2016

GOOD INTERNATIONAL PETROLEUM INDUSTRY PRACTICES (GIPIP)

Prepared by

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MINISTRY OF PETROLEUM & NATURAL GAS
GOVERNMENT OF INDIA

Table of Contents

Preamble

In India, Oil and Gas Exploration and Production (E&P) activities are carried out under a Production Sharing Contract (PSC) regime. The PSC prescribes adoption of Good International Petroleum Industry Practices (GIPIP), Modern Engineering Practices in carrying out petroleum operations efficiently, safely, prudently and in an environmentally sustainable manner.

The issues related to codification of "GIPIP" were also examined by Comptroller and Auditor General (CAG) during the audit of a block for 2006-07 and 2007-08 and the following conclusion was made in the final report of CAG:

"…….Clearly, GIPIP is not a clear, unambiguous and self evident "gold standard", but "reasonable judgement" exercised by operators."

Rangarajan Committee in its report on the "Production Sharing Contract Mechanism in Petroleum Industry", has recommended the following on the issue of codification of GIPIP:

"On technical and safety related issues, the Committee recommends Directorate General of Hydrocarbons (DGH) may undertake codification of Good International Petroleum Industry Practices (GIPIP) that are of relevance to the Indian geological set-up."

So far, there is no codified set of "GIPIP" standards in the areas of exploration, development and production activities. However, the Safety Regulations and Standards have been formulated by Oil Industry Safety Directorate (OISD). The guidelines of GIPIP would go a long way in establishing high standards in E&P operations. Such guidelines would also help the Contractors as well as the Government to remove ambiguities and hence help improving PSC administration.

In the absence of codification of such guidelines by DGH, enforcement and adherence to GIPIP is fraught with subjectivity and prone to unnecessary disputes. Such guidelines will render objectivity to the decisions of the regulator, operator and other stakeholders.

Ministry of Petroleum & Natural Gas (MoPNG), Government of India vide Office Memorandum no. O-23012/8/2013-ONG-I dated 27.12.2013 has set up a "Standing Committee on Petroleum Industry Practices" under the Chairmanship of Director General, DGH.

The Members of the Committee is as under:

S. No.	Designation	Committee Status
1	Director General, DGH	Chairman
2	Joint Secretary (Exploration), MoPNG	Member
3	Advisor (Finance), MoPNG	Member
4	Advisor (Energy), Planning Commission	Member
5	Director (Exploration), ONGC	Member
6	Nodal Officer, NELP, MOD	Member
7	Joint Secretary, MOEF	Member
8	Two representatives from AOGO	Members
9	Representative of DGH to be nominated by DG, DGH	Member - Secretary

The Standing Committee on Petroleum Industry Practices will have the following terms of reference:

i. To identify the areas requiring codification of GIPIP.

ii. Preparation of national codes for petroleum operations.

iii. Revivew of the code every two years to update in line with evolution of international standards.

Subsequently, the Standing Committee identified the areas requiring codification of GIPIP to suggest specific guidelines in conformance with the best international practices and applicable standards/legislations and prevalent regulatory regime. The Standing Committee formulated the scope of work for hiring of a consultant by DGH. Pursuant to an International Competitive Bidding (ICB) tender, DGH awarded the "Consultancy for Study of Good International Practices in Petroleum Industry" to M/s PetroTel Inc., USA.

PetroTel Inc. is a geoscience and engineering consulting company with headquarters in Plano, Texas, USA providing professional consulting and advisory services along with integrated project management support to domestic and international petroleum companies. Their experience includes working with NOCs, independent, and major oil companies in India, North and South America, Africa, South Asia, Russia, the Far East, Europe, and the Middle East.

Their study used a combination of their expertise, published documents, worldwide industry standards, and governmental regulations in various countries. Their report incorporated feedback from the regulatory body in India, representatives of the Operators in India, and independent experts.

The objective of this work is to provide guidelines for practices that are considered technically and contractually reasonable for different aspects of E&P. The guidelines are generally accepted practices that are used worldwide. The best and most applicable guideline for a particular scenario will be based on specific field and reservoir conditions.

This report provides a review of Good International Petroleum Industry Practices (GIPIP) in the following areas:

1. Exploration
2. Discovery
3. Appraisal
4. Declaration of Commerciality
5. Field Development
6. Production
7. Testing and Analysis – Reservoir and Production
8. Health, Safety and Environment (HSE) / Abandonment
9. Procurement Procedure
10. Other Areas

The Standing Committee also asserts the following:

a. Codes or standards are made and published for specific activities by Statutory agencies or world recognized bodies. The extant PSC provisions, several MoPNG notifications and other standards/ rules currently facilitate the E&P operations to a large extent. Moreover, the best practices cannot be laid down as codes immediately for the Indian E&P sector. However, they may evolve into codes/standards for petroleum operations in India in due course of time to be issued by appropriate authorities. As per PSC, all E&P operators are expected to exercise best-in-class techniques and technologies for obtaining the best results. Hence the Standing Committee recommends adoption of a compendium of "GIPIP-2016" for the time being, which will act as guiding principles for several facets of E&P activities, to be used by E&P operators in India, DGH and MoPNG.

b. In a rapidly evolving hydrocarbon scenario, the potential of lack of familiarity with the latest practices is real. There are a wide array of operators with varying experience working in India and some guidelines in the form of compendium should be in place to facilitate stakeholders in conducting petroleum operations.

c. These guidelines for GIPIP cannot be taken to over-ride the PSC provisions or the law of India or active MoPNG notifications or any other statutory provision of India including Indian Accounting Standards and Indian commercial practices, which will continue to prevail under all circumstances unless the competent authority issues a separate notification.

d. These guidelines are generally applicable for E&P operations in the realm of conventional hydrocarbons. Some of these guidelines may not apply partially or totally to E&P operations for unconventional hydrocarbons.

e. There could be variances from the guidelines provided in this report for technical or commercial reasons and with evolving technologies. It is recommended that discussions amongst DGH, MoPNG and the operator be held in case of unresolved variances.

f. In line with MoPNG office memorandum, it is recommended that these guidelines may be reviewed after two years.

g. This compendium is a joint effort of Government and the E&P industry, and hence should not be used as a basis for initiating any legal proceedings by any party. In case of any litigation, this compendium could, at best, be used as a reference book.

h. It is also understood that “Good International Petroleum Industry Practices”, “Modern Oil filed and Petroleum Industry Practices” or any other similar phrase in any upstream hydrocarbon sector contracts or otherwise, would mean the same and will be guided by these guidelines.

Signed and Adopted by the Standing Committee on 19th Feb 2016 at New Delhi.

(Name- SUDHIR KUMAR) Member – Secretary, DGH	B. Ananthakrishnan (Name- B. ANANTHAKRISHNAN) AOGO representative - Member
(Name- A. K. DWIVEDI) Director (Exploration), ONGC - Member	(Name-....................................) AOGO representative - Member
(Name- Anil K Jain) Advisor (Energy), Niti Aayog - Member	(Name- ASHISH SHARMA) Nodal Officer, NELP, Ministry of Defence - Member
for (Name- (LALIT BOKOLIA) AD) Joint Secretary, Ministry of Environment, Forest and Climate Change - Member	Alok Chandra 19/2/16 (Name- ALOK CHANDRA) Advisor (Finance), MoPNG - Member
(Name- (U.P. SINGH)) Additional Secretary (Exploration), MoPNG - Member	(R.S. PANDEY) (Name-....................................) Countersigned. Director General, DGH - Chairman (AJAY SAWHNEY)

Amit Wanchoo
BP.
CAIRN
CHIRAG SHAH

1 Exploration

Oil and gas exploration as a process involves developing an understanding of the geological potential of an area and then evaluating the economic potential for producing hydrocarbons within that area. The process as a whole involves gathering data from different sources to create an integrated, complex model of the subsurface. Disciplines involved in the exploration process start with the geology and geophysics and with the evolution from a general understanding of the basin architecture through the detailed definition of prospective reservoirs and resources contained within them.

1.1 *Geophysical Practices – Mapping Standards, Geodetic Positioning and Data Management*

1.1.1 Definitions and Discussion

There are some technical areas which are common to all phases of exploration and production efforts. These include standards for mapping and positioning.

Mapping standards are established to ensure accurate communication of information between participating agencies and operating companies. The standards described here help to define the appropriate presentation and archival of maps used from regional to prospect and field specific studies.

Mapping standards are provided for regional mapping and prospect mapping. Regional maps do not necessitate the detail of prospect maps and would appear much too cluttered if held to the same annotation standards. They should still include such details as scale bars, mapping projection information title bar, etc. Prospect mapping standards are much more rigorous.

Standardization in geodetic surveying and positioning is a pre-requisite to most phases of a project. There are international organizations such as the International Association of Oil and Gas Producers (http://www.iogp.org/geomatics) and the Association of Petroleum Surveying and Geomatics (APSG) (http://www.apsg.info/) that provide a consistence set of references for companies and contractors executing projects in the oil and gas industry worldwide.

1.1.2 Best Practices

- Mapping Standards include best practices for presentation of Prospect Cross-sections, Maps from Seismic Interpretation for Prospects and Basin Analysis. Best practice presentation standards are listed below:
    - Prospect Cross-sections – A Cross-section is a display of multiple wells presented to illustrate how geologic features such as reservoir, seals and source rocks are distributed across an exploration area. Each well should be displayed with a header and the distance between wells should be documented. Each well should be annotated with important geological and drilling information and test results and a title block and legend should also be included.
        - Log Header – gives a brief discretion of the well and should include:

- Operator and/or joint venture name
- Well name and number
- Total depth and date
- Co-ordinate and projection system

▪ Datum and lateral relation between wells

- Structural cross sections are referenced to TVDSS to illustrate elevations changes of geologic units between wells. Depth values should be displayed in both measured depth and true vertical depth subsea.
- Stratigraphic cross-sections are flattened on a specified marker to highlight depositional and/or erosional thickening and thinning of geologic units.
- Proportional cross sections display the wells laterally spaced proportional to the distance between wells with horizontal scale bar. This method is preferable where the well spacing between wells is relatively uniform such as across a field.
- Equidistant cross sections display wells an equal distance apart with distances between wells annotated. This method is preferable where the distance between wells displayed is very irregular and a proportional cross-section is not practical.
- Index map should be included to show the line of cross-section

▪ Required Annotations and Colors

- Industry standard well symbols correctly posted with reference
- Direction labels at both ends of cross section (i.e. NE, SW, etc.)
- Label fluid contacts as on structure maps
- Label significant shows with available porosity, permeability, and test data
- Indicate and label casing points and mud weights on logs when available to the Contractor
- Label dipmeter arrows on logs
- Sands are yellow
- Shales are grey

        - Gas is red and oil is green
        - Salt is light green
        - Annotate perforated intervals and test/production rates (if significant)
        - Label key Paleo data
        - On stratigraphic cross-sections, gap the log for missing section at fault cuts
        - All horizons or faults which are colored should be colored the same as the seismic interpretation

- Title Block
    - Name of cross section or name of prospect
    - Location (country, state, block)
    - Horizontal and vertical scales and vertical exaggeration
    - Author(s) and/or company name
    - Legend for colors and symbols used for annotation should be displayed adjacent to the title block.
- Seismic Sections
    - Basic Rules
        - Fully interpret the seismic section (i.e. mark all the fault traces and their extents on dip and strike lines)
        - Use consistent colors on each seismic line for both horizons and faults and all other illustrations used for the project
        - Interpretation of line must match interpretation on maps and cross sections
        - Cross posting of the fault and horizon interpretation for intersecting lines must be displayed
    - Annotation for Top of Section
        - Line name
        - Line direction (i.e. NE, SW, etc.)

- Post all line ties for lines used in interpretation (highlight key ties for presentations) NOTE: The above items are frequently annotated automatically using seismic interpretation software.

- Post all wells which may impact interpretation (highlight key wells for presentation).

▪ Well Annotation on Seismic Sections

- Operator

- Well name and number

- Standard industry well symbol correctly posted

- Directly beneath or adjacent to the well symbol, post 'CS' if the time depth curve used to display the well is from a check shot survey for that well, SYN if it is posted based on a synthetic tie and VSP if based on a vertical seismic profile. No annotation would indicate the well and tops are posted on the seismic using an estimated time depth relation not specifically measured at that well (i.e. a shared time depth curve from a nearby or regional well or best estimate)

- If the well is not on the seismic line, indicate the direction and distance projected to the well (i.e. projected 120 m NW to line, etc.) For deviated wells, the annotation should state the distance the marker of interest is projected onto the line.

- Plot the well trace on the seismic section and indicate the TD by ending the well trace at a short horizontal line

- Horizontal scale bar on top or base of section

- Block boundary annotated for lines that extend outside the Contractor's block

- Casing points for proposed wells, if available

- Label horizons

- Z scale either depth in meters or km or TWT in msec or seconds must be shown on the seismic line

▪ Maps from Seismic Interpretation for Prospect Analysis – There is a general progression of detail of expected annotation from regional maps used for basin analysis to prospect and field appraisal and extension maps. An exploration prospect is considered to be sufficiently defined by existing data to determine an x,y,z value for a drilling target and volumetric estimates and risk analysis for prioritization. All prospect maps should be converted to depth. Supporting documentation should include the TWT map before depth conversion and average velocity map that relates the two maps. Some depth conversion methods, such as maps created directly from PSDM or depth maps derived by a constant average velocity will not need to provide an average velocity map.

- Use correct industry standard well symbols (see seismic software section).
- Post the subsea marker value for the mapping horizon. If the well did not drill deep enough to reach the horizon post 'NR' together with an estimate of the top, if used in gridding the map (e.g. NR -2180 m est.).
- If the mapping horizon is faulted out of the well should post 'FO'
- If there is a check shot survey in the well post 'CS', if there is a synthetic calculated for the well post 'SYN', if there is a VSP in the well post 'VSP'.
- Display all seismic data used to create the structure map. All lines posted on the map should be interpreted. Uninterpretable seismic data should be annotated on the maps as "poor seismic data".
- Color maps should display an annotated color bar consistent with the grid color (i.e. color depth structure map would have a color bar in meters).
- Seismic attribute maps used for prospect analysis should post a color bar related to the displayed attribute and depth contours to show conformance to prospective fluid contacts.
- For prospects near or within existing fields of similar reservoir targets the known oil fields should be displayed with a solid green polygon line and/or shading over the extent of the productive area. Red polygons should be used for gas fields/gas caps. Potential gas fields (discovered but not delineated/developed) should be displayed with dashed polygon lines and/or striped red shaded area. Potential oil fields should be displayed with green dashed polygon lines and/or striped green areas. Only fields relevant to the mapped horizon should be shown on prospect maps.
- Prospects should be shaded orange. The estimate of the most reasonable area should be solid polygon line and/or solid shaded area and the potential upside should be dashed line and/or striped area (if displayed on the map).
- Opacity may be used to show polygons and underlying map details.
- Prospects that have wells within the prospective area must post standard abbreviations for fluid contacts as follows (provided the information is available to the interpreter and relevant to the prospect):
    - GWC for gas/water contact
    - GOC for gas/oil contact

        - OWC for oil/water contact
        - HKW for highest known water
        - LKO for lowest known oil
        - LKG for lowest known gas
        - HKO for highest known oil (as needed)
        - HKG for highest known gas (as needed)
    - Title block should include
        - Name of mapped level
        - Location, including country, state, Basin and exploration block(s)
        - Type of map
        - Projection information and Datum
        - Date
        - Author and/or Company
    - Map should also include
        - Contour interval
        - North arrow
        - Bar scale for horizontal distance
        - Source of referred document
- Maps from Seismic Interpretation for Basin Analysis
    - All regional maps should be converted to depth. Supporting documentation should include the TWT map before depth conversion and average velocity map that relates the two maps. Some depth conversion methods, such as maps created directly from PSDM or depth maps derived by a constant average velocity will not need to provide an average velocity map.
    - Use correct industry standard well symbols (see seismic software section)
    - Color maps should display an annotated color bar consistent with the grid color (i.e. color depth structure map would have a color bar in meters)
    - Seismic attribute maps used for basin analysis should post a color bar related to the displayed attribute and depth contours to show conformance to prospective fluid contacts.

    - Known oil fields displayed on prospect maps should be displayed with a solid green polygon line and/or shading over the extent of the productive area. Red polygons should be used for gas fields/gas caps. Potential gas fields (discovered but not delineated/developed) should be displayed with dashed polygon lines and/or striped red shaded area. Potential oil fields should be displayed with green dashed polygon lines and/or striped green areas.
    - Opacity may be used to show polygons and underlying map details
    - Title block should include:
        - Name of mapped level
        - Location including country, state Basin and exploration block(s)
        - Type of map
        - Projection information and Datum
        - Date
        - Author and/or Company
        - Contour interval
        - North arrow
        - Bar scale for horizontal distance
- Seismic Software Considerations
    - Most seismic interpretation is currently performed using seismic interpretation software. Most software has a set of standard well symbols. Also, much of the annotation is displayed automatically depending on user preference. The annotation is still dependent on how careful the data loader and/or seismic interpreter were in loading the data or making displays. Care must be taken to ensure that the well symbols accurately reflect the status and fluids encountered in the well and title blocks contain correct and complete information. In addition, interpreters often use screen captures for maps and seismic lines that may crop out needed documentation that would otherwise automatically display on plotted seismic lines or maps. Specific items the interpreter should include on all seismic displays that may or may not display automatically are discussed below.
- Seismic Lines
    - Line name
    - Orientation of the line (i.e. N, NE, S, SW, etc. or azimuth)

- Horizontal scale bar. If a horizontal scale bar is not included in a screen capture, the interpreter must annotate the display with an approximate scale bar.
- Vertical scale. The vertical scale annotation either TWT or depth should not be cropped.
- Correct well symbol. The displayed well symbol should accurately reflect the producing status and fluids for each well.
- Well projection distance and direction. Often times, the interpreter can specify a distance for which all wells within the specified distance will display on the seismic line automatically. Deviated wells often only show the portion of the well path within a specified distance from the plane of the section. It is often left to the interpreter to annotate the distance and direction the well and/or marker is projected to the seismic line. The allowable distance for projecting a seismic line is dependent on the geologic setting and spacing of seismic lines. Normally projection distances of less than or equal to 1 km are used but this may not fit all circumstances.

- Seismic Maps
  - Correct well symbol should be displayed. The displayed well symbol should accurately reflect the producing status and fluids for each well. For example, a depleted oil well that has been plugged, should not be displayed as a producing oil well on maps or seismic lines.
  - Horizontal scale bar. When a portion of a map is captured with a screen capture tool, the interpreter should add annotation of an approximate scale bar.
  - North arrow
  - Color bar. Often times the color bar is not included within a screen capture. The scale bar should be captured separately and appended to the display.
  - The throw of fault, symbol (Normal/reverse) should be clearly displayed.
- Seismic Interpretation Reports
  - There has been a trend in industry to reduce the amount of paper used for environmental considerations. As a result, a minimum number of scaled plots such as maps and plotted seismic lines are included in reports. Some reports may not have any such displays. As a result, much of the standard information displayed on plotted maps and seismic lines is missing. This includes information such as seismic acquisition parameters and abbreviated processing flows traditionally displayed on the side panel of seismic lines and projection information on title blocks. For seismic data acquired by the current Operator, this information must be documented in the report either in a section related to the data used or an appropriate appendix or a reference

to available acquisition and processing reports. For seismic data acquired previous to the current operator, this information should be provided if available from the EBCDIC header or reports from previous operators. All acquisition, processing parameters and co-ordinate reference system used must be included in this report.

- Geodetic Positioning
  - There are no specific standards that have been developed or adopted worldwide; however, there are best practices that have been developed for each of the disciplines, namely the geophysical industry and the drilling / rig positioning contractors. Current industry standards are primarily driven by the use of Global Positioning Systems and in most cases then reference the WGS84 standard. The UTM projection and WGS84 datum are widely used for international projects and have standard parameters. Less widely used projection should specify the parameters used including the projection used to include:
    - Semi major Axis
    - Semi minor Axis
    - Inverse Flattening
    - Datum
    - False Easting
    - False Northing
    - Central Meridian
    - Standard Parallel (if any)
    - Scale Factor and Latitude of Origin
  - It is particularly important to include a complete description of the positioning system employed, the reference datum, and the projection system. This is true whether the data being transmitted is in Latitude / Longitude or in X Y Z projection format since both require an accurate description of the Geodetic Datum.
- The best practices mentioned above are recommended; however, there may be geologic or economic reasons to deviate from the above standards. It is recommended that these standards be made available to the Operators and that Operators follow the standards that are relevant to their exploration objectives.
- Documentation of the positioning system used for any data must be clearly stated on all data that is presented and archived. Universal Transverse Mercator (UTM) projection system is primarily used worldwide where the projection is effective. In areas where multiple UTM zones cover a prospect or regional map it may be appropriate to use a

Transverse Mercator projection with a central meridian that allows for less convergence within the mapped area.

1.1.3 References

1. Tearpock, D. J., Bischke, R. E., 2002, Applied Subsurface Geological Mapping with Structural Methods (2nd Edition), Prentice-Hall PTR, Upper Saddle River, New Jersey 07458
2. For positioning related questions please visit http://www.apsg.info/ for Technical Resources and Official Publications.

1.2 *Geophysical Practices – Seismic Acquisition*

1.2.1 Definitions and Discussion

During the exploration, development and production stages of a PSC lifecycle, there are different geophysical data types that are acquired, processed and interpreted to better define the subsurface geology. Complex geology dictates acquiring the data that defines the structures or stratigraphy that are pertinent to the exploration targets or the reservoir under development. Different seismic methods result in data with varying limits to their resolution. The limits of resolution are therefore the critical components of the surveys and how they may be employed in exploration and production.

Seismic method is a primary tool used in defining a potential hydrocarbon accumulation during the exploration phase. Seismology is used to investigate the earth's structure and stratigraphy from a regional scale, such as refraction surveys to model the depth to the core or mantle, to small scale such as high resolution seismic reflection survey for investigations of hazards in the near surface. In certain cases, high resolution surveys are included in drilling site surveys when positioning drilling rigs to avoid shallow hazard whenever required.

Terminology for geophysical data in general and specifically regarding seismic data are defined using a standard set of terminology. To support this effort the Society of Exploration Geophysicists has implemented the SEG Wiki available at http://wiki.seg.org/index.php/Main_Page. Two valuable resources, which contain these information, are Robert Sheriff's Encyclopedia Dictionary of Applied Geophysics and Oz Yilmaz's Seismic Data Analysis. These references provide the global standards used by Operators worldwide. The most utilized methodology in oil and gas exploration is that of reflection seismology. Reflection seismology is based on the propagation of energy from a controlled source to receivers as an elastic wave. (For details refer to http://wiki.seg.org/wiki/Elastic_waves_and_rock_properties). In the case of reflection seismology, elastic wave theory describes the effect of the propagation of the energy from the seismic source to receivers -the wavefield having propagated through geological formations and having been modified by the rock properties.

Some of the important terminology used in seismic data acquisition, processing, analysis and interpretation include:

- Travel Time – Travel time is the basic unit of measurement for seismic data. Travel time is the elapsed time from a source event (explosives shot, airgun blast, etc.) until the wavefield is detected at the receiver. Travel time is used as the basis for determining the length of seismic record, insuring that all of the events of interest have been received during the period over which the signal is recorded. Two-way travel time is measured in surface seismic since it is the time for a signal to travel downwards to a formation and then travel upwards to the receivers.

- Group Interval – the group interval is the spacing between adjacent traces in the seismic acquisition geometry deployed in the field. This is a measurement of the lateral offset between two traces and is normally a consistent distance set to properly sample the wavefield.

- Sample Interval – the sample interval in seismic data is selected based on the Nyquist frequency that is needed to faithfully record all of the seismic frequencies of interest. For surface seismic data the sample interval is normally 2 milliseconds that should be sufficient to sample the wavefield up to 250 hertz. For high resolution and site survey data the sample interval is normally 1 millisecond as well as for VSPs. The sample interval may be chosen upto 0.25 millisecond for CBM surveys. During processing, data is resampled to 4 milliseconds to reflect the usable bandwidth and for compensating less storage capacity.4 milliseconds is rarely used in data acquisition due to the fact that storage (tape) is relatively inexpensive and the increased cost of preserving higher frequencies is minimal.

- Amplitude – Amplitude in a seismic signal represents the amount of energy that is reflected from a formation boundary. Amplitude is a measure of the properties of the formations (porosity, rigidity, density, etc.) and the fluid contained within the formations (oil, gas, and water) and is therefore an important measurement in seismic data. Amplitudes must be preserved starting with the seismic acquisition system. Current 24 bit A/D systems are capable of 144 dB of dynamic range.

- Velocity – the key unknown in a seismic survey is the velocity at which the sound wave propagates through the earth. To estimate velocities, there are methods used in seismic processing that can provide insights to the formation velocities. Likewise, from well data it is possible to measure the velocity of the formations directly using sonic or VSP / Checkshot data. Velocity is used in the seismic processing as well as for time to depth conversion in mapping reservoir targets based on seismic data.

- CDP or CMP – These parameters are Common Depth Point or Common Mid-Point and refer to the point in the subsurface that a down going seismic signal reflects off of a formation interface before traveling upward to the receiver. The CMP or CDP is the basis for seismic data processing of reflection seismic data. The CMP or CDP is normally assumed to be mid-way between the source location and the receiver location which is true for flat-lying formations.

- Fold – When processing surface seismic data to improve signal quality of the data, multiple traces that come from the same CMP are gathered. Fold is the number of traces that have come from the same point but have been acquired by using different source and receiver point locations. Adding these traces together will improve the signal level in the processed seismic section.

- Stack – A stacked seismic section is created by first applying a time correction based on estimated velocity in processing to the data in a CMP that has different travel paths so that all traces represent the travel time based on a wavefield that propagates vertically from the surface position of the CMP to the formations imaged by the seismic traces. Stacked data do not always reflect the accurate positioning of the events in the subsurface.

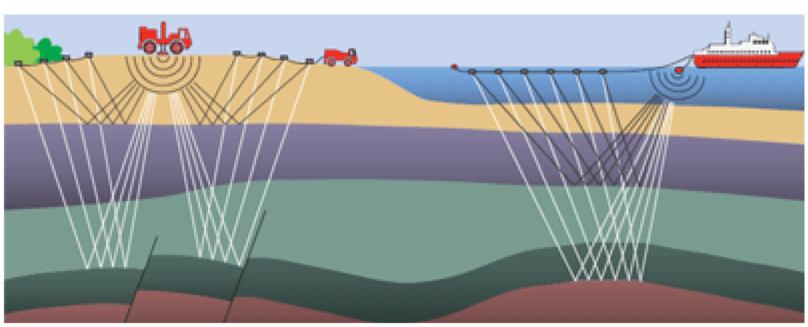
- Migration – In seismic processing terminology, migration is the process of calculating the subsurface position of seismic events imaged in the CMP gathers. The velocity determined from the data is normally used for time migration of data.

    - Post-Stack migration applies corrections to the Stacked seismic section to better position the events that are observed on a stacked section

    - Pre-Stack migration uses the data from the CMP gathers before stack to correct the position of the events and in doing so it re-positions energy into the correct CMP gather in an unstacked state. Mostly it is used in case of complex geological structure.

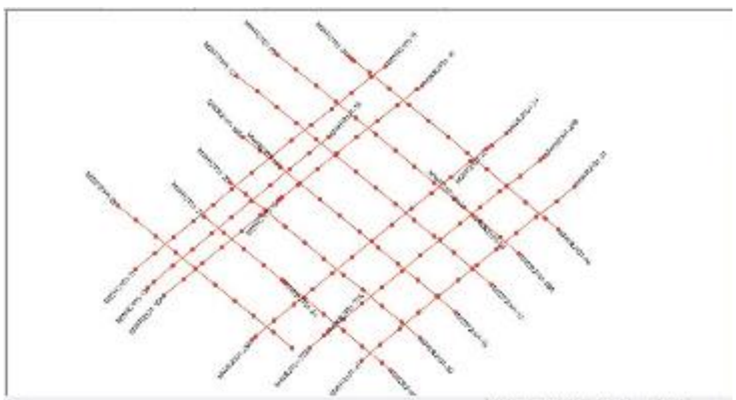
    - Depth Migration uses velocities either from externally generated models or by iterating the process using seismic derived velocities to first convert the data to depth and then migrate the energy to the correct position. Depth migration is more robust particularly in areas where there are inversions in the seismic velocity (velocity decrease with depth) or strongly varying lateral velocity changes. Depth migration may be used in either Pre-Stack or Post-Stack migration schemes.

- Seismic Surveys –The figure below illustrates the typical geometry for seismic data acquisition. This figure shows a typical land seismic geometry on the left where there is a recording unit and a source unit that operate independently. On the right a simplified illustration of a marine seismic operation is shown. In both cases, a source is activated to generate the down going elastic wavefield that propagates through the earth, reflecting off of geological interfaces and the up going wavefield is recorded via sensors distributed either on the land surface or in a marine streamer. A third case, Transition Zone, where there might be land type receivers onshore and underwater marine type receivers, that use either a land or marine based source depending upon the geology of the area.



Seismic Data Acquisition Geometries

- 2D surveys are comprised of a series of seismic lines that create a grid over the survey area (see figure below). In areas of strong structural dip it is important to consider the location of the axis of the structures in designing the program. 2D seismic data is acquired as vertical profiles through the geological section. The data represents the wavefield that has the shortest travel time from source to receiver, and in areas of dip, that travel time to the formation is normally to a position up dip from the location of the line. Strike lines allow the data to be tied together during interpretation. Strike lines should be located in areas where the structural dip is minimized if possible. A best practice is to focus more of the seismic program in the dip direction and to remain as orthogonal to structural dip as possible. Since seismic data records the reflected energy based on the shortest travel time from the source to the receiver that shortest distance is normally up dip of the line, if shooting parallel to strike. The net result is the strike and dip lines may not tie well at line intersections.



2D Seismic Grid

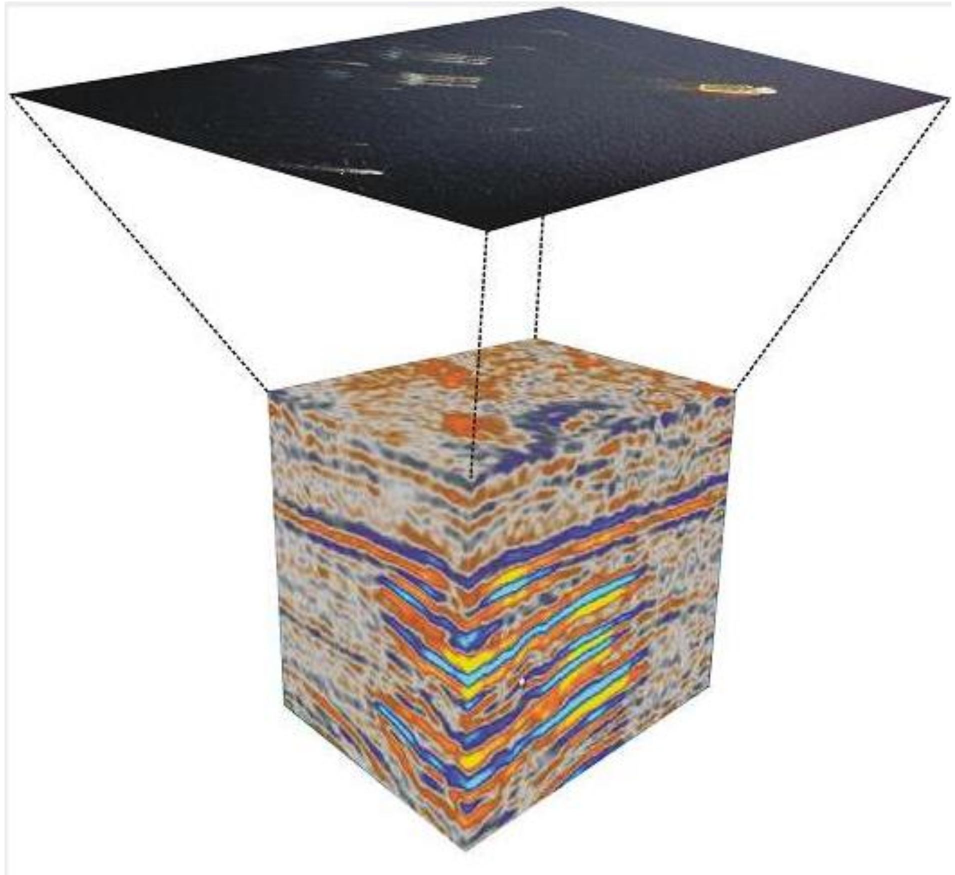
Crooked Line 2D Survey: Logistically difficult and hostile terrain of frontier areas poses terrific challenges ahead of explorationist and our most reliable seismic method of hydrocarbon exploration. Crooked line survey is outcome of that modification where seismic profiles meander along the existing roads and possible paths. It has better solution for no. of reasons in spite of further complication of reflection pattern due to irregular acquisition geometry inclusion at the time of acquisition. It requires special processing technique to deal with irregular geometry.

- 3D Seismic Surveys – Three Dimensional seismic surveys are used to obtain detailed subsurface images. The advantage of 3D seismic surveys is primarily in that they are able to provide much greater lateral resolution. In areas of complex geology or unusual velocity overburdens, 3D seismic is able to provide better insights into the geology.
    - Bins – In 3D seismic the data are acquired and processed based on Bins. A bin is the equivalent of the CDP or CMP in a 2D survey in that it is the center point between the source and receiver. Bins however are defined in advance of the acquisition with the concept that sufficient sources and receivers will be deployed to allow for the fold within a bin to meet the survey objectives.

- Marine 3D seismic surveys are acquired by vessels that tow multiple streamers & sources to collect a swath of data at a single pass as shown in the figure below. The survey samples a volume of the earth rather than a single vertical profile. Marine 3D seismic is normally very cost effective due to the ability to acquire data over the survey area in a short period of time. Current 3D seismic acquisition vessels may tow as many as 20 streamers simultaneously providing both lateral and temporal high resolution in the data.

- Land 3D seismic surveys are acquired by laying receivers over an area and then shooting vibroseis or explosives sources into the spread, repeating this process until the bin has been filled with the planned distribution of traces based on the distance from source to receiver (offset) and in some cases the azimuth between source and receiver. Because the receiver and source operate independently (unlike a marine survey) the design options are much more extensive. Designs for land 3D surveys incorporate establishing binning criteria such as offset & azimuth distribution, bin size, and fold, determining the most efficient layout of the receivers, and identifying the proposed location for sources. In land surveys, there are frequently locations where it may not be possible to locate sources and these may be identified during the design stage. Model output from the design tools can be used to test the geometry and determine whether it is possible to meet the survey objectives. If it is not possible then recovery source may be planned to meet survey objective.

- Full Azimuth Surveys – The use of properties of the rocks that provide different reflected responses based on the orientation of the wave field as it reflects from an interface enables the geophysicist to extract additional information from the 3D data. Full azimuth surveys are designed to obtain reflection data from a wide range of reflection angles and azimuths into each bin. These data may then later be processed to estimate fracture density and orientation or anisotropic velocity behavior.



3D Seismic

- Wide Azimuth Surveys – the objective of wide azimuth surveys is to acquire data that incorporates the greatest effects from non-normal incident reflections. In studying the properties of the formations, the geophysicist can model the impact on seismic reflection data due to effects at very wide reflection angles. These data provide greater insights into the rock properties and fluid content of the formations.

- 4D Seismic Surveys – 4D seismic is a method wherein multiple 3D surveys are conducted over a producing field. Based on changes in rock properties (fluid content) during the producing life of a field, the seismic shows how fluids have migrated. Water encroachment, water injection, gas cap expansion or parts of the field that are not getting drained in the current production scenario can be detected by looking at the difference between the baseline survey and surveys acquired at a later date. This technology has become known as Permanent Reservoir Monitoring as it involves a permanent receiver installation for acquiring the surveys.

- Passive Seismic Monitoring – Seismic technology is currently in use to monitor fracture treatments in unconventional reservoirs. The technology has been deployed both by using surface arrays and downhole arrays to monitor the impact of frac jobs which is used to increase permeability. The technology is used for identifying fracture length and propagation and can be used to identify the primary regional stress regimes. It basically uses natural earthquakes and activity as sources and broad band seismometer as receivers.

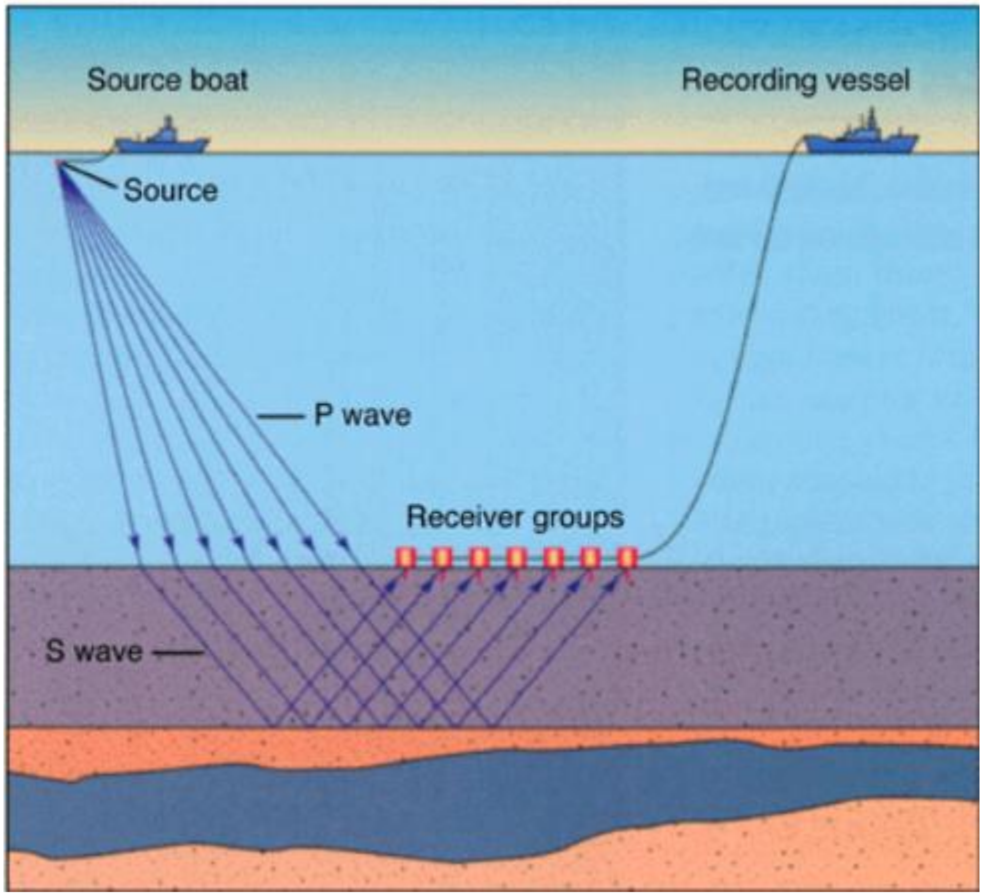
Nowadays it is used for monitoring the changes of reservoir properties during production so that further production strategy can be planned. It can be used in logistically challenged areas where conventional seismic method is difficult to apply.

- Transition Zone Seismic – Transition zone seismic surveys can be 2D or 3D programs that incorporate both land and marine operational characteristics. The operation is typically managed more like a land survey than a marine streamer operation since there will be sources and receivers deployed in an uncoupled fashion. Design efforts will need to address both the types of sources and receivers required for each of the environments.

- High Resolution (HR) Seismic Surveys – High resolution seismic surveys are designed to acquire data that can resolve small scale geologic features. These can be surveys designed for site investigations and geohazard identification, or in non-oil and gas industries may be used for mapping coal seams. Normally these surveys are designed for engineering purposes and not for mapping subsurface oil and gas accumulations although the techniques used in acquisition and processing High Resolution surveys can be incorporated into conventional 2D or 3D seismic surveys to obtain higher fidelity data that can resolve thin beds and small scale geologic features. It is also used in CBM exploration. Typical differences in acquisition approach for HR surveys include a source that has a wider frequency range, a streamer may be towed more shallow to avoid surface ghosts, group interval spacing may be closer, and sample interval for the recorded digital signal may be reduced to 0.5 milliseconds (or less if necessary). In certain cases, a recent 3D seismic survey may be reprocessed using high resolution techniques to provide the reflection seismic data for a site investigation survey.

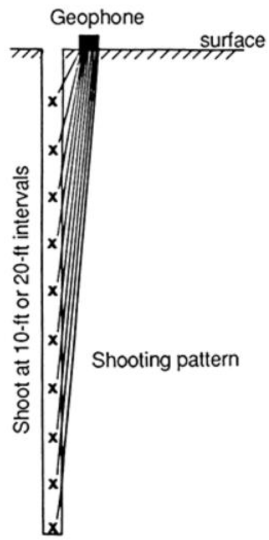
- High Definition (HD) Seismic Surveys – High definition surveys are designed to ensure geologic features are properly sampled in the subsurface so that they may be resolved in the interpretation and mapping process. HD surveys typically mean that the group interval spacing between traces or the line interval between adjacent lines, or the bin spacing in a 3D survey are reduced to oversample a subsurface feature. HD survey planning typically involves first considering the complexity of the geological environment and then designing a survey that oversamples the geology such that the imaging step can effectively address the degree of complexity encountered by the wave field during acquisition. The concept of the Fresnel Zone and how features are resolved in the subsurface comes into play and will be considered in the survey design.

- Ocean Bottom Cable (OBC) / Ocean Bottom Node (OBN) Seismic Surveys – OBC or OBN surveys are a subset of marine seismic surveys wherein receivers are located on the ocean floor. OBC surveys utilize a cable that is placed on the seafloor similar to a land seismic survey with the cable is connected to a stationary vessel recording the data while a source vessel traverses the area and shoots into the cable (see figure below). Once all of the source locations are recorded for a given cable location, the cable is picked up, re-deployed and additional source points are recorded. The difference between an OBC and OBN survey is that the OBN survey uses individual nodes that are deployed on the seafloor. In most cases, these nodes record and retain the data on internal memory until the node is retrieved and the data is downloaded. All source point Time Zero (T_0) are recorded based on an internal clock that is normally synchronized to a GPS time signal and an internal clock in the node is used to synchronize the recorded traces to the source T_0. OBC / OBN surveys are used for a variety of purposes, but one must recognize that there is a surface ghost notch in the data. The advantage of the bottom referenced acquisition is that a gimballed geophone may be used along with a hydrophone. These two signals can be combined in processing to remove much of the impact of the ghost. OBC Surveys are also useful for collecting multi-component seismic data in marine settings. Shear wave energy does not propagate through water, therefore OBC/OBN surveys are a useful means of recording shear wave data at the sea floor interface. The figure below depicts the use of receiver groups on the sea floor for recording converted Shear wave energy.

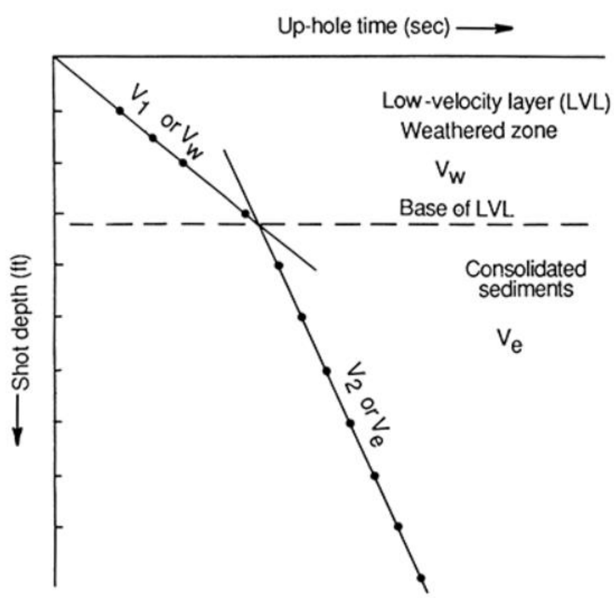


OBC Seismic Acquisition

- Uphole Surveys / Seismic refraction survey (LVL surveys) – Uphole surveys are frequently acquired during land seismic programs. These surveys are designed to determine the near surface velocity & depth of weathered and sub-weathered layer at pre-determined surface locations in the survey area. The acquisition of an uphole survey requires first a hole drilled depending upon the assumed low velocity layer thickness (normally to a depth of 75 to 100 meters), second a recording system, and third a source. There are two methods employed - either a string of receivers lowered into the hole at a preset interval between receivers with a source on the surface located close to the hole, or small charges (sources) are placed in the hole at pre-set depths and a geophone at the surface to record the arrival from the shots. In both methods, the direct arrival time at the receiver is recorded and plotted as shown below. Based on this information the near surface velocity can be determined and an estimated depth to the base of the Low Velocity Layer (LVL) is calculated. This information can subsequently be used in calculating the statics model and for dynamite surveys to determine what depth the charge should be placed in the hole (normally just beneath the LVL).The same principle applies in seismic refraction method. The receivers are laid on pre-determined location and different sources like light explosive, hammer etc. may be used to generate elastic wave on planned location. This also gives the velocity of LVL and depth of base of LVL.



Uphole Recording Geometry



Plot of arrival time versus depth

1.2.2 Best Practices

- Survey Design - The Geophysicist responsible for designing the survey takes all of the issues into consideration in developing an appropriate design for the acquisition program. This design is the input into the tender documents for determining which contractor will be selected for the project. The design is peer reviewed by other acquisition specialists, seismic processing specialists and the interpreter to validate the design which will be able to meet the survey objectives. Some or all of the following information will be used in optimizing a survey design:

    - Special requirements for the instruments to be used;
    - Depth of the target;
    - Required temporal and spatial resolution. These parameters define the focus of the survey, specifically differentiating between normal exploration oriented surveys and High Resolution or High Density surveys;
    - Velocity profile of the section of interest and overburden;
    - Seismic data quality in previous surveys;
    - Geometries used in prior seismic surveys
    - Seismic data quality issues such as source generated noise, frequency content, absorption (Q), surface statics;
    - Anticipated cultural noise;
    - Orientation of the geological structures;
    - Complexity of the geology including stratigraphy (carbonates versus clastics), fracture, structure, near surface anomalies, and stratigraphy; and
    - Interpretation objectives beyond conventional structure mapping such as sequence stratigraphic interpretation; fracture detection, seismic inversion for reservoir properties, AVO or AVA analysis, or Full Waveform Inversion.
    - Effect of economics & logistics of design.

- Environmental Impact Assessment - In most cases worldwide there are now requirements for an Environmental Impact Assessment (EIA) or Environmental Impact Report (EIR) prior to the start of a project. The survey design documentation will be used as a part of the input to the Environmental agency to understand how the seismic contractor will be operating in the field. Each country has their own processes and organizations in place for both the conduct of the assessments and for the approval of the project based on the assessment. Guidelines for field operations to minimize environmental impact are provided by the International Association of Geophysical Contractors (IAGC) (http://www.iagc.org). IAGC is the international trade association representing the industry that provides geophysical services geophysical data acquisition, seismic data ownership and licensing, geophysical data processing and interpretation, and associated service and product providers to the oil and gas industry. Their guidelines are not strict rules but are the international standards that most seismic contractors have knowledge of and will agree to operate under.

- Contractor Selection, Audit and Award - After award or during the analysis for awarding an acquisition contractor a program, an audit of the contractor's capabilities is performed before starting the survey. This purpose of the audit is to ensure the equipment is functioning properly, the personnel are capable of conducting the survey, and that the contractor understands the complexity of the program they will conduct. Audit is a necessary function and expertise in seismic instrumentation, surveying, operations, and HSE are all needed to verify the seismic contractor can perform the work. This is an integral part of the seismic survey and the cost of the audit is incorporated in the overall seismic project costs.

- Permitting – Before a Contractor can begin work in any area, proper permits for access are needed. Statutory permission from state and central govt are required. In land surveys this normally means receiving permission from the land holder to cross the land. Permitting also includes receiving authorization from other operators if the survey will be crossing into an adjoining contract area. In marine surveys, permits may be required from the military to operate in an area. Permit is also required from competent authority of rigs, platform, oil installation which falls within the area. In any survey, permit is required from local and state authority.

- 2D Seismic Program Layout

    - Orientation of program – In areas of significant structural dip, seismic lines are oriented perpendicular to the direction of geologic dip. The closer the seismic lines are to being perpendicular to the dip orientation, the more accurately the 2D seismic can represent the subsurface in cross-section. 2D migration algorithms cannot properly account for the image being outside a vertical plane through the seismic line.

    - Strike Lines - Strike lines are best located in areas of minimum dip to allow for consistent ties between strike and dip oriented lines. Mis-ties result when the image point for the strike and dip lines are in different positions in the subsurface even though the lines occupy the same surface location at the intersection.

    - Seismic Line Density – To obtain accurate depiction of the subsurface structures, the seismic line density must sample the structure sufficiently to capture the geological changes in the survey area. Sufficient seismic program to capture the full wavelength of a structure is needed to enable mapping the structure properly. For features with lateral variability on the order of 1 kilometer, it is necessary to have a seismic grid of 0.5 km or less. A greater density of dip lines improves the quality of the interpretation by capturing more of the structural variations.

- 3D Seismic Program Design

- Survey orientation – For 3D surveys the orientation of the acquisition is in many cases not a significant issue. In marine surveys, it is important to consider that the inline acquisition direction in the direction the vessel is streaming is capable of much smaller intervals than the cross-line direction. Cross-line spacing is one of the significant parameters in determining cost of a survey as it will dictate how many passes a vessel must make to survey the full area. In most of the cases, the inline follow the dip direction.

- Bin size / spacing – In 3D survey design, a primary criteria is the determination of the correct bin size and orientation.

    - For marine surveys, it is still preferable to orient the survey such that it is shot perpendicular to the strike of the geological structures. This provides better inline resolution and allows for greater lateral resolution of the structure.

    - For land surveys, the bin size is normally based on the geometry that can be deployed for acquiring the data. There are many different approaches to designing the surveys such as swaths, button-patch, cross-line, etc. Each of these methods have advantages and disadvantages that must be weighed during the design effort.

    - Bin size and spacing will also have an impact on the processing of the data. A greater bin spacing will result in lesser lateral resolution and in cases of strong dip, a less accurate vertical resolution of events. Bin size must be small enough to capture all events and give best possible resolution.

- Source versus Receiver deployments – In land 3D designs, there are trade-offs between whether more receivers or more shots are the most advantageous to the program design. There are currently land systems capable of deploying hundreds of thousands of channels making the receiver spacing decision less of an issue, but the operational effort in deploying and maintaining a spread with over 100,000 traces live can be significant.

- Simultaneous sources – Technology now exists that allows for separation of signal from multiple sources acting at the same time on a single spread. The advantage to this is that more data can be acquired over the same period of time as if only one source could be recording. This changes the dynamics of high channel count 3D surveys dramatically.

- Marine Seismic Survey Parameter Selection – Apart from design, the survey results depend on selection of marine source and receiver. Marine receivers are selected basically on its dynamic range and characteristic response. Normally the spacing between two receivers is fixed in streamers. Marine sources are normally planned based on the energy output such that the formations of interest may be imaged. Airgun arrays are measured in bar-meter output and are easily monitored. They are currently the most actively used source worldwide. There are different models of air guns although most work in the same fashion. The differences are primarily in operating pressure, chamber size, output energy and consistency of the wavefield generated.

- Marine Seismic Sources

  - The mainstay marine seismic source is the airgun array. This has been in use for many years and consists of a number of air guns that contain air chambers of various size. These air guns are operated by a solenoid controlled by the acquisition system onboard the seismic vessel that controls the timing for opening the chamber. By deploying a number of air guns spaced out over an area behind the seismic vessel, the interaction of the pressure from the bubble pulses generate a wavefield that is additive of the output from all guns. Various sized air guns are used in the array and through both modeling and measuring the output energy from the array it is possible to manage the directivity and consistency of the source signature. The measured or model signature may be used in the processing of the data to convert the acquired data to zero phase. The selection of an airgun source array is normally dependent on the depth of investigation needed. The shape of the wavelet and directionality of the source energy is also a consideration. There has been considerable discussion and concern about the potential impact of airgun arrays on marine mammals. The International Association of Geophysical Contractors (IAGC) along with governmental agencies worldwide have reports that discuss the studies of impact. To date, the result of the studies has been to implement procedures for startup of airgun arrays by slowly bringing up the output before the start of a line. This is intended to encourage the mammals to move away from the survey area. Additionally marine mammal observers are placed onboard seismic vessels to monitor and shut down shooting should there be close encounters with mammals. Airgun arrays may also be used in transition zone surveys as they can be effective in shallow water although the ability to deploy an array is limited by the type of vessel in use.

  - A relatively new source in the marine environment is the marine vibrator. Although developed many years ago, it is now coming back into the industry as a potential replacement for air guns. The marine vibrator works much like the land vibrator and sweeps through a frequency band to generate the source pulse. This source is less impacting on marine mammals. There are few Contractors that can offer this capability.

  - Sparkers are still used frequently for high resolution site surveys. The source is relatively weak but sufficient to penetrate the shallow sediments and provide input to the individuals interpreting the shallow hazards before placing jack-up rigs or setting anchors for semi-submersible rigs.

  - Sources for 3D acquisition are typically configured such that the vessel will tow at least two source arrays of identical design. The data is then recorded by flip-flop in which for example the starboard array shoots followed by the portside array on the subsequent shot. In this fashion, different bins are filled by each of the shots.

- Marine Cable Geometry

- 2D seismic Surveys – The selection of the cable configuration for a marine seismic survey is normally predicated on the geologic objectives of the survey. The parameters that are available are limited to cable length based on the acquisition system the contractor has on the vessel. This will dictate the group interval between hydrophone groups in the streamer and this may not be changed by the contractor. Cable length is a significant parameter in that it will define the quality of the velocity estimates and in complex geological areas it has an impact on the ability to image the dipping formations.

- Selecting cable length – Cable length is determined by the depth of the objectives along with the intended use of the data. A cable length equal to the depth of investigation is preferred and in most instances will more than meet survey requirements for velocity control, even in areas of steeper dips. For projects where AVO / AVA analysis is desired, a longer cable is helpful in that it improves the ability to record data from wider angle reflections. The angle response of the reflectivity function from Zoeppritz equations can be used to help design the cable length by modeling the AVO reflectivity response and use that to estimate the reflection angle at which detectable changes in reflectivity will be found. In addition to pre-stack seismic analysis, cable length can be helpful in multiple attenuation, particularly for free surface multiples from the water bottom and air-water interface. Multiples will appear in the data at a different velocity than the primary energy and the differential move-out can be helpful in stacking out the multiples as they will be out of phase in the CDP gather.

- 3D Cable Geometry – For marine 3D surveys, the second design criteria is the separation between cables. This parameter defines the cross-line bin dimension for marine 3D data. The cable length discussion for 3D is no different than 2D. Cable separation during acquisition is maintained through the use of paravanes that aid in separating the streamers.

- Cable length and cable geometry decides the azimuth distribution which is required to study anisotropic behavior of formation.

- 3D Binning Criteria – In shooting marine 3D seismic surveys, the design stipulates not only the bin dimensions, but the number of traces over specific offset ranges that must be included in each bin to fulfill the design criteria. Due to the fact that cross-currents can displace the streamers, there are normally areas where bins do not get filled with all of the required offset, and infill passes must be shot to meet the specifications.

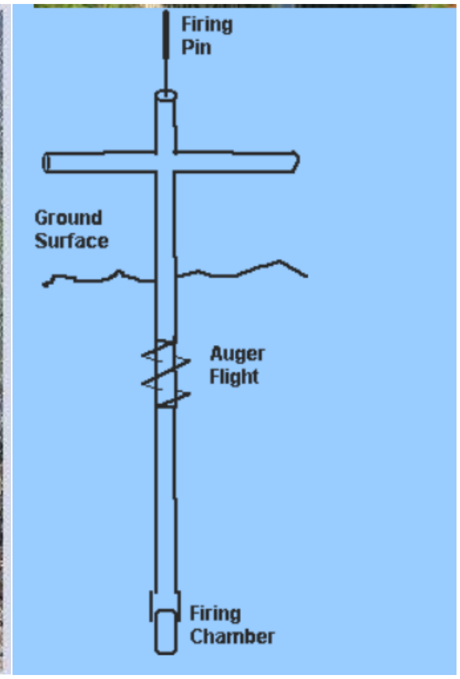
- The Sample Interval and Record length are selected to ensure sufficient data is acquired to image the formations of interest and normally to allow for imaging to basement unless the data is in a very deep clastic basin.

- Marine surveys also require planning when operating near shore or near shallow water hazards such as islands. Bathymetric surveys are conducted prior to the start of the survey to aid in establishing the appropriate points at which a marine vessel will need to veer off of a line to avoid a hazard. Operationally, this also means that the captain of the vessel must have experience working in these types of environments because they have the ultimate say as to when a vessel will turn off line. Lack of communication before and during the survey will result in poor coverage.

- Land Seismic Survey Parameter Selection
    - Land Seismic Source Selection – selecting a source for a land seismic survey is normally based on operational requirements.
        - Explosive – this is still a widely used source, particularly when access is more difficult. Explosives can be shot as a single charge or multiple charges that are fired simultaneously. In very rugged terrain the difficulty in using explosives is the ability to drill a hole deep enough with the light weight drill rigs to enable placement of large charge sizes. The depth of a charge is normally below the weathering layer and in the water table. Getting the charge to that depth minimizes the impact of blow-outs when shooting the charges and increases the energy penetration. Explosives specifically made for seismic operations are manufactured by a few different companies and the critical element is insuring that all of the explosives used for a survey burn at the same velocity; if not, the energy imparted into the ground is inconsistent. Charge sizes of different denomination are also available. Charge size is typically determined by testing to find the volume of explosives that image the target horizons at the range of offsets deployed. In cases where it is not possible to drill deeply enough to hold the charge size required, multiple shot holes may be used and the charges are detonated simultaneously. The source locations are laid out by the surveyors and subsequently a drilling crew drills the shot holes to the prescribed depth. Depending on the local laws, charges may be placed immediately after drilling or may need to be deferred until time to shoot that shotpoint. The normal practice is to either use two analog blasting caps or a single electronic blasting cap. Each shotpoint location must be surveyed including the geodetic position and elevation.
        - Vibroseis is a very commonly used source. The flexibility in deploying as well as the consistency in the source energy of vibrators make them a source of preference in most surveys. The picture that follows is a Vibrator that has been deployed using wide tires which enable it to work effectively in sandy environments with minimal impact from the tracks. Other types of tracks, wheels and tires can be used depending on the environment in which the vibrators will be deployed. Vibrators are rated based on their peak force output which is normally directly dependent on the weight of the vibrator along with the hydraulic actuator capabilities. When deploying vibrators, normally an array of 2-4 vibrators are used depending on the requirements. The vibrators operate simultaneously through control signals sent from the recording unit. A pre-defined sweep of frequencies is used to drive the

actuator and impart the signal into the ground. Part of the start-up exercise for a new survey is to test the sweep frequencies, selecting a range that minimizes the noise the vibrators generate and maximizes the reflected energy across all frequencies in the sweep. Each sweep may last from just a few seconds to 30 seconds or more while in most instances they last between 10 and 16 seconds. The vibrators may execute multiple sweeps at a single location with all of the data summed together in the recording unit to increase signal to noise (s/n). Positioning of the vibrators is initially surveyed during layout and then the final position is determined using GPS and transmitted to the recording unit.

- Other sources that may still be in use include weight drop, land air gun, and for shallow investigation, sources like the sledge hammer,



and the shotgun source shown in the picture. These are not normally used in oil and gas operations but may be effective for surveys such as shallow refraction spreads.

- Land survey design criteria

  - Surface Consistency – one part of designing a seismic acquisition program on land is that the design will address the requirements for a surface consistent processing approach. This is significant in that failure to meet these requirements may result in inconsistencies in statics calculations, amplitude and wavelet stability. Surface consistency dictates that there must be within the survey points which provide reciprocity between source and receivers that couple the entire line or 3D survey.

  - Offset requirements – for Land data the same criteria as referenced above for marine data holds. Offset distances are key to imaging both for depth of investigation and migration apertures as well as velocity determination. Multiple attenuation is a separate issue for land data as the dominant multiple type in land data is inter-bed multiples and offset is not in all cases sufficient to attenuate inter-bed multiples.

  - Azimuth requirement- It is very important parameter to study fractures, faults and anisotropic behavior of formation. It depends on the receiver line interval and length of the receiver line. It is basically planned during acquisition phase.

  - Source interval – the source effort in many cases has the most significant cost impact. If explosives data is being shot, the time involved in drilling the shot holes and handling the explosives add to costs. For vibroseis surveys the time on each source point is dependent on the number of sweeps and length of each sweep and the listen time. For a 10 second sweep and 6 second listen – six sweeps per VP with move-up between each sweep, the time per VP can exceed 5 minutes. Add to this the time for preparing the line, and although it is a very efficient process, the time quickly adds up. However, the source interval helps define the fold that will be acquired for the survey.

- Receiver Group Interval – The receiver group interval is designed with the primary goal of establishing the trace spacing that images the subsurface without aliasing. Aliased data provides ambiguous results in terms of the dip of a formation in the stacked or migrated data and in the pre-stack data may result in ambiguity in the velocity determined in processing. Modern acquisition crews have high channel count and are able to provide a sufficient number of channels to design for tight group intervals. The group interval defines the CMP interval in the processed data. It is possible in processing to combine two adjacent CMPs (which would increase the fold), if desired, to improve signal to noise of the data.

- The Sample Interval and Record length are selected to ensure sufficient data is acquired to image the formations of interest and normally to allow for imaging to basement unless the data is in a very deep clastic basin.

- Field Filters are normally not selected to aggressively filter the data in the field for the reasons discussed below about the use of 24 bit A/D converters. Severe ground roll may dictate some filtering in the field but this is a parameter that should be tested in the field before finalizing parameters.

- Geophone arrays – Seismic data onshore and at times in transition zone surveys are recorded using geophones or accelerometers that detect motion. The geophones are in most cases strung with multiple geophones on a single cable wired in series or series/parallel. The geophone array in theory is designed to attenuate unwanted noise and enhance signal. They do this by spreading the geophones over an area or along a line. Principally, the array attenuates a horizontally propagating wavefield since the geophones wired in series are all receiving the signal at different times based on the spacing of the geophones. Theoretically, the array enhances the reflected seismic signal since the assumption is the signal is received simultaneously on all geophones as a vertically propagating wavefield. Small intra-array statics caused by elevation differences or velocity differences in the near surface can cause the "signal" to also be attenuated to some degree. Geophone array designs must be carefully considered since they provide minimal attenuation to horizontal wavefields (typically ~13 dB) and can have an impact on the amplitude of the desired vertically propagating wavefield.

- Seismic Acquisition Systems –All modern seismic acquisition equipment has evolved to use a minimum of a 24 bit A/D converter. The number of bits in the A/D converter directly relate to the dynamic range that the recording instrument is capable of faithfully recording. Older seismic acquisition systems going back as far as the DFS V systems used a gain ranging amplifier as the front end to the A/D converter. While this allowed the recording of a wide range of amplitudes, it resulted in data that did not faithfully record the relative amplitudes in all cases and if there was a high amplitude event (such as a direct arrival) the system may not be able to detect the smaller amplitude signals in the presence of the larger amplitude events. This also drives decisions about the recording filter used because if ground roll is an issue and it is overwhelming the signal, the use of the filter meant that even though there might be seismic signal desired in that low cut filter range, the data was attenuated along with the noise.

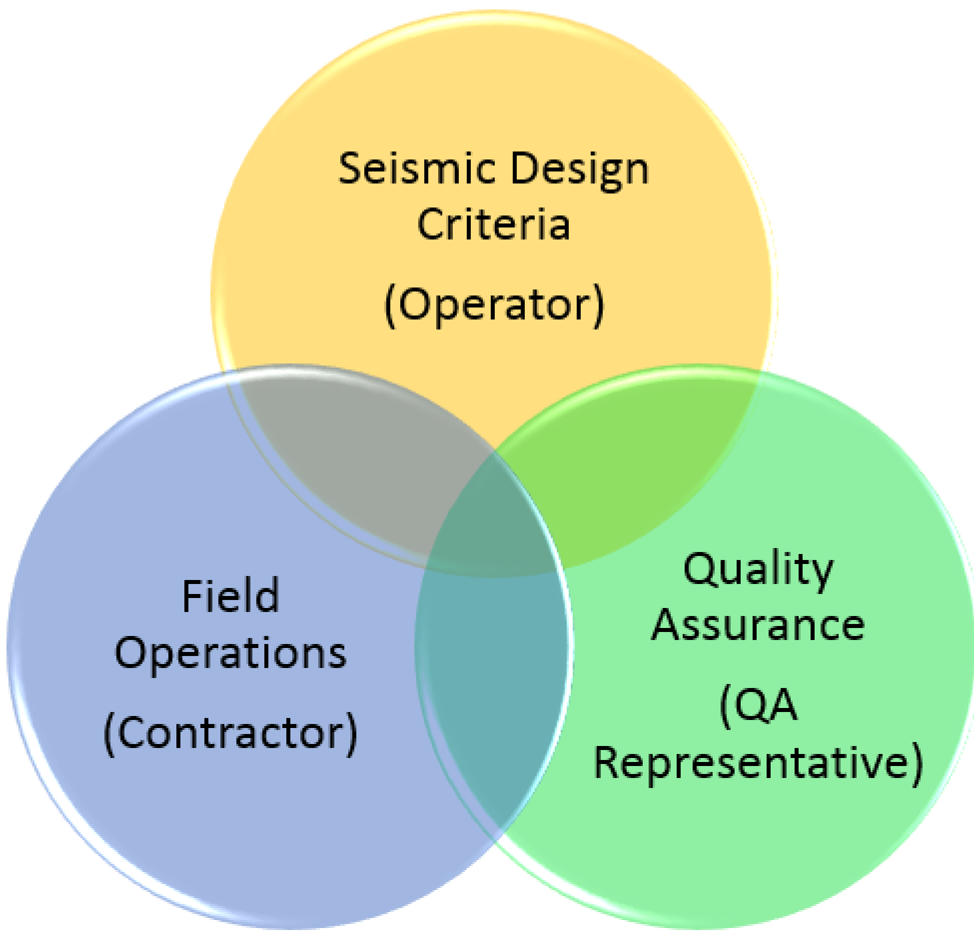
- Marine Systems – most marine systems utilize streamers with the A/D converters located in the streamer. This technology allows the digital signal to be translated through the streamer wiring and eliminates the issue of cross-feed between channels in the streamer. The recording system on the vessel collects all of the data. All collected data are written to a permanent media on the vessel itself for further usage and storage. The recording system is where the validation of the seismic streamer functionality takes place as the observer is able to review shot records as well as system tests to ensure all channels are functioning properly. Seismic acquisition contracts have specifications established by the Operator to define the number of bad or dead traces that may be allowed during the survey. Failure to maintain the system operating at that standard will require the contractor to reshoot data that is outside of specifications.

- Land Systems – There are basically two types of land systems – cabled and wireless. The cabled systems have physical cables that are connected with receivers throughout the field to bring the data to the recording unit. Typically there are remote receiver units in the field that have the A/D converters and filters set and those units transmit the data at the end of each shot. In some cases, there are units that are able to retain historic information for a given period of time before that data is overwritten by subsequent shots. The primary issue in very high channel count systems is the bandwidth of the cable / remote unit systems to transmit all of the data to the recording unit before the next shotpoint or vibrator point is activated. Wireless systems come in two types, those that can transmit the data to the recording unit and those that maintain all data within the unit until it is downloaded through either a wired connection, radio link, or physical connection to the recording system.

- Selecting a recording system – the recording system selected for a seismic survey is normally based on the availability for the Contractor with the winning bid on a survey. In all cases, the system selected should be using the 24 bit technology. Wireless systems that do not send data back to the recording unit immediately can be of concern due to the uncertainty of whether data was successfully recorded. In these cases the best solution is to ensure the geometry design in the field can tolerate missing traces and still achieve the survey objectives.

- Transition Zone surveys are a hybrid between the marine and land survey techniques. Special consideration must be made to determine the optimal source and receiver relationship and considerations for how the data will be collected and ultimately processed. Typically in Transition Zone surveys the dominant factor will be the land and shallow marine segments as they follow the same sort of design rules for the receiver configuration as a land survey. The source in the transition zone can be more problematic and there are options to use shallow water source vessels as well as shooting into the land / transition zone spread from the streamer vessel simultaneously as it is surveying offshore. This special case requires unique skills and capabilities and cannot be covered to a full extent here. Selection of the right contractor is going to be critical and often that does not lead to the lowest cost option.

- Seismic Field Operations – Seismic operations whether they are marine or land based are complex operations. During the conduct of the survey the Contractor is working under the design parameters provided by the Operator to generate the raw data. Critical steps in the field operations are overseen using specially trained Quality Assurance personnel. The Quality Assurance representative works alongside the seismic crew to verify they execute the survey to the Operator's specifications. In most cases, the QA staff are third party Contractors hired by the Operator. A QA representative has specialized skills and knowledge of the instrumentation, survey, and the operational needs for a survey. These individuals do not have the skillset that the operating company geophysicist has but complement those skills.



  - Marine QA – Marine survey QA includes considerations for the following
    - Vessel Positioning & surveying
    - Seismic Recording Instruments

        - Seismic Source Controls
        - Operational considerations
        - Knowledge of how all the systems interact
        - Seismic Record Quality checking
    - Land QA – Land Survey QA requires the following skills and responsibilities:
        - Surveying
        - Permitting
        - Project coordination
        - Explosives source deployment and execution – Operators are responsible for providing the offset distance requirements to the contractor and monitoring impact.
        - Vibroseis operations, deployment and execution
        - Recording cable and geophone quality assurance
        - Seismic Recording systems
        - Seismic record quality assurance

- HSE - IAGC has published HSE standards for marine and land seismic operations and these standards are widely adopted by IOCs, they are available for download from the IAGC (http://www.iagc.org/free-view-downloads/).
- Seismic Acquisition is a significant component of most work programs in PSCs. The quality of the data and ability to evaluate the hydrocarbon potential of a block is directly dependent on the effort placed on the planning, quality assurance, and execution of these projects. The following areas are minimum requirements for a successful program:
- Select a seismic method that meets the needs of the exploration or development program. 2D seismic is normally used for regional grids and 3 D seismic is used to further define the identified prospects as part of exploration projects. 3D seismic is usually carried out when the geological structures are complex and for development projects to optimize well placement and improve the understanding of the fields under development. 3D surveys will also aid in full field reservoir description by better sampling the subsurface and can be used for mapping reservoir properties using seismic inversion to demonstrate lateral changes in the formations of interest. Selection of these methods also depends on the geographical and geological set up of the area.
- Design seismic surveys to meet the spatial and temporal resolution requirements of the exploration and development programs.

