CHAPTER TWENTY THREE

Activity-Based Costing

Contents

Abstract

Activity-based cost models apply work decomposition methods and knowledge of engineering and market conditions to estimate cost. The tasks required to be performed are identified, and the time and duration to perform each task are estimated. Activity-based costing is the most detailed and transparent method that can be applied in operating cost estimation and require a higher level of expertise to successfully apply. In this final chapter, work decomposition methods are described to illustrate how the operating cost components of labor, logistics and transportation, materials and supplies, and repairs and maintenance are estimated. Examples are provided to develop analytic skills and intuition regarding the relative importance of cost components. Regional diving, helicopter, and marine vessel contracts and service markets are reviewed as part of this discussion.

Decommissioning Forecasting and Operating Cost Estimation
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23.1 OPERATING COST CATEGORIES

The primary cost categories for offshore oil and gas operations include the following:

- Salaries of operating personnel
- Transportation of products and people
- Materials and supply services
- Repair and maintenance of wells and flow lines
- Repair, maintenance, and inspection of equipment and structure

Cost may be incurred hourly, daily, monthly, or annually; be volume- or capacity-based; or be per person (Table 23.1). In activity-based costing, the tasks required to be performed are identified, and the time and duration to perform each task are estimated. If only a small number of facilities are evaluated, a detailed approach is feasible, but for more than a few structures, the resources required to complete an activity-based cost study are significant (Kaiser, 2019).

Table 23.1 Offshore Operating Cost Categories and Cost Basis

Element	Basis
Personnel	
Process operators	Annual
Process maintenance	Annual
Supervision	Annual
Crew transportation	
Helicopters	Monthly fixed, hourly flight rate
OSV	Monthly fixed, day rate
Logistics	
OSV supply boats	Day rate
Standby vessels	Monthly
Docking charges	Monthly
Warehouse	Monthly
Chemicals	Volume
Fuel, water	Volume
Repairs and maintenance	
Service company personnel	Rate + schedule
Service company equipment	Rate + schedule
Contractor services	Rate + schedule
Equipment standby	Monthly
Pipeline tariffs	Volume, capacity, distance, age
Communications, data transmission	Annual
Catering	Per person per day
Insurance	Annual

23.2 LABOR

In the GoM, facilities that are manned 24 h report a bed count to BOEM for the number of individuals that can be accommodated overnight (Fig. 23.1). Beds are required for production crew as well as service personnel, drilling and workover crew, supervisors, and visitors. The number of permanent crew required for operations typically range between one-third to one-half the number of permanent beds available.

Hourly wage rates for offshore production and drilling crew are about the same as onshore, but for offshore operations, the crews live onboard the platform which requires logistics planning, transportation, catering, safety process planning, and support staff, and makes the total expenses far greater than for onshore operations. Direct salary expense for permanent crew usually ranges between \$100 and \$150 thousand per year with many different personnel rates for different grades and occupations.

Example. Production crew salary

Offshore crews in the GoM typically work 2 weeks on and 2 weeks off, so a facility that requires a permanent crew of 24 such as Delta House would require an annual labor cost of 2 × 24 personnel × \$125,000 per person per year = \$6 million per year assuming a base salary of \$125,000 per person. A shallow-water facility such as a gas receiving platform may only require a four-man crew, which amounts to a crew salary of \$1 million per year.

Catering requirements are usually contracted on a dollar per person per day basis and include food service, cleaning, and laundry. Vendors can be contacted for the most up-to-date quotes, but values are easy to bound. It would be difficult for a GoM contractor to stay in business charging less than say \$10 per day per person to feed personnel three meals a day, while \$50 per day per person is an approximate upper bound. Actual values will depend on market competition and other conditions. Services such as cleaning linen and waste disposal may be added separately or included as part of the per person cost. Transportation to-from an onshore service base is provided by a logistic firm paid for by the operator unless the caterer contracts and charges for this service separately.

23.3 LOGISTICS AND TRANSPORTATION

Crews, supplies, and equipment must be transported to the platform, and so, the further the operation from the shore base, the greater the cost for fuel and vessel/helicopter rentals, and the more frequent the visits, the greater the expense. Larger vessels and helicopters usually charge a premium relative to smaller vehicles, and services with a shorter notice period and contract duration will also be more expensive, for all other things equal. All manned platforms in the GoM have helidecks, and all deepwater facilities are serviced using helicopters for crew, while closer to shore, both marine vessels and helicopters are utilized for crew change. Material transport is via supply vessel.

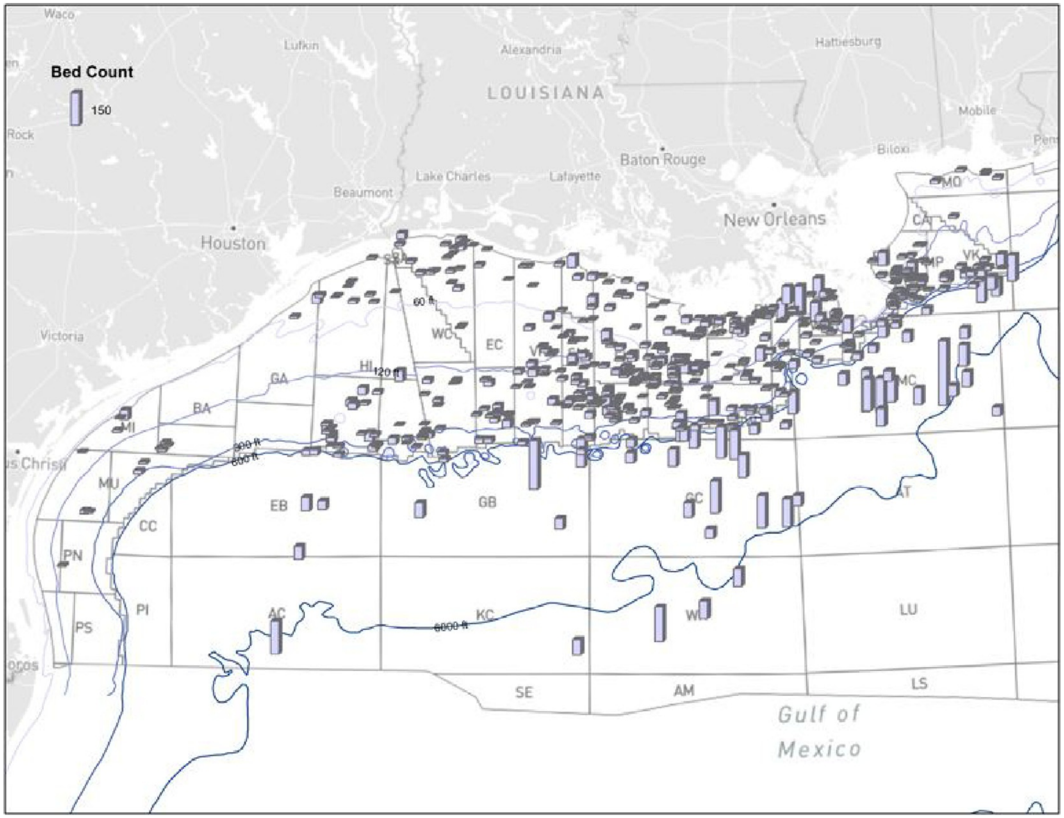


Fig. 23.1 Bed count on manned platforms in the Gulf of Mexico circa 2018. *(Source: BOEM 2018.)*

23.3.1 Marine Vessels

Vessel charters are either the product of direct negotiation or a competitive process that evaluates vessel capability and price. The day rate is the primary bid variable in contract negotiation and selection, but other factors such as safety record, history with the firm, and vessel specifications are also important.

Marine vessels are leased primarily on term or spot charters, although time and bareboat charters have also been used occasionally. Term charters are generally 3 months to 3 years in duration and are typical for drilling or production support. Spot charters are a short-term agreement (from one day up to three months) to provide offshore services. Spot charters are commonly employed for unscheduled or nonrecurring support, as in decommissioning, well work, or incident response. Under a time charter, the operator provides a vessel to a customer and is responsible for all operating expense including crew costs but typically excluding fuel. Under a bareboat charter, the operator provides a vessel to a customer, and the customer assumes responsibility for all operating expenses and associated risks.

Average monthly day rates for crew boats and offshore supply vessels (OSVs) in the GoM are published in WorkBoat Magazine based on contractor surveys and can be found on a consolidated annual (sometimes quarterly) basis in financial statements for public companies. Several consulting firms also provide marine vessel indexes. As a general proxy, market day rates and/or company data can often be used to infer fleet vessel rates because the ships and services are relatively homogeneous and commodity-like (Kaiser, 2015), whilst other activity data are site- and location-specific. High levels of competition mean that day rates are unlikely to deviate significantly among operators unless differentiated by technology or vintage.

