



## Petroleum Engineering Standards in the Oil and Gas Industry

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### Overview

Standards developed through various codes of practice, in addition to those enforced by regional and national standardisation bodies, are an integral part of operations in the oil and gas industry. The adoption of these standards have not only significantly improved safety levels, but also enhanced technical integrity and reduced damage to the environment. Also, the adoption of standards has created a business environment where oil and gas companies have embraced and actively promote efficiencies resulting in reduced operational costs thus maximising overall stakeholder value. The industry since the Deepwater Macondo accident in April 2010, in which 11 people lost their lives, has intensified its campaign for the development of a common set of international standards. These reflect the dynamic and global nature of operations in the industry taking into account the imperative for more efficient operations and the scope for cost reduction through standardisation. The adoption of standards has become particularly relevant as the oil and gas industry becomes increasingly technologically complex in an environment where many projects involve drilling in remote terrains and in ultra-deep geological systems.

### 1. Introduction

Standards - benchmarks, criteria, yardstick - refer to documented agreements containing technical guidelines to ensure that material, product, processes, representations and services are fit for their purpose.<sup>1</sup> The methods of achieving standards can be conceived of in three ways namely: (1) standards can be set through the market, on a de facto basis; (2) standards can be set by the government, through the regulatory process; and

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<sup>1</sup> Allen, R. H. and R. D. Sriram (2000). "The role of standards in innovation." *Technological Forecasting and Social Change* 64(2): 171-181



(3) standards can be negotiated through a voluntary consensus process.<sup>2</sup>

Standards form the basis for classification and measurement in most industrial setups and the petroleum industry is no different in this regard. The technical nature of the work in the oil and gas industry necessitates having in place certain prerequisite standards to guide operations. They are the tools through which the world of technical work is organised as standards provide the foundational basis that different systems, platforms and equipment are fit-for-purpose and will operate in a safe and reliable manner.<sup>3</sup> The industry defines standards *"to represent all the documents published by any of the many standards developing organisations around the globe. Their publications are frequently called standards, but they are also called recommended practices, specifications, bulletins, technical reports, publically available specifications, etc."*<sup>4</sup>

Many standards developed through various codes of practice and those developed by regional and national standardisation bodies have been adopted by the oil and gas industry.<sup>5</sup> The adoption of these standards have not only significantly improved safety levels and outcomes, but also enhanced the technical integrity and reduced damage to the environment. Also, they have as well created a business climate where oil and gas companies have adopted and actively promote efficiencies resulting in reduced operational costs and thus maximising overall stakeholder value.

## 1.1 Classes of Standards

There are generally four main classes of standards listed as:<sup>6</sup>

- a. **Metric Standards:** A standard against which to measure. All comparable quantities are thus measured in terms of this standard. An example of these are the International System

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<sup>2</sup> OTA, U. (1992). "Global Standards: Building Blocks for the Future." Washington: Office of Technology Assessment.

<sup>3</sup> See <http://www.ogp.org.uk/pubs/440.pdf>

<sup>4</sup> See pg. viii <http://www.ogp.org.uk/pubs/426.pdf>

<sup>5</sup> See <http://www.ogp.org.uk/pubs/381.pdf>

<sup>6</sup> Allen, R. H. and R. D. Sriram (2000). "The role of standards in innovation." *Technological Forecasting and Social Change* 64(2): 171-181



of Units such as the metre for length, kilogramme for mass and the second for time measurement,

- b. **Process Oriented or Prescriptive Standards:** These provide for descriptions of activities and processes in a standardised manner that by providing the methodology to perform tests and perform processes in a consistent and repeatable way. An example of this type of standard is the American Society for Testing and Material (ASTM) D4530 - 15 "Standard Test Method for Determination of Carbon Residue (Micro Method)" for the determination of the amount of carbon residue formed after evaporation and pyrolysis of petroleum materials under certain conditions. It is intended to provide some indication of the relative coke forming tendency of such materials.
- c. **Performance-Based or Goal Setting Standards:** The ultimate performance or objective is specified although a process or means of achieving compliance is not explicitly given. An example of this type of standard is the Safety Case Regulations that were enacted in the United Kingdom following the Piper Alpha accident in 1988. These regulations require the operator or owner of an offshore oil and gas installation operating in UK waters to submit a safety case that assesses the risks on the installation and provides mitigating measures for acceptance by a regulatory authority.
- d. **Interoperability Standards:** Here, processes and performance are not explicitly determined although a fixed format is specified. The goal ultimated of this type of standard is to ensure an even operation between systems that, for example, use the same physical entity or data. An example of such a standard is the ISO/IEC JTC1/SC 32 "Data management and interchange".

## 2. The Development of Industry Standards and Measurement

Operations in the oil and gas industry are highly technical and require equipment and materials which are also highly specialised to address specific industry needs.<sup>7</sup> This calls for the development of standards that guide activities to ensure safe operations along the production value chain as is shown in

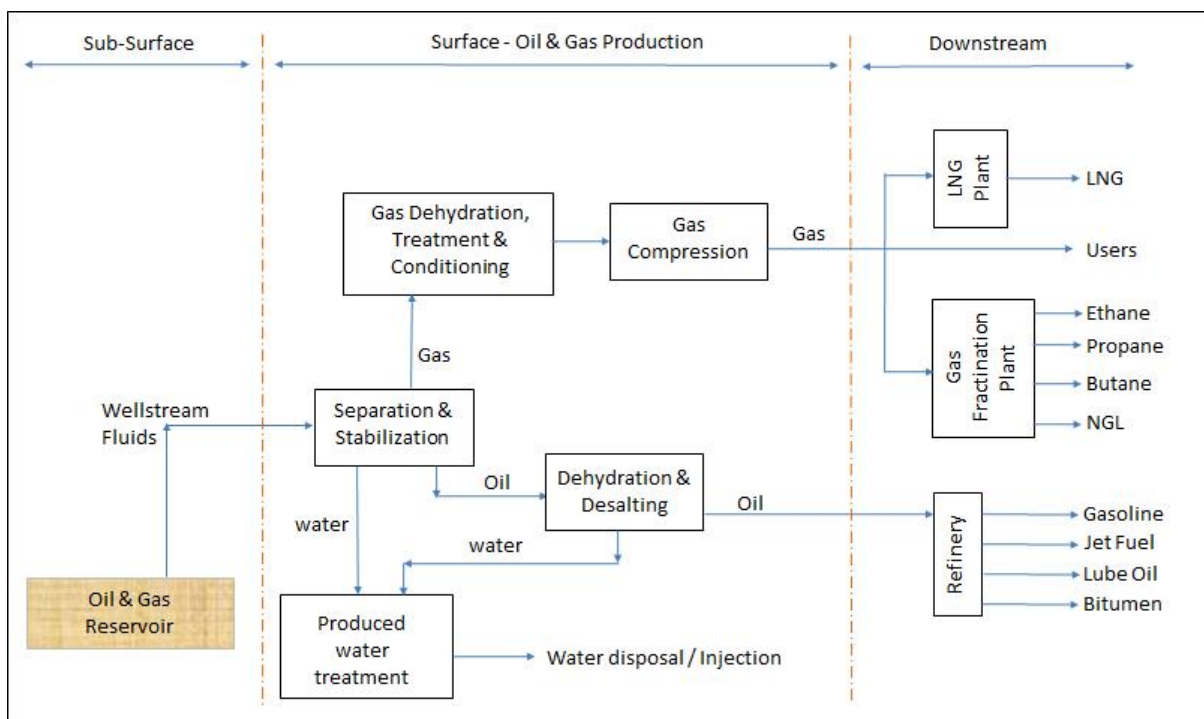
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<sup>7</sup> ibid pg. 1



Figure 1 below. Although a wide range of designs exist, most oil and gas production facilities share similar processing systems shown in this overview. The majority of standards which are discussed further in this work have been developed for the sub-surface - well control and integrity - and topsides to deal with oil and gas separation.