- Optimize the survey design to ensure the subsurface geology is best imaged. Consider strike versus dip orientations and optimize the design based on imaging criteria.

- Model the acquisition plan and validate the parameters to address any anomalous velocity characteristics of the subsurface. Consider whether an anomalous (e.g. low or high velocity) zone requires undershooting and determine whether the geometry selected will enable imaging beneath that zone.

- Pre-plan the seismic processing flow to address identified subsurface issues and test the acquisition parameters in the field to ensure the methods being employed meet the program objectives. If amplitude studies are part of the processing and interpretation flow, consider the requirements those studies place on the raw field data. Design the survey with adequate migration aperture to ensure the final imaged dataset covers the exploration or development area.

- Pre-Tendering planning of the seismic project will include determining the geological objectives for the survey, determining the appropriate technique to be employed and in many cases modeling the expected seismic response to ensure the survey can meet the objectives. Operators are responsible for ensuring the survey parameters are clearly defined and communicated to the seismic contractor.

- Tender evaluation must include consideration of the equipment to be deployed. The significant issue is not the age of the equipment but whether it is capable of meeting the survey objectives. In some cases older equipment will meet the objectives but the survey may take longer to execute. All of these considerations must be evaluated.

- Pre-Survey audit of the seismic contractor's equipment, personnel and processes are normally conducted by a seismic Quality Assurance specialist. The assessment will include consideration of the HSE, hardware capabilities being able to meet specifications, and environmental impact risks posed by the Contractor.

- Onboard or Onsite representation by the PSC Operator is imperative to ensure the seismic contractor is operating according to plan and meeting the environmental and HSE stipulations. The QA representative is also responsible for ensuring the data quality meets the survey requirements.

- Dynamite offset distances published by IAGC are recommended as a minimum standard absent any real time monitoring of the seismic source. Accelerometers may be placed adjacent to structures or pipelines as necessary to monitor ground acceleration as a result of dynamite operations; however, the Operator is responsible for the final approval of offset distances used for any survey.

- A final report from the Operator is required and should be submitted along with the data forwarded for archival. The report should summarize operational details and parameters; HSE Statistics; issues during the acquisition project along with their resolution; surveying and positioning systems used; and include the final report from the contractor, Quality Assurance, and Marine Mammal Observer if required.

- Seismic operations particularly on land can impact local land owners and in agricultural areas may result in some crop damage. A Particle Motion sensor may be deployed during surveys near buildings or bridges to monitor that actual impact of the seismic sources and may prove instrumental in proving to local building owners that a seismic source was not responsible for damage. Compensation for damages is an issue that must be managed carefully to avoid damaging relations in the local community and potentially impacting the ability to continue exploration activities in the area.

- Offshore seismic operation frequently encounter fish nets or traps and all reasonable effort to manage the impact is suggested. Early and frequent communication with local fishermen may help to eliminate some of the claims for damaged or lost equipment.

1.2.3 References

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1.3 *Geophysical Practices – Seismic Processing*

1.3.1 Definitions and Discussion

Seismic data in the oil and gas exploration and production process can influence a wide variety of interpretation results. The most basic interpretation effort yields structure maps in time that can be converted to depth through the use of velocity functions. Other uses for seismic data include acoustic inversion for rock properties, elastic inversion based on Amplitude versus Offset (AVO) or Amplitude versus Angle (AVA), Anisotropic analysis for fracture analysis, 4D Seismic for production monitoring, and more.

Seismic data processing takes the field data and transforms it into products that enable the geophysicist or geologist to interpret the subsurface geology based on it. There is no "standard" processing flow for seismic data but there are generally best practices that apply to land or marine data. Likewise, those processing flows are more refined for 2D versus 3D data but those differences are primarily in the specific algorithms used. The different algorithms are typically based on the individual issues that are identified with the field data and are meant to improve the signal quality at the earliest stage possible in the processing flow such that noise does not propagate through subsequent processing steps.

One key consideration with seismic data is comprehending the resolution of the data. Processing is the art of retaining and emphasizing the resolution that was obtained in the acquisition phase. There are many discussions about seismic resolution, both temporal and spatial. The Temporal Resolution is the vertical resolution of the data or a measure of how thin a bed may be either detected or have the top and base of the unit resolved. Thin bed analysis uses tools like amplitude analysis for calculating bed thickness based on the amplitude variations when the data is calibrated to wells and can be consistently mapped. The Spatial resolution is the ability to detect the presence or absence of a unit based on the sampling of the data. Narrow channels may require denser sampling in order to first detect and then resolve the presence of a particular channel sand body.

High Density or High Resolution surveys as discussed in Section 1.2 are special cases in the use of reflection seismic data. They specifically referred to either the spacing of the seismic traces or the ability to resolve thin bed units through greater seismic bandwidth and in fact result in a combination of both. The approach to process these types of data is not distinctly different from any other exploration processing project; however, the level of detail in the desired survey results dictates a higher degree of quality assurance to ensure the veracity of the data remains intact. Imaging criteria, intervals between velocity locations, and selection of parameters to maintain bandwidth all must be addressed.

Definitions of key terms is shown below:

- Seismic Processing Datum – Seismic sources and receivers are normally not co-located on the same vertical level. This is true for both land and marine seismic data. To account for the differences, a datum correction is applied to processed seismic data to shift the data to a known horizontal surface. To move the data, a correctional velocity is used. Land data is normally processed at a floating datum which means that the data is shifted to a datum that is relative to the surface elevation at the CMP location. One of the final steps in the processing is to move the data to a flat datum that is defined by the operator. This datum is called SRD (Seismic reference datum).

- Uphole Times – in processing explosives data, a common step is to add the travel time captured by the uphole geophone for each shot to move the shots to the surface elevation. The uphole times are reflective of the shallow velocity field in the survey area and may be used to develop a near surface statics model.

- Surface Consistent algorithms as discussed in the seismic acquisition section are important for land processing since they provide a means to address variability in the near surface in the statics correction, variability in the wavelet in the surface consistent Decon, and amplitude differences that are consistent at specific recording stations using the surface consistent amplitude corrections. The amplitude correction is at times used on marine data. Even though it does not obey the source criteria for surface consistency, it enables balancing of traces to eliminate amplitude differences due to electronic circuitry or receiver sensitivity.

- Noise Attenuation processing – dominantly the Random Noise Attenuation type of algorithms are designed to help remove noises due to production facilities that may be near the receiver spread.
- Both the land and marine data processing flows show Pre-Stack Time Migration (PSTM). It deals with complex geological structure where stacking does not work well. Nowadays it is routine practice to run PSTM. It gives seismic volume in time domain.
- Both the land and marine data processing flows show the optional Pre-Stack Depth Migration (PSDM). PSDM is used for several reasons:
    - To address abrupt velocity variations (mainly lateral velocity variation)that cannot be resolved through PSTM;
    - It addresses significant velocity inversions such as the effect of salt above sedimentary section of interest; and
    - For significant structural deformation it may yield better imaging of sub-thrust stratigraphic sections.

  PSDM does however require a velocity model that is more rigorous than PSTM as a starting point. The PSDM velocity field is more closely attuned to the geological model of the subsurface, so interaction with the interpretation team is critical to success.
- 2D land data in some instances is recorded such that the source and receivers are not in a straight line and they do not lie on the same vertical plane. As a result, crooked line processing is used in which the data are treated more like 3D sampling and the data are "binned" with the data gathered into Common Midpoint (CMP) gathers for processing, with the CMP centers being off of the line of source and receivers.

1.3.2 Best Practices

Like seismic data acquisition, processing is a specialty that requires knowledgeable geophysicists engaged from the original field design effort through the determination of the processing flow and subsequently in the quality assurance throughout the processing phase of the project. These quality assurance steps are critical to the proper selection of the processing steps and parameters used at each step. Due to this need for detailed input from the operator, these personnel may not be members of the operator's staff and are typically specialists brought into the project specifically to ensure quality results.

Few Operators have their own processing capabilities although many major E&P companies have processing centers where proprietary algorithms are developed and may be used in the processing of the data. These proprietary processes are not normally licensed to contractors and as such the ability to use this technology is limited to in-house processing centers. To maximize the value of seismic data, operating companies need the ability to employ proprietary technology by allowing for the data to be exported for use in processing centers where that technology is available. These will be addressed further in answer to another query in this report. Likewise, there are some "boutique" seismic processing contractors that have unique experience and capabilities beneficial for specific geological conditions. For the benefit of the host country, the ability to use the best available technology needs to be ingrained in the processes for managing the processing and interpretation of geophysical data.

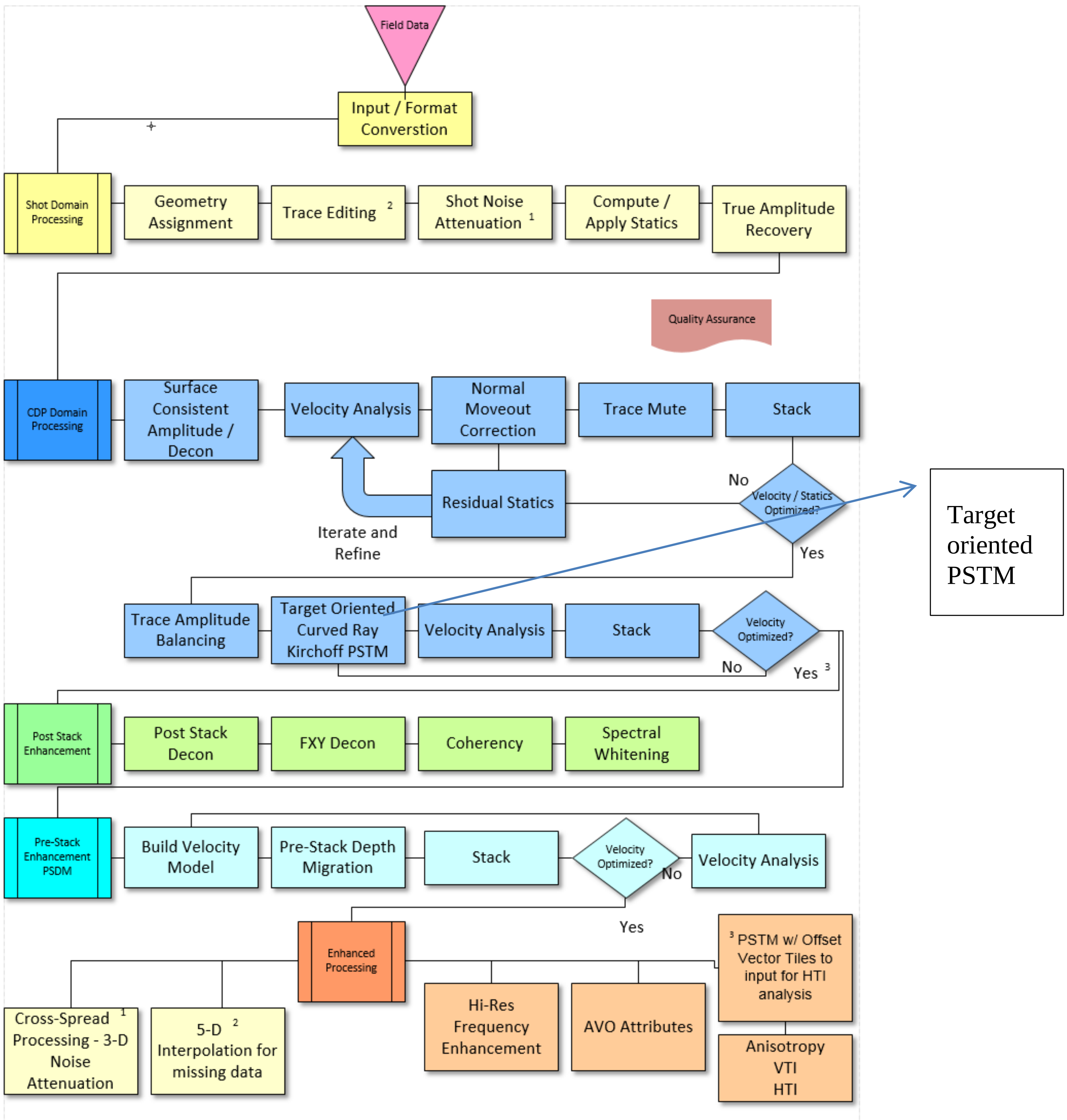
The objective of the processing step is to insure the best possible image of the geology is developed. This requires participation by the geologists and geophysicists working on the interpretation of the area along with the seismic processing specialists. Imaging is the focusing of the data that was acquired into a properly positioned and accurate representation of the structure and stratigraphy in the exploration area.

The best practice for processing seismic data is at its most basic level to ensure that the processing flow employed fits the demands of the data and the imaging criteria for the final product. Every geological environment has a unique set of challenges and as such a processing flow that will address the challenge is developed during the processing of that data. Processing tests are designed to evaluate the parameters to be used at each step of the flow and are revised if the results are found to not resolve data quality issues. Every project should have a defined testing program that will evaluate at a minimum the Deconvolution, Noise Attenuation, Velocity picking density requirements, the proper imaging technique (Migration, Pre-Stack Time or Depth Migration), and the final scaling and archival of data.

- Land Seismic Processing
    - Land seismic data has some unique characteristics that dictate the processing flow for the data. Due to the sources and receivers being located on or near surfaces that have variable velocity, elevation, geological formations and conditions, land seismic data requires unique pre-processing steps.
    - The processing flow shown in the figure below is a high level approach for processing land seismic data. It is generally applicable whether the data is 2D or 3D. The flow is intended to be a guideline for what processing steps are needed to generate interpretable seismic data. In this flow Pre-Stack Time Migration is the standard output of the processing flow. However in some areas PSDM is required to address geological challenges. Additional 2D and 3D processing optional steps are shown but this is not an exhaustive list of potential processing steps or output data types.
    - Statics are a significant issue in land seismic data. A typical processing flow for land data would include applying both a surface elevation static correction as well as using Refraction Statics to more accurately resolve near surface velocity issues. After the near surface issues are addressed the processing flow uses reflection statics (surface consistent solutions in most cases) to improve the solution and overall quality of the stacked and migrated data.
    - The Refraction Statics near surface velocity model can in some cases be improved through the use of uphole surveys that are designed to record the near surface velocities. The velocities measured in the uphole survey can be used to calibrate the refraction statics velocities. The Refraction Statics model is used to eliminate long wavelength velocity anomalies in the near surface and enable better signal to noise by removing jitter in the CMP gathers associated with anomalous velocity in at the source and receiver locations.

- Enhanced processing steps shown in the figure are of two types. There are the regularization or noise attenuation capabilities that go beyond normal processing flows. These tend to be incremental steps when provided by processing contractors and are meant to improve the data in the beginning of the processing flow. There are also "interpretive" processing results that can drive the manner in which the seismic data can enhance the interpretation results. These processes such as extraction of AVO attributes or Anisotropic Velocity attributes typically lead to better processed images, but also allow for output of analytical results that influence exploration. Anisotropic velocity analysis can lead to better definition of fracture orientation and density that is critical to drilling exploration or development wells in fractured reservoirs or tight shale plays. The input requirement for this analysis includes having recorded source – receiver azimuths over a wide distribution of orientations. Wide Azimuth acquisition techniques are required. As a result this is normally limited to 3D data.

- The Processing Flow shown here is indicative of the level effort for processing the data but is not intended to be either all-inclusive of technologies available or to replace expertise that a knowledgeable seismic processing specialist brings to a project.



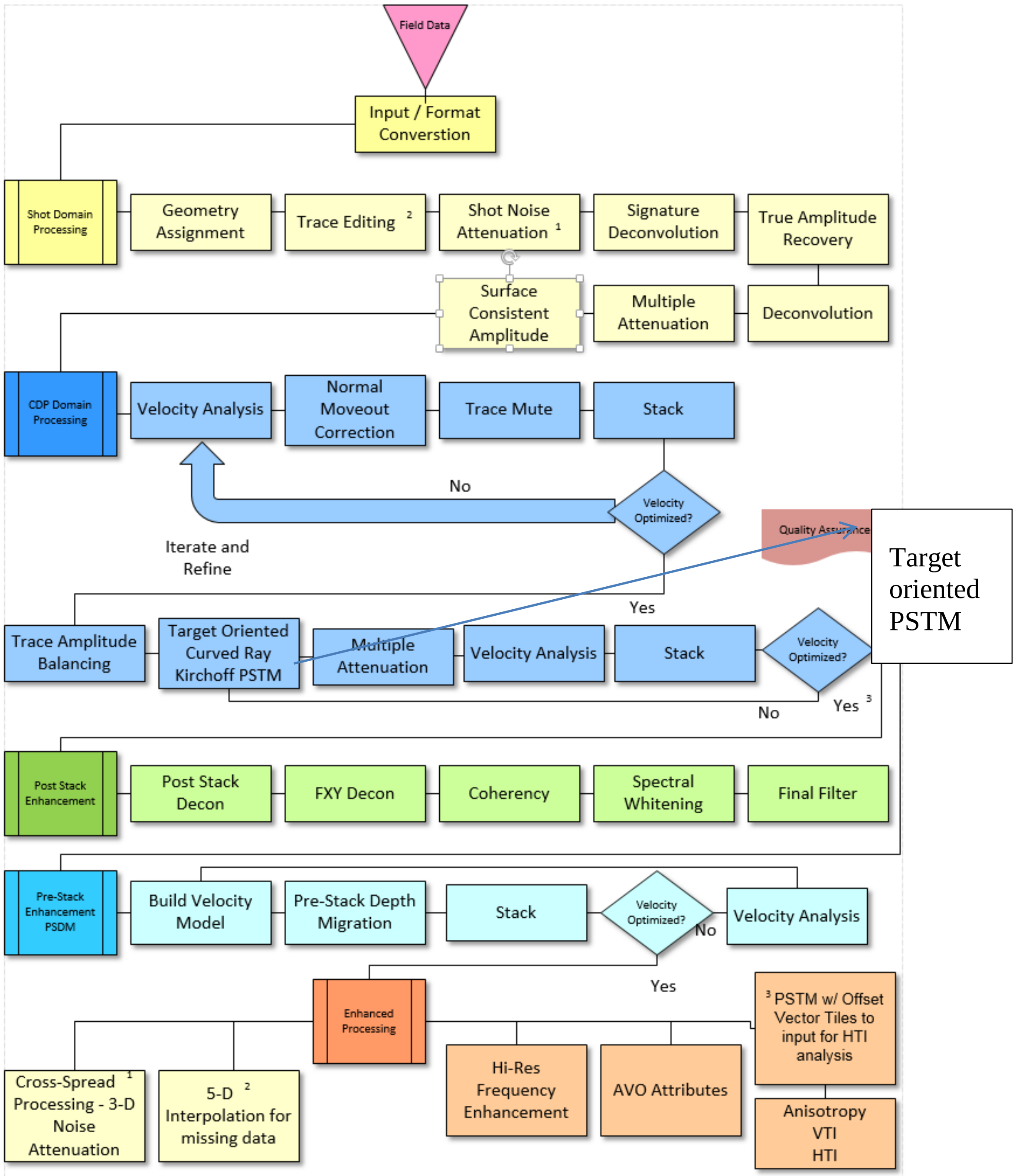
Generalised Land Seismic Processing Flow

- Marine Seismic Processing brings with it a different set of processing challenges. Generally speaking marine seismic data is better quality than land data, partially owing to the more consistent generation of source energy and consistent coupling and recording in the streamers. The processing flow shown in the figure that follows depicts the typical set of processing steps for marine seismic data.

    - Signature Deconvolution is normally applied to marine seismic data. The process is made possible due to the consistency of the seismic source and the ability to effectively model or measure the source signature. In the processing flow, signature deconvolution corrects the phase of the seismic data through the use of an inverse filter to move the data to zero phase. This enhances the temporal resolution. This enables the interpreter to more reliably interpret a peak or trough to represent an increase or decrease in seismic impedance.

    - Multiple Attenuation processes are very effective on marine data although they can be present in land data too. There are a variety of algorithms that are currently under development as well as in production that can remove water bottom multiples, free surface multiples, and interbed multiples. Each contractor has their own approach and depending on the severity of the problem the operators may elect to process the data at a contractor with a specific algorithm.

    - The Processing Flow shown here is indicative of the level effort for processing the data but is not intended to be either all-inclusive of technologies available or to replace expertise that a knowledgeable seismic processing specialist brings to a project.



Generalized Marine Seismic Processing Flow

- 2D Seismic Processing - There are few issues in seismic processing that are unique to 2D data. A significant difference between 2D and 3D processing in complex structural regimes is the impact of the orientation of the lines with respect to the structure and whether the 2D image is in the plane of the line. Out of plane structures will result in velocities that are not geologically reasonable, so understanding the geology is important when processing the data.

- A minor complication in processing is the proper recording of the position of the trace. Shotpoint and receiver positions are used to calculate the location of the CMP. There are typically more CMP locations than shotpoints and this especially becomes an issue in loading stacked seismic data into interpretation workstations. The original shotpoint locations are not necessarily relevant after the data is processed, yet systems still enforce shotpoint locations for the seismic traces. It is important to be aware that the CMP location and numbering is what should be used when loading the traces into an interpretation database.

- 3D seismic processing is unique in that it utilizes a binning system that may not have any relationship to the original shotpoint or receiver locations. The binning system calculates a grid over the survey area into which all of the data are collected. CMP positions are calculated for each trace and the traces are gathered into the bin nearest to the calculated CMP position. In Wide Azimuth surveys the orientation of the azimuth between the source and receiver station for each trace is also retained. This information is subsequently used when anisotropic velocity analysis is performed on the dataset.

- Most seismic processing projects are undertaken by third party contractors although in some large companies the ability to process the data internally is available. In all cases the need for quality assurance of the processing is necessary. Quality Assurance is essentially a technical audit of the approach being used to process the data.

- The Quality Assurance effort is focused on two levels. The first is that the appropriate application of technology is upheld. Experienced processing professionals review the results during each phase of the processing project to ensure the technical solution fits the underlying data. An example of this would be reviewing a refraction or reflection statics solution. Do the refractions appear to have been properly picked? Is the cable geometry appropriate for the Surface Consistent Statics solution? These are but a small sample of the areas requiring technical audit. The following list is an example of some of the areas to be evaluated during the QA process. It is not an exhaustive list nor does it address the degree to which newer technologies may be properly or improperly applied.

    - Amplitude Recovery – Test to validate the amplitude balancing of the raw shot records at the beginning of the processing flow;

    - Initial Filter – Does a frequency filter need to be applied early to clean up shot records?

    - Kill Bad Traces – Review random shot records to determine whether the processors are eliminating bad data from the processing flow before it can have a detrimental effect on the overall end product;

- Source Noise Attenuation – Are there source generated noises (ground roll, surface waves, etc.) that should be removed before processing?

- Shot Domain Deconvolution – Tests are done on the shot records to compare different deconvolution approaches. Deconvolution is an effort to balance the frequency spectrum early in the processing flow and will have an impact on the stability of the wavelet as velocity and statics solutions are applied;

- Multiple Attenuation – Are there shot domain or receiver domain multiple attenuation approaches that might impact the ultimate quality of the final product. Determine the appropriate methodology to be applied for attenuating the multiples. This is an area of extensive research in the industry and there are a wide variety of approaches. Different processing vendors will have either algorithms they have developed or experience from processing similar data that will impact the approach used. The experienced QA person will need to ensure there are tests and displays of fundamental data that validate the approach used has eliminated noise without impacting the underlying reflection data;

- Geometry Assignment – This is an area where the processor can have errors that will significantly impact the final product quality.

- Statics Solution – Both the refraction and reflection statics model must be reviewed to determine that they have been properly resolved;

- Velocity Analysis – Processors normally start the processing with a single velocity for a line and then progressively increase the density of velocities from 1 km spacing to 250 m as they progress through the processing sequence as the velocities will determine how accurate the normal move-out correction will be and hence has an impact on the wavelet stability and temporal resolution of the data. QA needs to focus on the velocity picking effort.

- Stacked Sections – Reviewing stacks along each step of the processing is critical. They help to illustrate issues with the geometry, velocity picks and all of the individual processing steps.

- Migration – Either Pre-Stack (PSTM) or Post Stack Time Migration can be used for both QA purposes to see how the overall section is developing or to finalize the output.

- PSTM Velocity picking – there are several approaches to PSTM velocity picking. Depending on the approach the critical element is to QA each line to validate the velocity picks are optimizing the focusing of the final output image. Due to the fact that there may be constructive interference that affects amplitudes, picking maximum amplitudes for velocity imaging is not always the right solution, this requires user input.

- PSDM Velocity Model – for Pre-Stack Depth Migration (PSDM) the process is driven by the velocity model. An initial model normally taken from the PSTM solution must be modified to fit the best geological interpretation. Iterations of the velocity model are used through tomographic imaging and user input to optimize the final output. PSDM may be a standard output for certain areas but will be limited to areas where a reasonably accurate velocity model can be developed based on the time sections. In areas where severe horizontal velocity variations and / or complex geological structures are present PSDM is preferred but may be limited by the need for a detailed velocity model as a starting point.

- There are many steps to be audited during the processing of seismic data and these require a trained eye of the processing specialist. The second level of quality assurance is that the geological model must be represented by the final processed section. The interpreters must be involved in validating that the processing approach being used is driving the solution towards correctly imaging the subsurface.

- All seismic processing projects including both new data and reprocessing of old data must be thoroughly documented to reflect the objectives, processing steps, and issues encountered during the processing of the data. Some of these observations are from the processing contractor, but an analysis of the results from the PSC Operator are necessary to ascertain whether the processed results achieved the intended results.

- Archival of processed seismic data in several forms is needed to enhance how the data may be used for future analysis or interpretation. The best practice is to archive the data in SEGY format at several stages of the processing such as:

    - After application of Deconvolution
    - After application of noise attenuation processes
    - Final CDP Gathers with statics applied – the input data to the final stack
    - Final Stacked Sections
    - Final Stacking Velocities
    - Final Migrations (either Pre or Post Stack Migrations or both)
    - For Pre-Stack Migrations the Migrated CMP gathers
    - Final Filtered and Gained data
    - Final Migration Velocities

- The SEGY EBCDIC headers must include details regarding the processing sequence used as well as co-ordinate reference system used and clarify the byte locations of key fields used in the processing flow. The format for these headers should follow the content as listed in the Yellow Book from the NPD in Norway unless there are other local requirements in place. Byte location in the stack section should be as per standard SEGY format.

- Processing seismic data is intended to provide a result that best addresses the geological issues in an area. An appropriate processing flow should be developed based on the quality of the input data as well as the geologic objectives.

- Quality Assurance throughout the processing project is required to ensure the geologic objectives as well as the appropriate technology is being used on the project. QA also ensures the processing parameters are appropriately selected for each of the steps throughout the flow.

- All seismic processing projects must include a report that summarizes the objectives of the project, the tests conducted to select the parameters used, examples of data quality issues and how they were addressed, and examples of the final output data. A summary of the seismic lines processed and the output data should be incorporated into the report.

1.3.3 References

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1.4 *Geophysical Practices – Seismic Interpretation*

1.4.1 Definitions and Discussion

The objective for the seismic interpretation and mapping guidelines is to provide seismic and mapping, presentation and documentation standards for budget meetings, management meetings and official documents submitted for approval such as Declaration of Commerciality (DoC) and Field Development Plan (FDP).

Exploration seismic interpretation best practice workflows can be divided into Basin Analysis and Prospect Analysis with expected products and mapping and presentation standards appropriate for the two categories. There may be circumstances unique to a particular block that requires additional products and workflow or data limitations that might preclude some products or require alternative workflows.

1.4.2 Best Practices

- Interpret All Available Data

    - Most blocks have pre-existing data that should be included in the seismic interpretation along with additional purchased and/or acquired data the Operator committed to in their Minimum Work Program (MWP) including pre-existing seismic data, Petrophysical data, well completion reports and Gravity and Magnetics studies. All the previous data and reports should be evaluated along with newly acquired data the Operator committed to in their MWP to develop an integrated interpretation of the seismic data.

- Generalised Seismic Interpretation Workflow for Basin/Block Analysis
  - Well to seismic tie from existing wells and identification of key horizons.
  - Relevant horizons should be identified and mapped along with faults. These horizons should include major stratigraphic intervals distributed above and including the exploration target. The work will culminate in a set of time/depth maps for use in Basin analysis and delineation of prospects. Multiple horizons are needed for basin analysis sufficient to represent the depositional and structural evolution of the basin from basement to most recent stratigraphy. Thicknesses of each unit define the timeframe for deposition—the period of time the sediments have been buried and the depth they were buried to.
  - The Operator should evaluate all the available 2D and 3D seismic data, well data, and other G&G data to prepare two-way time (TWT) and depth maps for the identified horizons, iso-chronopach and isopach maps between the identified horizons. Contractor should integrate the results of the available gravity and magnetic reports as needed while preparing the structural maps.
  - Paleostructural analysis to know the timing of generation of hydrocarbons vis-à-vis formation of structure/ other traps and origin of faults.
  - Seismic sequence stratigraphic study: Recognition of the most significant stratigraphic horizons (major unconformities, maximum flooding surfaces, sequence boundaries, etc.).
  - Seismic facies analysis of the interpreted seismic depositional sequences to know the distribution of reservoir and source/seal prone facies and preparation of play fairway maps.
  - Seismic attributes such as coherency cube (or equivalent) and other structural attribute volumes and maps should be used when relevant to show fault complexity and regional orientations. Attribute maps are generally only created from 3D volumes due to the fine bin spacing available with 3D seismic.
  - Determine the likely source rock distribution with kitchen area and maturation within the basin based on available reports/data/literatures.
- Generalised Seismic Interpretation Workflow for Prospect Analysis
  - The Operator should identify drillable prospects and assess geological risk (chance of success) for each prospect. The Operator should also prepare the geological cross section through the identified prospects and relate them to near-by drilled wells.

- Operator should provide depth maps from the seismic interpretation at relevant expected reservoirs with suitable estimates of the prospective resources for each prospect in Low (P90), Best (P50) and High (P10) categories. The parameters required for prospective resource estimation will be based on the petrophysical interpretation of the wireline logs of the drilled wells in and around the block area as available. Prospective resource estimates can be either deterministic or probabilistic.

- Direct Hydrocarbon Indicators (DHI) and Amplitude Variation with Offset (AVO) should be used to evaluate prospects where appropriate fluid substitution modeling supports a noticeable hydrocarbon effect on seismic or a correlation with nearby production can be established. A DHI that correlates to a closing contour of a mapped prospect should be used as the P50 case.

- In areas/intervals of known over pressure or areas/intervals where there has not been any drilling in the past, the Operator should carry out subsurface formation pressure study – generate pore pressure profile indicating top of abnormal pressure, if any, using well and seismic velocity data over each identified prospect. Operator should generate the pore pressure gradient profile and fracture pressure gradient profile of all the drillable prospects for well design.

- Fault seal analysis should be completed on prospects that require a fault seal either through use of an Allen Diagram to illustrate juxtaposition of reservoirs and seals across the fault or fault smear/gouge analysis for fault planes that are expected to act as sealing surfaces.

* Generalised Seismic Interpretation Report for Basin Analysis

  Operator should prepare comprehensive interpretation reports incorporating the following minimum information/details/maps conforming to regional mapping standards:

  - General Geo-tectonic setting of the block vis-à-vis the basin.

  - Generalized stratigraphic depositional regime.

  - Source rock maturity and distribution, likely source kitchens for proven and/or hypothetical petroleum systems.

  - Synthetic seismogram and/or corridor stack with well markers showing well tie to seismic data for key seismic horizons and/or seismic display with well markers displayed based on a VSP, check shot or other specified means for depth to time conversion illustrating how key well markers are tied into the seismic evaluation.

  - Seismic sequence stratigraphy and tectono-sedimentation model.

  - Seismic facies analysis and its correlation with lithofacies available from existing wells.

  - Seismo-geological sections along dip and strike of basin to be provided.

- Relevant Seismic Attribute analysis (such as Amplitude, Frequency, Impedance etc.).
- Two Way Time (TWT) maps at suitable contour interval on top of the key horizons in 1:100,000 scale over the total block area.
- Depth maps and corresponding average velocity maps at suitable contour interval on top of the key horizons in 1:100,000 scale over the total block area.
- Isochronopach and Isopach maps at suitable contour interval between the different horizons in 1:20000 (for production purposes) or 1:50000 (for exploratory purposes)scale over the block area.
- Map showing reservoir and seal/source facies distribution.
- Play fairway maps including the regional/block wide extent of structure and stratigraphic traps and other plays mapped. Major tectonic elements such as regional faults should be included as relevant.

- Generalised Seismic Interpretation Report for Prospect Analysis

  Operator should prepare a comprehensive interpretation report incorporating the following minimum information/details/maps conforming to Prospect mapping standards:

  - Relevant regional maps for regional context and index map to show where the prospects are located in the block.
  - Risking for each prospect unless such risk analysis is considered confidential by the Contractor.
  - Pore Pressure and Fracture Gradient analysis as needed.
  - Two Way Time (TWT) maps at suitable contour interval on top of the identified horizons in 1:50,000 scale for each prospect mapped.
  - Depth maps and corresponding average velocity maps at suitable contour interval on top of the identified horizons in 1:50,000 scale and/or in 1:25,000 scale over the identified prospects/leads for each prospect mapped.
  - Paleo-structural sections along several key 2D/3D lines across the identified prospects illustrating the generation timing of the prospects and age of the faults.
  - Geological and seismic cross sections through the identified prospects and the drilled wells.
  - Allen fault juxtaposition diagrams as needed.
  - Figures showing results of formation pressure and fracture gradient study as needed.
  - A table giving the resource estimates in minimum (P90), most likely (P50), and maximum (P10) categories, area, pay thickness, IOIP/GIIP.

  - Envisaged petroleum system, hydrocarbon plays, source rock, entrapment model and reservoir model.
  - Soft copies should include: a complete report in the format of either MS Word, MS Excel, PowerPoint, PDF, JPEG, TIFF or GIF, whichever is applicable.

- Generalised Seismic Interpretation Methodology

  A methodology for the 2D and 3D seismic interpretation and supporting Geologic, Geophysical and Petrophysical analysis for a block for the purpose of identifying and evaluating potential hydrocarbon traps / prospects suitable for drilling can be summarized as follows:

  - Data Loading and Quality Control

    - Seismic data and well log information should be loaded and quality controlled to assure correctness in map projection and well trajectory should any of the wells be deviated. A base map from the loaded data should be compared to the maps provided in the DGH Docket to assure correct loading location. Velocity information from the VSP, Checkshot, sonic log and/or seismic processing data should be reviewed for use in Time-to-Depth curves to display well traces on seismic and convert time maps to depth.
    - The information from the wells should be reviewed and analyzed by the geologist and petrophysicist for quality control to assure the best stratigraphic tie of reflection boundaries to the well for use in mapping and prospect generation.
    - Seismic line intersections should be reviewed using seismic transects to verify that seismic surveys acquired and processed by different processors tie in time and phase for an integrated seismic data set. If there are seismic mis-ties, the Operator should apply needed time shifts and/or phase shifts for the best integrated seismic data set. When possible, synthetic seismograms should be used to correct the merged data set to zero phase SEG normal or reverse polarity depending on the preference of the Operator. The polarity convention used by the Operator should be noted in reports and presentations.

  - Seismic Interpretation and Mapping

    - Well to seismic ties based on synthetic seismograms using available sonic, density and check shot or VSP data and wavelets extracted from the seismic should be done to assist in the selection of horizons interpreted. Interpretation of multiple horizons including any major unconformities maximum flooding surfaces, or other important stratigraphic horizons should be performed to enable identification of depositional or structural changes. Major faulting should be identified and incorporated into a block interpretation. This network should be used to determine which faults impact the development of the depositional sequence or potential traps for drillable prospects.

- Structure maps should include major faults, fault networks and identify prospective features. Maps should be refined as needed at potential prospect locations. Prospect maps should define the most likely and maximum closures for significant prospects on each prospective reservoir map. Any special anomalies and/or seismic attributes associated with prospects should be noted and used to assess geological implications on risks and/or potential hydrocarbon distribution. Information from other attribute volumes should be used as appropriate to delineate faults and/or evaluate prospects.

- The velocities from 2D and/or 3D seismic should be reviewed for velocity variations. In areas of overpressure due to under-compacted sediment, the seismic velocities should be calibrated to the well and pore pressure information of a drilled well should be used for pore pressure analysis to identify potential over pressured zones that should be considered for well plans. The most appropriate depth conversion method for the geologic area given the complexity of lateral velocity variations of the overburden, should be utilized to convert from time maps to depth. Depth conversion should include depth structure maps and isopachs for all horizons and the depth conversion method used should be documented.

- Geologic Framework

  - The Operator should create a tectono-stratigraphic framework of the region using the seismic tied to the wells on the block, incorporating regional geological data from a basin-wide context. Isochore maps should be prepared to provide quality assurance that horizons were mapped in a geologically meaningful way across faults. These maps should also be used to illustrate paleo lows where reservoir sands may be more likely to have accumulated and review timing of the structures relative to hydrocarbon generation and migration. A composite map of fault polygons should be provided to show that faults were interpreted consistently and sensibly for all key horizons. The work will culminate in a set of maps constructed on all horizons of interest, incorporating major tectonic elements,

- Petroleum Analysis Summary

  - Operator should evaluate petroleum generation and migration potential to the mapped prospects in the context of the existing wells in the block and existing studies of the petroleum system. The Operator should conduct a dry hole or failure analysis on the existing wells within the block with all the pertinent well data available such as core reports, mud logs, and geochemical reports etc. The Operator should assess the volume, quality and maturity (including migration efficiency) of the principal source rock interval(s) based on existing geochemical analysis results and reports. The Operator should estimate the phases and timing of petroleum generated and available for trapping. The Operator should identify and assess the volume (gross and net), quality (porosity and permeability), and distribution of the major reservoir intervals using any available analogues to evaluate potential production rates. The Operator should identify and evaluate the principal regional seals in terms of both presence and effectiveness. In areas of limited data, the petroleum system analysis may rely on existing publications and government geologic reports.

- Play Fairway Assessment

  - Define play types based upon principal reservoir intervals and their access to regional source and seals. Review, collate and prioritize all potential trapping mechanisms.

- Prospect Evaluation / Prioritization

  - Operator should review and summarize all data relating to each significant prospect identified, including at least two key seismic lines that define the trapping mechanism. To the extent practical, target depths will be considered in the context of reservoir quality prediction and estimation of formation volume (Bo) factors for oil and/or gas expansion (GEF) factors. The key geological risk factors of trap (presence and effectiveness of trap and including seal consideration), reservoir (presence and quality) and source (presence, maturity and migration efficiency) will be combined to derive overall geological risk.

  - Volumetric estimation of Stock Tank Oil Initially in Place (STOIIP) and/or Gas Initially in Place (GIIP) will be made on all prospects by combining gross reservoir volume (area multiplied by gross thickness) with averaged estimates of net-to-gross ratio, porosity, hydrocarbon saturation, fluid data (Bo/GEF) and volumetric conversion factors. Depending on data availability, a range of input factors will be included, and as requested, Operator should calculate Deterministic and/or Probabilistic resources on all significant prospects (i.e. those surpassing minimum thresholds of size and risk) to derive a distribution of volume versus probability. Commercially recoverable volumes should also be estimated by including a range of recovery factors.

  - Based on the Prospect evaluations described above, Operator should develop a drilling prioritization schedule, together with recommended drilling locations. Operator should make any recommendations they deem necessary to reduce the risk of the prospects.

- An industry standard seismic interpretation workflow has been provided for the analysis of an exploration block. Operators should follow the workflow above for most exploration blocks; however, certain geologic and economic considerations or data limitations may require other approaches to meet their exploration needs. It is recommended that the above workflow be made available to Operators as a reference for an acceptable workflow to evaluate most Indian exploration blocks; however, certain details related to risk analysis, resource calculation and certain company proprietary methods, although essential to the exploration process and useful to clarify interpretation results, may be excluded or generalized for meetings and reports outside the company.

1.4.3 References

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5. Davis, R.K., An, D.A. Medwedeff, & D. Yarwood. 1999, Fault seal analysis, offshore Myanmar: A case study. AAPG Hedberg Conference Special Volume, 1999.

1.5 *Geophysical Practices – Gravity Surveys*

1.5.1 Definitions and Discussion

Gravity and magnetic data are measurements of the potential field variations based on the total field measurement consisting of the mass of the earth or the earth's magnetic field in which local variations in the subsurface geology influence the measurements. These local variations are directly related to the density or magnetic susceptibility of the formations within the basin. The potential field methods are generally used for basin scale investigations to define large scale variations in the earth's crust, primarily due to the fact that the cost of these surveys is significantly less than other technologies. The exception to this is some high resolution surveys that are used to better predict the occurrence and distribution of features like major faults and salt domes.

Gravity and Magnetics are the two most dominantly used potential field methods employed worldwide. However, there are a number of other potential field methods that are used in either special circumstances or when those methods provide greater insights than other tools. Other methods include but are not limited to, Magneto Telluric, Controlled Source Electro-magnetic, and micro gravity. All have in common the fact that they use indirect measurements of the properties of the geologic features and normally require a model based solution to evaluate the observed responses. In most cases, the model(s) developed are non-unique solutions and for this reason, other technologies such as reflection seismic data take a more prominent role in the Exploration and Production operations since they are more closely associated with observable and quantifiable measurements of rock properties at a specific location. This document will not attempt to address all of the potential field methods, but has focused primarily on Gravity surveys as they are the most frequently used technology.

Acceleration is the measure of gravity expressed as mass dependent term. At the Earth's surface, the gravitational acceleration ranges from about 9.83 meter per second squared (ms^{-2}) at the poles to 9.77 ms^{-2} at the Equator.

Units used in gravity survey are:

Micrometer per second squared (μms^{-2}) = 10^{-6} ms^{-2} (the SI units)

Milligal (mgal) = 10^{-3} cm s^{-2} = 10^{-5} ms^{-2} = 10 μms^{-2} (the traditional CGS unit)

Gravity unit (gu) = 1 μms^{-2} (the old American measure = 1 meter scale division)

Microgal (µgal) = 10-8 ms^{-2} = 0.01 μms^{-2} (often used for absolute measurements)

Newton meter per kilogram (Nm.kg-1) = 1 ms^{-2} (an alternative form of units)

Gravity is a useful tool for investigating deep tectonic structures. It is used for outlining sedimentary basins, rifts, faults, dikes, or sills, granitic plutons, regolith drainage patterns, or kimberlite pipes. A surveyor should first decide what he is looking for, and then design the gravity survey accordingly.

Gravity can help in mapping subsurface geologic structures where the rocks have significant density contrasts. Gravity surveying is only useful if the subsurface geological structure involves bodies of different density. The density contrast between the rock bodies must be high enough to give gravity anomaly higher than the background noise recorded in the survey. Gravity will not be the best tool for the job if the differences in magnetization or susceptibility are more characteristic of the rock bodies than the density changes.

The geologic structures may vary in density in the direction of the measurements; flat lying strata of constant thickness will not give any changes in the anomaly at the Earth's surface. Also, a complicated geological structure at depth may not give a signal at the surface that can be resolved into separate anomalies. In these cases, a seismic survey will be more effective.

The optimum observation spacing for the gravity survey will be determined based on the size and depth the bodies the surveyor is looking for. For shallow bodies, an observation spacing may equal to the dimension (in the measurement direction) of the body or twice the dimension for deeper bodies will detect the existence of the body but not define its shape. In order to get any reasonable idea about the shape of the body, observations should exceed the dimensions of the body.

If the Operator is interested in structures of dimensions less than the spacing of the existing gravity coverage in the area, then the Operator should see some evidence of these bodies in the existing anomaly pattern. However, if the structures have no significant density contrast, the anomaly pattern will be featureless. In performing a gravity survey, it is important to look at the existing data and use that in the decision process and survey planning.

1.5.2 Best Practices

- Gravity Survey Design – Choosing Survey Parameters

All of the following parameters are considered when planning a gravity survey. Careful pre-planning can avoid significant issues when executing the survey in the field.

- Orientation
  - In case of existing subsurface structure (e.g., dike) with known strike direction, designing gravity survey at 30/60 degrees to the strike direction of the geology can often provide more information than one oriented at 90 degrees. However it should be decided on basis of available geological information during planning stage.

- Density/Spacing
  - In regional surveys, observation density or station spacing is often calculated from the area to be covered divided by the number of stations that can be afforded within the budget. When planning the station spacing, the Operator should consider the existing anomaly pattern in conjunction with the known geology. Using this information and, if available, the aeromagnetic anomalies a series of polygons can be constructed to delimit areas of higher and lower desired station density. In areas of long linear features, the operators may consider anisotropic spacing (e.g. 2 x 1km) with the closer spacing aligned across the features. If no existing or indicative gravity data is available an evenly spaced coverage should be surveyed first, followed by targeted in-fill based on the results of this even coverage.

- Regular grid or opportunity (along roads)
  - In some parts of the country a regular grid of observations will necessitate the use of a helicopter for transporting the equipment to enable timely completion of the survey; this will increase the cost by 50 to 100% compared with road vehicle gravity surveys. In urban areas and farming areas, regular grids of 1, 2 or 4 km can be achieved by utilizing road transport.

- Effectiveness of detailed traverses
  - Detailed traverses give useful information for interpreting extensive linear features but are of limited use in constructing a reliable gridded surface of an area. For planning a regional gravity survey of an area, the coverage should be as regularly spaced as possible in all directions.

- Station selection
  - The aim of choosing the position of the gravity station carefully is to avoid the reading being influenced by physical effects that are difficult to quantify.

- In areas of significant local elevation changes
  - The standard formulae for the calculation of simple gravity anomalies assume a flat earth surface at the observation point. Any deviation from a

flat surface model needs to be compensated for through a terrain correction. Since terrain corrections are difficult to compute accurately for features near the station, the gravity station should be sited in a flat area with at least 200m clearance from any sharp change in ground elevation.

- What to avoid: moving locations
    - In addition to avoidance of large changes in elevation nearby, the gravity station may need to be moved from its pre-designated location due to:
        - Dense vegetation preventing helicopter landing or interfering with the GPS
        - Boggy, swampy or snow covered ground preventing access to the site
        - Soft sand, loose rock or mud not providing a stable footing for the meter
        - The site being exposed to strong winds
        - The site being in a river or lake
        - The site having an important cultural significance
        - Access to the site not being granted or the site being dangerous
    - In pre-planning the survey these issues can be identified by the use of satellite imagery such as Google Earth, or topographic maps that are readily available.
- City Gravity surveys
    - There are a number of terrain effects that are not immediately obvious. These terrain effects can be induced by construction in cities, towns, airports or mines. Below are points that need to be considered:
        - Measurements near excavations (pits, tunnels, underground car parks) will need to be corrected for terrain effects.
        - Dams, drains, sumps and (underground) tanks that have variable fluid levels should be avoided.
        - Measurements in or near tall buildings or towers will be affected by terrain and are susceptible to noise from wind shear. GPS reception may also be poor.
        - Sites near major roads, railways, factories or heavy equipment will be subject to intermittent vibration.

        - In urban areas, measurement should be made in parks, outside low-rise buildings or at benchmarks (for quick position and height control).

- Combining different disciplines

    - Gravity and geology - competing requirements

        - Joint gravity and geochemical sampling have been done successfully in some areas with a reasonably regular 4 km gravity grid being established. The demands of the geological sampling may bias the positions to streambeds, outcrops or particular soil types. These positions may also cause terrain effect problems. The combined methods can best be accommodated in regional in-fill using 4 or 5 km station spacing.

    - Gravity bases at geodetic or magnetic sites - synergies

        - There are a number of advantages of locating gravity stations at geodetic or magnetic primary reference points. The total number of sites can be reduced. Measurements can be made concurrently thus reducing the operational costs. Precise measurements at exactly the same point over time can be correlated to define crustal movement.

- Assessment of different platforms

    - Gravity meters measure gravity acceleration so any other acceleration acting on the meter, such as that occurs in a moving platform (aircraft, ship, etc.), will distort the measurement. If the platform is moving at a constant speed or the instantaneous accelerations can be calculated, a correction can be applied to the gravity reading to give a meaningful result, however, the value will not be as accurate as a measurement made on the ground.

- Airborne Gravity and Gradiometry surveys

    - Airborne gravity can be carried out at accuracy of $10\mu ms^{-2}$. But the absolute accuracy is about $50\mu ms^{-2}$. The $10\mu ms^{-2}$ may reflect the relative precision along a flight line but the values are subject to instrument drift and air movements that can be adjusted using crossover ties. Airborne readings can be filtered by a moving average 5 or 10 point filter so the effective wavelength is longer than the sample spacing would imply. However, these methods are quite expensive compared with conventional ground readings and do not compete on price or quality. Airborne gravity surveys are effective in areas which are very remote, forested, water covered, swampy or dangerous (pollution, mines or animals). And they are ineffective in areas of rugged terrain due to terrain effects and the extreme difficulty in maintaining a perfectly steady flight path.

    - Airborne gradiometry is much more useful exploration tool. It depends on the simultaneous measurement of gravity at two or more closely separated locations. The apparatus is designed in such a way that nearly all the extraneous forces will cancel out in the comparison of the two (or more) observations and the output will be a gravity gradient tensor (gradient vector). The gradients are useful, they are of high frequency response sensors of the geology, but for quantitative modeling, a good ground gravity survey of the area is required to provide the ground constraint.

- Airborne gravity has advantages and disadvantages over other methods. These advantages and disadvantages are shown below:

Advantages	Disadvantages
- Provides intermediate and shorter wavelengths - Provides possibility for seamless coverage between land and ocean - Coverage of inaccessible areas (jungles, ice sheets, coastal regions) - Fast and economical	- Limited resolution - Downward continuation over rugged topography

- Ship - submarine

    - Seaborne gravity surveys have lesser stability problems than airborne gravity surveys are. The movements of deep water is slower and more predictable than air currents. Large ships will not be highly affected by chop and swell on a calm day. Gravity surveying in rough weather will give poor results.

- Vehicle - car, 4WD, quadbike, motorbike

    - Conducting conventional gravity surveys require a wheeled vehicle to transport the Operator and equipment between the observation sites. The gravity meter is lifted out of its box at the observation site and placed on the ground or a base-plate and the meter is leveled and read (optically or digitally). Standard vehicles are used in built up areas. But on rough tracks, along fence lines or across paddocks, 4WD vehicles are used. Quadbikes are useful in densely timbered or scrubby areas where turning ability and vehicle weight are important. And two wheel motorbikes may be convenient along traverse lines. Gravity meters must be protected from bumps and vibration as much as possible.

- Helicopter - Heligrav

    - Helicopters are the most effective (but more expensive) method of transport in remote areas. The Scintrex Heligrav system is a self-leveling digital reading gravity meter. The attached tripod is suspended by cable from a helicopter. After the system is carefully lowered onto the ground, the helicopter hovers while the reading is made. The data flows between the helicopter and the meter through an umbilical cord attached to the cable.

- Precision and Accuracy

The most absolute gravity measurements are 0.01 µms-2 or 1µgal. Gravity anomalies are the most useful representation of the gravity field for interpreters. They can be calculated from gravity survey data to an accuracy of about 0.3 μms^{-2}.

Gravity surveys rely on a number of independent variable than may affect accuracy and effectiveness. These variables are described below.

  - Positions
    - Positions (obtained by graphical methods) are plotted on topographic maps and transferred to base maps. The precision of these methods was about 0.1 minute of arc (~200m). Theodolites were used for detailed gravity surveys. These surveys are accurate to about 10 m. Advanced positioning instruments may provide more detailed gravity survey.
  - Heights
    - Heights for regional gravity surveys are measured using digital barometers. Airborne elevations were measured by altimeters (pressure gauges) or radar but now GPS receivers are used. Marine water depths are measured by sonar.
  - Gravity
    - The new electronic quartz meters, such as the Scintrex CG-3, have a worldwide range and incorporate software to compensate for meter tilt and to remove tidal effects and drift; they have a precision of 0.01 μms^{-2}. La Coste and Romberg (LC&R) steel spring gravimeters have a worldwide range and a precision of 0.01 μms^{-2}.
    - For good gravity survey, the accuracy required of the three components (gravity value, position, and height) is determined by the object of the measurements.
  - Base network
    - For gravity surveys, it is necessary to establish gravity base stations which are points where the gravity value is well defined and which value can be used as a reference for gravity surveys being done in that area. Only the gravity value is necessary at these points. The gravity value should be accurate to at least 0.05 μms^{-2}.
    - For gravity, the base stations should accurate to 0.1 μms^{-2} and for height to 0.05 meter.
  - Reconnaissance coverage

    - For 11 km and 7 km spaced stations, an adequate accuracy is 1μms^{-2} and 1 meter. These numbers will give an anomaly accurate to about 3.2 μms^{-2}. Much of the historic reconnaissance data has height accuracy of only 5 meters.

  - In-fill

    - For 4 km and 2 km spaced stations, the desired accuracy is 0.3 μms^{-2} in gravity and 0.1 meter in height. These figures will give an anomaly accurate to about 0.42 μms^{-2}.

  - Mineral prospect

    - For mineral prospect gravity surveys, an anomaly of 0.1 μms^{-2} may be quite significant in the delineation of an ore body. This will require an accuracy of 0.05 μms^{-2} and 0.1 meter.

  - Engineering

    - In engineering gravity surveys which are extremely detailed and limited extent, the height precision is important. The required accuracy is 0.05 μms^{-2} and 0.05 meter. Repeated measurements at the same points over time, to detect crustal movements, need to be of the highest possible accuracy.

  - Detailed traverse - cross-section

    - High accuracy relative anomaly require detailed accuracy for modeling. Relative gravity and height values to an accuracy between 0.1 and 0.05 μms^{-2}, and 0.1 and 0.05 meter depending on the station spacing 9 e.g. 250 m and 50 m.

- Equipment

  - Gravity equipment

    - The three main classes of gravity measuring instruments:

      - Pendulums- where the period of the pendulum in inversely proportional to g (g is the gravitational acceleration)

      - Sensitivity spring balances- where the spring extension is proportional to g

      - Falling bodies timed over a fixed distance of fall in a vacuum tube

    - Within each class there are several variants. The spring balances are relative instruments, they can only be used to measure the difference in gravity between two or more points. Pendulums can be used for relative and absolute measurements by calculating the ratio of periods measured at two points or the exact period at a particular point. The falling body class measures the absolute gravity.

- Positioning equipment

  - Positions and particularly heights had been key factors in calculating accurate gravity anomalies. Modern survey instruments should be used for positioning the more detailed gravity surveys.

- Pressure based height instruments

  - Atmospheric pressure decreases with altitude, so pressure measurements can be used to calculate elevation. A rough estimate of the pressure decrease is 1 millibar for each 8.7 meter increase in altitude. Accurate height differences can be measured in a local area (within the same pressure regime as the base) if base pressure variations are recorded, the weather pattern is stable and repeat readings are made at the base and selected field stations during the loop. The height difference network can then be tied into the Height Datum at one or more benchmarks. Pressure measuring apparatus that have been used in gravity surveys are altimeters, precision micro-barometers and digital barometers.

- Global positioning system receivers

  - The introduction of the Global Positioning System (GPS) in the late 1980s enabled gravity to take its place as a precision tool in mapping the fine detail of crustal structure. The GPS receiver monitors time encoded signals being broadcast by a constellation of GPS satellites orbiting the Earth, from 3 or more of these signals the position of the receiver can be calculated in reference to the center of the Geoid. The position values are referred to as the geocentric coordinates. Differential GPS (DGPS) is the standard method deployed for surveying. In DGPS all of the GPS readings for each site are tied back to known base stations established at the start of the survey. These stations are normally tied to known benchmarks or new benchmarks are created and tied into an existing network.

- Positioning

  - Early Gravity surveys use plane table and theodolite for positioning. Working with these types of tools, the surveyors would exert tremendous amounts of effort to cover small areas with less accuracy.

  - GPS system is widely used in gravity surveying where it has greatly reduced the cost of providing accurate positions and heights. Commercial GPS receivers can be single frequency or dual frequency. The accuracy of a position obtained with a single frequency receiver is about 7m horizontal and 12m vertical compared with about 5m horizontal and 8m vertical accuracy for a dual frequency receiver. Obviously this vertical accuracy is insufficient for gravity surveying but can be improved by employing differential or relative techniques using two or more receivers. Differential GPS can work in a simple way where one receiver is set up over a known point, the base, while another receiver, the rover, occupies unknown points. Corrections may need to be applied to the GPS positions. Accuracy of DGPS is in millimeters.

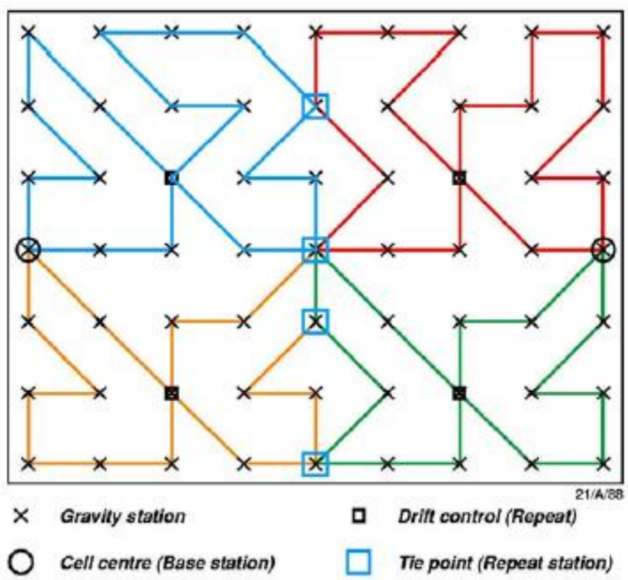
- The level of accuracy required in the determination of gravity station positions is dependent on the type of gravity survey and the size of the anomalies that are expected to be detected. An error of 10 cm in the height of a station would result in an error of about 0.3 μms^{-2}. Errors of this magnitude are acceptable in regional gravity surveys with station spacing one or more kilometers, but for more detailed surveys the height of the gravity station needs to be determined more accurately.

- Gravity survey logistic planning and preparation
  - Survey numbering
    - Most survey numbering schemes involve the year, or last two digits of the year, in the survey number.
  - Plotting proposed points on the base maps
    - It is good practice to plot the proposed observation locations on a topographic map before starting the gravity survey. Re-positioning of some stations in areas of difficult terrain and cultural features will be required. It is also needed to inform private landholders and ask their permission for working on their property.
  - Native title clearances
    - In most countries, it is necessary to negotiate access to the land with the leaders of the community. Maps of the proposed station locations will be necessary to help identify areas of exclusion and sacred sites.
  - Station sequencing
    - The cost of transport for the gravity survey and the efficiency of operation may have been significantly affected by the order in which stations are read. The risk of error propagation and the loss of data through equipment problems can be also reduced by keeping the time taken for each loop and the distance travelled to a minimum. For best results, the position of repeat and tie stations should be evenly spaced in the reading order of the loop.
  - Leapfrogging
    - In difficult terrain, areas of limited access, or when transport is limited, controlling loops from a single base station is impracticable. In this case, one crew may start working from a base station, travel out to the limit of baseline reliability and set up a new base. The old base crew then travels past the new base crew and works until they set up a further base. This leapfrogging procedure continues until a loop closure can be achieved. In case of limited transport, two crews may set out from base on the helicopter or vehicle, one crew is dropped off at the first station and the second crew is carried to and

dropped off at the second station. The transport then returns to the first station and transports the first crew to the third station, then the second crew to the fourth station and so on. This method of leapfrogging is particularly efficient when each crew needs to spend a significant length of time at each station.

- Designing a robust network
  - A gravity survey network is a series of interlocking closed loops of gravity observations. The design of the gravity survey loop structure, the bases, the repeat and tie stations is critical in enabling accurate station values to be computed with confidence. An example of gravity loop network is shown in the figure below.

    (From:http://www.ultramag.com/Downloads/Gravity/AGSO_Gravity_Best_Practice.pdf)



Gravity Loop Network

- Minimum number of ties required
  - Gravity survey ties to base networks, position control stations and where possible other existing gravity surveys are essential for the data to be made compatible with other data in the National Gravity Database (NGD). A qualified contractor will be knowledgeable of local databases and procedures as the availability of data varies by country.
- Ties to position control and benchmarks
  - Ties to height control points (benchmarks) should be made more frequently than to gravity control points. Position control should only be taken from a point that is a recognized geodetic point or, in the case of heights, from a

benchmark. It should be noted that geodetic points have an accurate x and y but not necessarily a good z and benchmarks have a good z and poor x and y.

- Gravity survey bases
  - Gravity survey base stations and cell-centers should be located in flat easily accessible locations and be marked as permanently as practicable. To avoid errors in readings, reoccupations of the point during the current gravity survey should be exact. For primary base stations, photographs should be taken from two directions and a sketch made to facilitate relocation of the station in future.
- Control points should not be cell centers
  - Cell-centers and other repeat stations should not be located at position of gravity control points.
  - A control point may be used for the primary base station of the gravity survey but this point should not be used as a cell center as this would have the effect of splitting the network. The cell center can be an arbitrary distance from the control point and must have a different station number. Ties between loops should not be made at control points.
- Repeat and tie stations
  - Each observation in gravity surveying is subject to from various sources, the more repeats to verify the data, the better. Repeat stations are stations where a reading is made two or more times within the loop. Tie stations are stations read in two or more loops or two or more gravity surveys. Repeat stations are used to check equipment and processing performance. There should be two repeat or tie stations in addition to the cell-center in a loop of 23 stations. For a standard cloverleaf pattern of four loops radiating from a cell center, if each loop has 23 stations and the cell-center is common, there are 89 distinct stations. Now, if there are two repeats or ties in each loop and one cell-center there will be nine repeats; which is close to 10% of the total.
- As an insurance against equipment failures
  - Many problems can arise during a gravity survey. These problems may be due to equipment; battery failure, transport problems or faulty data logging; or external sources; earthquakes or lack of satellites. If a problem occurs, there will be a loss of the most recently measured data. Data loss can be minimized by designing repeat or tie stations to be no more than ten stations apart, data loss is then limited to the stations after the last repeat station.

- Gravity Survey – Contractor Selection
  - Gravity surveying is normally undertaken by a 3rd party contractor. The contractor needs to be qualified and experienced with a proven track record of successfully

executing gravity surveys in the type of terrain that the proposed survey will be conducted. Companies with only marine experience may not be a good choice to do a gravity survey on an onshore block.

- Equipment must be calibrated and properly maintained. Current surveys will in nearly all cases be conducted using GPS for positioning and altitude calibration. When merging existing and new survey areas there must be an overlap that allows for the datasets to be properly tied and any tidal effects or elevation differences due to different surveying techniques must be addressed.

- Gravity Survey – Reporting Standards
  - Reports may provide and apply:
    - Apply the standard gravity units in their reports.
    - Apply the optimum observation spacing for gravity acquisition.
    - Look at the existing data when making decisions for survey planning.
    - Provide Residual gravity maps- for shallow structures
    - Provide Regional gravity maps- for deep-seated structures
    - Provide Density maps
    - Provide co-ordinate reference system
  - Final interpretation reports must incorporate a comprehensive summary of the source of the data, processing methodology, interpretation, and serve as an archive to locate all of the data used in the development of the findings.
- Gravity Survey Advantages and Disadvantages
  - The main advantages and disadvantages of Gravity surveys over other methods are shown below:

Advantages	**Disadvantages**
- Fast, inexpensive tool for evaluating large areas - Can distinguish sources at exploration depths - Nondestructive; measures an existing field through a passive measurements - Can use old data today and easily integrate with new data - High accuracy using GPS system for positioning	- Ambiguous - Does not directly provide a structural cross section without additional geologic input - Overlapping anomalies may confuse the interpretation - Cannot image finer structures - Resolution deteriorates with depth - Less accuracy positioning using plane table and theodolite

Limitations	Survey Type						
	Borehole Gravity	Land Based	Helicopter	Airborne Gravity	Airborne Gradio-metry	Ship-borne Gravity	Submarine
Resolution							
Reservoir	✓						
Formation	✓	✓	✓		✓		
Geological Structures		✓	✓	✓	✓	✓	✓
Basin Scale		✓	✓			✓	✓
Estimated Depth of investigation	1-10 meters	10 - 5000 m *	10 - 5000 m *	500 - 5000 m *	10 - 5000 m *	1000 - 10000 m	1000 - 10000 m
Sensitive to							
Well Casing		✓	✓				
Survey Duration - Diurnal variations		✓	✓	✓	✓	✓	
Height of instrument				✓	✓	✓	✓
Topographic variations in survey area (requires terrain corrections)		✓	✓		✓		
Drift (spring tension)	✓	✓	✓	✓		✓	
Primary Use							
Reservoir Monitoring	✓						
Subsurface mapping							
Prospect Scale		✓	✓		✓		
Regional Scale		✓	✓	✓	✓	✓	✓
Basin Scale		✓	✓	✓	✓	✓	✓

* Depth of investigation is dependent on the length of a profile or area covered by the survey

- Potential field methods are most effective when the geologic bodies being investigated demonstrate significant contrast in a property that the technology is able to detect. Gravity data reacts to differences in formation density, Induced Polarization reacts to changes in conductivity, and Magnetics reacts to differences in magnetic susceptibility of the rocks. These examples are a subset of the range of potential field methods and the correct method must be identified based on the expected or modeled differences in an area. Acquiring data using one of these methods requires an understanding of the wavelength of the phenomena and the sampling required to properly measure and model the response.

- Gravity and Magnetic surveys are primarily used for basin scale interpretation. They can be helpful in defining the presence or absence of geological features that have distinctive density or magnetic potential when contrasted to the surrounding medium. The different gravity survey types have their own set of challenges and selecting the correct method for the identified project should consider the limitations of the method. Gravity surveys may be useful for defining depth to basement in areas where other techniques have ambiguous results or for defining general basin shapes. Gravity data is also useful for identification of low density lenses such as salt to verify whether an anomalous zone may be due to a salt lens versus a volcanic intrusion. Geological and Geophysical staff in the Production Sharing Contractor's staff must determine the incremental value of the potential field data and how it will be integrated into their overall evaluation of the contract area. Recent advancements in GPS positioning and gravity and gradiometer equipment have improved the resolution and accuracy of airborne methods such as helicopter and fixed wing platforms to be nearly comparable to land acquisition with some notable advantages in uniform coverage, increased accessibility and data processing of more uniformly sampled data. It is recommended that the Operator use the most appropriate and efficient method to satisfy their objectives for the gravity surveys.

- Production Sharing Contract Operators should use qualified contractors in the conduct of gravity and magnetic surveys. These contractors will be knowledgeable of local issues and can integrate new data into existing datasets. Likewise, constraints on the use of the instruments, collection, processing and interpretation of the results enforced by governmental institutions must be considered and a reliable contractor will be informed of any limitations.

- Where base networks are available and data is readily available from governmental agencies these networks should be integrated into the gravity or magnetics surveys to ensure consistency between all surveys. When integrating existing gravity data into new surveys, the positioning accuracy must be considered. Older surveys collected using Plane Table mapping techniques have a different level of accuracy for their positioning and elevations, therefore those locations may need to be weighted differently than data acquired using a DGPS method.

- Quality Assurance of potential field surveys is important. Third party consultants or internal company specialists with expertise in the potential field method should be involved in the planning and execution of any survey. These experts will ensure appropriate technology and equipment are used to meet the demands of the survey as designed. Consultants or contractors who specialize in the field as a third party to ensure proper field methods are used are an important part of any survey.

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1.6 *Geochemistry Practices – Geochemical Sampling and Analysis*

1.6.1 Definitions and Discussion

The integration of geochemical methods of material characterization into an exploration program is essential to evaluate the presence of potential liquid and gas phase hydrocarbons generated in source rocks and trapped in reservoirs. Sampling techniques and analytical methods used in a geochemical exploration program are generally selected based on the nature of the physical environment in which operations are conducted.

Exploration geochemical environments include:

- Onshore near-surface sampling
- Outcrop sampling
- Marine basin seepage at the water/sediment interface
- Borehole cores and fluids

Onshore soil gas samples are collected through a probe inserted into the ground and the light hydrocarbon gases are analyzed by gas chromatography. The method is adaptable to various geologic terrains covering large areas. Advantages include low acquisition cost, rapid collection, and little surface damage. C1-C4 gases and their ratios along with helium are reported. However, wet surface conditions can cause poor results and should be avoided.

Onshore geologic studies frequently include the gathering of outcrop samples for geochemical analysis. Samples are typically collected from formations that are anticipated to include mature or immature source rocks that may be evaluated through pyrolysis to determine the type and maturity of the kerogen in the rocks. These data are integrated into the basin analysis to estimate the charge potential to potential reservoirs in the exploration area.

An offshore geochemical exploration program can be much more complex requiring program design and consulting. Sampling can include vibro-coring and drilling programs, piston/gravity core sample collection, bottom water sampling, and onboard sample processing. Onboard testing and analysis can include sediment extract and headspace gas analysis, as well as "sniffer" methods using a sonde a few meters above the bottom to survey seeps by traversing the bottom by selected grid patterns. Marine programs are obviously more expensive and time intensive but provide data from different environments.

Borehole geochemical sampling consists of openhole percussion sidewall sampling at predetermined sample spacing (shots per foot) or full core retrieval. Sampling formation gases during drilling at "shows" as well as utilizing special analytical methods such as special core analysis (SCAL) provide valuable information allowing for analysis of source/source and source/oil correlation data. Sampling gases to be used in "Rock Eval" analysis provides information on gas versus oil prone kerogen and hydrocarbon maturity.