Example. Shallow-water vs. deepwater transportation charters

In December 2016, average day rates in the GoM for crew boats <170 ft in length and OSVs <2000 deadweight ton (DWT) were reported in WorkBoat Magazine to be \$3230 per day and \$7800 per day, respectively (Fig. 23.2). Assuming 1 day per trip for OSVs and 6 h per trip for crew, 2-week on/off schedule for crew and a weekly OSV visit to the platform, an assumed 80% discount to the average OSV spot rates yields the annual cost estimate for crew and material transportation:

$$\text{Crew boat}: \$3230 \text{ per day} \cdot 0.25 \text{ day per trip} \cdot 26 \text{ trips per year} = \$21,000 \text{ per year.}$$
$$\text{OSV}: 0.80 \cdot \$7800 \text{ per day} \cdot 1 \text{ day per trip} \cdot 52 \text{ trips per year} = \$324,000 \text{ per year.}$$

For OSVs >5000 DWT, average day rates reported in WorkBoat Magazine were \$30,662 per day, and helicopter spot rates are assumed to be \$2500/h. If a round trip to a deepwater facility takes 2 days by boat and 5 h by helicopter, then for a weekly OSV visit and biweekly crew change, the annual crew and logistics cost are estimated as.

$$\text{Helicopter}: \$2500/\text{h} \cdot 5 \text{ h per trip} \cdot 26 \text{ trips per year} = \$325,000 \text{ per year.}$$
$$\text{OSV}: \$30,662 \text{ per day} \cdot 2 \text{ days per trip} \cdot 52 \text{ trips per year} = \$3.19 \text{ million per year.}$$

Structures in deepwater are farther from shore bases and require larger crew than shallow-water structures, which translate into higher labor, catering, transportation, and logistics cost.

Fig. 23.2 Offshore supply vessel *Gloria B. Callais (top)* and fast support vessel *Cougar (bottom)*. *(Source: Seacor.)*

Example. Shallow-water vs. deepwater labor and transportation cost

In Table 23.2, labor, subsistence, and transportation cost for a manned platform in shallow water with five permanent crews and a deepwater facility with 30 permanent crews are estimated circa 2017. Annual labor and transportation cost for a five-man shallow-water platform is estimated at $1.7 million versus $11.6 million per year for a 30-man deepwater facility. Deepwater labor and transportation costs are about an order of magnitude larger than the shallow-water platform.

Table 23.2 Labor and Transportation Cost Comparison—Shallow Water vs Deepwater

Component	Shallow-Water Manned Platform	Cost ($1000/yr)
Labor	5 men · 2 weeks per cycle · $125,000 per man-year	1250
Material transport	0.8 · $7800 per day · 1 day per trip · 52 trips per year	324
Crew transport	$3230 per day · 0.25 day per trip · 26 trips per year	21
Catering	5 men · $50 per man-day · 365 days per year	91
Total		1687

Component	Deepwater Manned Facility	Cost ($Million/yr)
Labor	30 men · 2 weeks per cycle · $125,000 per man-year	7.5
Material transport	$30,662 per day · 2 days per trip · 52 trips per year	3.19
Crew transport	$2500/h · 5 h per trip · 26 trips per year	0.33
Catering	30 men · $50 per man-day · 365 days per year	0.55
Total		11.57

23.3.2 Helicopters

The majority of helicopters in the GoM are chartered through master service agreements, subscription agreements, and day-to-day charter arrangements. Master service agreements and subscription agreement typically require a fixed monthly fee plus incremental payments based on flight hours. These agreements have fixed terms ranging from 1 month to 3 years and contain terms that index fuel costs to market rates so the helicopter operator is not exposed to fuel price variation. Contracts are cancelable by the client with a notice period ranging from 30 to 180 days specified in the contract. In the GoM, short-term contracts for 12 months or less are common. Ad hoc (spot or term charter) services usually entail a shorter notice period and shorter contract duration and are based on an hourly rate or a daily or monthly fixed fee plus additional fees for each hour flown. Generally, ad hoc services have a higher margin than other helicopter contracts due to supply and demand conditions.

Helicopters range in size from small to large. Single-engine and light-twin helicopters perform multiple takeoff/landings to shelf platforms and have a typical passenger capacity of five to nine. Single-engine helicopters are the largest population of helicopters in the GoM, and most are single pilot and use aviation gasoline and reciprocating engines, which not only are cheaper to operate and build than turbine engines but also provide less performance. Medium and heavy helicopters have twin-turbine engines and a typical passenger capacity of 16–19 and can fly in a wider variety of operating conditions using instrument flight rules, travel longer distances, and carry larger payloads than light helicopters. Medium and heavy aircraft are used for crew changes on large production facilities and drilling rigs and all deepwater facilities.

When an aircraft company purchases a helicopter, direct cost is an important feature since it shows the revenue a company must receive to recover its cost and stay in business. The fixed cost and hourly flight cost serve as the primary point of negotiation between operator and customer. Terms depend on the age and type of aircraft, as well as market conditions at the time of negotiation and safety record of the operator. If flight activity is less than anticipated, then the revenue rate may not cover the actual cost per hour, and operators balance this risk through a combination of fixed and variable components.[1] Producers with significant offshore operations may operate their own fleets.

Example. Master Service Agreement for Eurocopter 135/145

Direct cost calculations for a light-twin Eurocopter 135/145 (Fig. 23.3) at a purchase price of $700,000 are considered (Table 23.3). A 5-year depreciation period with a 30% residual value per year is applied. Operators buy hull and liability insurance to protect against damage to aircraft and related liabilities, which is assumed to be 10% of the purchase cost. One pilot with annual salary of $90,000 is assumed. Fuel rates are taken from the EC 145 spec sheet, and the oil and lubricants, maintenance labor, spare parts, and engine overhaul to maintain safe and reliable operations are additional cost terms. Fuel costs are assumed to be $2/gal for Jet A.

[1] Helicopter operators report that they typically receive about half of their revenue from fixed cost, similar to the PHAs described in Chapter 22.

Fig. 23.3 Eurocopter 135 EC. *(Source: Helis.com.)*

Table 23.3 Direct Cost Calculation for a Light-Twin Helicopter

			Cost Per Year ($)		
I	**Fixed Costs**		**500 h**	**1000 h**	**2000 h**
	A Depreciation (5 years, 30% residual value)		98,000	98,000	98,000
	B Insurance				
	1. Liability and property damage	$5000			
	2. Hull insurance (10% of initial cost)	$70,000			
	Total insurance per year	$75,000	75,000	75,000	75,000
	C Pilot ($90,000 per year)		90,000	90,000	90,000
II	**Hourly Costs**	**$**			
	A Fuel (85 gal at $2/gal) per hour	170			
	B Oil and lubricants (10% of fuel) per hour	17			
	C Maintenance labor per hour	20			
	D Spare parts and spares in reserve per hour	25			
	E Engine overhaul per hour	8.50			
	Total cost per flying hour	240.50	120,500	240,500	481,000
	Total cost per year		383,250	503,500	744,000
	Total cost per hour		766.50	503.50	372.00

Note that all values are meant to be illustrative. Purchase cost assumed to be $700,000.

The fixed cost for the 5-year depreciation period is $263,000 per year. The hourly costs for flying are estimated at $240.50/h and are computed for different flight hours. To recover the cost of operations, an operator will need to negotiate a monthly rate of $263,000/12 = $21,900 per month and an hourly rate of $504/h flight time if the flight hours are expected to be 1000 h. If the flight hours are expected to be 500 h, a minimum hourly rate of $767/h is required to breakeven.

23.4 MATERIALS AND SUPPLIES

Materials and supplies are usually not a significant cost in oil and gas operations until late in life since after the equipment is purchased and installed, the primary energy for their operation derives from the reservoir itself and from separated production gas. Facilities that support production from the reservoir, such as gas and water injection, and fields with low-quality crude that exhaust their reservoir energy require more equipment and greater material and energy use relative to young fields with lighter crudes and strong reservoir drives. Gas facilities typically use fewer materials and supplies on a heat-equivalent basis relative to oil facilities, and platforms that support subsea wells require greater utilities and chemical usage relative to dry tree wells.

Chemicals are used for controlling corrosion, emulsions, foaming, scales, paraffins (waxes), asphaltenes, hydrates, hydrogen sulfide, and water quality. The chemistry of produced fluids significantly impacts the design and development of a field, and focused efforts to understand and characterize the fluids are needed during the design stage. Before any treatment is applied, it is important to conduct a thorough investigation of the problems, their root causes, and any implications of the treatment. Chemical cost should be considered from a life-cycle perspective and compared against methods where the problem is managed in a different way. Chemical cost is usually not the overriding driver in chemical selection, but rather, the technical performance must be able to manage the risk.

23.4.1 Chemicals for Water Treatment

Produced oil and water create emulsions that need to be demulsified to satisfy the export pipeline requirements on water (< 1 vol%) and the produced water discharge criteria in the GoM (monthly average of 29 mg/L oil and grease). Therefore, all water–oil emulsions are treated to achieve appropriate separation with mechanical separation (e.g., hydrocyclones) and application of heat and chemicals. Water may also be injected into the reservoir to supplement oil recovery or to dispose produced water. In either case, water will require treatment depending on the source and issues identified (Table 23.4).