**Figure 1 Oil and Gas Production Piping and Instrumentation Diagram**



Source: Piping Engineering<sup>8</sup> (2015)

Standards in the industry are promulgated and adopted by local, regional, national or international bodies to guide equipment use and processes. Historically, the development of engineering standards was done by the industry through its representative bodies. These include standards developed by organisations such as the American Petroleum Institute (API), British Standards Institution (BSI), American Society of Mechanical Engineers (ASME), Society for Petroleum Engineers (SPE), and the National Association of Corrosion Engineers (NACE) among others.

API standards for many years served as the de-facto international standard for the oil and gas industry. The need to have consistent standards that have global acceptability and

<sup>8</sup> See <http://www.piping-engineering.com/crude-oil-processing-offshore-facilities.html#>



application has pushed the industry to renew its commitment to developing a new set of consistent international standards based on the ISO system. For example, 72 API standards were transferred to ISO technical committee ISO/TC 67 "*Materials, equipment and offshore structures for petroleum and natural gas industries*" which have subsequently become global ISO International Standards.<sup>9</sup>

International standards often form the basis for national regulations although there are regulatory differences across jurisdictions due to specific operational and cultural contexts.

Figure 2 below shows the evolution of the hierarchy of standards as one would typically find in the oil and gas industry. The two international standards development organisation (SDOs) that have produced standards related to the oil and gas sector are the International Organisation for Standardisation (ISO) and the International Electrotechnical Commission (IEC). The International Organisation for Standardisation an independent, non-governmental international organisation that has a membership of over 160 national standards bodies. It develops various ISO standards by a panel of experts within a technical committee.<sup>10</sup> The International Electrotechnical Commission remains one of the world's leading organisation's which publishes International Standards for all electrical, electronic and related technologies.<sup>11</sup> Both ISO and IEC standards undergo a rigorous review process by subject matter experts, and these standards are periodically reviewed and revised to reflect current industry practice.

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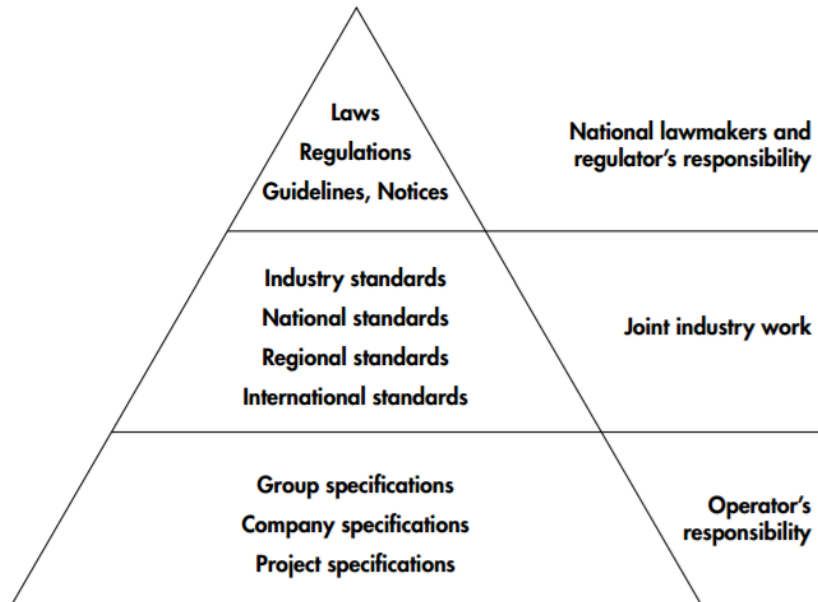
<sup>9</sup> See [http://www.iso.org/iso/home/news\\_index/news\\_archive/news.htm?refid=Ref795](http://www.iso.org/iso/home/news_index/news_archive/news.htm?refid=Ref795)

<sup>10</sup> See [http://www.iso.org/iso/home/standards\\_development.htm](http://www.iso.org/iso/home/standards_development.htm)

<sup>11</sup> See <http://www.iec.ch/about/?ref=menu>



**Figure 2 Evolution of the Hierarchy of Standards**



**Source: International Association of Oil and Gas Producers<sup>12</sup> (2010)**

One lesson from the Deepwater Macondo accident is that it is important in the design of standards, particularly at the national level, to get the right balance regarding both goal-setting versus prescriptive approaches. This becomes pertinent in areas such as the offshore safety regime where a goal-setting approach should incorporate standards representing global best practice. The "Goal-based regulatory framework" does not specify a specific means of achieving compliance but sets goals that allow alternative ways of achieving compliance within a Safety Management system (SMS) subject to available technological and cost considerations.<sup>13</sup> The prescriptive approach, on the other hand, provides very specific means of achieving compliance through the reference standards and the technology that have to be utilised.

Figure 3 provides evidence of the regulatory changes in the Post-Macondo Era that captures the ethos of getting this balance right. Here, US regulators have adopted new oil spill

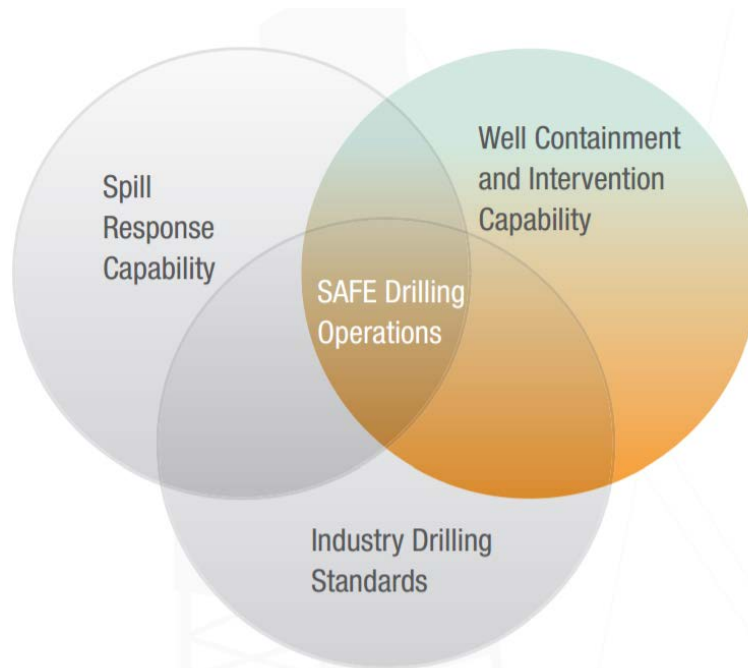
<sup>12</sup> See <http://www.ogp.org.uk/pubs/426.pdf>

<sup>13</sup> Penny, J., Eaton, A., Bishop, P. G., & Bloomfield, R. E. (2001). The practicalities of goal-based safety regulation. In *Aspects of Safety Management* (pp. 35-48). Springer London



response measures that include revised guidelines on the design and operational considerations for deepwater wells.<sup>14</sup>

**Figure 3 Regulatory Changes in the Post-Macondo Era**



**Source: American Petroleum Institute<sup>15</sup> (2015)**

## 3. Case Studies

### 3.1 Case Study I: Production, Well Integrity Standards and Best Practice

A key factor in ensuring smooth drilling and subsequent production of a well is to ensure that its integrity is not comprised. Well integrity is not only about the safety of the personnel operating the well, but it is also about ensuring the safety and protection of a company's assets, its reputation and the environment. Compromising on the integrity of a well completion may lead to disastrous consequences such as a well blowout as it happened in the Macondo incident in the Gulf of Mexico.

