report exhibit showing model assumptions regarding residency data of Beaufort OCS workers by activity

Source: Arctic IMPAK Final Technical Report, Jack Faucett Associates, March 2003.

Figure 91 shows the worker residency assumptions by activity for the sub-arctic model, the assumption in this model is that:

> …oil and gas industry related workers in existing or new production areas are primarily drawn from existing pools of workers in the Kenai, the Anchorage area, and the other 49 states. For projects in the Cook Inlet area, it is assumed that labor will continue to be drawn from the various areas in the current percentages. Note that for all tasks other than geological surveys, a large percentage of workers at present, 50 to 100, are drawn from the Kenai itself. The concentration of projects in this area has slowly induced workers to move to the Kenai for long-term assignments and to avoid commuting. The remaining workers are drawn in roughly equal percentages, from Anchorage and the rest of the U.S. These represent more specialized workers and those hired for shorter term assignments. As a result, more specialized and shorter-term assignments such as geological surveys, off-shore pipeline construction, and major platform maintenance tend to utilize higher non-local labor percentages.

For the sub-Arctic models, it was noted that while in some cases labor will be flown in for the early work and then workers may settle locally for operations, this process may not always occur for the remotest areas and for the more specialized technical tasks. For example, for Cook Inlet projects, workers have settled on the Kenai, while resettlement to the Arctic areas has been rare. Similarly, activities such as construction will have higher local (Kenai Peninsula Borough) percentages than operations; presumably because that region already has a construction industry that can meet some of the construction requirements.

Figure 91 also provides employee place of residence percentages for these types of projects. For remote projects, the pattern of residence is similar to that for the Cook Inlet projects, except that the percentages of labor supply have shifted away from the Kenai and towards Anchorage and the rest of the United States. For remote projects near a labor supply, the pattern for remote projects holds, with the exception that selected tasks are assumed to draw 10 to 20 percent of their workforce from the local area. Labor supplies near remote projects in the Gulf of Alaska would be the communities of Valdez, Cordova, Yukutat and possibly other communities in southeast Alaska.

Exhibit 3-4: Estimated Percent of Production Employees By Place of Residence and Activity

	Cook Inlet Projects			Remote Projects			Remote Projects Near Labor Supply			
Activity	Kenai	Anchorage	Other U.S.	Kenai	Anchorage	Other U.S.	Local (If Near Labor Supply)	Kenai	Anchorage	Other U.S.
1. Geological Survey	25	25	50	25	25	50	0	25	25	50
2. Spill Contingency Response	100	0	0	100	0	0	0	100	0	0
3. Construct Exploration Shore Base	100	0	0	50	50	0	20	40	40	0
4. Operate Exploration Shore Base	100	0	0	50	50	0	20	40	40	0
5. Install Exploration Platform	90	10	0	40	40	20	0	40	40	20
6. Operate Exploration Platform	90	10	0	40	40	20	0	40	40	20
7. Drill Exploration Well	60	20	20	50	25	25	0	50	25	25
8. Construct Production Shore Base	100	0	0	50	50	0	20	40	40	0
9. Operate Production Shore Base	100	0	0	50	50	0	0	50	50	0
10. Install Production Platform	90	10	0	40	40	20	0	40	40	20
11. Operate Production Platform	90	10	0	40	40	20	0	40	40	20
12. Drill Production Well	70	20	10	60	20	20	0	60	20	20
13. Lay Offshore Pipeline	50	10	40	45	10	45	0	45	10	45
14. Lay Onshore Pipeline	80	15	5	60	15	25	0	60	15	25
15. Construct Onshore Production Facility	70	15	15	40	45	15	0	40	45	15
16. Operate Production Facility	80	15	5	15	65	20	10	10	60	20
17. Construct Marine Terminal	80	15	5	40	45	15	0	40	45	15
18. Operate Marine Terminal	80	15	5	15	65	20	10	10	60	20
19. Major Platform Maintenance	50	30	20	20	50	30	0	10	50	30
20. Well Workover	70	20	10	60	20	20	0	60	20	20
21. Helicopter Support	90	10	0	50	50	0	10	40	50	0
22. Large Workboat	60	30	10	40	40	20	20	30	30	20
23. Small Workboat	60	30	10	40	40	20	20	30	30	20
24. Landing Craft	60	30	10	40	40	20	20	30	30	20
25. Dive Boat	60	30	10	40	40	20	20	30	30	20
26. Camp Support	85	10	5	45	50	5	10	40	45	5

Figure 91. Screenshot of IMPAK model report exhibit showing model assumptions regarding residency data of Cook Inlet model OCS workers by activity.