Table 23.4 Water Injection Problems and Solutions

Problem	Possible Effect	Solution
Suspended solids	Formation plugging	Filtration or flotation
Precipitates	Scaling and plugging	Scale inhibitors
Bacteria	Loss of injectivity and reservoir souring	Biocides and selection of sour service materials
Dissolved gas	Corrosion and loss of injectivity	Degasification

Source: Jahn, F., Cook, M., Graham, M., 2008. Hydrocarbon Exploration and Production. 2nd ed. Elsevier, Amsterdam, The Netherlands.

Example. FPSO seawater injection cost

For an FPSO with a $100,000 daily operating cost and 16-person crew, water treatment cost per barrel based on seawater injection and produced water treatment at $4/L chemical cost represents about 5% production cost (Table 23.5).

Table 23.5 FPSO Daily Water Treatment Costs per Barrel Based on Seawater Injection and Produced Water Treatment

Chemical Treatment	Dosage (ppm)	Volume (L)	Chemical Cost ($ at $4/L)	General Cost ($/bbl Water)
Seawater injection, 300 Mbbl per day				
Filter aid	2	95	380	0.001
Oxygen scavenger	2	95	380	0.001
Weekly biocide	200	125	500	0.002
Scale inhibitor	2	95	380	0.001
Daily manpower $			4384	0.015
Facility cost $			100,000	0.33
Total cost $			106,024	0.35
Produced water, 10 Mbbl per day				
Water clarifier	5	8	32	0.003
Weekly biocide	200	53	212	0.021
Corrosion inhibitor	20	32	128	0.013
Scale inhibitor	2	95	380	0.001
Daily manpower $			4384	0.004
Facility cost $			100,000	0.614
Total cost $			105,136	

Note: Assumes a 16-person crew and 2-4 h weekly biocide treatment.
Source: Wiggett, A.J., 2014. Water – chemical treatment, management and cost. In: SPE 172191. SPE Saudi Arabia Annual Technical Symposium and Exhibition. Al-Khobar, Saudi Arabia, Apr 21–24.

23.4.2 Chemicals for Corrosion

Highly corrosive fluids (e.g., sour >10,000 ppm H_2S, heavy oil <25° API, gas-oil ratio < 500 cf/bbl, and high water cut >80%) will require greater chemical spending for corrosion control and account for a higher percent of operating expense than non-corrosive fluids. There are many chemical corrosion treatments, including hydrogen sulfide scavenging chemicals, combination treatment chemicals, single-purpose inhibitors, and biocides that can be applied. Pilot studies are often performed to determine the best treatment before implementation (Wiggett, 2014).

Production chemicals are typically injected directly into the wellbore's tubing-casing annulus, wellhead, and flow lines and throughout the separation train to treat for corrosion, emulsions, scale, and H_2S content. Reducing chemical spend can lead to mechanical integrity issues that are more costly to remediate than to prevent (Cavaliaro et al., 2016). Tubing failures are a common impact of corrosion.

Example. Corrosion inhibitors

Natural gas with impurities such as H_2S and CO_2 is highly corrosive and is commonly treated with chemical inhibitors. Typical corrosion inhibitor concentrations are 5–50 ppm for continuous addition and up to 250 ppm for batch dosing. Inhibitor use increases in proportion to flow rate. Gas inhibitor dosage rates are typically in the range of 0.25–0.75 L/MMcf of gas, and at $10/L, chemical cost translates into an annual chemical cost of $1825 and $91,250 for flow rates of 1 and 50 MMcfd (Table 23.6).

Table 23.6 Corrosion Inhibitor Cost for Two Gas Flow Rates

Gas Rate	Inhibitor at 0.5 L/MMcf	Cost at $10/L	Annual Cost
50 MMcfd	25 L per day	$250 per day	$91,250
1 MMcfd	0.5 L per day	$5 per day	$1825

Source: Cavaliaro, B., Clayton, R., Campos, M., 2016. Cost-conscious corrosion control. In: SPE 179949. SPE International Oilfield Corrosion Conference and Exhibition. Aberdeen, Scotland, May 9–10.

In moderately corrosive environments, batch chemical treatments can provide sufficient protection to downhole equipment and flowlines. In highly corrosive environments and larger produced volumes, chemical treatment may be uneconomic. When flow rates are high, turbulence in the pipelines helps ensure that the full interior of the line is inhibited with chemical, but as flow velocities decline and turn laminar, untreated areas are more likely to arise.

23.4.3 Chemicals for Flow Assurance

In general, the greater the change in temperature and pressure that produced fluids experience in traveling from the reservoir to the host, the greater the number of flow assurance problems and chemical treating needs (Fig. 23.4). Flow assurance issues are generally not a concern in shallow water and with dry tree and direct vertical access wells, but are dominate design considerations in subsea development. The list of chemicals utilized in subsea developments may be substantial to avoid problems with solid deposition and to ensure safe and reliable operations. They include methanol, low-dosage hydrate inhibitors (LDHI), asphaltene inhibitor, paraffin inhibitor, pour-point depressant, corrosion inhibitor, and scale inhibitor (Bomba et al., 2018).

Strategies to reduce the magnitude of the changes occurring, especially in temperature that drives wax and hydrate formation and to a lesser extent scale formation, require capital. Flow assurance strategies typically involve a combination of equipment design/selection, operational methodologies, and chemical treatments (Table 23.7). The overall objective of flow assurance is to keep the flow path open.

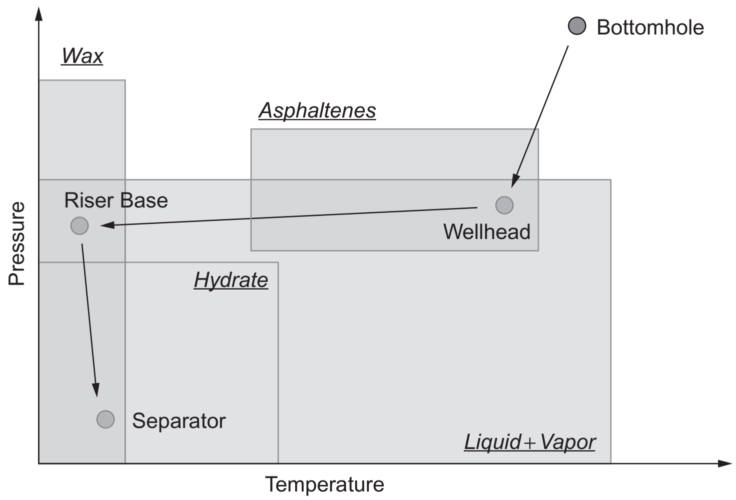


Fig. 23.4 Generalized schematic of pressure-temperature regions that will create asphaltenes, wax, and hydrate production issues.

Table 23.7 Production Chemical Applications and Injection Points

Chemical	Operation Mode	Injection Point(s)	Combinations	Rate (ppm)
Methanol	Continuous (gas) Intermittent (oil)	Tree/downhole	CI	50–100 vol%
Glycol	Continuous (gas) Intermittent (oil)	Tree/downhole	CI	50–100 vol%
PPD	Continuous	Tree/downhole	CI	100–300
PI	Continuous	Tree/downhole	CI or AI	100–300
AD	Continuous	Downhole at packer	CI	100–500
AS	Intermittent	Tree	CI	50–500
CI	Continuous	Tree	MeOH, glycol, AD	10–50
SI	Continuous	Downhole at packer	CI	1–2 vol%
LDHI	Continuous	Tree/downhole	MeOH, MEG	1–2 vol%

Note: AA, antiagglomerant low-dosage hydrate inhibitor; AD, asphaltene dispersant; AS, asphaltene solvent; CI, corrosion inhibitor; MeOH, methanol; MEG, ethylene glycol; LDHI, low-dosage hydrate inhibitor; PI, paraffin inhibitor; PPD, pour-point dispersant; SI, scale inhibitor.

Source: Bomba, J., Chin, D., Kak, A., Meng, W., 2018. Flow assurance engineering in deepwater offshore – past, present, and future. In: OTC 28704. Offshore Technology Conference. Houston, TX, Apr 30–May 3.

Example. Methanol hydrate inhibitor cost

A well produces 1000 bpd water, and 0.5 bbl of methanol per barrel of water is used to prevent hydrate formation. In the GoM, methanol cost varies with market conditions and transportation and historically has ranged from $25 to $75/bbl. For $50/bbl ($1.2/gal) methanol, hydrate inhibitor cost for the well will be $25,000 per day or $9 million per year. For some fields, the methanol delivery system may define the abandonment conditions of the well.

Methanol and LDHI are commonly employed in oil wells and are usually consumed (i.e., not recovered) in the process. Gas-dominated systems typically use MEG rather than methanol because of the lower amounts required and MEG offers the advantage of being recyclable. Selection is normally based on the lowest cost per volume produced, but other factors may also play a role. For example, since methanol is partially soluble in crude oil, excessive use results in the crude oil being contaminated at concentrations ranging from 10 to 10,000 mg/L, which will negatively impact the price received since methanol causes catalyst poisoning in refineries. Most oil contracts limit methanol concentration to below 50 mg/L. Topside storage volume constraints may also play a role in chemical selection.