For example, to maintain the integrity of a reservoir formation during drilling, a special mixture of fluids or drilling mud is

<sup>14</sup> See [https://www.scor.com/images/stories/pdf/library/newsletter/pc\\_nl\\_macondo\\_mel-07-04.pdf](https://www.scor.com/images/stories/pdf/library/newsletter/pc_nl_macondo_mel-07-04.pdf)

<sup>15</sup> See [http://www.api.org/~media/Files/EHS/Clean\\_Water/Oil\\_Spill\\_Prevention/After-Macondo-report-April-2015.pdf](http://www.api.org/~media/Files/EHS/Clean_Water/Oil_Spill_Prevention/After-Macondo-report-April-2015.pdf)



pumped down a wellbore to provide the hydrostatic pressure needed to overcome the formation (reservoir) pressure. Under normal drilling conditions, this hydrostatic pressure exerted by the mud column in the wellbore should balance or exceed the formation pressure to prevent an influx of gas or other formation fluids which can cause a blowout during the drilling process. However, a balance between these two pressures is required as extremely high hydrostatic pressures can cause formation damage. Formation damage can impair the productivity of the well as measured by the productivity (PI) index or in some cases permanently ruins the oil and gas reservoir.<sup>16</sup> The density of the mud composition changes as the well formation pressure increases thus maintaining the balance needed for safe operations - that is, to prevent blowouts or kicks. Maintaining appropriate wellbore fluid density that takes into account the pressure regime is critical to safety and wellbore stability.

The most widely accepted definition for well integrity is Norsok D-010: "Application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the lifecycle of a well."<sup>17</sup> The International Organisation Standardisation Technical Specification (ISO/TS 16530-2) also defines Well Integrity as "Containment and the prevention of the escape of fluids (i.e. liquids or gases) to subterranean formations or surface".<sup>18</sup>

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<sup>16</sup> Schubert, J. J., & Wright, J. C. (1998). Early kick detection through liquid level monitoring in the wellbore. In IADC/SPE Drilling Conference. Society of Petroleum Engineers.

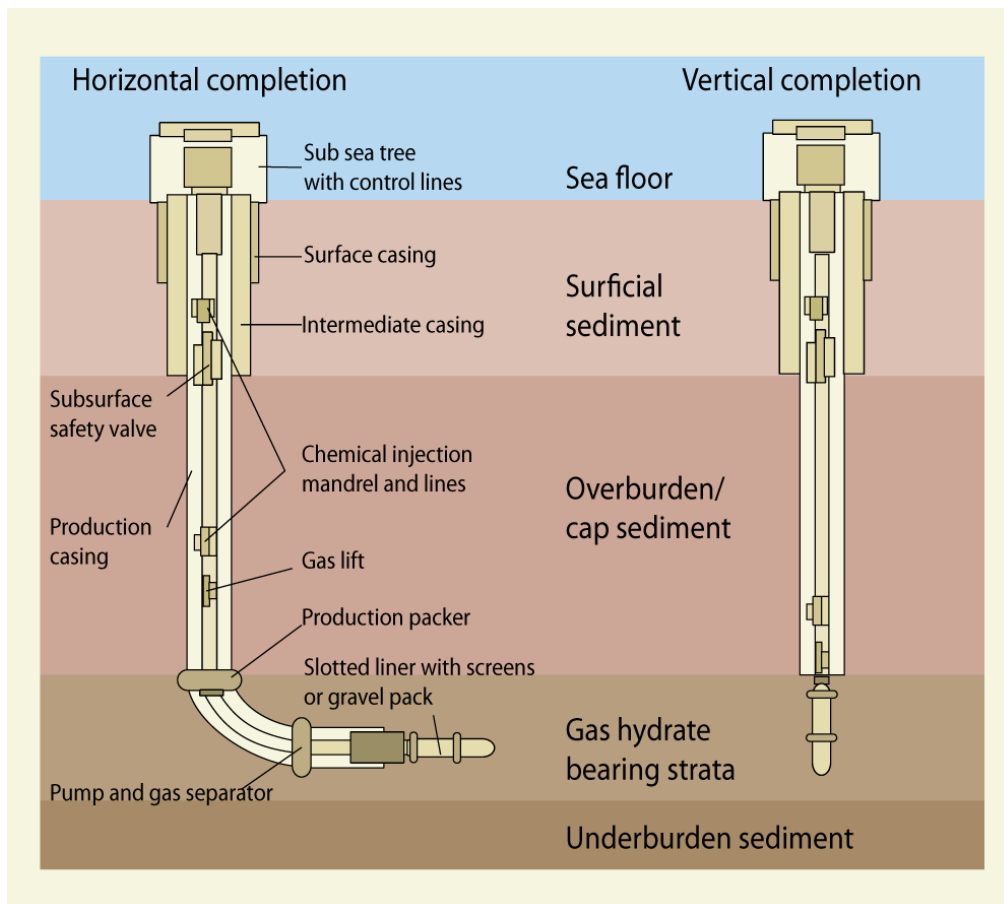
<sup>17</sup> [http://petrowiki.org/Well\\_integrity#cite\\_note-r1-1](http://petrowiki.org/Well_integrity#cite_note-r1-1)

<sup>18</sup> [ibid](#)





**Figure 4 Example of a Well Completion for Gas Hydrate Production**



Source: GRID-Arenda<sup>19</sup>

Ensuring well integrity is a key safety component during the operationalisation of the well and care must be taken not to expose personnel to the dangers of compromising the integrity of the well. Some of the factors that could lead to a compromised well integrity during well operations include corrosion, wellbore instability, expansion/contraction, and cement bond deterioration among others. In addressing issues of well integrity, the following need to be done:

- a. **Training of Personnel:** The competency of the personnel operating the well is vital to mitigating any occurrence of well integrity problems.
- b. **Well Integrity Management:** There needs to be in place a well integrity management system with detailed description of what needs to be done when anything unusual is detected

<sup>19</sup> See [http://www.grida.no/graphicslib/detail/well-completion-for-gas-hydrate-production\\_3359](http://www.grida.no/graphicslib/detail/well-completion-for-gas-hydrate-production_3359)



in the well that has the potency of compromising the integrity of the well. A typical example is with fluid invasion and having in place fluid containment devices to curb any hazardous occurrence.

**Well Design:** The design and construction of an oil and gas well is done with a need to produce hydrocarbons safely while minimising the risk to people, the environment and property. The key objectives that need to be taken into consideration when designing new wells include<sup>20</sup>:

- a. Taking steps to prevent any interconnection between water aquifers and petroleum reservoirs.
- b. Taking steps to ensure that formation fluids are contained within the well to prevent leakages.
- c. Taking steps to ensure that no substances that may cause environmental harm are not introduced.

**Site Selection and Preparation:** The key factors that come into play when determining a drilling location include geography, topography, ecology and cultural heritage.<sup>21</sup> The government must grant appropriate approvals and the site prepared before a drilling rig arrives on location and before any drilling takes place.