1.6.2 Best Practices

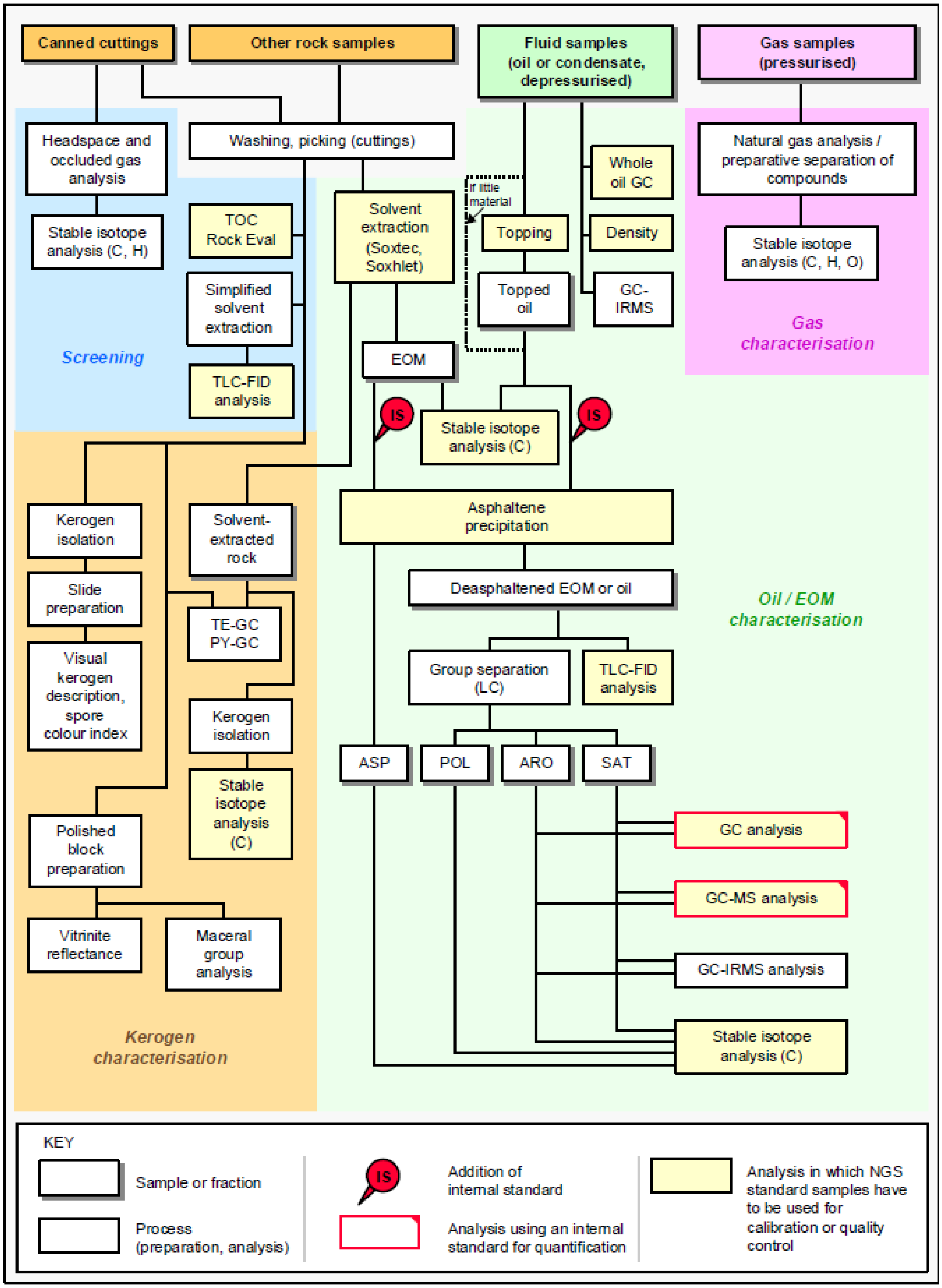
- The flow chart in the figure that follows covers a "General Analysis Scheme" for geochemical evaluation published by Norsk Hydro, Statoil, Geolab Nor, SINTEF Petroleum Research and the Norwegian Petroleum Directorate which is the de facto standard for the Norwegian Industry Guide to Organic Geochemical Analyses (NIGOGA). The flow chart describes the analytical scheme and fractionation of the various sample material that may be analyzed during a geochemical evaluation of an exploration or producing asset.

- In gathering geochemical samples for head-space gas analysis the samples should be placed in sealed containers as soon as possible and the container remains closed until the analysis is to be performed.

- Analytical procedures marked on the flowchart with an "IS" require the use of an internal standard. Three NGS standard samples are available and are identified as:

    - THE NORWEGIAN GEOCHEMICAL STANDARD SVALBARD ROCK 1 (NGS SR-1)
    - THE NORWEGIAN GEOCHEMICAL STANDARD JET ROCK 1 (NGS JR-1)
    - THE NORWEGIAN GEOCHEMICAL STANDARD NORTH SEA OIL 1 (NGS NSO-1)

- It should be made clear at the beginning of the analytical flowchart that only "canned cuttings" can be used for headspace gas analysis. All other types of "rock samples" are washed to remove contaminants and then crushed to provide "picked cuttings" for Rock Eval/Solvent Extraction analysis. Canned cuttings are also treated in the same way for Rock Eval/Solvent Extraction analysis.



General Analysis Scheme for Geochemical Evaluation

- Standard sample documentation as well as reference values for the NGS samples is based on analyses carried out according to the Norwegian Industry Guide to Organic Geochemical Analyses, third edition(NIGOGA) (Patience et al. 1993).
- NIGOGA is divided into an "Analysis Guide" and a "Reporting Guide".

- Analysis Guide

  - The analytical procedures above assume wells were drilled with water-based mud. The use of oil or synthetic-based mud may require modified sample treatment depending on client requirements. Norwegian Geochemical Standard Samples (NGS) are available through the Norwegian Petroleum Directorate to be used as internal standards for Geochemical analysis and reporting "permissible ranges" and "most likely values." A consistent format was introduced for all analysis descriptions for ease of use and centralized reporting. The Reporting Guide now contains only the general rules for reporting as given below.

- Reporting Guide (Principal Rules and Remarks)

  - The aim of a standard geochemical report is to present and describe the data obtained by the various analyses. The extent of detailed interpretation – in the form of both text and figures – should be agreed upon by customer and Service Company.

  - As a general principle, all results must be provided in digital form, in addition to the written report. Unless specified otherwise, the requirements stated below therefore apply to both the written report and the digital data transfer.

  - If any analyses are not carried out in accordance with this Guide, this must be noted.

  - If results cannot be obtained from an analysis, or if the obtained results are unreliable or doubtful, this must be noted and the reason should be mentioned.

  - Wherever the Guide requires control analyses, the results from these must be reported, separately from the "normal" analyses. The tables must contain all variables used as quality criteria (which may differ from those to be reported for the "normal" analyses). They must also include the name(s) of the control sample(s) and should contain the most likely values and permissible ranges quoted in the NIGOGA.

  - The sample type must be given. It must be clear if bulk or picked cuttings were used.

  - Both top and bottom depth must be reported for cutting, drill stem test and production test samples. Measured depth relative to Rotary Kelly Bushing (MD RKB) must always be reported, and it must be stated whether this is driller's or logger's depth. The customer must make this information available to the service company.

  - All tables and figures should be mentioned in the text.

- Any nomenclature (for peaks, ratios, kerogen constituents etc.) and units of measure stated in the NIGOGA must be followed, unless items (e.g. compounds, ratios) are reported which are not mentioned in this Guide.

- All terms (codes, abbreviations, compound names) and units of measure that are necessary for the understanding of the report text, the figures or tables and that are not defined or specified in this Guide must be explained. This information can conveniently be collected in a separate table (list of terms) which has to be included also in the electronic data transfer.

- The unit of measure must be given for each reported variable. “Implicit” or “self-explanatory” units of measure do not exist. Incomplete concentration units such as “%”, “ppm”, “ppb” etc. are not acceptable, as they neither tell which properties were determined (e.g. volume, weight, peak area, peak height) nor to which variable the values were normalized (e.g. sum of recorded peak areas, sample weight, sample volume). When concentrations are determined from GC or GC-MS peak data, it must be clearly stated whether these are based on peak areas or peak heights. When peak ratios are reported, the formula must be given, and it must always be stated whether the ratios are based on areas or heights or concentrations. If they are based on concentration, it must be stated whether the concentrations ultimately are based on peak heights or areas.

- Geochemical analysis of data from both wells and surface sampling is an important step in the exploration evaluation of any area. The procedures outlined above are provided as a reference to the methodology documented by NIGOGA and is accepted worldwide. Use of this methodology will ensure consistency in the comparison of source rock potential on a global scale and is therefore appropriate for application in all areas. The recommendation is to follow the Best Practices as outlined.

1.6.3 References

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1.6.4 Geological Practices – Field Geological Practices

Geological field mapping is the process of selecting an area of interest and identifying all the geological aspects of that area with the purpose of preparing a detailed geological report which must include a map. A map showing the occurrence of structural features across a region, the distribution of rock units and their type and age relationship is termed a geological map. Good geological mapping should be executed in three phases; planning, data collection and reporting. Certain parameters must be considered when mapping geology, geological landforms, structures and geothermal manifestations the most important being detail, accuracy and precision.

Geological mapping is a highly interpretive, scientific process that can produce a range of map products for many different uses. The geologic mapper strives to understand the composition and structure of geological materials at the Earth's surface and at depth, and to depict observations and interpretations on maps using symbols and colours. Within the past 10 to 20 years, Geographic Information System (GIS) technology has begun to change aspects of geological mapping by providing software tools that permit the geometry and characteristics of rock bodies and other geological features (such as faults) to be electronically stored, displayed, queried, and analysed in conjunction with a seemingly infinite variety of other data types.

1.7 *Geological Practices – Wellbore Sampling and Uses*

1.7.1 Definitions and Discussion

During the drilling process, in addition to any geochemical canned cuttings it is general practice for the mudlogging crews to collect wellbore cuttings at the shale-shaker or possum belly or desander/desilter depending on the rock type at a specified depth interval. The purpose of these samples is to determine the lithology and formation the bit is drilling through. The lithology is determined by microscopic inspection by an experienced wellsite geologist. It should be recognized that uphole cavings and mud additives can contaminate the cuttings and should be ignored for interpretation purposes. The formation (age and deposition related) can be determined by correlation with other nearby or correlative logs and mudlogs.

Cutting samples can also be used for micropaleontology (tests of ancient plantonic and benthonic organisms) and palynology (study of primarily spores and pollen and other organic microfossils). The result of these studies is essential for understanding the biostratigraphy and age of the different formations in the borehole, which will result in better correlation of age of deposition with offset wells and environment of deposition (EOD) which can be valuable for predicting potential reservoir distribution.

The primary collection point for well cuttings is the shale-shaker. Other collection points are the possum belly and desander/desilter. Possum belly sample collection is thought to preserve larger cutting such as sandstones or conglomerates. While the desander/desilter sample collection is good for unconsolidated samples. The sampling requirements for the collection of cuttings varies in the industry, and is generally determined at the discretion of the operator, also considering any requirements by the government or local administrations.

Samples are collected and either bagged wet or dried for storage and later analysis. Samples are analyzed at the drilling site to determine the formation being drilled and fluid content. Samples should be collected by the mudlogging team to insure that it is done properly.

For sedimentological samples, the best method to supplement the cuttings are side wall cores and cores. In most instances cuttings do not provide a sample of the consolidated rock, which is better for sedimentological studies. Side wall cores are taken with a percussion or rotary drilling method depending on the consolidation of the rock in the wellbore. Side wall cores are generally around 2.5 cm in diameter and 6.25 in length depending on the rock and method of acquiring these cores. Sidewall cores provide a good snapshot of the lithology and thin sections can be used for sedimentological study. Conventional cores are 11.43 cm in diameter and can be cut in drill pipe lengths (about 10 m) for hundreds of meters. Conventional cores provide the best sample for sedimentological study. Both of these core types can be used for other reservoir and rock properties studies as well. Sidewall cores are generally taken by a wireline tool after all logging runs have been made. Conventional cores are taken while drilling and require a swap out of the bottomhole assembly and are more costly and time consuming.

1.7.2 Best Practices

- Cuttings sampling interval will be decided prior to the drilling of a well by the geology and drilling teams, and are included in a geo-prognosis and drilling plan.
- For exploration wells, the following would be considered a standard good practice:
    - For surface-hole sections, 10m cuttings samples are collected.
    - For intermediate to target-hole sections, 5m cuttings samples are collected.
    - Sampling rate can be increased to 1m samples through a zone of interest. If it is necessary to collect samples at this rate, drill rates should be slowed to ensure accurate sampling or stop drilling and a “bottoms up” sample can be collected.
    - Paleontological and Palynology samples are commonly collected every 10m interval.

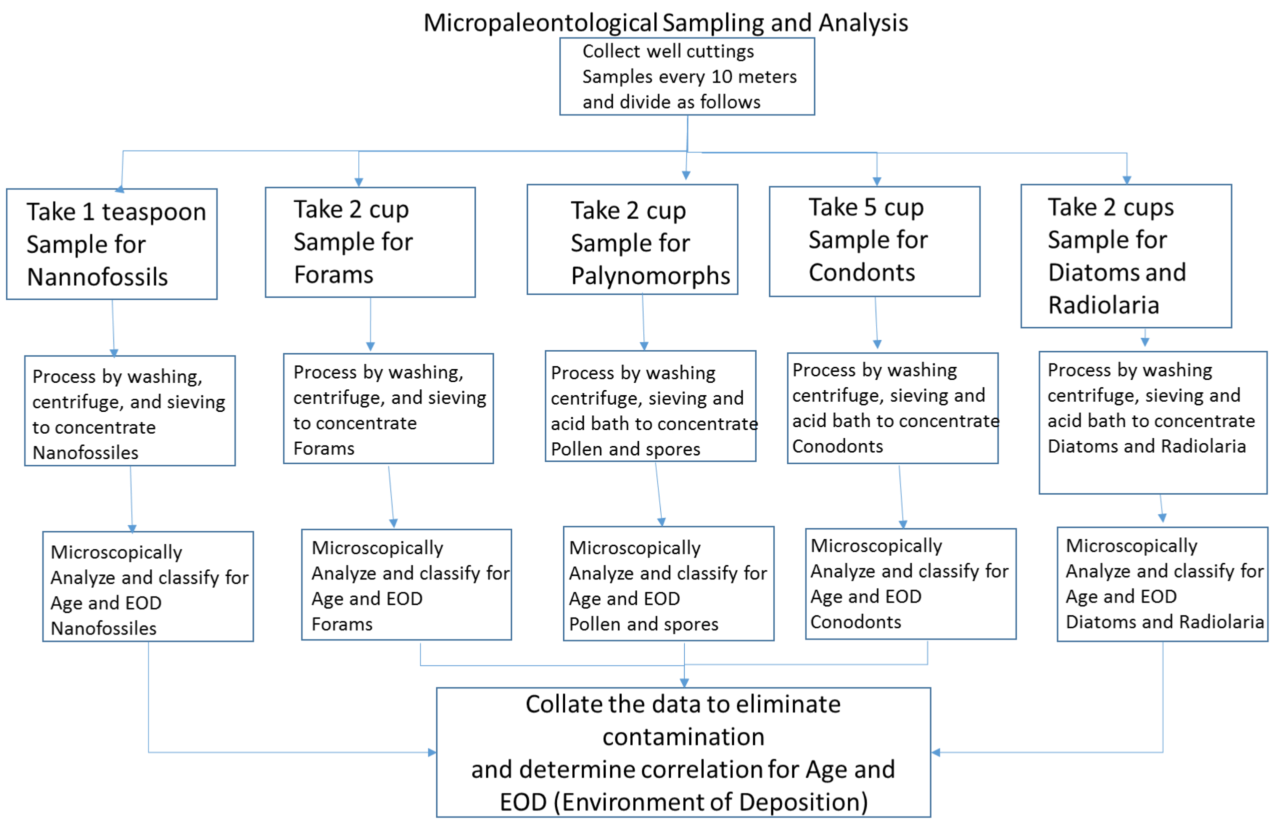
- For development wells, the following would be considered a standard good practice:
    - For surface-hole sections, cuttings samples are collected at 10-15 m interval.
    - For intermediate to production-hole sections, cuttings samples are collected at 10 m interval.
    - Depending on production zone, sampling rate can be increased to 5m.
    - For paleontological and palynology study, samples are commonly collected at every 10m interval.
- The geology of a particular well can often dictate when samples are collected. If a zone of interest lies in between a 5m sample interval for example, the Well Site Geologist or geology team can request the mudloggers "catch" a sample from a specific depth, also known as a "spot sample." Reasons for this could be due to:
    - A drilling break, or unexpected change in rate-of-penetration (ROP).
    - Abrupt or noteworthy MWD/LWD response that may indicate a zone of interest.
    - An increase in gas shows or petroleum odor at the shale-shakers.
    - If approaching an expected formation top, and a lithology confirmation is necessary.
- If the Well Site Geologist identifies any change in drilling or gas parameters they deem to be worthy of a spot sample, it is at their discretion to request one.
- Once a sampling rate is agreed upon, the operator will specify the amount of cuttings to be archived. In exploration wells, general practice calls for:
    - At least three sets of washed, dried and bagged cuttings samples are to be labeled and boxed by mudlogging personnel – one set for any government requirements, and two for the operator's research purposes.
    - At least one set of unwashed, wet samples (still containing drilling mud and potentially formation gas or oil) are bagged to potentially be used later to analyze any formation fluids or gases.
- Development wells may only require washed, dried samples, if it is decided that sufficient subsurface data and/or cuttings already exist.
- Accurate labeling of samples is extremely important. All samples must be depth corrected by using a "lagging" method, i.e., using calcium carbide in the wellbore and the resulting acetylene gas as a tracer or determining the bit to surface lag time of samples coming from the drill bit or both. The Well Site Geologist will closely monitor the collection and labeling of cuttings by the mudlogging personnel. All containment supplies will be provided by the mudlogging contractor, who should only use supplies intended for the purpose of containing drill-cuttings.

  - For washed, dried cuttings, samples will be contained within a small paper envelope or cloth bag – both of which must clearly state the depth-range for that particular sample, the company/operator name, and the well-name.
  - Wet samples are collected at the shale-shakers in a plastic bag previously labeled with the well-name and depth interval. This plastic bag is then contained within a cloth or paper bag that also notes the company/operator, well-name, and depth interval for the sample.

- All bagged samples are then neatly placed into their own respective sturdy cardboard boxes that clearly label the depth-range of the samples within, all relevant company information, the well-name, and any shipping instructions.
- Micropaleontological cutting samples are dried and treated, sidewall cores and conventional cores can also be used for analysis. Note that the techniques used for concentrating micropaleontological samples are in general destructive, i.e. only the particular microfossils are preserved.
- Pitfalls to avoid for micropaleontological sampling are as follows:
  - Avoid reusing drilling fluid from previously drilled well(s) as there may be contamination from previous well(s).
  - Drilling fluids are made from naturally occurring minerals and may contain microfossils- these should be recognized and treated as background to be filtered for interpretation.
  - Mechanical effect of different bit types may destroy fossils through the heat and pressure.
- These samples are used in a lab and treated depending on the composition and size of the microfossils which are to be studied.

Fossil Group	**Quantity of sample**	**Type of fossils**
Nannofossils	pea to teaspoon size	Calcareous microfossils
Foraminifera	1–2 cups	Calcareous microfossils
Palynomorphs	1–2 cups	organic microfossils
Conodonts	5 cups	Phosphatic microfossils
Diatoms and Radiolaria	1-2 cups	Silicate microfossils

- Fossils are separated by a combination of washing, centrifuge, chemical and sieving techniques. Care must be taken to label all samples properly with type of microfossils, depth, well location and Operator.



Micropaleontological Sampling and Analysis

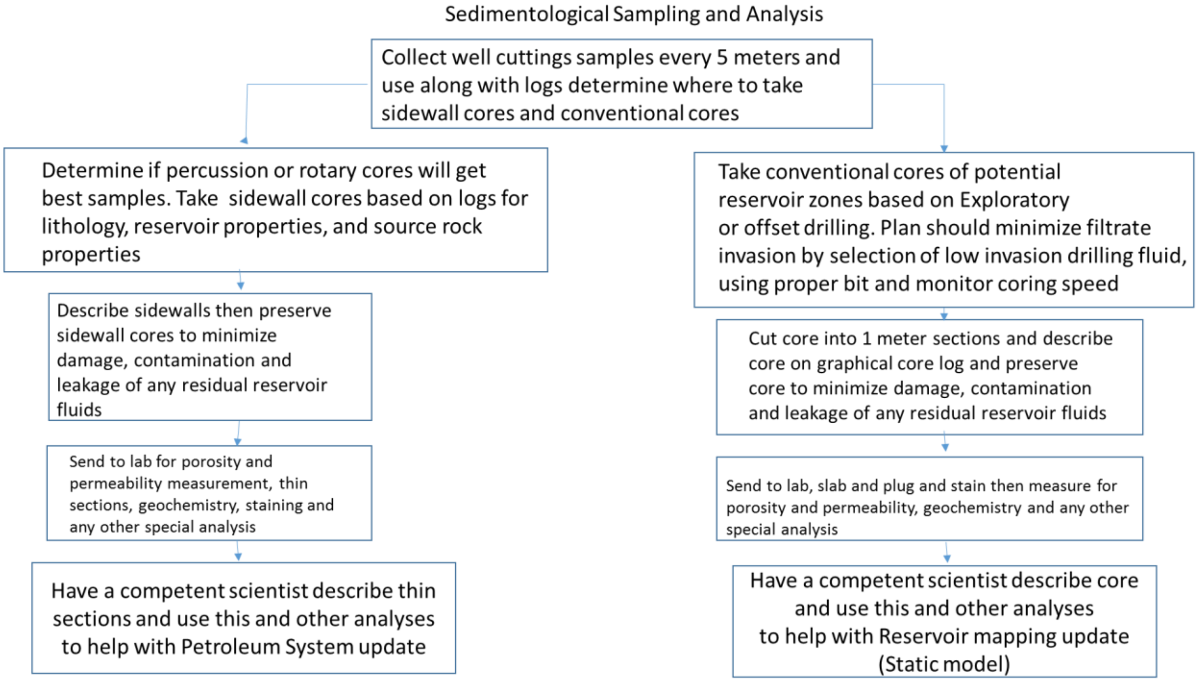
- Sedimentological samples should be preserved in as pristine condition as possible. Filtrate invasion, fluid expansion and expulsion and physical damage to the sample should be avoided.
    - Filtrate invasion in conventional cores can be avoided by careful selection of the drilling fluid used for coring (chemistry and weight), coring bit selection, monitoring coring speed, and can be monitored by doping the drilling fluid with a tracer to determine invasion.
    - Fluid expansion and expulsion can be combated by using pressurized or sleeved core barrels. This expansion and expulsion can be minimized by slow retrieval of the core form coring depth to the surface.
    - Physical damage can be caused by jamming of the core barrel or in the case of sidewall cores the process of taking a percussion core will cause fracturing. The best way to prevent jamming of the core barrel is to monitor the coring speed and keep the weight on bit (WOB) low so that the ROP is low (actual rate depends on rock

type). The best way to preserve sidewall cores from physical damage is to use rotary sidewall cores rather than percussion, this should be consider if the rock is very brittle or unconsolidated.

- Typical handling operation for sidewall cores is to inspect the gun to see if all bullets were fired. Next cores are extracted and described then wrapped in plastic wrap or aluminum foil and then placed in glass jars or ProtecCore sleeves as soon as possible. Then the sample is labeled with depth, well name, location and operator. Sample description is on a separate paper but accompanies the sample to the lab. Sidewall cores can also be frozen, jacketed in lead sheets or left in the bullets from the actual sidewall coring operations depending on the condition of the rock.

- Typical handling operation for conventional cores is to lay down the core barrel, cut into 1 meter sections, and inspect and describe as quickly and carefully as possible. Description should be recorded in a core log in graphical format noting the thickness of a lithologic zone, grain size changes, sedimentary structures, fossils, diagenetic features, lithology, nature of contacts between different lithological zones, oil staining, fracturing, and visible porosity as well as other attributes which are deemed important by the operator. After description, the core is generally wrapped in plastic wrap or foil (ProtecCore) and coated with wax for shipping. Other methods for sealing is to place in metal cans which will preserve reservoir fluid, fractured, and unconsolidated sediments, sealing in tubes which will preserve pressure and reservoir fluid, or freezing in dry ice which will preserve unconsolidated sediments. Core preservation should take care to not cause dehydration and salt precipitation, oxidation, redistribution of fluids, evaporation and condensation, expansion of shales, and bacterial growth.

- Core and sidewall coring samples should be sent to a lab for slabbing, thin section preparation and staining for lithology. These processed samples can then be used for sedimentological interpretations, such as overall description, lithologic content, contacts, grain size, environment of deposition, porosity, and permeability. Geochemical analysis (see Section1.6) can also be used for sedimentological interpretations.



Sedimentological Sampling and Analysis

- A dry sample of wellbore cutting is required for the study of sub-surface.
- Description of the sample and analysis for micropaleontology is recommended to help determine if the well has met the formation requirement as per PSC. Also unconformities and depositional environments can be determined by good micropaleontological analysis.
- Sidewall and conventional cores are recommended for exploratory wells. Sidewall cores locations should be picked from the logs for the purpose of study of reservoir fluid, lithology, or organic content. Sedimentological studies of side wall & conventional cores will help determine reservoir properties and be useful in mapping reservoir facies .
- Conventional or specialized cores are also recommended for development wells for reservoir characterization.

1.7.3 References

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1.8 *Geological Practices – Petrophysical Parameters (Log-Derived and Laboratory Data Derived)*

1.8.1 Definitions and Discussion

- Log-Derived Petrophysical Parameters
    - Data handling and conditioning
        - Data acquisition: data can be acquired either on real time basis or in batch-wise runs from the well site wireline service company.
        - Quality check: usually, the wireline service company reports about the data quality issues that they might experience during data acquisition.
    - Caliper
        - Caliper tool measures the actual borehole diameter. The tool can have 2 to 4 arms. It is run usually with micro resistivity, density, sidewall neutron, sonic and dipmeter logs.
        - Parameters: borehole size, hole quality, mud cake
    - Gamma Ray (GR)

      Natural gamma ray is measured by the gamma ray tool detector. Also, the source of the emission like potassium, uranium and thorium can be determined using advanced gamma ray tools known as spectral gamma ray. The first step that can be followed is a quality check of the measured data that will need to be corrected, if applicable.

        - Environmental correction: apart from service provider tool characteristics, the measured data quality can be affected by many external factors like specific formation radioactivity, formation bulk density, borehole fluid (mud) properties, borehole size and detector position in the borehole (centered/eccentered). Service companies (such as Schlumberger, Halliburton etc.) provide chart books that contain charts to correct the borehole effect (borehole size, borehole fluid and detector position).
        - Parameters: shale volume, bed thickness, clay typing, well and log run correlation

- Spontaneous Potential (SP)

  - SP is the measure of small electrical voltage potential resulted from electrical currents in the borehole due to differences in salinities of formation water and mud filtrate

  - Environmental correction: borehole, bed thickness and depth of invasion

  - SP correction charts are available to correct for the bed thickness and it becomes more important especially in thin beds

  - Parameters: shale volume, bed thickness, water resistivity, qualitative permeability, well correlation

- Resistivity

  Geophysical exploration method consists of inducing a low frequency current into the subsurface with metallic electrodes placed at the surface (Bassiouni, 1994). The resistivity is environmentally corrected that includes borehole, bed thickness and invasion effect. The borehole correction is determined by mud resistivity, mud cake resistivity, borehole diameter, and mud cake thickness.

  The effect of bed thickness is related by bed thickness, vertical resolution of the tool and resistivity contrast between main bed of interest and adjacent bed (Bassiouni, 1994). Both the effects are corrected with charts (Schlumberger Well Surveying Corporation, 2013) (Halliburton, 2012).

  The invasion effect is the effect of the flushed zone (with different resistivity and depth of invasion). The resistivity is affected by 2 zones: flushed and invaded zone. The effect correction can be taken care with published tornado charts provided by logging companies. (Schlumberger Well Surveying Corporation, 2013) (Halliburton, 2012)

  - Induction

    - Induction log is the response proportional to the formation conductivity (inverse of resistivity). The tool has multiple receivers and transmitter coils with measurements of the in-phase and out-of-phase parts of signal.

    - Parameters: deep, medium and shallow Resistivity

  - Laterolog

    - The electrical current flows from the tool into formation through borehole. Electrode arrays on either side of the source electrode force the measurement current into a horizontal disk-shaped pattern around the borehole. Formation resistivity is determined by monitoring the amount of current flowing from the tool. (Krygowski, 2003)

- Parameters: deep, medium and shallow Resistivity

- Micro-resistivity

    - Electrical current is forced into the formation by closely spaced electrodes mounted on pads pressed against the borehole wall.

    - Parameters: flushed zone resistivity

- Lithology and Facies (mud logging)

  The lithology or the nature of formation can be determined by the following prior to any petro-physical analysis:

    - Mud logging

    - Geology

    - Integrated well log analysis in the nearby wells

- Calculating Porosity

    - Sonic

      Conventional sonic tools measure the reciprocal of the velocity of the compressional wave (Bassiouni, 1994). A high frequency acoustic pulse from a transmitter is detected at two or more receivers. The time of the first detection of the transmitted pulse at each receiver is processed to produce an interval transit time. Compensated tools are used to minimize the effects of borehole sizes. (Krygowski, 2003)

        - Lithology correction: accurate matrix properties must be used as per lithology (limestone, dolomite and clastics)

        - Parameters: sonic porosity

    - Density

      High energy gamma rays are emitted from a chemical source (Ce 137) and interact with the electrons of the elements in the formation. Two detectors in the tool count the number of returning gamma rays which are related to formation electron density that is indicative of formation bulk density. (Krygowski, 2003)

        - Environmental correction: borehole size, mud and formation salinity and lithology

        - Parameters: density porosity

- Neutron

  High energy neutrons (emitting source: Americium-Beryllium), slowed by formation nuclei, are detected by 2 detectors that generates count rates. The count rates are inversely proportional to hydrogen in the formation. By assuming that all the hydrogen resides in the pore spaces of the formation, the hydrogen index can be related to formation porosity (Krygowski, 2003).

  - Environmental correction: Borehole size, mud formation properties, standoff, pressure, temperature and lithology (shale, sandstone and limestone)
  - Parameters: Neutron porosity

- Cased hole and production well logs: service companies offer wireline services in cased hole section that generates the parameters discussed above. Particular production logging is run to meet specific objectives as mentioned below:
  - Fluid tracking in formation: temperature surveys, mechanical flowmeter surveys, borehole fluid density or fluid capacitance
  - Cement job quality: temperature log, unfocussed gamma ray log and regular bond log
  - Zonal isolation (cement channeling): cement bond logs, acoustic noise, temperature, radioactive tracer, neutron-activation logs
  - Monitoring fluid contacts and recompletion zones: neutron, pulsed neutron and spectral logs

- Core Derived Petrophysical Parameters

  The recommended Practices for Core Analysis published by API (American Petroleum Institute, 1998)has the following objective:

  - Geological objectives
    - Lithologic information
      - Rock type
      - Depositional environment
      - Pore type
      - Mineralogy/geochemistry
    - Geologic maps
    - Fracture orientation

- Petrophysical and reservoir engineering (&Special Core Analysis)
    - Petrophysical Correlation Measurements
    - Permeability information
        - Permeability/porosity correlation
        - Relative permeability
    - Capillary pressure data
    - Steady state and unsteady state
    - Wettability determination
    - Archie Exponents – a, m, n
    - NMR Core Analysis
    - SEM (Scanning Electron Microscopy) and EDS (Energy-dispersive X-ray spectroscopy)
    - Asphaltene precipitation
    - Data for refining log calculations
        - Electrical properties
        - Grain density
        - Core gamma log
        - Mineralogy (FTIR) and cation exchange capacity
        - Enhanced oil recovery studies and reservoir condition corefloods
        - Improved oil recovery (IOR, EOR) Studies
        - Reserves estimate:
            - Porosity
            - Pore volume compressibility
            - Fluid saturations
- Drilling and completions
    - Fluid/formation compatibility studies:
        - Formation damage remediation

- Rock fluid sensitivity
- Pore fluid compressibility
- Mud completion fluid damage

▪ Grain size data for gravel pack design

▪ Rock mechanics data

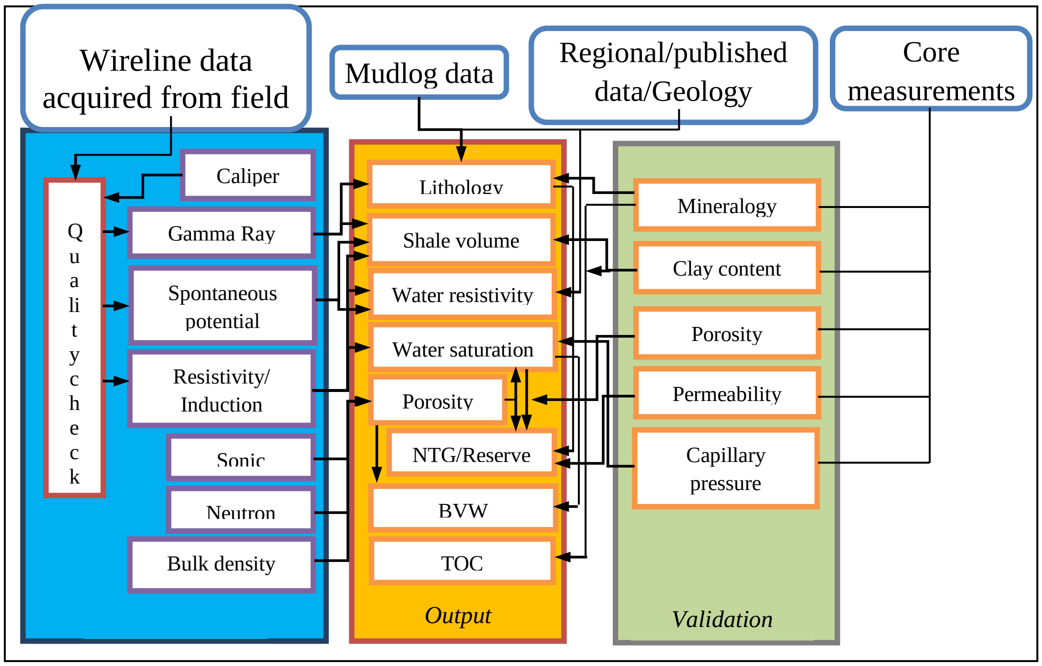
▪ Perforation optimization

1.8.2 Best Practices

- A detailed program for an exploration well should include but not be limited to the following:
  - Logging suite in hole sizes of 17 ½" or greater should be at the discretion of the operator as per requirement and to include Gamma ray, Caliper, Resistivity, Sonic, Neutron and Density in hole sizes of less than 17 ½". Sonic and Density may also be required at in the shallow hole at Operator's discretion if synthetic seismograms are needed to tie well markers to the seismic data.
  - Acquisition of Open Hole Logs and/or LWD/MWD Logs including Gamma Ray, Caliper, bit size resistivity/conductivity, induction, neutron and bulk density from intermediate section (12 ¼" most of the time) to Total Depth.
  - Increased drill cutting sample interval to 3 – 5 meters in anticipated reservoir sections or known reservoir sections
  - Preparation of mud log – includes sample description plus data from sensors on rig, i.e. rate of penetration (ROP), weight on bit, calcimetry, oil shows, gas measurements (C1, C2, C3, iC4, nC4, iC5, nC5, total gas) and rock cutting lithological description
  - Above services to be provided by a Mud Logging Contractor
  - The operator must report H2S and CO2 presence (quantitatively if possible)
  - Preparation of Lithology Log by Well Site Geologist
  - The final form of the following log curve types and images in open hole/cased hole portion of wellbore, sidetrack or bypass as per requirement.
    - Caliper and bit size
    - Tension
    - Gamma Ray
    - Spontaneous Potential (On land in water based mud)

        - Resistivity/conductivity/Induction
        - Neutron
        - Bulk density
        - Photoelectric
        - Density correction
        - Sonic or Acoustic
        - Equivalent circulation density
        - Temperature
        - Interpreted logs: porosity, water resistivity and water saturation
        - Borehole Image logs
        - Nuclear Magnetic Resonance (data mainly includes quality control curves, computed curves and T2 bin distributions)
        - Elemental spectroscopy
        - Cement Bond Logs (CBL) and Casing Colar Locator (CCL)
        - Production Logging Tool (PLT) data
        - Vertical Seismic Profiles (VSP)/ Check shot
    - Acquisition and detailed analysis of sidewall cores, rotary sidewall and/or conventional cores
    - Geochemical analysis
    - Preparation of Completion Log at end of well – includes Lithology Log data plus Open Hole or LWD log curves, gas measurements, geological formation tops
    - Preparation of End of Well Report(s): one prepared by Well Site Geologist and one by Drilling Department
    - Complete well details, analysis of well logs, testing recommendation and Final Evaluation Report by Geologist/Petrophysicist
    - Formation testing program that include any logging tool that collects pressure data and/or fluid samples from the borehole. The data acquisition includes log images, pressure gradient plots and preliminary sample analysis. It may also include the fluid related analysis like PVT analysis.
- Petrophysical interpretation work flow

- The figure below is a schematic workflow for undertaking a petrophysical analysis. The analytical process involves integrating the different data types into a detailed interpretation. This interpreted result is then the input to the reservoir model. Petrophysical analysis is a specialized skill and professionals with training in performing this work must be used to obtain reliable results.



Schematic workflow of Integrated Petrophysical Interpretation

- The first step is to check the log quality that is received from the service companies. The practice is to check the Caliper (for open hole) or cement bond log (Cased hole) or Neutron Density data for any sign for deterioration in data. After carefully identifying the quality issues and applying environmental corrections, the steps below are performed.

- Well and logging run correlation

  A combination of logs is used to correlate formations between wells. More details are in the Well Log Correlations section later in this report.

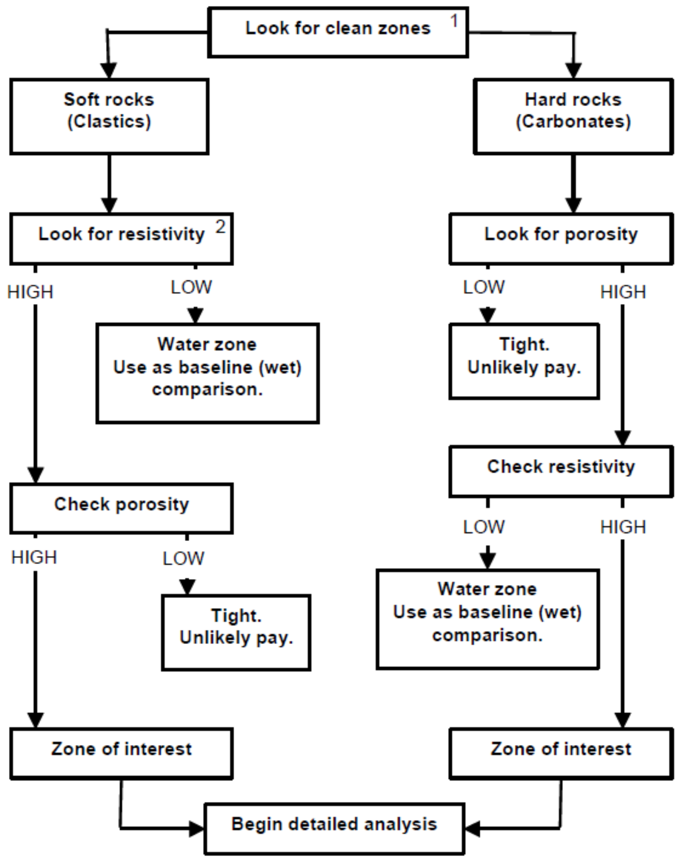
- Zone selection and Bed thickness

  - The shape and magnitude of the combination of logs can be used to estimate formation or bed thickness.

- Shale volume

  - Various empirical correlations are available to estimate shale volume using GR. The shale volume is function of gamma ray index that is estimated using the following correlations:

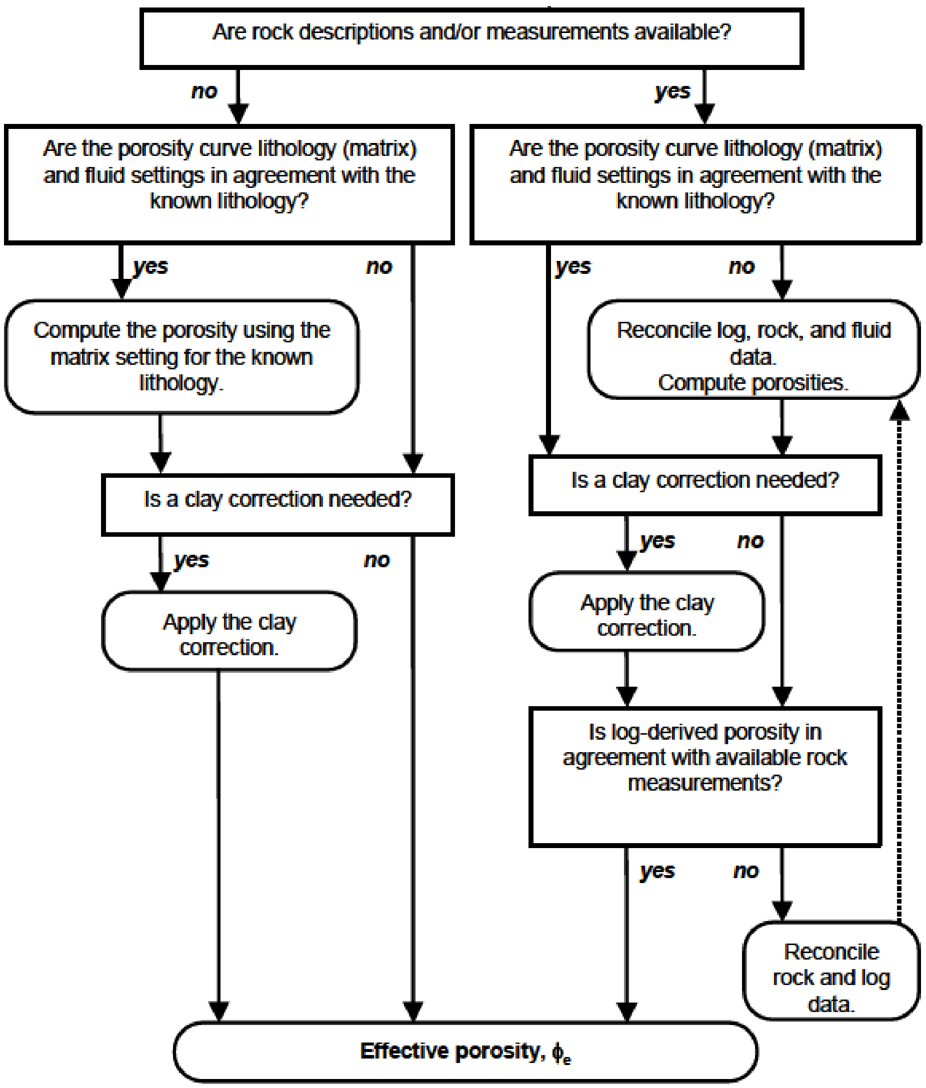
        - Stieber (Stieber, 1970)
        - Clavier (Clavier, Hoyle, & Meunier, 1971)
        - Larionov (Larionov, 1969)
    - Alternatively, shale volume can be also estimated from linear relationship with SP. Also, when Uranium is present in the formation, use of spectral gamma ray log is recommended. Using this logging tool, the shale content is approximated by Potassium or Thorium.
    - Shale volume can be also estimated from the logs like Density-Neutron and Sigma.
- TOC
    - The Total Organic Content (TOC), is the amount of organic carbon content estimated either in laboratory or logs. The amount of organic carbon indicated by the amount of Kerogen is an important indicator of hydrocarbon presence especially in unconventional reservoirs. Kerogens are known to be good sources of hydrocarbons. TOC is estimated using the following method:
        - Schmoker (Schmoker & Hester, 1983)
        - Modified Schmoker (Schmoker, 1994) (Gonzalez, et al., 2013)
        - DeltaLogR (Passey, Creaney, Kulla, Moretti, & Stroud, 1990)
        - Uranium (Gonzalez, et al., 2013)
        - NMR (Gonzalez, et al., 2013)
    - Apart from the above techniques, laboratory core measurements are also performed to estimate total organic content.
- Lithology
    - The first step of identifying lithology is to determine shale and non-shale intervals (clean). Then, the following algorithm can be followed:



Detection of zone of interest for detailed analysis (Krygowski, 2003)

- Zones which appear to be shales may be radioactive productive zones. Neutron Density cross-plot technique is a quick way of determining formation lithology. The most important aspect of the technique is determining the relative positions of the neutron and density curves (with respect to each other). Also, it can be combined with photoelectric effect curve to resolve any uncertainty (Krygowski, 2003).
- Mud log data, recorded by well site geologist, is also used to get first-hand information on lithology encountered during drilling.
- Advanced logs such as elemental spectroscopy, spectral Gamma Ray, and Image logs can also help to characterize lithology.
- The multiple logs, core and other sub-surface data are integrated either deterministic or probabilistic to create a petrophysical lithology (or facie) model.
- In unconventional reservoirs, determining the minerals is key to the determination of lithology. The mineralogy can be determined using spectral Gamma Ray data, Core study (such as petro-typing study, FTIR, ultrasonic measurements, etc.)

- Dipmeter
  - The dip angle and direction of planar surface (such as bedding, fracture, strata, etc.) required elevation and geographical position of at least 3 points. The tool measures formation parameters such as resistivity and travel time by means of 3 or more sensors mounted on caliper arms so as to scan different sides of the borehole wall. The anomalies/changes in the sensor measurements recorded with relative displacement, radial and azimuthal positions are used to compute dip relative to the tool. (Goetz, 1993)
  - The parameters are used to determine lamination thickness, contrast, continuity and frequency in thin shale sand sections, fracture geometry, density and intensity, mapping, correlation intervals and other structural and stratigraphic applications.
  - The dipmeter is presented by arrow or tadpole plot along with the well logs.
- Porosity
  - Porosity is determined by following the workflow mentioned below. Based on availability of data, the right set of log curves is used.



In case lithology is known, the work flow can be followed to determine effective porosity (Krygowski, 2003)

- Porosity is estimated using individual tools as or combination of the following:
    - Density log (Bassiouni, 1994)
    - Sonic log (Wyllie, Gregory, & Gardner, 1958)
    - Gardner-Hunt-Raymer Equation (Raymer, Hunt, & Gardner, 1980)
    - Neutron Log

- Using two porosity measurements in X-Y crossplot tends to minimize some of the environmental and lithologic effects that produces better estimates of porosity (and lithology, in case unknown) than using single porosity as mentioned above. Most of the cross-plots have similar algorithms as mentioned below (Krygowski, 2003):

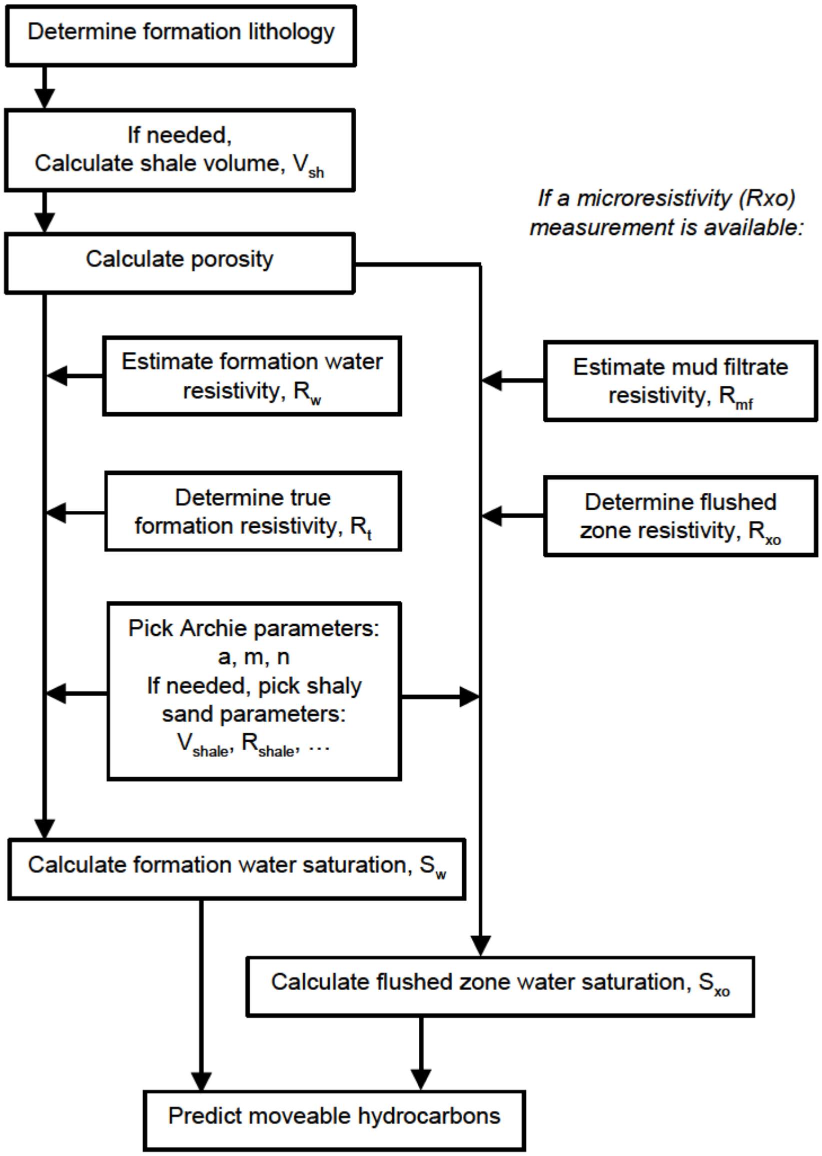
List of crossplots that are used to estimate porosity (Krygowski, 2003)with advantages and limitations

Crossplot	*Advantages*	*Limitations*
Neutron-Density	**Given two possible lithology pair solutions, the porosity will remain relatively invariant between solutions.** The combination of neutron and density measurements is the most common of all porosity tool pairs.	In rough holes or in heavy drilling muds, the density data may be invalid.
Neutron-Sonic	**Given two possible lithology pair solutions, the porosity will remain relatively invariant between solutions.** The sonic is less sensitive to rough holes than the density.	The combination of sonic and neutron data (without the density) is not common.
Density (bulk density-Pe)	Both measurements are made with the same logging tool; both will often be available.	**The choice of lithology pair will have a significant effect of the estimation of porosity.** In rough holes or in heavy drilling mud, the data may be invalid. The Pe measurement is relatively new, and will not be present in wells logged before about 1978.
Sonic-Density	Best for identifying radioactive reservoirs, rather than predicting lithology and porosity: Potential reservoirs will plot along the closely spaced lithology lines while shales will tend to fall toward the lower right of the plot. This can indicate the presence of radioactive reservoirs which are intermingled with shales (which tend to have high radioactivity).	**The choice of lithology pair will have a significant effect of the estimation of porosity.** The lithology lines are closely spaced, so any uncertainty in the measurements will produce large changes in the lithology and porosity estimates.

- Using total porosity, effective porosity is calculated by applying shale correction. Both porosities are validated with core based porosities. Also, based on depth, limited availability of advanced logging tool data such as NMR, capillary and bulk volume porosities are correlated with interpreted effective porosity (usually present throughout the well).

- Unconventional: The unconventional reservoir has more complex pore structure than conventional reservoir. It is dealt with multiple porosity system: Inter-particle, Intra-particle and organic porosities. (Loucks, Reed, Stephan, & Hammes, 2010). The organic porosities are correlated with TOC and maturity to determine the potential pore fluid contribution.

- Water resistivity and movable hydrocarbons
  - The workflow in the figure below is presented to predict movable hydrocarbons. The first three steps are discussed in the previous sections. Remaining parameter is formation water resistivity in order to estimate formation water saturation.



Workflow to predict moveable hydrocarbons (Krygowski, 2003)

- There are numerous ways to estimate formation water resistivity. One of the techniques is to calculate an apparent water resistivity from the porosity and uninvaded zone resistivity measurements. The lowest value of the apparent water resistivity in the porous and permeable zone among all other zones does indicate actual water resistivity. (Krygowski, 2003) However, there are some assumptions:
    - The zones have same water resistivity
    - The lowest value of apparent water resistivity in all zones is the true water resistivity. The higher values of apparent water resistivity are indicative of hydrocarbons.
- The other methods are:

  - From SP (Gondouin, Tixier, & Simard, 1957)
  - Using Pickett Plot (Pickett G. R., 1973) (Pickett G. R., 1966)
  - From Production tests (this can be the most accurate value when available) (Krygowski, 2003)
  - From Drill stem tests
  - From water catalogues
  - Local knowledge
  - Temperature correction (Arps, 1953)
  - Dynamic Formation Tester

- Once the knowledge of water resistivity is gained, mud filtrate resistivity is required for calculation of water resistivity from SP and water resistivity in flushed zone. Mud filtrate resistivity is acquired while logging at a specific temperature and is corrected using Arps equation (Arps, 1953).

- The water saturation of reservoir's uninvaded zone is estimated using various techniques. The true formation resistivity is one of the inputs to the techniques that is determined from deep induction or deep Laterolog corrected for invasion (Krygowski, 2003). The techniques are:

  - Archie Model (Archie, 1942)
  - Simandoux Model (Simandoux, 1963) (Worthington, 1985)
  - Poupon-Leveaux (Indonesia) model (Poupon & Leveaux, 1971)
  - Dual water Model (Waxman & Smits, 1968) (Clavier, Coates, & Dumanoir, 1984)
  - Waxman-Smits-Thomas (Waxman & Smits, 1968) (Waxman & Thomas, 1974)
  - Psuedo Archie Method

- The interpreted water saturation (S_w) is correlated with core based capillary pressure measurements and flooding experiments. Also, core plugs are used for Dean-Stark water volume determination method of estimating water saturation in order to validate the interpreted water saturation.

- In Dean Stark Distillation extraction, a core sample pore fluid water is vaporized and oil is dissolved by heated solvents. The water is collected and weighted. The oil content is the difference in total weight loss and weight of water recovered.

- Minimum recommended logging details that should be acquired in an exploration well are as follows:

- Acquisition of Open Hole/Cased Hole wireline Logs and/or LWD and/or MWD Logs that shall be used to correlate and shall at least enable an interpretation of lithology and estimation of porosity and water saturation.
- Logging suite in hole sizes of 17 ½" or greater should be at the discretion of the operator as per requirement and to include Gamma ray, Caliper, Resistivity, Sonic, Neutron and Density in hole sizes of less than 17 ½". Sonic and Density may also be required at in the shallow hole at Operator's discretion if synthetic seismograms are needed to tie well markers to the seismic data.
- Collection, bagging and description of drill cutting samples of all rock types from all geological formations shall commence at a maximum of 10 meter intervals as soon as return of drilling fluid has been established.
- Preparation of a Lithology Log based on drill cutting sample description by Well Site Geologist
- Preparation of End of Well Reports by Well Site Geologist and Drilling Department
- Well head information such as name, spud date, mud properties, temperature, deviation survey of the well (if deviated), start and stop depth, run and bit details, personnel and data acquisition details.
- Analysis of well logs, testing recommendation and Final Evaluation Report by designated Geologist/Petrophysicist.
- Formation test logging should be carried out in exploration wells to evaluate pressure gradient and type of fluids in potential or known formation.
- Fluid samples shall be taken associated with formation testing and logging.

- Composite formation evaluation is derived from solutions of petrophysical analysis integrating all available well logs (includes LWD/MWD and wireline), core and fluid data, mud data, well deviation details and previous/existing well details. The more data available, the less the uncertainty; however, the data must be calibrated, environmentally corrected and quality checked.
- Lithology, porosity, permeability and water saturation are some of the crucial data provided for geo-modeling. Such parameters can be validated or generated from Core NMR analysis. Core based NMR provides T2 relaxation cutoffs and permeability relationships for downhole logging calibration. Apart from that, it helps to determine pore structure and wettability. NMR analysis on core sample (of any lithology) provides: effective porosity, BVI and FFI, pore size geometry, pore size distribution, fluid saturation, diffusion coefficient, permeability models, wetting characteristics and oil viscosity. The above measurement also helps in evaluating NMR logs if acquired. Due to the cost and time consuming nature of the analysis, Core NMR analysis is not recommended in all situations.
- The method discussed in best practices is generally valid for all clastic reservoirs. For carbonate and thin shale sand reservoirs, correct matrix parameters should be used along

with the methodology discussed. Also, due to complexity of the reservoirs, ~~low~~ high resolution and advanced tools are more effective.

- Wireline tools in oil based mud drilling fluid are Gamma Ray, Caliper, Sonic, Litho-density and, instead of Laterolog, Induction tools are preferred.

- Formation evaluation in unconventional reservoirs is quite challenging and needs a different approach of petrophysical methodology. The shale characterization is achieved with the interpretation of TOC (organic content, kerogen maturity/vitrinite reflectance), mineralogy, geo-mechanical properties (that includes, fracture study, brittleness, moduli, etc.), detailed pore study (such as 3D imaging) and shale petro-typing. The above can be used to establish the hydrocarbon presence, volumetrics and flow capacity.

- Cased hole is recommended only when open hole cannot be acquired due to hole / wellbore instability. However, due to quality and noise issues in case hole logging, open-hole wireline is recommended to be used wherever possible.

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1.9 *Exploration Well Evaluation Practices*

1.9.1 Definitions and Discussion

- All exploration wells should follow an evaluation process to determine whether there is hydrocarbon bearing potential in the area. There are processes that take place during the drilling of the well along with formation evaluation and testing procedures that take place before the well is either suspended, placed into production, or plugged and abandoned. The logs must include sufficient coverage to cross the entire reservoir intervals.

1.9.2 Best Practices

- Minimum requirements include the following:
    - Acquisition of Open-hole/Cased-hole wireline Logs and/or LWD and/or MWD logs that shall be used to correlate and shall at least enable an interpretation of lithology and estimation of porosity and water saturation.
    - Logging suite in hole sizes of 17 ½” or greater should be at the discretion of the operator as per requirement and to include Gamma ray, Caliper, Resistivity, Sonic, Neutron and Density in hole sizes of less than 17 ½”. Sonic and Density may also be required at in the shallow hole at Operator’s discretion if synthetic seismograms are needed to tie well markers to the seismic data.
    - Collection, bagging and description of drill cutting samples of all rock types from all geological formations shall commence at maximum of 10 meter intervals as soon as return of drilling fluid has been established.
    - Preparation of a Lithology log based on drill cutting sample description by Well Site Geologist.
    - Preparation of End of Well Reports by Well Site Geologist and Drilling Department.
    - Wellhead information such as name, spud date, mud properties, deviation survey of the well (if deviated), start and stop depth, run and bit details, personnel and data acquisition details, casing Policy, Cement Data, Cement Rise.
    - Analysis of Well Logs, Testing Recommendation and Final Evaluation Report by designated Geologist/Petrophysicist.
    - Formation test logging should be carried out in exploration wells to evaluate pressure gradient and type of fluids in potential or known formation.

- Fluid samples shall be taken associated with formation testing and logging.

- Detailed program should include but not be limited to the following:
  - Logging suite in hole sizes of 17 ½" or greater should be at the discretion of the operator as per requirement and to include Gamma ray, Caliper, Resistivity, Sonic, Neutron and Density in hole sizes of less than 17 ½". Sonic and Density may also be required at in the shallow hole at Operator's discretion if synthetic seismograms are needed to tie well markers to the seismic data.
  - Increase drill cutting sample interval to 3 - 5 meters in anticipated reservoir sections or known reservoir sections.
  - Preparation of Mud Log – includes sample description plus data from sensors on rig, i.e. Rate of Penetration (ROP), weight on bit, calcimetry, oil shows, gas measurements (C1, C2, C3, iC4, nC4, iC5, nC5, Total Gas) and rock cutting lithological description.
  - Above services to be provided by a Mud Logging Contractor.
  - The Operator must report H_2S and CO_2 presence (quantitatively if possible).
  - Preparation of Lithology Log by Well Site Geologist.
  - Acquisition of Open Hole Logs and/or LWD/MWD Logs from surface to Total Depth.
  - The final form of the following log curve types and images in open hole portion of wellbore, sidetrack or bypass:
    - Caliper and bit size
    - Tension
    - Gamma Ray
    - Spontaneous Potential
    - Resistivity/conductivity/Induction
    - Neutron
    - Bulk density
    - Photoelectric
    - Density correction
    - Sonic or Acoustic
    - Dipmeter (computed)

    - Equivalent circulation density
    - Temperature
    - Interpreted logs: porosity, water resistivity and water saturation
    - Borehole image logs
    - Nuclear Magnetic Resonance (data mainly includes quality control curves, computed curves and T2 bin distributions)
    - Elemental capture spectroscopy
    - Cement bond logs (CBL) and Cased Colar Locator (CCL)
    - Pipeline logging tool (PLT) data
    - Vertical Seismic profile (VSP)
  - Acquisition and detailed analysis of sidewall cores, rotary sidewall and/or conventional cores.
  - Geochemical Analysis
  - Preparation of Completion Log at end of well – includes Lithology Log data plus Open Hole or LWD Log Curves, Gas Measurements, Geological Formation Tops.
  - Preparation of End of Well Report(s): one prepared by Mud Logging Contractor and one by Well Site Geologist and one prepared by Drilling Department.
  - Complete well details, Analysis of Well Logs, Testing Recommendation and Final Evaluation Report by Geologist/Petrophysicist.
  - Formation testing program that include any logging tool that collects pressure data and/or fluid samples from the borehole. The data acquisition includes log images, pressure gradient plots and preliminary sample analysis. It may also include the fluid related analysis like PVT analysis.
- The minimum well evaluation practices outlined in Best Practices above constitute the basic level of effort required to fully ascertain the hydrocarbon bearing potential of an exploration well and should be completed for each well. These data should be encapsulated with the Final Well Report that is submitted to DGH.

The Well Completion Report (WCR) should include following details also:-

- Kick/High Pressure encountered during drilling with depth and BHP.
- Details of any fish left in the hole.
- If Bull dozing has been carried out in the well then details of bull dozing i.e. pressure, quantity, bull dozing depth with previous shoe depth.

1.9.3 References:

1. NTL No. Feb 2010, Notice to lessees and operators of federal oil and gas leases in the outer continental shelf, Gulf of Mexico OCS region, United States Department of the Interior Minerals Management Service Gulf of Mexico OCS region.

2. International Business Publications, 2013. USA Norway Oil and Gas Exploration Laws and Regulations Handbook, Washington D.C.

1.10 *Geological Practices – Well Log Correlations*

1.10.1 Definitions and Discussion

- Operators, in accordance with the PSC, inherit the responsibility of well log correlation during the exploration phase. Good International Petroleum Industry Practices (GIPIP) for well log correlations vary greatly and are based on formation ages, well log data, lithology, palynology data, paleontology data, quality of data, etc. Since there is much variance in data when it comes to well log correlations, much of the decision lies heavily on the interpreter. It is he or she who must use their best judgment and decide how they're going to correlate based on the data they have been given.

- Construction of geological maps is necessary to define the structure in the subsurface, and to show the areal extent and variation of reservoir parameters in a hydrocarbon discovery. These maps can be used in a geological 'static' model of any hydrocarbon discovery, and so maps should be constructed in a way that they can be input into common modeling software.

1.10.2 Best Practices

- The figure below is a general work flow that summarizes the input data, interpretive steps, and output products in the process of correlating wells in an exploration or production setting. The workflow is intended to be a guideline and is a high level summary of the process but should be used at the geologist's discretion.

Workflow for well correlations

- It is recommended that GR be used as the primary correlation parameter wherever applicable and the remaining well log suite is supplemental. GR is the best indicator of lithology and has the sharpest response to changes in lithology.

- Radiometric dating techniques should be used on distinct high gamma ray beds; shales or tuffaceous beds from volcanic events. The absolute ages should provide time constraints when correlating.

- Biostratigraphy has constraints and should only be used when a sufficient data set is acquired throughout the entire well. Palynology and paleontological data is typically restricted to shales and carbonate formations, while sandstones typically have a low abundance of specimens. Fossil and faunal floras are nonexistent past certain ages so a variety of biostratigraphic data must be used to obtain a full record. The biostratigraphic record may be used as a relative age constraint when a sufficient record is collected.

- Once an absolute or relative age sequence has been established the interpreter may begin correlation of the well log suite by recognizing beds of similar well log values, responses, thicknesses, etc. Correlated formations must have similar fossil and faunal flora or must lie between similar absolute marker beds.

1.10.3 References

1. Industry experience

1.11 *Geological Practices – Geological Maps*

1.11.1 Definitions and Discussion

- Structure Maps - Structure maps should be constructed on zones of interest/marker horizons prior to drilling and should be updated after a well is drilled. The map will show the depth of the formation top in the mapped area of interest. Map contouring should honour and be consistent with the formation top picked up in well logs. Structure maps indicate the tectonic grain present in the area along with structural high and low trends and broad disposition of reservoirs. Wherever the fluid contacts are available, these can be plotted on this structure map. These maps are also useful to determine possible locations to drill for hydrocarbons.

- Thickness Maps - Two types of thickness maps may be created; an isopach or isochore. It's important to distinguish the two from each other. Typically if dip data is available, an isopach map is created. If dip data is not available, then an isochore map is created. Both maps should be created when possible, isopach maps will show the true thickness while isochore maps show vertical thickness.

- Porosity Maps - Porosity maps show the porosity distribution for a particular reservoir for a specific interval. The horizontal and vertical resolution is determined by the interpreter based upon their needs.

- Saturation Maps - Saturation maps show the distribution of fluid saturation for a particular reservoir at a specific interval. The horizontal and vertical resolution is determined by the interpreter based upon their needs.

- Reservoir Maps- These can be a variety of maps:

    - Net pay maps are maps of the hydrocarbon thickness of the reservoir rock based on resistivity, porosity and fluid contact data. These maps are needed to determine the reserves of the field. Seismic attribute maps can contribute to the contouring of the map if the attribute is shown to have a correlation to net pay.

    - Net sand maps, which are constructed from logs using gamma ray and/or porosity cutoffs, are useful for interpreting environment of deposition. A net sand map should contain all data available, even outside of the productive area of the field. Seismic attribute maps can contribute to the contouring and extending the map if the attribute is shown to have a correlation to net sand.

- Net to gross sand percentage map can be constructed by using the entire reservoir interval as a gross value and the net sand from the cutoff values. This map can also be useful in field development and environment of deposition interpretations. Seismic attribute maps can contribute to the contouring and extending the map if the attribute is shown to have a correlation to sand percentage.

- Another useful map is the product of the porosity*thickness (PhiH map), which gives the pore volume of the reservoir and can show possible trends to exploit during development. Seismic attribute maps can contribute to the contouring of this map if the attribute is shown to have a correlation to porous feet of a reservoir.

- A useful addition is to multiply this pore volume map times saturation, this will give a map of hydrocarbon pore volume of the reservoir (SoPhiH map). This map can also indicate areas which can be exploited during primary, secondary or tertiary field development. Seismic attribute maps can contribute to the contouring and extending the map if the attribute is shown to have a correlation to hydrocarbon pore volume.

- If there is sufficient data to show a good correlation between porosity and permeability then permeability maps (k map) can be constructed by multiplying the porosity map by that correlation algorithm. Sufficient core permeability data is needed to make the algorithm accurate.

- The product of the permeability and hydrocarbon pore volume maps (kSoPhiH map) are very useful in planning field development.

- Fluid Contacts - There are several types of contacts which need to be determined and mapped: oil-water, gas-water, oil-gas, oil-down-to, gas-down-to. These contacts are displayed on a structure map and are indicated by a contour line that is distinguishable from the other contour lines.

- Faults and Other Geological Boundaries - Faults are denoted on structure maps by polygons. Faults are projected on the structure map where they intersect at that particular depth. The contours lines must honor the fault by following the basic contouring laws mentioned in the contouring section below. Wavy lines represent the location where formations or reservoirs sub crop due to unconformities.

1.11.2 Best Practices

- Contouring

  - Contouring is an integral step in the creation of structure maps, thickness, maps, porosity maps, etc. Basic contouring laws must be followed, but there is stylistic liberty where there is limited information or if regional geology indicates probable patterns.

  - A contour map has data on it separated by isolines, which are lines of equal value. The name of an isoline is dependent on the data being contoured (stratigraphic thickness = isopach; true vertical thickness = isochore; elevation = contour line).

- Contour lines are straightforward:
  - a contour line cannot merge with other contour lines
  - repeated contours indicate a slope reversal
  - hachured contour lines indicate depressions
  - contour lines cannot cross each other (except overhanging surfaces in which case it is best practice to map two maps or use different colors to distinguish upthrown and downthrown blocks)
  - the contour interval must remain constant
  - every 5th contour is labeled
  - all values between two contour lines must be within the contour range
  - each contour is a continuous line that must be closed within the map, project outside the map, or intersect a fault break (Evenick, 2008).
- To construct a contour map, the interpreter should first accurately plot the desired data on a base map, and add a scale bar and north arrow. Then determine the maximum and minimum values and choose a contour interval that would allow a desirable number of contours to be drawn on the map. Too many contour lines will clutter the map and too few contour lines will not adequately portray data patterns. The interpreter should draw contour lines through and around the data until all the data falls properly between contour lines. Contour lines should pass closer to data with similar values and farther away from data with considerable different values. Sometimes it's necessary to draw a circular contour line around a data point, but this may indicate an invalid point (Evenick, 2008).