Example. Methanol vs. LDHI cost comparison

For a subsea well producing a 39° API condensate, application costs for methanol at $1/gal and 35% water flow are compared with LDHI at $30/gal and 0.5% water flow (Swanson et al., 2005). If there is no recovery of the chemical, then the monthly chemical cost to inhibit hydrates for a water flow rate of 1300 bpd is estimated as:

Methanol cost = 0.35(1300 bpd)(42 gal/bbl)($1/gal)(30 day per month) = $573,300 per month.

LDHI cost = 0.005(1300 bpd)(42 gal/bbl)($30/gal)(30 day per month) = $246,300 per month.

Hydrate inhibitors treat the aqueous phase, and therefore, the higher the water rate, the higher the dosage. Hydrate prevention costs vary with the water flow rate, chemical cost, and prevention mechanism.

Example. K2 chemical injection system

The K2 field is a three-well subsea development in 4200 ft water depth tied back 7 mi to its host at the Marco Polo TLP (Brimmer, 2006). Pipe-in-pipe flow lines and insulated risers with a chemical injection system for each well were selected in development. LDHI was selected as the main hydrate inhibitor, and methanol was used as a backup system. At start-up after a shutdown, it is necessary to inject wax inhibitor to prevent wax formation while the flow rates are low and the temperature is below the WAT. Chemical injection to control asphaltenes is used when needed and varies with each well.

The injection points are shown schematically in Fig. 23.5, and the umbilical assembly for chemical delivery is shown in Fig. 23.6. Two deep-set chemical injection mandrels are located above the production packer approximately 18,000 ft below the mudline, and one shallow-set mandrel is located above the

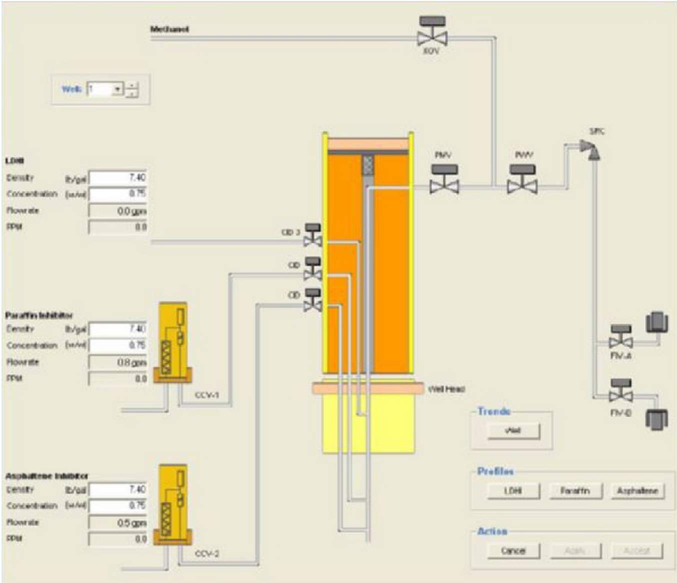
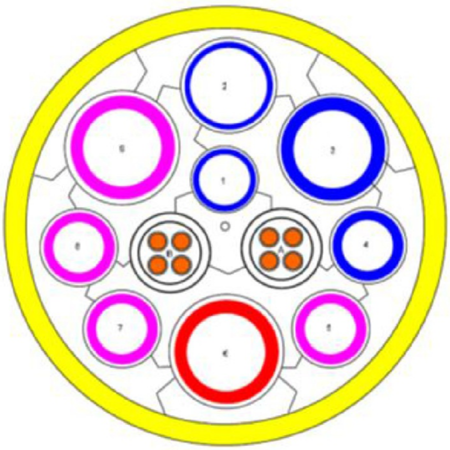


Fig. 23.5 Tree injection system and downhole locations at the K2 field. *(Source: Brimmer, 2006.)*



#	Tube Size (ID)	Max Pressure (psi)	Line Function
1	½"	10,000	HP "A"
2	¾"	5,000	LP "A"
3	¾"	15,000	LP "B"/share
4	½"	15,000	HP "B"/share
5	½	15,000	Asphaltenes inhibitor
6	¾"	15,000	Annulus access line
7	½"	15,000	LDHI
8	½"	15,000	Paraffin wax
9	¾"	15,000	Methanol line
A			Power/single cable
B			Power/single cable

Fig. 23.6 Umbilical cross section for K2 subsea development. *(Source: Brimmer, 2006.)*

downhole safety valve that is 3900 ft below the mudline. The deep-set mandrels are used for asphaltenes and wax inhibitor injection to protect the wellbore and pipeline. LDHI is injected downhole for better mixing, and methanol is injected at the tree for start-up.

23.4.4 Fuel, Water and Utilities

"Fuel is free" is a common adage in the oil field, and indeed, as long as wells are not low volume black crude (GOR < 500 cf/bbl), most oil wells produce enough (associated) gas to use at site to satisfy a significant portion of fuel usage and export the surplus. Backup fuels are always required during start-up and after shutdown operations since process systems will be off-line during these times and the gas from processing will not be available.

If a structure produces gas from its lease, it is used free of charge to provide electricity, heat, cooling (e.g., via pumping seawater), and related power requirements. Of course, gas use will reduce sales revenue, but from a cost perspective unless purchased, fuel cost is not a primary design variable. If gas is not available at site, fuel will need to be purchased and delivered to the platform. For start-up operations and as a backup power, diesel is commonly used offshore and stored in bulk or in tanks. Gas supply may be provided by a nearby platform by running a flowline to the facility and installing a metering system.

Utility systems support production operations and include the power plant, seawater and potable water treatment system, chemical and lubricating oils, alarm and shutdown systems, fire protection and firefighting system, and instrumentation and utility air system. Power generation and electric systems are required for large or complex facilities and manned platforms. Water needs to be transported to manned facilities for personnel use.

Example. Power generation at Appomattox

Shell's deepwater Appomattox development required 150 MW power generation equipment for a combined-cycle power plant. The 150 MW power plant features four 27 MW gas turbine-driven generator sets equipped with heat recovery systems and a 40 MW steam turbine generator.

23.5 REPAIRS AND MAINTENANCE—WELLS AND FLOWLINE

23.5.1 Maintenance

Pigging is performed as part of regular operations to facilitate flow and reduce corrosion and buildup in pipelines.

Example. Paraffin cutting at Pompano

In the Pompano development, subsea wells are maintained using a through-flowline (TFL) system to transport (simple) tools and chemicals to the wellbores through the manifold/template (Fig. 23.7). TFL systems were introduced in the late 1960s to provide a low-cost wellbore reentry capability for mechanical removal of paraffin deposits, but many early systems were plagued by operational problems and equipment failures and were not widely adopted (KepRta, 1976). Circulating pressure moves the tool through the looped system. Because of the waxy nature of the crude (3.2 wt% paraffin content, 95°F cloud point, −6°F pour point) and the distance between the subsea wells and host facility, frequent paraffin cutting of the service lines was expected (Kleinhans and Cordner, 1999).

A base-case and a worst-case scenario in the types of TFL operations required and their expected frequencies were estimated by engineers to understand the downtime and operating cost requirements (Table 23.8). Operations require different tools to be employed and contractor cost for equipment and crew

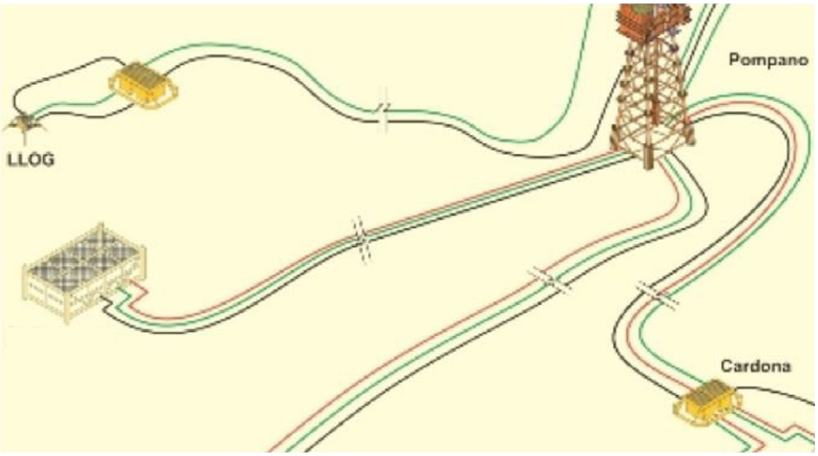


Fig. 23.7 Pompano subsea tieback schematic.

Table 23.8 Pompano Subsea Well Maintenance Operations Requirements (per Well per Year)

Operation	Base Case	Worst Case
Paraffin scraping	6.0	15.0
BHP survey	1.0	1.0
Set and recover plug	0.2	0.5
Tubing caliper survey	0.125	0.25
SCSSV repair	0.05	0.125

Source: Kleinhans, J.W., Cordner, J.P., 1999. Pompano through-flowline system. SPE Prod. Facilit. 14 (1), 37–48.

will depend upon requirements. When wells are producing at high rates (> 2000 bopd), downhole cutting is not expected, but as the well rates diminish, routine paraffin cutting is required. As reservoirs deplete and fluid chemistry changes, the worst-case scenario was considered more likely to arise.