**Drilling the well:** Drilling operations commence once the drilling rig is moved to the drilling lease and all necessary equipment connections made. Drilling of an oil or gas well starts the moment the drill bit shown in the bottom of

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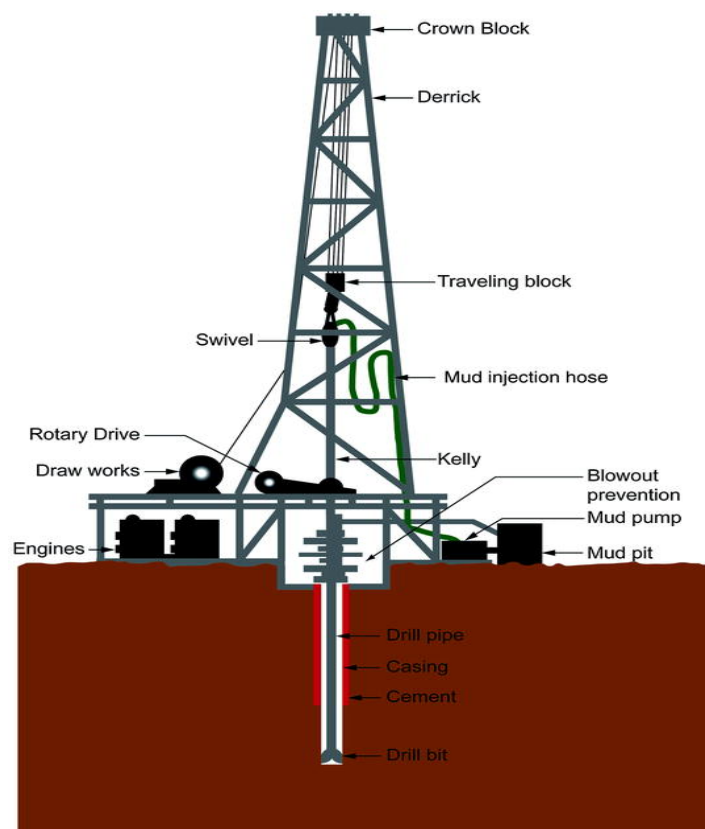
<sup>20</sup> See <http://www.aph.gov.au/DocumentStore.ashx?id=939a57d7-e315-4cb0-afed-ab03a647406b&subld=411217>

<sup>21</sup> Santos (2016). Drilling and Oil Integrity Technical Fact Sheet - Unconventional Gas Mining Submission 57 - Attachment 1. Australia, Santos 18.



Figure 5 below first penetrates the ground (spudding of the well) and continues until the target depth has been reached. The duration for the drilling of an oil or gas well depends on factors such as geology, depth of the well, nature of the well that is whether the well is vertical, deviated or horizontal.

**Figure 5 Drilling Rig with Drill Bit Section**



Source: Stober and Bucher<sup>22</sup>

### 3.1.1 Crude Oil Separation and Processing

#### WELLHEAD

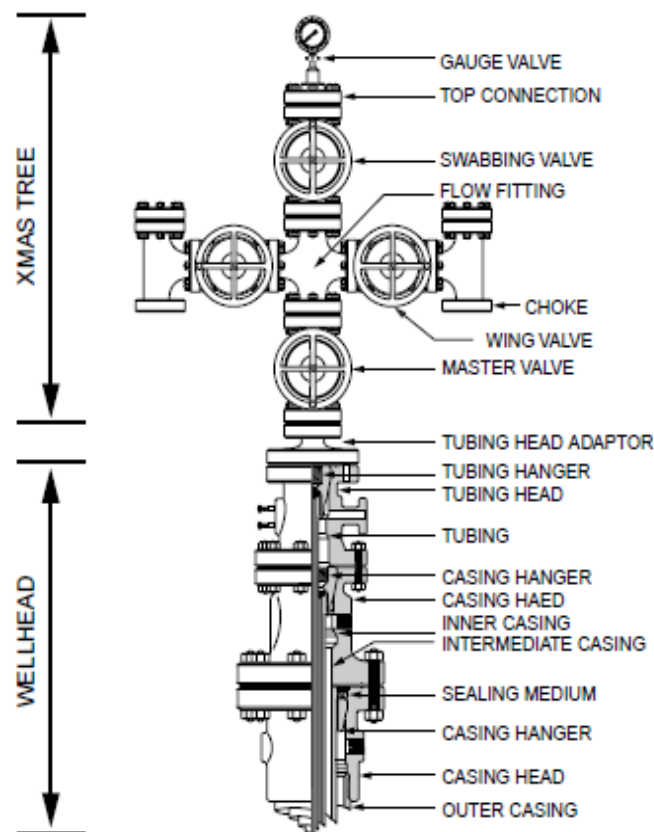
The wellhead has the strategic relevance of ensuring the safety of personnel and the well and it happens to be one of the first installations in the life of a well. Its use spans across drilling operations, production and subsequent decommissioning at the end of field's life. In the early stages of the drilling operation, the wellhead provides the platform for the

<sup>22</sup> Stober, I., & Bucher, K. (2013). Drilling Techniques for Deep Wellbores. In Geothermal Energy (pp. 203-219). Springer Berlin Heidelberg.



installation of the Blowout Preventer (BOP) and the installation of a Christmas Tree during production operations. During decommissioning, the wellhead stump also helps to abandon the well. The wellhead enables the suspension of casings and tubulars concentrically in the well and also provides annular access for cementing casing strings in place as well as for the circulation of fluids in and out of the well.

**Figure 6 A Wellhead with Christmas Tree**



**Source: Heriot Watt University Production Engineering Book**

The API 6A and ISO 10423 lists the acceptable standards that a wellhead must meet to be able to carry out its desired functions. These standards cover areas such pressure ratings, i.e., the pressures the wellhead should be designed to withstand, the temperature ratings, as well as the nature of the materials that are used in the design. These are given in the tables below: [10 API SPECIFICATION 6A /ISO 10423 2004].



**Table 1 Pressure Ratings for Internal Threaded and or Outlet Connections**

Type of thread	Nominal pipe size in	Size OD mm	Rated working pressure	
			MPa	(psi)
Line-pipe/NPT (nominal sizes)	1/2	21,3	69,0	10 000
	3/4 to 2	26,7 to 60,3	34,5	5 000
	2 1/2 to 6	73,0 to 168,3	20,7	3 000
Tubing, non-upset, and external upset round thread	1,050 to 4 1/2	26,7 to 114,3	34,5	5 000
Casing (8 round, buttress, and extreme line)	4 1/2 to 10 3/4	114,3 to 273,1	34,5	5 000
	11 3/4 to 13 3/8	298,5 to 339,7	20,7	3 000
	16 to 20	406,4 to 508,0	13,8	2 000

The next table gives the specifications for temperature. This provides information on the degree of temperature the equipment should be able to withstand. This selection is made by the operator taking cognizance of prevailing temperature conditions in the formation.

**Table 2 Temperature Ratings**

Temperature classification	Operating range			
	°C		°F	
	min.	max.	min.	max.
K	- 60	82	- 75	180
L	- 46	82	- 50	180
P	- 29	82	- 20	180
R	Room temperature		Room temperature	
S	- 18	66	0	150
T	- 18	82	0	180
U	- 18	121	0	250
V	2	121	35	250

The material classification of the wellhead must also meet standards as stated in the API SPECIFICATION 6A/ ISO 10423. These material classification standards are given in the table below:



**Table 3 Material Requirements**

Material class	Minimum material requirements	
	Body, bonnet, end and outlet connections	Pressure-controlling parts, stems and mandrel hangers
AA — General service	Carbon or low-alloy steel	Carbon or low-alloy steel
BB — General service	Carbon or low-alloy steel	Stainless steel
CC — General service	Stainless steel	Stainless steel
DD — Sour service <sup>a</sup>	Carbon or low-alloy steel <sup>b</sup>	Carbon or low-alloy steel <sup>b</sup>
EE — Sour service <sup>a</sup>	Carbon or low-alloy steel <sup>b</sup>	Stainless steel <sup>b</sup>
FF — Sour service <sup>a</sup>	Stainless steel <sup>b</sup>	Stainless steel <sup>b</sup>
HH — Sour service <sup>a</sup>	CRAs <sup>b</sup>	CRAs <sup>b</sup>

<sup>a</sup> As defined by NACE MR 0175.  
<sup>b</sup> In compliance with NACE MR 0175.