- Structure Maps
  - Structure maps should be constructed on zones of interest prior to drilling and should be updated after a well is drilled. The map will show the depth of the formation top in the mapped area of interest. Map contouring should honor and be consistent with the formation top picked in well logs.
- Thickness Maps
  - Thickness maps should not be constructed until after structure maps have been created and quality checked with formation tops from well logs.
- Porosity Maps
  - The decision to prepare a separate map on the top of porosity, where the upper portion of a unit is not productive or is a correlative marker above the actual reservoir, needs to be made on a reservoir-by-reservoir basis. Depending upon the geometry of the reservoir and thickness of the zone, the difference in volume

between a map on the top of a correlative marker and a map on the top of porosity may be too insignificant to warrant additional mapping.

- Top porosity maps are created based off of marker data for the reservoir of interest. Top porosity maps differ from structure maps in regard to showing the actual reservoir configuration instead of the overall structure. A marker at the top of the reservoir is picked off of e-logs. Top porosity maps should only use well data when sufficient well data is present. If there is poor well control, top porosity maps may trend structure maps and honor top reservoir markers in existing wells.

- Saturation Maps
  - Generally, saturation maps use a S_w-height function as best practice. S_w-height modeling allows spatial distribution of S_w, aerially and vertically. Typically it is impractical to map Archie inputs and parameters because they may introduce inadvertent consequences. S_w-height models can be applied to dynamic simulation, thus maintaining equilibrium with rock properties. Saturation maps may then be displayed on each of the pay horizon surfaces.

- Reservoir Maps
  - To be constructed after sufficient wells data is available, i.e., after field discovery during appraisal and development.
  - Net pay maps are essentially thickness maps of the hydrocarbon bearing zones being produced. A cutoff of resistivity and porosity of the minimum productive zone is used to as a lower bound for generating thickness values from logs then the values are contoured. This map is useful for infield development.
  - Net sand maps are essentially thickness maps of the potential reservoir and usually would use all well data available even outside of the known field boundaries. A cutoff value of gamma ray and porosity can generate the thickness data which would then be contoured. This map is useful for environment of deposition and can provide ideas about the more permeable trends in the reservoir.
  - Net to gross maps can be constructed for sand or pay. The data is from the log and uses a predetermined cutoff using gamma ray, porosity or resistivity or a combination of two or three depending on the net value to be generated. See above net pay and net sand discussions. The net value is divided by the gross interval of sand or pay in the logs to give the ratio.
  - The Phi-H or reservoir pore volume map is constructed using well log data and an average porosity value over the reservoir interval. Another way to model these values is with a geostatistical approach to create the map.
  - Once the PhiH and hydrocarbon saturation maps are created then it is only necessary to multiply the two maps to get the hydrocarbon pore volume (SoPhiH) map.
  - A permeability (k) map is created by multiplying the reservoir pore volume map by an algorithm based on core permeability to core porosity correlation.

  - Multiplying the permeability map times the hydrocarbon pore volume map will get the kSoPhiH map to show the potentially most productive areas of the field.

- Fluid Contacts
  - Fluid contacts in a discovered hydrocarbon deposit can be mapped in different ways. Good Industry Practice requires using a combination of methods to determine fluid contacts, and then to map them on a structure map.
  - The methods for determining the contacts are:
    - Oil and gas down-to depths using electric logs.
    - Oil and gas down-to depths using electric logs, in particular the resistivity curves to define the hydrocarbon and water zones. The water zones will typically have lower resistivity than hydrocarbon zones.
    - Dynamic Formation Tester pressure measurements can be used to define zones with oil or gas pressure gradients, which are distinct from pressure gradients in a water zone.
  - Once a contact is determined, it should be represented by a contour on the structure map.
- Faults and Other Geological Boundaries
  - Faults may be interpreted and mapped using seismic lines which offsets the reservoir/formation.
  - Faults may also be determined using well log correlations and represented on the map.
    - If a well path crosses a normal fault, there will be a zone of missing section when the well is correlated to other nearby wells.
    - If a thrust or reverse fault cuts a well, there will be a zone of repeated section in the well log.
  - Another boundary which can trap hydrocarbons is an unconformity. Angular unconformities can be mapped on seismic when a prominent bed truncation is visible. Unconformities can also be mapped with well data, and in particular paleo data may show zones in the well with gaps in the ages of strata encountered in the well.

1.11.3 References

1. Evenick, J.C., 2008, Introduction to Well Logs & Subsurface Maps: Tulsa, PennWell Corporation, 236 p.

1.12 *Geological Practices – Resource and Reserve Estimation*

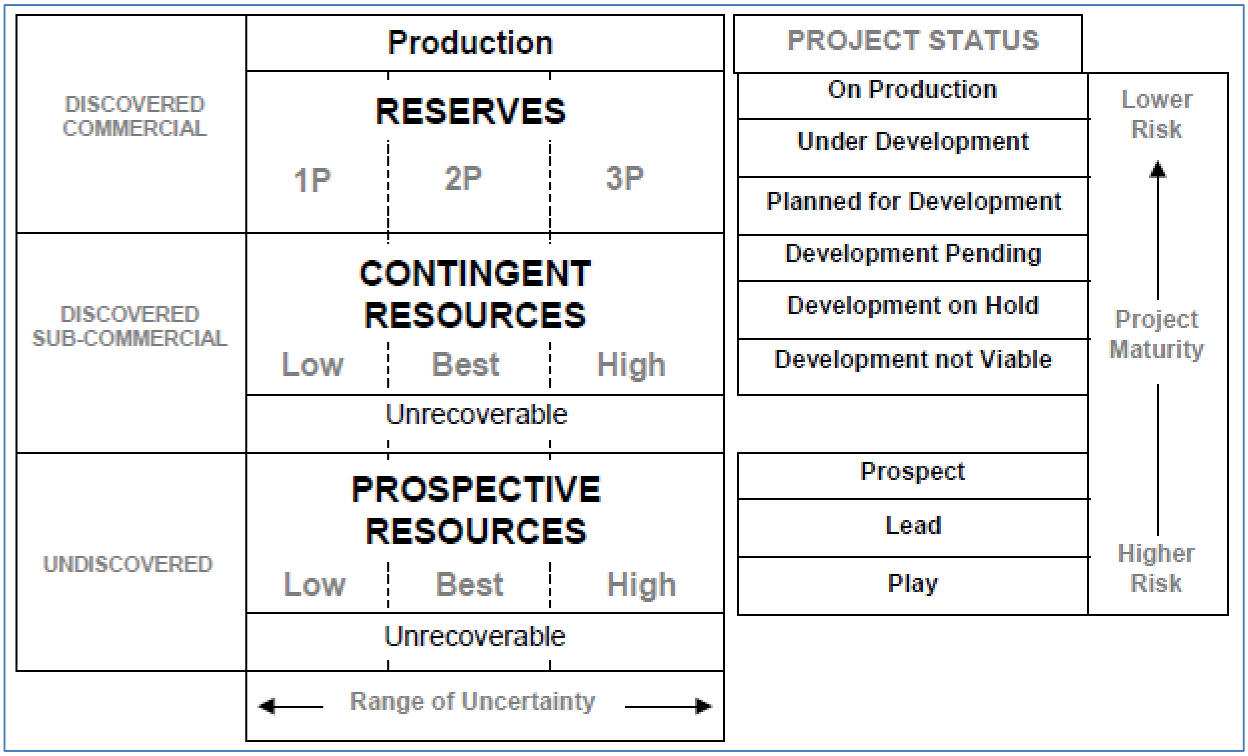
1.12.1 Definitions and Discussion

According to the SPE Oil and Gas Reserves Committee (OGRC) final report of 2005, the goal of resource classifications is to provide a common framework for estimating quantities of oil and gas, both discovered and undiscovered, associated with reservoirs, properties and projects. The classification should cover volumes originally in-place, technically and/or commercially recoverable, on production or already produced.

In the initial phase, a potential accumulation is identified, the hydrocarbon type(s) is forecast, a range of in-place volumes are assessed, and a chance of discovery is estimated. These undiscovered volumes are termed Prospective Resources. Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Prospective and contingent resources are classified dependent on the projects status, as illustrated in the table below. Prospective resources are undrilled plays, leads, or prospects, while contingent resources may be developed later subject to certain contingencies. The prospective and contingent resources have a range of uncertainty, which can be captured by Low, Best, and High estimates.

Based on results of an exploratory well, all or a portion of the recoverable volumes in the accumulation may be categorized as discovered, and economic discoveries are categorized as Reserves. Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. For reserves the range of uncertainty is captured by 1P (highest certainty), 2P, and 3P (lowest certainty) volumes.



Resource estimates may be prepared using either deterministic or probabilistic methods. A deterministic estimate is a single discrete scenario with in a range of outcomes that could be derived by probabilistic analysis. In the deterministic method, a discrete value or array of values for each parameter is selected based on the estimator's choice of the values that are most appropriate for the corresponding resource category. A single outcome of recoverable quantities is derived for each deterministic increment or scenario. Deterministic estimates may have broadly inferred confidence levels, but they do not have quantitatively defined probabilities. Nevertheless, a range of uncertainty may be captured by doing a Low, Mid, and High deterministic volumetric estimate.

In the probabilistic method, the estimator defines a distribution representing the full range of possible values for each input parameter. These distributions may be randomly sampled, typically using Monte Carlo simulation software, to compute a range and distribution of in-place and recoverable quantities. This approach is most often applied to volumetric resource calculations in the early phases of exploration and appraisal projects.

SPE guidelines state both deterministic and probabilistic methods may be used to estimate petroleum volumes.

A number of oil industry consulting companies provide volumetric estimation and reserve audits, and each has an established methodology. The following reviews the methods employed by some of these companies, from a survey of industry reports.

- DeGolyer & MacNaughton

D&M classifies resources in accordance with the PRMS approved in March 2007 by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers.

- Standard probabilistic methods are used in the uncertainty analysis. Probability distributions are estimated for porosity, petroleum saturation, net hydrocarbon thickness, geometric correction factor, recovery efficiency, fluid properties, and productive area for each prospect. The probability distributions are input to a Monte Carlo simulation to produce low estimate, best estimate, high estimate, and mean estimate prospective resources for each prospect.

- The parameters used to model the recoverable quantities are productive area, net hydrocarbon thickness, geometric correction factor, porosity, petroleum saturation, formation volume factor, and recovery efficiency. Minimum, mean, and maximum distributions are used to statistically model the input P_{90}, P_{50}, and P_{10} parameters. Productive area and net hydrocarbon thickness are modeled using truncated lognormal distributions. Truncated normal and triangular distributions were used to model geometric correction factor, formation volume factor, and recovery efficiency. Porosity and petroleum saturation were modeled using truncated normal distributions.

- A geologic chance factor, P_g, is applied to estimate the quantities that may actually result from drilling these prospects. P_g is defined as the probability of discovering reservoirs that flow petroleum at a measurable rate. P_g estimates were made for each prospect from the product of the probabilities of the four geologic chance factors: trap, reservoir, migration, and source. For multiple zones in a prospect, the highest zonal P_g is used to represent the prospect P_g.

- Prospective resources are presented both before and after adjustment for Pg. The 'Pg-Adjusted Mean Estimate' is calculated by multiplying Pg by the prospect's Mean estimate. Total prospective resource estimates are based on the probabilistic summation of these Pg-Adjusted Mean Estimate for the total inventory of prospects.

- D&M makes an estimate of the Predictability vs Portfolio Size (PPS). This involves an estimate of how many prospects in the portfolio must be drilled to yield at least one success. PPS also provides an estimate, given the current set of geologic chance factors and probabilities of geologic successes in the portfolio, of the estimated mean number of geologic discoveries.

- RPS

  - RPS volumes and risk factors are calculated in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (PRMS). Estimating the range is undertaken in a probabilistic way (i.e. employing Monte Carlo simulation), by using a range for each input parameter to derive a range for the output volumes. Key contributing factors to the overall uncertainty are data uncertainty (both quantity and quality), interpretation uncertainty and model uncertainty. Volumetric input parameters, Gross Rock Volume (GRV), porosity (Ø), net-to-gross ratio (N/G), water saturation (Sw), fluid / gas expansion factor (Bo or Bg) and recovery factor, are considered separately.

- Volumetric estimates are prepared probabilistically using Logicom's REP™ Monte Carlo program.
  - Gross rock volumes (GRV) are derived using Area / Depth contours defined by top reservoir surfaces.
  - The P50 gross reservoir thickness of each target formation is based upon the penetrated thickness in the well with +/- 10% variability applied to account for possible thickness variability across the structure.
  - The maximum mapped closing contour is taken as the P10 input allowing for mapping uncertainty and possible deeper contacts, but with the distribution upside clipped at 110% of the P10 value to ensure unrealistic spill points are excluded. The P90 input is adjusted so that the derived minimum value on the distribution equaled the smallest justifiable area of the structure which is often the 4-way dip (i.e. non-fault seal dependent) closure.
  - A petrophysical assessment provides the basis for the range of inputs for the reservoir parameters used in the program REP. For fractured reservoirs dual porosity (matrix and fracture) systems are predicted. Net to gross ratio (N/G) ranges for the matrix are based on the RPS petrophysical sensitivities; whereas for the fracture element N/G was set at 100% as it was assumed that fracturing could affect the whole of the gross reservoir interval.
  - Matrix porosity ranges are established petrophysically. Fracture porosity is assumed to range between 0 and 1% Sw ranges, guided by regional information, are used for the matrix porosity across all target horizons. More optimistic (lower) Sw values are applied to the fracture porosity.
  - Formation volume factors (Bo) are varied according to the hydrocarbon indications and published details of oils encountered in nearby fields and discoveries. Bo is assumed to increase with depth as the oil API increases.
- Recovery factors (RF) are applied deterministically. A range of recovery factors for the matrix pore volume are applied, whereas for open fracture pore volume higher recovery factors are predicted. Volume weighted recovery factors, for matrix and fractures, are used to derive the technically recoverable volumes.
- Volumes categorized by RPS as Prospective Resources have an associated Geological Probability of Success (GPoS).RPS assesses risk by considering both a Play Risk and a Prospect Risk. When assessing undrilled prospects RPS assigns a geological Chance of Success (CoS) which represents the likelihood of source rock, charge, reservoir, trap and seal conspiring to result in a present-day hydrocarbon accumulation. RPS considers three factors when assessing Play Risk: source, reservoir, seal and consider four factors when assessing Prospect Risk: trap, seal,

reservoir and charge. The CoS for the Play and Prospect are multiplied together to give a Geological Probability of Success (GPoS). The result is the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to surface.

- RPS aggregates Prospective Resources by a statistical consolidation including the geological probability of success.

- For reserves, a range of reserves are determined deterministically according to whether a zone was tested, its structure fill-point (LKO vs. spill) and distance from the discovery well. The terminology used is 1P (Proved; P90), 2P (Probable; 1P+2P; P50) and 3P (Possible; 1P+2P+3P; P10). The 1P, 2P, and 3P areas are based on proximity to the discovery well and an assumed structural fill.

- Schlumberger

    - Each prospect is assessed using the GeoX software, an application that creates a Monte Carlo simulation of all possible outcomes. The simulation calculates the prospect's chance of success (chance that at least one zone will contain enough oil to be called a "discovery") and the prospect's resource uncertainty.

    - Volumetric calculations are made using GeoX. For each prospect, the following assessment workflow is utilized:

        - Define the appropriate reservoir parameters for each zone.

        - Estimate resource uncertainty for each individual zone.

        - Estimate the chance of success for each individual zone.

        - Aggregate the zones to define the prospect's resource uncertainty and chance of success.

        - Aggregate prospects to define the resource uncertainty and chance of success for the block or area of interest.

    - A prospect's resource is the recoverable hydrocarbon within the prospect. Uncertainty refers to the range of possible resource volumes, and their associated probabilities, that may be contained within a prospect. Risk is the chance of failure: the probability that a prospect will contain an insignificant resource volume. The chance of success (COS) is 1 – Risk. A prospect's chance of success is roughly the probability that the prospect will contain enough hydrocarbons to be called a discovery, though not necessarily enough to be economic.

    - For an individual reservoir or formation within a prospect (referred to as a zone), resource uncertainty is a function of parameters such as thickness, column height, net-to-gross, porosity, recovery factor, and the uncertainty around those individual parameters. The chance of success for each individual zone is estimated by the assessment team. For a multiple-zone prospect, both the resource uncertainty and the chance of success are a result of aggregating the potential zones within the prospect. The prospect aggregation accounts for the chance that a given zone will contain oil, the potential oil volumes within each zone, and the number of zones that may succeed.

- When aggregating the zones within a prospect, the Trap and Charge elements are assumed to be dependent. In any given realization, a closure (trap) is assumed to be either present for all zones, or absent for all zones. Likewise, in a given realization, the source-migration system either charges all zones or fails to charge all zones.

- In order to create a proper aggregation of a multiple-zone prospect, the chance of success (COS) is estimated for each individual zone. COS is estimated by examining four geologic elements (trap, seal, reservoir, and charge) and estimating the probability that each element is present and is adequate to support a volume large enough to be deemed a discovery (though not necessarily a commercial discovery). In Schlumberger's terminology the chance for each element is known as the Chance of Adequacy. Multiplying the chances of adequacy yields the zone's chance of success.

1.12.2 Best Practices

- Prospective Resource Estimation

  - Resources should be estimated with a proper range of uncertainty, depending on the information available. Probabilistic (Monte Carlo) methods should be used when reservoir and mapping input parameters are not well known. In the probabilistic method a P10, P50, and P90 volumetric estimate are usually provided, along with a Mean.

  - A deterministic assessment can be done when parameters are well constrained by well control. Reservoir parameters like gross thickness, net-to-gross (NTG), porosity, and oil saturation are computed using petrophysics. GRV above an assumed oil-water contact is obtained from mapping programs. Uncertainty can be captured in a deterministic estimate by doing Low, Mid, and High cases.

  - For prospects with multiple zones, a prospect aggregation should be done. The aggregation will be a prospect volumetric estimate that is a chance-weighted volumetric estimate that incorporates the chance a given zone will contain oil, the potential oil volumes within each zone, and an estimate of the number of zones that may succeed on the prospect.

  - Risked resources should be presented by applying a geologic chance factor to the unrisked volumes. Prospective resources should be presented both before and after adjustment for the GCF/COS/POS. Total prospective resources estimates should be based on the probabilistic summation of the volumes, summed across the total inventory of prospects.

- Reserve Estimation
  - After a successful exploration well, reserves may be estimated. The reserve estimation will take into account results from an appraisal work program, and from a development plan.
  - Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied.
  - Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status.
  - To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable timeframe.
  - For reserves the range of uncertainty is captured by 1P, 2P, and 3P volumes. The terminology used is 1P (Proved; P90), 2P (Probable; 1P+2P; P50) and 3P (Possible; 1P+2P+3P; P10).
  - The range of reserves can be determined deterministically by using a range of estimates of structure fill-point or by using polygon areas that vary by the distance from the discovery well.
  - The SPE guidelines as defined in the 2007 Petroleum Resources Management System and the 2011 Guidelines for Application of the Petroleum Resources Management System are very succinct in their definition of the resource and reserve calculation and allocation process and should be followed for consistency with all parties.

1.12.3 References

1. Oil industry reports on resource estimation.
2. Guidelines for Application of the Petroleum Resources Management System. November 2011. http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf
3. Petroleum Resources Management System. 2007. http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

1.13 *Geological Practices – 3D Volumetric and Computer Models*

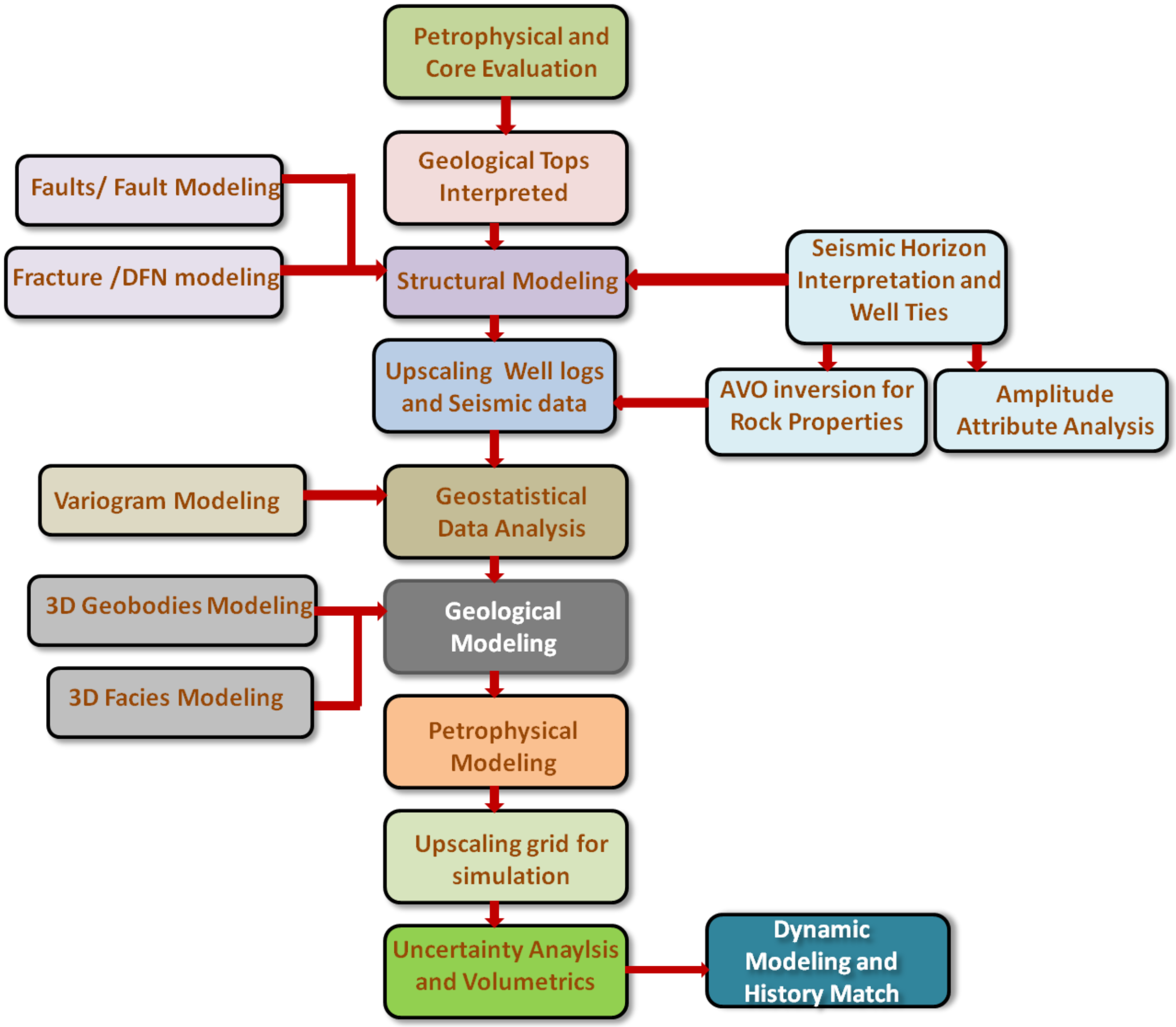
1.13.1 Definitions and Discussion

Creating a model of the reservoir is becoming a common practice during several stages of the reservoir life. From exploration to field abandonment, reservoir modeling pursues the general goal of understanding and predicting important geological, geophysical and engineering components of the reservoir. Knowledge about the properties of the reservoir changes from one stage to the other as more data become available. During the early exploration stages the need to estimate the OOIP in the reservoir takes precedence; however, during the late production stages the necessity of forecasting production for the next few years, with the purpose of planning new wells or new surface facilities becomes very important.

Reservoir modeling calls for the integration of expertise from different disciplines, as well as the integration of data from various sources. Each type of data provides information about the reservoir heterogeneity on a different scale; therefore, they have different degrees of accuracy and redundancy.

The reservoir model needs to simultaneously (not hierarchically) honor all available data, both static (well-log, geological information and 3D seismic) and dynamic (production), in order to preserve its predictive capabilities.

The following flowchart depicts a general roadmap for the 3D geological modeling process.



General road map for 3D modeling process

- Input Data / Acquisition
  - Surface data in depth or in time
    - point data
    - line data
    - grid data
  - Well data
    - well locations
    - well deviation surveys

        - well logs
        - well completion data
        - casings and liners
        - well tops / markers
    - Fault data
        - Fault polygon
        - Fault surface
        - Fault sticks
        - Seismic Interpretation
    - 3D grids
    - Core data
- Data Editing and Quality Control
    - Well data
        - Well section
        - displaying logs
        - well correlations
        - visualizing and editing well tops/markers
        - creating new well tops
    - Surface data
        - editing the input point data or line data
        - creating surfaces
        - choosing the correct gridding algorithm
        - well correction for the gridded surface
        - editing the gridded surface (if necessary)
        - creating and honoring fault polygons and the map
- Stratigraphic Modeling (Geological Modeling)
    - Well correlations

        - Displaying data
        - Well tops
        - Well correlations
        - Editing well tops
        - Creating new well tops
        - Making surfaces from well tops

- Fault Modeling
    - Corner Point Gridding
    - Fault Sticks
    - Fault Polygons
    - Digitize the fault polygons on the surface
    - Creating the key pillars
    - Adjusting the key pillars
    - Connecting the faults
    - QC the faults and the truncation at the faults
    - Creating a segment grid boundary
    - Inserting Trends and Directions to the fault
    - Building Pillar grid
    - QC the skeleton of the Pillar Grid
    - Insert Surfaces into the skeleton
    - Make horizons
    - Tying Horizons to well tops
    - Fault settings to the horizon
    - QC of the resultant horizons using an intersection plane
    - Make zones
    - QC the zones by building intersection windows
    - Layering the zones

  - QC the layering using the resolution of the well logs
- 3 D Grid Construction
  - Construct the structural grid
  - Define the 3D grid domain
  - Corner point gridding
  - Create the skeleton
  - Insert surfaces into the skeleton
- Stratigraphic Architecture for the Flow Units (Unfaulted Model)
  - Make horizons
  - Tying the horizons to the well tops
  - Well influence radius
  - Make zones
  - QC the zones by building intersection windows
  - Layering the zones
  - QC the layering using the resolution of the well logs
- Scale up Well logs
  - Arithmetic average
  - Statistical check of the scaled up well logs
- Facies Modeling
  - Fluvial modeling
  - Geometry
  - Drift
  - Sequential Indicator Simulation
  - Interactive facies modeling
- Petrophysical Modeling
  - Deterministic modeling
  - Stochastic modeling

  - Stochastic modeling conditioning to facies

- Volume Calculations
  - Calculating bulk volume
  - Calculating STOIIP with Phi, S_w
    - Individual runs
    - Monte Carlo simulations
  - Construct report

1.13.2 Best Practices

- Input data acquisition Data editing and Quality control
  - Acquire well and core data
  - Convert well.las files to .gslib with subsea depths
  - Convert lat-long to X-Y
  - Load well data
  - Study regional geology, petroleum system
- Well Correlations
  - Review markers for top and base of reservoir targets
  - Construct stratigraphic cross-sections, adjusting markers if necessary
- Structure
  - Review the input surfaces
  - Import surfaces and create 2D grid
  - Create structure maps on Top of reservoir horizons and seals
  - Create isopach map of reservoir sands
- Fluid Contacts
  - Analyze well tests, create stick plots of oil, gas, water in wells
  - Determine free water level and fluid contacts (oil-water, gas-oil)
- Fault modeling
  - Import fault data as fault planes, fault sticks or fault polygons

  - Create fault surfaces from the input data by creating 2D grid for the surfaces
  - Edit the faults if necessary using key pillars
  - Connect the faults wherever necessary
- 3D Grid Construction
  - Create a 3D grid skeleton
  - Create a grid boundary and quality check the 3D grid
  - If creating a faulted grid, QC the skeleton grid and create segment grid boundary
  - Insert the surfaces into the 3D skeleton grid
  - Tie the surfaces in the grid to the markers
  - Create zones
  - Review the zones using intersection planes for quality control
  - Layer the zones accordingly and review the layering using the resolution of upscaled well logs
- Petrophysics
  - Cross-plot well data and core data
  - Generate calculated curves for Vshale, porosity and permeability
  - Analyze capillary pressure data; plot J curves, plot S_w as a function of J (phi, k, Pc)
  - Calculate oil and gas saturation as a function of height above free water level
- Lithofacies
  - Cross-plot well data and core data; identify data clusters
  - Relate measured values to lithofacies types (core data)
  - Create a LITH log for each well, assigning a number to each lithofacies
  - Map lithofacies distribution
  - Relate maps to environments of deposition
  - Investigate seismic attributes that may correlate spatially to lithofacies
- Lithofacies and Property Distribution in 3D
  - Create property (PHI, K, LITH) files based on petrophysical analysis of wells
  - Create variograms for each property showing how well the data correlates spatially

- Determine a randomly selected path to visit unsampled locations
- Use geo statistical methods to estimate values at unsampled locations
- Sequential Gaussian Simulation is generally regarded as good oil field practice
- Distribute Lithofacies in a Sequential Indicator simulation
- Distribute Porosity by lithofacies in a hybrid Gaussian simulation
- Distribute Permeability by lithofacies in a Gaussian co-simulation
- Distribute S_w by height above FWL, using 3D lithofacies, porosity, and permeability grids

- OGIP and OOIP
  - Calculate gas-in-place and oil-in-place using Phi and S_w grids with fluid contacts
  - Prepare final report

1.13.3 References

1. Industry experience

1.14 *Geological Practices – Heterogeneous 4D Surveys*

1.14.1 Definitions and Discussion

- 4D seismic is a multi-disciplinary technology in that geophysicists, geologists and engineers must work together to integrate the disparate data that is modeled to create value out of the technology.

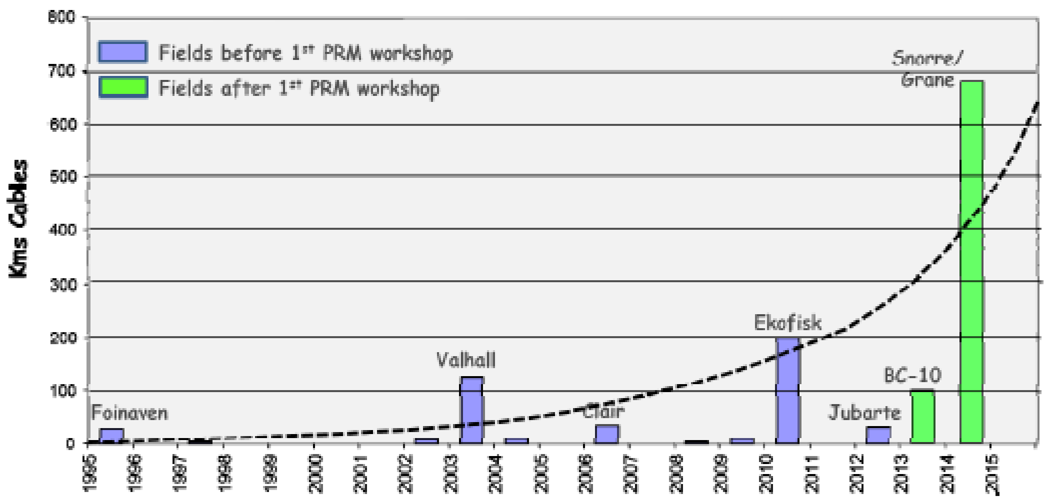
- 4D Seismic surveys have been utilized over the last two decades in the monitoring of the results of producing oil and gas fields to determine where bypassed pay or reservoir that is not in communication with the producing horizons.

- By definition, a 4D seismic survey is a repeat 3D survey over the same field at a later point in time—time being the fourth dimension. Repeatability of the survey data is an underlying requirement and includes both considerations of the geometry of the survey and the geological nature of the problem being addressed. The second, third, and subsequent surveys must be calibrated such that the relative amplitude differences observed in the follow-on surveys are verified to be due to changes in rock and fluid properties resulting from production of hydrocarbons or injection of water into the reservoir.

- 4D surveys can be used simply on an empirical basis to visually inspect the areas within an interpreted seismic sequence that have undergone change in the period of time that has elapsed since the previous survey, then to draw conclusions based on those observations.

- Obtaining the greatest value in 4D seismic surveys requires detailed planning and analysis in advance and then calibration of the results to ascertain the changes in rock and fluid properties that have occurred over the intervening period. The technology has evolved to Permanent Reservoir Monitoring (PRM) installations to improve quality and frequency of 4D surveys.

- The figure below shows the North Sea area 4D installed base of PRM installations. The impact of these installations has been that PRM systems originally designed for reservoir management and placing infill wells are now used for well optimization, frac monitoring, EOR, monitoring water injection, and well surveillance for HSE monitoring.



North Sea 4D PRM installations Keynote Address (Second EAGE Workshop on Permanent Reservoir Monitoring 2013)

- 4D seismic is frequently attempted using existing 3D datasets as the baseline. The issue with this approach is primarily that there are significant differences in the noise environment between the surveys. Success in using this approach is dependent on how well the processing contractor can address the noise and balance the amplitudes between the original and follow-on surveys.

- In an ideal setting, 4D seismic data from multiple surveys would all be acquired using an identical geometry. In some cases the use of existing 3D surveys and calibrating subsequent 3D surveys to match in background amplitude response is done to address changes that occurred in fluid content from the original survey to future repeat surveys. Different geometry makes calibration more difficult but does not preclude using surveys not recorded with identical parameters. Reliability of results from dissimilar surveys is diminished but it may be the only means of obtaining a baseline measurement.

- 4D surveys over heterogeneous reservoirs will enable the geologists and engineers to plan development wells by identifying reservoir areas that are not being effectively drained by the current wells. Although this is a case where 4D seismic is of significant value, there are other instances where the 4D seismic may be useful including evaluation of structural changes throughout the history of the field due to hydrocarbon extraction, passive seismic monitoring for fracture propagation during frac operation as well as during production; and for Carbon Sequestration projects it is a way to monitor changes in the rock properties related to the injection of CO2 for storage.

- 4D seismic technology is recommended for large scale developments both onshore and offshore. Through integrating production data, rock properties, petrophysical log results and seismic data into a holistic interpretation, greater recovery of the oil or gas from fields is possible. The EAGE conference on PRM has demonstrated that the technology is being employed broadly and is being used successfully. Norway has been a strong supporter of the technology. It has aided in moving recovery factors into the 60% range.

- Other considerations for the use of 4D seismic surveys are the economics of the data's impact on field development. Seismic data that demonstrates changes in rock properties related produced hydrocarbons is very impactful. Scale of the project will dictate how large of an investment is justifiable. The both the figure above and the table below are included to provide some insight into the scope and timing for many of these projects. The technology has demonstrable value and for many of the Host Governments they are finding value in the use of 4D seismic technology to improve recovery factors from fields that have been in decline for many years.

Permanent Reservoir Monitoring employed in the North Sea and Offshore Brazil (first break volume 32, May 2014)

Field	Operator	Installation	Seismic cable	Sensor coverage	Water depth	Number of surveys
Valhall	BP	2003	120 km	45 km²	70 m	16
Clair	BP	2006	45 km	11 km²	140 m	5
Ekofisk	ConocoPhillips	2010	200 km	60 km²	75 m	6
Snorre	Statoil	2013-14	480 km	190 km²	325 m	-
Grane	Statoil	2014	180 km	50 km²	130 m	-

Field	Operator	Installation	Seismic cable	Sensor coverage	Water depth	Number of surveys
Jubarte	Petrobras	2012	36 km	9 km²	1250 m	2
BC-10	Shell	2013	95 km	36 km²	1650 m	1

1.14.2 Best Practices

- 4D seismic technology is recommended for large scale developments both onshore and offshore. Through integrating production data, rock properties, petrophysical log results and seismic data into a holistic interpretation, greater recovery of the oil or gas from fields is possible.

- Designing a 4D Seismic Survey Project normally includes the following sequence of events:

    - Initial Rock Property Studies

- Upon successful discovery of a hydrocarbon accumulation a detailed petrophysical study of the reservoir is undertaken. This study needs to incorporate all of the core and wireline data available that depicts the reservoir as well as non-reservoir sequences in the well. It is important to establish an understanding of the properties of the productive as well as non-productive intervals along with the boundaries that generate the reflection coefficients observed in the seismic data.

- Understanding the influence of fluid content on seismic reflection amplitudes is critical. Laboratory studies of the reservoir rocks under pressure with water – oil – gas saturations will improve the ability to determine what any observed amplitude changes represent.

- Another affect that may be studied is the impact of consolidation of the reservoir after production has reduced the reservoir pressure. In some cases this pressure reduction leads to collapse of the reservoir which results in changing the rock properties independently of the fluids contained in the pore spaces.

o Modeling of seismic response

- The rock properties study enables the geophysicist to undertake a more detailed study of the impact of hydrocarbon presence in the reservoir. This study will investigate the impact of offset or reflection angle at the seal / reservoir contact and where applicable the model response at fluid contacts. The objective of this modeling exercise is to establish whether there is any quantifiable observation that is possible based on the potentially different rock properties that may be present in the reservoir. The modeling will also lead to better understanding of the requirements during the acquisition of the 4D surveys to follow.

o Calibration of Initial 3D Seismic Data

- In many cases there is a 3D seismic survey that was shot prior to the exploration discovery. The results of the rock properties study will enable the geophysicists to further calibrate this survey to demonstrate whether the original survey was able to discern the gas-oil and /or oil-water contacts based on amplitudes in either the pre-stack or post-stack data. Full Waveform Inversion may be utilized particularly if the original survey was acquired using a wide azimuth geometry.

- The initial calibration is significant for several reasons. It provides insights into whether the initial state of the reservoir is yielding a seismic response that is indicative of the presence of hydrocarbons. It also helps to determine what the effective processing flow for subsequent surveys may need to be to provide accurate estimates of changes in the reservoir properties. A lack of AVO response may not be sufficient to indicate that a 4D survey is not going to be required. Other indications from the 4D surveys such as subsidence due to pressure relief in the reservoir may be valid reasons for follow-on surveys.

- Designing the 4D survey

  - Parameters for acquiring the follow-on survey or surveys over a producing field is normally based on the results of the previous studies. The rock properties study may indicate that the 4D survey will be needed to evaluate changes due to reservoir collapse. The Modeling study may indicate that the 4D survey requires shear wave data to enable the detection of the parameters that are of most interest during development and production. The calibration study may provide indications that there are missing elements in the original survey (a lack of azimuthal distributions, insufficient aperture angles for the reflections, etc.) that dictate a different design for subsequent surveys.

  - Original 4D surveys were undertaken as repeat 3D surveys in marine environment primarily. These surveys were able to demonstrate changes in rock properties or fluid contents but were prone to issues related to the signal to noise ratio (s/n) of the surveys. Current best practice is to utilize buried geophone arrays that are permanently emplaced. The buried cables are much quieter therefore much better s/n. They also lead to more consistent measurements for follow-up surveys, many of the fields being monitored today conduct multiple surveys during the life of the field. The other benefit of a permanent buried array is that passive seismic measurements may also be made during the life of the survey. The passive seismic can be used for monitoring frac jobs or natural fracturing that is a result of pressure depletion or pressure build-up in the case of an EOR project with water or gas injection.

- Processing the 4D survey

  - The key to processing the 4D surveys is in the ability to consistently bin and then calibrate the amplitudes in the surveys. For follow-on surveys that use a different geometry than the original survey this results in re-binning them to a consistent grid. For surveys that were acquired in noisier environments it is critical to normalize the amplitudes carefully. Operators that are doing multiple follow-on surveys develop a consistent processing flow that enables rapid turnaround of the new data.

  - The final step in the processing is creating the delta set where the differences between the first and second survey are calculated. If the data are not properly calibrated and amplitudes balanced the difference data is difficult to get value from. The interpreting geophysicist will normally start by using the horizons picked in an original interpretation and use them to validate the new and old surveys are similar. An amplitude extraction over the zone(s) of interest is then used to investigate the differences and begin to assign significance to the observed differences.

- Using the 4D data
    - The 4D results may be used by geologists, geophysicists and engineers to further refine existing reservoir models. It allows better planning of production wells and to determine the optimal locations for placing injection wells. Depending on the quality of information it may be able to integrate the history matching from the production profiles with relative amplitude changes in which an estimate of future recovery volumes can be made. All of these cases are instances of integrated subsurface studies that impact field development

- The steps outlined above are all part of a PRM project or a 4D seismic project using repeat 3D seismic surveys without a permanently installed recording system. PRM has the distinct advantage of being able to be used as a passive as well as an active seismic acquisition system. PRM normally yields more consistent results between surveys and has lower overall noise than repeat surveys using surface or streamer surveys. With the permanent installation it can be used to monitor frac jobs and for HSE purposes to correlate production events observed throughout the life of the field.

- The workflow outlined above is a minimum requirement for conducting a 4D seismic program. The ability to detect rock or fluid property changes from seismic data is dependent on the quality of the data and the physical nature of the formation to demonstrate fluid content changes. Detailed studies of the rock properties are needed to determine how the seismic signature will change in a noise free state and then ascertain whether the signal to noise ratio of the seismic data will allow detection of the difference.

- All 4D projects require sufficient modeling to demonstrate the rock property alterations due to fluid content changes are detectable in seismic data. Once that effort has been completed the design of an acquisition program to accurately capture the amplitude variations can be completed and a PRM system deployed.

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1.15 *Global Oilfield Practices for Alternate/Substitute Data Types against the Contract Committed Data Types of the Minimum Work Program Bid by Contractor*

1.15.1 Definitions and Discussion

The primary issue with alteration of the agreed work program is that the Production Sharing Contract is a commitment by a Contractor/Operator to perform certain work in exchange for the right to explore for and develop hydrocarbon resources. That Contract is established within the

Government typically by a Hydrocarbon Resource Law passed by the governmental legislative body and enacted by Decree or signing into law the basis for the Model PSC/PSA contract. The PSC award to the Contractor/Operator is based on the current law and establishes the relationship between the Government and the Contractor/Operator. Any alteration to that contract will in most cases require going back to the granting authority to request a variance, an act that while not impossible is in most cases impractical.

There are numerous instances of modifications to the PSC/PSA terms initiated by the government and agreed to by the Contractor/Operator. These are not in the normal practices of either party and can result in significant disagreement between the parties. To initiate such change from the Contractor/Operator side, while not impossible, may require governmental approval at a very high level. In the cases where substitution of alternate work program is suggested, the normal practice would be to increase the commitment by the Contractor/Operator. Since it is not a trivial process to get approval from the PSC granting authority, there will by necessity need to be a significant motivating factor to get the administrative group to willingly move forward with any such proposal.

In many PSCs around the world, the exploration period can be extended to allow for additional time to complete the Minimum Work Requirement; however, in all contracts reviewed, the Minimum Work Requirement must be fulfilled or the Government must be compensated for the remaining unfulfilled work; the other option is to relinquish the entire Contract Area. Commitment of financial investment should be fulfilled.

In some countries, such as Pakistan and Mexico, a "work unit" concept has been introduced relating to the Minimum Work Program to provide a mechanism of modifying work commitments as exploration progresses. Under this work unit concept, each work unit is deemed equivalent to an expense of US$10,000 and the Contractor has the ability to modify the work program as technically justified to optimize the exploration program. As long as the number of agreed upon work units have been achieved, the Contractor is deemed to have fulfilled its contractual obligations.

GOI has already issued guidelines for change in MWP in November 2014 and it is agreed by the contractors.

1.15.2 Best Practices

- Any alteration to the minimum work program in the PSC/PSA requires going back to the granting authority, Government to request a variance
- In case of unfinished minimum work program in a block, the same can be substituted by equivalent work program, in another block of Contractor or in new acreage as approved by Regulator. This can be achieved in terms of equivalent work units.

1.15.3 References

1. Production sharing contracts for Brazil, Indonesia, Oman, Pakistan, Myanmar & Australia.

1.16 *Procedure for Calculating Cost of Unfinished Work Program*

1.16.1 Definitions and Discussion

Most Host Governments (HG) have determined in their PSC Model agreements an approach for assessing a penalty to be levied on a Contractor/Operator that fails to complete the work program established at the time of contract award. While there are some PSC agreements that do not include a penalty or Liquidated Damages clause, others have more detailed mechanisms included for calculating the amount of the penalty. To analyze this situation, a number of model agreements have been reviewed and while the list is not exhaustive, there are only a few variants of the methodology for calculating the value of the unfulfilled program. For all agreements reviewed, it was clear that the Liquidated Damages or penalty was associated with the relinquishment of the contract area. In most cases, it was at the end of an exploration period, but in some cases, the forced relinquishment is an option that the HG can exercise normally for cause.

The Indian Model PSC agreement used in the NELP VII offers a specific stated dollar figure for the amount of the Liquidated Damages per well, per square kilometer of 3D seismic and per line kilometer of 2D. This applies to both the Mandatory and Minimum Work Programs as defined in Article 5.

The Angola Model PSC incorporates clauses for payments to the HG in the event the Contractor fails to complete the program within the deadlines established based on the commitment wells that were not drilled or seismic program that was not completed. Likewise, in the event an exploration well did not fulfill a depth or penetration of a formation stipulated and a substitute well was not drilled a minimum expenditure level is required to be met or a penalty equal to the difference is levied. In this agreement all of the dollar figures are negotiable line items or determined when the contract is finalized.

The Kenya Model PSC addresses the Minimum Work Obligation based on a work quota plus a dollar figure for that work. The penalty clause or Liquidated Damages are based on the difference between the actual expenditures for the work program as defined and the contractual amounts. This agreement also stipulates that the payment amount will be uplifted based on the discount rate that is included in the contract.

The Timor Leste Model PSC is similar with to the Kenyan model with the exception that the work commitment is expressed in a yearly amount. Failure to complete the work in the year stated may result in Termination of the agreement, Liquidated Damages, or a deferral of the program into the following year / work period. The Liquidated Damages are in the amount agreed in the PSC.

The Kurdistan Model PSC incorporates in the Minimum Exploration Obligations a “Minimum Financial Amount” (MFA) for the work program in Articles 10.2 and 10.3 for the initial and any subsequent exploration periods. Failure to complete the work program as outlined would then impose on the Contractor a penalty amounting to the MFA. This amount is negotiated at the time of the PSC signature and comprises the amount of the levy. The language is not clear in terms of partial completion of the program and whether that offsets any of the MFA based penalty. The China PSC Model follows the same process.

In some cases the PSC dictates that a non-revocable Performance Bond will be issued in the amount of the Minimum Exploration Obligation. The expenditures made in each year of the exploration phase as they are approved are deducted from the outstanding balance on the Performance Bond.

Some model PSC agreements do not address a compensation process for failure to meet the Minimum Work Obligation. There are some PSC agreements that stipulate a minimum work program but do not clearly indicate a value assigned to completing that program.

In general, the methodologies employed in determining the Liquidated Damages if there is a clause that addresses this issue are either based on:

- A fixed amount for each activity not executed
- A fixed amount for the program and reduced by the actual amount expended

The means of providing security for the Host Government for those Liquidated Damages is not stipulated in all agreements, but where noted it is most frequently a Performance Bond. If there is such a Performance Bond, the value of the bond may be reduced periodically depending on the actual expenditures towards the work program with Host Government approval. The periodicity of this adjustment is not stated in all cases and is inconsistent when it is stated.

1.16.2 Best Practices

- In general, the methodologies employed in determining the Liquidated Damages owed by the Contractor/Operator to the Government in the event of failure to fulfill work commitments, if addressed, are either:
    - A fixed amount for each activity not executed, as specified in the PSC
    - In the event the agreed upon work commitment has a dollar figure or number of work units attached to it, the difference between the agreed upon and actual program costs, as specified in the PSC
- In the event a commitment has been partially completed but the full intent has not been achieved, the Management Committee should address the issue and subsequently refer to the Government for approval.
    - Credit should be given for wells drilled which have achieved the exploration objective (see broadened definition of Basement and Achievement of Exploration Objective in Section 1.20)
    - Secondly, for calculation of amount payable for unfinished MWP, it is proposed that Period Wise Fixed Rates should be calculated and uniformly applied to ensure transparency and reasonableness.
- In cases where the Work Program has not been fulfilled based on a special case, the issue should be raised to the Management Committee and with agreement of the Management Committee, the issue would be elevated to the appropriate governmental agency / ministry for approval.

1.16.3 References

1. Production sharing contracts for India, Angola, Kenya, Timor Leste, Kurdistan

1.17 *Standard Guidelines on the Type of Tapes/Media for the Operators to Submit their Acquired/Processed/Interpreted Data*

1.17.1 Definitions and Discussion

During the life of a Production Sharing Contract, Contractors/Operators provide the Host Government with E&P value chain-related electronic data and information to archive. The data represents the raw field information recorded, processed/reprocessed data, and interpretation results. Archival of these data has been a challenging process for all Host Governments and Contractors/Operators to ensure the integrity and accessibility of the data to current and future Contractors/Operators as well as the government departments responsible for managing the resources. Data types addressed, include geological, geophysical, petrophysical, geochemical, log, map, tapes, cores, cuttings, other interpretation and analytical reports.

The oil and gas industry uses a large number of standards which include industry organizations, national guidelines bodies, and international standards groups. Benefits of these standards include promoting technical integrity, reducing project cycle time, improving return on investment, diminish operation environmental impact, and promoting technical and business efficiencies. Through this effort it is possible to manage operational and business related costs.

Equipment, digital media and software and application workflow standards used by the oil and gas industry are highly specialized and can benefit in a measurable way to a company's financial bottom line. Development of technical specifications for all segments of standard users caters to general needs and specialized applications at the project level. This impacts costly field development designs through addressing technical and operating challenges. Guiding principles for use in development of standardization for the oil and gas industry includes support of internationalization of data and equipment standards, simplicity and fit for purpose design guidelines, available resources employed in an efficient manner, and development priorities of international standards should be based on a consensus of need.

The Norwegian Petroleum Directorate has developed Diskos which is a database used for their National Data Repository (NDR) for exploration and production data for the Norwegian Continental Shelf. This NDR serves as an industry standard around which a number of Host Governments have adopted with the goal of managing their Exploration and Production Data as a national asset. Energistics (www.energistics.org/)is a global, non-profit, industry consortium that facilitates an inclusive user community for the development, adoption and maintenance of collaborative, open standards for the energy industry in general and specifically for oil and gas exploration and production. The Blue Book from the NPD is used as a primary reference for data reporting standards.

1.17.2 Best Practices

Global practices for managing all exploration and production data include a comprehensive data management structure. A National Data Repository (NDR) is either in development or actively in use in a number of countries. The NDRs employ data catalogues that define the data types, archive format, physical media formats, and processes for input and output to / from the system.

- Please refer to the Norwegian Petroleum Directorate "Blue Book" for well data and "Yellow Book" for geophysical data for guidelines which serve as an industry standard NDR adopted by a number of Host Governments (links are given in References below)

- The advantage to a NDR is that there is a common form that manages all of the data and it is easy for the Host Government to place the requirement for archival on the operators.

- Some challenges encountered in establishing the NDR include:

    - The expense in creating the NDR is considerable and operating it in perpetuity is an ongoing cost that must be considered;

    - Insuring the operators provide the data in the correct format;

    - Validating the data being added to the archive is in useable form; and

    - Managing both digital data and the physical files / cores / samples requires forethought on how to establish the facilities and underlying support structure.

- The cost for maintaining the NDR is in many cases shared by the Contractors/Operators through an annual assessment as part of their operating budget.

- India has already begun the implementation of a National Data Repository (NDR). The NDR is responsible for determining the requirements for submitting the data for archival. The Blue Book and Yellow Book references from Norway are included as examples of the level of detail the NDR should provide to the operators in order to capture all of the data in a systematic fashion so that it can be retrieved efficiently for future operators.

- The Norwegian Data Bank utilizes a website to collect the details regarding data to be submitted for addition to their archives. Procedures for online submission are found here:

  http://www.npd.no/Global/Norsk/5%20-%20Regelverk/Skjema/Borerapportering/HowtotransferCDRSXMLdatafilestoPSA1.pdf

  The processes for submission of data are all included at the following website:

  http://www.npd.no/en/Reporting/Submission-of-material-and-information-required-by-the-rules-and-regulations/

1.17.3 References

1. Guidelines for reporting well data to authorities after completion, "Blue Book", Version 6, http://www.npd.no/globalassets/Global/Norsk/5-Regelverk/Tematiske-veiledninger/B_og_b_digital_rapportering_e.pdf

2. Guidelines for reporting of Geophysical Data to Authorities, Yellow Book, Ver 1.4, 2013, Norwegian Petroleum Directorate (http://www.npd.no/Global/Norsk/5-Regelverk/Tematiske-veiledninger/Geophysical_guidelines_e.pdf)

1.18 *Choice of Accounting System (Successful Efforts, Full Cost)*

1.18.1 Definitions and Discussion

Accounting is the language of business. It is used by the business world to communicate the business transactions that have occurred in the operations. Due to the complexity of the business, culture, taxation and legal systems, there is diversification of the accounting policies throughout the world. Due to the diverse nature of the accounting policies worldwide, it becomes difficult to make comparison between the companies that reside in different parts of the world. It makes it difficult and more tasking to for the investor and other interested parties to make financial and non-financial decisions.

The US GAAP used to have four alternative accounting methods:

- Full Cost Method
- Successful Efforts Method
- Discovery Value Accounting Method
- Current Value Accounting Method

The amended SFAS 19 rejected the use of the Discovery Value Accounting and Current Value Accounting methods in 2008. Thus, only two methods viz, Successful Efforts Method and Full Cost Method are recommended for use in accounting for the oil and gas companies.

Definitions of terms used in accounting are given below:

- Costs
    - Pre-license costs - Cost that is incurred in the period prior to the acquisition of a legal right to explore for oil and gas in a particular location.
    - License acquisition costs - Costs that are incurred to purchase, lease or otherwise acquire a property.
    - Exploration and appraisal costs - Costs incurred after obtaining a license or concession but before a decision is taken to develop a field or reservoir.
    - Development costs - Costs incurred after a decision has been taken to develop a reservoir

  - Operating costs - Costs of producing oil and gas including costs of personnel engaged in the operation, repairs and maintenance and materials, supplies and fuel consumed and services utilized in such operations.

- Decommissioning

  - The process of plugging and abandoning wells, dismantlement of wellhead, production and transport facilities and restoration of producing areas in accordance with license requirements and/or relevant legislation.

- Full cost accounting

  - A method of accounting for oil and gas exploration and development activities whereby all costs associated with exploring for and developing oil and gas reserves are capitalized, irrespective of the success or failure of specific parts of the overall exploration activity. Costs are accumulated in cost centers known as ‘cost pools’ and the costs in each cost pool are written off against income arising from production of the reserves attributable to that pool.

- Impairment

  - Capitalized development costs - a change in circumstances leading to a conclusion that the recoverable amount from reserves associated with capitalized development costs is likely to be less than the amount at which those costs are carried in the books.

  - Costs capitalized whilst a field is still being appraised - a change in circumstances leading to a conclusion that there is no longer a reasonable prospect that commercial reserves will result and will be developed.

- Successful efforts accounting

  - A method of accounting for oil and gas exploration and development activities whereby exploration expenditure which is either general in nature or relates to unsuccessful drilling operations is written off. Only costs which relate directly to the discovery and development of specific commercial oil and gas reserves are capitalized and are depreciated over the lives of these reserves. The success or failure of each exploration effort is judged on a well-by-well basis as each potentially hydrocarbon bearing structure is identified and tested.

1.18.2 Best Practices

- Accounting Theory

  - The accounting choice is any decision whose primary purpose is to influence the output of the accounting system in a particular way. Three major factors that influence the accounting choices are the size of the firm and the level of capital intensive nature of the firm and the competition in the industry that the firm faces.

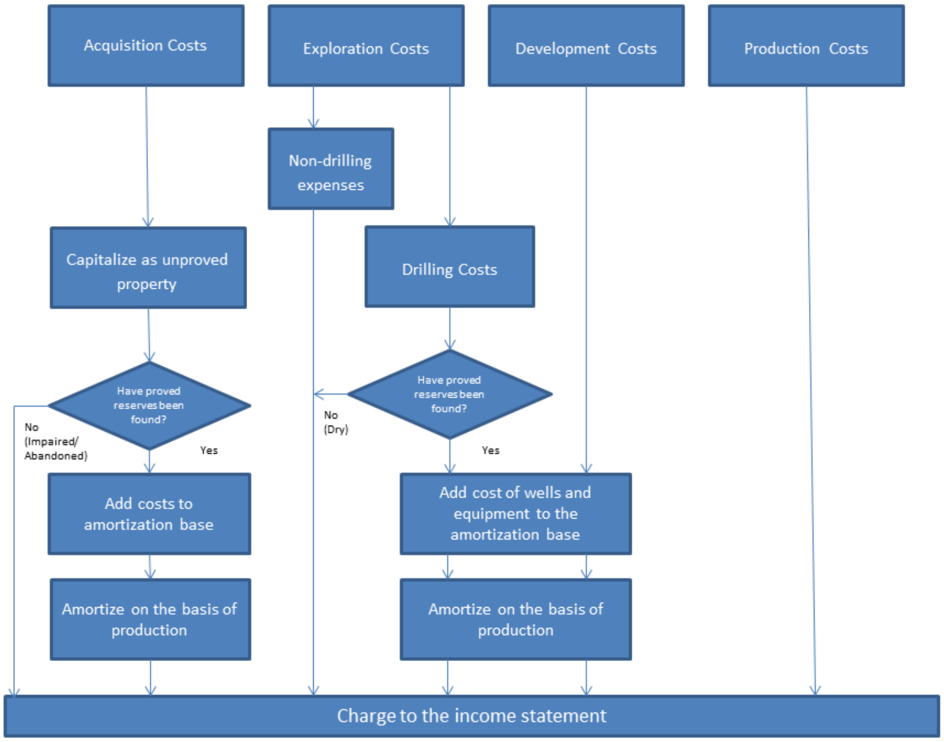
  - Oil and gas E&P activities have several distinctive features:

- High risk
- High cost of investment
- Time lag between exploration and production
- No necessary correlation between the capital expenditure for exploration and development and the value of the oil and gas reserves discovered as a result of the activities

- These and other factors make the accounting for oil and gas operations complex and specialized and thus have led to development of a wide range of accounting practices in the industry. The two most commonly used and recommended historical cost methods in accounting for oil and gas industry is:
  - Successful Efforts Method
  - Full Cost Method
- Oil and Gas accounting can be related to three basic activities carried out by oil and gas exploration and production companies.
  - Pre-production and development activities
  - Production activities
  - Decommissioning activities
- These three basic types of activities must be accounted for using one of the two above named generally accepted historical cost methods. These methods of accounting have been described in the sections below.

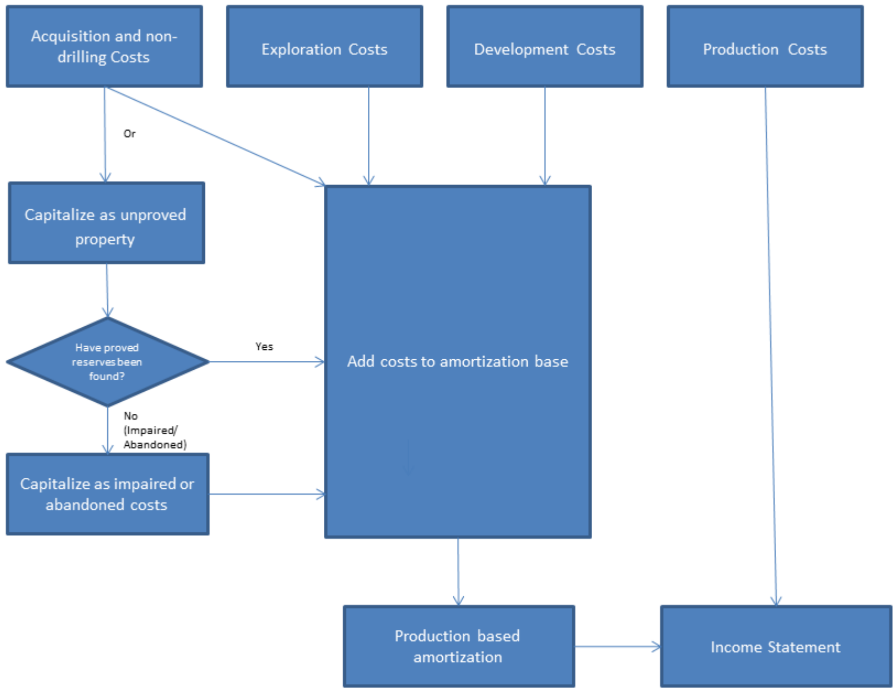
- Accounting Systems
  - Successful Efforts Method

    The chart below describes the functioning of the Successful Efforts Method



- Full Costs Method

  The chart below describes the functioning of the Full Costs Method



- The primary difference between successful efforts and the full cost is in whether a cost is capitalized or expensed when incurred. Thus the difference is in the timing of expense or loss charge against the revenue.

- The second difference between the two methods is the size of the cost center over which the costs are accumulated. For the successful efforts method the cost center is the lease, field or reservoir whereas for the full costs method the cost center is the country.

- Under the successful efforts method, only exploratory drilling costs that are successful are considered to be a part of the cost of finding oil and gas and thus capitalized. Unsuccessful exploratory drilling costs do not result in any economic benefit and thus are expensed. In contrast full cost method considers both unsuccessful and successful costs incurred in search for reserves as a necessary part of finding oil and gas. Thus, both successful and unsuccessful costs are capitalized even though the unsuccessful costs have not future economic benefit.

- A comparison of the accounting treatment between the various costs under both successful efforts method and full costs method is shown in the table below:

Item	Successful Efforts Method	Full Cost Method
Acquisition Costs	Capital	Capital
G&G Costs	Expense	Capital
Exploratory Dry Hole	Expense	Capital
Successful Exploratory Well	Capital	Capital
Development Dry Hole	Capital	Capital
Successful Development Well	Capital	Capital
Production Costs	Expense	Expense
Amortization Cost Center	Property, Field or Reservoir	Country

- Application of Accounting Systems
  - Pre-production activities and development activities
    - Successful Efforts Method
      - All pre-license, license acquisition, exploration and appraisal costs should initially be capitalized in well, field or general exploration cost centers as appropriate. Expenditure incurred during the various exploration and development phases should be written off unless commercial reserves have been found.
      - Any expenditure which is incurred prior to the acquisition of a license and the costs of other exploration activities should be written off in the accounting period itself.
      - Exploration and appraisal costs should be accumulated on a well-by-well basis in case the evaluation of the resources is pending.
      - If any commercial reserves are found after the appraisal, then the net capitalized costs which were incurred in the process of discovering the field should be transferred into a single field cost center. Any subsequent development costs, should be capitalized in this cost center.
      - All successful exploration and development expenditure should be capitalized as additions to fixed assets in the period in which it is incurred.
      - When the existence of commercial reserves is established, directly related exploration and appraisal expenditure should be capitalized and reclassified in the financial statements as tangible assets. Subsequent field development costs should be classified as tangible assets.
      - Subsequent expenditure should be capitalized where it enhances the economic benefits of the tangible fixed assets.

- Full Cost Method

  - All the expenditure on pre-license, license acquisition, exploration, appraisal, and development activities including enhanced oil recovery and extended life projects should be capitalized.

  - Pre-license acquisition, exploration and appraisal costs of individual license interests may be held outside cost pools until the existence or otherwise of commercial reserves is established. These costs will therefore remain undepreciated pending determination, subject to there being no evidence of impairment.

  - The accounting policy of the firm should provide the basis under which cost pools are established, for example geographic area, region or country.

  - The aggregate net book value of full cost pools should be disclosed, together with the aggregate of costs held outside cost pools.

- Production activities

  - All the expenses under the production activities are expensed under both Successful Efforts and Full Cost methods of accounting.

  - Inventory Valuation

    - Inventories should be stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

    - Supplies should be valued at cost to the firm mainly using the weighted average cost method or net realizable value, whichever is the lower.

  - Pipeline fill

    - Crude oil which is necessary to bring a pipeline into working order should be treated as a part of the related pipeline on the basis that it is not held for sale or consumed in a production process, but is necessary to the operation of a facility during more than one operating cycle, and its cost cannot be recouped through sale (or is significantly impaired). This shall apply even if the part of inventory that is deemed to be an item of property, plant and equipment (PP&E) cannot be separated physically from the rest of inventory. Valuation should be at cost and it should be depreciated over the useful life of related asset.

1.18.3 References

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1.19 *Standards for Sending Geophysical Data Abroad Online for Processing/Interpretation*

1.19.1 Definitions and Discussion

There are different approaches by Host Governments with respect to permitting the exportation of data or raw materials for analysis and processing. In most cases exportation of data is allowed to the extent that the facilities or capabilities necessary for conducting the work are not resident in the host country, thus requiring the analysis or processing to be done out of country. The primary advantage to allowing the export of Geophysical data is the potential for core discipline experts that may not be available locally to work with the data, thus adding a higher level of expertise in the analysis. This benefits both the Government and Contractor/Operator in that the quality of the analysis or processing will most likely be better as a result.

It is not unusual for Host Governments to allow the export of data or materials for analysis and processing. Countries that clearly allow for this activity are Brazil, Angola, Kurdistan, Ghana, Mozambique and Timor Leste which all have provisions allowing for the export of data. The critical element appears to be that for nearly all cases where the issue is addressed, the original data, a portion of the samples, or copies of must be retained in country unless expressly approved by the Host Government or National Oil Company.

1.19.2 Best Practices

- All data, raw materials, information, samples, etc. that are obtained in the process of executing the work program in a PSC are the exclusive property of the Government.
- The Contractor is required to provide all data and materials to the Government.
- Where exportation is allowed for analysis or processing the original data, a sub-sample, or a copy of the original data must be retained in country.
- In most cases the Government must be notified of the planned exportation and give approval.
- Approval to perform the work out of the country is based on an understanding that equivalent capabilities do not exist in-country.
- For cases where the expertise available in country may not address the level of expertise required for specific analysis or processing, during the tender evaluation the local contractors would be excluded for technical reasons and therefore the cost differential is not an issue.
- The export of data for analysis and processing in other countries is a very common practice and should be endorsed where needed. As outlined in the Best Practices, an approval by the Government is needed. The process will in many circumstances be initiated through a tender for analysis or processing services such that the local services companies may demonstrate whether the capability to do the work exists locally. Technical evaluation of the tenders results in the qualification of the bidders. Rationale for the technical evaluation may include:
    - Specific algorithms that the Operator considers to provide incremental value beyond routine processing algorithms that may be used by local contractors;
    - Technical work that may require use of data that exists in a unique database that is not local to the operation; or
    - Specific personnel with unique experience / knowledge that add value to the analysis and processing due to their expertise in the field of study.

- The cost of the project can also be a reason for exporting the data to a contractor that is out of the country. Lower cost for performing the work outside the country may be due to:
    - The commercial tender shows the work can be performed at the same technical level outside the country for a lower cost;
    - The incremental cost for the quality assurance personnel in the case where these individuals are not local. An individual may be required travel frequently to a contractor's location during the processing effort therefore these total costs should be incorporated in the commercial evaluation; or
    - Computing facilities or laboratory facilities that are not present or available in the country would be prohibitively expensive to access or import to complete a project.
- The mechanism for assessing the reasons for exporting the data are frequently addressed during the tender evaluation process. Consideration to allow for the application of the right technology for a project should outweigh the insistence that the data be maintained in the country.
- Normal processes for exporting data stipulate that the original raw data or sample must remain in country. To allow for completing the work outside of the country in the case where a sample must be sent only part of the sample may be exported. For digital data, the original copy is retained and a secondary copy is shipped or transmitted. Digital transmission is the preferred method if possible. An issue is that the volume of data from some large 3D seismic field datasets may be too great to transmit.

1.19.3 References

1. Brazil Concession Agreement; Clause 17
2. Angola Model Production Sharing Agreement; Article 24
3. Kurdistan Model PSC, Article 18
4. Ghana Model PSC, Article 7
5. Mozambique Model PSC
6. PSC Model Timor-Leste; Article 15.4

1.20 *Standards for Drilling*

1.20.1 Definitions and Discussion

There are four fundamental questions asked with respect to drilling practices worldwide: the definition of meeting the exploration objective during the drilling of an exploration well; the applicability of IADC, API guidelines; the practices for various types of drilling – vertical, inclined, horizontal, multilateral, casing policy, cementing policy, mud policy, LWD/MWD; and the definition of basement. Research of other PSC and PSA contracts can be used to illustrate the global approach to some of these questions.

1.20.2 Best Practices

- Defining Attainment of Exploration Objective during Exploratory Drilling
    - Approved target depth / formation
        - There is not a unanimous approach globally to contractually specifying the formation to be tested or the total depth required for an exploration well. Some of the Model PSCs and PSAs have language that indicates that prior to signing the agreement there will be a stipulation of the depth or formation, however this is most likely a negotiable term. It may be one of the determining factors in the contract award process. The most unanimous approach is however, that there is a Management Committee or the National Oil Company (NOC) responsible for oversight wherein they have the singular ability to either allow for the approval of a well proposal or to reject the proposal.
        - The net result of this analysis is the indication that in definition of the objective horizons as defined in the PSC / PSA agreement or in the well plan as approved by the Management Committee it becomes necessary to translate those requirements into operational steps. There are geological criteria that may be imposed if it is a matter of definition of a particular horizon, whereas attainment of a depth is relatively straight forward. Contention will normally occur when the NOC or Government believes that the operator has failed to reach the proposed target. Failing to reach the proposed depth can have an impact on whether the well will be credited against the commitment and can involve a significant cost.
    - Attainment of the objective
        - Attainment of the exploration objective where a specified horizon or formation is stipulated is decided upon by use of electric logs and sample cuttings. The geologist must determine when the objective was penetrated by identifying abrupt or gradual changes in lithology or recognizable formation differences on electronic logs or LWD/MWD logs. Similarly, the objective has been attained once the geologist has identified abrupt or gradual changes in lithology or recognizable differences on electric logs, so that he or she is confident that they are in a deeper formation.
        - If the exploration objective was never penetrated, the geologist must identify that the well is in a deeper formation and that failure to penetrate the objective horizon is either due to non-deposition or having crossed a fault into a younger or older formation. Entering a younger formation would be evidence for having crossed a reverse fault and the geologist must determine whether there is evidence of reverse faulting. In this case, there is cause to question whether the well has reached the pre-drill objective and the decision to continue drilling to reach that objective is required.