23.5.2 Stimulation

Wells need to be maintained for maximum productivity, and in the event that a well stops producing, a decision has to be made on the merits of attempting to bring the well back online. A useful categorization divides well constraints as completion interval constraints and production tubing constraints (Table 23.9). The type and frequency of activities vary significantly as well as the success of action.

The three primary causes of well impairment include the movement and rearrangement of reservoir fines, deposition of solids from produced crudes, and deposition of mineral scales from produced water (Table 23.10). Scale formation may occur in the reservoir and inside the production tubing and may be removed chemically or mechanically. A well producing at high water cut may be choked back, or a change of perforation interval may be considered to shut off unwanted fluids. Skin problems may be resolved by acidizing or additional perforations.

Organic deposits such as asphaltenes in the oil are usually not a significant concern in operations except when unstable. Deposition can occur in the reservoir, tubing, subsea, and topsides depending on the asphaltene onset pressure and saturation pressure.

Table 23.9 Completion Interval and Tubing Wellbore Constraints

Completion Interval Constraints	Production Tubing Constraints
Damage skin	Tubing string design
Sand production	Artificial lift
Scale formation	Sand production
Emulsion formation	Scale formation
Asphaltene dropout	Choke size

Table 23.10 Primary Causes of Well Impairment

Category	Description	Remedy
Scale	Inorganic minerals deposited from water	Calcium carbonate removed with HCl or organic acids, barium sulfate-treated chelates
Organic deposits	Deposition of solids from the oil phase, usually a combination of asphaltenes and resins	Asphaltenes remediated with aromatic solvents
Fine migration	Flow-induced movement of clay-sized particles from pore bodies to pore throats causing a reduction in permeability	Combination of HCl and/or organic acids with HF acid

Note that remedy represents typical industry guidelines. For example, scale treatment involves injecting treatment solution, soaking (e.g., 12–24 h), and flowing the well back. For fine migration treatments, a 9% HC1/1% HF is commonly used.

Reservoir impairment would require stimulation of the near-wellbore region, whereas tubing or flowline deposition would require a solvent soak. The logistics, expenses, and safety issues are different in each case.

Tubing corrosion requires monitoring, and if a leak develops, the tubing needs to be replaced or the well shut in. As reservoir pressure declines, the tubing may need to be reduced in diameter to maintain maximum flow. When the natural drive energy of the reservoir has reduced, artificial lift may be justified that will increase both capital and operating expense. Sand production from loosely consolidated formations may erode tubulars and valves and cause problems at the surface separators and necessitate recompletion. Paraffin cutting is a common maintenance requirement for high-wax crude.

Personnel separate from the production crew are required for operations and are performed by a service crew that require transportation and logistics support. Because the well is shut in during operations, logistics coordination and efficiency are critical. Stimulation of subsea wells is more challenging and costly than dry tree and direct access wells but may be highly profitable if technology solutions have been developed and outcomes are successful.

23.5.3 Well Failure

When wells stop producing, the probable cause of the shut-in is determined, and the expected cost, benefit and risk of three options are identified:

- Sidetrack the well,
- Perform a workover to remediate problem, or
- Leave the well shut in.

The decision to invest capital in an attempt to bring the well back online depends on many factors. The price of oil/gas and equipment/rig day rates play an important role as well as the uncertainty associated with the problem and its solution. New wells that fail have a much greater chance of getting a workover than an old well that has already drained most of the reservoir. Workover decisions in old wells are risky since the operator may not get their investment back, and so, once an older well stops producing, a workover may not even be contemplated if production rates are low. Decisions may also be based on maintaining a lease position or infrastructure.

Example. Troika well TA-6

The Troika field in Green Canyon 201 is a subsea development tied back to the Bullwinkle platform in GC 65 (Bednar, 1998). Well TA-6 was brought online in November 2000 and produced 3.9 MMbbl of oil and 4.5 Bcf of gas for 14 months before a gravel-pack failure occurred (Gillespie et al., 2005). Sidetracking was not considered the best option due to low oil price forecasts and the uncertainty of the remaining reserves caused by increasing water production. It was decided to clean out the well and run a screen insert inside the failed screen. If this option failed, the well would be shut in.

The workover was completed in one week at a cost of about $8 million. The well was returned to production in January 2003, and the postworkover production was 1.95 MMbbl oil and 2.7 Bcf through June 2005, an obvious success since the postworkover revenue far exceeded the cost of the intervention. Operators seek workovers with strong positive results but cannot always control or predict the outcome of operations.

23.5.4 Flowline and Export Repairs

Hydrates, wax, and asphaltenes in the hydrocarbon streams have the potential to disrupt production due to deposition at many points in the production system.

Example. Stuck pig at Marlin

The Marlin TLP is located in Viosca Knoll 915 in 3250 ft water depth and is host to several dry tree and wet tree wells (Fung et al., 2006). Oil export is via a 22 mi noninsulated 10 in line to facilities at Main Pass 225 in 200 ft water depth. The oil export management plan used a regular single-trip pigging technique to remove the wax buildup every 14 days and was selected over continuous wax inhibition because of the high operating expense of the chemical treatment.

Oil leaves the Marlin TLP at a temperature of approximately 120°F and drops to 40°F over the first 7300 ft (1.4 mi) of flowline and then warms to about 65°F at the MP 225 location (Fig. 23.8). Since the pipeline does not have any insulation, higher-flow-rate fluids will retain heat for longer distance until the fluid heat has been lost (at about 20,000 ft distance) where slower flow rates will warm up more than fast fluids. The WAT of the comingled oil streams is approximately 95°F. Heavy molecular weight paraffinic

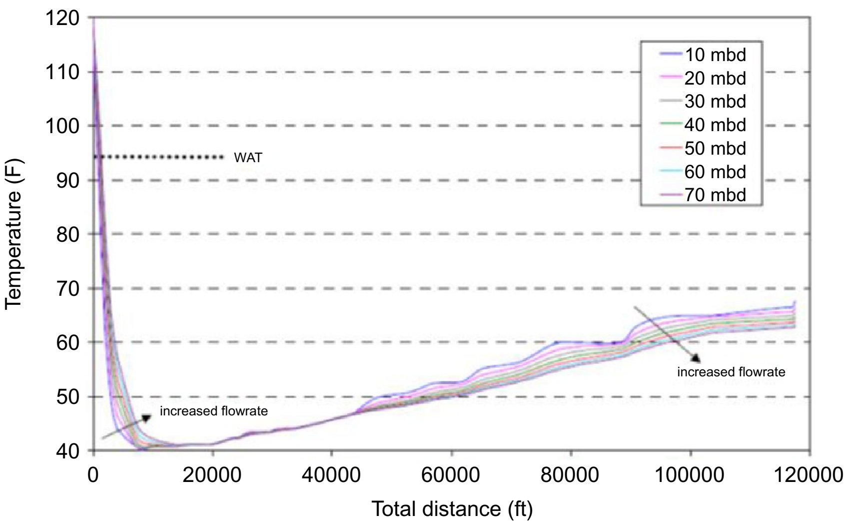


Fig. 23.8 Marlin oil export line temperature profile. *(Source: Fung, G., Backhaus, W.P., McDaniel, S., Erdogmus, M., 2006. To pig or not to pig: the Marlin experience with stuck pig. In: OTC 18387. Offshore Technology Conference. Houston, TX, May 1–4.)*

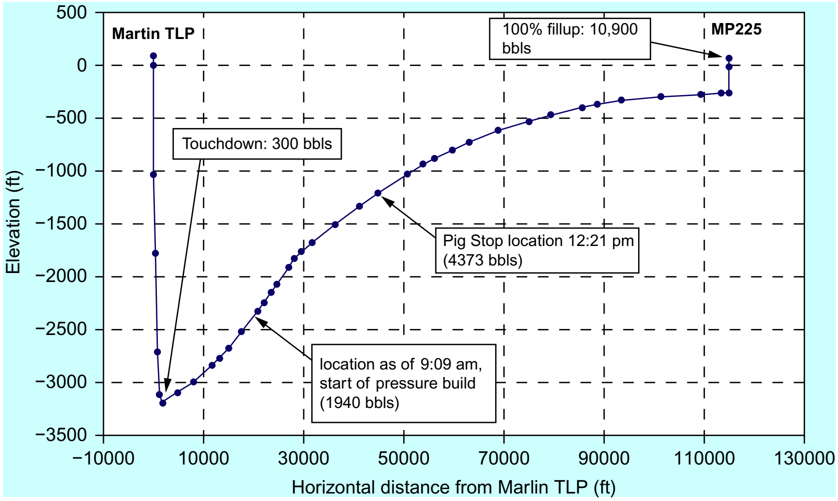


Fig. 23.9 Marlin oil export pipeline elevation and estimated stuck pig location. *(Source: Fung, G., Backhaus, W.P., McDaniel, S., Erdogmus, M., 2006. To pig or not to pig: the Marlin experience with stuck pig. In: OTC 18387. Offshore Technology Conference. Houston, TX, May 1–4.)*

hydrocarbons begin to solidify and deposit on the pipe wall over time and give rise to an increasing pressure drop due to reduction in the flow diameter and increase in the pipe roughness.