**MANIFOLDS AND GATHERING**

A manifold is a “system of headers and branched piping that can be used to gather or distribute fluids, as desired. Typically manifolds include valves for controlling the on/off flow of fluids, and may also include other flow control devices (e.g. chokes) if these are not mounted on the individual subsea trees.” <sup>23</sup> They can be used to gather produced fluids and direct selected wells to a well test line, as well as to distribute injected fluids (gas or water) or gaslift gas to individual wells.” <sup>24</sup>

According to ISO-13628, manifold systems design must take into consideration the type of fluid that will pass through it as well as the pressures the fluids will be flowing. The other parameters that must be considered include pour point, pour point, temperature, viscosity, corrosivity, chemical composition, sanding problems and the ratio of the fluids. Generally, the size of the manifolds is determined by the flow rates.

<sup>23</sup> Source: API RP 17A, Design and Operation of Subsea Production Systems—General Requirements and Recommendations, Fourth Edition, Reaffirmed 2011. Global Standards

<sup>24</sup> *ibid*



**Figure 7 Example Production Manifold**



**Source: Jim Blecha | oil and gas stock photography**

## SEPARATION

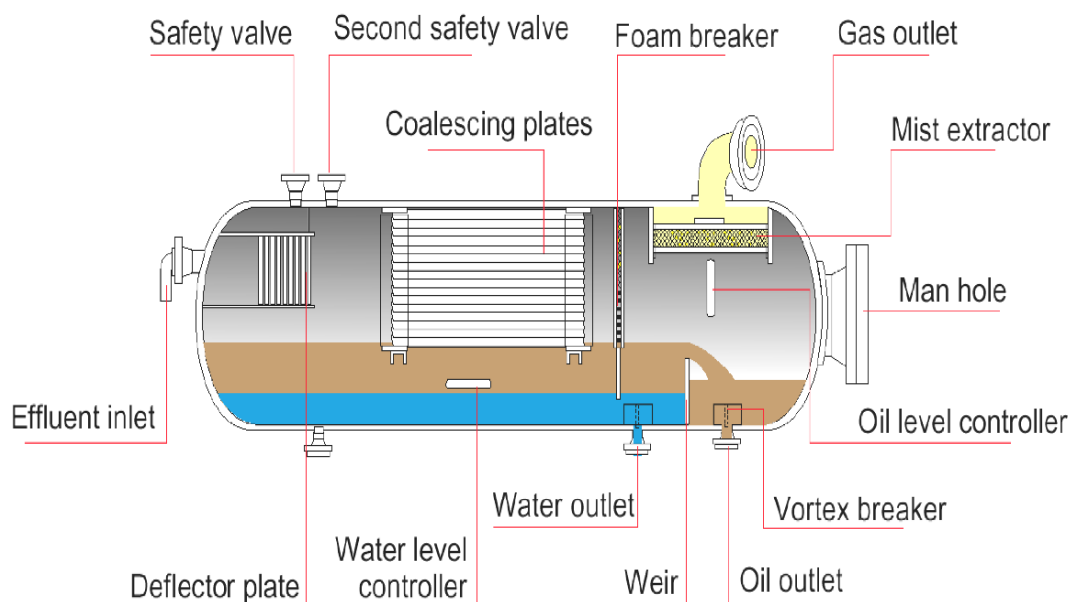
Underground fluids are produced commonly with hydrocarbons to the surface where they are separated into individual constituent components of oil, gas and water depending on the type separator being used. Separators can be categorised into the following:



1. A two-phase separator where the liquids are separated from the gas and discharged separately in different outlets.
2. A three-phase separator where the constituent components are separated into oil, gas and water.

The internationally recognised standard that guides the selection and operation of a separator is the API SPECIFICATION 12J. This set of standards gives a detailed description of what a separator should be; design, painting, internal coating, fabrication, etc. The three general configuration classification of separators are: Vertical Separators; Horizontal Separators and Spherical Separators.

**Figure 8 An Example Separator**



**Source: Schlumberger – Oilfield Services Company**

## ENHANCED OIL RECOVERY (EOR)

This refers to methods used to produce hydrocarbons that hitherto cannot be produced using conventional techniques or a reservoir's natural pressure. Using a reservoir's natural pressure mechanisms, only about 30% of the oil in place can be recovered, leaving behind about 70% that still needs to be produced. The physical properties of the remaining hydrocarbons





in place such as high viscosity make it difficult for them to flow naturally. It is therefore imperative that some other techniques are deployed to overcome these viscous forces so as to be able to displace the fluids from the reservoir into the wellbore for subsequent production to the surface. These techniques are what is referred to as Enhanced Oil Recovery or EOR. Fundamentally, EOR operations can be categorised into four main categories:

1. Thermal flooding techniques
2. Microbial techniques
3. Chemical flooding
4. Miscible flooding processes

**Thermal flooding** uses heat to overcome the viscous forces. Here, the processes could be In-situ combustion where a part of the reservoir is oxidised to generate heat which subsequently moves to heat other parts of the reservoir to release the oil into the wellbore for production or fire flooding or steam injection where steam is injected from surface via an injector to heat the reservoir to produce the desired results.

**Microbial Flooding Techniques** involve the use of microbial organisms are released into the formation to react with the residual oil producing polymers and surfactant chemicals in the process. These polymers and surfactants react with the oil to reduce their surface tension so the oil can be displaced.

**Chemical Flooding Processes** rely on the injection of chemical polymers and surfactants solutions to reduce the interfacial tension between the residual oil and fluids so that the oil can be displaced. The injected solution could also be alkaline based which helps to reduce the viscosity of the remaining oil so they can be easily displaced and produced.

**Miscible Flooding Processes** methods involve the injection of gases such as supercritical carbon dioxide which has the capabilities of lowering the viscosity of the residual oil and can also cause the swelling of the oil so it is displaced easily into the wellbore for production.

### 3.2 Case Study II: Petroleum Reserves and Evaluation Standards

There are various means of estimating reserves. That is how many barrels of oil are deposited in a particular field even before a single barrel of it is produced. There are also



methods that are used in reserve estimations when a significant percentage of the reserve has been produced. Before these reserve estimation methods are discussed, it is important we understand the various categories of reserves based on internationally recognised standards. These are only estimates in the sense that, the various variables and parameters that are used in the estimates have inherent uncertainties that cannot be overlooked. It is also the reason why several different methods are used.

Efforts aimed at bringing some level of uniformity in the categorisation of reserves started as early as 1930 with bodies such the Society of Petroleum Evaluation Engineers leading these efforts. These efforts have now given rise to a system of standardised definitions and classifications of reserves that are accepted in the international petroleum industry.

The Society of Petroleum Engineers (SPE) defines petroleum as "Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulphide and sulphur. In rare cases, non-hydrocarbon content could be greater than 50%."<sup>25</sup> The SPE further explains the term resources to mean "all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional".<sup>26</sup>

### *3.2.1 Classification of Reserves*

In 1997 The Society of Petroleum Engineers SPE and World Petroleum Council jointly published the definition for reserves that have become accepted internationally and have aided in the classification of reserves.