- In addition, paleontology/palynology data may also be used to identify the attainment of the exploration objective. Much like lithology, the palynology or paleontology data may be used to identify when the exploration objective was penetrated and when the objective had been attained. If the objective was never penetrated the specimens must indicate that there is a hiatus.

- Drilling issues precluding attaining the target depth / horizon

  - Most PSC agreements carry clauses that address the cases where a well has been or is being drilled and a decision to pre-maturely terminate drilling is needed. Once again the issue is whether "credit" for the exploration well against the Minimum Work Obligation is decided by the terms of the contract. Specific cases typically addressed include:

    - Safety due to abnormal or unforeseen conditions or a situation where personnel and equipment are at risk;

    - Hydrocarbons formations are encountered, requiring the installation of protective casings which prevent reaching the above-mentioned minimum contractual depth;

    - Hard formations encountered that make the continuation of drilling using standard equipment impractical; or

    - Basement is encountered.

    - Very narrow or no drilling window between pore and fracture pressure may require drilling to be terminated prior and reaching the well objective.

  - If a well does not meet the objectives, the Management Committee, appropriate Ministry or Government may declare that the well has failed to relieve the contractor of the obligation(s) under the terms of the agreement. This issue exposes the contractor to the potential liability for either drilling a substitute well to the MWP depth or liquidated damages or the cost of drilling a replacement well. The credit for having drilled a well normally has a financial as well as a geological or depth requirement.

- Recommendation on attainment of drilling objective

  - The existing agreements address this issue in different ways. It is recommended that the final decision should rest with the Management Committee (or its equivalent) and that the reasons for early termination are taken into consideration. Credit will normally be given in the case where the well drilled has met the minimum financial obligation, has contributed in acquiring valuable geological data from the well and the well was drilled with best efforts by the operator.

- The ability to obtain relief from the Minimum Work Obligation for a well drilled that does not reach the intended horizon is still left to the discretion of the Management Committee but the cases outlined above are the most frequently cited as exceptions where the operator is allowed to dispatch the obligation.

- Applicability of IADC, API Guidelines

  The IADC, API, are applicable to different phases of drilling design, selection of materials, operating guidelines and standards. It is not within the scope of this document to capture each and every aspect of design and operations. A brief summary of each application is presented below.

  - International Association of Drilling Contractors (IADC)

    - The association publishes operations manuals and guidelines for drilling rig operations and maintenance practices. In addition they also publish safety alerts and other rig improvements from time to time.

    - Their guidelines are mostly applicable to the Drilling Contractors. All rig operations and preventive maintenance must be performed in accordance with IADC guidelines.

    - Operator’s drilling team should familiarize themselves with these guidelines.

  - American Petroleum Institute (API)

    - API's Standards Committees are made up of subcommittees and task groups of industry experts who develop API standards. These groups identify the need, then develop, approve, and revise standards and other technical publications. New projects must be justified by valid business and safety needs.

    - All drilling practices should be performed as per API standards.

    - API recommended standards should be followed as a minimum for all material selection, manufacturing and testing.

    - In case of exploration wells, since there are many unknowns, e.g. pressures, formation lithology, formation tops, presence of H2S, etc., most designers use the worst case scenario.

    - For exploration wells, all materials for casings, wellheads, trees, etc., should be suitable for “Sour Service”, except where H2S is known to be absent. Refer to NACE document MRO175.

  - International Well Control Forum (IWCF) Training

    - Several certifications are globally recognized, e.g. IWCF, Wellcap by IADC, Randy Smith Well Control.
    - All Company and Contractor personnel related to drilling must be trained in Well Control.
    - They should have a valid certification and must undergo re-certification after the expiry of the certificate.
    - All Company and Contractor personnel should be trained in mandatory operational and safety training/certification programe.

- Practices for various Types of Drilling
  - Most of the exploration wells are designed vertical to allow for better formation evaluation and determining the geological formation tops. Sometimes directional wells are required to meet the exploration objectives. Horizontal and Multilateral wells not drilled for exploration they are mostly used in development program if required.
    - In very high inclination wells, use of LWD/MWD may be the best option.
    - Torque and drag analysis should be thoroughly done for high angle wells.
    - Use of rotary steerable system is advised where tight control of angle and azimuth is required, i.e. very small geological targets.
  - Casing policy
    - Casings serve many important functions in drilling and completing oil and gas wells. It prevents collapse of borehole during drilling and isolates the wellbore fluids from sub-surface formations and fluids. It provides a flow conduit for the drilling fluid to the surface. Along with BOP, it permits the safe control of formation fluids.
    - In order to perform the above mentioned functions, the casing strings need to be designed carefully. Moreover, the execution of casing job needs to be performed as per standard industry practices.
    - All casings must be designed for Maximum Anticipated Pressure (MASP) using maximum anticipated loads for each casing throughout the well life.
    - Safety factors must meet or exceed API or Company Standards.
    - Materials and Manufacturing must comply with API, ISO, NACE and any other applicable guidelines.
  - Cementing policy

- Cement is used in drilling operation to protect and support the casing, prevent the movement of fluid through annular space outside the casing and to close an abandoned portion of the well.
- Commonly used QA/QC practices in cementing require that all cements must have API monogram and specifications.
- Cementing design should consider, bottom-hole temperature, estimated job time, required "Pump Time", need for spacers, and compressive strength requirements. Some regulatory agencies specify minimum compressive strength required prior to drilling out.
- All cement slurries must be tested as per API recommended practices.
- All fresh water zones must be isolated by cement.
- Every attempt should be made to cement conductor and surface casings to "Surface", except where mud-line or subsea wellheads are used.

o Mud policy

- The drilling mud is used to bring the rock cuttings to surface, exert sufficient hydrostatic pressure against formations, and cool and lubricate the drill string. However, the properties of the mud need to be carefully designed in order to prevent corrosion of drilling equipment, and excess loss into the formation.
- Selection of proper mud and properties is critical to successful drilling and well completion.
- Use of "Water Base Mud" is the preferred system. However, in some cases due to sensitive clays, hole stability, Gas Hydrate and to mitigate any other anticipated drilling complications, an "Oil Base Mud" is preferred.
- All the mud products must meet API specifications and must be environmentally safe.
- If Oil Base Mud is used, proper cuttings and waste disposal plan must be in place as required by statutory regulations.
- MSDS (Materials Safety Data Sheets) for all the chemicals to be used must be available on site.

o Logging While Drilling (LWD) / Measurement While Drilling (MWD)

- LWD is a type of well logging that incorporates the logging tools into the drill string, administering, interpreting and transmitting real-time formation measurements to the surface.

- MWD is a type of well logging that incorporates the measurement tools into the drill-string and provides real-time information such as azimuth, inclination, etc., to help with steering the bit.
- In very high inclination wells, use of LWD/MWD may be the best option.
- LWD and MWD acquire evaluation and drilling optimization data during drilling operations to guide well placement and to provide data for survey management and development planning.

- Drilling Rig Selection
  - Most drilling contractors use IADC (International Association of Drilling Contractors) recommended practices for rig operating and design practices including preventive maintenance recommendations.
  - Proper rig selection involves preparing detailed maximum load well designs and evaluating the rig capability and limitations to ensure the rig is suitable for the job. In some cases the well design and drilling procedures may have to be altered to match rig limitations.
  - Soil evaluation for rig foundation must be conducted for rig stability except for drill ships and floaters.
  - Other environmental factors that will impact the rig stability are wind, wave and current. These factors must be considered in rig selection.
- Rig Personnel
  - All relevant personnel of Company and Contractor must be trained in Well Control. Several certifications are globally recognized, e.g. IWCF (International Well Control Forum), Wellcap by IADC, Randy Smith Well Control, etc.
  - Other commonly used training programs are:
    - EHS (Environment, Health and Safety)
    - FiFi (Fire Fighting)
    - H2S Handling
    - HUET (Helicopter Under-water Egress Training)
- Geo-Technical Order (GTO)
  - Most operators develop a document that provides a “snapshot” of key geological and drilling information and a road map for drilling. This document provides agreed geological objectives, well design and other drilling information. It is sometimes referred to as a “Well Montage”, “Drilling Plan Summary”, etc.

- Each operator should develop a similar document for each well. The following information is generally presented:
    - Geological map: cross section with key formation/s to be encountered
    - Key formation tops and lithology
    - Casing program: hole sizes, depths, casing specifications
    - Expected pore pressure, mud weights, fracture gradients plot
    - Expected drilling problems, loss circulation, abrasive formations, abnormal pressures
    - Directional plan: kick off depth, build/drop rate, inclination, azimuth
    - Mud program: mud weights, mud type
    - Formation evaluation: type of logs by hole section
    - Cementing program for each casing
    - Days versus depth plot
- A GTO type document must be prepared for each well and reviewed/approved by the relevant department.

o BOP and wellhead fitting/testing and maintenance

- The blow out preventer (BOP) and wellhead are critical surface pressure control equipment. Proper material selection, pressure rating and configuration are essential to safe drilling operation. Design and selection criteria must consider the following:
    - Maximum anticipated bottom hole and surface pressure.
    - Maximum anticipated bottom hole and surface temperature.
    - Type and volumes of fluid expected: oil, gas, H2S, CO2, etc.
    - For sub-sea wellheads and BOP, the current and other marine conditions.
    - BOP number and configuration.
- All wellheads and BOP components must be designed and manufactured as per API, ISO and ASTM and NACE QA/QC-guidelines.
- Installation must be in accordance with the manufacturer’s procedures.
- Testing must be performed as per API RP 53 recommended practices.

- Wellheads and BOP must be selected to meet the latest API recommended practices, IADC guidelines and ISO QA/QC
- Material selection must comply with NACE standards
- Design must meet ASTM and other manufacturers' procedures
- Installation must be in accordance with manufacturers' procedures
- All maintenance and repairs must comply with manufacturers' procedures and use OEM parts only
- After any repairs, wellheads and BOP must be re-certified as per API requirements

o Sustained Annular/Casing Pressure

- Sustained annular pressure is defined as pressure in an annulus of non-structural casing strings that is:
    - measurable at the wellhead of a casing annulus that rebuilds to at least the same pressure level when bled down;
    - not caused solely by temperature fluctuations; and
    - not a pressure that has been imposed by the operator.
- As explained in API RP 90, Section 3, Annular Casing Pressure Management Program, this RP is based on establishing an annular casing pressure management program that filters out non-problematic wells that present an acceptable level of risk, thus allowing for a more focused effort on wells that are problematic. The management program, as outlined in API RP 90, includes monitoring, diagnostic testing, determining maximum allowable wellhead operating pressure (MAWOP) for each annulus, documentation, and risk assessment considerations.
- US Regulations
    - The US Minerals Management Service (MMS) regulations (30 CFR Part 250) require elimination of sustained casing pressure (SCP).
    - MMS also grants waivers ("departures") permitting operation of wells with small SCP problems.
    - According to US MMS regulations, diagnostic testing is required in any well exhibiting SCP. The departure (waiver) decisions are solely based on the results from casing pressure diagnostic tests.
    - Results of the test determine if immediate SCP removal could be temporarily waived (departure permit) and continuing operation of the well permitted.

- Norway Regulations (Norsok D-10)

    - Pressures in all accessible annuli shall be monitored and maintained within min and max operational pressure limits to verify that the integrity status of well barriers is known at all times
    - Annulus pressure in all wells and in multipurpose and gas lifted wells shall be monitored through continuous recording
    - For subsea wells, the casing must be designed to withstand thermal pressure build up, or have an acceptable pressure management system
    - Shall be able to secure well in the event of failure
    - In the case of a failed barrier, the only activity in well should be to restore the well integrity

- Each Operator must prepare and implement the SCP Management Guideline Document which addresses:

    - Maximum Allowable Wellhead Pressure (MAWP) based on design
    - Maximum Allowable Wellhead Operating Pressure (MAWOP)

- The American Petroleum Institute Recommended Practice 90, Annular Casing Pressure Management, First Edition (API RP 90) provides the best available technology for the evaluation and management of wells with casing pressure. MMS encourages use of this document for guidance on recognizing and evaluating casing pressure on all well types and on testing methods and data collection.

- Maximum Allowable Wellhead Operating Pressure (MAWOP) is a concept taken from API RP 90. The MAWOP is a measure of how much pressure can be safely applied to an annulus and is applicable to all types of annular pressure, including thermal casing pressure, sustained casing pressure, and operator-imposed pressure. The MAWOP for the annulus being evaluated is the lesser of the following:

    - 50 percent of the minimum internal yield pressure (MIYP) of the pipe body for the casing or production riser string being evaluated; or
    - 80 percent of the MIYP of the pipe body of the next outer casing or production riser string; or
    - 75 percent of the minimum collapse pressure (MCP) of the inner tubular pipe body.

- For the last outer casing or production riser string in the well, the MAWOP is the lesser of the following:

  - 30 percent of the MIYP of the pipe body for the casing or production riser string being evaluated; or

  - 75 percent of the MCP of the inner tubular pipe body

- International Definition of "Basement"

  Internationally, the geologic terms basement and crystalline basement are used to define the rocks below a sedimentary platform or cover, or more generally any rock below sedimentary rocks or sedimentary basins that are metamorphic or igneous in origin. In the same way the sediments and or sedimentary rocks on top of the basement can be called "cover" or "sedimentary cover".

  There may be instances when an igneous or metamorphic rock is penetrated above the lowest sedimentary rocks in a basin. A volcanic flow, dike or sill may exist within the sedimentary rock column as a late stage emplacement while there is still prospective sedimentary rock below that feature. Normally this type of occurrence would be predicted before drilling and provisions included in the drilling program to reach objective horizons below the igneous section. The geologic definition, therefore, should be adjusted It is therefore recommended to adjust the geologic definition of Basement to the section below the lowest anticipated sedimentary section present in a basin as determined through a geologically reasonable interpretation of the formations.

  - For the purposes of determining whether an exploration well has penetrated all of the prospective section and drilling can be terminated, the definition of "basement" must be appropriately wide in its scope and not limited to the strict geological definition.

- Defining Attainment of Exploration Objective during Exploratory Drilling in case of early termination

  - One or more of the following criteria is recommended to be used for the purpose of establishing whether an exploration well has achieved the exploration objective:

    - The objective horizon in the drilling plan agreed by the Management Committee has been reached based on logs, cuttings or paleontological evidence;

    - Drilling has encountered a hard to drill crystalline igneous or metamorphic formation above prospective sedimentary formation;

    - Drilling and or logs have demonstrated the entire prospective stratigraphic section in a basin has been penetrated;

    - Geologic conditions such as over-pressure have been encountered and the safety of the personnel and equipment is at risk if drilling continues; or

- A Discovery has been made and to preclude damage to the potential productive zone casing must be set.

- However, the final decision on attainment of Exploration Objective should rest with the Management Committee (or its equivalent) and that the reasons for early termination are taken into consideration.

1.20.3 References

1. As practiced by Major Oil Companies
2. API RP 10B – Testing Well Cement
3. API D10 – Selecting Rotary Drilling Equipment
4. API RP O4G – Inspection, Maintenance and Repair of Drilling and Servicing structures
5. API RP 13B – Field testing of Drilling Fluids
6. API RP 54 – Occupational Safety Oil and Gas Drilling Operations
7. API Spec 16D – Well Control Equipment Systems
8. ISO 9001
9. ISO 29001 – Quality management requirements for the design, development, production, installation and service of products for the petroleum, petrochemical and natural gas industries
10. NACE TM0175 – Testing of materials for SSC in H2S environment
11. NACE TM0187 – Evaluating elastomeric material in H2S environment
12. PSCs from Kurdistan, Ghana, Kenya, Republic of Cyprus, Tanzania
13. "Remember Basement in your Oil and Exploration: Examples of Producing Basement Reservoirs in Indonesia, Venezuela and USA" (http://cseg.ca/assets/files/resources/abstracts/2007/038S0126.pdf)
14. International Association of Drilling Contractors- IADC-Manual
15. National Association of Corrosion Engrs-NACE- document MRO175
16. International Well Control Certification- IWCF
17. Helicopter Under-water Egress Training)-HUET
18. American Petroleum Institute-API- RP53- BOP
19. American Petroleum Institute-API- RP90- Casing Annular Pressure
20. ONGC – BOP Installation/testing procedures

1.21 *Popularity of "Stopping the Clock" Internationally*

1.21.1 Definitions and Discussion

The question involved in this topic is interpreted to mean the ability to revise the timeframe stipulated in the PSC for execution of a program.

The issue of stopping the clock is essentially a form of declaration of Force Majeure. While not specifically Force Majeure, the processes required to declare it and stop the clock are nearly identical. The desired effect is the suspension of the time period for completion of the work program agreed with the Host Government either as part of the original PSC or as it may be defined in the Appraisal or Development plan. The effect of stopping the clock is that it allows the Contractor/Operator to have additional time for completion of the required program before the Host Government declares the Contractor/Operator to be at fault for non-performance under the contract. Although this does not fall under the definition of Force Majeure normally implemented in Production Sharing Contracts, the Brazilian PSC has re-defined this under the Contract Clause 33 in which they stipulate not only Acts of God but Force Majeure and other causes that might delay the execution of the program:

> "Clause Thirty-Third -Act Of God, Force Majeure and Similar Causes"
>
> > 33.4 Overcome the unforeseeable circumstances, force majeure or similar causes, it will be up to the Members to fulfill the obligations affected by extending the deadline for the fulfilment of these obligations by the period corresponding to the duration of the event.
> >
> > 33.4.1 Depending on the extent and severity of the effects of unforeseeable circumstances, force majeure or similar causes, the parties may agree to amend the agreement or its extinction.

India had such an issue in the recent past where the availability of deep water rigs for drilling exploration wells was an issue. This was resolved by the DGH issuing a statement "Grant of Rig Holiday in Deepwater Blocks and implementation issues under Production Sharing Contract (PSC) regime". This statement indicated the Government's position and forward plan for 30 offshore deepwater blocks signed till NELP-V.

The timeframe for execution of an Exploration, Appraisal or Development program is typically defined well in advance of the actual execution of such a program. There are many issues that may interfere with the successful execution of the program in the timeframe specified. Since this is a contractual issue between the Host Government and the Contractor/Operator, the declaration of Force Majeure as defined in the contract may not fit the circumstance. As such an alternate means of addressing this issue is needed.

The solution is to amend the contract and in almost all cases this requires the contract amendment to be agreed by both parties and approved at the same signatory level on behalf of both. The question that remains unresolved is whether the approving Host Government body has the authority to re-negotiate the terms of the contract after signature. The approach taken by the DGH referenced above appears to be a reasonable one.

The questions that remain to be answered are with respect to what portions of a work program should come into consideration for such waivers, and the justifiable rationale for such an alteration to the work program schedule. International practices for this tend to be limited to cases where there is an excessive financial burden due to limited availability of contractors to undertake a program; limited contractor resources (such as drill rigs); delays in contractor timing due to work load in other countries or contract areas; and in general due to limited resources (such as specialized drill pipe, or drilling materials).

Another source of delays relates to Host Government approvals and permits required for carrying out the work program. Many governments allow for extensions for delays in obtaining approval, permits, clearances, etc. The Government of India included policy which permits extensions to Contractors on account of securing Government approvals/permits/clearances, deeming these "excusable delays."

1.21.2 Best Practices

- It is up to the Contractor/Operator to petition the Government for delays to any program. After such a petition is received, the Government would assess the impact and either approve or disapprove the petitioned delay.
- In the event delays are directly the result of delays in obtaining Government approvals, permits, clearances, etc., extensions of equal duration of the delay should be provided to Contractors.
- Policies for "stopping the clock" are difficult to administer. These situations should be considered only when there are multiple Operators that are impacted by a commercial or physical constraint that is global or regional in scale. In the case of the Indian PSC agreements the ability to stop the clock is not a provision within the agreement and will necessitate action by the government. An extension policy regarding excusable delays could be added to future production sharing contracts.
- If an Operator believes the situation to fall under the category of Force Majeure, then they can petition for consideration by the Government.

1.21.3 References

1. Federative Republic of Brazil Ministry of Mines and Energy, Production Sharing Contracts for Exploration and Production of Oil and Natural Gas.
2. Letter dated July 19, 2010, from Government of India Ministry of Petroleum and Natural Gas to Director General of Hydrocarbons, Subject: Grant of Rig Holiday in Deepwater Blocks and implementation issues under Production Sharing Contract (PSC) regime reg.
3. Policy Framework for Relaxations, Extensions and Clarifications at the Development and Production Stage under the PSC Regime for Early Monetization of Hydrocarbon

Discoveries. Letter dated November 10, 2014. From Government of India Ministry of Petroleum and Natural Gas to Director General of Hydrocarbons.

1.22 *Data Acquisition in Adjoining Areas to Establish Regional Geological Context*

1.22.1 Definitions and Discussion

To properly evaluate an exploration license area, the contractor requires sufficient regional information to place the information gathered within the contract area into context. The ability to extend data acquisition projects into adjoining areas is necessary to properly conduct the assessment. Operators need the ability to extend seismic surveys, potential field surveys, and other geological sampling efforts into adjoining areas. Additionally, data may be available in adjacent blocks/licenses located either onshore or offshore may include such items as the following: a) 2D and 3D seismic data, b) gravity surveys, magnetic surveys, and other Geophysical data, c) well data, d) surface geological data, e) published Government reports plus f) Industry and Academia reports. Access to the existing database is essential to avoid repetition of a data.

It is in the Host Government's best interest to provide access to all Operators needing data in adjoining areas rather than to require the Operator to acquire new data unless that new data is being acquired with a newer technology that might make the older data obsolete. In PSCs the ownership of the data in the preponderance of cases will lie with the Host Government, and the cost of acquiring that data is recoverable. As such there is no basis for an Operator to sell a license to use the data to a third party. This in itself creates issues when a quid pro quo trade cannot be negotiated due to an imbalance in the value of the data being traded.

1.22.2 Best Practices

- At the inception of a licensing round Governments typically offer data packages which may be purchased by IOCs, NOCs or smaller companies considering making a bid on any given Block.
- Often Governments will acquire speculative 2D seismic data over unlicensed Blocks to generate interest by potential Operators in these open Blocks. This data is usually available for purchase by interested Operators.
- Governments maintain copies of all data acquired on all Blocks throughout the life of each Block. This data is also often available for purchase from the Government by interested parties.
- Upon award of a Block, the Operator will often be provided with more detailed data, especially seismic data, than that which was included in the original data package provided to interested companies.
- Award of a Block will require that the Operator must carry out a work program that will likely include reprocessing of existing seismic data, acquisition of 2D seismic and/or 3D

seismic, potential field data, geological studies, geochemical sampling and the drilling of one or more exploration wells.

- Acquisition of new data by the Operator may include programs that extend beyond the contract area. In these cases, the normal operating procedure is to get approval from the government and from Operators in the adjoining Block(s) (if the acreage is held) to acquire data over the areas under their control. The typical practice is that this “mineral trespass” is granted to the Operator in exchange for the current license holder being provided copies of the new data. The Operator will negotiate a Data Trade agreement that encapsulates the data to be provided and receive governmental approval for the trade.

- Certain seismic or other data acquisition projects might cross out of the Operators concession area into an adjoining area. In most cases the surveys must continue to allow for the full imaging of the area within the concession. This type of trespass also requires approval by the adjoining concession holder. A typical agreement between the two operators will grant the holder of the trespassed area an amount of data in the Operator’s concession area equal to the amount of data acquired within the trespassed block.

- Data trade agreements must stipulate the type of data being traded and will normally include specific reference to the level of processing applied to the traded data. Access to the raw data is negotiable.

- Once the Operator has obtained reprocessed or new data they will be in a position to trade with Operators of adjacent blocks. Normal practice in countries where Production Sharing Contracts exist is to negotiate a trade wherein a quid pro quo trade is made after receiving Government approval.

- The acquisition of data in adjoining areas is an important part of assessing the viability of the exploration targets within the contract area. The ability to conduct this work is important but must consider the rights of the holders of adjacent acreage.

- For open acreage – the Government will be the grantor of permission to extend the survey over the acreage not currently under license. Since the Government is technically the “owner” of all data collected these data will ultimately reside in the National Data Repository. While the Operator still holds the Exploration License for the block under which the data was originally acquired, a normal practice would retain proprietary rights to use this data with that Operator. Other companies that wish to gain access to that data will need to petition the Operator and the Government for the data and depending on the trade agreement reached between the two companies the Government normally approves the trade agreement.

- For held acreage – the Operator must petition the Operator of the block to “trespass” during their acquisition efforts. Normally there is no reason for the contract holder to deny the trespass agreement. Such Agreement must be completed in a time bound manner. A common practice for a data trespass is to provide 1 for 1 data from the Operator’s block as compensation for allowing the trespass. These principles hold for well and seismic data. Operators frequently trade well data to improve the understanding of their blocks by either pre-trading wells they are committed to drill or wells already drilled in their acreage. It is the ability of each Operator to properly place their block in a regional context that adds value to the Government, therefore support for these transactions is not reasonably withheld.

1.22.3 References

1. Production sharing contracts for Ghana, Kurdistan, Indonesia, Oman, India and Nigeria.
2. 2013 Global Oil & Gas Tax Guide - includes discussion of terms for Columbia, Equatorial Guinea and Ecuador.

1.23 *Continued Exploration throughout the Life of the PSC*

1.23.1 Definitions and Discussion

This topic concerns the continuation of exploration operations throughout the term of the PSC held by the Contractor. Exploration activities, especially exploration drilling, in general, is encouraged as it leads to more discoveries which is beneficial for both the Government and the Contractor.

Different PSCs around the world have different relinquishment requirements with regard to the area for development. These PSCs do not specifically bar any further exploration drilling. Allowing additional exploration activities provides incentive to look for additional resources that may be economic and improve the longevity and profitability of the producing asset.

Indonesia PSC allows continued exploration in the unexplored portion within the retained Contract Area; however, if the Contractor does not submit an exploration program for 2 consecutive years then that portion of the Contract Area is relinquished.

Kurdistan PSC requires relinquishment of the area not included in the Production Area at the end of the exploration period. Other country PSCs allow Contractor to retain Production Areas and Discovery areas.

1.23.2 Best Practices

- Many PSCs have mandatory relinquishments of the Contract Area over time to reduce the retained Contract Area to a minimum percentage of the original area or to Production/Development Areas and/or Discovery Areas. These PSCs do not specifically bar any further exploration drilling within the retained Contract Area.
- Countries which require mining permits for the development of the discovery typically allow for further exploration activities undertaken under the mining permit.
- In the United States, continuous exploration throughout the life of a producing field is allowed and encouraged which leads to additional discoveries in the area.
- The specific issue in this case is the fact that once a contract area is converted to a mining license the question is raised regarding cost recovery of exploration related costs. All the exploration cost should be allowed for cost recovery otherwise there will be no incentive

for incremental high risk exploration effort. The "Ring Fencing" of production areas to limit cost recovery creates a disincentive to continue looking for additional resources. Extension exploration has one of the highest success rates of any type of exploration drilling activity and should be encouraged.

- Exploration in ML areas is permitted and not ring fenced and the terms and conditions of PSC are applicable in to any new discovery in the ML Area.

1.23.3 References

1. Model PSC for the Republic of Kenya, Angola, Kurdistan, Brazil, Oman and Indonesia
2. Minerals Program regulations in New Zealand
3. Gulf of Mexico for Continued Exploration in Mining Area

1.24 *Standards for Work Program Approval Process with Respect to Bid, Budgeted and Actual Cost in a PSC Regime*

1.24.1 Definitions and Discussion

- The Minimum Work Program (MWP) and/or Minimum Expenditure Commitments (MEC) for the Exploration period/s are commonly specified in the PSC which has been signed by all parties. Contractors/Operators are expected to deliver on the commitments or face penalties. In most PSCs there is also a form of Management Committee (MC) with Government and Contractor/Operator representation that reviews, discusses, and in most cases, approves the Annual Work Program and Budget.
- "Work Program" means a work program formulated for the purpose of carrying out Petroleum Operations
- Most countries require submission of AFEs for each actionable item along with a proposed Work Program and Budget for MC approval.

1.24.2 Best Practices

- PSC agreements generally include provisions for the implementation of a Management Committee (MC) made up of members representing Government and Contractor/Operator with the primary role of supervising Petroleum Operations.
- The MC is usually charged with making sure that all petroleum operations move forward in a safe and expeditious time frame and adhere to the contractual obligations of the Minimum Work Program and Minimum Expenditure Commitment.
- Prior to the beginning of each Financial Year (typically 3 months prior), Contractor/Operator shall submit an Annual Work Program and Budget which shall be reviewed by the MC who can accept or propose revisions to the document. MC and

Contractor/Operator shall reach an agreement prior to the start of the Financial year on the work program and budget.

- Each reviewed/approved Annual Work Program and Budget may include an agreed upon contingency that will apply to the total of such reviewed/approved Annual Work Program and Budget.

- Details of the Annual Work Program may change through the course of the Financial Year and the Contractor/Operator should not be limited from making these changes as long as the objectives of the Annual Work Program and approved expenditures in the Budget and Operating Costs remain the same. Material changes to objectives and/or budgeted expenditures of the Annual Work Program during implementation shall require approval of the MC.

- In the case of emergencies or extraordinary circumstances requiring immediate actions, either party may take all actions it deems proper or advisable to protect its interests and those of its employees and any costs so incurred shall be included in Operating Costs.

- In the exploration phase of a concession the work program is primarily the responsibility of and is paid for by the contract holder. Costs incurred go into a cost recovery pool and are recovered in the event of a discovery leading to commercial production. Decisions regarding these expenditures should remain in line with the risk / reward of the prospects in the block and comply with the MWP/MEC. During the Exploration Phase, the Management Committee holds an advisory capacity. For exploration activities during this phase, the Management Committee hold an advisory capacity.

- In the Development Phase of the granted mining lease, the Management Committee holds an approval capacity. This control is in place to ensure the operator is efficiently and effectively developing the asset. As mentioned in Section 1.23, continued exploration within the mining lease should be allowed as this could lead to an increase in production from the asset to the benefit of both the Contractor and the Government.

1.24.3 References

1. Production sharing contracts for Tanzania, China, Ghana, Angola, Oman, Indonesia, India.

2 Discovery

2.1 *Standards for Area Demarcation for Development, Discovery and Mining Lease*

2.1.1 Definitions and Discussion

In the India Model PSC, an operator may announce a Discovery, and must submit a Discovery report after completion of well tests. Operator must then submit an Appraisal Program with a Work Program and Budget specifying the boundaries of a potential development area. Operator may then submit a Declaration of Commerciality (DoC) with a full report. Operator must then submit a Field Development Plan (FDP) with the boundaries of the proposed Development Area. Subsequent to approval of the FDP, a Mining Lease (ML) is granted for commercial production of oil and gas from the ML area, as approved in the FDP.

A Discovery may be of conventional or unconventional resources. Conventional resources exist in discrete petroleum accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a downdip contact with an aquifer, that may be established subsequent to appraisal drilling and which is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water. The petroleum recovered typically requires minimal processing prior to sale. A Discovery is actual evidence (testing, sampling, and/or logging) from at least one well penetration in one of the accumulation to have demonstrated presence of potentially moveable hydrocarbons.

Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences. Examples include coalbed methane (CBM), basin-centered gas, shale gas, gas hydrates, natural bitumen, and oil shale deposits. Typically, such accumulations require specialized extraction technology (e.g., dewatering of CBM, fracturing programs for shale gas or oil, steam and/or solvents to mobilize bitumen for in-situ recovery).

In the Oman PSC, an operator must submit an Appraisal Plan after a Discovery. The Appraisal Plan defines an area where appraisal activities will be conducted. After the appraisal work is conducted, an Appraisal Report must be submitted followed by a FDP. DoC is made upon approval of the FDP. The Development Area is defined in the FDP.

In the Kurdistan PSC, an operator may announce a Discovery, and then must submit a Discovery report. Operator must submit an Appraisal Work Program after the Discovery report, and the appraisal area may not be greater than two times the size of the mapped geologic structure. After the appraisal work is completed, operator must submit an Appraisal Report. With the Appraisal Report, operator may submit a Declaration of Commerciality. Operator must then submit a FDP after declaring the Discovery as commercial. FDP should define the production area, taking into account the results of the appraisal work program.

Good Industry Practices must be defined for the demarcation of Development versus Exploration areas, and for how a Discovery may be appraised and progressed to a Declaration of Commerciality.

2.1.2 Best Practices

- Area Demarcation for Discovery Best Practices
    - After drilling a successful well, Contractor should submit a notice of discovery as per PSC with all relevant and required information. Contractor should then submit an appraisal plan showing the appraisal area, where the appraisal program will be conducted. The appraisal plan may include shooting additional seismic, additional drilling, an extended well test and/or an Early Production facility.
    - The appraisal plan should define the area for appraisal, which should consist of a map with geographical coordinates (a series of UTM x and y points) defining a polygon around the area to be appraised. The appraisal area should be decided based on the size of the geologic structure and/or stratigraphic condition.
- Area Demarcation for Development Best Practices
    - After a successful appraisal, Contractor should submit a Declaration of Commerciality, with an evaluation report on the appraisal activity. Such report should include seismic interpretation, structural geology, petrophysics, OOIP, fluid contacts, well testing, proposed development, forecasted field and well production, and preliminary economics.
    - The DoC report should define the area for development, which will consist of a map with geographical coordinates (a series of UTM x and y points) defining a polygon around the hydrocarbon accumulation. The area should take into account results from the appraisal work program.
    - Operator must then submit a Field Development Plan (FDP) with the boundaries of the proposed Development Area. The FDP should include seismic interpretation, structural geology, petrophysics, OOIP, fluid contacts, well testing, proposed development, forecasted field and well production, and preliminary economics. The 1C and 2C contingent resources (i.e. the resources prior to FDP approval) should be included in the FDP, and may include a range of recovery factors. The 1C resources may assume a primary depletion recovery, while the 2C resources may include secondary recovery techniques.
- Area Demarcation for Mining Lease Best Practices
    - Subsequent to approval of the Field Development Plan (FDP), a Mining Lease (ML) is granted for commercial production of oil and gas from the ML area, as approved in the FDP.
    - The Mining Lease Area should typically be the development area defined in the FDP.
    - Mining Lease approval should be granted by the government.

- Appraisal Area
    - After the discovery of a conventional resource, the appraisal area should be basis of judged prospectivities, delineated from G&G data set, prior to drilling. This will involve defining the hydrocarbon entrapment by updating existing maps with the new well data. An appraisal program should be defined to upgrade the resources within this area.
    - For an unconventional play such as shale oil, condensate, or gas, the appraisal area should include the area on the lease where the shale is sufficiently thick, sufficiently high in TOC and mature for hydrocarbon generation such that hydrocarbons should be present in the shale. An appraisal drilling program should be defined to prove up the unconventional resources within this area, to produce at commercial rate.
    - For tight gas or basin-centered gas, the appraisal area should include the area on the lease where the reservoir is sufficiently thick. An appraisal program should be defined to prove up the resources within this area, to produce at commercial rate.
    - The Appraisal Area may not include the whole block. To retain an area outside of the Appraisal Area when entering the next exploration phase, additional exploration as per the PSC agreement will be required.
- Development Area
    - After a successful appraisal of a conventional resource, the Development Area should be defined in the DoC and FDP reports, based on G&G data generated till completion of appraisal program. The Development Area is equivalent to (FDP approved area and represents the area where the areal extension of oil/gas pool limits of reservoirs/geobodies have been defined/mapped with a reasonable confidence. The FDP will define a plan to develop the resources within the Development Area.
    - For an unconventional play such as shale oil or shale gas, the Development Area should include the area on the lease where the shale is sufficiently thick to produce at commercial rates, sufficiently high in TOC and mature for hydrocarbon generation such that hydrocarbons should be present in the shale, and is an area confirmed by appraisal drilling. The FDP will define the program to develop the unconventional resources within this area.
    - For tight gas or basin-centered gas, the Development Area should include the area on the lease where the reservoir is sufficiently thick to produce at commercial rates. This area will be confirmed by an appraisal drilling program showing the extent of the reservoir.
    - Mining Lease approval should be granted by the government in a timely manner.

2.1.3 References

1. Oman, Kurdistan, and India Model PSC agreements.

2.2 *Standards for Declaration of "Discovery", "Commercial Discovery" and "Potential Commercial Interest (PCI)" and its Acceptance by Regulators*

2.2.1 Definitions and Discussion

The Directorate General of Hydrocarbons (DGH) has been entrusted with the responsibility for monitoring of PSCs awarded under Pre-NELP and NELP and field bidding rounds on behalf of the Government of India. These PSCs require monitoring of exploration work commitments during exploration phase, and further monitoring of appraisal work and approval of development work, in the case of any hydrocarbon discovery.

The Government/DGH will essentially undertake roles related to technical/commercial supervision in the management committee, such as review of any proposal for an appraisal program, or revisions or additions thereto; review of any proposal for declaration of a discovery as a Commercial Discovery; approval of any proposal of Development Plans, or modifications or revisions thereto; and determination of a Development Area.

The PSC provides for a stipulated time period for submission of Declaration of Commerciality (DoC) report for hydrocarbon discovery after implementation of the Appraisal Work Program. The time period for submission of DoC is mentioned in the PSC Articles 10 and 21.

During implementation of the Appraisal Program, the Contractor should be allowed to probe the potential of additional reservoirs, if any, through additional exploration activities for proper assessment of commercial viability within the Contract Area.

2.2.2 Best Practices

- Declaration of Discovery Best Practices
    - Once a discovery is made, the Contractor should notify the same. A notice of discovery may be based on production testing results. As a practice, the production testing must be witnessed by DGH representative as guided by respective PSC.
    - After completion of well testing, Contractor should submit a Discovery Report, reviewing the relevant well data which proves the discovery of hydrocarbons in the well. Such report should include geological maps, OOIP / GIIP, well test results and possible fluid contacts.
- Declaration of Commerciality Best Practices
    - A DoC for a hydrocarbon discovery should be based on a flow to the surface that is measured. In case of proximity of the Discovery to a nearby field, will a DoC be accepted based solely on logs or measurements using a Dynamic Formation Tester, RDT, RCI tool.

- A DoC for a hydrocarbon discovery should be submitted after implementation of an Appraisal Work Program and should be accompanied by an Appraisal/DoC Report.
- Operator should then submit a FDP after declaring the Discovery to be commercial. Such a report should include seismic interpretation, structural geology, petrophysics, OOIP, GIIP, fluid contacts, well testing, proposed development, forecasted field and well production, and preliminary economics.
- In case the oil is highly viscous or bituminous in nature (e.g.low API oil), special/additional time should be provided to the operator to establish Potential Commercial Interest (PCI) for the oil to be produced which may need employing thermal exploitation and may take longer duration in the process before the DoC is submitted. The existing PSC is mainly confined to approve PCI for normal crude oil and gas production and does not specify/elaborate special time line for low API crude oil.
- Government may request modifications to the FDP prior to its approval. Government may reject the FDP if modifications are not adequately addressed.

2.2.3 References

1. Oman, Kurdistan, and India Model PSC agreements.

2.3 *International Norms for Well Flow Tests such as DST and any other Test Procedures in Open Hole, Cased Hole, Gravel Pack, Frac Pack Required for Evaluating or Approving the "Discovery".*

2.3.1 Definitions and Discussion

- The Directorate General of Hydrocarbons (DGH) has been entrusted with the responsibility for monitoring of PSCs awarded under Pre-NELP and NELP and field bidding rounds on behalf of Government of India. These PSCs require monitoring of exploration work commitments during the exploration phase, and further monitoring of appraisal work and approval of development work. In the case of a hydrocarbon discovery, an issue is what constitutes a discovery, and what data must be collected to demonstrate a discovery has been made. Relevant data includes mud logs, electric logs, Dynamic Formation Tester /RDT/RCI sample collection, and DST results.
- There are different types of tests conducted for discovery wells are:
    - Dynamic Formation Tester, RDT, or RCI or a similar test tool depending on the service company
    - DST

2.3.2 Best Practices

- Two types of tests are normally run on the exploration and/or appraisal wells using formation testers (formation testing tools):
    - Open-hole Formation Testing
        - In an open-hole environment wireline formation testers are commonly used to prove or disprove an oil or gas discovery.
        - These tools have been given different names depending on the service companies who have developed them. For example such tools by Schlumberger are known as MDT or RFT (older tool), whereas RCI tool is provided by Baker Hughes. Similar tools are also provided by other service companies. Tools are named differently by different companies with their company trade-marks and they may have varying testing capabilities.
        - These tools use packers to isolate the zone of interest for testing. They also have probes which can be inserted into the formation interval of interest to measure static and/or flowing pressures and can also collect pressure transient type data. They also have chambers to collect reservoir fluid samples.
        - These tests can be repeated at several vertical locations in the well using the prior information obtained from well logs.
        - These tools may have to be retrieved from down-hole to surface from time to time to unload fluid samples and pressure data from memory gauges.
        - Static pressure measurements can be used to establish gas gradient, oil gradient, and water gradient as applicable.
        - Pressure transient data obtained from very short flow and short shut-in periods can be used to estimate approximate values of formation permeability using rate and PVT data. However, pressure transient results will not be as good as those obtained from the DST type tests, which have longer duration flow and shut-in periods.
        - Since Dynamic Formation Tester type tests are run in an open-hole environment, they can save significant completion costs in case the discovery is not confirmed or proven Dynamic Formation Tester type tool is run based upon the results of well logs and mud logs at many more vertical locations than the DST type tool. DST type tool is run on the selected intervals based on the results of the Dynamic Formation Tester tool.
    - Cased-hole Formation Testing
        - In the cased-hole environment, cased-hole Drill Stem Test (DST) is normally run to test the quality and productivity of formation in a single perforated interval or multiple perforated intervals of interest determined

from the Dynamic Formation Tester results and supported by well logs but one test at a time.

- In the past, as the name applies, a DST tool with packers and tester valve used to be attached at the end of the drill string and run into the well to test the perforated interval of interest. However, the current day DST tool consists of a bottom-hole testing assembly which is normally attached at the end of suitable tubing string rather than the drill string.

- These tools have multiple valves and a bundle of four or more high accuracy pressure and temperature gauges. They also have capability of shutting-in the well very close to downhole; however, their functional ability needs to be evaluated and confirmed.

- Testing times and flow rates for each test need to be pre-determined depending on the type of fluid (oil or gas), quality of the formation (high or low permeability), wellbore effects and other factors such as reservoir pressure and temperature etc. The use of a commercial or in-house software (if available) is recommended for this purpose.

- Test sequence for each test interval consists of the following four major steps:

    - STEP 1: Short time (e.g. 10 to 15 minutes) flow and one to two hours of shut-in period to determine initial reservoir pressure.

    - STEP 2: Longer period cleanup flow with varying (small to large) choke sizes followed by a cleanup pressure buildup test.

    - STEP 3: Main flow with an intermediate but fixed choke size (determined from the STEP 2 test) followed by a main pressure buildup test. Since data from this test is analyzed to determine reservoir properties, this important test should be properly designed taking into account wellbore storage effect, etc., for determining flow and shut-in test times.

    - STEP 4: This test is used to determine the flow potential of an oil or gas well. It should consist of the well flowing at least at four increasing flow rates with equal time flow periods. In low permeability formations, each flow period can be followed by a shut-in period of equal duration.

- Steps 1 through 4, as discussed above, are recommended but are not mandatory. Depending on the type of well tested, it is okay to add to or subtract from the above described four steps. In any case, testing steps for any particular well should be well documented and shared with the staff of the Service Company, rig floor and office personnel and anyone else involved with the test.

  - Pressure and temperature data can be recorded even every few seconds and transmitted to surface or any remote location via internet. However, it is important that appropriate gauges have been selected depending upon the range of anticipated pressures and temperatures and have been properly calibrated and tested.

  - It is important to record flow rates very accurately.

  - The above discussed testing procedure can also be used for gravel pack and frac-pack wells in case they fall into the category of discovery wells. In this case one or two pressure gauges can be set to read annulus pressures and remaining gauges are set to read tubing pressures. The pressure difference between the tubing and annulus should indicate the pressure loss due to gravel pack or sand production.

  - The pressure difference between the two tubing gauges at two different vertical locations can help to determine the wellbore fluid gradient. This information can be also used to extrapolate measured pressures to the mid-point perforation interval (MPP) in case the pressure gauges are vertically away from the MPP.

  - Such tests can be run in open-hole but are not usually recommended because of the possibility of encountering formation integrity problems including the risk of losing the well.

- The use of the Dynamic Formation Tester tool should not be considered a substitute for the DST type tool and vice versa especially for the first discovery well~~s~~ until enough confidence has been gained regarding discovery or non-discovery of a given oil and gas play.

- The use of both Dynamic Formation Tester and DST are recommended for discovery or exploration type offshore wells in deep water and ultra-deep water environment as well as deep wells in the onshore environment where the cost of drilling and completing wells is very high.

- In certain cases, where a good correlation has been established between the well logs and the Dynamic Formation Tester and DST results, the use of only Dynamic Formation Tester tool may be sufficient. However, the flow and shut-in test periods in such cases need to be much longer than the usual short test periods utilized during Dynamic Formation Tester type open-hole tests. Moreover, it should be also confirmed that the formation is competent enough to withstand longer testing periods unless the Dynamic Formation Tester tool is run in a cased-hole environment.

- In other cases, cost benefit analysis should be performed to evaluate whether both the Dynamic Formation Tester and DST type tools should be run or the use of only the DST type tool will be sufficient. This condition should be applicable in case of shallow offshore wells and/or less expensive onshore wells.

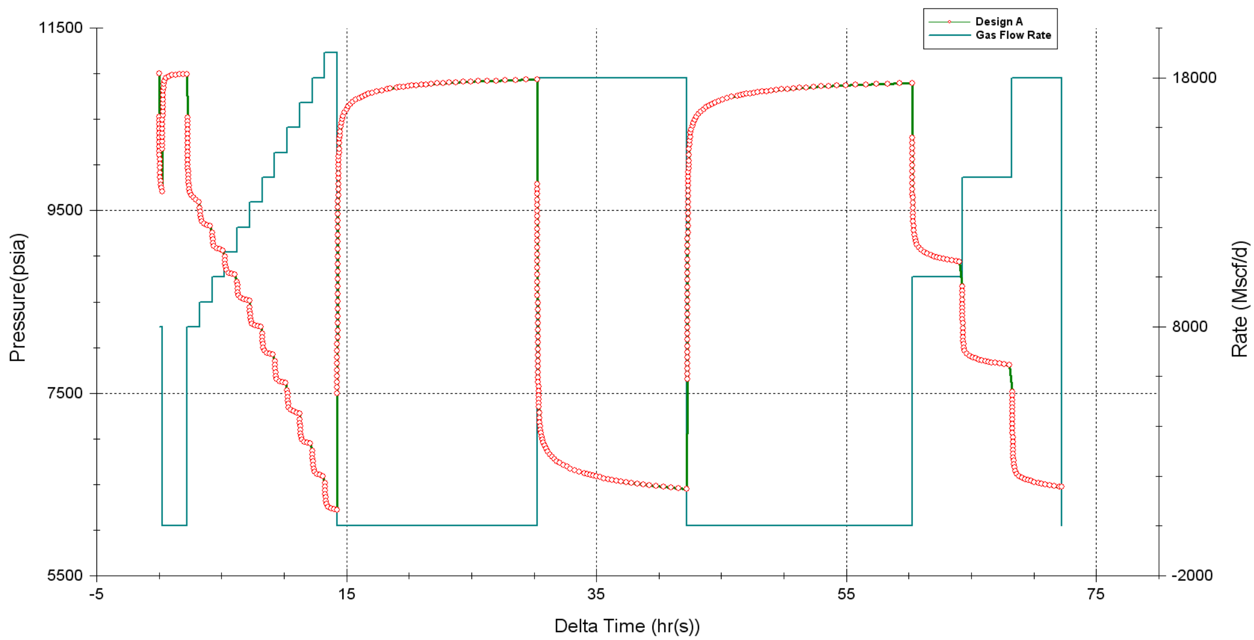
- In case of DST of oil wells, where the reservoir pressure is lower than the hydrostatic pressure, the well may or may not flow to the surface. In this case, to determine well's flow potential, tools like coiled tubing may need to be used to assist the fluid flow to the surface. After CTU job, influx study may be carried out to determine the liquid influx rate followed by pressure gradient survey to know the fluid content in the tubing column. Such wells also require specialized well testing methods such as slug and impulse testing to derive the reservoir parameters.

- Another challenging situation may occur in case of the DST of a heavy oil reservoir, where API oil gravity is low and oil viscosity is very high. The result may be that oil can barely flow into the well. To bring the oil flow to the surface, the use of tools like jet pump may be required. Testing methods such as slug tests and/or impulse tests may be used to derive reservoir parameters. In this case, to confirm or deny the discovery, screening criteria required for the thermal exploitation of heavy oil reservoirs need to be checked prior to the submission of the DoC.

- The third challenging situation may occur in case of the DST of unconventional oil and gas reservoirs, where the formation permeability will be in micro-Darcy. Based on the experience of the exploitation of such reservoirs in USA, it is obvious that wells in such type of reservoirs will have to be hydraulically fractured and wells will require to be drilled on a small and closer spacing. Such information should be pertinent in DoC. In testing of such wells using DST, flow rates will be low during the flow period and wellbore storage effects will be high requiring down-hole shut-in during the pressure buildup testing. Testing of such wells will require careful planning and execution.

- In this write-up, three challenging cases related to DST have been discussed as above. It should be pointed out that there could be other special cases which would require special testing and analysis considerations.

- A schematic of a DST type test procedure for each test interval is shown in the figure below. It should be pointed out that axis values depicting pressures, rates, and test times in this figure are arbitrary.



- Based upon our experience in USA and certain European locations such as United Kingdom and Norway, it is not a requirement that a representative of the Regulatory Agency should attend the well-site during the Dynamic Formation Tester and DST type testing of discovery wells or pressure transient testing of other wells. However, in India, a government representative, if available, can be assigned to be at the well-site during testing of discovery wells or other wells, if considered important or deemed appropriate as per the PSC rules.

2.3.3 References

1. *Fundamentals of Formation Testing*, published by Schlumberger, Sugarland, Texas (2006)

2. Vella, M., Veneruso, T., Lefoll, P., McEvey, T. and Reiss, A.,:"The Nuts and Bolts of Well Testing", Oilfield Review (April, 1992)

3. *Types of Formation Testing Tools* described at the websites of Service Companies such as Schlumberger, Baker Hughes, Halliburton and Weatherford, (Dec 2014).

4. Three SPE Monographs on Well Testing namely a) Vol. 1 by Matthews & Russell (1967), b) Vol. 5 by Earlougher, Jr. (1977), and c) Vol. 23 edited by Med Kamal (2009).

5. *SPE Textbook Series on Well Testing* vol. 1 by John Lee (1982)

6. Ramey, Henry J., Jr., Agarwal, Ram G., and Martin, Ian:"*Analysis of 'Slug Test" or DST Flow Period Data, J. Cdn. Pet. Tech.* (July-Sept 1975) 37-42.

2.4 *Standard Activities Usually Conducted between Hydrocarbon Discovery and Declaration of Commerciality (DoC).*

2.4.1 Definitions and Discussion

In the India Model PSC, Operator must submit an Appraisal Program with a Work Program and Budget after the Discovery announcement, specifying the boundaries of a potential development area. Operator may then submit a Declaration of Commerciality (DoC) with a full report.

In the Oman PSC, operator must submit an Appraisal Plan after Discovery. After the appraisal work is conducted, an Appraisal Report must be submitted. In Oman an extended well test may be done and/or an Early Production facility may be installed prior to Declaration of Commerciality.

In the Kurdistan PSC, Operator must submit an Appraisal Work Program after the Discovery report, and the appraisal area may not be greater than two times the size of the mapped geologic structure. After the appraisal work is completed, operator must submit an Appraisal Report. With the Appraisal Report, operator may submit a Declaration of Commerciality.

2.4.2 Best Practices

- Activities between Discovery and Declaration of Commerciality (DoC)
  - After declaration of a discovery, Operator should submit an Appraisal Program with a Work Program and Budget. Appraisal Program may include an extended well test and/or an Early Production facility.
  - The appraisal area should be based on the size of the mapped geologic structure.
  - After the appraisal work is completed, operator should submit an Appraisal Report. Such report should include seismic interpretation, structural geology, petrophysics, OOIP, fluid contacts, well testing, proposed development, forecasted field and well production, and preliminary economics.
- After declaration of a discovery, a testing program should be conducted that establishes flow to the surface that is measured unless it is established through a nearby well or field. It may be noted that in many geographies (including GOM etc), especially in deep water, MDT/ Other modern testing methods chosen by contractor are accepted for DoC.
- Prior to a DoC, an appraisal program of seismic and/or drilling should be conducted to establish the extent of the accumulation. The program should prove up an area large enough to establish commercial viability for a development.

2.4.3 References

1. Oman, Kurdistan, and India Model PSC agreements.

2.5 *How to Reduce Timelines between Discovery(ies) to Delivery Period (Commercial Production)?*

2.5.1 Definitions and Discussion

In the India Model PSC, Operator must submit a notice of discovery, then run tests and furnish a discovery report. The Operator then submits an Appraisal Program with a Work Program and Budget specifying the boundaries of a potential development area. Upon completion of the appraisal program, the Operator then submits a full report for review for Declaration of Commerciality (DoC). Upon DoC, the Operator submits a Field Development Plan and upon approval of the FDP, development begins. Each of these steps has time allocated both for Operator to assemble relevant documents as well as for Management Committee (Government) approvals. Each step may have back and forth amendments and responses which may add additional time. An issue is how to reduce the time period between a discovery and commercial production.

Indonesia PSC says that if petroleum is discovered in any portion of the contract area which in the judgment of the Government and Contractor can be produced commercially, based on consideration of all pertinent operating and financial data, then development will commence and oil must be produced within 5 years of the end of the exploration period or the Contract Area must be relinquished.

In Kurdistan, the government has pressed operators to reduce or eliminate an appraisal work program, and proceed directly to a DoC and planning a development. A phased development plan is then typically submitted by the operator, allowing some appraisal activities during the first phase of development.

An argument could be made that the interests of the Operator and the government are aligned in that both would like to produce oil as soon as possible in the interest of generating cash flows for commercial discoveries.

2.5.2 Best Practices

- In some cases a Discovery can be judged by the Operator and Government to be large enough to be likely commercial, even before appraisal. Such a Discovery could be indicated by high flow rates, a thick pay zone, combined with a clearly mapped trap. If an appraisal program is to be conducted, Operator could plan a limited appraisal program, one that proves up a minimum commercial volume of petroleum.
- Operator could accelerate the Front-End Engineering and Design (FEED) studies and plan a staged development, with an early production system that expedites first production.
- Operator could develop a contracting and procurement strategy that prioritizes activities such as ordering long lead items well in advance of production.
- Both the Operator and Government should adhere to the PSC specified timelines.
- Government should expedite the review and approval process and the issuance of permits and approvals.

2.5.3 References

1. Kurdistan, Indonesia and India Model PSC agreements.

2.6 *Best Practices on Maximum Time Allowed to the Contractor to Retain the Discovery Area for Discoveries not Monetized*

2.6.1 Definitions and Discussion

The Kurdistan PSC states that, at the end of the exploration period, all of the remaining area that is not included in a Production Area (Development Area) is relinquished. Therefore, any discovery not deemed commercial will not result in an additional Production Area and shall be relinquished; the time allowed would be the time to follow PSC specified procedure of going from discovery to determination of commerciality. Extension of the exploration period is allowed for discoveries made near the end of the exploration period to allow for determination of commerciality.

The Brazilian concession agreement contains a similar approach to that employed by the Kurdistan PSC.

The Mozambique EPC is also similar in that the Exploration Phase is extended to allow for an evaluation period of the Discovery and, if determined to be of commercial interest, the Exploration Phase is further extended until approval of the Development Plan.

The Indonesia PSC specifies that, in the event of an approval to develop a field, the area must be surrendered if no production occurs for five years after the end of the Exploration Period; however, special provisions are made for Natural Gas production. If production begins, but ceases for five continuous years, then the area must be surrendered.

Under the Petroleum Resources Management System (PRMS) suggested sub-classes (see figure on sub-classes in Section 4.3), the lowest sub-class of reserves is “Justified for Development.” This classification “...covers the period between (a) the operator and its partners agreeing that the project is commercially viable and deciding to proceed with development on the basis of an agreed development plan (i.e. there is firm intent), and (b) the point at which all approvals and contracts are in place (particularly regulatory approval of the development plan, where relevant) and a final investment decision has been made by the developers to commit the necessary capital funds. In PRMS, the recommended benchmark is that development would be expected to be initiated within 5 years of assignment of this sub-class.”

The Indian PSC stipulates that the Contractor has 10 years from the date of discovery to commence development of a gas field else the Discovered Area shall be excluded from the Contract Area. There is no such provision in the case of oil; however, it is reasonable to suggest similar treatment.

2.6.2 Best Practices

- In the case of discoveries made during the late stage exploration period, exploration period is typically extended (typically maximum of 18 months to 2 years) to allow for commercial evaluation of the discovery as per PSC specified procedures. If commerciality cannot be established, discovery area shall be relinquished and exploration period ends.

- Maximum time allowed to retain Development / Production Area for commercial discoveries not being monetized
    - Development / Production Area shall be relinquished if no development occurs for five years after the approval of FDP unless an extension is granted on merit.
    - If production begins, but ceases for five continuous years, then the Development / Production Area shall be relinquished unless an extension is granted by government on merit.

    In both the cases mentioned above, extension of timeline can be granted by Govt. depending on merit of the case, if delays are due to reasons beyond the control of the contractor

- In the case of discovery of non-commercial hydrocarbons, development must commence within ten years from the date of the first Discovery Well.

2.6.3 References

1. Production sharing agreements for Kurdistan, Mozambique, Indonesia, India, Oman.
2. Guidelines for Application of the Petroleum Resources Management System. November 2011. http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf

3 Appraisal

3.1 *Best Practices Regarding Various Methods of Appraisal Considering the Extent of Reservoir, Hydrodynamic Systems and Connectivity, and Different Fault Blocks*

3.1.1 Definitions and Discussion

- "Appraisal" is the assessment of exploration prospects after a discovery of Petroleum with the aim to better define the parameters of the Petroleum and the reservoir to which the discovery relates. The appraisal phase takes place following discovery of oil or gas, upon which the Operator requires further information about the extent of the deposit or its production characteristics to determine whether it can be commercially exploited.

- Prospecting, exploration and appraisal operations are conducted so as to ensure that good quality data is acquired, within reasonable economic and technical constraints. Sufficient data needs to be gathered to test the understanding of the reservoir and to minimize uncertainties that affect the success of petroleum recovery.

- During appraisal, more wells are generally drilled to collect information and samples from the reservoir. Additional seismic surveys might also be acquired in order to better image the reservoir. These activities can take several years and cost tens to hundreds of millions of dollars. More seismic surveys and wells help petroleum geologists, geophysicists and reservoir engineers to better understand the reservoir. For example, they try to find out whether rock or fluid properties change away from the discovery well, how much oil or gas might be in the reservoir, and how fast oil or gas will move through the reservoir. The prospective development can successfully move past the appraisal stage if a company decides that the oil or gas fields can be develop economically. One risk that companies face is that, even after investing time and money in the appraisal stage, they may not find a way to develop the field profitably and responsibly.

- In addition to drilling appraisal wells and furthering geological and geophysical testing, the appraisal and evaluation phase typically includes conducting detailed engineering studies to determine the nature and extent of the reserves potential and the formulation of a plan for developing and producing the potential reserves in order to obtain maximum economic recovery. Marketing studies may also be necessary, especially in the case of gas discoveries, in order to evaluate transportation costs and market price potential.

- In operations in the United States, especially in areas with a history of production, when an exploratory well discovers hydrocarbons, the company may briefly evaluate the results of drilling and then move directly into development. This is particularly likely in onshore operations in locations where an transportation and marketing infrastructure exists. In U.S. domestic offshore operations, the market and transportation infrastructure may also be in place; however, drilling of additional wells may be necessary in order to determine whether the potential reserves are sufficient to warrant construction of a production platform, additional pipelines, and/or onshore facilities to handle the production. If additional wells are drilled in order to determine whether potential reserves are sufficient to justify installing the necessary infrastructure, they are often treated as a part of the exploration phase.

- In operations outside the United States, the appraisal and evaluation phase is more likely to be necessary and is much better defined. Production sharing contracts and risk service agreements often specify certain appraisal activities that must be carried out by the contractor in the event that an exploratory well results in a discovery.

- The Appraisal Report shall include all available technical and economic data relevant to the determination of commerciality. An appraisal report shall include but not be limited to the following information:

    - Geological and petrophysical characteristics of the discovery;
    - Estimated geographical extent of the discovery;
    - Thickness and extent of productive layers; depth of pay zones;
    - Pressure, volume and temperature data (PVT);
    - Productivity index of wells tested; anticipated production performance;
    - Recovery drive characteristics;
    - Characteristics and quality of petroleum discovered;
    - Preliminary estimates of Hydrocarbons in place and reserves;
    - Enumeration of other important characteristics and properties of the deposits and fluids discovered;
    - Preliminary economic study with regard to the exploitation of the discovery;
    - Technical and economic feasibility studies relating to processing and transport of petroleum from the location; and
    - Additional information and assessments as required.

3.1.2 Best Practices

- The specific requirements for the Appraisal phase are dependent on the nature of the reservoir and the availability of data from other sources (analog data).

- The purpose of Appraisal is to establish the size and commerciality of the discovery. This can involve several activities including additional seismic work, longer-term flow tests, or the drilling of further wells. Sufficient data needs to be gathered to test the understanding of the reservoir and to resolve uncertainties that may affect the success of development of the discovery.

- During the Appraisal phase, good practice will normally require that all the information needed to determine the most appropriate development has been gathered and analyzed properly. This will allow for consideration of all realistic options for field development, including the application of new or innovative technology.

- Good industry practice may include activities designed and conducted to maximize data gathering for maximum economic petroleum recovery and minimum wastage within reasonable technical and economic constraints. Such activities may include:
    - Drilling of additional wells
    - Long term flow test and Pressure Transient Analysis (PTA)
    - Additional 2D/3D seismic acquisition
    - Reprocessing, reinterpretation and remapping of proposed development area
    - Rock and fluid sampling and analysis
    - Interference test between two wells to determine pressure communication across a fault
    - Drilling a well at the flanks to predict aquifer behavior or to test injectivity in the water leg
- The purpose of appraisal is to better establish the size and commerciality of the discovery. Different methods and techniques, including the use of new innovative technologies, should be acceptable if they can accomplish the goal of the appraisal phase. As discussed above, different tests and data may be required to determine the size of the discovery and its commerciality. The international practice is geared toward achieving the ultimate objective rather than to follow any particular approach.

3.1.3 References

1. Hydrocarbon Exploration and Production by Frank Jahn, Mark Cook and Mark Gaham.
2. Planning and practice guidance for oil and gas. Published by the Government of UK.
3. Guidelines published by the Government of UK for onshore and offshore oil and gas field development plans.
4. Upstream Petroleum Operations by Wright.

3.2 *Whether during Appraisal of a Discovery, the Contractor can explore other Reserves/Pools*

3.2.1 Definitions and Discussion

- The exploratory phase seeks to acquire data to establish whether hydrocarbons are present. It may involve geological and geophysical studies including seismic surveys, aerial surveys, surface geology, etc. to determine the need and location for drilling an exploratory well.

- "Exploration operations" are defined in the Indian model PSC as operations conducted in the Contract Area in search of Petroleum and in the course of an Appraisal Program and shall include but not be limited to aerial, geological, geophysical, geochemical, palaeontological, palynological, topographical and seismic surveys, analysis, studies and their interpretation, investigations relating to the subsurface geology including structural test drilling, stratigraphic test drilling, drilling of Exploration Wells and Appraisal Wells and other related activities such as surveying, drill site preparation and all work necessarily connected therewith that is conducted in connection with Petroleum exploration.

- "Exploratory Well" means a well drilled in the course of Exploration Operations and whose purpose at the commencement of drilling is to explore for an accumulation of petroleum whose existence was at the time unproven by drilling.

- "Appraisal Area" means an area within the Contract Area encompassing the geographical extent of a Discovery that is subject to an Appraisal work program and corresponding budget in accordance with the terms of the PSC.

3.2.2 Best Practices

- The Operator or permit holder should submit to the DGH an appraisal work program to delineate and appraise any discovery.

- The contract holder or operator may also elect when submitting the program to:

    - Continue with the exploration work program over the remainder of the Contract Area, or

    - Relinquish the areas not required for the appraisal of the discovery

- In certain situations, it may be difficult to be precise about the actual limits of a field before the appraisal work is completed. In such scenarios, Operator or permit holder may be allowed a reasonably adequate area to enable it to appraise the discovery.

- If there is more than one discovery:

    - All discoveries may be included into a single work program, or

    - Separate work programs may be allowed for each discovery

- The general practice is to allow the permit holder to continue with exploration activities in conjunction with the appraisal of a Discovery during contract period.

3.2.3 References

1. Production sharing contracts/concession agreements for Kenya, Angola, Kurdistan, Oman, Tanzania, Liberia, Ghana, Indonesia, Brazil
2. Minerals Program regulations in New Zealand
3. Activities and Guidelines on upstream oil and gas activities in China
4. Petroleum Regulations of the Republic of Equatorial Guinea

3.3 *Appraisal Program – Pre-Development Drilling and Activities*

3.3.1 Definitions and Discussion

- "Appraisal Well" means any well drilled following a discovery of Petroleum in the Contract Area for the purpose of mapping of thickness, areal extent & other petro-physical parameters of the reservoir (s) and in order to estimate the initial in-place volume of hydrocarbons to which the discovery relates.
- "Appraisal Program" means an approved work program and budget prepared for the purpose of Appraisal.
- The objective of the Appraisal phase is to reduce uncertainty related to the discovery by confirming and evaluating the presence extent and how potential of hydrocarbons that have been indicated by previous exploratory drilling, well testing and other G&G studies. The appraisal phase can involve several activities including additional seismic work, long-term flow tests or the drilling of further wells. Appraisal activities should be based upon the information required to reduce uncertainty.
- "Exploration operations" are defined in the Indian model PSC as operations conducted in the Contract Area in search of Petroleum and in the course of an Appraisal Program that shall include but not be limited to aerial, geological, geophysical, geochemical, palaeontological, palynological, topographical and seismic surveys, analysis, studies and their interpretation, investigations relating to the subsurface geology including structural test drilling, stratigraphic test drilling, drilling of Exploration Wells and Appraisal Wells and other related activities such as surveying, drill site preparation and all work necessarily connected therewith that is conducted in connection with Petroleum exploration.
- "Unconventional hydrocarbons" refers to oil and gas having an unconventional source and entrapped in unconventional reservoir rocks.

3.3.2 Best Practices

- Drilling of wells:
    - Wells are drilled to collect additional information about reservoir parameters and extent of the accumulation.
    - Location of the wells could vary depending on the information that is required.
    - Additional exploration drilling may continue in parallel to appraisal and pre-development efforts as this could result in additional discoveries and production from the Contract Area.
- Running productivity tests:

  - Well tests may be carried out in the appraisal or exploratory wells to gain a better understanding of the reservoir.

  - Extended Well Tests (EWT) may also be authorized if it can be demonstrated that this will result in better technical understanding or confidence in the performance of the field needed to assess commercial potential. EWTs should have realistic and definable appraisal objectives essential to the success of a development.

  - The revenue from the produced oil called “Test Oil” may be shared between the parties. The sharing of revenue is as per PSC guidelines.

- In certain situations, an interference test between two wells may be used to determine pressure communication across a fault.

- For unconventional hydrocarbons it may involve further hydraulic fracturing followed by flow testing to establish the strength of the resource and its potential productive life. Much will depend on the size and complexity of the hydrocarbon reservoir involved.

- Collecting special geological samples and reservoir fluids.

- Conducting supplementary studies and acquisition of geophysical and other data, as well as the processing of same data.

- In addition to drilling appraisal wells and further geological and geophysical testing, the appraisal phase typically includes conducting detailed engineering studies to determine the nature and extent of the reserves and the formulation of a plan for developing and producing the reserves in order to obtain maximum economic recovery.

- Marketing studies may also be necessary, especially in the case of gas discoveries, in order to evaluate transportation costs and market price potential.

- The pre-development field activities such as drilling of new wells, testing of existing wells, geological/geophysical surveys, etc., that are needed for improved understanding of reservoir parameters should be allowed if they assist in achieving the goal of the appraisal phase.

- The international practice with regard to “Test oil” is that if DoC has been approved, then the revenue can be shared between the parties as per PSC guidelines. The same may be followed here.

3.3.3 References

1. Hydrocarbon Exploration and Production by Frank Jahn, Mark Cook and Mark Gaham
2. Planning and practice guidance for oil and gas. Published by the Government of UK
3. Guidelines published by the Government of UK for onshore and offshore oil and gas field development plans
4. Production sharing contracts/concession agreements for Kenya, Angola, Kurdistan, Oman, Tanzania, Liberia, Ghana, Indonesia, Brazil

5. Minerals Program regulations in New Zealand
6. Activities and Guidelines on upstream oil and gas activities in China
7. Petroleum Regulations of the Republic of Equatorial Guinea

4 Declaration of Commerciality (DoC)

4.1 *Data requirement at the time of submission of DoC/FDP which is comprehensive and transparently known to operator and approving body in advance so that the entire dataset is submitted in a single instance*

4.1.1 Definitions and Discussion

As outlined in the Indian Model Production Sharing Contract (PSC), once a discovery has been made, the Contractor will test the discovery well to evaluate commercial potential. If the discovery exhibits commercial potential, an Appraisal Program will be formulated by the Contractor to evaluate the extent of the discovered hydrocarbons and to determine whether the discovery is commercially producible. The results of the appraisal program will be summarized in an Appraisal Report (DoC Report) setting forth all technical and economic data, including the boundaries of the proposed Development Area. Based on the Appraisal Report, a determination will be made as to whether or not the discovery represents a Commercial Discovery. If determined to be commercial, a Declaration of Commerciality will be made and work will begin on the Field Development Plan (FDP).