Source: Sub-Arctic IMPAK Final Technical Report, Jack Faucett Associates, June 2003.

The residency data in the updated model are now different from the IMPAK worker residency data that were developed using expert opinion; the updated MAG-PLAN uses data from the Alaska Department of Labor and Workforce Development (ADOLWD), which tracks actual residency data of workers. ADOLWD relies on a unique set of databases including the unemployment insurance wage records that contain worker occupation and place of work, the Alaska Permanent Fund Dividend database, and other data series, to accurately monitor the resident hire status of employers, industries, occupations, and regions in the state. According to an ADOLWD report, non-residents accounted for 29.8 percent of the oil industry workers (including major oil companies and oilfield services) in 2008 (“Nonresidents Working in Alaska, ADOLWD, January 2010).

Figure 92 provides an example of the ADOLWD data on residency of workers in Alaska; the values shown are for year 2006.

16 Resident and Nonresident Workers and Wages
By where they work and live, Alaska 2006

Where They Work: Borough or Census Area		Where They Live: Resident Workers: Live Where They Work	Resident Workers: Live Elsewhere in Alaska	Nonresident Workers: Number	Nonresident Workers: Percentage Nonresident	Wages (in millions): Live Where They Work	Wages (in millions): Live Elsewhere in Alaska	Wages (in millions): Nonresident	Percentage of Total Wages that were Nonresident
Anchorage/Mat-Su Region									
Anchorage, Municipality of	State	8,492	1,277	504	4.9%	$343.4	$51.3	$8.1	2.0%
	Local	11,419	805	521	4.1%	$455.5	$34.4	$7.4	1.5%
	Private	101,966	16,068	21,133	15.2%	$3,521.4	$558.4	$453.7	10.0%
Mat-Su Borough	State	981	152	42	3.6%	$35.4	$5.3	$0.8	1.9%
	Local	3,035	138	94	2.9%	$93.8	$4.0	$0.9	0.9%
	Private	15,761	2,251	2,866	13.7%	$353.6	$56.7	$29.4	6.7%
Gulf Coast Region									
Kenai Peninsula Borough	State	1,147	117	59	4.5%	$42.8	$5.2	$1.2	2.4%
	Local	3,519	76	210	5.5%	$127.1	$2.1	$3.6	2.7%
	Private	14,965	1,474	4,518	21.6%	$389.4	$40.7	$46.1	9.7%
Kodiak Island Borough	State	264	26	31	9.7%	$10.4	$0.6	$0.5	4.6%
	Local	903	45	102	9.7%	$26.5	$1.3	$1.3	4.5%
	Private	4,153	369	2,200	32.7%	$101.1	$6.5	$22.1	17.1%
Valdez-Cordova Census Area	State	283	72	35	9.0%	$9.8	$3.4	$0.8	5.5%
	Local	916	73	80	7.5%	$26.3	$1.8	$1.0	3.4%
	Private	3,032	714	1,683	31.0%	$101.6	$27.4	$19.7	13.2%
Interior Region									
Denali Borough	State	23	7	2	6.3%	$1.1	$0.2	n/d	n/d
	Local	142	17	12	7.0%	$3.4	$0.3	$0.1	2.5%