The SPE defines **RESERVES** as "those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date

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<sup>25</sup> See [http://www.spe.org/industry/docs/Petroleum\\_Resources\\_Management\\_System\\_2007.pdf](http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf)

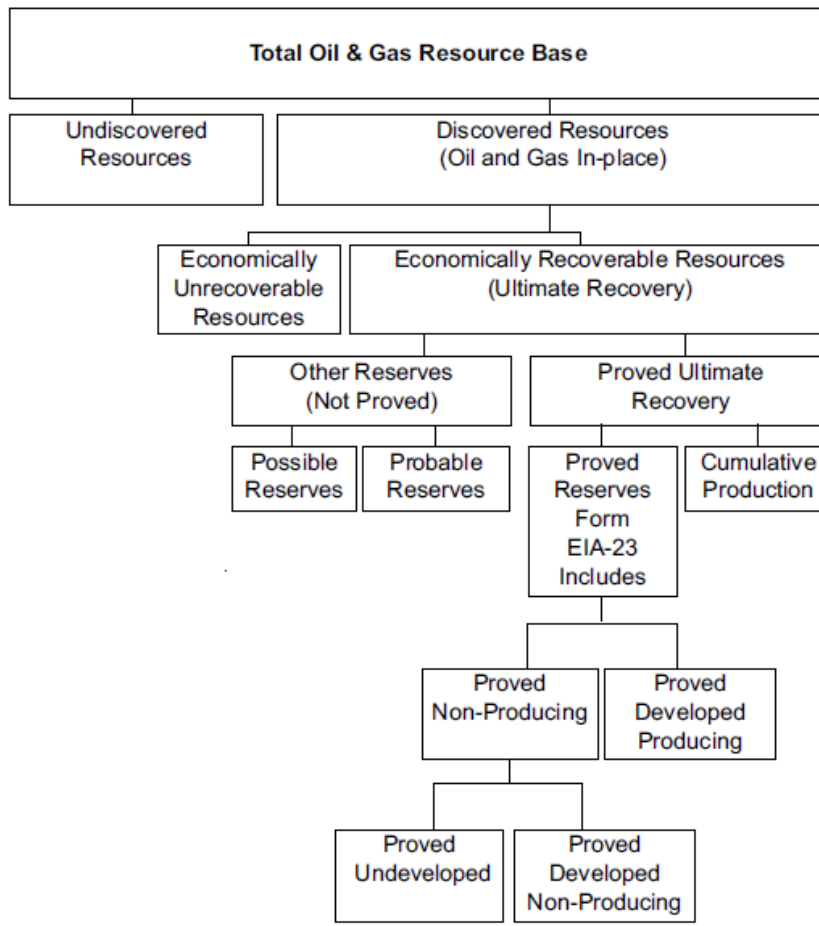
<sup>26</sup> *ibid*



forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status [SPE - PRMS 2007]." Simply put, reserves refer to what can be produced in the future.



**Figure 9 Categorisation of the Resource Base**



**Source: Energy Information Administration**

It is worth noting that all reserve estimates have some inherent uncertainties in them which depend largely on the amount of geological and engineering data available at any moment in time in the life of the field during the estimation and interpretation of the data. This inherent relative degree of uncertainty that exists in the data leads to the broader categorisation of reserves as belonging to either of the two classes - ***Proved or Unproved***.

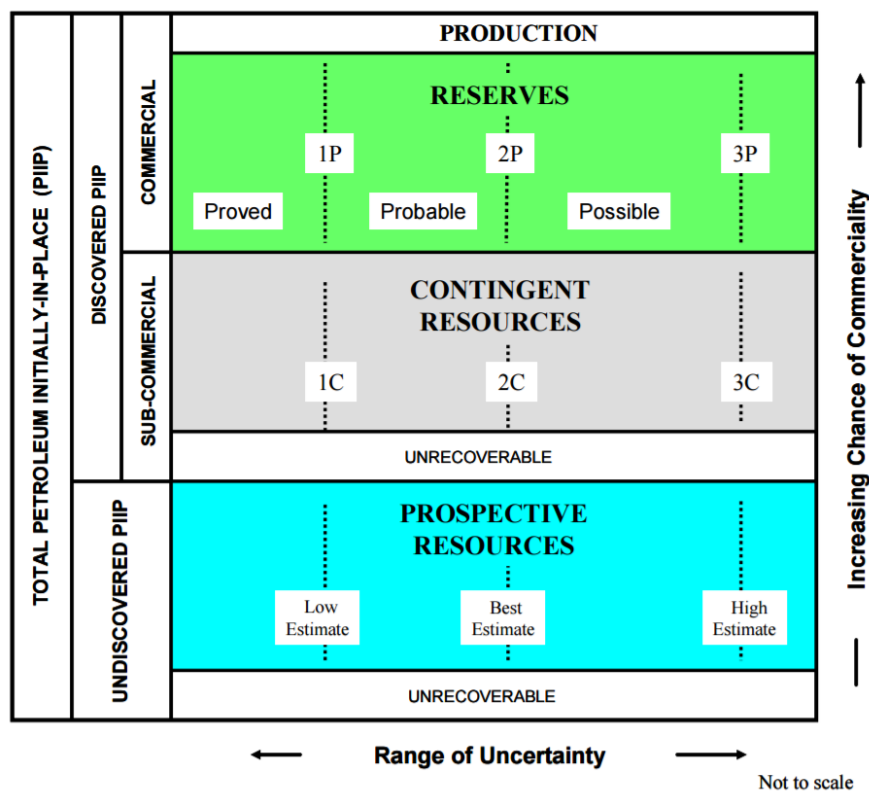
Regarding the degree of certainty of recoverability, proved reserves are more likely to be recovered than unproved reserves. Unproved reserves are further classified under the two sub-categories as ***probable and possible*** denoting the progressively increasing uncertainty in their recoverability.



**PROVEN RESERVES:** They are those quantities of petroleum that can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under current economic conditions, operating methods, and government regulations. These reserves can be further categorised as *Developed and Undeveloped*.

The expression reasonable certainty as used in the deterministic method is used to express a high degree of confidence that those quantities will be recovered. If probabilistic methods are used, then there should be at least 90% probability that the quantities will equal or exceed the quantities estimated. The figure below shows how the reserves vary over time in the life of the field.

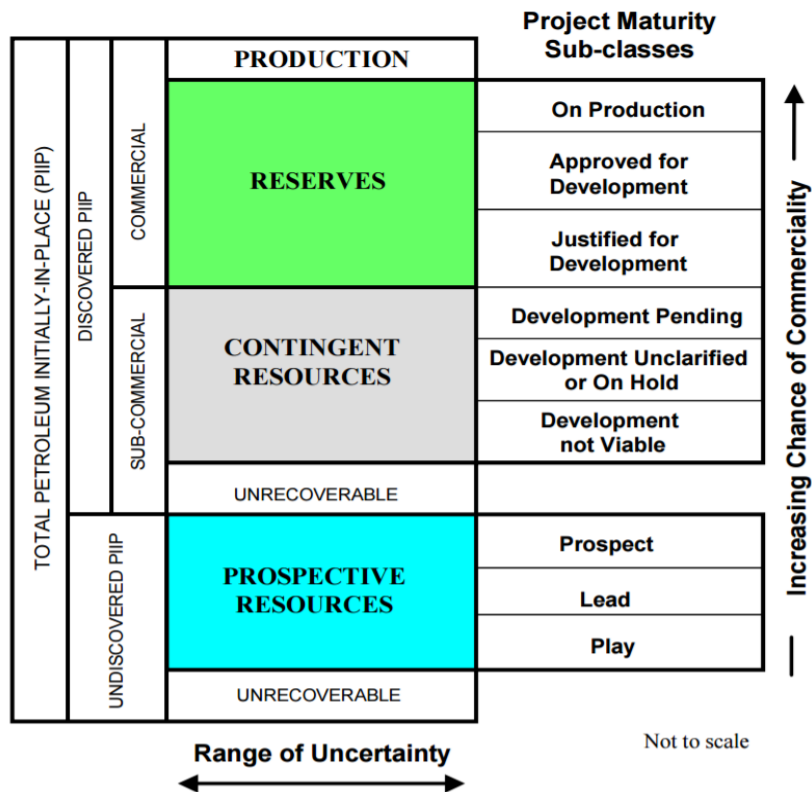
**Figure 10 Reserves Variation**



Source: SPE Petroleum Resources Management System (PRMS)



**Figure 11 Project Maturity Sub-Classes**



Source: SPE Petroleum Resources Management System (PRMS)

**UNPROVED RESERVES:** They are based on geologic and/or engineering data similar to that used in estimates of proved reserves. However, technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves. Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.<sup>27</sup>

**PROBABLE RESERVES:** Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually

<sup>27</sup> See <http://www.spe.org/industry/petroleum-reserves-definitions.php>



recovered will equal or exceed the sum of estimated proved plus probable reserves.<sup>28</sup>

**POSSIBLE RESERVES:** Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.<sup>29</sup>

### 3.2.2 Reserve Status Categories

Developed reserves may be sub-categorised as producing or non-producing.