Oman Exploration and Production Sharing Agreement (EPSA) is similar to that described above except Declaration of Commerciality is made upon approval of FDP.

Indonesia PSC allows much freedom to the Contractor and simply says that if petroleum is discovered in any portion of the contract area which in the judgment of the Government and Contractor can be produced commercially, based on consideration of all pertinent operating and financial data, then development will commence and oil must be produced within 5 years of the end of the exploration period or the Contract Area must be relinquished.

Both India and Oman contracts outline the general informational requirements for the aforementioned Appraisal (DoC) and FDP reports but do not provide an itemized list of the data/documents to be submitted along with both reports.

The Directorate General of Hydrocarbons of India has provided guidelines for the minimum information to be submitted for DoC and FDP evaluation which has been reviewed and summarized below as best practices.

4.1.2 Best Practices

- The following data are recommended for submission with the DoC Report:
  - Geology and Geophysics data
    - The processed version of the 2D/3D seismic used for the seismic interpretation used to generate the maps and seismic displays covering the development area.
    - Seismic velocity data (if used for time to depth conversion for depth maps)

- Depth conversion procedure
- Annotated final time/depth structure maps for key horizons with 1P/1C/P90, 2P/2C/P50 and 3P/3C/P10 polygons
- Representative seismic cross sections with seismic interpretations
- If seismic attributes were used to assist with delineation of hydrocarbon extent or distribution of reservoir quality, these attribute maps should be provided with depth contours superimposed on the maps of the reservoir top or bottom as applicable with 1P/1C/P90, 2P/2C/P50 and 3P/3C/P10 polygons. The attribute maps should be clearly labeled based on the type of attribute used along with a color scale bar of the attribute values.
- Map of the proposed development area with a series of UTM x and y points (latitudes and longitudes)defining a polygon around the hydrocarbon accumulation.
- Geo-cellular model with all input data (seismic data, well data, interpreted horizons, interpreted faults, etc.)
- VSP data and deviation data of inclined wells, if any
- Log correlations for drilled wells
- Test data for drilled wells
- Net pay maps for 1P/1C/P90, 2P/2C/P50 and 3P/3C/P10 scenarios
- Fluid contacts shown on maps
- Relevant interpretation reports
- Well completion reports

- Petrophysical data
  - Well raw log data in DLIS/LIS/LAS and in PDF/PDS formats of all the suits recorded in different borehole sections
  - Processed (merged and depth matched, environmentally corrected, quality controlled, etc.) log data in LAS format comprised of standard log curves (GR, caliper, SP, Deep-Shallow-Medium resistivity, neutron, density, sonic log)
  - Hard copy log prints
  - Well deviation data
  - Mud properties and mud log data in DLIS/LIS/LAS and in PDF/PDS formats

- Petrophysical analysis report containing:
  - Pay summary table with Gross thickness, Net Pay thickness in MD, TVD/TVDSS, average effective porosity, average water saturation, HCPT, cut-off values for Vcl, PHIE and S_w, and fluid contacts
  - Petrophysical model used
  - Rw and a,m,n parameters
  - Analyzed logs in LAS and PDF format
- Petrophysical core analysis reports, if any
- Special log analysis reports like NMR logs, Borehole-image logs, ECS Sonic logs, etc., if any
- Flow test reports

- Reservoir data
  - Testing details of all wells and horizons
  - Well test data (flow rates, watercut, GOR/CGR, SBHP/FBHP/Pressure Gradient Survey, STHP/FTHP and BHT, AOFP estimation and PI calculation, etc.) for each proposed reservoir
  - Pressure transient analysis results (initial/average reservoir pressure, capacity (Kh), permeability (K), skin, PI and radius of investigation, etc.)
  - PVT data (Phase behavior diagram, bubble point/dew point pressure, FVF, solution GOR, fluid density/gravity, condensate dropout analysis in case of retrograde gas reservoir, etc.)
  - Crude/gas analysis report (oil and gas composition, specific gravity, viscosity, water salinity, etc.)
  - Equation of State, if prepared
  - Relative permeability data (Kro/Krg/Krw with respect to respective saturations)
  - SCAL data with capillary pressure, if available
  - Proposed development strategy including envisaged drive mechanism, IPR curves, EOR/pressure maintenance, artificial lift or stimulation requirements, type of wells, etc.
  - Swelling test, slim tube/MMP test results in case of gas injection
  - Reservoir simulation results and input data files

- P/Z inputs and gas deviation factor (Z) for gas reservoirs
- Forecasted production profiles (oil/gas/water production/injection rates, watercut, GOR/CGR, cumulative production/injection, reservoir pressure and decline rate considered along with basis/assumptions)
- Map of well locations with 1P/1C/P90, 2P/2C/P50 and 3P/3C/P10 polygons

- In addition to the recommended data for submission with the DoC Report, the following additional data is recommended for submission with subsequent FDP Report
  - Geology and Geophysics data
    - All details of additional data/information/analyses generated since DoC report submission
    - Any revisions to defined development area
  - Petrophysical data
    - All details of additional data/information/analyses generated since DoC report submission
  - Reservoir data
    - All details of additional data/information/analyses generated since DoC report submission

4.1.3 Recommendations

- The data requirements at the time of submission of DoC and FDP reports have been outlined as best practices and are recommended for India.

4.1.4 References

1. Production sharing contracts from Oman, Indonesia, Kurdistan, Iraq, and India
2. Directorate General of Hydrocarbons "Guidelines for evaluation of Declaration of Commerciality (DoC), Field Development Plan (FDP) & Well locations. DGH/FDP/Checklist/14, November 11, 2014.

4.2 *Strategies to allow DoC and Exploitation of Marginal Fields*

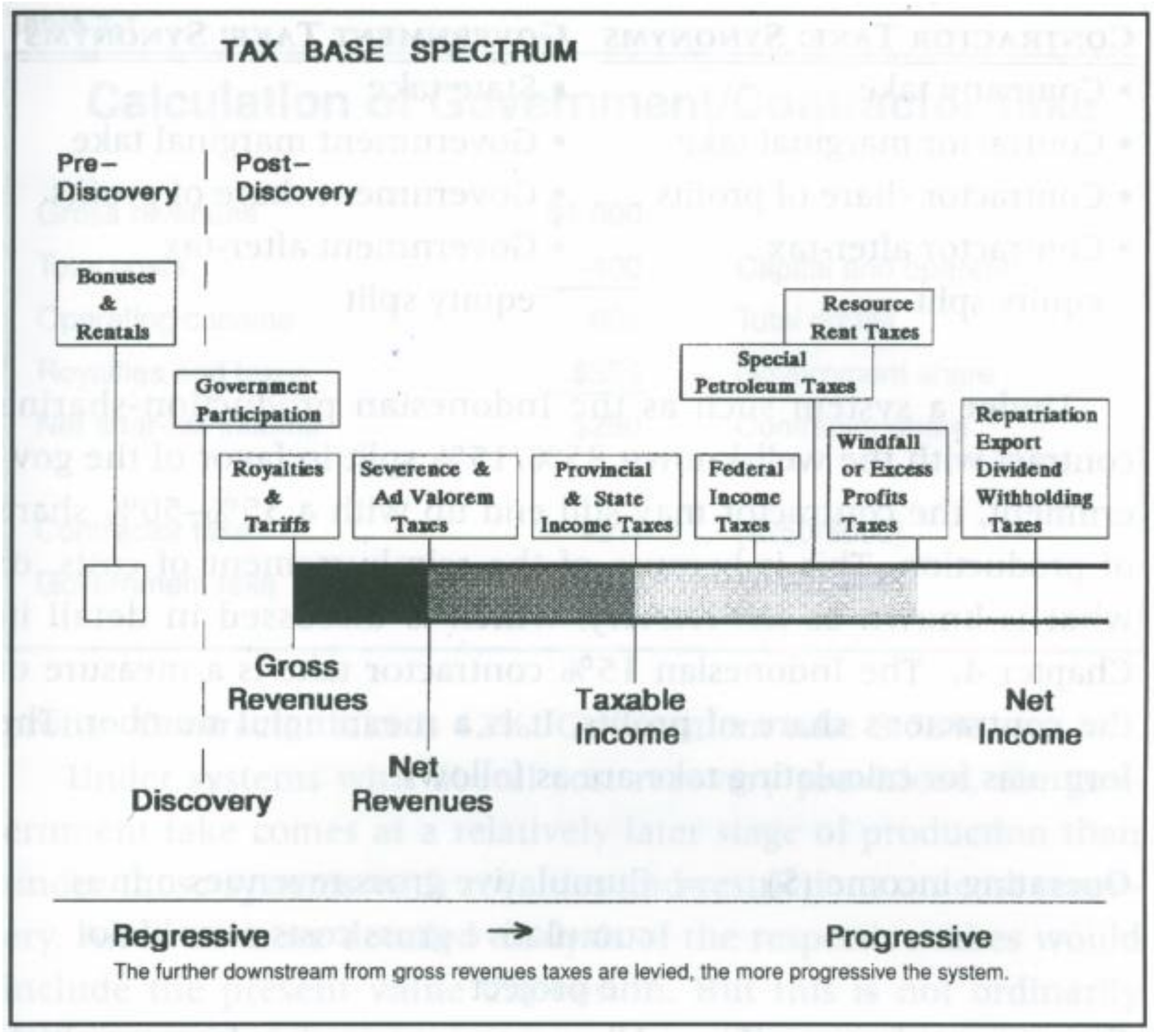
4.2.1 Definitions and Discussion

- SPE defines marginal fields as discoveries which have not been exploited for a long time, due to one or more of the following factors:
  - Very small sizes of reserves/pool to the extent of not being economically viable

  - Lack of infrastructure in the vicinity and profitable consumers
  - Prohibitive development costs, fiscal levies and technological constraints

- Nigeria's Department of Petroleum Resources (DPR) defines marginal fields as:
  - A field located within an area covered by an existing mining lease (OML) held by one or more companies, which:
    - has oil and gas reserves booked and reported annually to the DPR;
    - has remained unproduced for 10 years; and
    - is declared to be a marginal field by the President.
  - Marginal fields may also have some or all of the following features:
    - oil reserves with unconventional crude oil characteristics (such as very high viscosity and low API gravity);
    - high gas and low oil reserves; and
    - they may have been abandoned by the oil mining lease holder for upwards of three years.
- Some countries define Marginal fields based on reserve levels
  - UK defines marginal field as a field holding less than 20 million boe.
  - Malaysia defines marginal field as a field holding less than 30 million boe.

Many fiscal regimes include a cost recovery mechanism to allow the contractor to recover costs associated with exploration, appraisal, development and production. In the case of marginal fields with large sunk costs (such as an extensive exploration program), the resulting percentage of gross production obtained by the government after cost recovery can be greatly reduced. This is more of an issue with progressive regimes where government take is based more on profitability than gross revenues (Johnston, 1994). Progressive and regressive fiscal policies are summarized in the figure below from Johnston's book.



The spectrum of taxation (Johnston, 1994)

In order to receive a minimum desired percentage of gross production, many countries have adjusted the terms of their fiscal agreements accordingly. An example is the addition of a royalty payment (or First Tranche Petroleum in Indonesia) to assign a fixed percentage of gross production to the government before cost recovery deductions. Another example is limiting cost recovery to a certain percentage of gross production (such as 60% in Oman), ensuring a portion of production carries through to the production split between government and contractor.

However, in cases where the volume of hydrocarbons discovered is small or in mature fields where profitable production is no longer achievable under the terms of the PSC, certain strategies must be employed in order for profitable development to occur. Either the terms of the PSC could be relaxed to provide additional economic incentive, or the discovery or field could lay idle until a time where increases in oil or gas prices or enhancements in engineering technologies improve project economics.

For oil/gas importing countries, it may be best to incentivize development of marginal fields through relaxed/amended PSC terms, resulting in the direct benefits of additional government revenues and reduced reliance on imports as well as the indirect benefits of jobs and income into local communities.

Some countries include a clause in their agreements allowing for the terms of the contract to be revisited in the case of marginal fields. In this scenario, the Contractor/Operator is to give notice and consult with the Government concerning any alterations to the terms of the PSC which would permit commercial development of the marginal field.

This has been practiced in Nigeria where an aggressive campaign targeting marginal fields began in 2010. 116 oil and gas fields have been classified as marginal fields and have been targeted for incentivized development by qualified companies. As an additional stimulus to development of these marginal fields, the government has granted a number of fiscal incentives such as lower sliding scale royalties and substantially reduced petroleum profit taxes.

Another way to incentivize development of marginal fields is to manage the existing inventory of processing and transportation facilities and infrastructure to arrange access for marginal fields to reduce the costs of bringing these fields to production. The US and UK-Norwegian Code of Practice are examples of regional/national infrastructure sharing systems. Sharing of infrastructure is discussed in Section 10.2 of this report.

4.2.2 Best Practices

- Allow for amendments to PSC terms mutually agreed upon by Contractor/Operator and Government which allow for commercial development of marginal fields.
- Proactively manage the planning of processing and transportation facilities and infrastructure to help reduce the costs of bringing marginal fields to production.
- Apply these principles to include stranded discoveries, especially in DW, UDW, HPHT, Difficult areas

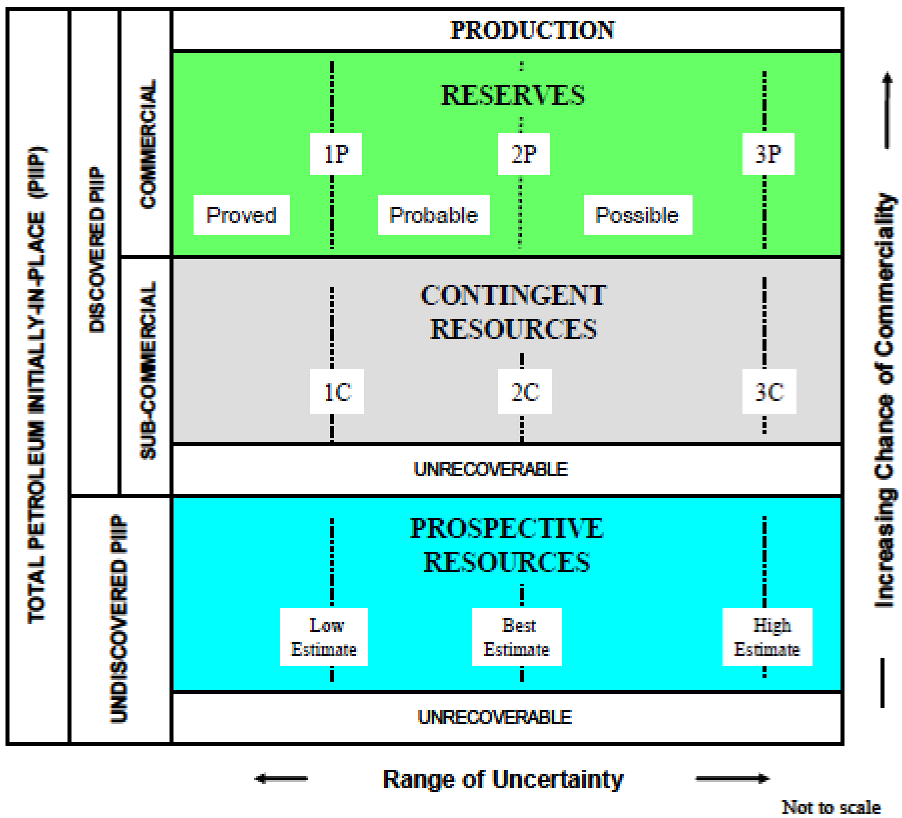
4.2.3 References

1. Johnston, Daniel. 1994. *International Petroleum Fiscal Systems and Production Sharing Contracts.* Tulsa, OK. PennWell Publishing Company.
2. Production sharing contracts for Indonesia and Oman.
3. www.spe.org
4. Nigeria Oil and Gas: Marginal Fields. March 2014.Ashurst London.
5. Manaf et al. 2014. *Effect of Taxation and Fiscal Arrangement on Marginal Oil Field Investment Climate: A Theoretical Framework.*
6. Mart Resources: http://www.martresources.com/operations/introduction-to-nigeria/

4.3 *International Guidelines for Classification and Evaluation of Resources and Reserves*

4.3.1 Definitions and Discussion

The International Standards for evaluating resources and reserves are provided in the November 2011 release "Guidelines for Application of the Petroleum Resources Management System" or PRMS, sponsored by SPE, AAPG, WPC, SPEE and SEG. A summary of the PRMS classification system is given below. Please reference the original document for a complete view of PRMS Guidelines.



PRMS resource classification framework (from PRMS November 2011 release)

PRMS definitions

- "Prospective Resources" are those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
- "Contingent Resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies.

- “Reserves” are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: They must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.

- “Unrecoverable” refers to that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are estimated, as of a given date, not to be recoverable. A portion of these quantities may become recoverable in the future as commercial circumstances change, technological developments occur, or additional data are acquired.

- “Discovered”refers to one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery.

- “Commercial”project implies that the essential social, environmental, and economic conditions are met, including political, legal, regulatory, and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame.

4.3.2 Best Practices

- Resource/Reserve Classification Summary

    - Prospective resources are undiscovered resources. When an exploratory well results in a discovery, the discovered resources are classified as contingent resources and are thus contingent on commerciality. Upon establishment of commerciality, the commercial resources are reclassified as reserves.

    - Resources and Reserves are typically reported in barrels (bbl) and cubic feet (ft^3).

- Range of Uncertainty

    - In PRMS, the range of uncertainty is characterized by three specific scenarios reflecting low, best, and high case outcomes from the project. The terminology is different depending on which class is appropriate for the project, but the underlying principle is the same regardless of the level of maturity. In summary, if the project satisfies all the criteria for Reserves, the low, best, and high estimates are designated as Proved (1P), Proved plus Probable (2P), and Proved plus Probable plus Possible (3P), respectively. The equivalent terms for Contingent Resources are 1C, 2C, and 3C, while the terms “low estimate,” “best estimate,” and “high estimate” are used for Prospective Resources. The three estimates may be based on deterministic methods or on probabilistic methods.

    - While estimates may be made using deterministic or probabilistic methods, the underlying principles must be the same if comparable results are to be achieved. It is useful, therefore, to keep in mind certain characteristics of the probabilistic method when applying a deterministic approach:

- The range of uncertainty relates to the uncertainty in the estimate of Reserves (or Resources) for a specific project. The full range of uncertainty extends from a minimum estimated Reserve value for the project through all potential outcomes up to a maximum Reserve value. Because the absolute minimum and absolute maximum outcomes are the extreme cases, it is considered more practical to use low and high estimates as a reasonable representation of the range of uncertainty in the estimate of Reserves. Where probabilistic methods are used, the P90 and P10 outcomes are typically selected for the low and high estimates.

- In the probabilistic method, probabilities actually correspond to ranges of outcomes, rather than to a specific scenario. The P90 estimate, for example, corresponds to the situation whereby there is an estimated 90% probability that the correct answer (i.e., the actual Reserves) will lie somewhere between the P90 and the P0 (maximum) outcomes. Obviously, there is a corresponding 10% probability that the correct answer lies between the P90 and the P100 (minimum) outcome, assuming of course that the evaluation of the full range of uncertainty is valid. In a deterministic context, "a high degree of confidence that the quantities will be recovered" does not mean that there is a high probability that the exact quantity designated as Proved will be the actual Reserves; it means that there is a high degree of confidence that the actual Reserves will be at least this amount.

- In this uncertainty-based approach, a deterministic estimate is, as stated in PRMS, a single discrete scenario that should lie within the range that would be generated by a probabilistic analysis. The range of uncertainty reflects our inability to estimate the actual recoverable quantities for a project exactly, and the 1P, 2P, and 3P Reserves estimates are simply single discrete scenarios that are representative of the extent of the range of uncertainty. In PRMS, there is no attempt to consider a range of uncertainty separately for each of the 1P, 2P, or 3P scenarios, or for the incremental Proved, Probable, and Possible Reserves, because the objective is to estimate the range of uncertainty in the actual recovery from the project as a whole.

- Because the distribution of uncertainty in an estimate of reserves will generally be similar to a lognormal shape, the correct answer (the actual recoverable quantities) will be more likely to be close to the best estimate (or 2P scenario) than to the low (1P) or high (3P) estimates. This point should not be confused with the fact that there is a higher probability that the correct answer will exceed the 1P estimate (at least 90%) than the probability that it will exceed the 2P estimate (at least 50%).

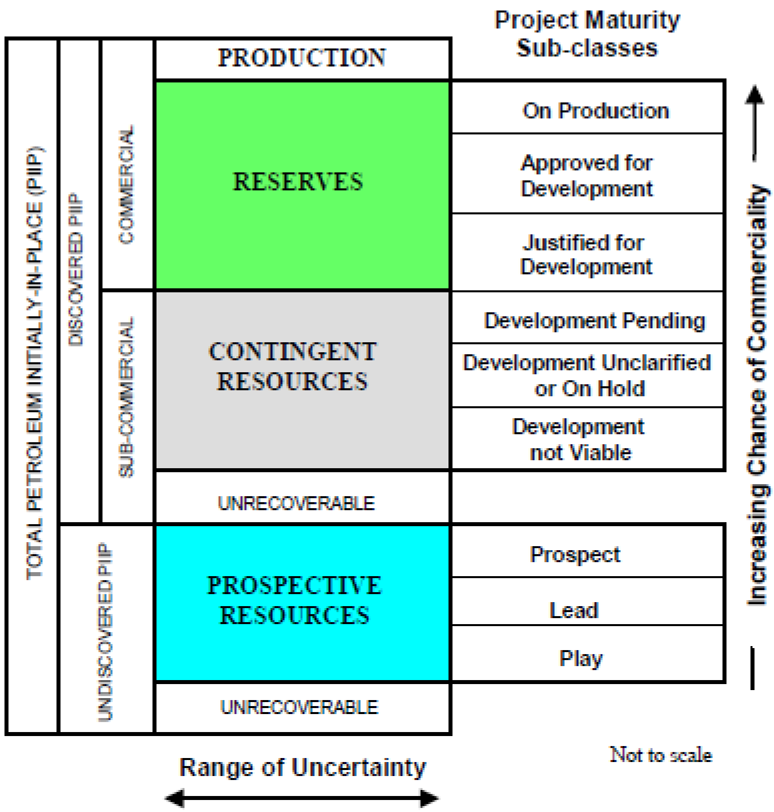
- Commercial Risk and Reported quantities

- In PRMS, commercial risk can be expressed quantitatively as the chance of commerciality, which is defined as the product of two risk components:
    - The chance that the potential accumulation will result in the discovery of petroleum. This is referred to as the “chance of discovery.”
    - Once discovered, the chance that the accumulation will be commercially developed is referred to as the “chance of development.”
- Because Reserves and Contingent Resources are only attributable to discovered accumulations, and hence the chance of discovery is 100%, the chance of commerciality becomes equivalent to the chance of development. Further, and as mentioned previously, for a project to be assigned Reserves, there should be a very high probability that it will proceed to commercial development (i.e., very little, if any, commercial risk). Consequently, commercial risk is generally ignored in the estimation and reporting of Reserves.
- However, for projects with Contingent or Prospective Resources, the commercial risk is likely to be quite significant and should always be carefully considered and documented. Industry practice in the case of Prospective Resources is fairly well established, but there does not appear to be any consistency yet for Contingent Resources.
- Consider, first, industry practice for Prospective Resources. The chance of discovery is assessed based on the probability that all the necessary components for an accumulation to form (hydrocarbon source, trap, migration, etc.) are present. Separately, an evaluation of the potential size of the discovery is undertaken. Typically, this is performed probabilistically and leads to a full distribution of the range of uncertainty in potentially recoverable quantities, given that a discovery is made. Because this range may include some outcomes that are below the economic threshold for a commercially viable project, the probability of being above that threshold is used to define the chance of development, and hence a chance of commerciality is obtained by multiplying this by the chance of discovery.
- Once a discovery has been made, and a range of technically recoverable quantities has been assessed, these will be assigned as Contingent Resources if there are any contingencies that currently preclude the project from being classified as commercial. If the contingency is purely nontechnical (such as a problem getting an environmental approval, for example), the uncertainty in the estimated recoverable quantities generally will not be impacted by the removal of the contingency. The Contingent Resource quantities (1C, 2C, and 3C) should theoretically move directly to 1P, 2P, and 3P Reserves once the contingency is removed, provided of course that all other criteria for assigning Reserves have been satisfied and the planned recovery project has not changed in any way. In this example, the chance of commerciality is the probability that the necessary environmental permit will be obtained.
- However, another possible contingency precluding a development decision could be that the estimated 1C quantities are considered to be too small to commit to the

project, even though the 2C level is commercially viable. It is not uncommon, for example, for a company to first test that the 2C estimate satisfies all their corporate hurdles and then, as a project robustness test, to require that the low (1C) outcome is at least break-even. If the project fails this latter test and development remains contingent on satisfying this break-even test, further data acquisition (probably appraisal drilling) would be required to reduce the range of uncertainty first. In such a case, the chance of commerciality is the probability that the appraisal efforts will increase the low (1C) estimate above the break-even level, which is not the same as the probability (assessed before the additional appraisal) that the actual recovery will exceed the break-even level. In this situation, because the project will not go ahead unless the 1C estimate is increased.

  - As mentioned above, there is no industry standard for the reporting of Contingent Resource estimates. However, the commercial risk associated with such projects can vary widely. If Contingent Resources are reported externally, the commercial risk can be communicated to users (e.g., investors, Governments, etc.) by various means, including: (1) describing the specific contingencies associated with individual projects; (2) reporting a quantitative chance of commerciality for each project; and/or (3) assigning each project to one of the Project Maturity Subclasses.

- Project Maturity Subclasses
  - Under PRMS, identified projects must always be assigned to one of the three classes: Reserves, Contingent Resources, or Prospective Resources. Further subdivision is optional. Example subclasses are shown below.



Subclasses based on project maturity (from PRMS November 2011 release)

- Auditing and Reporting of Oil and Gas Resources and Reserves
    - Financial Accounting Standards Board (FASB) requires publicly traded entities that have significant oil and gas producing activities to include, with complete sets of annual financial statements, disclosures of proved (1P) oil and gas reserve quantities, changes in reserve quantities, a standardized measure of discounted future net cash flows relating to reserve quantities, and changes in the standardized measure. These disclosures are considered to be supplementary information and may be presented outside the basic financial statements.
    - Reporting and auditing of Company Oil and Gas reserves should be conducted on an annual basis for publicly traded companies. Auditing should be performed by reputable National or International agencies.
    - For private companies, auditing of reserves should be performed on an as-needed basis, usually on account of divestment of equity, to raise long term financing, or when requested by a funding partner/bank.
- The PRMS guidelines have been sponsored by SPE, AAPG, WPC, SPEE and SEG and are viewed internationally as the recommended best practice for classification and evaluation

of resources and reserves. It is therefore recommended that India adopt the PRMS guidelines.

- It is recommended that reporting and auditing of oil and gas reserves should be performed by reputable National or International agencies.
    - For publicly traded companies, auditing should be performed annually or as per the requirements of the Government.
    - For private companies, auditing should be performed on an as-needed basis.
- Changes in Reserves estimate may be acceptable based on new data and fulfillment of PRMS guidelines

4.3.3 References

1. Guidelines for Application of the Petroleum Resources Management System. November 2011. http://www.spe.org/industry/docs/PRMS_Guidelines_Nov2011.pdf
2. American Institute of Certified Public Accountants (www.aicpa.org)
3. Society of Petroleum Evaluation Engineers (secure.spee.org)

Changes in Reserves estimate should be acceptable based on new data

4.4 *Reliable Technology to Establish Reserves under SEC Guidelines*

4.4.1 Definitions and Discussion

According to SEC guidelines and filings, to establish reserves with “Reasonable Certainty” or “High Degree of Confidence” (e.g., low estimate, 1P) one must use “Reliable Technology.” SEC defines “Reliable Technology” as technology (including computational methods) that has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation. This new, broader definition is part of the SEC’s modernized regulations for reporting oil and gas reserves. When asked (on October 26, 2009) whether a list will be made public of reliable technologies that the SEC will accept for the determination of proved reserves, their response was as shown below:

> “No. An issuer has the burden of establishing and documenting the technology (or set of technologies) that provides reliable results, consistent with the criteria set forth in Rule 4-10(a)(25) of Regulation S-X. This information should be made available to the Commission’s staff upon request in support of any reserves estimates that the staff may be reviewing.”

Rule 4-10 of SEC Regulation S-X does define Proved Oil and Gas Reserves as shown below:

Proved Oil and Gas Reserves: Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

- The area of the reservoir considered as proved includes:
    - The area identified by drilling and limited by fluid contacts, if any; and
    - Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
- In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
- Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
- Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
    - Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
    - The project has been approved for development by all necessary parties and entities, including governmental entities.
- Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

4.4.2 Best Practices

- The reliable technology concept employed by SEC allows companies to use new technologies (not necessarily in existence even at the time the new rules were written) to establish proved reserves;

- The reliable technology concept permits companies to prepare their reserve estimates using new types of technology that companies were not permitted to use under the previous rules;
- The new definition of reliable technology permits the use of technology (including computational methods) that has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation;
- An example (the only example in the SEC commentary) of reliable technology is a combination of seismic data and interpretation, wireline formation tests, geophysical logs, and core data to estimate reserves;
- Use of reliable technology is a necessary condition for classification of resources as reserves;
- Reliable technologies can be used to establish the reasonable certainty of proved reserves;
- Reliable technologies can be used to establish lowest known oil and highest known oil and can be added to well penetrations as acceptable ways to establish these levels;
- Reliable technology can be used to establish reasonable certainty of “undeveloped oil and gas reserves” in improved recovery projects as an alternative to requiring evidence from projects in the same reservoir or an analogous reservoir;
- Required disclosures of reliable technology will be limited to a concise summary of the technology or technologies used to create the estimate; and
- A company will not be required to disclose proprietary technologies, or a proprietary mix of technologies, at a level of specificity that would cause competitive harm.
- Reliable technology, as defined by the SEC,
    - Can be a single technology (e.g., interference tests establishing pressure communication throughout an entire, but partially undeveloped, reservoir with potential undeveloped reserves);
    - Can be a combination of technologies (e.g., a combination of seismic data and interpretation, wireline formation tests, geophysical logs, and core data);
    - Can include computational methods (e.g., a statistical analysis of PUDs in a resources play);
    - Must have been tested (and verified) in the field (i.e., theory alone is insufficient);
    - Must provide reasonable certain results (not necessarily 90% or greater probability of being correct, but much more likely than not);
    - Must be consistent (application of proposed technologies must, with few exceptions, have been demonstrated to lead to the same conclusion when applied in the same way); and
    - Must be repeatable (measurements or computations must have been demonstrated to be identical within a specified tolerance when made on/for a specific application).

- Reliable technologies, as outlined above, must be used to establish reserves with "reasonable certainty" or "high degree of confidence." It is recommended to follow such practices to determine reserve quantities for field development planning, reserve auditing, etc.

4.4.3 References

1. SEC regulations

2. Lee, J. The "Reliable Technologies" Rule: What Did the SEC Intend? Presented at Offshore Technology Conference, Houston, Texas, USA, 3-6 May 2010. *OTC 20379.*

5 Field Development

5.1 International Norms for Monetization of Reserves in Probable & Possible Categories

Descriptions

5.1.1 Definitions and Discussion

- Reserves classification is mainly intended for auditing and reporting purposes to outsiders of the company and the audit is performed by third party auditors.
- A Field Development Plan means a plan submitted by the contractor for the development of a commercial discovery, which has been approved by the competent authority pursuant to the relevant provisions of the contract. All Reserves and Resources definitions are to be governed by prevailing SPE Petroleum Resource Management System (PRMS).

5.1.2 Best Practices

- An approved FDP may be staged on proved (1P) OR proved + probable (2P) reserves, to adhere to the government regulations and must be commercially viable. As additional information is obtained from the field performance, the FDP is usually allowed to be modified to include development of Possible (3P) reserves. Contractors/Operators should be allowed to carry out field activities while keeping Probable and Possible reserves in consideration to avoid delays and reduce costs in the future.
- All FDPs should contain an agreed plan for the commissioning and production phases of the development. The plan should set out the principles and objectives on which continuing technical analysis and data gathering shall be conducted, based on which field management decisions will be taken.
- During field development, the Contractor/Operator may gain additional knowledge which may justify development of reserves earlier classified under probable and possible categories. In this scenario, a revised & commercially viable Field Development Plan is to be prepared which identifies deviations from the agreed plan and proposes revised approaches to field development and management.
- However, under certain conditions, further phases of development may be required with substantial alterations to the original development strategy, or major changes may be required to existing or new facilities. In these conditions, a more formal revision to the relevant sections of the Field Development Plan may be required and agreed upon by the Contractor/Operator and the government agency.
- The FDP should include sensitivities to show alternate development scenarios in case of additional reserves are to be developed at a later stage.

- In case of a high degree of confidence on the part of the Operator, the Operator may provide a plan for facilities to accommodate 3P reserves. Such a plan should be staged in a way to minimize economic risk. The regulatory body may decide to approve the cost of only the facilities associated with the 2P reserves in the beginning and provide further approvals as the 3P reserves move to 2P and 1P categories.

5.1.3 References

Petroleum Resource Management System, 2007, Richardson, Texas, http://www.spe.org/industry/docs/Petroleum_Resources_Management_System_2007.pdf

5.2 Improved Oil Recovery (IOR) / Enhanced Oil Recovery (EOR) Practices

5.2.1 Definitions and Discussion

- Primary recovery uses the natural energy of reservoir to produce oil and gas with or without any lift mechanism, etc

- Secondary recovery involves the injection of an injectant (typically water or gas) to re-pressurize the reservoir and displace the oil. Waterflooding is the most common secondary recovery method but gas re-injection for pressure maintenance is also considered a secondary method.

- Enhanced oil recovery (EOR) comprises of reservoir processes that recover oil left behind by secondary recovery. EOR processes focus on rock/oil/injectant system and the interplay of viscous and capillary forces.

- Improved oil recovery (IOR) is defined as any practice that is used to increase oil recovery. This can include secondary and tertiary recovery processes (EOR) as well as practices to increase sweep such as infill drilling, horizontal wells and polymers to increase conformance.

- Implementation of established IOR/EOR techniques is a prudent measure by any Operator to maximize the ultimate recovery. Governments encourage the use of IOR/EOR methods to optimize their petroleum resources. Hydrocarbons, carbon dioxide, nitrogen, chemicals or approved substance injection are considered EOR methods.

- The implementation of EOR is intimately tied to the price of oil and overall economics. EOR is both capital and human resource intensive, primarily due to high injecting costs and the additional levels of analysis and operations required. The timing of EOR is also important: a case is made that advanced secondary recovery (e.g. IOR) technologies are a better first option before full-field deployment of EOR. Realization of EOR potential can only be achieved through long-term commitments, both in capital and human resources, a vision to strive towards ultimate oil recovery instead of immediate oil recovery, research and development, and a willingness to take risks. While EOR technologies have grown over the years, significant challenges remain.

5.2.2 Best Practices

- Advances in technology and the utilization of best-in-class reservoir management practices will enable the maximization of water flooding oil recovery. Some technologies which are used to optimize recovery include deployment of maximum reservoir contact wells (MRC), intelligent autonomous fields, gigacell simulation, deep diagnostics (ability to see inside the reservoir with clarity), and advanced monitoring and surveillance technologies. These are just a fraction of the available technologies that may help improve oil recovery.

- One of the emerging EOR techniques is Smart Water Flooding. Here, the idea is to inject water with an optimized composition (in terms of salinity and ionic composition) into the reservoir instead of any available water that may currently be injected or planned to be injected. Recent research has shown that salinity and/or ionic composition can play a significant role in oil recovery during water flooding and may yield up to 10 per cent or higher additional oil recovery when compared to un-optimized water injection. This option has several advantages compared to conventional EORs:

    - It can achieve higher ultimate oil recovery with minimal investment in current operations (this assumes that a water flooding infrastructure is already in place). The advantage lies in avoiding extensive capital investment associated with conventional EOR methods, such as expenditure on new infrastructure and plants needed for injectants, new injection facilities, production and monitoring wells, changes in tubing and casing, etc.

    - It can be applied during the early life cycle of the reservoir.

    - The payback is faster, even with small incremental oil recovery.

- Another aspect of water flooding that can be improved is the monitoring and surveillance (M&S) of projects. In many cases, adequate monitoring is not done because of the cost involved. This may be detrimental to the overall recovery during water flooding. While an optimum M&S plan cannot be predetermined for a given reservoir, some of its components include: the time-tested open/cased hole logging, coring, flood-front monitoring, single and inter-well tracer tests, and emerging technologies, such as: borehole gravimetry, cross-well and borehole to surface electromagnetic (EM), and geophysical methods (cross-well seismic, 4D seismic and 4D vertical seismic profiler (VSP)). A good M&S plan is essential in optimizing oil recovery at the secondary recovery stage, and even more important during the EOR phase.

- Choice, timing, and strategy of secondary or tertiary recovery should be based on reservoir characteristics and project economics;

- Any plans to accelerate production should not cause a decrease in ultimate recovery. For example, producing a reservoir at very high rates without increased injection support will cause a surge in oil production rate, but ultimate recovery will be sacrificed as the reservoir pressure decreases. So optimal bean size as is worked out during Initial Production Testing be used during production in order to conserve reservoir energy.

- As the easy and conventional light oil gets depleted, the focus should move towards more difficult hydrocarbon resources, like heavy and extra heavy crudes, oil sands, bitumen and shale oil.
- Investment in R&D may be essential to generate the right options for field development in certain cases.
- EOR implementation may be aided by a company's or country's need for energy security concerns.
- Environmental concerns are important factors that have boosted EOR in recent years. For example, CO_2-EOR projects are implemented to sequester CO_2, a greenhouse gas.
- The objective of any FDP should be to maximize the ultimate oil recovery from the field within an economic threshold.
- For oil fields, FDPs should include a techno-economic evaluation of a secondary recovery project. Example of secondary recovery projects that could be included are water flooding, gas injection project, etc. that provide improved sweep and/or pressure maintenance.
- Reservoir health being the primary issue during exploitation, pressure maintenance measures to be taken up before the setting in of Bubble Point Pressure to maximize the recovery based on economic viability
- IOR/EOR processes should be encouraged and may be evaluated during the FDP stage to avoid causing long term damage to the reservoir and at the same time maximizing recovery. The process of pressure support should be considered and implemented in the field as early as possible.

5.2.3 References

1. Stosur, G.J., Hite J.R., Carnahan N.F., Miller K., The Alphabet Soup of IOR, EOR and AOR: Effective Communication Requires Definitions of Terms, SPE-84908, presented at SPE International Improved Oil Recovery Conference in Asia Pacific held in Kuala Lumpur, Malaysia, 20-21 October 2003.
2. Enhanced Oil Recovery Program Guidelines, http://www.energy.alberta.ca/Oil/docs/EORP_Guidelines_2014.pdf
3. Kokal, Sunil, and Abdulaziz Al-Kaabi. "Enhanced oil recovery: challenges & opportunities." World Petroleum Council: Official Publication (2010): 64-68.

5.3 Practices for Prompt and Orderly Field Development

5.3.1 Definitions and Discussion

- In reviewing Field Development Plans, the overall objective is to maximize the ultimate recovery and associated economic benefits of the oil and gas resources, taking into account the environmental impact of hydrocarbon development and the need to ensure secure, diverse and sustainable supplies of energy to businesses and consumers at competitive prices.

5.3.2 Best Practices

- Plans for development and operation of petroleum deposits shall be approved by the authorities in a timely fashion, and the authorities shall consent to the installation and operation of required facilities.

- The authorities want to emphasize that the resource base and the technical solutions, as well as the economic estimates, must be sufficiently well-prepared. Estimates should be made that highlight the uncertainties that are critical for the project. The plan(s) should also contain an overview of future business opportunities that can provide a basis for changes in the scope of investments.

- Description of the scope of the development

    - A clear and exact description must be provided of the scope of the development with regard to the deposits that are included, both in terms of area and stratigraphy.

    - If the plan entails development in two or more stages, the plan shall address the overall development, to the extent possible.

    - The first stage of a development can set guidelines for further development. These guidelines can affect the total recovery from the field, and the recovery of other petroleum resources in the area.

    - A description shall be provided of what is entailed in each stage, with consideration both for the deposits to be produced and the facilities to be used.

- Reservoir description and development

    - Geology, petro-physics, in-place resources, drive mechanisms and reservoir simulation, recovery rate and production schedule, and methods for improving recovery (IOR and EOR to the extent possible,) shall be discussed.

    - For smaller fields, material balance and other analytical methods of hydrocarbon recovery estimation shall be discussed.

- Production strategy

    - Describe the selected production strategy for the field

  - Provide short-term and long-term production plans
  - Describe measures that will have an impact on production rate and the total recoverable volumes of petroleum

- In case of a radical change in market/environment conditions, the Contractor/Operator should be allowed to exercise prudence in project activities; however, substantial deviation from the approved plan should require approval from authorities.
- Within the PSC specified timeframe, the Contractor/Operator should provide a detailed field development plan to the authorities for approval in a timely manner.
- The Operator should plan properly for equipment, logistics, etc. and not delay implementation of the approved FDP as per the agreed timeline. Substantial deviation from the approved plan should require approval from authorities.
- The DGH/Government should facilitate feedback and required approvals in a timely fashion for implementation of the FDP.

5.3.3 References

1. Plan for development and operation of a petroleum deposit (PDO) and plan for installation and operation of facilities for transport and utilization of petroleum (PIO). 4 February 2010.
2. Guidance notes for onshore oil and gas field development plans, https://www.gov.uk/oil-and-gas-fields-and-field-development.

5.4 Practices on Unitization of Discoveries in Adjacent Blocks

5.4.1 Definitions and Discussion

Unitization is generally acknowledged as the best method of producing oil and gas efficiently and fairly, for the following reasons:

- It avoids the economic waste of unnecessary well drilling and construction of related facilities that would otherwise occur under the competitive rule of capture.
- It allows sharing of development infrastructure, thus lowering the costs of production through economies of scale and operating efficiencies.
- It maximizes the ultimate recovery of petroleum from a field according to the best technical or engineering information, whether during primary production operations or enhanced recovery operations.
- It gives all owners of rights in the common reservoir a fair share of the production.

- It minimizes surface use of the land and surface damages by avoiding unnecessary wells and infrastructure.

Definitions:

- "Unitization": Unitization is the joint, coordinated operation of a petroleum reservoir by all the owners of rights in the separate tracts overlying the reservoir.
- "Sole-Country Unitization": Unitization which takes place wholly within one country; the reservoir does not extend beneath state borders, but it does extend underneath the boundaries of different license areas, usually with different licensees.
- "Cross-Border Unitization": Unitization which takes place for a reservoir underlying two or more countries that have a delimited border between them. Such unitization will typically involve two or more different licensees.
- "Joint Development Agreement": An agreement between countries that authorizes the cooperative development of petroleum resources in a geographic area that has (or had) disputed sovereignty.

5.4.2 Best Practices

- Circumstances Triggering Unitization
    - The trigger for requiring unitization is geological: A petroleum reservoir is found to extend underneath contiguous contract areas, so different parties have rights over the common reservoir.
    - If part of a single oil and gas field is located in one contract area and extends into the contract area of a different contractor, the contractors may enter into an agreement with the proper executive authority to unitize the field.
- Voluntary or Compulsory Unitization
    - It is required that the parties first attempt to secure unitization by voluntary agreement. If the parties cannot agree voluntarily, a unitization plan will be imposed on them through government intervention.
- Unitization Development Provisions
    - Unitization policies and provisions are outlined in the respective Production Sharing Contract; and unitization and development programme shall be carried out in accordance with the provisions contained therein.

5.4.3 References

1. Unitizing Oil and Gas Fields around the World: A Comparative Analysis of National Laws and Private Contracts.

2. Model from International Unitization and Unit Operating Agreement.
3. Plan for development and operation of a petroleum deposit (PDO) and plan for installation and operation of facilities for transport and utilization of petroleum (PIO). 4 February 2010.
4. Model Production Sharing Contract (MPSC), Ministry of Petroleum & Natural Gas Government of India, 2009.

6 Production

6.1 International Practices for Submitting Long Term Production Profile and Medium Term Production Forecast and Mid-Course Changes

6.1.1 Definitions and Discussion

- A "Long-term" forecast means a year-by-year forecast of injection and production volumes which extends to the end of economic life of the field.
- A "Short-term" forecast means a month-by month forecast of injection and production volumes for the period of 2 to 3 years.

6.1.2 Best Practices

- Long-term forecasts should be based upon commonly accepted forecasting techniques. For fields having historical production, the forecasting techniques, in order of preference, are full-field history-matched reservoir simulation models, sector models which are scaled to the field, and decline-curve analysis. For new fields (no historical production), forecasts may be made directly from simulation models, without history match.
- The assumptions underlying the long-term and short term forecasts should be explained.
- Long-term forecasts of injection and production should be submitted as required by regulatory authorities.
- Short-term injection and production profiles should be updated yearly. Any changes, whether increases or decreases, in the profiles should be explained.
- Proposed changes in the Field Development Plan should be clearly documented and justified based on technical studies and analysis. Where appropriate, a discussion of additional longer-term development opportunities should be provided.

6.1.3 References

The UK Department of Energy and Climate Change (DECC) lists requirements for onshore oil and conventional gas field development plans in their document "Guidance Notes for Onshore Oil and Gas Field Development Plans (October 2009)".

6.2 Issues Related to Underproduction and Overproduction from FDP Approved Production Profile and Suggested Remedial Measures Based on International Best Practices

6.2.1 Definitions and Discussion

- "FDP" refers to the field development plan for producing hydrocarbons from the reservoir.
- "Underproduction and overproduction from FDP" refers to differences in yearly production between the approved FDP and the actual production volumes.

6.2.2 Best Practices

- Every year, a comparison should be made by the operator between the actual and forecasted (FDP) injection and production volumes for the field.
- Differences between the actual and forecasted production volumes should be explained.
- Specific recommendations related to underproduction of hydrocarbons should be provided.
- Likewise the reasons for overproduction may also be provided; to evaluate that the overproduction is not at the cost of reservoir health.
- Any recommendation for remedial action should include an estimate of the incremental / sustained volume of hydrocarbon that will be produced due to the remedial action.
- In case there is a substantial variation in actual production as compared to projected estimates in the approved FDP, following steps are recommended:
    - Contractor would submit the technical justifications for the variation
    - Contractor and Regulatory Authority would make best endeavor to understand the reasons for variation between projected volumes as per approved FDP and actual productions and steps to be undertaken for future course of action.
    - In case mutually agreed by Contractor and Regulatory Authority, an independent 3rd party will be appointed to study and submit their findings. Findings will be treated as advisory in nature.
    - Based on the discussions, proposal of the contractor and findings submitted by the 3rd party and any other relevant matter, a mutually agreed action plan would be undertaken.

6.2.3 References

1 The UK Department of Energy and Climate Change (DECC) lists requirements for onshore oil and conventional gas field development plans in their document "Guidance

Notes for Onshore Oil and Gas Field Development Plans (October 2009)". The section on "Annual Field Reports" addresses issues related to deviations from the agreed FDP.

2 Natalya Morozova, "Chapter 20: Subsoil Law", in 'Doing Business in Russia', Vinson & Elkins LLP, 2009.

3 "Draft Model Revenue Sharing Contract (MRSC)", Directorate General of Hydrocarbons, Ministry of Petroleum and Natural Gas, Government of India.

4 Marcia Ashong, "Cost Recovery In Production Sharing Contracts: Opportunity For Striking It Rich Or Just Another Risk Not Worth Bearing". Dundee, CEPLMP, 2009.

6.3 Well Completion Practices

6.3.1 Definitions and Discussion

- The well completion conveys and controls flow of fluids from the reservoir to the surface.
- Many aspects of well completion design are the same for onshore, offshore, deepwater, and ultra-deepwater wells, although additional requirements may apply depending as per well requirements.
- No industry standard depth specification exists for deepwater and ultra-deepwater, although the following depths are generally accepted. Governments sometimes specify the depth requirements when these wells/developments receive favorable treatment in the PSC.
    - o Deepwater – distance from sea level to seafloor greater than 400 m (~ 1200 ft)
    - o Ultra-deepwater - distance from sea level to seafloor greater than 1500 m (~5000 ft)
- Well completion design and execution is based on the reservoir context, technical feasibility, safety, economic viability, operability and all relevant risk, reliability and assurance analysis. The requirements are field and / or well-specific.

6.3.2 Best Practices

- General
- The well completion generally allows access for rig / rigless intervention methods such as slickline, wireline, and coiled tubing operations etc. This requirement may be reviewed and waived depending on the economics. However while doing so; safety aspects should be kept in mind.
    - o Well casing and tubing strings must meet technical requirements for the environment and life of the well.
- Artificial lift
    - o The need for artificial lift should be determined according to the field development plan, production rate forecasts, and the feasibility of artificial lift methods such as sucker rod

pumps, electric submersible pumps, progressive cavity pumps, gas lift, plunger lift, and jet pumps, ESP, PCP, etc.

- When artificial lift methods are used, the equipment should comply with industry standards (API, ISO etc).
- The type of artificial lift should be chosen according to well rates, fluid types, power/lift fluids available, and field development economic analysis etc

- Sand control measures: gravel pack, frac pack, etc.
  - Sand control should be used as needed to prevent ingress of sand in well and facilities, thereby maximizing the safe and economic life of the well and facilities.
    - The choice of downhole sand control (pre-packed screens, gravel pack, frac pack, etc.) should be made to maximize the economic value of the treatment and to achieve the production objectives of the field development plan.
    - Equipment used for sand control should comply with industry standards (API, ISO, etc).
- Well completion materials selection should follow the relevant standards (NACE, API, ISO, etc) based upon services / production environment.
- Additional requirements for offshore, deepwater, and ultra-deepwater wells
    - A subsurface safety valve is required.
    - Subsea Wells should have well control flow shutoff at the sea bed.
    - Subsea wellheads must be designed to withstand fatigue loading from risers.
  - Tubular burst/collapse requirements should include annular pressure build-up due to temperature changes.

6.3.3 References

1 NORSOK Standard D-010, “Well Integrity in Drilling and Well Operations”, August, 2004.

2 List of ISO standards related to well completions:

Standard Number	Description
ISO 10426-1:2009	Cements and materials for well cementing -- Part 1: Specification

ISO 10426-1:2009/Cor 1:2010	Cements and materials for well cementing -- Part 1: Specification
ISO 10426-1:2009/Cor 2:2012	Cements and materials for well cementing -- Part 1: Specification
ISO/DIS 10426-2:2003	Cements and materials for well cementing -- Part 2: Testing of well cements
ISO/DIS 10426-3:2003	Cements and materials for well cementing -- Part 3: Testing of deepwater well cement formulations
ISO/DIS 10426-4:2004	Cements and materials for well cementing -- Part 4: Preparation and testing of foamed cement slurries at atmospheric pressure
ISO/DIS 10426-5:2004	Cements and materials for well cementing -- Part 5: Determination of shrinkage and expansion of well cement formulations at atmospheric pressure
ISO/DIS 10426-6:2008	Cements and materials for well cementing -- Part 6: Methods for determining the static gel strength of cement formulations
ISO/DIS 15156-1	Materials for use in H_2S-containing environments in oil and gas production -- Part 1: General principles for selection of cracking-resistant materials
ISO/DIS 15156-2	Materials for use in H_2S-containing environments in oil and gas production -- Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons
ISO/DIS 15156-3	Materials for use in H_2S-containing environments in oil and gas production -- Part 3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys
ISO/DIS 17348	Petroleum and natural gas offshore platforms -- Guidelines for materials selection for high content CO_2 environment for casings, tubings and downhole equipment

ISO 23936-1:2009	Non-metallic materials in contact with media related to oil and gas production -- Part 1: Thermoplastics
ISO 23936-2:2011	Non-metallic materials in contact with media related to oil and gas production -- Part 2: Elastomers
ISO/TR 10400:2007	Petroleum and natural gas industries -- Equations and calculations for the properties of casing, tubing, drill pipe and line pipe used as casing or tubing
ISO 10405:2000	Petroleum and natural gas industries -- Care and use of casing and tubing
ISO 10417:2004	Subsurface safety valve systems -- Design, installation, operation and redress
ISO 10423:2009	Drilling and production equipment -- Wellhead and Christmas tree equipment
ISO 10427-1:2001	Equipment for well cementing -- Part 1: Casing bow-spring centralizers
ISO 10427-2:2004	Equipment for well cementing -- Part 2: Centralizer placement and stop-collar testing
ISO 10427-3:2003	Equipment for well cementing -- Part 3: Performance testing of cementing float equipment
ISO 10428:1993	Sucker rods (pony rods, polished rods, couplings and sub-couplings) – Specification
ISO 10431:1993	Pumping units – Specification
ISO 10432:2004	Downhole equipment -- Subsurface safety valve equipment
ISO 11960:2014	Steel pipes for use as casing or tubing for wells

ISO 13678:2010	Evaluation and testing of thread compounds for use with casing, tubing, line pipe and drill stem elements
ISO 13679:2002	Procedures for testing casing and tubing connections
ISO 13680:2010	Corrosion-resistant alloy seamless tubes for use as casing, tubing and coupling stock -- Technical delivery conditions
ISO 14310:2008	Downhole equipment -- Packers and bridge plugs
ISO 14998:2013	Downhole equipment -- Completion accessories
ISO 15136-1:2009	Progressing cavity pump systems for artificial lift -- Part 1: Pumps
ISO 15136-2:2006	Progressing cavity pump systems for artificial lift -- Part 2: Surface-drive systems
ISO 15463:2003	Field inspection of new casing, tubing and plain-end drill pipe
ISO/FDIS 15551-1	Drilling and production equipment -- Part 1: Electric submersible pump systems for artificial lift
ISO 16070:2005	Downhole equipment -- Lock mandrels and landing nipples
ISO/CD 16530-1	Well integrity -- Part 1: Life cycle governance manual
ISO/TS 16530-2:2014	Well integrity -- Part 2: Well integrity for the operational phase
ISO 17078-1:2004	Drilling and production equipment -- Part 1: Side-pocket mandrels
ISO 17078-2:2007	Drilling and production equipment -- Part 2: Flow-control devices for side-pocket mandrels

ISO 17078-3:2009	Drilling and production equipment -- Part 3: Running tools, pulling tools and kick-over tools and latches for side-pocket mandrels
ISO 17078-4:2010	Drilling and production equipment -- Part 4: Practices for side-pocket mandrels and related equipment
ISO/AWI 17776	Offshore production installations -- Guidelines on tools and techniques for hazard identification and risk assessment
ISO 17824:2009	Downhole equipment -- Sand screens
ISO 28781:2010	Drilling and production equipment --Subsurface barrier valves and related equipment

6.4 Best Practices on Workovers: Well Interventions, and Stimulations

6.4.1 Definitions and Discussion

- Hydraulic fracturing is injection of fluids into a formation at high pressure creating fractures. It is used as a stimulation method to increase production / injection rate. This technique is widely used in tight formations. Several fracturing stages are used to create multiple parallel fractures in horizontal wells.
- Proppant is used to keep the fracture open after the fracture is created, providing a high conductivity conduit to the wellbore. Proppant can be natural sand or synthetic ceramic proppant. The proppant type and size is selected to achieve the desired fracture conductivity.
- Acid fracturing is fracturing with acid as the injected fluid—proppant is not used. Fracture conductivity is created by acid etching of the fracture face.
- Side-tracking is drilling to a different bottom-hole location from an existing wellbore. This may be done when the existing wellbore becomes unusable (e.g. blocked by stuck equipment) or uneconomical..

6.4.2 Best Practices

- Workover and well interventions
  - Workovers may be required for many situations, including the following:
    - Any downhole safety issue

        - Pull tubing for replacement or to change size.
        - Retrieve any downhole equipment(s).
        - Shut off zones producing water or gas.
        - Replace gravel pack.
        - Change reservoir target interval.
        - Clean out fill, wax, or scale.
        - Fishing Operations
        - Installation and / or change of Artificial Lift

    - Workover plan and execution should consider the reservoir context, technical feasibility, economic viability, safety, operability, and all relevant risk, reliability, and assurance analysis.
    - Workover operations may be done with a rig or by rigless operations such as slickline, wireline, e-line or coiled tubing etc.
    - New technology is continually evolving, especially for deepwater, and this technology should be developed, used and approved as appropriate.
    - Zones producing excess water or gas can be shut off by cement or chemicals such as relative permeability modifiers. Zone shutoff can be done by mechanical means also e.g Bridge Plug.
    - Wax and scale can be removed mechanically by slickline scrapers when chemical treatments are not effective or economical.
    - Deepwater well interventions

- Rig workovers require vessels such as drill ships or semisubmersibles.
    - Some rigless operations can be done through the riser, for wells that are tied back to a wellhead on a platform.
- Well stimulations
- The need for well stimulation should be determined in accordance with the field development plan and required well rates.
    - Hydraulic fracturing
        - Hydraulic fracture design computer models should be used to design and execute the stimulation job. Injection pressures, rates, and fluid properties should be monitored and recorded during the job.

- Hydraulic fractures should not be allowed to penetrate formations that provide drinking water.
- Hydraulic fractures should not be allowed to penetrate producing formations which are being operated as a different accumulation, unless permission is granted by the appropriate oil/gas licensing and regulatory agencies.
- In deepwater applications, weighted fracturing fluids may be required in order to prevent exceeding the pressure ratings of the wellhead.
- Disposal of the water and gel used for hydro fracturing must be planned, as this water is highly contaminated. This is discussed in Section 6.16.
- Hydraulic fracturing involves pumping of a high viscosity fluid and proppant (sand) mixture at high pumping rate and pressure. Therefore, the supervisor/Engineer In-charge should hold a pre-job meeting with the service crew and other involved personnel to review responsibilities and to coordinate the operations to be performed.
- Pre-plan the equipment locations and position equipment considering the well location, wind direction and gas sources etc.
- Conduct a pre-job inspection to identify and to eliminate or correct hazardous work surfaces.
- Provide adequate anchoring and grounding for blending, pumping and sand transfer equipment, manifold, high pressure pumping lines etc.
- Require all non-essential personnel to stand clear from site.
- Wear proper PPE (Personal protective equipment) including fall protection and respiratory protection where appropriate.

o Acid stimulation

- Matrix acid stimulations may be performed to remove mud damage and/or provide near wellbore permeability enhancement. The acid pumping pressure is below fracture pressure.
- Rock mineralogy should be considered in acid treatment designs. Iron control agents and other chemicals may be required.
- Acid fracture fluids with proppant are not recommended. Acid treatment releases fine particles that plug the proppant, reducing conductivity.
- Acid treatment in sandstone formations releases fine particles or insoluble precipitates that may plug the pore throats and reduce near wellbore conductivity. In some cases, live or spent acids may generate emulsions and/or sludge with the crude oil present in the reservoir. Therefore, the acid formulation should be

compatible to the reservoir rock as well as reservoir fluids. Special additives such as clay stabilizer, anti-sludge agent may be required to carry out effective treatment.

- Acid fracturing is used in carbonate formations and normally not effective in sandstone formations. Acid fracturing treatments involves a high viscous fluid for creating fracture in the reservoir followed by pumping of suitable acid formulations at high rate and pressure.
- Adequate precaution to be taken in handling of acid and other hazardous chemicals used for acid treatments.
- All the surface pumping lines should be pressure tested and provide adequate bonding and grounding of manifold, high pressure pumping lines etc.
- Allow only the authorized and experienced personnel in the well site.
- Wear proper PPE including fall protection and respiratory protection where appropriate.

- Planning of workovers, well interventions, and stimulations should consider the reservoir context, technical feasibility, economic viability, safety, operability, and all relevant risk, reliability, and assurance analysis.
- The techniques used should follow the best practices described above and continue to evolve as new technology is developed.

6.4.3 References

1. "Hydraulic Fracturing", Petroleum Engineering Handbook, SPE
2. "Effects of Water Depth on Offshore Equipment and OperationsTopic #3: Well Drilling & Completion Design and Barriers", Proceedings of Effects of Water Depths Workshop, U.S. Bureau of Safety and Environmental Enforcement, Galveston, Texas, November 2-3, 2011.
3. Drilling and well-servicing equipment, ISO 14693:2003.
4. Design and operation of subsea production systems -- Part 4: Subsea wellhead and tree equipment, ISO 13628-4:2010.
5. Design and operation of subsea production systems -- Part 7: Completion/workover riser systems, ISO 13628-7:2005.
6. "IRF Performance Measurement Project", International Regulator's Forum (www.irfoffshoresafety.com)

6.5 Best Practices on Onshore/Offshore/Deepwater/Ultra-Deepwater Facilities: Collection, Separation, Processing, Storage, Compression, Evacuation, and Effluent Disposal

6.5.1 Definitions and Discussion

- An oilfield facility is a collection of equipment that is used to separate the fluids that come out of an oil or gas well into separate streams that can then be sold and sent to a gas plant or refinery for further processing.

- Basic sediment and water (BS&W) is the percent by volume of water and solid impurities in the oil.

6.5.2 Best Practices

- Generally Facility design and construction should consider the reservoir context, technical feasibility, economic viability, safety, operability, and all relevant risk, reliability, and assurance analysis. Below are broad guidelines. The specific facility design should be based on field requirements, availability of technology, and industry practices.

- Safety systems

    - All facilities require safety systems based on field requirements, location, environment, and as per the relevant safety standards such as DGMS, OISD, API, NACE, ASME, BIS, ISO etc.

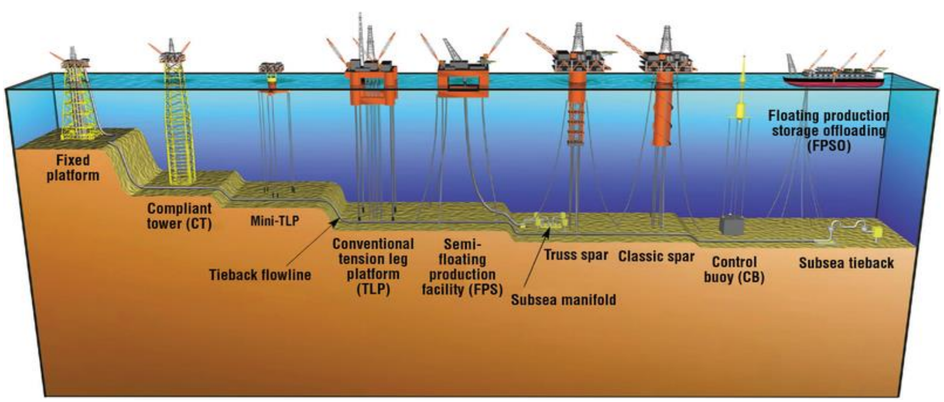
- Oil processing

    - Oil facilities separate the oil, gas, water, and solids; measure and sample the oil to determine its value; and deliver it to the transportation system (i.e., pipeline, truck, ship, or railroad car); treat the oil to meet sales specifications.

    - The contract between the oil seller (normally the producer) and the purchaser (a pipeline company or refinery) specifies the allowable water content, and may specify the maximum salt content in the crude oil.

    - The liquid stream is generally stabilized, by removing light hydrocarbons, to meet vapor pressure limits for storage in tanks for shipping at atmospheric pressure by truck, train, barge, or ship without excessive vapor venting.

- Gas processing
    - Gas is treated for sales, internal consumption, gas lift, or reinjection. This may involve only separation from the liquids or may include additional processes such as compression, dehydration, removing H2S and CO2 etc.
    - The amount of water vapor in the sales gas is usually limited by pipeline specifications, in order to avoid corrosion and hydrate-formation problems. A standard pipeline specification is 7 lbm of water per million standard cubic feet of gas (lbm/MMscf). This corresponds to a water dew point of approximately 32°F at 1,000 psi.
- Water processing
    - Water treatment facilities depend upon the inlet effluent characteristics and the local statutory requirements to disposal, as a minimum, to be adopted.
- Offshore facilities
    - Types of offshore platforms:

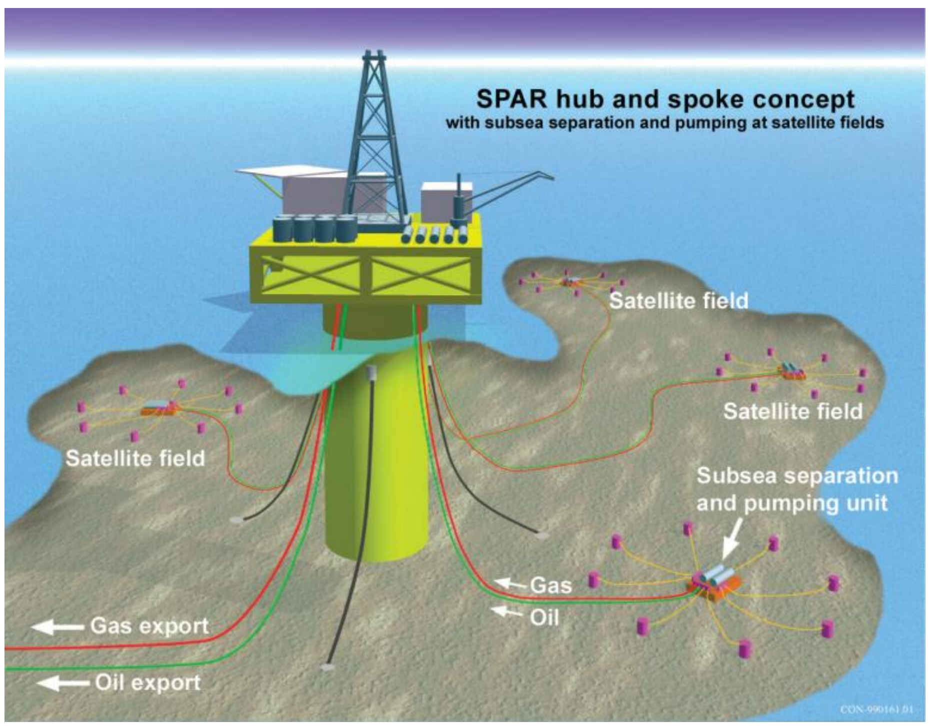


- Differences between the process equipment (oil and gas separators, free-water knockouts, gas scrubbers, pumps, compressors, etc.) installed on a platform and those installed on land are minor. Consideration is given to using vessels and machinery that are compact and lightweight (e.g., electric motors are commonly used instead of gas engines for driving pumps and compressors). Vertical clearance between decks may impose height limitations and dictate equipment choices such as the use of horizontal instead of vertical separators.

- Offshore process equipment is often packaged in modules for ease of installation. This also reduces space and weight requirements.

• Subsea/Deepwater facilities

- Conceptual subsea processing facility:



- Wellheads and trees on the seabed may be installed individually, in clusters, or on a template where the reservoir fluids from all the wells are channeled to a manifold that is tied back to a host platform.

- Some wellheads and wet trees are designated as "diverless" or "guidelineless" because they can be installed, maintained, and repaired either by remote control using equipment that does not need guidelines or tools that are wire guided from a vessel.

    - Produced fluids flow to a host facility for processing and export. They may flow unassisted or with the assistance of multiphase pumps. Alternatively, subsea separation allows single-phase pumping of liquids.
    - Utilities, control lines, and chemicals are supplied from the host facility via umbilicals.
    - The need for subsea processing is driven by economic evaluation of factors such as lower wellhead pressure, water depth, tieback distance, and processing capacity of topside facilities.

- Offshore pipelines and collection systems
    - Crude-oil production is usually transported from platforms by subsea pipelines. Because most offshore producing areas involve multiple platforms and more than one operating company, the pipelines are generally common carriers.
    - Flow assurance should be incorporated into design and operations in order to avoid delivery disruptions due to hydrates, wax, scale, corrosion or slugging. Measures may include chemical inhibition, heating, pigging, or slug catchers.
    - Conventional welded steel pipe is used for most subsea flowlines. The steel is protected against external corrosion by coatings, anodes, or both. An alternative is the use of flexible piping that comprises laminations of steel wires and other materials. Flexible pipe can be installed relatively quickly from large-diameter reels and does not need a separate external coating.
    - Facilities such as single buoy mooring systems, turret mooring, cantilever anchoring may be used to load oil directly into tankers for transport.
- The specific facility design should be based on field requirements, availability of technology, and industry practices. Best practices are described above.
- Safety and environmental protection should be incorporated into the design of every facility and process.
- New technology should be used as appropriate, especially in rapidly evolving technologies such as deepwater.

6.5.3 References

1 "Oil and Gas Processing", Petroleum Engineering Handbook, SPE.

2 RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, API.

3 "Safety Systems", Petroleum Engineering Handbook, SPE.

4 "Offshore and Subsea facilities", Petroleum Engineering Handbook, SPE.

5 "Subsea and Downhole Processing", Petroleum Engineering Handbook, SPE.