	Private	451	789	1,186	48.9%	$16.7	$25.1	$12.0	22.3%
Fairbanks North Star Borough	State	4,758	318	628	11.0%	$179.6	$6.0	$10.2	5.2%
	Local	3,525	129	185	4.8%	$115.1	$2.8	$2.0	1.6%
	Private	27,118	3,069	7,087	19.0%	$821.5	$82.9	$120.4	11.7%
Southeast Fairbanks Census Area	State	132	16	14	8.6%	$5.2	$0.4	$0.2	3.0%
	Local	393	36	45	9.5%	$9.2	$0.7	$0.3	3.0%
	Private	1,470	775	733	24.6%	$38.6	$35.0	$29.9	28.9%
Yukon-Koyukuk Census Area	State	80	86	11	6.2%	$2.4	$4.1	$0.2	3.5%
	Local	1,575	296	170	8.3%	$25.3	$7.8	$2.3	6.6%
	Private	604	597	364	23.3%	$12.1	$24.7	$6.8	15.6%
Northern Region									
Nome Census Area	State	216	31	12	4.6%	$10.5	$1.4	$0.4	3.2%
	Local	1,815	104	137	6.7%	$31.7	$1.7	$1.9	5.3%
	Private	2,129	274	368	13.3%	$63.6	$10.1	$9.2	11.1%
North Slope Borough	State	22	26	3	5.9%	$1.0	$1.5	n/d	n/d
	Local	1,856	222	189	8.3%	$58.6	$9.1	$4.7	6.4%
	Private	1,360	8,009	4,462	32.3%	$44.5	$524.8	$280.8	33.0%
Northwest Arctic Borough	State	71	11	2	2.4%	$3.1	$0.4	n/d	n/d
	Local	1,181	82	119	8.6%	$25.4	$2.4	$1.9	6.5%
	Private	1,677	587	395	14.9%	$53.7	$32.8	$18.2	17.4%
Southeast Region									
Haines Borough	State	53	2	6	9.8%	$1.7	n/d	$0.1	n/d
	Local	187	5	20	9.4%	$4.1	n/d	$0.2	n/d
	Private	647	59	503	41.6%	$12.5	$1.1	$4.5	25.0%
Juneau Borough	State	4,109	318	309	6.5%	$165.8	$12.2	$6.3	3.4%
	Local	2,291	107	218	8.3%	$83.8	$2.6	$3.1	3.5%
	Private	9,560	1,149	3,121	22.6%	$265.4	$34.8	$52.8	15.0%
Ketchikan Gateway Borough	State	597	120	118	14.1%	$24.1	$4.5	$3.0	9.5%
	Local	1,139	36	77	6.2%	$41.4	$0.7	$1.5	3.5%
	Private	4,555	434	2,306	31.6%	$117.5	$9.7	$22.4	15.0%
Prince of Wales-Outer Ketchikan CA	State	42	4	2	4.2%	$1.3	n/d	n/d	n/d
	Local	899	83	86	8.1%	$22.1	$1.9	$1.2	4.9%
	Private	1,106	251	630	31.7%	$23.1	$5.4	$8.7	23.4%
Sitka Borough	State	319	20	38	10.1%	$11.0	$0.6	$0.4	3.1%
	Local	672	60	58	7.3%	$22.5	$0.5	$0.6	2.6%
	Private	2,958	274	1,139	26.1%	$78.3	$6.0	$13.9	14.2%
Skagway-Hoonah-Angoon CA	State	30	1	2	6.1%	$0.8	n/d	n/d	n/d
	Local	360	37	50	11.2%	$8.1	$0.8	$0.5	5.5%
	Private	770	171	1,032	52.3%	$14.8	$2.8	$11.0	38.5%
Wrangell-Petersburg Census Area	State	87	3	2	2.2%	$2.8	n/d	n/d	n/d
	Local	580	26	41	6.3%	$16.3	$0.7	$0.6	3.3%
	Private	1,636	213	1,303	41.3%	$32.5	$3.8	$10.3	22.1%
Yakutat Borough	State	17	2	1	5.0%	$0.5	n/d	n/d	n/d
	Local	129	8	10	6.8%	$2.5	$0.1	$0.1	4.2%
	Private	159	34	100	34.1%	$3.0	$0.4	$1.1	24.8%

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figure continues on next page

Figure 92. Screenshot of ADOLWD report on residency of workers based on 2006 data

Figure 92, screenshot continued from previous page.