Equipment failure stopped the 14-day pigging cycle and resulted in a stuck pig at the next pig run. The stuck pig was estimated to be approximately 9 mi from the MP 225 facility in approximately 1200 ft water depth (Fig. 23.9). Pumping equipment at MP 225 was used to pump the pig back to Marlin using buyback crude with 5000 gal of wax solvent and 300 ppm of wax inhibitor.

23.6 REPAIRS AND MAINTENANCE—EQUIPMENT AND STRUCTURE

Offshore equipment and platforms are inspected on a periodic basis dictated by company practices and regulatory requirements.

23.6.1 Regulatory Requirements

The OCS Lands Act authorizes and requires the BSEE to provide for both an annual scheduled inspection and periodic unscheduled (unannounced) inspection of all oil and gas operations on the OCS. In addition to examining all safety equipment designed to prevent blowouts, fires, spills, or other major accidents, the inspections focus on pollution, drilling operations, completions, workovers, production, and pipeline safety. Inspections also include a review of painting integrity.

Upon detecting a violation, the inspector issues an incident of noncompliance (INC) to the operator and uses one of two main enforcement actions (warning or shut-in),

Table 23.11 In-Service Inspection Intervals for Fixed, Manned, and Unmanned Platforms

	Exposure Category		
Level	**L-1**	**L-2**	**L-3**
I	1 year	1 year	1 year
II	3 years (5 years)	5 years (10 years)	5 years (10 years)
III	6 years (6 years)	11 years (11 years)	

Note: Unmanned platform inspection intervals are denoted in parenthesis.
Source: NTL 2009-G32.

depending on the severity of the violation. If the violation is not severe or threatening, a warning INC is issued. The warning INC must be corrected within a reasonable amount of time specified on the INC. The shut-in INC may be for a single component (a portion of the facility) or the entire facility and must be corrected before the operator is allowed to resume operations.

The BSEE can also assess a civil penalty of up to $40,000 per violation per day if (i) the operator fails to correct the violation in the time specified on the INC or (ii) the violation resulted in a threat of serious harm or damage to human life or the environment. Operators with excessive INCs may be required to cease operations in the Gulf of Mexico.

BSEE regulations require operators perform in-service inspection intervals for fixed platforms according to API Recommended Practice 2A-WSD (NTL 2009-G32, 2009). Section 14 of API RP 2A-WSD describes the inspection program survey levels and frequencies to monitor periodically the adequacy of the corrosion protection system and determine the condition of the platform.

23.6.2 Inspection Schedules

The time interval between platform inspections depends upon structure exposure category (L-1, L-2, or L-3), survey level (Level I, Level II, and Level III), and manned status (Table 23.11).

Exposure Category

Two classes of risk are used to define exposure category, those associated with life safety and those associated with consequences of failure (Ward et al., 2000a, 2000b). The three levels of exposure to life safety are manned and nonevacuated, manned and evacuated, and unmanned (Table 23.12). Consequences of failure are categorized as high, medium, and low and encompass damage to the environment, economic losses to the operator and the government, and public concerns. Economic losses to the operator can include the costs to replace, repair, and/or remove destroyed or damaged facilities; costs to mitigate environmental damages due to released oil; and lost revenue. Economic losses to the government include lost royalty revenues.

Table 23.12 Risk Considered for Consequence-Based Criteria for the Gulf of Mexico

Exposure	Life Safety	Consequences of Failure
L-1	Manned, nonevacuated	High
L-2	Manned, evacuated	Medium
L-3	Unmanned	Low

Source: Ward et al., 2000.

Level Surveys

A Level I survey is required to be conducted for each platform at least annually and a grade assigned to the coating system as A, B, or C. Grade A indicates the coating system is in good condition with no maintenance needed within 3 years. Grades B and C refer to fair and poor coating system conditions requiring maintenance within 3 years or 12 months, respectively.

A Level II survey is required for each platform at the minimum survey interval for each exposure category, at least every 3 years for L-1 platforms and at least every 5 years for L-2 and L-3 platforms.

A Level III survey is required for each platform at the minimum survey interval for each specified exposure category, at least every 6 years for L-1 platforms and at least every 11 years for L-2 platforms.

For unmanned platforms, BSEE may approve an increased interval for Level II and Level III inspections if the operator is in compliance with all structural inspection requirements and the platform is in good structural condition according to previous Level I and Level II surveys.

Inspection Levels

Level I inspections are topside inspections performed annually. Topside maintenance is relatively easy to perform as long as equipment is accessible and paint schedules are followed. Flare towers, crane booms, and lower deck levels present more complicated regions because of access. Level I inspections are normally performed by an operator's maintenance personnel or staff personnel.

Level II inspections are underwater inspections performed every 3–5 years to check for debris and gross damage, measure cathodic potential readings, and verify anode connections. On large shelf structures, anode connections may number in the hundreds and on deepwater structures in the thousands. For example, the cathodic protection system on the Bullwinkle jacket in 1350 ft water depth consists of approximately 6300 aluminum-zinc-mercury anodes totaling about 2400 t of anode material (Wolfson and Kenney, 1989). Level II inspections generally do not involve cleaning or marine growth removal for weld inspections and fractures. One or two days per platform are considered adequate for Level II inspections.

Level III inspections are underwater inspections required to be performed on a 6- to 11-year interval. Typically, Level III inspections include the cleaning and inspection of selected member ends, conductor areas near the bell guides, and connection points of anodes. Member ends with lower fatigue life are selected for inspection, and if damage is detected, the inspection scope is likely to be extended. Level III inspections will usually take several days to a week or longer per platform.

23.6.3 Three Zones

There are three separate zones in platform corrosion control: the immersed zone, the splash zone, and the atmosphere. Corrosion rates for each zone are broadly similar throughout the world, but site-specific factors lead to differences. Tides, water temperature and velocity, salinity, humidity, and wave forces all affect corrosion rates and the design of the corrosion control system.

The bulk of the platform is immersed, and this portion is also the simplest to protect with cathodic protection being the most common method. The process typically involves welding sacrificial nodes throughout the structure before installation to supply protective current to the steel members. The splash zone is the most critical area with the highest corrosion rates due to the alternate submergence and aeration. Splash zone protection in the GoM is often installed a few feet below the waterline to several feet above (e.g., from −3 to 7 ft). Steel members in the splash zone are also normally designed with a greater wall thickness to account for greater corrosion. The atmospheric zone includes structural steel, equipment, piping, vessels, and valves and has the least corrosion rate but the most surface area and is the most expensive to maintain.

Structures and piping in the splash zone are painted to protect the steel from aggressive corrosion due to wave action and continuous wetness. Structures are painted above the splash zone to assure that equipment will remain functional. Bare flanges, valves, and rotating equipment will quickly become inoperable, and pressure equipment may become too thin to hold pressure creating safety hazards if not properly maintained.

23.6.4 Painting

Objective

The primary objective of painting platforms and equipment is to protect structures to ensure integrity and that the structure will last for its intended design life (Choate and Kochanczyk, 1991; Knudsen, 2013). The selection of a coating system is a design choice made by engineers based on the trade-offs between steel thickness and the corrosion allowance that the coating system is engineered to protect (Taekker et al., 2006; Kattan et al., 2013).

During the fabrication of offshore structures, surfaces are painted and treated to the operator's specification, and assuming activities are performed according to requirements, these will provide protection against saltwater corrosion, ultraviolet radiation, rust, splash zones, changing temperatures, and related deterioration for several years. After a period of time, however, depending on the specifications and materials used, environmental conditions, and other factors, the coating will need to be replaced according to the level of deterioration. Coatings are monitored and treatment is performed before major interventions are needed. Regular maintenance extends the structure life integrity and lowers repair frequency.

There are design standards for offshore coating systems (ISO 20340, NORSOK M-501, and NACE TM 0104) and the qualification of products, procedures, companies, and (inspection) personnel. The primary aim of standards is to provide optimum surface protection with a minimum need for maintenance. Each standard describes different coating systems for application on various parts of an offshore structure and is described with requirements on surface preparation, the number of coats, and requirements for prequalification testing.

Inspections are performed to survey the coatings and develop an annual plan and to ensure quality control during application. The blasting crew prepares the surface by hand and power tools and abrasive wet jets to remove contaminants such as oil, grease, and soluble salts, as well as paint chips and metal debris. Garnet and equipment (air compressors, blasting hoses, spray assemblies, and paint-mixing equipment) must be transported to the facility, and blasting generates waste that must be collected, bagged, and transported off the structure and disposed or recycled in dedicated sites associated with industrial (hazardous and nonhazardous) waste.