6 List of related ISO specifications:

Standard number	Description
ISO/DIS 15926	Industrial automation systems and integration -- Integration of life-cycle data for process plants including oil and gas production facilities (11 parts)
ISO/DIS 17349	Guidelines for offshore platforms handling streams with high content of CO_2 at high pressures
ISO/TR 12489:2013	Reliability modelling and calculation of safety systems
ISO/DIS 15156-1	Materials for use in H_2S-containing environments in oil and gas production -- Part 1: General principles for selection of cracking-resistant materials
ISO/DIS 15156-2	Materials for use in H_2S-containing environments in oil and gas production -- Part 2: Cracking-resistant carbon and low-alloy steels, and the use of cast irons
ISO/DIS 15156-3	Materials for use in H_2S-containing environments in oil and gas production -- Part 3: Cracking-resistant CRAs (corrosion-resistant alloys) and other alloys
ISO/DIS 17348	Petroleum and natural gas offshore platforms -- Guidelines for materials selection for high content CO_2 environment for casings, tubings and downhole equipment
ISO/DIS 17781	Petroleum, petrochemical and natural gas industries -- Test methods for quality control of microstructure of austenitic/ferritic (duplex) stainless steel
ISO 21457:2010	Materials selection and corrosion control for oil and gas production systems

ISO 20815:2008	Production assurance and reliability management
ISO 23936-1:2009	Non-metallic materials in contact with media related to oil and gas production -- Part 1: Thermoplastics
ISO 23936-2:2011	Non-metallic materials in contact with media related to oil and gas production -- Part 2: Elastomers
ISO 3977-5:2001	Gas turbines -- Procurement -- Part 5: Applications for petroleum and natural gas industries
ISO 10418:2003	Offshore production installations -- Analysis, design, installation and testing of basic surface process safety systems
ISO 12736	Wet thermal insulation coatings for pipelines, flow lines, equipment and subsea structures
ISO/NP 13628-1	Design and operation of subsea production systems -- Part 1: General requirements and recommendations
ISO 13628-2:2006	Design and operation of subsea production systems -- Part 2: Unbonded flexible pipe systems for subsea and marine applications
ISO 13628-3:2000	Petroleum and natural gas industries -- Design and operation of subsea production systems -- Part 3: Through flowline (TFL) systems
ISO 13628-4:2010	Design and operation of subsea production systems -- Part 4: Subsea wellhead and tree equipment
ISO 13628-5:2009	Design and operation of subsea production systems -- Part 5: Subsea umbilicals
ISO 13628-6:2006	Design and operation of subsea production systems -- Part 6: Subsea production control systems

ISO 13628-7:2005	Design and operation of subsea production systems -- Part 7: Completion/workover riser systems
ISO 13628-8:2002	Design and operation of subsea production systems -- Part 8: Remotely Operated Vehicle (ROV) interfaces on subsea production systems
ISO 13628-9:2000	Design and operation of subsea production systems -- Part 9: Remotely Operated Tool (ROT) intervention systems
ISO 13628-10:2005	Design and operation of subsea production systems -- Part 10: Specification for bonded flexible pipe
ISO 13628-11:2007	Design and operation of subsea production systems -- Part 11: Flexible pipe systems for subsea and marine applications
ISO/DIS 13628-14	Design and operation of subsea production systems -- Part 14: Subsea high integrity pressure protection systems (HIPPS)
ISO 13628-15:2011	Design and operation of subsea production systems -- Part 15: Subsea structures and manifolds
ISO/FDIS 13628-16	Design and operation of subsea production systems -- Part 16: Specification for flexible pipe ancillary equipment
ISO/FDIS 13628-17	Design and operation of subsea production systems -- Part 17: Guidelines for flexible pipe ancillary equipment
ISO/DIS 13702	Control and mitigation of fires and explosions on offshore production installations -- Requirements and guidelines
ISO 13703:2000	Design and installation of piping systems on offshore production platforms
ISO 15544:2000	Offshore production installations -- Requirements and guidelines for emergency response

ISO/AWI 17776	Offshore production installations -- Guidelines on tools and techniques for hazard identification and risk assessment
ISO 19900:2013	General requirements for offshore structures
ISO 10439:2002	Centrifugal compressors
ISO 13709:2009	Centrifugal pumps for petroleum, petrochemical and natural gas industries
ISO 15761:2002	Steel gate, globe and check valves for sizes DN 100 and smaller, for the petroleum and natural gas industries
ISO 16812:2007	Shell-and-tube heat exchangers
ISO/AWI 18796	Internal coating and lining of carbon steel process vessels
ISO/DIS 23251	Pressure-relieving and depressurizing systems
ISO 25457:2008	Flare details for general refinery and petrochemical service
ISO 28300:2008	Venting of atmospheric and low-pressure storage tanks

6.6 Quantity and Quality Measurement: Applicable Standards and Best Practices for Measurement of Oil, Gas and Water

6.6.1 Definitions and Discussion

- Repeatability is the variability of the measurements obtained by one person while measuring the same system repeatedly using the same instrument and under the same flow conditions.
- Meter factor = Prover known volume / measured volume
- Lease Automated Custody Transfer (LACT) units typically include a strainer, centrifugal pump, vapor eliminator, capacitance probe for water measurement, and a liquid meter.
- Reference point: A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions

prior to custody transfer (or consumption). Also called Point of Sale or Custody Transfer Point.

6.6.2 Best Practices

- **Liquid metering**: The metering of liquid hydrocarbons should be dealt in accordance with relevant **API** petroleum measurement standards or **equivalent** standards.

- **Gas metering**: The metering of hydrocarbon gas should be dealt in accordance with relevant **AGA** gas measurement standards or **equivalent** standards.

The main international standards for these meters are:

  - **Orifice meters**: ISO Standard 5167 and AGA Standard 3.
  - **Turbine meters**: ISO Standard 9951, Measurement of Gas Flow in Closed Conduits: Turbine Meters and OIML R32, Rotary Piston Gas and Turbine Gas Meters.
  - **Ultrasonic meters**: ISO Standard TC30/SC5/WG1 and AGA Report 9 &10, Measurement of Gas by Multipath Ultrasonic Meters.
  - **Coriolis meters**: ISO Standard TC30/SC12 and AGA Report, Coriolis Flow Measurement for Natural Gas Applications.
    - The meter measurements should be within the specified operating range for the quoted accuracy of the meter.
    - Measured gas volume should be converted to volume at standard conditions.

- Multiphase meters
  - Typically used for replacement of a well test separator rather than for custody transfer. In some instances of commingled production, they may be used for production allocation.
  - Continually being developed and improved.
  - Accuracy is less than single phase meters.
  - V-cone meters may be used for wet gas metering in non-custody transfer applications.

- **Hydrocarbon delivery point** shall be in accordance with the respective contracts.

- General practice for reconciliation between petroleum produced and stored and petroleum sold.
    - Sales quantities are equal to raw production less non-sales quantities (quantities that are produced at the wellhead but not available for sales at the Reference Point).
    - Non-sales quantities include petroleum consumed as fuel, flared, lost in processing, etc. plus non-hydrocarbons that must be removed prior to sale. Each of these non-sales quantities may be allocated using separate Reference Points but when combined with sales, should sum to raw production.
    - All volumes should be reconciled to account for variations in temperature, pressure, and fluid composition to the Standard Conditions/ Contract conditions.

- Quality measurements generally include
    - Oil: API gravity, water content, salt content, sulfur content, vapor pressure, pour point etc.
    - Water: Hydrocarbon content, salinity, sulfur content, radioactivity, etc.
    - Gas: Water content, composition, etc.

- Meters should meet the appropriate accuracy and specified performance criteria for custody transfer or field operations management.

- Records of metered volumes should be maintained and provided to co-owners and the appropriate government agency, as required in the field rules.

6.6.3 References

1. Petroleum Engineering Handbook, SPE. Manual of Petroleum Measurement Standards (MPMS), American Petroleum Institute (API), an ongoing publication in which chapters are periodically revised and then released.
2. Petroleum Resource Management System. Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists (AAPG), World Petroleum Council (WPC), Society of Petroleum Evaluation Engineers (SPEE), 2007.
3. List of related ISO specifications:

Standard number	Description
ISO/NP 91	Temperature and pressure volume correction factors
ISO 2714:1980	Volumetric measurement by displacement meter systems other than dispensing pumps
ISO 2715:1981	Volumetric measurement by turbine meter systems
ISO/NP 4267	Calculation of oil quantities -- Dynamic measurement
ISO 5024:1999	Measurement -- Standard reference conditions
ISO 7278	Dynamic measurement -- Proving systems for volumetric meters
ISO 7507	Calibration of vertical cylindrical tanks
ISO 8697:1999	Transfer accountability -- Assessment of on board quantity (OBQ) and quantity remaining on board (ROB)
ISO 9403:2000	Transfer accountability -- Guidelines for cargo inspection
ISO 13740:1998	Transfer accountability - Assessment of vessel experience factor on loading (VEFL) and vessel experience factor on discharging (VEFD) of ocean-going tanker vessels

6.7 Best Practices for Production, Measurement and Allocation in Case of Production of Different Hydrocarbons (Oil/Gas, CBM, Shale Oil/Gas) from the Same Wells or Different Wells in the Same Field

6.7.1 Definitions and Discussion

- "Production allocation" refers to the assignment of commingled production volumes back to the individual points of production.
- "Injection allocation" refers to the assignment of commingled injection volumes to individual points of injection.
- "Production battery" refers to the collection point where commingled production volumes are measured.

6.7.2 Best Practices

- Oil, water, and gas production from individual wells should be measured at a frequency that ensures an accurate accounting of well production. A well must be tested after any well-work has been completed (e.g. choke changes, re-perforating, squeeze cementing, etc.).
  - As per best practices globally, the minimum frequency of production testing is once every 3 months. However testing frequency may be decided by operators at their own discretion.
  - Production testing should be conducted in accordance with relevant API Standards.
  - Production testing should be conducted in accordance with relevant API Standards.

- Several allocation techniques may be considered to back-allocate commingled production to individual wells. A typical Proportional allocation technique is discussed below.

- Proportional Allocation Methodology
  - Based on well tests, the individual monthly production of oil, water, and gas from each well is estimated. The estimated well-level monthly production is summed to arrive at the production-battery's estimated total monthly production of water, oil, and gas.
  - As per industry definition, the oil, water, and gas allocation factors are defined as (actual battery monthly production) / (estimated battery monthly production)
  - The proportion of commingled oil production allocated to each well is the (estimated well-level monthly oil production) X (oil allocation factor). The same approach is used for the water and gas production.

  - The resulting well-level oil, water, and gas rates should be checked for GOR and WOR consistency with the well-test data. Significant deviations between well-test WOR or GOR and the allocated values will require additional tuning of the allocation procedure.

- When an allocation factor is found to exceed the specified limits, the cause should be investigated, documented and corrected.

- For wells which are completed and commingled in multiple zones, the best-practices method for back-allocation of production to individual zones is through the use of production logs. Other acceptable practices for zonal allocation include permeability-thickness weighting, simulated results, and tracer monitoring.

6.7.3 References

1. "Directive 017: Measurement Requirements for Oil and Gas Operations",Alberta Energy Regulator (www.aer.ca), May 15, 2013.

2. "HM 96: Guidelines for the allocation of fluid streams in oil and gas production",UK Energy Institute.

3. "Allocation Measurement", API MPMS Chapter 20.1 (R2011).

6.8 Transportation of Oil/Gas/Water by Tanker or Pipeline

6.8.1 Definitions and Discussion

- Tanker – a container for transportation of liquid or gas that may be free-standing or mounted on a truck, train, or ship.

6.8.2 Best Practices

- Choice of transportation by tanker or pipeline depends on produced volumes, infrastructure, demography, geography and economic viability. Existing pipeline, road, and port infrastructure can be used or capital investment can be made as part of the development project.

  - Pipelines are the preferred mode of transportation and are almost compulsory for 3-phase transportation.

  - Overland transportation in tankers is used in cases where a pipeline is impractical or uneconomical.

  - Tankers are normally used for liquid transportation rather than gas, although this is not a requirement.

- The choice of tankers versus pipeline is normally determined by economic comparison of each option.

- Typical considerations are:
  - Production rate: Generally Tankers are preferred when volumes are low. Pipelines are preferred when volumes are high.
  - Distance and terrain: Tankers may be preferred when construction of pipelines is not feasible.
  - Life of well/project: Short operating lives favor tankers over capital investment in a pipeline.
  - Destination: Tankers may be preferred if the selected location of the processing facility or markets may change.

- Tanker transportation
  - Tanks can be truck-mounted, rail-mounted or ship-mounted, depending on onshore or offshore location of facilities and transportation routes.
  - Tankers must comply with all local road and maritime transportation laws for hazardous and/or flammable materials. These regulations specify design, construction, and certification of the tanks. In addition, they specify inspection and testing requirements for re-certification. Inspections are normally required at intervals ranging from 2 to 5 years.
  - International maritime shipping is governed by the MARPOL convention (International Maritime Organization) and SOLAS requirements.
  - Outlets of road tankers shall be properly sealed after completion of loading and measurement at Loading Point and the same shall be checked as unbroken prior to unloading to prevent pilferage. In case the seal is found broken, the transporter shall be penalized for the shortfall quantity.
  - Fluid weight/volume should be measured and recorded when tanker is loaded and at delivery site before unloading. Any discrepancies should be investigated immediately.
  - Leaks/spill volumes when loading/unloading tankers should be recorded and reported.

- Pipeline transportation
  - Operation
  - Records should be kept of fluid volumes entering and exiting the pipeline and any discrepancies investigated immediately.

        - Instrumentation and automatic controls are preferred to protect the pipeline integrity.
        - Security of pipelines, storage tanks, and pump stations should be controlled and monitored by appropriate fencing, surveillance, and alarms.
        - Systems associated with pipeline operation should be protected against unauthorized user access.
    - Maintenance
        - Pig (Pipeline Inspection Gauge) launchers and catchers are generally included in the design and construction of the pipeline based on the requirements.
        - Pigging should be done as required to clean and inspect the inside of the pipe. Pigging frequency should be mentioned in the standard operating practices of the field/operating facility.
        - Surface Pipelines should be visually inspected for leaks or damage visible from the outside.
        - Above-ground pipelines should be protected by barriers in locations where they may be damaged by vehicles or construction.
        - Underground pipelines should have above surface signage and the exact location should be marked before any digging or construction activities.
    - Corrosion
        - Pipeline wall thickness for critical points should be closely monitored and inspected as per OISD / relevant standards or guidelines.
        - Methods such as Radiography, Ultrasound may be used to measure wall thickness.
- Corrosion coupons / probes inside the pipe are also used to monitor corrosion rates.
        - Corrosion inhibitors should be used as needed.
        - All pipelines must have appropriate corrosion protection, such as cathodic protection, increased wall thickness allowance, coatings, etc.
    - Leaks and spills
        - Any amount of leakage requires immediate repair.

- All leaks/spill volumes must be recorded and reported.
- All incidents involving leaks, spills, fires, etc. must be reported to the respective Government/statutory bodies etc, as per specified timelines.

- Regardless of transportation method, appropriate measures should be taken to prevent spills and protect the environment. Construction, maintenance, and inspection of all pipelines and tankers must comply with the relevant local and international laws and industry practices.

6.8.3 References

1. "Pipeline Design Consideration and Standards", Petroleum Engineering Handbook, SPE.
2. Pipeline Pigging, Petroleum Engineering Handbook, SPE.
3. List of related ISO specifications:

Standard number	Description
ISO/FDIS 1823	Rubber hose and hose assemblies for oil suction and discharge service – Specification
ISO 3183:2012	Steel pipe for pipeline transportation systems
ISO 12490:2011	Mechanical integrity and sizing of actuators and mounting kits for pipeline valves
ISO/TS 12747:2011	Pipeline transportation systems -- Recommended practice for pipeline life extension
ISO 13847:2013	Pipeline transportation systems -- Welding of pipelines
ISO/DIS 14313	Pipeline transportation systems -- Pipeline valves
ISO 14723:2009	Pipeline transportation systems -- Subsea pipeline valves
ISO 15589	Cathodic protection of pipeline transportation systems

ISO 15590	Induction bends, fittings and flanges for pipeline transportation systems
ISO/DIS 16440	Pipeline transportation systems -- Design, construction and maintenance of steel cased pipelines
ISO/NP 16441	Pipeline transportation systems - Actuation mechanical integrity and sizing for subsea pipeline valves
ISO 21809	External coatings for buried or submerged pipelines used in pipeline transportation systems

6.9 Well Production and Reservoir Pressure Performance Reporting Practices

6.9.1 Definitions and Discussion

General reporting practices are covered in this section.

- Monthly well-level and zone-level injection and production volumes for oil, water, and gas should be reported including:
  - Unique Well Identifier / Well name
  - Field name
  - Zone name
  - Well type (oil producer, gas producer, water injector, gas injector, etc.)
  - Production mechanisms (flowing, gas-lift, ESP, etc.)
  - Days on production
  - Monthly oil, water, and gas production; monthly water and gas injection
  - Average flowing tubing pressure
  - Tubing-head injection pressure
  - Choke Size
  - Any other relevant parameter
- Reservoir pressure measurements should also be reported including but not limited to;
  - Well name and zone

- Date Tested
- Perforated / completed Intervals
- Shut-In / Flow-In time
- The survey type (SGS, PBU, RFT, DST, PFO, Multi-Rate, etc.)
- The tool depth (TVDSS)
- The datum depth (TVDSS)
- Pressure gradient
- Pressure at tool depth
- Pressure at datum depth.

- Fields with continuous down-hole measurements of pressure and well head measurements should report the relevant data on a monthly basis.
- It is preferred that SBHP should be measured at least annually, but not limited to, in key wells, aerially spread in major pay zones, based on reservoir conditions.
- It is good practice to adopt a system for uniquely identifying wells. For example, a system for assigning unique well identifiers has been implemented for wells within the United States per API Bulletin D12A. The PPDM (Professional Petroleum Data Management Association) has published a framework for assigning unique global well IDs.

6.9.3 References

1. The Norwegian Petroleum Directorate (NPD) has published "Guidelines for Production Reporting" which abide by the PRODML standard.
2. The State of Alaska has published this format for reporting reservoir pressure.
3. "Well Identification Global", Booklet from the PPDM Association (Sept, 2014).
4. American Petroleum Institute, 1979, The API well number and standard state and county numeric codes including offshore waters, Dallas, TX, American Petroleum Institute, API Bulletin D12A.

6.10 Influx Studies

6.10.1 Definitions and Discussion

- "Influx Studies" are used to calculate the fluid influx rates from the formation into the wellbore, for purposes of selecting tubing size, artificial lift equipment, etc.

6.10.2 Best Practices

- Wellbore influx is normally modeled by an inflow performance relationship (IPR) such as Vogel, productivity index, etc. The selection of inflow method depends on the known reservoir data and type of flow (gas, liquid, multiphase).
- Nodal analysis is normally used to couple the reservoir inflow with the tubing outflow. This model would also include any artificial lift methods in the wellbore outflow calculation.
- When possible, the results of nodal analysis modeling should be compared to field measurements in order to validate the inflow and outflow calculations.
- If artificial lift is planned, then nodal analysis and influx studies should be implemented to help design and optimize the system.

6.10.3 References

1. Bertuzzi et al, “Wellbore Hydraulics”, Chapter 34 in the Petroleum Engineering Handbook, SPE.

6.11 PVT Studies

6.11.1 Definitions

- “PVT Studies” are studies / analysis of the reservoir fluids pressure, volume and temperature that are selected to model the relevant recovery mechanism in the reservoir of interest.

6.11.2 Best Practices

- The PVT study / analysis should be as per the relevant API or equivalent standard.

6.11.3 References

- “Sampling Petroleum Reservoir Fluids”, API Recommended Practice 44, Second Edition, April 2003.

6.12 Fluid Properties and Composition:Oil, Gas, and Water

6.12.1 Definitions

- “Fluid properties” for oil refers to the bubble-point pressure, solution gas-oil ratio, formation volume factor, viscosity, density, API gravity, isothermal compressibility etc.

- "Fluid Properties" for gas refers to the dew-point pressure, solution oil-gas ratio, formation volume factor, viscosity, specific gravity etc.
- "Fluid Properties" for water refer to the formation volume factor, viscosity, density, isothermal compressibility etc.

6.12.2 Best Practices

- Generic elements of a basic black-oil PVT study depending on field conditions are, but not limited to:
    - Rigorous validity assessment of fluid samples (downhole or surface samples)
    - Selection of the most suitable samples for analysis
    - Measurement of reservoir fluid composition
    - Physical recombination of fluids (if separator samples)
    - Constant Composition Expansion (CCE) Experiment
    - Constant Volume Depletion (CVD) Experiment
    - Differential Liberation (DL) Experiment
    - Viscosity Measurement
    - Separator Test Experiments
    - Mercury measurement

- If the planned recovery mechanism is compositionally dependent (e.g. CO2 injection) then additional studies specifically related to the recovery mechanism are recommended. Shown below are typical additional studies for a gas injection project.
    - Solubility-Swelling Test
    - Rising Bubble Test
    - Multiple Contact Miscibility Test
    - Slim Tube Displacement Test
    - Minimum Miscibility Enrichment Test
    - Asphaltene Precipitation Studies
    - Wax Deposition Studies

- PVT studies must include basic quality-control checks including the following, but not limited to:
  - The gas sample should have minimum air content and minimum difference between gas-bottle opening pressure and the separator pressure for the recombined PVT sample.
  - The oil sample bubble point pressure and bottle opening pressure should be compared with separator pressure for the recombined PVT sample.
  - PVT studies should include a general information sheet with (1) separator gas/oil ratio (GOR) in standard cubic feet/separator barrel, (2) separator conditions at sampling, (3) field shrinkage factor used (= 1/Bo at separator pressure), (4) flowing bottom-hole pressure (FBHP) at sampling, (5) static reservoir pressure, (6) minimum FBHP before and during sampling, (7) time and date of sampling, (8) production rates during sampling, (9) dimensions of sample container, (10) total number and types of samples collected during the drill stem test, and (11) perforation intervals and sampling depth (if it is a bottom-hole sample).
  - All laboratory measurements should follow the guidelines in the API "Manual of Petroleum Measurement Standards (MPMS)."

6.12.3 References

1. API Manual of Petroleum Measurements Standards (MPMS) Chapters 8.1 and 8.2.
2. Whitson, C. H. and Brule, M. R., "Phase Behavior", SPE Monograph Volume 20 SPE (2000).
3. The Properties of Petroleum Fluids by William D McCain Jr

6.13 Guidelines for Reservoir Management for Optimum Exploitation Rate and Maximum Recovery of Reserves

6.13.1 Definitions and Discussion

- "Reserves" and "Resources" as defined in PRMS.

6.13.2 Best Practices

- Operators should develop and document a reservoir management plan that maximizes the economic recovery of reserves.
- The reservoir management plan should include an up to date reservoir description, plans for monitoring and modeling field performance, a flexible phased development approach, a strategy to handle well interventions through rig / rigless (squeeze, re-perforations, etc.), optimization of the production mechanism to maximize areal and vertical sweep (completion strategy, horizontal wells, well

locations and spacing), optimizing well productivity (optimizing artificial lift), assessment of IOR techniques, mitigating the impact of heterogeneities on recovery, and maintaining reservoir energy, wherever applicable.

- RMP should be part of FDP and shall be updated from time to time as deemed necessary.

6.13.3 References

1. "Good Engineering Practice Area Application Guideline" from the British Columbia Oil and Gas Board.

2. "Maximizing Economic Recovery of the UK's Oil and Gas Reserves" from the UK PILOT report.

3. "Production Efficiency Guidance Notes", from the UK Department of Energy and Climate Change (DECC), January 2010.

6.14 Best Practices for Testing Individual Production Wells, Especially Sub-Sea Wells: Norms for Extended Well Testing (EWT) and Disposal of Oil/Gas during Testing Periods

6.14.1 Definitions and Discussion

- Well testing is performed to collect production history of individual wells for reservoir management, identify issues that might require remedial well work, and/or allocate production in commingled operations.

- Extended well testing (EWT) is performed to assess field size, well flow rates, and produced fluid properties before designing and constructing permanent production facilities. This is usually done to reduce the economic risk of the development as well as to construct facilities that are better matched to the production characteristics of the field. The radius of investigation of an EWT is much larger than for a drill stem test, and the EWT provides more information about long term productivity, large-scale permeabilities and reservoir boundaries.

6.14.2 Best Practices

- Production Well testing

    - Test separators provide the most accurate measurements. Standards for the gas and liquid meters attached to the test separator are given in Section 6.6.

    - Multiphase meters have been used generally in some cases when logistics/operability of test separators is having constraints, as in case of subsea and remote wells. Meters may be preferably attached to each well for continuous measurement or to a test manifold for use like a test separator.

- Individual wells are usually connected to a test manifold, which allows a single test separator or multiphase meter to test all of the wells.
- Testing by difference may be acceptable in some situations. In this method, the rate from a well is deduced by the change in total commingled rate when the well is shut in. Drawbacks are that production is lost when the well is shut in, and that restarting production from the well may be problematic.
- Testing of subsea wells may be done on surface or on the seabed.
- Extended well testing (EWT)
- The need for an EWT should be technically and economically evaluated in comparison to combinations of other techniques such as offset/analogous well information, seismic, logs, core analysis, MDT, etc.
- Time limits for EWT may vary as per field conditions. .
- The EWT may necessitate the flaring of substantial quantities of gas. However, the test should be designed so that the gas flaring is kept to the minimum.

6.14.3 References

1. "Subsea and Downhole Processing", Petroleum Engineering Handbook, SPE.
2. "Well Test- Extended", Oil and Gas UK, Environmental Legislation Website. http://www.ukooaenvironmentallegislation.co.uk/contents/topic_files/offshore/extended_welltest.htm
3. "Guidance on the Content of Offshore Oil and Gas Field Development Plans", United Kingdom Department of Energy and Climate Change (DECC), December 2013.
4. Leeson, T.J., Barr, J. and Selboe, J.O., "Appraisal of Exploration Prospects using Extended Well Testing", Offshore Magazine, Volume 57, Issue 8, 1997.
5. Si, W., "A Brief Description of Extended Well Testing (EWT) System", SPE 29998, 1995.
6. AXIS Energy Projects, Web-reference: http://www.axis-ep.com/extended-well-test-export-systems.html.
7. Leeson, T.J., "Extended Well Testing Boosts Prospects For Development of Marginal Fields", Oil and Gas Journal, Volume 95, Issue 34, August 1997.
8. Earlougher, Robert C., Jr.: Advances in Well Test Analysis, Monograph Series, Society of Petroleum Engineers of AIME, Dallas (1976) vol. 5.

9. Agarwal, Ram G.: "Direct Method of Estimating Average Pressure for Flowing Oil and Gas Wells," paper 135804 presented at the 2010 SPE Annual Technical Conference and Exhibition, Florence, Italy, Sept. 19-22.

6.15 International Norms of Gas Flaring

6.15.1 Definitions and Discussion

- Gas flaring is burning of produced gas at the end of a flare stack. It is performed when no gas production facilities are available or when operating conditions require discharge of gas in order to prevent injury to personnel or damage to equipment / assets or any other emergency/safety requirement.

- Venting is the controlled release of gases (hydrocarbons, water vapor, carbon dioxide, etc.) into the atmosphere in the course of oil and gas production operations. Venting must comply with pollution/ local laws. Venting is normally not a visible process. However, it can generate some noise, depending on the pressure and flow rate of the vented gases.

6.15.2 Best Practices

- If possible, all gas of commercial value should be sold rather than flared.

- Venting, in general, is not an acceptable alternative to flaring or incineration and should be avoided whenever possible. If gas volumes are sufficient to sustain stable combustion, the gas should be burned or conserved.

- If venting is the only feasible alternative, it must comply with local laws.

- In-line testing, in which produced fluids flow to a production line, should be done when economic and feasible. This is recommended when: (a) suitable infrastructure exists in proximity to the well and can be connected at moderate cost and where use of the infrastructure does not compromise integrity, or (b) sufficient productivity information is known about a development well so that connecting pipelines can be built with minimal financial risk before testing.

- When flaring sour gas, personnel should be trained in H2S safety procedures and provided with protective gear. H2S sensors and alarms should be present on site. It should be carried out as per the statutory / OISD / relevant guidelines. An evacuation plan should be in place.

- The H2S content of flared or incinerated gas should be measured at the beginning of operations. Gas analysis for H2S content should be done at least once in 12 months.

- Records of flaring events and measured / estimated volumes should be kept by the operator. The regulatory agency may request these records as and when required.
- Design of flare system should be as per DGMS / API / OISD / relevant standards and as per field requirements

6.15.3 References

- API Recommended Practice RP51R, Environmental Protection for Onshore Oil and Gas Production Operations and Leases, 2009.
- Flare details for general refinery and petrochemical service, ISO 25457:2008.
- Industry Recommended Practice (IRP) Volume 4: Well Testing and Fluid Handling from the Canadian Petroleum Safety Council, 2014.
- Flaring and Venting in the Oil and Gas Exploration and Production Industry: An Overview of Purpose, Quantities, Issues, Practices, and Trends, International Association of Oil and Gas Producers (IOGP), Report No. 2.79/288, January 2000.
- API Recommended Practice 55, "Recommended Practices for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide", 2nd Edition, February 1995.
- “Zero Routine Flaring by 2030”, The World Bank (www.worldbank.org).

6.16 Water Management

6.16.1 Definitions and Discussion

- Hydraulic fracturing is injection of fluids into a formation at high pressures, creating fractures. It is used as a stimulation method to increase production rate.
- Flowback water is water injected during hydraulic fracturing that flows back to surface. It is often mixed with produced formation water.
- Slickwater is water that has a friction reducer added. This reduces pumping pressure required for fracturing.

6.16.2 Best Practices

- Sourcing of water for fracturing

- Water used for fracturing usually comes from surface water sources such as lakes, rivers, aquifers, and municipal sources. Relatively fresh water is required because contaminants and salts reduce the effectiveness of fluid additives. These additives are needed to achieve the required fluid properties for fracturing.
- The source of fracturing water should be determined and approved by the appropriate local authorities before it is used.
- Slickwater fracturing fluids are less sensitive to salinity and impurities than crosslinked fluids, but usually require more water volume.
- Water is normally transported in tanks to the well location.
- Newly developed methods for recycling produced and fracture flowback water should be considered wherever techno-economically feasible.

  - Disposal of produced and flowback water

- Produced water and fluids flowed back after fracturing are injected into disposal wells, routed to evaporation ponds, or treated to meet standards for offshore or surface disposal. The selection of disposal method depends on the operating context, e.g. onshore, shallow water offshore, deepwater offshore.
- The regulatory requirements for oil-in-water content for overboard water disposal vary from place to place, and are regulated by the government environmental authority.
- Responsibly operated offshore facilities provide means for the contaminants in produced water to be diluted quickly.

  - Sourcing and treatment of water used for injection (waterflood)

- Injection water may be provided from surface water sources or produced water.
- Water should be treated in order to maintain well injectivity, prevent reservoir souring, and minimize corrosion of tubulars.
- Loss of injectivity may reduce waterflood pattern effectiveness or require drilling additional water injection wells. Unless the following are removed or reduced to desired level from injection water, permeability / injectivity near well bore can be affected:
- Solids
- Biological material (bacteria, algae, etc.)
- Hydrocarbons (which change the relative permeability to water)
- Corrosion byproducts and corrosion inhibitor chemicals

- Reservoir souring may occur or become worse by injection of sulfate-reducing bacteria. Injection water should be treated with biocide at levels sufficient to eliminate these bacteria.

- Corrosion of tubulars can be reduced by use of chemicals / physical processes to remove oxygen from injected water. This also reduces the amount of corrosion inhibitor chemicals required.

- Water sourcing, treatment, and disposal methods should comply with all relevant laws and the best practices listed above.

6.16.3 References

a. "Water for Hydraulic Fracturing", Petroleum Engineering Handbook, SPE.

b. Boschee, P. 2012. Handling Produced Water from Hydraulic Fracturing. Oil and Gas Facilities1 (1): 23—26.

c. "Water Treating Facilities in Oil and Gas Operations, Petroleum Engineering Handbook, SPE.

d. "Oil Facility", Petroleum Engineering Handbook, SPE.

e. Surface water treatment for Injection", Petroleum Engineering Handbook, SPE.

f. "Water (Prevention and Control of Pollution) Act, 1974 (amended 1988)", Ministry of Environment, Forest, and Climate Change, Government of India (enfor.nic.in).

g. "Environmental Protection Agency: Subchapter N - Effluent Guidelines and Standards. Part 435—Oil and Gas Extraction Point Source Category", United States Code of Federal Regulations, Title 40.

6.17 Reduction of Environmental Footprint in Limited Land Areas

6.17.1 Definitions and Discussion

- Directional drilling constructs a well whose bottomhole location is not directly below its surface location.

- Extended reach drilling (ERD) refers to advanced directional drilling where the horizontal reach is more than the vertical depth.

6.17.2 Best Practices

- Drilling

  - Optimize pad size by spacing wells closely at the surface, similar to offshore platform well spacing, with directional drilling of wells.

- Optimize number of pads required for field development by use of extended reach drilling.
- Optimize the number of wells required to develop the field by drilling horizontal or multilateral wells and/or by hydraulic fracturing, which increase recovery volume per well.
- While carrying out drilling activities in inhabited areas, noise level should be kept as low as possible and should not exceed the limits set as per the local laws / guidelines.

- Pipelines and flowlines
    - Optimize the right-of-way width
    - Encourage facility and pipeline infrastructure sharing agreements between fields/companies when feasible.
    - Use of common corridors for utilities (water, electricity), gas and oil pipelines, flowlines, and roads to minimize fragmentation of land
- In limited land areas, environmental footprint should be minimized by reducing pad size and limiting construction of new infrastructure when possible.
- Maximize land efficiency of roads, utility corridors, and pipelines.

6.17.3 References

- Finer M, Jenkins CN, Powers B (2013) Potential of Best Practice to Reduce Impacts from Oil and Gas Projects in the Amazon. PLoS ONE 8(5): e63022. doi:10.1371/journal.pone.0063022
- EPA Office of Compliance Sector Notebook Project, Profile of the Oil and Gas Extraction Industry, October, 2000.

7 Testing and Analysis – Reservoir and Production

7.1 Testing– Well Testing Considerations

7.1.1 Definitions and Discussion

- Well tests are conducted by flowing and/or shutting an oil or gas well or wells in a controlled manner to collect rate and pressure data which can be analyzed to obtain information about the reservoir fluid, reservoir description, reservoir connectivity, reservoir pressure and temperature, well's flow potential and flow regimes, etc. It is also important to know about the wellbore effects (such as wellbore storage and skin effects) because they mask the early time pressure data and require extending the duration of a well test. The derived well and reservoir information also depends upon the well types which have been categorized as follows:

    - Exploration Well: Well testing is used to confirm or deny discovery based upon the exploration well data. It is also used to determine the type of reservoir fluid, reservoir properties, flow rate potential, and initial reservoir pressure and temperature. Tests on exploration wells are normally short duration tests because of the high daily cost of the rig.

    - Appraisal Well: Well testing is used to refine the reservoir description, to confirm reservoir heterogeneities and boundaries, to determine drive mechanisms, to determine the type of flow regime such as radial, elliptical, or channel type to name a few. Fluid samples are collected for PVT analysis. Duration of tests is usually longer than those for exploration wells. Tests on appraisal wells are normally short to intermediate duration tests

    - Development Well: Periodic well tests on producing wells are used to further refine the reservoir description, to evaluate the need for any workover job such as acidizing or fracturing, to determine the reservoir connectivity or lack thereof by means of interference testing, and to monitor changes in reservoir pressure as a function of time. Tests on development wells can vary from short term to long term depending upon the test objective.

7.1.2 Best Practices

- Best practices in well testing requires consideration and implementation of the items listed below but not limited to:

    - Objectives of a test
    - Types of well test
    - Design of a test
    - Selection of suitable pressure gauges
    - Selection of test equipment--tools/bottom-hole tool assembly for the well

  - Regulatory considerations
  - Documentation of test objectives, test procedure etc.

- Objectives of a well test – These have been classified in three major categories and are discussed below

  - Well test for reservoir evaluation

    - This normally applies to exploration wells and includes tests for the reservoir fluid sampling, the reservoir flow capacity, and the initial reservoir pressure and temperature.
    - It may include a single zone or multiple zones in a well.

  - Well test for reservoir description

    - This may apply to most appraisal wells and a few development wells. Tests are run to gain knowledge about reservoir permeability, reservoir heterogeneity, drainage shape and boundary, and the existence of no flow boundaries such as faults and reservoir pinch-outs. It is also desirable to know about the type of reservoir boundary such as constant pressure or no flow closed system boundary. However, it may not be possible to determine all of the above listed parameters during the practical testing times.

  - Well test for reservoir management (monitoring)

    - This usually applies to development wells and requires the periodic collection of rate and pressure data from single or multiple wells.
    - Both drawdown (flowing) pressures and buildup pressures can be collected on an as needed basis on all wells or selected wells to identify any well problems such as formation plugging or water production to name a few.
    - Periodic Pressure buildup (PBU) tests helps to diagnose and address well problems. It also provides valuable information about reservoir pressure and its changes as a function of time. To obtain an estimate of field-wide average reservoir pressure, candidate wells for pressure buildup tests should be selected in such a way that they offer a good areal coverage of the field for each of the pay zone wherever feasible and valuable.
    - In general, the pressure buildup data need to be collected on a regular basis, preferably on annual basis wherever required, to maintain a reasonable pressure history of the field based on the reservoir conditions.
    - If applicable, plant and/or offshore platform facility maintenance or shutdowns times can offer an excellent opportunity to collect such pressure data with minimum loss to production.

- Some of the conventional and special tests are as under:
    - Conventional Single Well Tests
        - Production Wells
            - Pressure drawdown test
            - Pressure buildup test
            - Multi-rate Tests
            - Flow after flow test
            - Isochronal tests
            - Modified isochronal tests
        - Injection Wells
            - Injection test
            - Pressure falloff test
            - Multi-rate Tests
            - Step rate test (preferably at increasing rates)
            - Two step rate test
- Conventional Multi-well Tests
    - Interference Test
    - Pule Test
- List of well and reservoir information desired from well tests is provided below:
    - Desired well information
        - Determine wellbore damage or improvement (positive or negative skin effect +S or -S)
        - Evaluate effectiveness of an acid or fracture job
        - Estimate fracture length and fracture conductivity
        - Determine well parameters for vertical, slanted, or horizontal wells
        - Be knowledgeable of wellbore effects such as storage, type of storage, and also phase redistribution effects

- Desired reservoir information
    - Initial or average reservoir pressure
    - Reservoir flow capacity (k x h = permeability x net pay)
    - Existence of a single fault, multiple faults, and reservoir heterogeneities and boundaries
    - Reservoir connectivity or continuity or discontinuity
    - Estimate inter-well (phi*c_t = porosity x compressibility)
    - Estimate oil and gas in-place (Resources and Reserves)
    - Evidence of pressure support or depletion
    - Well testing layouts with equipment and classification of zones of hazardous area to be indicated

- Documentation of test objectives, test procedure, etc. The documentation should include, but not limited to, and should be shared with all parties concerned:

- Well test objectives
- Well test design
- Operation plan, wherever applicable
- Surface rate, pressure and temperature measurements
- Continuous Bottom Hole Pressure and Temperature data
- Type and Depth of the gauges etc
- Sequence of operation
- Analysis of the Well test and report

7.1.3 References

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2. Matthews, C. S. and Russell, D. G.: *Pressure Buildup and Flow Tests in Wells, Monograph Series*, Society of Petroleum Engineers of AIME, Dallas (1967) 1.
3. Earlougher, Robert C., Jr.: *Advances in Well Test Analysis*, *Monograph Series*, Society of Petroleum Engineers of AIME, Dallas (1976) vol. 5.

4. Bourdet, Dominique, "Well Test Analysis: The use of Advanced Interpretation Models", *Handbook of Petroleum Exploration & Production*, Elsevier Publications, 2002, Vol. 3, 1-45.

5. Lee, John: *Well Testing, Text Book Series*, Society of Petroleum Engineers of AIME, Dallas (1982) vol. 1, 1-71.

6. Lee, J., Rollins, J. S., and Spivey, J. P.: *Pressure Transient Testing, Text Book Series*, Society of Petroleum Engineers of AIME, Dallas (2003) Vol. 9.

7. Spivey, J. P. and Lee, John: *Applied Well Test Interpretation, Text Book Series*, Society of Petroleum Engineers of AIME, Dallas (2013) Vol. 13.

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9. British Colombia Well Testing and Reporting Requirements, BC Oil and Gas Commission, March 2013.

7.2 Testing – Pressure Gauges

7.2.1 Definitions and Discussion

- Pressure, temperature, flow rate, and fluid compositions are at the heart of the well testing measurements and analysis. The quality, quantity, frequency, duration, and location of these measurements determine the ability to extract meaningful information for well test analysis. Of these measurements, pressure is one of the most important basic input data required for any well test or pressure transient analysis. Therefore, it is important that measurement of pressure data is as accurate as possible.

- Calibration of Gauges – Regardless of the gauge system that is used, the quality of the data will depend on how accurately the gauges have been calibrated. The ever increasing sophistication of gauges requires high accuracy calibration systems and particular attention to detail in terms of calibration procedures.

- The frequency of calibration of pressure gauge should be as per OEM recommendation.

7.2.2 Best Practices

The following are general guidelines and generic gauge recommendations:

- Mechanical gauges should only be used as a back-up to electronic gauges, unless used for HP/HT tests. Electronic gauges are, however, common today and should be used because of their superior precision and resolution.

- It is also recommended that the recorder section of the gauge is checked before running the gauge to make sure that the stylus moves freely when the recorder is not connected to the clock or to the pressure element.

- When running a self-contained gauge, it is important to choose the clock so that most of the length of the chart is used during the test. It is also advisable to choose the clock so that the gauge needs to be run only once during the test, if possible.

- If there is a doubt that a clock is running throughout a test, small pressure events may be put on the chart at known times simply by raising the gauge several feet and then lowering it back to its original position. The hours per inch calculated between each event should be the same.

- If the chart obtained from a gauge shows a stair-stepping pattern, a recorder malfunction is indicated. That pattern indicates that the pressure must change by a certain amount before the stylus moves. This difficulty must be corrected for good pressure results by freeing the recorder so it does not get stuck.

- In reservoirs with temperature above 150^{o}C, run at least four gauges, preferably using different gauge technologies.

- When pressure is to be measured in high temperature environments, it is usually necessary to specifically calibrate the gauge at the temperature of interest. Bourdon-tube gauges demonstrate hysteresis effect, so calibration must be done with specific sequence of flexing and relaxing the Bourdon tube.

- In situations in which packers are being set and/or tubulars are perforated, pressures above reservoir pressures can be anticipated for short durations. Select the proper gauge rating to accommodate these conditions.

- It is advisable to choose the gauge pressure range so that the maximum observed pressure (current and future anticipated) falls between 60 and 80 percent of the upper limit of the gauge. If a gauge with too high pressure range is chosen, the accuracy and sensitivity obtained may not be adequate.

- For long-term installation, gauge drift characteristics should be considered before the choice is made.

- It should be ensured that the gauge battery life is sufficient for the test duration at the expected bottom-hole temperature with contingency built in.

- For best results, pressure should be measured near the sand-face. If that is impossible, useful data are usually obtained by correcting wellhead-pressure or fluid-level measurements to bottom-hole conditions. Run the gauges as close to the perforations as possible.

- Use surface pressure and temperature data along with bottom-hole data to resolve ambiguous wellbore effects.

- Run static and flowing gradient surveys before and/or after a test is complete, wherever possible.
- Prior to permanent abandonment of a well, sufficient pressure data shall be available to take an informed decision.
- Have all equipment certified for sour-gas service for testing reservoirs containing H2S.
- Quality of pressure measurement data is an important aspect of well testing operations. Operators are recommended to carefully follow the best practices listed above.
- Pressure measurement technology is constantly evolving. Hence it is recommended that operators select technologically advanced gauges, with the help of service companies, which ensures quality of data, ease of collection, and quick reporting of data for analysis purposes.

7.2.3 References

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2. Lee, J. et al, "Pressure Transient Testing", SPE Textbook Series Vol. 9, 2003.
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5. Mattar, L., "Critical Evaluation and Processing of Data Before Pressure Transient Analysis", SPEFE 24729-PA, 1996.
6. McAleese, S., "Operational Aspects of Oil and Gas Well Testing, Handbook of Petroleum Exploration and Production, Vol. 1, Elsevier Science, 2000.

7.3 Testing – Analysis

7.3.1 Definitions and Discussion

- Well testing provides the short term production of reservoir fluids to the surface permitting the operator to confirm the hydrocarbon show indicated by drill cuttings, cores and logs and estimate reservoir deliverability.
- Measured pressure transients caused by abrupt changes in production can characterize completion damage, reservoir permeability and distant reservoir heterogeneities and hence should be carefully dealt with.

7.3.2 Best Practices

Typical well test analysis best practices are outlined in the form of work-flow:

- For the traditional test comprising two flow periods and two buildups. Generally transient analysis focuses on the second buildup.
- The first step is to identify the various flow regimes on the log-log plot of Δp and derivative vs. time. The second step is to choose the most likely model for each.
- Estimation of model parameters is then made using specialized plots that allow a focused analysis of each flow regime.
- Using a workstation or computer, the reservoir engineer interacts with a commercially available Pressure Transient Analysis (PTA) software to build a comprehensive model using all the parameters found for the various flow regimes, predict what the entire transient should look like, and compare the results with the data.
- In this forward modeling process, the interpreter interprets parameters, either manually or automatically using a nonlinear regression scheme, and perhaps alters the choice of model for one of the regimes to obtain the best possible fit.
- The final interpretation step, called history matching or verification, uses the model established in the relevant buildup to predict pressure response throughout all flow and shut-in periods of the test and confirms that the model satisfactorily accounts for all data.
- This may result in more parameter adjustment because every period must now be matched simultaneously; even though the second flow period is planned intentionally long to minimize the influence of previous periods.
- Well testing analysis involves a multitude of input parameters with high degrees of uncertainty associated with them. Hence it is recommended that each analysis needs to be accompanied by a parametric sensitivity study.
- Well test analysis, on many occasions, results in a non-unique solution. Hence it is recommended that supporting data be collected from a variety of sources e.g. geologic interpretation, log analysis, etc. to reduce ambiguity of the results and to enhance understanding of the interpretation.
- The analysis platform should involve a minimum of one commercial software and/or in-house computations. This ensures the validity and credibility of the analysis results.

7.3.3 References

1. Bourdet, Dominique, "Well Test Analysis: The use of Advanced Interpretation Models", *Handbook of Petroleum Exploration & Production,* Elsevier Publications, 2002, Vol. 3, 1-45.

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7.4 Core Studies and Special Core Analysis – Core Preparation and Screening

7.4.1 Definitions and Discussion

- Core analysis and core studies aim to provide rock and/or rock-fluid interaction properties and fundamental guidelines relevant to reservoir management and field development planning to maximize economic hydrocarbon recovery.

- Special Core Analysis (SCAL) is a critical part of core analysis and typically includes drainage/imbibition capillary pressure, drainage/imbibition water/oil and gas/oil relative permeability, rock wettability, pore volume compressibility and electrical properties.

- Drainage process refers to the process in which the non-wetting phase saturation increases while the imbibition refers to the process in which the wetting phase saturation increases. For instance, for a water-wet reservoir, oil production by water flooding is an imbibition process which results in increasing water saturation and decreasing oil saturation.

7.4.2 Best Practices

- Cylindrical core samples are required for most of the special core analyses. Irregular core samples can be used for mercury injection test.

- Samples should be visually examined and X-Ray CT scanned to exclude severely heterogeneous core samples with laminations, flow barriers, vugs or micro-fractures.

- For reservoirs with severe heterogeneity, whole core samples should be used for core analysis.

- Composite cores are often used to eliminate or minimize capillary end effects.

7.4.3 References

1. American Petroleum Institute: “Recommended practices for core analysis procedures” Dallas, TX. API, 1998.

2. Andersen, G., “Coring and Core Analysis Handbook,” Tulsa, OK, PennWell Books, 1975.

7.5 Core Studies and Special Core Analysis – Capillary Pressure

7.5.1 Definitions and Discussion

- Capillary pressure generally is defined as the pressure in the non-wetting phase minus the pressure in the wetting phase. It should be noted that for a water/oil system, capillary pressure is sometimes expressed as the pressure in the oil phase minus the pressure in the water phase. If the reservoir is preferentially oil-wet, then the capillary pressure is a negative value.

- Capillary pressure is commonly measured using one of the three methods: porous plate (or diaphragm) method, centrifugal method and mercury injection method. The objective of the measurement is to provide a relationship between capillary pressure and water saturation. The resulting capillary pressure curve can relate water saturation to height above water-oil contact in a reservoir which can be used to calculate hydrocarbons in place.

- Porous plate method is also referred to as porous diaphragm or restored state method. For a gas-brine system, the measurement is commonly performed with a semi-permeable ceramic plate saturated with brine.

- Centrifugal method uses centrifugal force to de-saturate a wetting (drainage process) or non-wetting (imbibition process) phase of a rock sample.

- Mercury injection method is fast and reasonably accurate but conversion is required from mercury/air capillary data to reservoir fluid systems.

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7.5.2 Best Practices

- Relevant AIME standards for core analysis and measurement to be followed. Some of the examples are provided below.

- The best practice for porous plate method is as follows:

  - Measure the weight of the dry core samples, fully saturate the samples with brine and measure the weight of the saturated core samples.

  - Place the brine saturated core samples in a porous plate capillary pressure cell.

  - Increase the cell pressure to a pre-determined value and record the brine production after equilibrium has been reached. Repeat until a pre-determined maximum pressure has been reached.

  - Plot capillary pressure versus water saturation.

  - The best practice for mercury injection capillary pressure is as follows:

  - Introduce mercury into the core sample chamber at a constant volumetric rate and measure the equilibrium pressure.

- At each equilibrium injection pressure, the amount of cumulative mercury injection is determined.
- Determine capillary pressure as a function of mercury saturation and pore size distribution based on the measured pressure, invaded mercury volume and other data.

- The best practice for centrifuge method is as follows:
  - Place brine-saturated rock samples in core cups or core-holders which contain a displacing fluid.
  - Spin the core samples at a constant rotational speed until there is no further brine production. Measure the amount of brine expelled from the core sample with a stroboscope and calculates the average brine saturation of the core sample.
  - Repeat the test at higher rotational speeds to generate lower brine saturations.
  - Convert centrifuge rotational speeds to capillary pressures and plot capillary pressure versus brine saturation.

- The following equation is recommended to determine the maximum capillary pressure needed to perform capillary pressure test with centrifuge
  - $P_c = (\rho_w - \rho_o)H$
  - ρ_w – water density gradient (psi/ft)
  - ρ_o – oil density gradient (psi/ft)
  - H – height above free water level (ft)

7.5.3 References

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3. Hassler, G. L., Brunner, E.: "Measurement of Capillary Pressure in Small Core Samples," Trans. AIME (1945) 160, 114-123.
4. Kalam, M.Z., Hammadi, K.A., Wilson, O. B., Dernaika, M., and Samosir, H.: "Importance of Porous Plate Measurements on Carbonates at Pseudo Reservoir Conditions," SCA2006, 28, Trondheim, Norway.

7.6 Core Studies and Special Core Analysis – Rock Wettability

7.6.1 Definitions and Discussion

- Either of the following two methods, Amott-Harvey method or USBM method, can be used to determine reservoir core wettability.
- Amott-Harvey wettability measurement consists of spontaneous and forced imbibition and drainage processes. Core wettability is determined based on the spontaneous and forced imbibition and drainage data.
- The USBM method determines core wettability by comparing the thermodynamic work required for one fluid to displace the other fluid. The required work is found to be proportional to the area under the drainage and imbibition capillary pressure curves. Core wettability can be evaluated through the USBM wettability index which is calculated using the following equation.
- $W = \log(A_1 / A_2)$
- Where $A_1$and $A_2$are the areas under the drainage and imbibition capillary pressure curves respectively.

7.6.2 Best Practices

- The practice for Amott-Harvey wettability measurement is as follows:
    - Load the core plugs into centrifuge sample cups and displace the cores with fresh synthetic formation brine.
    - Spin the core plugs under stock tank oil to establish initial water saturation.
    - Conduct spontaneous imbibition of brine by placing the cores in graduated imbibition cells full of degassed formation brine at reservoir temperature.
    - Record oil production displaced by spontaneous imbibition of the brine as a function of time until oil production ceases (Volume A).
    - Load the cores into centrifuge sample cups.
    - Spin the cores under synthetic formation brine until residual oil saturation is reached and record the amount of oil displaced by the brine (Volume B).
    - Conduct a spontaneous drainage test by placing the cores in graduated glass cells full of stock tank oil.
    - Record water production by spontaneous drainage of oil, and stop the test when there is no water production (Volume C).
    - Load the cores into centrifuge sample cups.

  - Spin the cores under stock tank oil until there is no water production and record the amount of water displaced by the oil (Volume D).
  - Calculate the Amott-Harvey water and oil wettability index based on the spontaneous and forced imbibition test data using the following equation and determine core wettability.
- $WI = \frac{A}{A+B} - \frac{C}{C+D}$
  - Clean the tested cores with Dean-Stark method.
  - Determine core porosity, permeability, and grain density.
- The best practice for USBM wettability measurement is as follows:
  - Load core plugs into centrifuge sample cups.
  - Spin the cores under degassed synthetic formation brine until there is no oil production.
  - Spin the cores under stock tank oil at incrementally increasing rotational speeds until a capillary pressure of 70kpa is reached.
    - Record water production and determine the fluid saturation at each centrifuge speed.
    - Spin the cores under the degassed formation brine at incrementally increasing rotational speed until a capillary pressure of -70 kPa is reached.
    - Record oil production and determine the fluid saturation at each centrifuge speed.
    - Determine imbibition and drainage centrifugal capillary pressure curves and the areas under these curves.
    - Determine USBM wettability index and assess core wettability.
    - Clean the tested cores using the Dean-Stark method.
    - Determine core porosity, permeability, and grain density.
- USBM/Amott combined wettability test is recommended which would provide USBM and Amott wettability index.
- For wettability tests with restored state core samples, it is recommended to age the core samples for 40 days to restore reservoir wettability unless there are convincing reasons to age the core samples for a shorter period of time.

7.6.3 References

1. Anderson, W. G.: "Wettability Literature Survey: Part 2-Wettability Measurement," JPT (Nov., 1986).

7.7 Core Studies and Special Core Analysis – Relative Permeability

7.7.1 Definitions and Discussion

- Relative permeability is defined as the ratio of the effective permeability of a fluid to the absolute permeability of the rock or to the effective permeability of the non-wetting phase at irreducible wetting phase saturation.
- It can be measured using either steady-state or unsteady-state method.
    - The steady-state test is run by injecting two or three fluids simultaneously at specific fluid ratios at constant rate or pressure for extended hours to reach saturation equilibrium. This method can provide reliable relative permeability data over a wider range of saturation levels but it is time consuming.
    - Unsteady-state method can provide quick results and is typically performed by injecting a fluid at a constant rate or pressure until there is no further production of the displaced fluid. This method involves many uncertainties and the results are therefore considered as qualitative.
- Relative permeability is a strong function of the fluid saturation and it also depends on the direction of saturation changes. For the same level of fluid saturation, relative permeability can be different due to difference in interstitial fluid distribution. Thus, for the same level of the fluid saturation, drainage (increasing non-wetting phase saturation) relative permeability can be different from imbibition (increasing wetting phase saturation) relative permeability.

7.7.2 Best Practices

- The following is a general procedure for determining water/oil steady-state imbibition relative permeability. However, in certain cases unsteady-state imbibation relative permeability also may be considered. The procedure includes establishment of connate water saturation and restoration of rock wettability:
    - Load core plugs in sample cups of a high-speed centrifuge and spin the cores under stock tank oil at predetermined centrifuge speed to achieve initial water saturation.
    - Load a core sample into a Hassler-type core holder specially designed for steady-state displacement tests. Place the core plugs in an ascending permeability order to

minimize capillary end effects. Capillary continuity between the composite cores can be improved by use of Kleenex or filter paper.

- Apply desired confining pressure and pore pressure to the cores.
- Raise the temperature of the core assembly to the reservoir temperature.
- Flush the core with certain amount of live reservoir oil containing 10 vol% iododecane at a controlled flow rate at reservoir conditions. Determine effective oil permeability at initial water saturation. X-ray scans the core plugs to determine CT number.
- Age the core plugs for 40 days to restore rock wettability.
- Inject water and oil simultaneously at a low fixed water/oil ratio into the core samples until pressure drop across the core samples reach constant. Determine effective permeability and X-ray scans the cores to determine CT_x. Repeat at increasing water to oil injection ratios and determine corresponding effective permeability and X-ray CT number (CT_x).
- Determine imbibition relative permeability as a function of brine saturation.

- The following is a general procedure for determination of water/oil steady-state drainage relative permeability
  - Continue above test to determine secondary drainage relative permeability
  - Inject water and oil simultaneously at a low fixed oil/water ratio into the core samples until pressure drop across the core samples reach constant. Determine effective permeability and X-ray CT scans the cores to determine CT number. Repeat at increasing oil fractions. Determine effective permeability and X-ray CT scans the cores to determine CT number.
  - Clean the cores and saturate with live reservoir oil containing 10vol% iododecane to determine X-ray CT number.
  - Clean the cores and saturate with the synthetic formation brine to determine CT numbers.
  - Determine fluid saturation and drainage relative permeability to oil and water.
  - Clean the cores using Dean-Stark method or Soxhlet method if saturation data is needed.
  - Determine the porosity, permeability and grain density of the extracted cores.
- Use of composite cores in order to minimize capillary end effect is recommended. If individual core plugs are used, displacement rate should be high enough to eliminate/minimize capillary end effect and low enough to avoid core damage.

7.7.3 References

1. Honarpour, M. and Mahmood, S.M.: "Relative Permeability Measurements: An Overview", SPE18565.

2. Honarpour, M., et. al.: "Relative Permeaiblity of Petroleum Reservoirs", CRC Press Inc., Boca Raton, FL (1986).

3. Longeron, D. G., Kalaydjian, F., Bardon C., and Desremaux, L.M.: "Gas-Oil Capillary Pressure: Measurements at Reservoir Conditions and Effect on Gas Gravity Drainage", SPE 28612 presented at the SPE 69th Annual Technical Conference and Exhibition, New Orleans, LA, U.S.A, 25-28 September 1994.

4. Ross, W.: "Relative Permeability", Petroleum Production Handbook, SPE, Richardson, TX (1987), Chap. 28, 28-l-28-16.

7.8 Core Studies and Special Core Analysis – Electrical Properties

7.8.1 Definitions and Discussion

- Formation resistivity index, cementation exponent, and saturation exponent should be determined on core samples at net overburden pressure at various levels of water saturation from which resistivity index versus brine saturation can be plotted.

- Formation resistivity factor (FRF) should also be determined at net formation overburden pressure.

- Formation water resistivity should be measured at ambient and reservoir temperature.

- Note that generally centrifuge method, instead of Dean-Stark distillation/extraction method, should be used to recover formation brine sample for measurement of resistivity since Dean-Stark distillation method leaves salts in the pores.

7.8.2 Best Practices

- The following are best practices for evaluating core electrical properties:

  - Evacuate and saturate a core plug with synthetic formation brine.

  - Load the brine saturated core into a core holder and apply reservoir equivalent net overburden pressure.

  - Measure resistivity until a constant value has been obtained.

  - Determine formation resistivity factor (FRF) and cementation exponent.

  - Displace the core with humidified air at incrementally increasing pressures to de-saturate the core.

- Measure electrical resistivities at each saturation stage until a constant value has been attained.
- Calculate resistivity index and saturation exponent at each brine saturation value.
- Clean the core with toluene and methanol and dry the core at 60oC until a constant weight has been achieved.
- Determine Cat-ion Exchange Capacity (CEC) using ammonium acetate wet chemistry technique.
- Calculate clay-corrected cementation and saturation exponent using Waxman-Smits-Thomas equations.

7.8.3 References

1. Durand, C. and Lenormand, R.: “Resistivity Measurements While Centrifuging”, Proceeding of the International Symposium of the Society of Core Analysts, Calgary (1997).
2. Fleury M. and Longeron D.: “Combined Resistivity and Capillary Pressure Measurements Using Micro-pore Membrane Technique”, Proceeding of the International Symposium of the Society of Core Analysts, Montpelier (1996).

7.9 Core Studies and Special Core Analysis – Pore Volume Compressibility

7.9.1 Definitions and Discussion

- Pore volume compressibility is defined as the fractional change in pore volume per unit change in pressure. It is common in laboratory to measure pore volume compressibility by varying confining pressure and holding pore pressure constant. Under this condition, the pore volume compressibility is mathematically expressed as follows:
- $C_{pc} = \frac{-1}{V_p}(\frac{\partial V_p}{\partial P})_{P_p}$
- Where, the pressure outside the parentheses indicates that the pore pressure is kept constant when the pore volume compressibility is measured with change in confining pressure.
- Pore volume compressibility is usually measured under hydrostatic stress condition, that is, the entire outer boundary of the rock sample is subjected to the same confining pressure.
- The hydrostatic loading results in a greater pore volume compressibility than in the reservoir. It is the uniaxial pore volume compressibility that is needed for reservoir engineering calculations. Therefore, hydrostatic compressibility must be reduced to uniaxial compressibility using appropriate equations.

7.9.2 Best Practices

- The following are best practices for evaluating pore volume compressibility:
  - Evacuate and pressure saturate samples with simulated formation brine.
  - Load the brine saturated samples into hydrostatic core holders and allow to equilibrate at a low net overburden pressure.
  - Raise the net overburden pressure incrementally and monitor the corresponding pore volume reductions. The overburden pressure is then raised to the next higher pressure when pore volume reduction has stabilized.
  - Calculate hydrostatic compressibility data from pore volume reduction data versus increasing overburden pressure and convert these data to equivalent uniaxial loading using procedures outlined by Dirk Teeuw or equivalent guidelines or standards.

7.9.3 References

1. Teeuw, Dirk: "Prediction of Formation Compaction from Laboratory Compressibility Data", Trans: AIME (1971) 251, 263-271.

2. Zimmerman, R. W.: "Pore Compressibility under uniaxial Strain", Proceedings, International Symposium on Land Subsidence, Ravanna, Italy, 2000

7.10 Core Studies and Special Core Analysis – Application of Capillary Pressure: Determination of Water Saturation

7.10.1 Definitions and Discussion

- Capillary pressure functions are used to determine water saturation in transition zones. The estimated water saturation is then compared with log derived water saturation at different depths of the subject reservoir. If the water saturation from these two sources is comparable, the water saturation is used to determine in-place hydrocarbon volumes and in other reservoir engineering calculations. If there is an obvious discrepancy in water saturation, log and core data must be critically analyzed and adjusted to reflect the in-situ water saturation.

7.10.2 Best Practices

- Derive a J-function as a function of water saturation for each rock type based on laboratory measured capillary pressure data. Apart from J-function several other methods of estimation of water saturation can be used for example log derived water saturation, Dean-Stark method etc.

- If there is an obvious discrepancy in water saturation, log and core data must be critically analyzed and adjusted to reflect the in-situ water saturation.

- Calculate capillary pressure as a function of the height above free water level using the following equation:
- $P_c = (\rho_w - \rho_o)H$
- ρ_w – water density gradient (psi/ft)
- ρ_o – oil density gradient (psi/ft)
- H – height above free water level (ft)
- Calculate J using the following equation:
- $J = \frac{0.21167 * P_c}{\sigma cos\theta}\sqrt{\frac{k}{\emptyset}}$
- P_c – water/oil capillary pressure (psi)
- k – absolute permeability (mD)
- $\emptyset$ - porosity (fraction)
- σ – reservoir brine/oil interfacial tension (dyns/cm)
- θ – contact angle for rock/brine/oil system
- Calculate connate water saturation using the derived J-function for each rock type
- Plot height versus the Pc-derived water saturation and height versus the log-derived water saturation. Compare the water saturation and make necessary adjustment based on data reliability.
- Water saturations from other sources, such as oil based mud (OBM) core, single well chemical tracer test etc., are recommended for use to help finalize the water saturation.

7.10.3 References

1. Efnik, M. S. et al.: "Evaluation of Water Saturation from Laboratory to Logs," SCA2006-56.
2. Thornton, O. F., and Marshall, D. L.: "Estimating Interstitial Water Saturation by the Capillary Pressure Method," Trans AIME (1946).

7.11 Decline Curve Analysis – Flow Testing of Wells

7.11.1 Definitions and Discussion

- The purpose of decline curve analysis is to estimate the ultimate recovery (EUR) of reserves of a pay zone. In case of commingled completions, the pay zones are bundled to estimate the gross reserves.

7.11.2 Best Practices

- When adequate (2 or more years) production data is available and production is declining, the past production curves of individual wells, lease, reservoir or a field can be extended to indicate future performance. The very important assumption in using decline curves is that all factors that influenced the curve in the past remain effective throughout the producing life. Many factors influence production rates and consequently decline curves. These are perforations, changes in production methods, workovers, well treatments, pipeline disruptions, weather, market conditions and drive mechanisms that govern the production.

- Commonly used decline curves are:

  - Log of production rate vs. time to determine the decline.

  - Production rate vs. cumulative production to know the ultimate reserves.

- Other conventional decline curve analysis methods such as ARPS equation, Fetkovich liquid system decline curves etc may be used depending upon the field / reservoir requirements.

7.11.3 References

1. Agarwal, Ram G., Gardner, David C., Kleinsteiber, Stanley W., and Fussell, Del D.: “Analyzing Well Production Data Using Combined Type-Curve and Decline Curve Analysis Concepts,” SPE Reservoir Eval. & Eng., Vol. 2, No. 5, October 1999, 478-486.
2. Agarwal, Ram G.: “Direct Method of Estimating Average Pressure for Flowing Oil and Gas Wells,” paper 135804 presented at the 2010 SPE Annual Technical Conference and Exhibition, Florence, Italy, Sept. 19-22.

8 Health, Safety and Environment (HSE)

Background

The long term success of oil and gas operations requires the Contractor/Operator to continually improve the quality of its operations, the quality of its services, and the quality of its products, while protecting its employees, its communities, and the environment. To that effect, significant emphasis should be placed on human health, safety, environmental protection, quality improvements, and community involvement. Commitments to health, safety and the environment (HSE) benefit the company, the employees, the customers, the contractors, the shareholders, and the communities in which the company operates and resides.

Due to the complexities of activities in the oil and gas industry, number of elaborate HSE guidelines and best practices for oil and gas operations are available that include industry best practices as well as compliance/ regulatory requirements. This document intends to collate various best practices and provide a working guide to Contractor/Operator that can be adopted by oil and gas contractors and operators to maintain and continually improve their HSE performance

Scope :

The scope of this chapter applies to following stages/aspects of E&P activity:

- Evaluation phase
- Appraisal phase
- Design phase
- Execution/operations phase
- Retiring phase

This chapter covers the following aspects:

- Environmental Protection -Section 8.1
- Health & Safety - Section 8.2
- International Timelines for Permit -Section 8.3
- Contingency, Emergency Response and Disaster Management Plan -Section 8.4

The indicative list of applicable statutory requirements in India have been mentioned in section 8.1.3 and are applicable to sections 8.2 and 8.4 also.

HSE Management System Framework

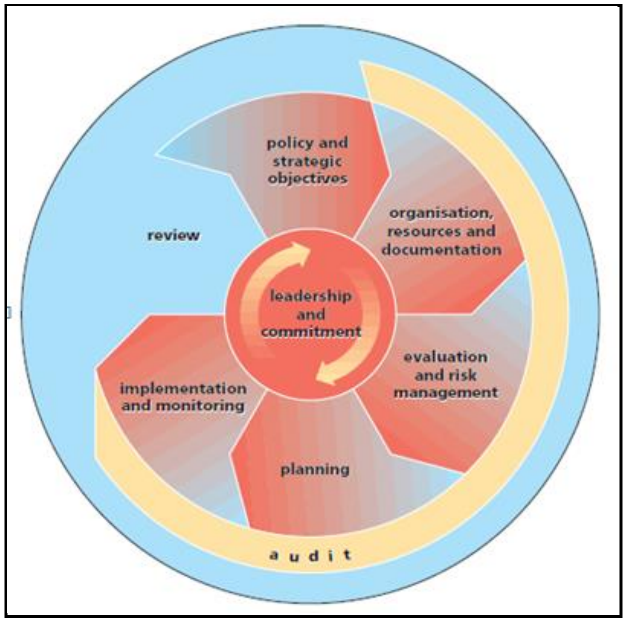
Individual Health, Safety and Environment (HSE) systems, management tools and techniques have evolved over years in line with organizational HSE principles, minimum regulatory requirements and industry best practices. The HSE Management System (HSEMS) Framework is critical and provides a basis for companies to consistently manage health, safety and environmental issues.

The Guidelines suggested here build on experience gained in the application of earlier systems and arrangements and also draws on external developments such as Quality Management standards (ISO 9000), Health and Safety Management (HS(G)65), Environmental Management (ISO 14000) and HSE Management (E&P Forum). These Guidelines are intended to meet following objectives,

- Assist in the development and application of HSEMS in exploration and production operations.
- Cover relevant Health, Safety and Environment (HSE) issues in a single document.
- Be relevant to the activities of the E&P operations in line with industry best practices.
- Be sufficiently generic to be adaptable to different companies and their cultures.
- Recognize, and be applicable to, the role of contractors and subcontractors.
- Facilitate operation within the framework of statutory requirements.
- Facilitate evaluation of operations to an international standard(s) as appropriate.

The Guidelines describe the main elements necessary to develop, implement and maintain an HSEMS. They do not lay down specific performance requirements, but recommend that companies set policies and objectives taking into account information about the significant hazards and environmental effects of their operations. These may be used as a template by any operating or contracting company seeking to help assure itself and others (such as regulators, neighbours, partners, clients, insurers) of compliance with stated HSE policies within an objective-setting management system. Furthermore, the Guidelines are intended to support, rather than to suggest replacement of, existing sound, workable and effective company systems and practices.