Where They Work		Where They Live: Resident Workers		Where They Live: Nonresident Workers		Wages (in millions)			
Borough or Census Area		Live Where They Work	Live Elsewhere in Alaska	Number	Percentage Nonresident	Live Where They Work	Live Elsewhere in Alaska	Nonresident	Percentage of Total Wages that were Nonresident
Southwest Region									
Aleutians East Borough	State	11	16	10	27.0%	$0.4	$0.2	$0.1	16.1%
	Local	207	44	42	14.3%	$5.0	$1.4	$0.6	8.3%
	Private	353	259	3,190	83.9%	$9.3	$9.0	$58.5	76.1%
Aleutians West Census Area	State	39	6	2	4.3%	$1.9	$0.2	n/d	n/d
	Local	427	45	69	12.8%	$15.9	$1.2	$1.2	6.7%
	Private	1,356	628	3,636	64.7%	$51.0	$19.7	$62.1	46.8%
Bethel Census Area	State	401	62	36	7.2%	$16.0	$2.6	$0.6	3.3%
	Local	3,296	367	273	6.9%	$56.8	$6.4	$4.8	7.1%
	Private	3,540	1,107	634	12.0%	$92.2	$30.2	$18.4	13.1%
Bristol Bay Borough	State	24	14	9	19.1%	$1.3	$0.1	$0.1	8.2%
	Local	126	12	18	11.5%	$3.5	$0.3	$0.3	8.2%
	Private	273	332	1,916	76.0%	$8.9	$6.3	$19.3	56.0%
Dillingham Census Area	State	90	24	8	6.6%	$3.8	$0.5	$0.2	4.0%
	Local	877	66	94	9.1%	$17.7	$1.6	$1.4	7.0%
	Private	1,030	270	728	35.9%	$29.0	$7.2	$9.3	20.4%
Lake and Peninsula Borough	State	7	7	3	17.6%	$0.3	$0.1	n/d	n/d
	Local	417	105	66	11.2%	$6.9	$3.3	$0.7	6.2%
	Private	179	322	685	57.8%	$3.5	$5.3	$8.0	47.7%
Wade Hampton Census Area	State	79	18	7	6.7%	$1.8	$0.7	$0.1	2.3%
	Local	1,422	103	136	8.2%	$19.9	$2.1	$2.2	9.0%
	Private	1,038	218	84	6.3%	$12.6	$6.0	$2.4	11.4%
Other/Unknown		0	1,860	5,820	75.8%	$0.0	$48.2	$98.5	67.2%
Total		269,528	48,440	78,840	19.9%	$8,474.0	$1,815.1	$1,529.6	12.9%

Notes:

Local resident workers were residents of the reported borough or census area as determined by the zip code of their most recent Alaska Permanent Fund Dividend mailing address. Worker employment records showing place of work information were matched with PFD applicant address information to determine the number of local residents, Alaska residents and nonresidents working in each borough or census area. Place of work was based on employer-reported place of work information. Workers were assigned to a geographic area based on the place of work where they earned the most money in 2006. If employers didn't provide specific place of work information for the worker, the borough or census area of the primary business location was used to determine the place of work.

The abbreviation n/d means not disclosable.

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section

Source: Alaska Economic Trends, Alaska Department of Labor and Workforce Development

The latest available information on worker residency was requested for this project and is used in the model.

Because of this revision, the model specifically tracks the spending effects in the major population centers—Anchorage, Mat-Su, Kenai, Fairbanks—which are the places of residence of most of the oil and gas workers in the state.

3.9 *GOVERNMENT REVENUES FROM OCS ACTIVITIES*

The potential government revenues from OCS activities that would accrue to the federal, state, and regional governments are included in the Stage 1 results of MAG-PLAN. The economic impacts to the state and the regional economies resulting from subsequent government spending of these direct OCS revenues are estimated as part of Stage 2 results. The model does not estimate the economic impacts to the nation or other states of federal spending of OCS-related revenues.

The objective of the model update with respect to the revenue estimates is to modify, where appropriate, the revenue types and functions in the previous model, and update the revenue parameters with the latest data available for the State of Alaska and for each potentially impacted regional/local government—Borough, Census Area, or Municipality.

Revenue Types (RTs) are activities that result in payments to government entities. The Revenue Types are directly related to the E&D scenarios provided by BOEM. Revenue Functions (RFs) are the equations used in the model to quantify the various revenue streams that accrue to the federal, state, and local governments. The RTs and RFs contained in the updated MAG-PLAN are described in the sections below.

3.9.1 Revenue Categories

The direct government revenues resulting from OCS activities are grouped into three major categories: i) lease revenues; ii) property taxes; iii) state corporate income taxes; and iv) state revenues due to lower TAPS tariff. These are discussed below along with a fifth item—other potential revenue streams.