Maintenance Painting Schedule

There are several methods of conducting maintenance painting and determining which method to use is a philosophical as well as technical decision. Maintenance implies sustaining a particular level of coating integrity and performance, while repair implies restoring a coating to a previously higher level of integrity and performance. Operators with small maintenance budgets or that delay or reduce maintenance activities will often face higher repair costs than operators with a constant painting budget. For low-cost equipment and with a short operation life, corrective maintenance is the common approach (i.e., fix it when it breaks). For high capital cost structures and equipment, preventative and predictive monitoring is standard and painting are year-round activities (Witte and Ribeiro, 2012).

After original painting, spot touch-up and repair are expected to occur at the practical life (or service life) of the coating system shown in Table 23.13 for different coating systems for offshore atmospheric and immersion service.

Structures are often separated by horizontal and vertical zones, and the condition of the coating in each zone is assessed. One example of zones might include below the spider deck, spider deck to the bottom of cellar deck, top of cellar deck to the bottom of

Table 23.13 Estimated Service Life for Selective Offshore Maintenance Coating Systems

Type (Exposure)	Coating System	Preparation	Coats (#)	DFT (Mils)	Life (Year)
Alkyd (Atm)	Alkyd/alkyd/urethane	Blast	3	6	4
Epoxy (Atm)	Surface tolerant epoxy/STE	Power	2	10	9
Epoxy (Atm)	Epoxy/polyurethane	Blast	2	6	8
Epoxy zinc (Atm)	Epoxy zinc/epoxy/epoxy	Blast	3	11	14
Zinc (Atm)	Zinc/epoxy/polyurethane	Blast	3	12	15
Zinc/epoxy (Imm)	Zinc/epoxy/epoxy	Blast	3	10	12
Metallizing (Imm)	Metallizing/epoxy/spoxy	Blast	3	13	18

Note: Atmospheric (Atm) marine exposure is defined as very high corrosion in offshore areas with high salinity. Immersion (Imm) service is saltwater immersion at ambient temperature and pressure. Coating system includes primer/midcoat/topcoat. Service life is the time until 10% coating breakdown occurs and active rusting is present.
Source: Helsel, J.L., Lanterman, R., 2016. Expected service life and cost considerations for maintenance and new construction protective coating work. In: NACE 7422. NACE International Corrosion Conference and Expo. Vancouver, BC, Canada.

production deck, and production deck and above. Component groupings may also be based on where abrasive blasting is not permitted. The structure and decks are usually evaluated separately from equipment and piping.

Paint and Coating Cost

In Table 23.14, typical material costs of paints and protective coatings are depicted based on 2016 survey data from US paint and coating suppliers (Helsel and Lanterman, 2016). Costs are expressed in dollars per square foot at typical dry film thickness (DFT) and assume 30% spray painting losses and 10% brush/roll losses.

There are many factors that impact the volume of paint required to protect steel surfaces. The theoretical spreading rate of paint for a given dry film thickness on a smooth surface is calculated as (Hempel 2016)

$$\frac{\text{Volume solids }(\%)\times 10}{\text{Dry film thickness }(\mu m)}=\frac{10\text{ VS }(\%)}{\text{DFT }(\mu m)}=\text{m}^2/\text{L}$$

Table 23.14 Typical Offshore Paint and Protective Coating Cost Circa 2016

Coating	DFT (Mils)	Spray ($/ft^2)	Brush/Roll ($/ft^2)
Epoxy, 100% solids	20	1.89	1.47
Polyurethane, aliphatic acrylic	2	0.28	0.22
Siloxane, epoxy	4	1.02	0.79
Zinc rich, inorganic	3	0.40	0.31

Source: Helsel, J.L., Lanterman, R., 2016. Expected service life and cost considerations for maintenance and new construction protective coating work. In: NACE 7422. NACE International Corrosion Conference and Expo. Vancouver, BC, Canada.

Table 23.15 Approximate Conversion of Member Weight in Tons to Footage of Surface

Member	Square Feet per Ton
Typical mix size/shapes	250
Large structural	100
Medium structural	200
Light structural	400
Light trusses	500

where volume solids (VS) express the ratio of dry film thickness (after drying) to wet film thickness (as applied). The practical consumption is estimated by multiplying the theoretical consumption with a relevant consumption factor. Consumption factor is not given in painting specifications since it depends on several conditions such as the size and shape of the surface (small complex area vs square flat area), application method (hand/brush vs spray), surface roughness (rough vs smooth), physical losses, experience of the painters, and atmospheric conditions.

The maintenance and repair cost for an offshore structure depends on the size and location of the project, type and volume of paints used, scope of work, and contracts applied. Work can range from a full blast to repair. Painting may be performed at night (Judice, 2007).

Since total square footage of a structure is rarely reported in public documents, approximations are required to estimate painting areas. Useful conversions based on deck and topside weight are shown in Table 23.15. As an example, deck weight at the Auger TLP is 10,500 t, and total steel surface area was reported as 1.8 million square feet. For medium structural steel and a 200 ft^2/t conversion yields 2.1 million square feet deck surface area, a 15% error from the reported value.

Example. Painting cost estimation at Enchilada, Prince, and Mars

The Enchilada platform was installed in 1997 and sits in 705 ft water depth with a total topside operating weight of 9000 t. The Prince TLP was installed in 2001 in 1490 ft water depth and consists of a three-level deck capable of carrying topside payload of 6100 t. The Mars TLP was installed in 1997 in 2933 ft water depth and has topside operating weight of about 23,000 t.

Assuming 4% of the total area of a deepwater structure requires treatment per year after the service life is reached, and using a topside weight to square foot conversion of 200 ft^2/t, topside painting areas for Enchilada, Prince, and Mars are estimated at 1.8, 1.2, and 4.6 million square feet, respectively.

Normalizing by the unit cost estimated at Shell's Auger TLP ($1.9 million for 75,000 ft^2 treatment per year; see Box 23.1), the annual painting and blasting costs at Enchilada, Prince, and Mars are estimated at $1.8 million, $770,000, and $2.9 million, respectively. The structures are all deepwater facilities and approximately the same age as Auger, serve similar functions, and are of similar complexity. Assuming similar original coat systems and degradation, maintenance cost would likely be similar. Enchilada and Mars are also Shell-operated, which will likely have similar maintenance programs in place.

BOX 23.1 Auger TLP Painting Cost Estimation

Shell's Auger TLP in 2860 ft water depth is composed of four 74 ft diameter by 159 ft high columns connected by four 35 ft wide by 28 ft high pontoons, a drilling rig, production facility, associated power plants, and living accommodations for 142 people (Fig. 23.10). The deck section measures 290 × 330 × 20 ft high, and steel weight is 10,500 t (Bourgeois, 1994). The TLP is held in position with twelve 26-in diameter tendons, three per corner, attached to a foundation template anchored to the seafloor (Fig. 23.11). An eight-point lateral mooring system is also employed. First oil was in April 1994.

Shell reported performing 75,000 ft^2 blasting and painting activities at Auger TLP each year, which is approximately 4% of the total surface area of 1.8 million square feet (Satterlee et al., 2009). Using work decomposition methods and data described in Satterlee et al. (2009), Auger's annual maintenance painting is estimated at $1.9 million per year or about $25 per square foot serviced (Table 23.16).

Shell reported employing a six-man blasting and painting crew with a foreman and inspector. Assuming $150,000 annual salary for foreman and inspector and $100,000 for paint contractors and blasting crew, the total annual labor budget for blasting and painting is $1.2 million per year.

Garnet costs about $500/t and can be reused up to eight times, although there are issues regarding recycle and performance that often limit reuse. In surface preparation, 2–4 lb of garnet is assumed to be used per square foot steel surface[3] and reused once in operations and then disposed onshore. For 75,000 ft^2 steel surface requiring blasting, the annual garnet budget is estimated at $26,000 as follows:

Fig. 23.10 Bird's eye view of the Auger tension leg platform. *(Source: Shell, BOEM.)*

[3] For comparison, the amount of garnet used in ship conversion operations typically requires 10–15 lbs of garnet per square foot steel surface because of the intensive surface preparation requirements (Azevedo, 2011).

Continued

BOX 23.1 Auger TLP Painting Cost Estimation—cont'd

$$0.5 \cdot 75,000\,\text{ft}^2 \cdot 3\,\text{lb/ft}^2 \cdot \$500/\text{t} \cdot \text{t}/2200\,\text{lb} = \$26,000$$

or $0.35/ft^2. For high-solid sprayed paint expenditures of $1.5/ft^2, a similar calculation yields $112,500 paint cost per year.