**Producing:** Reserves subcategorised as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.<sup>30</sup>

**Non-producing:** Reserves subcategorised as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.<sup>31</sup>

**Undeveloped Reserves:** Undeveloped reserves are expected to be recovered:

- a. From new wells on undrilled acreage,
- b. From deepening existing wells to a different reservoir, or
- c. Where a relatively large expenditure is required to
  - a. Recomplete an existing well or

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<sup>28</sup> *ibid*

<sup>29</sup> *ibid*

<sup>30</sup> See [http://www.unece.org/fileadmin/DAM/energy/se/pp/unfc/IntWs\\_UNFC\\_Bangkok\\_Feb2012/CCOP/2\\_CambodiaMPRS.pdf](http://www.unece.org/fileadmin/DAM/energy/se/pp/unfc/IntWs_UNFC_Bangkok_Feb2012/CCOP/2_CambodiaMPRS.pdf)

<sup>31</sup> *ibid*

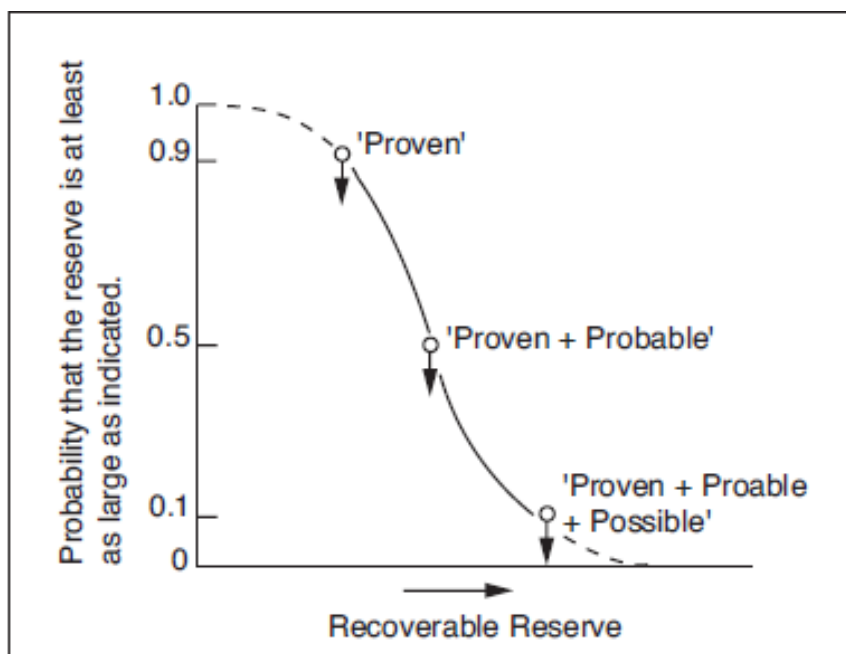


- b. Install production or transportation facilities for primary or improved recovery projects.

### 3.2.3 Probabilistic Representation of Reserves

As compared to the deterministic approach in which reserves classified using calculation of values determined for the various parameters, the probabilistic approach employs statistical analysis using tools like Monte Carlo methods among others. The curve as shown in Figure 12 below presents the probability that the reserves will have a volume greater or equal to the chosen value.

**Figure 12 Probabilistic Representation of Reserves**



The proven reserves on this curve represent the reserves volume corresponding to 90% probability on the distribution curve. The probable reserves represent the reserves volume corresponding to the difference between 50 and 90% probability whereas the possible reserves represent the reserves volume corresponding to the difference between 10 and 50% probability on the distribution curve.

### 3.2.4 Reserve Estimation Methods





One of the most essential tasks in the petroleum industry is reserves estimation. This is the process by which the economically recoverable hydrocarbons in a field, area, or region are quantitatively evaluated.<sup>32</sup> Attempts by oil companies in 2004 to revise downward U.S. Security and Exchange Commission (SEC)-booked reserves brought the issue of reserves estimation and disclosure under public scrutiny. There were calls from investors and lending institutions for more-reliable reserve estimates. In response, the oil and gas companies re-audited their reserves estimation procedures.

Reserves estimation has always been a challenge for the industry arising from many factors, (tangible and intangible) that enter the estimation process. Judgment is an integral part of the process. Uncertainty, along with risk, is an endemic problem that must be addressed. Consequently, the industry's record of properly predicting reserves has been mixed. Despite appeals from some quarters, there currently is no standardised reserves-estimation procedure."<sup>33</sup>

The first step towards ascertaining the commercial viability of any newly discovered field is to determine how many barrels or standard cubic feet of gas it holds in place and how what percentage of these barrels is recoverable. Various methods or techniques are used in estimating petroleum accumulations. These include Analogy, Volumetric, Decline analysis, Material balance calculations for oil reservoirs and Reservoir simulation. Decline Curve Analysis and the Material Balance Equation are referred to as Performance Based methods in the sense that they need production data to be executed but their main limitation lies in the fact that they do not factor inherent reservoir properties such as reservoir heterogeneities.

**ANALOGY:** The analogy method for reserve estimation represents the simplest method among all the techniques currently used. It is mainly used for yet-to-be-drilled and sparsely drilled areas. The technique is simple in that it is based on a comparison of geologic and reservoir information of nearby producing areas. That is to say, if an undrilled field has

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<sup>32</sup> Demirmen, F. (2007). Reserves estimation: the challenge for the industry. *Journal of Petroleum Technology*, 59(05), 80-89.