3.9.1.1 Lease Revenues

OCS lease revenues include (i) *bonus bids* (cash payments paid to the federal government in exchange for the right to explore and develop the petroleum reserves in the OCS areas); (ii) *rental payments* (a rental payment is established in the lease agreement and paid to the lessor [U.S. Department of Interior] every year; rental rates vary per year and are usually specified in the *Final Notice of Sale);* and (iii) *royalty payments* (a royalty is a share of the minerals produced from a lease; it is a percentage of production paid either in money or in kind that a federal lease holder is required to pay).

Almost all lease revenues accrue to the federal government except for the revenues associated with the 8(g) zone. The State of Alaska receives 27 percent of OCS lease revenues from leases that are in the 8(g) zone. The 8(g) revenue stream is the result of a 1978 Outer Continental Shelf Lands Act (OCSLA) amendment that provides for a “fair and equitable” sharing of revenues from 8(g) common pool lands. These lands are defined in the amendments as submerged acreage lying outside the 3-nautical mile state-federal demarcation line, typically extending to a total of 6 nautical miles offshore. The states’ share of the revenue (27 percent) was established by the OCSLA amendments of 1985 (P.L. 99-272) and is paid directly to the states.

Estimates of these lease revenues—total bonus bids, total rental payments, total royalties, and the corresponding 8(g) lease revenues are directly specified in the E&D scenario for each of the OMA. These estimates are provided by BOEM’s Economics Division.

3.9.1.2 Property Taxes

On-shore facilities that will be built to support OCS oil and gas development will be subject to property taxes. As per Alaska statute, oil and gas property values are assessed by the State of Alaska. While oil and gas property is exempt from local municipal taxation, the state levies a 20 mill tax against this property and reimburses each municipality or (local jurisdiction) that has oil and gas property located within its boundaries an amount equal to taxes which it would have levied, up to the 20 mill limit. Essentially, a local tax is levied on the state’s assessed value for oil and gas property within a city or borough, and is subject to the local property tax limitations established in AS 29.45.080 and AS 29.45.100. The state’s mill rate, as noted above, is effectively 20 mills minus the local rate, which in the case of the North Slope Borough, is 18.5 mills.

In the IMPAK model and the previous version of MAG-PLAN Alaska, estimates of tax revenues by jurisdiction were based on ratios of total tax revenues to personal income. Personal income was used as a proxy for the level of economic activity and the resulting associated state and local government take generated from economic activity. Level of personal income generated by OCS development was driven by employment estimates derived from the manpower requirements estimated within the previous models.

The updated MAG PLAN Alaska model now explicitly estimates annual property tax payments. In order to do this, additional Revenue Types were added to account for the different taxable onshore oil and gas infrastructure, including onshore oil and gas pipelines, exploration shore base, production shore base, marine terminal and LNG facility, oil terminal, supply boat terminal, air support base, and search and rescue base. The E&D scenario specifies the start year of the construction of each of these facilities and the share of capital cost spent each year. The total costs of the facilities are included in Stage 1 results.

The property tax calculation uses the capital cost of each taxable infrastructure as the basis for estimating the local and state property taxes. The calculation assumes a straight-line depreciation over each project's depreciable life to a salvage value ranging from 0 percent to 50 percent. At the end of the depreciation period, the salvage value represents the remaining economic value still subject to taxation. Facilities with a zero salvage value are assumed to have no taxable value at the end of their depreciation periods. Projects with non-zero salvage value, on the other hand, continue to have a taxable economic value until the end of their useful lives. The assumptions regarding Depreciable Life and Useful Life for each taxable facility are provided. These can be changed by the user. For most of the production facilities, the useful life of the facility is longer than the depreciable life, to account for the way the State of Alaska values production facilities—which is based on the remaining oil and gas reserves.

For each facility, five parameters are specified: the capital costs, including the year in which it is incurred; the first year in which the project will begin to depreciate; the depreciable life; the useful life; and the salvage value. Capital costs accrue over time until the first year in which depreciation will occur. During this build-up of capital costs, the accrued value is subject to taxation. Once depreciation begins, the calculation uses the declining book value to determine taxes paid.