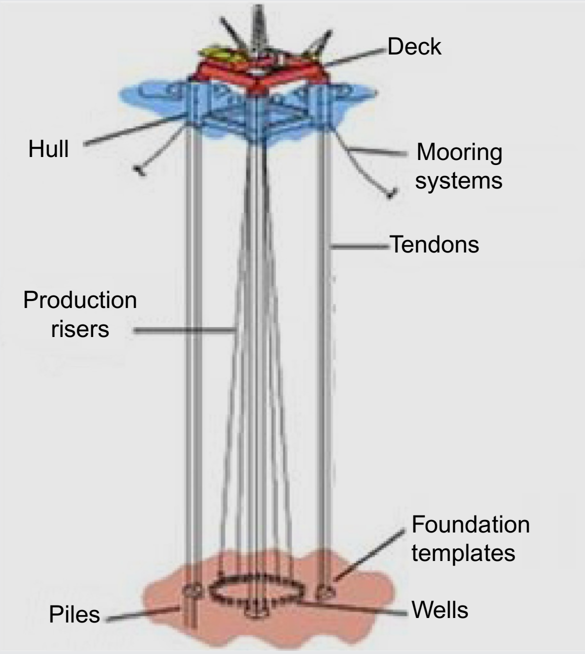


Fig. 23.11 Schematic of the Auger tension leg platform.

Table 23.16 Estimated Annual Maintenance Painting Cost at Auger TLP

	Annual Cost ($)	Unit Cost ($/ft^2)
Labor	1,200,000	16.00
Material		
Paint	112,500	1.50
Garnet	26,000	0.35
Disposal		
Nonhazardous	7670	0.10
Hazardous	5100	0.07
Subtotal	1,351,270	18.02
Indirect (40% subtotal)	540,508	7.21
Total	1,891,778	25.22

Note: Assumes six-man crew with garnet reused once. Logistics, transport, and catering costs assumed to be 40% of the direct cost.

Continued

BOX 23.1 Auger TLP Painting Cost Estimation—cont'd

Disposal of spent abrasive material is assumed to cost \$50/t for nonhazardous material and \$300/t for hazardous material. Shell reported about 10% spent abrasive material hazardous due to cadmium-coated bolts that were blasted or older areas containing lead paint. If 5 lb waste per square foot arises from the spent abrasive, corrosion, and paints removed from the steel and 10% is hazardous, annual disposal cost is estimated as

$$\text{Nonhazardous disposal cost} = 0.9 \cdot 170\,\text{t per year} \cdot \$50/\text{t} = \$7670$$
$$\text{Hazardous disposal cost} = 0.1 \cdot 170\,\text{t per year} \cdot \$300/\text{t} = \$5100$$

Indirect costs associated with operations include logistics, catering, travel for the paint crew and equipment, downtime, and weather delays. A 40% indirect rate is assumed to cover these costs.

23.6.5 Underwater Maintenance

Operators deploy underwater inspection schedules according to regulatory requirements and base decisions on the cost-benefit of maintenance. Cleaning is the most time-consuming task, and a good cleaning will remove marine growth down to black oxide 1 to 2 in on each side of welds and cleaned to bright metal. High-pressure water blasters are used for cleaning and need to be set up and properly positioned. Gross damage around the circumference of members (e.g., wide cracks) and fractures are identified, if any, and video and photo documentation performed.

Remotely operated vehicles (ROVs), divers, and supporting equipment may be based on the platform or workboat, but usually, workboats are preferred for economic, safety, and logistic reasons. In shallow water <200 ft, divers are typically used exclusively; in 200–400 ft water depth, divers and/or ROVs are employed; and in >400 ft, ROVs are primarily employed with divers employed in the top water section.

Example. Level II and III inspection cost at Cognac

Shell conducted time studies during Level II and III inspection at Cognac which stands in 1025 ft water depth and documented that it took on average 6 h per member for cleaning and inspection (Miller and Hennegan, 1990). Half of this time was spent on cleaning with the setup time, positioning, and video recording comprising the remainder. On average, 1.5 member ends were cleaned and inspected in a 12 h workday.

Level II and III inspections performed in 1990 were reported to cost \$480,000, about \$293,000 for the Level III inspection and \$175,000 for the Level II inspection (Table 23.17). The top 200 ft of the structure was inspected by divers. The inferred ROV dayrate was \$227,000 per 15 days = \$15,133 per day or \$275/ft of structure. The inferred Level III diver dayrate was \$23,000/200 ft or \$115/ft. The inferred Level II cost was \$161,000/825 ft = \$195/ft. Cost excludes mob/demob fee.

Table 23.17 Level II and III Inspection Costs at Cognac

Activity	Inspection Type	Cost ($1000)
Diver inspection	Level III, top 200 ft	23
ROV-1 inspection	Level II, entire structure	161
ROV-2 inspection	Level III, 200–1025 ft	266
Mooring		28
Total		480

Source: Miller, B.H., Hennegan, N.M., 1990. API Level III inspection of Mississippi Canyon 194 A (Cognac) using an ROV. In: OTC 6355. Offshore Technology Conference. Houston, TX, May 7–10.

Diving

The underwater service industry in the GoM is highly competitive. In deepwater, several companies compete worldwide, while in the shallow water, numerous small companies that operate locally offer services. For services that require less sophisticated equipment, small companies are able to bid for contracts at prices that are uneconomic to larger companies, and this is reflected in the gross margins reported by large contractors for inspection services in the Gulf that are typically the smallest among their business segments. In shallow water, high levels of competition, low day rates, and low technological requirements constrain profits.

Manned diving operations utilize traditional diving techniques of air, mixed gas, and saturation diving, all of which are surface-supplied breathing gas. In water depths >1000 ft, traditional diving techniques are not used, and instead, ROVs are employed (Fig. 23.12). ROVs are tethered submersible vehicles remotely operated from the surface, usually a specially outfitted vessel, either owned or chartered (leased) by the company (Figs. 23.13 and 23.14).

Fig. 23.12 Work class ROV sitting on vessel's deck.

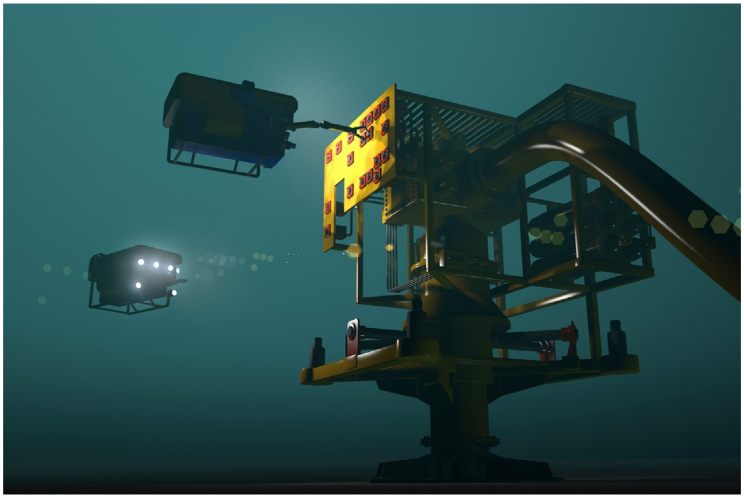


Fig. 23.13 Rendition of ROV manipulating a control valve on a subsea wellhead.

Divers provide high-quality fast cleaning rates and can adapt to difficult positioning and changing conditions, but safety is always a concern with saturation diving as water depths increase. ROVs are expensive and may be difficult to maintain position in high currents or reach difficult areas between conductors, within the structure interior, and at the mudline. Significant technical advancement in ROVs has been made over the years.

Fig. 23.14 Rendition of ROV manipulating subsea wellhead controls under a steel structure.

ROV

Service for ROV contracts is typically awarded on a competitive bid on a dayrate basis for contracts <1 year in duration, although multiyear contracts may also be awarded for significant work campaigns. Under dayrate contracts, the contractor provides the ROV, vessel or equipment, and the required personnel to operate the unit, and compensation is based on a rate per day for each day the unit is used. Lower dayrates often apply when a unit is moving to a new site or a separate mobilization fee is applied or when operations are interrupted or restricted by equipment breakdowns, adverse weather, or water conditions or other conditions beyond the contractor's control. Contracts often specify a 12 h workday and an ROV downtime allowance (e.g., 30 h downtime per month).

Day rates depend on the market conditions, the nature of the operations to be performed, the duration of the work, the equipment and services to be provided, the geographic areas involved, and other variables. Video inspections typically include wellheads, valve positions, pipeline end terminations and manifolds, flowlines, jumpers, moorings, risers, and associated cabling (Kros, 2011). This equipment is often spaced over many square kilometers requiring the support vessel to maneuver in DP mode for days.

Example. Oceaneering International Inc. ROV dayrates, 2008–16

Oceaneering is one of the largest underwater service contractors in the world and as of 31 December 2016 owned over 300 work-class ROVs, the largest fleet in the world. The average revenue per day on hire from 2008 to 2016 was reported between $8500 and $11,000 per day. Revenue per day on hire is not the same as dayrate but provides an indication of dayrate ranges.

AUV

Autonomous underwater vehicle (AUV) inspection technologies for the offshore oil and gas industry are in its infancy but promise to reduce the cost of inspecting subsea facilities for a range of activities, including pre and post-hurricane inspection, decommissioning structure surveys, and pipeline and riser inspection (McLeod et al., 2012). In diving and ROV operations, support vessels are required with large crews to collect relatively simple visual inspecting records. AUVs use advanced technology to reduce costs and are not proved technology, but the technology is advancing and is likely to play a future role in inspection.

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