<sup>33</sup> *ibid*

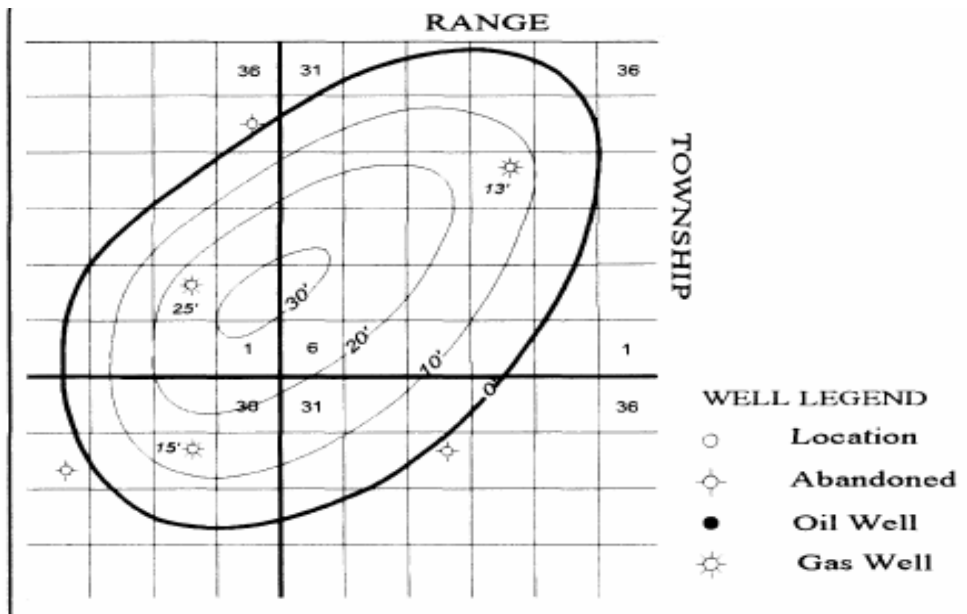


similar properties and data information to an area that is already under production, the then chances are that, the estimates are also likely the same. Once this simple analogy is proven valid, then the method is also valid. One key factor that most companies disregard is the location, in most instances, for the analogy method to hold, the fields under comparison must be situated within the same geological locations and not far apart a factor which oftentimes disregarded by most companies. Some even compare fields on different continents when clearly there is no geological correlation between those fields.

**VOLUMETRIC METHOD:** The volumetric method operates by taking into account the physical size of the reservoir, i.e., how far it extends laterally and how deep it extends or its thickness. The pore volume of the rock matrix is first considered. What percentage of the rock matrix contains pores, what fraction of those pores contain fluids and what further fractions of those pores are hydrocarbons which is referred to as the hydrocarbon pore volume. From these, the hydrocarbon hydrocarbons in place can be estimated and the degree of recoverability of those hydrocarbons can then be calculated using the appropriate recovery factor. Like stated earlier, every factor used herein has some inherent uncertainties just as it is for all estimation techniques. The figure below show a typical isopach map used in the volumetric method of reserve estimation.



**Figure 13 Typical Isopach Map often used in Volumetric Estimates of Reserves**



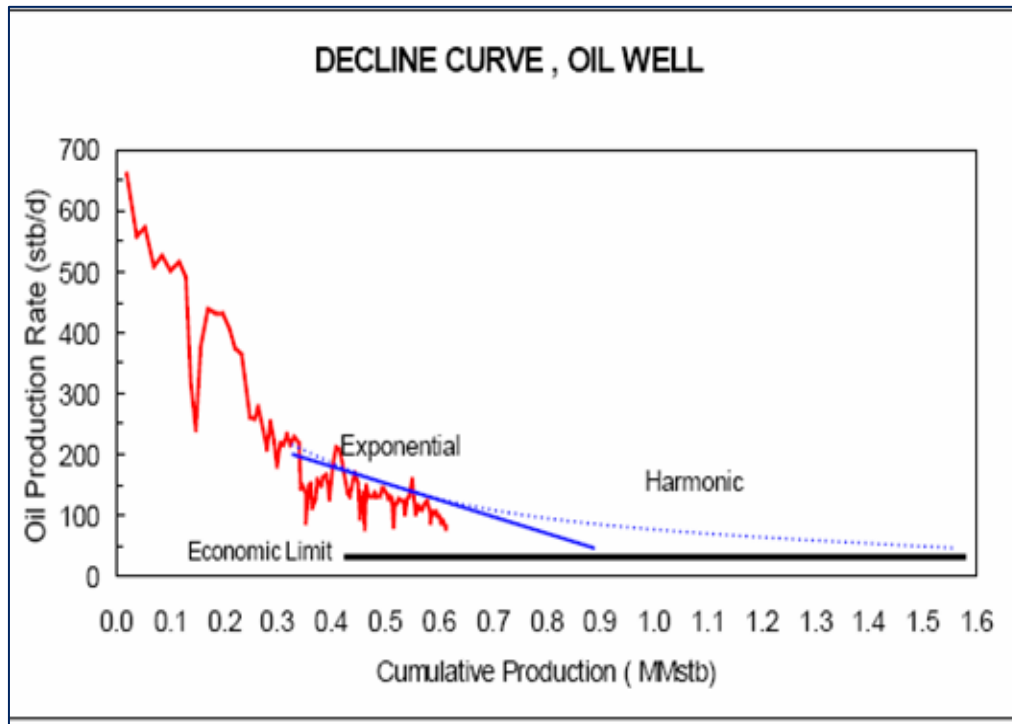
Source: PetroSharp 2015

**DECLINE CURVE ANALYSIS:** A decline curve of a well is simply a plot of the well's production rate on the ordinate versus time on the abscissa. The plot is usually done on a semi-log paper. When the data plots as a straight line, it is modeled with a constant percentage decline "exponential decline". When the data plots concave upward, it is modeled with a "hyperbolic decline". A special case of the hyperbolic decline is known as "harmonic decline". The most common decline curve relationship is the constant percentage decline (exponential). With more and more low productivity wells coming on stream, there is currently a swing toward decline rates proportional to production rates (hyperbolic and harmonic). Although some wells exhibit these trends, hyperbolic or harmonic decline extrapolations should only be used for these specific cases.<sup>34</sup> Over-exuberance in the use of hyperbolic or harmonic relationships can result in excessive reserves estimates. The figure below is an example of a production graph with exponential and harmonic extrapolations.

<sup>34</sup> See <http://petrosharp.com/services/petroleum-reserves/petroleum-reserves-estimation>



**Figure 14 Decline Curve of an Oil Well**



**Source: PetroSharp 2015**

**MATERIAL BALANCE METHOD:** The material balance method or the material balance equation (MBE) for reserve estimation defines a system of equations that relates the volume of hydrocarbons in place to the volumes recovered also known as underground withdrawal, relative to pressure decline. This technique is more reliable in estimating reserves compared to volumetric because here, the method is used after a significant percentage of the reservoir has been produced which means more reservoir parameters and information as used in this method are known with a relatively higher degree of certainty. In most instances as stated, information on reservoir parameters such as permeability of the formation, reservoir porosity, fluid saturations and contacts and even the bulk volume are not clear in the initial stages with any reasonable degree of certainty for which reason the estimates made from volumetric method calculations are not very reliable and hence not advisable. The material balance provides much reliable estimates of a reservoir's petroleum accumulation and serves as a useful tool in predicting future reservoir performance. It is therefore



worth noting that, the MBE's fundamental use lies in its ability to predict reservoir performance and not necessarily as a tool for estimating reserves although it holds the potential of doing both.

## 4. Key Policy Considerations

The key policy considerations in the design and implementation of standards are:

- i. There is a need to regularly update national standards at least every five years in line with provisions of the International Organization for Standardization (ISO). The standards should be revised as necessary to ensure commonality regarding approach and should apply to all processes, including those provided by sub-contracting companies.
- ii. Oil and gas companies (operators and sub-contractors) must be required to demonstrate to have met all standards and at the required competency levels. That is, they must demonstrate appropriate assessment of the hazards and risks concerned and mitigation plans put in place.
- iii. National standards and regulatory bodies need to be effectively resourced to ensure their capabilities keep pace with evolving regulatory and technological standards. This provides them with an opportunity to stand up to powerful industry and political influences.
- iv. National standards authorities need to regularly review and continuously improve standards taking into account best practice. For example, standards for well integrity and control such as operating practices, adequacy and reliability of safety-critical equipment, human and organisational factors among others.
- v. In addressing issues of well integrity, the training and competency of the personnel operating the well is vital to mitigating any occurrence of well integrity problems.
- vi. There is a need to put in place a well integrity management system with detail description of what needs to be done when anything unusual is detected in the well that has the potency of compromising the integrity of the well.