3.9.1.3 State Corporate Income Tax

State corporate income tax is another source of revenue for the State of Alaska. This revenue stream, as in the property taxes, was calculated indirectly in the previous version of MAG-PLAN using a personal income-to-tax revenue coefficient. The updated model estimates this revenue stream differently. Alaska levies a corporate income tax on Alaska taxable income. The state taxes corporate income at graduated rates ranging from 1 percent to 9.4 percent. A corporation that does business both inside and outside Alaska apportions a percentage of the corporation's total income to Alaska using a formula. Oil companies combine on a worldwide basis and are required to use a "modified" apportionment formula of property, sales, and extraction. The extraction factor is the production of oil and gas in Alaska divided by production everywhere.

Oil and gas related corporate income tax is typically calculated as 9.4 percent of the Alaska share of worldwide income for each corporation. The Alaska tax base for the special corporate income tax on petroleum depends not only on activity and profits within Alaska, but also on activity and profits in other locations (worldwide), making it challenging to forecast.

In the study conducted by Northern Economics and the Institute of Social and Economic Research on the economic impacts of future OCS development in the Beaufort, Chukchi, and the

North Aleutian Basin, a conservative approach was used to estimate direct corporate income tax revenues to the state from OCS activity. The estimate was based on the wellhead value of OCS production and a modified apportionment formula that reflects the special OCS conditions as follows: (1) The estimate excludes the sales and extraction components of the formula, on the assumption that all OCS sales and extraction would occur outside the jurisdiction of Alaska, in federal waters; (2) the estimate includes only that share of the property associated with OCS activities which is onshore; and (3) it assumes that the OCS operation of the companies would have "stand alone" status, in that the characteristics of their other operations, either onshore Alaska or elsewhere in the world, would not impact their Alaska OCS tax liability. These modifications would result in a very small share of OCS income to the state petroleum income tax base. The historical 2.6 percent ratio of state corporate income tax revenues to the value of production is adjusted downward to 0.13 percent to estimate future corporate petroleum revenues to the state from OCS production. Although the onshore share of petroleum property is likely to differ among the OCS basins, the analysis will use the 0.13 percent for each basin because of the inherent uncertainty surrounding this estimator.

3.9.1.4 Additional State Revenues

OCS oil from the Beaufort Sea and the Chukchi Sea is assumed to be transported to market through the existing TAPS oil pipeline, therby increasing TAPS throughput. Higher throughput would reduce the tariff on all the oil flowing through the line. Because the price of oil at the wellhead is determined by deducting the transportation costs from the market price, a lower tariff essentially increases the wellhead value of North Slope oil. Since the royalty on oil from state lands and the production tax are based on the wellhead value of oil, a lower tariff would increase the revenues to the state.

3.9.1.5 Other Potential Revenue Streams

A number of other potential revenue-sharing arrangements could come about once oil and gas development in the Alaska OCS occurs. It is likely that various stakeholders, particularly the state government, would initiate efforts to gain the same kind of revenue sharing arrangement as the arrangement in place in the Gulf of Mexico. MAG-PLAN can be revised to have the flexibility to consider an alternative revenue sharing arrangement that mirrors the Gulf of Mexico Energy Security (GOMES) Act, for example. Under the Gulf of Mexico Energy Security Act of 2006, the revenue sharing provision in S.3711 (P.L. 109-432) allows selected Gulf States to receive 37.5 percent of the revenue generated from specified federal oil and gas leases off their coasts. Also, local revenue sharing is provided for under Sec. 105(b)(3): Payments to Coastal Political Subdivisions. Qualifying CPSs will receive 20 percent of the amount received by each producing state. This share will be divided among the state's CPSs based upon the same allocation formula used for CIAP: 25 percent based upon relative length of coast line, 25 percent based upon relative population, and 50 percent inversely proportional to the respective distances between the points of each CPS that are closest to the geographic center of the lease (see discussion above). If this arrangement applied to Alaska, the 50 percent would be divided equally among the two closest CPSs; therefore, in the Chukchi and Beaufort, it would be the North Slope Borough and the Northwest Arctic Borough. Money allocated to a CPS is paid directly to the CPS and does not go through the state.

3.9.2 State and Local Government Spending Patterns

The State of Alaska has a database of municipal finances that is easily accessible. Historical spending patterns were obtained for the years 2004 to 2009. Table 22 is an example of the data gathered for the North Slope Borough.

Table 22.

Historical Spending Data for the North Slope Borough, 2004 to 2009

Expenditures	2004	2005	2006	2007	2008	2009
General Government	43.11	36.37	34.43	37.38	39.35	47.37
Public Works	31.59	35.41	36.39	41.46	45.27	54.64
Public Safety	13.37	13.91	14.79	17.07	19.02	22.29
Health and Social Services	13.84	13.66	11.33	12.21	15.11	17.39
Wildlife Management	3.70	3.59	3.87	3.85	3.62	4.83
Primary and Secondary Education	22.96	23.56	22.99	24.05	23.91	28.08
Higher Education	7.12	6.82	6.52	6.52	6.84	8.00
Debt Service	143.37	115.21	112.52	112.54	107.91	108.72
Capital Projects	43.16	55.66	54.03	58.32	56.57	61.66
Total Expenses	322.22	304.18	296.88	313.39	317.60	352.97

The spending categories shown in Table 22 were further categorized according to the following spending types:

1. Education;
2. Non-Education; and
3. Capital Projects.

These categories correspond to the institutional spending patterns for these government programs available in the IMPLAN database.

State and Local Government Education is the operational spending pattern of all levels of public education, from pre-K to higher education. State and Local Government Non-education is the operational spending pattern of all other divisions of administrative state and local government including police, fire, hospitals, prisons, and similar activities. This does not however include market driven (enterprise) activities such as sewer, water, power and public transportation. State and Local Government Investment is spending pattern that reflects the new construction and capital goods expenditures by all levels of state and local government.

The updated model contains per million dollar coefficients of output, employment, and labor income effects of state and regional government spending. The formula is specified as: estimated state revenue (expressed in $millions) multiplied by share of revenue for education programs multiplied by the per million dollar output coefficient for the State of Alaska. The result is the economic impacts to the state of the spending for education.

3.9.3 On-shore Area Distribution

The previous model's default offshore modeling areas and associated affected local government entities are shown in Table 23.

Table 23.

Current Model's Offshore Modeling Areas and Associated Affected Local Jurisdiction

Offshore Modeling Area	**Local Jurisdiction/Affected Local Government**
South Alaska-Semi Remote (Gulf of Alaska Planning area)	Kenai Peninsula Borough
South Alaska-Remote (Kodiak, Shumagin, Aleutian Arc)	Kenai Peninsula Borough
South Alaska-Cook Inlet/Shelikof Strait	Kenai Peninsula Borough
Southeastern Bering Sea (North Aleutian Basin, St. George Basin (shallow water)	Dillingham
North Bering Sea (Norton Basin, St. Mathew Hall, Navarin Basin)	Nome Bethel
Western Bering Sea Deepwater (Aleutian Basin, Bowers Basin, Navarin Basin (deepwater), St. George Basin (deepwater))	Kenai Peninsula Borough Aleutians West
Arctic-Chukchi/Hope	North Slope Borough Northwest Arctic Borough
Arctic Beaufort	North Slope Borough

The updated model specifies specific local/regional jurisdictions for each the offshore modeling area (as shown in Table 23). These are the same as the primary onshore area/s discussed in the sections above.

Table 24.

List of Local/Regional Government Jurisdictions by Offshore Modeling Area

Offshore Modeling Area	Local Jurisdiction/Affected Local Government
Aleutian Arc	Aleutians West Census Area
Aleutian Basin	Aleutians West Census Area
Beaufort Sea	North Slope Borough
Bowers Basin	Aleutians West Census Area
Chukchi Sea	North Slope Borough
Cook Inlet	Kenai Peninsula Borough
Gulf of Alaska	Kenai Peninsula Borough
	Yakutat City and Borough
	Sitka, City and Borough of
Hope Basin	Northwest Arctic Borough
	Nome Census Area
Kodiak	Kodiak Island Borough
Navarin Basin	Aleutians West Census Area
North Aleutian Basin	Aleutians East Borough
	Aleutians West Census Area
	Bristol Bay Borough
Norton Basin	Northwest Arctic Borough
	Nome Census Area
Shumagin	Aleutians East Borough
	Aleutians West Census Area
St George Basin	Aleutians West Census Area
St Matthew-Hall	Bethel Census Area
	Wade Hampton Census Area

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APPENDIX A: SOURCES USED IN MODEL CREATION

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