The model Health, Safety and Environmental Management System (HSEMS) is described below,



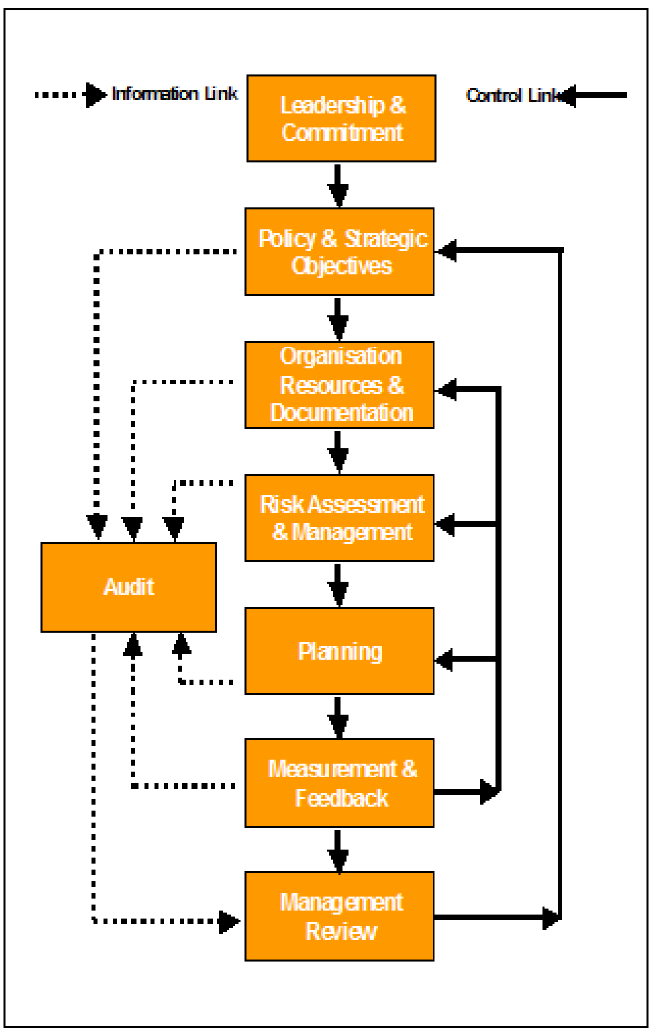
These guidelines provide a basis for Contractors/Operators to develop, maintain, and implement HSE Management Systems for all their activities. The HSE management system should include management commitment, work flows, HSE manuals, training, environment, safety and occupational health and hygiene audits and continuous improvement (see figure below). The actual activities within each phase of the project as mentioned above depend on the actual project itself and will dictate the relevant and applicable HSE protocols to adopt.

HSE Management System Flow Chart

The framework details outlined below provide a structure for a comprehensive HSE management program for upstream oil and gas development operations and as a minimum, are relevant to:

- Seismic exploration activities
- Exploration and appraisal drilling activities
- Field development and production activities
- Construction activities
- Decommissioning, abandonment, and restoration activities

The system is structured on eight related key elements as mentioned below,



HSSE Management System Model

Leadership & Commitment: This element describes leadership from management, commitment from staff and development of a culture essential for continued HSE success.

Senior management of the company should provide strong, visible leadership and commitment, and ensure that this commitment is translated into the necessary resources, to develop, operate and maintain the HSEMS and to attain the policy and strategic objectives. Management should ensure that full account is taken of HSE policy requirements and should provide support for local actions taken to protect health, safety and the environment.

The company should create and sustain a company culture that supports the HSEMS, based on:

- belief in the company's desire to improve HSE performance;
- motivation to improve personal HSE performance;
- acceptance of individual responsibility and accountability for HSE performance;
- participation and involvement at all levels in HSEMS development;

Employees of both the company and its contractors should be involved in the creation and maintenance of such a supportive culture

Policy & Strategic Objectives: This element describes corporate intentions, principles of action and aspirations with respect to HSE.

The company's management should define and document its HSE policies and strategic objectives and ensure that they:

- are consistent with those of any parent company;
- are relevant to its activities, products and services, and their effects on HSE;
- are consistent with the company's other policies;
- have equal importance with the company's other policies and objectives;
- are implemented and maintained at all organisational levels;
- are publicly available;
- commit the company to meet or exceed all relevant regulatory and legislative requirements;
- apply responsible standards of its own where laws and regulations do not exist;
- commit the company to reduce the risks and hazards to health, safety and the environment of its activities, products and services to levels which are as low as reasonably practicable;
- provide for the setting of HSE objectives that commit the company to continuous efforts to improve HSE performance.

The company should establish and periodically review strategic HSE objectives. Such objectives should be consistent with the company's policy and reflect the activities, relevant HSE hazards and effects, operational and business requirements, and the views of employees, contractors, customers and companies engaged in similar activities

Organization, Resources & Documentation: This element requires that responsibilities are assigned, adequate resources applied, competence assured, contractor HSE performance managed, HSE matters are effectively communicated, and documentation is controlled and maintained.

Successful handling of HSE matters is a line responsibility, requiring the active participation of all levels of management and supervision. This should be reflected in the organizational structure and allocation of resources. The company should define, document and communicate—with the aid of organizational diagrams where appropriate—the roles, responsibilities, authorities, accountabilities and interrelations necessary to implement the HSEMS, including but not limited to:

- provision of resources and personnel for HSEMS development and implementation;
- initiation of action to ensure compliance with HSE policy;
- acquisition, interpretation and provision of information on HSE matters;
- identification and recording of corrective actions and opportunities to improve HSE performance;
- recommendation, initiation or provision of mechanisms for improvement, and verification of their implementation;
- control of activities whilst corrective actions are being implemented;
- control of emergency situations.

The company should stress to all employees their individual and collective responsibility for HSE performance. It should also ensure that personnel are competent and have the necessary authority and resources to perform their duties effectively.
The organizational structure and allocation of responsibilities should reflect the responsibility of line managers at all levels for developing, implementing and maintaining the HSEMS in their particular areas. The structure should describe the relationships between:

- Different operating divisions
- Operating divisions and supporting services (whether the services are provided on the same facility or from a larger corporate organisation)
- Onshore and offshore organisations
- Employees and contractors
- Partners in joint activities

Risk Assessment & Management: This element requires Hazards, effects and threats are identified and the risks are assessed. Risk control and recovery measures are developed.

Identification of hazards and effects :

The company should maintain procedures to identify systematically the hazards and effects which may affect or arise from its activities, and from the materials which are used or encountered in them. The scope of the identification should cover activities from inception (e.g. prior to acreage acquisition) through to abandonment and disposal.

The identification should include consideration of:
- Planning, construction and commissioning (i.e. asset acquisition, development and improvement activities).
- Routine and non-routine operating conditions, including shut-down, maintenance and start-up.
- Incidents and potential emergency situations, including those arising from:
    - Product/material containment failures
    - Structural failure
    - Climatic, geophysical and other external natural events
    - Sabotage and breaches of security
    - Human factors including breakdowns in the HSEMS
- Decommissioning, abandonment, dismantling and disposal
- Potential hazards and effects associated with past activities

Personnel at all organizational levels should be appropriately involved in the identification of hazards and effects.

Evaluation :

Procedures should be maintained to evaluate (assess) risks and effects from identified hazards against screening criteria, taking account of probabilities of occurrence and severity of consequences for:

- People
- Environment
- Assets
- Reputation

It should be noted that any evaluation technique provides results which themselves may be subject to a range of uncertainties. Consequently formal risk evaluation techniques are used in conjunction with the judgment of experienced personnel, regulators and the community.

Risk evaluation should:

- include effects of activities, products and services;
- address effects and risks arising from both human and hardware factors;
- solicit input from personnel directly involved with the risk area;
- be conducted by qualified and competent personnel;
- be conducted according to appropriate and documented methods;
- be updated at specified intervals.

Evaluation of health and safety risks and effects should include, where appropriate, consideration of:

- Fire and explosion.
- Impacts and collisions.
- Drowning, asphyxiation and electrocution.
- Chronic and acute exposure to chemical, physical and biological agents.
- Ergonomic factors.

Evaluation of acute and chronic environmental effects should include, where appropriate, consideration of:

- Controlled and uncontrolled emissions of matter and energy to land, water and the atmosphere
- Generation and disposal of solid and other wastes
- Use of land, water, fuels and energy, and other natural resources
- Noise, odour, dust, vibration
- Effects on specific parts of the environment including ecosystems
- Effects on archaeological and cultural sites and artefacts, natural areas, parks and conservation areas

Recording of hazards and effects :

The company should maintain procedures to document those hazards and effects (chronic and acute) identified as significant in relation to health, safety and the environment, outlining the measures in place to reduce them and identifying the relevant HSE-critical systems and procedures.

The company should maintain procedures to record statutory requirements and codes applicable to the HSE aspects of its operations, products and services and to ensure compliance with such requirements.

Objectives and performance criteria :

The company should maintain procedures to establish detailed HSE objectives and performance criteria at relevant levels.

Such objectives and performance criteria should be developed in the light of policy, strategic HSE objectives, HSE risks, and operational and business needs. They should be quantified, wherever practicable, and identified with defined timescales; they should also be realistic and achievable.

As a follow-up to risk evaluation , the company should maintain procedures to set performance criteria for HSE-critical activities and tasks, which stipulate in writing the acceptable standard for their performance. It should also, at specified intervals, review the continuing relevance and suitability of the criteria.

Risk reduction measures :

The company should maintain procedures to select, evaluate and implement measures to reduce risks and effects. Risk reduction measures should include both those to prevent incidents (i.e. reducing the probability of occurrence) and to mitigate chronic and acute effects (i.e. reducing the consequences). Preventative measures such as ensuring asset integrity should be emphasized wherever practicable.

Mitigation measures should include steps to prevent escalation of developing abnormal situations and to lessen adverse effects on health, safety and the environment and, ultimately, emergency response measures to recover. Effective risk reduction measures and follow-up require visible commitment of management and on-site supervision, as well as the understanding and ownership of operations personnel.

In all cases consideration should be given to reducing risk to a level deemed 'as low as reasonably practicable' reflecting amongst other factors local conditions and circumstances, the balance of cost and benefits and the current state of scientific and technical knowledge.

Procedures should be in place to:

- Identify prevention and mitigation measures for particular activities, products and services which pose potential HSE risks.
- Re-appraise activities to ensure that the measures proposed do reduce risks, or enable relevant objectives to be met.
- Implement, document and communicate to key personnel interim and permanent risk reduction measures, and monitor their effectiveness.

- Develop relevant measures such as plans for emergency response to recover from incidents and mitigate their effects.
- Identify hazards arising from risk prevention and mitigation and recovery measures.
- Evaluate the tolerability of consequent risks and effects against the screening criteria.

Planning: This element requires that plans are developed for achieving HSE objectives, targets & risk reduction measures, performance improvement, conduct of work activities, management of change and emergency response.

The company should maintain, within its overall work program, plans for achieving HSE objectives and performance criteria. These plans should include:

- a clear description of the objectives;
- designation of responsibility for setting and achieving objectives and performance criteria at each relevant function and level of the organisation;
- the means by which they are to be achieved;
- resource requirements;
- time scales for implementation;
- programmes for motivating and encouraging personnel toward a suitable HSE culture;
- mechanisms to provide feedback to personnel on HSE performance;
- processes to recognize good personal and team HSE performance (e.g. safety award schemes);
- mechanism for evaluation and follow-up.

Asset Integrity : The company should maintain procedures to ensure that HSE-critical facilities and equipment which it designs, constructs, procures, operates, maintains and/or inspects are suitable for the required purpose and comply with defined criteria. Pre-procurement and pre-construction assessment of new facilities and equipment should include explicit assessment of appropriateness to meet HSE requirements and should emphasize design as the best preventative measure to reduce risk and adverse HSE effects.

Procedures and systems for ensuring asset integrity should address (amongst other factors) structural integrity, process containment, ignition control and systems for protection, detection, shutdown, emergency response and life-saving.

Deviation from approved design practices and standards should be permitted only after review and approval by designated personnel and/or authorities, and the rationale for the deviation should be documented.

Procedures and Work Instructions: Activities for which the absence of written procedures could result in infringement of the HSE policy or breaches of legislative requirements or performance criteria, should be identified. Documented procedures or standards should be prepared for such activities, defining how they should be conducted—whether by the company's own employees, or by others acting on its behalf—to ensure technical integrity and to transfer knowledge effectively.

All written procedures should be stated simply, unambiguously and understandably, and should indicate the persons responsible, the methods to be used and, where appropriate, performance standards etc. The company should maintain procedures for planning and controlling changes, both permanent and temporary, in people, plant, processes and procedures, to avoid adverse HSE consequences. The procedures should be suitable to address the HSE issues involved, according to the nature of the changes and their potential consequences.

Contingency and emergency planning: The company should maintain procedures to identify foreseeable emergencies by systematic review and analysis. A record of such identified potential emergencies should be made, and updated at appropriate intervals in order to ensure effective response to them.

The company should develop, document and maintain plans for responding to such potential emergencies, and communicate such plans to :

- command and control personnel;
- emergency services;
- employees and contractors who may be affected;
- others likely to be impacted.

Emergency plans should cover:

- Organisation, responsibilities, authorities and procedures for emergency response and disaster control, including the maintenance of internal and external communications.
- Systems and procedures for providing personnel refuge, evacuation, rescue and medical treatment.
- Systems and procedures for preventing, mitigating and monitoring environmental effects of emergency actions.
- Procedures for communicating with authorities, relatives and other relevant parties.
- Systems and procedures for mobilizing company equipment, facilities and personnel.
- Arrangements and procedures for mobilizing third party resources for emergency support.
- Arrangements for training response teams and for testing the emergency systems and procedures.

To assess the effectiveness of response plans, the company should maintain procedures to test emergency plans by scenario drills and other suitable means, at appropriate intervals, and to revise them as necessary in the light of the experience gained.

Procedures should also be in place for the periodic assessment of emergency equipment needs and the maintenance of such equipment in a ready state.

Measurement and Feedback: This element requires that activities are conducted against relevant procedures. Performance is measured against objectives, targets, external benchmarks and performance criteria. Corrective action is taken when necessary.

Management should ensure, and be responsible for, the conduct and verification of activities and tasks according to relevant procedures. This responsibility and commitment of management to the implementation of policies and plans includes, amongst other duties, ensuring that HSE objectives are met and that performance criteria and control limits are not breached. Management should ensure the continuing adequacy of the HSE performance of the company through monitoring activities.

The company should maintain procedures for monitoring relevant aspects of HSE performance and for establishing and maintaining records of the results. For each relevant activity or area, the company should:

- identify and document the monitoring information to be obtained, and specify the accuracy required of results;
- specify and document monitoring procedures, and locations and frequencies of measurement;
- establish, document and maintain measurement quality control procedures;
- establish and document procedures for data handling and interpretation;
- establish and document actions to be taken when results breach performance criteria;
- assess and document the validity of affected data when monitoring systems are found to be malfunctioning;
- safeguard measurement systems from unauthorized adjustments or damage.

Audit: This element requires that audits are conducted as a normal part of business control to independently assess the robustness, effectiveness and continued suitability of the Management System practices, and conformance with planned arrangements.

The company should maintain procedures for audits to be carried out, as a normal part of business control, in order to determine:

- Whether or not HSE management system elements and activities conform to planned arrangements, and are implemented effectively.
- The effective functioning of the HSEMS in fulfilling the company's HSE policy, objectives and performance criteria.
- Compliance with relevant legislative requirements.
- Identification of areas for improvement, leading to progressively better HSE management.
- For this purpose, it should maintain an audit plan, dealing with the following:
- Specific activities and areas to be audited. Audits should cover the operation of the HSEMS and the extent of its integration into line activities, and should specifically address the following elements of the HSEMS model:
    - organisation, resources and documentation;
    - evaluation and risk management;
    - planning;
    - implementation and monitoring.
- Frequency of auditing specific activities/areas. Audits should be scheduled on the basis of the contribution or potential contribution of the activity concerned to HSE performance, and the results of previous audits.
- Responsibilities for auditing specific activities/areas.

Environmental & Safety Monitoring and Auditing

Environment, Safety and Health programs benefit from effective planning, full implementation, and careful ongoing management. Correcting common deficiencies is important to protect the health and safety of site workers, deleterious impact on surrounding environment and to maximize the benefit and cost effectiveness of site health and safety programs. Information collected during environmental and safety audits are used to improve worker safety and health, effectively prevent injury and illness and manage environmental hazards. This can reduce costs and avoid regulatory citations and fines. Environmental and safety audits are important in evaluating compliance of the Operator's environment and work safety programs through the assessment of properties, facilities, processes, and operations against regulations and standards as well as internal policies and goals. Environmental and safety audits should be conducted to ensure that oil and gas operators have efficient management of environment, safety and health programs, effective self-monitoring programs to evaluate site hazards, and effective management of hazards such as carbon, greenhouse gases (GHG), water, effluent and waste etc. Environmental and safety audits are performed based on safety standards such as ISO 14001, ISO 14064 and other GHG guidelines.

Management Review: This element requires that the HSE Management System is reviewed periodically by senior management to ensure that it continues to be effective and to identify changes for continuous performance improvement.

The company's senior management should, at appropriate intervals, review the HSEMS and its performance, to ensure its continuing suitability and effectiveness. The review should specifically, but not exclusively, address:

- The possible need for changes to the policy and objectives, in the light of changing circumstances and the commitment to strive for continual improvement.
- Resource allocation for HSEMS implementation and maintenance.
- Sites and/or situations on the basis of evaluated hazards and risks, and emergency planning

The review process should be documented, and its results recorded, to facilitate implementation of consequent changes. Reviews should be used to reinforce continuous efforts to improve HSE performance.

8.1 *HSE Best Practices in Petroleum Operations: Guidelines for Conducting Petroleum Activities/Operations to Minimize the Risk of Environmental Damage*

8.1.1 Definition and Discussions

Oil and gas exploration and production operations have the potential for a variety of impacts on the environment. These 'impacts' depend upon the stage of the process, the size and complexity of the project, the nature and sensitivity of the surrounding environment and the effectiveness of planning, pollution prevention, mitigation and control techniques.

The purpose of this section is as follows,

- to provide an overview of environmental issues in the oil and gas exploration and production industry, and of the best approaches to achieving high environmental performance.

- to provide ready reference of various requirements related to environmental management in relation to current regulatory requirements as well as various best practices.

Definitions :

- **Petroleum Activities/Operations:** In this context, petroleum activities/operations are defined as all upstream oil and gas exploration and development activities from seismic activities through field development and production to field abandonment and restoration activities.
- **Company:** An organisation engaged, as principal or contractor, directly or indirectly, in the exploration for and production of oil and/or gas. For bodies or establishments with more than one site, a single site may be defined as a company.
- **Environment:** The environment is defined here to include aquatic (water), atmospheric (air), terrestrial (land), ecosystems, and the inter-relationship which exists among and between water, air and land, and human beings, other living creatures, plants, micro-organism and property.
- **Environmental Pollutant:** Environmental pollutant means any solid, liquid or gaseous substance present in such concentration that is capable of damaging the environment. Also, noise is included as a potential pollutant to the environment.
- **Environmental Damage:** Environmental damage is defined as the presence in the environment of an environmental pollutant in concentrations/levels above and beyond the minimum acceptable safe standards.
- **Environmental Protection:** Environmental protection is defined as practices adopted for the purpose of mitigating the introduction of pollutants into the environment.

Environmental Impacts:

Petroleum operations have the potential for a variety of impacts on the environment. These impacts depend on the stage of the project, the size and complexity of the project, the nature and sensitivity of the surrounding environment and the effectiveness of planning, pollution prevention, mitigation, and control techniques. Most of these impacts could be harmful to the environment. However, with proper care and attention, the adverse effects could be avoided, minimized or mitigated. It is thus important that Contractors/Operators remain committed to the development of management systems, operational practices and engineering technology targeted at minimizing the adverse impact on the environment due to oil and gas activities and operations.

To that effect, best industry practices should be adopted during petroleum operations so as to minimize or mitigate adverse impacts on the environment. First the potential impacts are discussed for the purpose of awareness, then operational guidelines aimed at minimizing the negative impacts and enhancing the positive impacts are provided. These guidelines are based on best industry practices and recommendations as provided in multiple international publications including API's Recommended Practice 51R, technical publications by E&P Forum/UNEP, and multiple IFC publications (see references for details). The practices presented here are in agreement with various Acts and Rules previously adopted by the Indian Ministry of Environment, Forests and Climate

Change, other governing bodies related to HSE. The guidelines presented here do not replace the Acts and Rules, but rather supplement (see section below for an indicative list of the Acts and Rules). Companies engaging in petroleum operations should also refer to these documents so as to be compliant in their practices.

Petroleum operations can have the following impacts:

- Human, social, economic, and cultural impacts;
- Atmospheric impacts;
- Aquatic impacts;
- Terrestrial impacts;
- Biosphere impacts.

These are further outlined below.

- Human, Social, Economic and Cultural Impacts
    - Exploration and production operations can induce social, economic and cultural changes to the inhabitants in the environments in which the operations are occurring. The extent of these changes is especially important to local populations, particularly indigenous people who may have their traditional lifestyle affected indefinitely.
    - The key impacts may include changes in:
        - Land-use patterns such as agriculture, fishing, logging, hunting, as a direct consequence or as a secondary consequence by providing new access routes, leading to unplanned settlement and exploitation of natural resources;
        - Demography, change in local population levels as a result of immigration (labour force) and in-migration of a remote population due to increased access and opportunities;
        - Socio-economic systems due to new employment opportunities, income differentials, inflation, differences in per capita income, when different members of local groups benefit unevenly from induced changes;
        - Socio-cultural systems such as social structure, organization and cultural heritage, practices and beliefs, and secondary impacts such as effects on natural resources, rights of access, and change in value systems influenced by foreigners;
        - Availability of, and access to, goods and services such as housing, education, healthcare, water, fuel, electricity, sewage and waste disposal, and consumer goods brought into the region;

        - Planning strategies, where conflicts arise between development and protection, natural resource use, recreational use, tourism, and historical or cultural resources;
        - Aesthetics, because of unsightly or noisy facilities; and
        - Transportation systems, due to increased road, air and sea infrastructure and associated effects (e.g. noise, accident risk, increased maintenance requirements or change in existing services).
    - Some positive changes will probably result as well, particularly where proper consultation and partnership have developed. For example, improved infrastructure, water supply, sewerage and waste treatment, health care and education are likely to follow. However, the uneven distribution of benefits and impacts and the inability, especially of local leaders, to predict the consequences, may lead to unpredictable outcomes. With careful planning, consultation, management, accommodation and negotiation some, if not all, of the aspects can be influenced.

- Atmospheric Impacts
    - The primary sources of atmospheric emissions from oil and gas operations arise from:
        - Flaring, venting and purging gases;
        - Combustion processes such as diesel engines and gas turbines;
        - Fugitive gases from loading operations , waste dumps, landfills, tank age and losses from process equipment;
        - Airborne particulates from soil disturbance during construction and from vehicle traffic; and
        - Particulates from other burning sources, such as well testing.
    - The principal emission gases include carbon dioxide, carbon monoxide, methane, volatile organic carbons and nitrogen oxides. Emissions of sulfur dioxides and hydrogen sulphide can occur and depend upon the sulfur content of the hydrocarbon and diesel fuel, particularly when used as a power source. In some cases sulfur content can lead to odor near the facility.
    - Flaring of produced gas is the most significant source of air emissions, particularly where there is no infrastructure or market available for the gas. However, where viable, gas should be processed and distributed as an important commodity. Thus, through integrated development and providing markets for all products, the need for flaring will be greatly reduced. Flaring may also occur on occasions as a safety measure, during start-up, maintenance or upset in the normal processing operation.

    - Flaring, venting and combustion are the primary sources of carbon dioxide emissions from production operations, but other gases should also be considered (See also section 6.156.15).

- Aquatic Impacts
    - Resource depletion due to intake of water for entire life cycle of the E & P operation
    - The principal aqueous waste streams resulting from exploration and production operations are:
        - Produced water;
        - Drilling fluids, cuttings and well treatment chemicals;
        - Process, wash and drainage water;
        - Sewerage, sanitary and domestic wastes;
        - Spills and leakage;
        - Cooling water.
    - The volumes of liquid waste produced depend on the stage of the exploration and production process. During seismic operations, waste volumes are minimal and relate mainly to camp or vessel activities. In exploratory and appraisal drilling the main aqueous effluents are drilling fluids and cuttings, whilst in production operations—after the development wells are completed—the primary effluent is produced water (See also section 6.16).
    - The high pH and salt content of certain drilling fluids and cuttings pose a potential impact to fresh-water sources. Produced water is the largest volume aqueous waste arising from production operations, and some typical constituents may include in varying amounts inorganic salts, heavy metals, solids, production chemicals, hydrocarbons, benzene, PAHs, and on occasions, naturally occurring radioactive material (NORM).
    - Hydrofracturing and polymer flooding are high potential water polluting operations. Unless reused it has potential risk of contamination and resource depletion

- Terrestrial Impacts
    - Potential terrestrial impacts arise from the following basic sources:
        - Physical disturbance as a result of construction (access roads, camps, facilities, etc.);
        - Contamination resulting from spillage and leakage of oil, chemicals or unregulated solid waste disposal; and
        - Indirect impact arising from opening access and social change.

- Potential impacts that may result from poor design and construction include soil erosion due to soil structure, slope or rainfall. Left undisturbed and vegetated, soils will maintain their integrity, but, once vegetation is removed and soil is exposed, soil erosion may result. Alterations to soil conditions may result in widespread secondary impacts such as changes in surface hydrology and drainage patterns, increased siltation and habitat damage, reducing the capacity of the environment to support vegetation and wildlife.

- In addition to causing soil erosion and altered hydrology, the removal of vegetation may also lead to secondary ecological problems, particularly in situations where many of the nutrients in an area is held in vegetation (such as tropical rainforests); or where the few trees present are vital for wildlife browsing (e.g. tree savannah); or in areas where natural recovery is very slow (e.g. Arctic and desert ecosystems). Clearing by operators may stimulate further removal of vegetation by the local population surrounding a development.

- Soil contamination may arise from un-regulated discharge of effluents and garbage particularly during project stage, spills and leakage of chemicals and oil, causing possible impact to both flora and fauna. Simple preventative techniques such as segregated and contained drainage systems for process areas incorporating sumps and oil traps, leak minimization and drip pans, should be incorporated into facility design and maintenance procedures. Such techniques will effectively remove any potential impact arising from small spills and leakage on site.

- Biosphere impacts

  - Plant and animal communities may also be directly affected by changes in their environment through variations in water, air and soil/sediment quality and through disturbance by noise, extraneous light and changes in vegetation cover. Such changes may directly affect the ecology and biodiversity: for example, habitat, food and nutrient supplies, breeding areas, migration routes, vulnerability to predators or changes in herbivore grazing patterns, which may then have a secondary effect on predators.

  - Soil disturbance and removal of vegetation and secondary effects such as erosion and siltation may have an impact on ecological integrity, and may lead to indirect effects by upsetting nutrient balances and microbial activity in the soil. If not properly controlled, a potential long-term effect is loss of habitat which affects both fauna and flora, and may induce changes in species composition and primary production cycles.

Environmental Management Program

Given that oil and gas operations (from exploration to decommissioning) can have a significant and long lasting impact on the environment and the community, positive steps are needed to protect the environment and the local communities. As such, a comprehensive Environmental Management Program should be developed prior to initiating operations. As part of the management program, an environmental and social impact assessment should be completed prior to starting any project.

The results from the assessment are to be incorporated into the design, execution, operating and decommissioning stages of the project.

The Environmental Management Program should clearly stipulate the Contractor's/Operator's commitment to safeguarding the environment and social integrity. Based on the results from specific project assessments, the Contractor/Operator will state clearly how it intends to meet all the environmental and social issues/challenges that have been identified.

The Environmental Management Program should assure that the following activities are taken into consideration and checked off before embarking on any project:

- An environmental baseline is established prior to project activities;
- Key environmental issues are identified early enough before the start of project activities;
- The community and other stakeholders related to the project are fully informed of the project and any potential impact to the environment and/or to the community is intimated to all parties;
- Relevant environmental and social issues are taken into account during project design and implementation, in a way that eliminates or minimizes any negative impact;
- Corrective plans and the commitment to apply such plans are fully documented prior to the start of project activities.
- Regular monitoring and checking is ensured during implementation of the project to ensure effectiveness of plans.

Furthermore, the Environmental Management Program should cover the following areas:

- Regulatory requirements;
- Leadership commitment, awareness and accountability;
- Risk assessment and management;
- Employee training;
- Roles and responsibilities of all parties;
- Working with contractors/subcontractors and others;
- Facilities design and construction;
- Operations and maintenance;
- Management of change to project plans;
- Community and stakeholder awareness;
- Emergency management;

- Incidents analysis and prevention;
- Reporting and documentation of incidents;
- Assessments and improvements;
- Verification and monitoring to ensure compliance.

The Environmental Management program should also comply with the Acts and Rules issued by the relevant statuary bodies in India and should address all potential environmental risks associated with oil and gas operations. These risks include, but are not limited to:

- Terrestrial impact and project footprints;
- Noise generation;
- Waste water management;
- Land/Soil degradation;
- Solid waste management (including used batteries, biomedical and e-Wastes);
- Hazardous waste and chemicals management;
- Ecological risk management;
- Loss of green belt and biodiversity;
- Oil spills management;
- Air emissions;
- Greenhouse gas emissions;
- NORM;
- Asbestos Management (particularly from gaskets and roof sheets);
- Well blowouts.

8.1.2 Best Practices

Best industry practices should be adopted during petroleum operations so as to minimize or mitigate adverse impacts on the environment. The guidelines presented here do not replace the Acts and Rules currently in operation in India, but rather supplement. See section 8.1.3 for a list of related Acts and Rules. Companies engaging in petroleum operations should also refer to these documents so as to be compliant in their practices. Companies engaging in petroleum operations shall first conduct a detailed environmental and social impact assessment (ESIA) with appropriate mitigating measures and get it approved from regulatory authorities prior to starting any operations.

- General Considerations for Site Selection, Access Roads, Construction of Facilities for All Petroleum Activities

    - Conduct a detailed environmental and social impact assessment of planned petroleum activities on the environment prior to any operations. Use the environmental assessment to identify protected areas and sensitive areas. Consult with local authorities and other stakeholders for preferences regarding site selection, access roads and construction of facilities.

    - Choose sites to minimize impacts on water resources, conservation interests, settlement, agriculture, sites of historical and archaeological interest and landscape. Consider using sites that have been cleared/disturbed previously or of low ecological value, or which may be more easily restored, . Choose sites to encourage natural rehabilitation by indigenous flora.

    - Avoid or minimize road construction, minimize clearing and disturbance, minimize footprint, use existing infrastructure if available. Do not cut down trees of a diameter greater than local regulations permit.

    - Minimize the size of camps/facilities consistent with operational, health and safety requirements.

    - Incorporate drainage and minimize disturbance to natural drainage patterns. Engineer slopes and drainage to minimize erosion. Design for storm conditions to ensure offsite natural runoff does not wash over site.

    - Take account of topography, natural drainage and site runoff. Ensure adequate and proper drainage.

    - Create awareness and train the crew particularly security staff to behave sensibly to uphold the laws, policies and procedures that protect the rights of indigenous people and others.

- Seismic Exploration Activities

    - Review environmental and social conditions– (Environmental Impact Assessment Notification-2006 and subsequent amendments).

    - Assess potential noise pollution from seismic activities – {Noise Pollution (Regulation and Control) Rules, 2000, The Wildlife (Protection) Act 1972 amended in 1993 and The Wild Life (Protection) Amendment Act, 2002.}.

    - Monitor noise and other environmental impact from operations such as line clearing and vibrator or dynamite explosions (onshore) and air gun and streamer towing (offshore) on wildlife and marine life.

    - Adopt best industry practices during operations for health and safety of seismic survey personnel (See also section 8.2).

- Educate workforce on environmental concerns.
- Formulate contingency plans for minimizing the impact of operations on wildlife, migratory birds and surrounding community– such as shutting down operations during certain periods of high activity in the community or by indigenous wildlife.
- Specifically, adopt the following operating guidelines during seismic operations:
  - Schedule operations during least sensitive periods, avoiding migration, nesting and mating seasons.
  - Shot-hole methods should be considered in the place of vibroseis machinery where vegetation cover is required and where access is a concern. Ensure that the charge is small enough and deep enough to avoid cratering. Consider aquifer protection and suitable plugging. Use offsets to avoid specific sensitivities. Ensure that misfired charges are disabled and removed. Mobilize clean-up crews after operations.
  - If using vibroseis machinery on soft ground, avoid excessive compaction from vehicles and base plate.
  - Ensure appropriate handling and storage of fuels and hazardous materials (e.g., explosives).
  - Preferably, cut seismic lines by hand to minimize disturbance.
  - Minimize the width of corridors to ensure compatibility with operational, health and safety requirements.
  - Do not cut trees that are larger in diameter than local regulations permit. Use equipment that can accomplish the required seismic activity with minimal impact to the environment.
  - Consult local authorities and other stakeholders regarding preferred locations for base camps and access.
  - Select site to minimize impact on the environment and local communities.
  - Avoid or minimize road construction, minimize clearing and disturbance of vegetation, minimize footprints, use existing infrastructure, use existing access if available. Minimize developing new access.
  - Minimize size of camps and/or facilities consistent with operational, health and safety requirements.
  - Take account of topography, natural drainage and site runoff. Ensure adequate and proper drainage.
  - Use helicopters within safety limits where minimization of ground transport is required (e.g. access, clearing, etc.).

- Construct helipads to minimize disturbance consistent with operational, health and safety requirements.
- Control access to sites and facilities. Control workforce activities e.g. hunting, interaction with local population, etc. Allow only authorized employees to access sites.
- Minimize waste, control waste disposal (solids, sewerage).
- Prepare and maintain contingency plans for spills, fires, and other potential hazards.
- Minimize extraneous noise and light sources, and their impact on the environment and local communities. Keep noise levels below national /international specifications(See also section 8.2.2 for noise management).

o Additionally, for offshore operations:

- Plan seismic surveys and offshore construction activities so as to avoid sensitive times of the year.
- Identify sensitive areas for marine life, such as feeding, breeding, calving, and spawning grounds. Minimize impact of operations on sensitive areas.
- Identify fishing areas and reduce disturbances by scheduling seismic surveys and construction activities for less productive times of the year, where possible.
- Use local expertise to support operations e.g. spotting marine mammals, wildlife, etc.
- Maximize the efficiency of seismic surveys so as to reduce operation times, where possible.
- If sensitive species are anticipated in the area, monitor their presence using experienced observers before the onset of sound-creating activities that have the potential to produce adverse effects, and continue monitoring throughout the seismic program or construction.
- When marine mammals are observed congregating close to the area of planned activities, seismic start-up or construction should begin at least 500 meters away.
- If marine mammals are sighted within 500 meters of the proposed seismic array or construction area, postpone start-up of seismic activities or construction until they have moved away, allowing adequate time after the last sighting.
- Crew should be trained for fauna observations (e.g. marine mammal and turtle identification) and environmental sensitivities, and to look out for potential collision risks ahead when sailing to and from the project site. A

record of all sighting would be kept and reported as part of the environmental monitoring of the project.

- Use soft-start procedures—also called ramp-up or slow buildup—in areas of known marine mammal activity. This involves a gradual increase in sound pressure to full operational levels.
- Use the lowest practicable power levels to image the target surface throughout the seismic surveys and document their use.
- Where possible, use methods to reduce and/or baffle unnecessary high-frequency noise produced by air guns or other acoustic energy sources.
- For pile driving, use vibratory hammers, air bubble curtains (confined or unconfined), temporary noise attenuation piles, air filled fabric barriers, and isolated piles or coffer dams, where practical.
- Dispose all waste materials and oily water properly to meet local, national and international regulations. See Annex IV and Annex V of MARPOL 73/78.
- Apply proper procedures for handling and maintenance of cable equipment and particularly cable oil.
- All towed equipment must be highly visible and labelled. Make adequate allowance for deviation of towed equipment when turning.
- Prepare contingency plans for lost equipment and oil spillage. Attach active acoustic location devices to auxiliary equipment to aid location and recovery.
- Remain on planned survey track to avoid unnecessary interactions.

- Exploration and Appraisal Drilling Activities
  - Review environmental and social conditions– (Environmental Impact Assessment Notification-2006 and subsequent amendments).
  - Assess impact of the drilling infrastructure on the environment- roads, basecamp and drilling pad (onshore) {The Wildlife (Protection) Act 1972 amended in 1993 and The Wild Life (Protection) Amendment Act, 2002 and The Forest (Conservation) Act 1980, amended 1988}and drillship or jack up placement and activity of supply boat and barges (offshore) {The Coastal Regulation Zone Notification 2011 and subsequent amendments and The Merchant Shipping (Amendment) Act, 2003}.
  - Assess impact of drilling operations on the environment- disposal or containing of garbage, sewage, drilling fluid and cuttings{The Water (Prevention and Control of Pollution) Act, 1974, amended 1998 and The Water (Prevention and Control of Pollution) Cess Act, 1977 amended 1992 and The Water(Prevention and Control of

Pollution) Cess (Amendment) Act, 2003, MSIHC, HW-2008, MSW, PLI, electronic waste, biomedical etc}.

- Monitor operations to minimize impact on wildlife and local population, also monitor garbage collection, sewage treatment, drilling fluid and cuttings to assure compliance with existing guidelines.

- During operations, practice best industry practices for health and safety of rig personnel (see Section 8.2).

- Develop contingency plan for drilling accidents, such as H_2S gas releases, blowouts, oil spills and fires. Ensure that the equipment needed for controlling the incident is available and in good working order. Practice drills for readiness. Have alarms installed and tested for warning of various drilling accidents.

- Specifically, adopt the following operating guidelines during drilling activities:

    - For site preparation:

        - All aspects of site preparation presented in "General Considerations for Site Selection, Access Roads, Construction of Facilities for All Petroleum Activities" discussed above are applicable here. See also section 6.17 of this report for additional practices related to the reduction of footprints during drilling operations.

        - Select least sensitive location within confines of bottom target/drilling envelope. Consider directional drilling to access targets beneath sensitive areas.

        - Select drilling sites to minimize impacts on water resources, conservation interests, settlement, agriculture, sites of historical and archaeological interest and landscape. Consider using sites that have been cleared/disturbed previously or of low ecological value, or which may be more easily restored, e.g. agricultural land.

        - Consult local authorities and other stakeholders regarding preferred location for drilling sites, camps and access. Maximize use of existing infrastructure. Maximize use of existing access/roads.

        - Consider cluster drilling to minimize footprint.

        - Protect groundwater from drill stem penetration and shallow aquifers from possible site contamination. Where water courses and aquifers are deemed sensitive, consider a fully sealed site. Avoid use of mud pits, preferentially use steel tanks, but if mud pits are used they must be lined.

        - GSR 546(E) of 2005 as issued by MoEF & CC, New Delhi is to be followed w.r.t. disposal of Solid Waste, Drill Cutting and Drilling Fluids for Offshore and Onshore Drilling Operation.

- Adequate and Proper health and sanitation facilities should be available at drill site and base Camp.
- Use water based mud as practicably possible and mud chemicals should contain heavy metals below prescribed limits.
- Water to be used for drilling operation should be reused/recycled to the extent possible, the maximum fresh water consumption for exploratory drilling to be limited and accordingly waste water recycling pit should be designed.

- For operations:
  - Develop contingency plans for managing oil spills, well blowouts, and other emergencies before starting operations.
  - Develop plans for managing hazardous wastes, solid wastes, waste water, and other wastes before starting operations. Ensure that extraordinary drilling waste management measures that meet international best practices for drilling in sensitive environments (if appropriate) are included in the design.
  - Use water based mud as practicably possible and mud chemicals should contain heavy metals below prescribed limits.
  - Hazardous materials usage, storage and disposal requirements must meet planning requirements and local regulations.
  - Train personnel in proper waste management, with particular focus on waste segregation, prohibition of waste dumping, and handling and storage of hazardous wastes.
  - Apply special care when transporting/delivering hazardous materials. Delivery should be supervised at all times. Tanks and containers should be properly labelled with the nature and volume of their contents. Clearly define and identify delivery and material storage areas.
  - Ensure hazardous materials storage areas are properly segregated, properly enclosed, have impermeable floors, have adequate ventilation, and are properly covered to prevent rainfall from entering.
  - Ensure hazardous materials containers are compatible with the hazardous substance they are holding, resistant to corrosion, maintained in a good condition, securely closed, and labelled.
  - Provide specialized training and appropriate PPEs to workers who are required to handle hazardous materials.

- Maintain a complete list of chemicals, including type, quantity and proposals for transport, storage, handling, use and disposal; register them with appropriate local authorities and obtain appropriate permits for management of the chemicals.

- Water supply – Carefully consider water supply sources (ground water, surface or marine). In areas of water shortage consider water separation/recycling package in mud system. If marine sources are used care must be taken with regard to disposal.

- GSR 546(E) of 2005 as issued by MoEF & CC, New Delhi is to be followed w.r.t. disposal of Solid Waste, Drill Cutting and Drilling Fluids for Offshore and Onshore Drilling Operation.

- Waste water– Exploration sites rarely incorporate sophisticated effluent treatment systems , therefore treat contaminated water as liquid waste. Any produced water from well test operations must be properly disposed of. Ensure disposal options are addressed in planning phase and requirements are met.

- Solid wastes –Where approved disposal sites are available and suitable these should be used for all offsite waste disposal. On-site disposal may be considered for inert materials. Ensure proper documentation and manifesting. Ensure adequate consultation with local authorities regarding nature, type and volumes of wastes arising and capability and capacity of local resources.

- In general, minimize waste generation, reuse/recycle waste materials when possible. Minimize the amount of waste that goes to landfill. Separate waste streams at source to aid reuse/recycling.

- Utilize local sewerage disposal facilities where available. For small, isolated sites, soak away/septic field system can be utilized, biodegradable solids may be buried, liquid discharges should be controlled to ensure that local water resources, both surface and ground water, are not contaminated.

- In isolated/remote areas, with no local disposal facilities, non-toxic waste may be buried at a depth of 1m or more during decommissioning. Ensure local water resources are not at risk from contamination.

- In isolated/remote areas, with no local disposal facilities, non-toxic dry and liquid wastes should be treated properly, giving due consideration to atmospheric effects. If necessary portable incinerators can be used to provide a cleaner burn.

- Preferentially use non-toxic water based mud. Minimize the use of synthetic oil based mud to where required for operational reasons.

Mud make-up and mud and cuttings disposal options must be addressed during the planning phase; ensure all regulatory requirements are met.

- In case of use of Oil based mud, specific permissions to be obtained from regulatory agency.

- Follow industry best practice and MSDS requirements for the storage, handling, use and disposal of the materials used in drilling mud. The requirements regarding hazardous materials management presented above could be applied here for drilling mud components that are hazardous.

- Drill cuttings and used-mud return pit should be properly lined with impermeable liner, which will form a barrier preventing the migration of materials into the surrounding soil. The integrity of the liner should be regularly checked to ensure there is no damage and the liner is still impermeable.

- Atmospheric emission/noise/light– Ensure requirements from the planning phase are met to minimize the effects from engine exhausts and extraneous noise and light. Ensure any H_2S problems are addressed. H_2S emissions must be effectively controlled. Ensure well test procedures are followed. Any burn pits utilized for well test operations must be lined. If possible produced oil should be stored for subsequent use.

- Use modern, energy-efficient machinery and equipment, both for civil engineering / preparation works, for the drilling campaign and on-board vessels, operated to manufacturer's standards.

- Use machinery and equipment with appropriate combustion control technologies (e.g. as available and applicable to the equipment used, injection timing retard, pre-ignition chamber combustion, air-to-fuel ratio adjustments, derating, selective catalytic reduction, etc.) in order to optimize combustion and minimize emissions of combustion by-products (NOx, CO, un-burnt hydrocarbons)

- Ensure machinery is turned off when not in use. Check machinery periodically to ensure efficient control of emissions. Monitor emissions regularly.

- Do not use ODS that is banned or being phased-out.

- Carry out frequent servicing and maintenance, including checking for leaks, to maintain the equipment in good working order. All servicing and maintenance would be undertaken by qualified technicians using the correct equipment, including recovery systems to avoid venting of the ODS.

- Noise levels at the site boundary should meet local and/or company specified levels. Ensure all machinery and equipment are properly cladded.

- Light sources should be properly shaded and directed onto site area.

- Control workforce activities, e.g. hunting, interaction with local population, etc. Purchase food from recognized local suppliers, not directly from local people without evaluating implications. Workforce should keep within defined boundary and to the agreed access routes.

▪ Additionally, for offshore operations:

  - Consult with local authorities regarding site selection and support infrastructure—ports, vessel and air traffic.

  - Select the least sensitive location within the confines of bottom target/drilling envelope. Consider directional drilling to access targets beneath sensitive areas. Consider cluster well drilling.

  - In coastal areas, select site and equipment to minimize disturbance, noise, light and visual intrusion. Exercise strict control on access and all vessel and rig activity.

  - Consult with local authorities regarding emissions, discharges and solid waste disposal/notifications in regard to other resource users.

  - Aqueous discharges: Oily water from deck washing, drainage systems, bilges etc. should be treated prior to discharge to meet local, national (Merchant Shipping and CPCB) and international consents (See Annex IV of MARPOL 73/78).

  - Sewerage must be properly treated prior to discharge to meet local and international standards. Treatment must be adequate to prevent discoloration and visible floating matter (See Annex IV of MARPOL 73/78).

  - Produced water from well tests must meet local and national regulations/standards prior to discharge.

  - Preferentially separate and store oil from well test operations. If burnt, ensure burner efficiency is adequate to prevent oil fallout onto sea surface.

  - Biodegradable kitchen wastes require grinding prior to discharge, if permitted under local regulations.

  - Collect all domestic waste and compact for onshore disposal. Ensure proper documentation and manifesting. Ensure onshore receiving and disposal meet local requirements. Consider waste segregation at source for different waste types—organic, inorganic industrial wastes, etc.

- No debris or waste to be discarded overboard from rig or supply vessels. Waste containers must be closed to prevent loss overboard.
- Spent oils and lubes should be secured in containers and returned to shore for disposal as per the local regulation.
- Consider bulk supply of materials to minimize packaging wastes.
- Mud and cuttings– Preferentially use low toxicity water/synthetic oil -based drilling mud with LC50 value more than 30000 mg./l. Mud make-up and mud and cuttings disposal requirements addressed in the planning process must be met.
- To use Oil based mud, if essential for geo-formation, specific permissions to be obtained from regulatory agencies for its use.
- Most spills occur during transfer operations. Ensure adequate preventative measures are taken and that spill contingency plan is in place.
- Ensure proper control documentation and manifesting and disposal. Do not dispose of waste chemicals overboard.
- Emission– Ensure air emissions generated by the project meet 'Regulations on Air Pollutants Emitted by Stationary Sources' as applicable and MARPOL 73/78 Annex VI discharge conditions for NOx and SO_2 for vessels.
- Assess treatment of waste gases and emission limits, particularly where gas flaring is necessary. Avoid gas venting. See also Section 6.15 of this report for additional practices related to gas flaring and venting. Avoid the uncontrolled release on greenhouse gases (CHG) into the atmosphere.

- Field Development and Production Activities
    - Review environmental and social conditions– (Environmental Impact Assessment Notification-2006 and subsequent amendments).
    - Assess impact of long term drilling operations on the environment- disposal or containing of garbage, sewage, drilling fluid and cuttings{The Water (Prevention and Control of Pollution) Act, 1974, amended 1998 and The Water (Prevention and Control of Pollution) Cess Act, 1977 amended 1992 and The Water(Prevention and Control of Pollution) Cess (Amendment) Act, 2003}.

- Assess impact of field development activities (additional infrastructure, production facilities, separation facilities, storage facilities) on the environment- additional access roads, facilities and drilling platforms {The Indian Wildlife (Protection) Act 1972 amended in 1993 and The Wild Life (Protection) Amendment Act, 2002 and Forest (Conservation) Act 1980, amended 1988}and drillship or jack up placement and activity of supply boat and barges (offshore) {Coastal Regulation Zone Notification 2011 and subsequent amendments and The Merchant Shipping (Amendment) Act, 2003}.

- Monitor operations to minimize impact on wildlife and local population, also monitor garbage collection, sewage treatment, drilling fluid and cuttings to assure compliance with existing guidelines and local regulations.

- Practice best industry practices during operations for health and safety of personnel.

- Develop contingency plan for drilling accidents, such as H_2S gas, blowouts, oil spills and fire. Ensure that equipment needed for controlling the above is available and in good working order. Practice drills for readiness. Have alarms installed and tested for warning of various drilling accidents.

- Adopt the following operating guidelines:

    - For site preparation:

        - Apply all aspects of site preparation presented under "Exploration and Appraisal Drilling Activities".

        - Design and construct production facilities for long term use. Incorporate the impact of long term access and activities , including the use of vehicles, boats, helicopters, etc, on the environment and the local population.

        - Consider locating all facilities at single site to minimize footprint.

        - Consider maximizing use of satellite/cluster drilling sites, horizontal wells, and extended reach drilling in sensitive areas.

        - The alignment of pipelines should take into account potential impacts on the environment (terrestrial and/or aquatic).

    - For operations:

        - Contingency plans for managing oil spills, blowouts, other fires and explosions, and other emergencies must be developed and approved before operations commence. Personnel must be properly trained on the plans.

        - Assess implications of well treatment and workover, process, storage, power generation and other support and accommodation facilities in terms of long-term disturbance and impact.

- Assess implications of development on local infrastructure in particular water supply, power supply, waste disposal and socio-economic considerations—housing, education, welfare, medical, employment/economy, etc.

- Install proper waste treatment facilities, particularly if local infrastructure cannot support requirements. In particular, treatment of waste waters—wash water, well fluid, process water, drainage, sewage, produced water. Reinjection of produced water after adequate treatment is a preferred option (Also see section 6.16).

- Assess treatment of waste gases and emission limits, particularly where gas flaring is necessary. Avoid gas venting. See also section 6.15 of this report for additional practices related to gas flaring and venting. Avoid the uncontrolled release of GHG into the atmosphere.

- Prepare a detailed waste management plan. Solid wastes, particularly toxic and hazardous substances, will require full assessment in terms of treatment and disposal options. If local facilities unavailable, proper incineration facilities may be required and a full assessment of implications will be necessary. Monitor waste streams so as to ensure compliance. Ensure all wastes generated are managed in compliance with local laws.

- Provide contained storage areas for produced oil, chemicals and hazardous materials, including treatment of tank sledges.

- All waste management (water, solid, hazardous, etc.) requirements presented under "Exploration and Appraisal Drilling Activities" above are applicable here as well.

▪ Additionally for offshore operations:

- Evaluate implications of development on local infrastructure in particular, infrastructure related to onshore service functions—port and harbour operations, resource use conflicts, waste treatment and disposal, socio-economic implications, employment, local services and supply, support infrastructure for employee and family accommodation, etc.

- Incorporate oily water treatment system for both produced water and contaminated water treatment to meet local, national and international discharge limits (Annex IV of MARPOL 73/78).

- Ensure all wastes generated are managed in compliance with local laws and MARPOL 73/78 Annex V for waste generated on-board vessels.

  - Include sewerage treatment system, particularly if close to shore, to meet local requirements.

  - Treatment and disposal of solid, toxic and hazardous wastes onshore will require proper planning, particularly if local infrastructure is limited in capacity and capability. A detailed waste management plan that complies with local laws will be required.

- Abandonment and Site Restoration

  - Develop and implement a detailed plan for abandonment and restoration of the site. The detailed plan will include the methods to be followed , the operations to carry out, etc.

  - A detail EMP is to be prepared based on approved decommissioning/abandonment plan to minimize the environmental impact on the surrounding.

  - Guidelines being developed by MoP&NG are to be followed for abandonment and site restoration of onland and offshore oil and gas fields.

8.1.3 References

1. Environmental, Health and Safety General Guidelines. International Finance Corporation, World Bank Group. 2007.

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3. Environmental, Health and Safety Guidelines for Onshore Oil and Gas Development. International Finance Corporation, World Bank Group. 2007.

4. Guidelines for Offshore Oil Spill Response Plans; API Technical Report 1145, 2013.

5. MoEF&CC (http://www.envfor.nic.in/).

6. Environmental Management in Oil and Gas Exploration and Production; Joint E&P Forum/UNEP Technical Publication.

7. Annex IV of MARPOL 73/78 Regulations for the Prevention of Pollution by Sewage from Ships.

8. Annex V of MARPOL 73/78 Regulations for the Prevention of Pollution by Garbage from Ships.

9. Annex VI of MARPOL 73/78 Regulations for the Prevention of Air Pollution from Ships.

10. Field Guide to Environmental Compliance, Oil and Gas Production Facility Checklists, *US EPA Archived Document*.

INDICATIVE LIST OF ACTS AND RULES RELATED TO HEALTH, SAFETY AND ENVIRONMENT IN INDIA

11. The Environment Protection Act, 1986 and subsequent amendments.
12. The Wildlife (Protection) Act 1972 amended in 1993 and The Wild Life (Protection) Amendment Act, 2002.
13. Forest (Conservation) Act 1980, amended 1988.
14. Coastal Regulation Zone Notification 2011 and subsequent amendments.
15. Biological Diversity Act, 2002.
16. Environmental Impact Assessment Notification-2006 and subsequent amendments.
17. The Water (Prevention and Control of Pollution) Act, 1974, amended 1998.
18. The Water (Prevention and Control of Pollution) Cess Act, 1977 amended 1992 and The Water(Prevention and Control of Pollution) Cess (Amendment) Act, 2003.
19. The Air (Prevention and Control of Pollution) Act, 1981 amended 1987.
20. Bio- Medical Waste (Management and Handling) Rules, 1988.
21. The Public Liability Insurance Act, 1991, amended 1992 and The Public Liability Insurance Rules, 1991,amended 1993.
22. Chemical accidents (Emergency Planning, Preparedness and Response) Rules, 1996 and Subsequent amendments.
23. Noise Pollution (Regulation and Control) Rules, 2000.
24. The Batteries (Management and Handling) Rules, 2001 and subsequent amendments.
25. The Merchant Shipping (Amendment) Act, 2003.
26. The Motor Vehicle Act, 1988.
27. The Factories Act, 1948.
28. The Hazardous Waste (Management, Handling and Tran boundary Movement) Rules, 2008.
29. National Oil Spill Disaster Contingency Plan (NOS-DCP) and Preparedness.
30. Petroleum and Natural Gas (Safety in Offshore Operations) Rules 2008.
31. Mines Act 1952 and its amendments.
32. Oil Mines regulation 2011.
33. All other applicable OISD standards.

8.2 *HSE Best Practices in Petroleum Operations: Guidelines for Conducting Petroleum Activities/Operations to Maximize Health and Safety*

8.2.1 Definitions and Discussion

Petroleum operations can have adverse effects on the safety and health of employees and the population. As such, sufficient steps are required to protect the safety and health of the people. The occupational health and safety hazards associated with petroleum operations can be categorized as workplace safety and injury hazards, workplace health and illness hazards, and community health and safety hazards.

Oil and gas exploration and production operations include hazardous activities and have the potential for a variety of risk exposures and consequences on safety, asset integrity and occupational health. These 'risks and potential consequences' depend upon the stage of the process, the size and complexity of the project, and the effectiveness of planning, pollution prevention, mitigation and control techniques.

The purpose of this section is as follows,

- to provide an overview of safety and occupational health issues in the oil and gas exploration and production industry, and of the best approaches to achieving high safety and occupational health performance.
- to provide ready reference of various requirements related to safety and occupational health management in relation to current regulatory requirements as well as various best practices

Definitions

Occupational Health (OH): Occupational Health is a multifaceted activity concerned with the prevention of ill health and improving the work environment. Its main aim is to prevent, rather than cure, ill health from wherever it may arise in the workplace.

Occupational Illness: Any abnormal condition or disorder, other than one resulting from occupational injury, caused mainly or aggravated by exposure to factors associated with employment. It includes acute and chronic illnesses or diseases that may be caused by inhalation, absorption, ingestion or direct contact.

Occupational Hazard: Any article, substance or situation at the workplace that has the potential to cause harm. A hazard is defined as 'something with the potential to cause harm' and a health hazard is something with the potential to adversely affect an individual's health.

The difference between safety hazards and health hazards is that safety hazards have the potential to cause sudden injury, whereas health hazards have the potential to cause latent occupational illness, varying degrees of disability and death.

Occupational Health

Health Risk Assessment:

A full Health Risk Assessment (HRA) for each activity identified as a significant risk shall be completed. HRAs shall be documented and available as a functioning tool. HRA process shall be subjected to periodic audit, to maintain the quality and value of the process. The following hazards shall be managed in line with recognised good practice:

- Domestic/potable water
- Food safety
- Benzene
- Exposure to chemical and biological agents
- Fatigue
- Stress
- Ergonomics

Health risk assessment shall be reviewed whenever there are significant changes and on a regular basis in order to capture changes that have not been otherwise noticed.

Health Surveillance:

Health surveillance programs shall be put in place in line with findings as indicated by the health risk assessment. Health surveillance involves specifically examining individuals, in order to determine if work exposure to health hazards is having a deleterious effect upon their health. The results may be used in direct management of an individual's exposure, but may also be useful as aggregated, or collective, anonymous data to indicate if risk exposure control measures are working (i.e. as part of the health risk assessment feedback loop.) The Health Surveillance Program shall be reviewed on a continuous basis to ensure this is effective and helps achieve the following:

- Allow detection of harmful effects at an early stage – protecting employees
- Give assurance that employees can safely continue with their work without causing themselves harm (at least from the specific risk addressed)
- Provide monitoring to ensure that control measures are working
- Occasionally, provide data to detect and evaluate new health risks
- Provide an opportunity to instruct and train employees in health risk management.

The key features and requirements of Health Surveillance (HS) programs are as follows,

- The surveillance can range from simple questionnaires to invasive blood tests. Depending on the need as an outcome from HRA, the HS method can include simple questionnaire, simple examination, physiological tests, biological monitoring, biological effect monitoring, clinical examination etc. as appropriate.
- The Health Surveillance will be conducted by a competent person. Health surveillance shall be performed only when appropriate.
- Health surveillance shall be performed at the correct frequency.

- Industrial hygiene surveys shall form part of the surveys that shall help determine physical, chemical and biological exposures to all personnel working at sites. The inputs from these surveys will feed into the HRAs that would also be conducted on a periodic basis.

Health Surveillance activities shall either be carried out as part of the annual health assessments, or as special campaigns. e.g. Health Surveillance activities carried out can include following on a risk-based approach:

- Vision screening;
- Audiometry;
- Blood pressure measurements;
- Lung function tests;
- ECG;
- Cholesterol/blood glucose quick tests;
- Urine tests;
- Blood analysis;
- Stress test.

Conduct Health Surveillance according to agreed Clinical Standards to ensure a consistent level of screening, with clear fitness criteria.

Fitness for Work:

A medical assessment is an evaluation of the state of health of an individual, with particular reference to his/her fitness for work. It is a proactive measure and helps identifying individuals who may need greater protection. The scope and periodicity of assessments will largely depend on the type of employment undertaken.

The fitness standards for offshore employment require high standards of fitness to account for the assigned roles and responsibilities known in offshore circumstances. High standards of fitness are also necessary where public safety may be factor.

Types of medical assessments:

- Pre -employment medical assessment
- Routine medical assessment both for onshore and offshore personnel
- Special risk groups medical assessment (e.g. staff handling benzene)
- Assessment after work accident, maternity leave and long term illness
- Travel health assessment

Sickness Absence Management:

Sickness Absence Management process shall be put in place to ensure that individuals suffering illness that causes absence or impairment of work ability are treated in a fair, reasonable and consistent manner and are given appropriate support to return to meaningful work. Sickness absence shall be recorded by medical category and duration. Sickness absence levels shall be recorded including the number of sickness spells and days, as well as the number of cases of absence of more than 28 days.

Medical Emergency Response:

A Medical Emergency Response Plan (MERP) shall be developed and maintained, which can be integrated into a more general Emergency Response Plan, without compromising with effectiveness of communications. Periodic tests/drills shall be carried out, dependent on risk to test the potential medical emergency requirements and that shall include; major incident management with multiple casualties, specific hazard management and first aid procedures. For management of multiple casualties a Mass Casualty Response Plan (MCRP) shall be developed

First Aid Provision:

Suitable and sufficient first aid provision shall be made available in all areas of operation, including first aid trained employees, facilities and first aid kits. Designated competent first aiders shall be made available in line with likely risks and shall be maintained through periodic exercises and refresher training

Substance Misuse :

Offshore workers and other safety critical employees shall be tested for substance misuse at the same intervals as routine medicals. Comprehensive Alcohol & Substance Abuse Policy shall be implemented. Preparation and readiness shall be there at locations and installations to carry out post-incident (‘for cause’) substance abuse testing, and after considering unannounced testing programs if thought useful

Safety

Workplace Safety and Injury hazards include:

- Well blowouts
  - Uncontrolled flow of reservoir fluids into wellbore
  - Lack of, or ineffective blowout prevention mechanisms
- Fire and explosions (excluding well blowouts)
  - Presence of highly combustible hydrocarbons
  - Presence of oxygen and ignition source
- Motor vehicle/Transportation accidents and hazards
  - Narrow/poor roads to and from well sites

        - Unsafe driving
        - Fatigue due to long driving distances/hours and long working shifts
    - Other hazards/injuries
        - Slips, trips, and falls
        - Accidents due to machinery and other objects
        - Accidents due to falling objects
- Workplace Health and illness hazards include:
    - Chemical hazards
        - Toxic, corrosive, carcinogens, asphyxiates, irritants, etc.
    - Physical hazards
        - Noise, vibration, radiations, extreme weather conditions
    - Other hazards
        - Manual handling activities, repetitive motions, awkward postures
        - Over work, odd working hours, isolation, etc.
        - Working at height,
- Community Health and Safety hazards include:
    - Potential exposure to spills, fires, and explosions
    - Potential exposure to active or abandoned petroleum facilities including wells and pipelines, with potential for failure
    - Hazards associated with transport of hazardous materials
    - Potential exposure of members of the community to facility air emissions including H_2S
    - Security concerns

The above hazards do occur at various stages of petroleum operations including seismic survey and evaluation, exploration and appraisal drilling, development and production, and decommissioning.

To that effect:

- Contractors/Operators should maintain a comprehensive HSE protection management program that includes provisions for Occupational Health and Safety management (OHS) and Community Health and Safety (CHS) management.

- For any given project, the results from OHS and CHS assessments will be used for health and safety planning and management prior to and during all stages of the project.
- Contractors/Operators should maintain a Health and Safety manual that is available/accessible to all employees, contractors and sub-contractors. The manual should provide clear guidelines for conducting detailed health and safety assessments prior to initiating any project. Results from the assessment(s) should clearly document all assessed potentially hazardous activities, as well as mandatory safety protocols to be followed before and during these hazardous operations. The risk management plan should indicate clearly the necessary steps to follow in the case of an accident.
- Contractors/Operators should also be equipped with experienced onsite first aid responders and medical facilities either onsite or offsite with the appropriate training to handle emergencies related to company's hazardous operations.
- Based on the results from OHS and CHS assessments, the facilities and operations should be designed to eliminate or minimize the potential for injury and the risk of accidents.
- The health and safety planning and management should clearly demonstrate that sufficient controls have been implemented and effective to reduce risks. The controls should include a health and safety committee that provides regular training to staff, manages safety equipment, and ensures compliance of safety protocols during all phases of the project.
- A recommended OHS/CHS management program should include the following aspects:
    - Leadership commitment and awareness/responsibilities
    - Employee risk awareness and commitment
    - Employee responsibilities
    - Employee training
    - Emergency management
    - Incidents analysis and prevention
        - Monitoring and reporting of key indicators
        - Reporting and documentation of incidents
        - Monitoring and reporting of risky behaviors
    - Safety Culture and HSE maturity level

8.2.2 Best Practices

- For well blowout prevention
    - Complete proper well planning prior to drilling

- Maintain appropriate wellbore hydrostatic pressure by correctly estimating formation fluid pressures and strength of subsurface formations
- Maintain sufficiently high drilling fluid and completion fluid density to balance wellbore pressures
- Install and maintain a working blowout preventer with hydraulic accumulator. Blowout system should operate hydraulically, triggered automatically, and tested regularly
- Provide periodic training on well control
- Install and use emergency shutdown valves
- Perform well control drills regularly
- During production, inspect well head equipment regularly, monitor wellhead pressure regularly
- Maintain a blowout contingency plan
- Provide personal protective equipment (PPE) for dealing with blowouts

- For fire and explosions
  - Design and construct production facilities to meet national, international standards including safeguards to reduce hazards associated with the storage, handling, and use of flammable and combustible liquids. Mitigate/prevent the release of flammable material and gases
  - Implement systems for early detection and interruption of leaks of flammable material and gases
  - Separate potential ignition sources from flammable materials
  - Separate oil and gas processing facilities from other buildings. See US NFPA Code 30. Provide protection for living areas and other safe areas. Maintain safe distance between facilities and living quarters
  - Classify facilities based on degree/level of hazardous material processed and/or stored and the likelihood of release of flammable gases and liquids. Use API RP 500/505 for classification.
  - Provide proper ventilation for facilities with flammable materials
  - Design facilities such that the spread of fire is minimized in the case of a fire and explosion
    - Design facilities to have passive fire protection measures including fire-rated walls, fire protection on load-bearing structures, fire-rated partitions

between rooms, load-bearing structures that can resist explosions, walls that can resist explosion.

  - Prevent potential electrical ignition sources by proper grounding of electrical outlets and the use of safe electrical installations
  - Maintain a combination of automatic and manual fire alarm systems that can be heard from across each facility
  - Implement safety procedures for loading and unloading of flammable products into transport systems including ships, rail and tanker trucks, vessels, etc. Safety procedures should include the use of fail-safe control valves and emergency shutdown equipment.
  - Maintain fire suppression systems, strategically located in safe areas (protected from fire) within each facility. Fire suppression systems include foam suppression systems, water suppression systems, CO_2 extinguishing systems, portable fire extinguishers and specialized vehicles. The system maintained should be based on a fire impact assessment. Check and maintain the fire-fighting equipment regularly.
  - Maintain a working fire response plan
  - Provide regular training on fire safety and response including the use of fire suppression systems
  - Provide personal protective equipment (PPE) for dealing with fire and explosions

- For transportation accidents/hazards (land and air)
  - Maintain a road safety management plan for the facility during operations
  - Train all drivers in safe and defensive driving methods
  - Train all drivers on the safe transportation of passengers (Journey Management Plan)
  - Implement and enforce speed limits
  - Keep vehicles in road worthy conditions
  - Equip vehicles with safety equipment and first aid equipment
  - Develop and maintain safety procedures for air transportation using helicopters
  - Air transportation procedures should follow international civil aviation requirements

- For transportation accidents/hazards (offshore ship collision)
  - Offshore facilities should be equipped with navigational aids that meet national and international requirements. Navigational aids include radar and lights on facility structures and, where appropriate, on support vessels. A 500-meter radius facility

safety zone, at a minimum, should be implemented around offshore facilities. The facility should monitor and communicate with vessels approaching the facility to reduce the risk of vessel collision. Risk from passing out vessel should also be ascertained.

- The relevant maritime, port, or shipping authority should be notified of all permanent offshore facilities, as well as safety zones and routine shipping routes to be used by project-related vessels. Permanent facility locations should be marked on nautical charts. Maritime authorities should be notified of the schedule and location of activities when there will be a significant increase in vessel movement, such as during facility installation, rig movements, and seismic surveys.
- A subsea pipeline corridor safety zone (typically 1,000 meters wide) should be established to define anchoring exclusion zones and provide protection for fishing gear. In shallower waters with high shipping activity, consideration should be given to burying the pipeline below the seabed.

- For chemical hazards
    - Use chemical hazard assessment and risk management techniques to evaluate chemicals and their effects
    - Risk from nearby facilities to be ascertained
    - Test chemicals for environmental hazards; follow MSDS
    - Design facilities to reduce exposure of personnel to chemical substances, fuel, and products containing hazardous substances
    - Avoid using products classified as toxic, carcinogenic, allergenic, mutagenic, teratogenic, strongly corrosive, etc.
    - Select and use chemicals with least hazards and lowest adverse potential on health and on the environment
    - Avoid the use of ozone depleting chemicals/substances (ODS)
    - Maintain a Material Safety Data Sheet (MSDS) for all chemicals used
    - Provide personal protective equipment (PPE) for dealing with chemical hazards
- For air quality hazards
    - Equip facility with a reliable system for gas detection such that the source of release can be readily isolated and controlled
    - Use gas detection devices when accessing confined spaces
    - For the case of deadly gases including hydrogen sulphide

    - Develop and maintain a comprehensive hydrogen sulphide release contingency plan. Plan should include evacuation procedures and conditions for resumption of operations

    - Install monitors to activate warning signals whenever hydrogen sulphide levels exceed minimum acceptable levels. Locate and install monitors based on safety assessment.

    - Provide self-contained breathing apparatus and emergency oxygen supplies to be used in cases of emergency

    - Provide adequate ventilation to occupied buildings to prevent accumulation of hydrogen sulphide

    - Provide appropriate wind tracker (windsock) to know the prevailing wind direction to avoid toxic/flammable traps.

    - HC/CO detector should be installed

    - Methane hydrocarbon, non methane hydrocarbon and VOC should be monitored at appropriate locations

  - Provide regular training in the use of safety equipment. Provide training on response in the event of gas leakage. Provide personal protective equipment (PPE) for dealing with H_2S hazards.

- For physical hazards (noise, vibrations, extreme weather conditions)

  - Avoid exposing employees to a noise level greater than 85 dB(A) for more than 8 hours per day without hearing protection. No unprotected ear should be exposed to a peak sound level of more than 140 dB(C). The use of protective devises should be enforced for sound levels greater than stipulated here. Regularly measure noise levels and clearly identify, map and mark noisy equipment / areas.

  - Use modern machinery and equipment with low noise generation. Operate according to manufacturer's specifications.

  - Fit engine covers, silencers, mufflers and other forms of acoustic linings if possible, to noisy equipment

  - Conduct regular testing and maintenance of noisy engines, generators and other equipment

  - Ensure machinery is turned off when not in use

  - Acoustically dampen rock breaking and other noisy construction activity

  - Carefully schedule construction activities in order to limit concurrent noisy operations

  - Enforce speed limits for vehicles to reduce noise levels within the site

- Perform periodic medical hearing checks on employees exposed to high levels of noise
- Control/minimize the effect of vibration through the use of appropriate equipment, the installation of vibration dampening pads or devices and limit the duration of exposure to vibration.
- Provide personal protective equipment (PPE) to protect against extreme weather conditions
- Monitor weather forecast for outdoor work to provide advanced warning of extreme weather and schedule work accordingly
- Adjust work and rest periods according to temperature stress management procedures provided by ACGIH
- Provide access to adequate hydration such as drinking water during extreme hot weather

- For other hazards/injuries:
    - Respect labour laws
    - Keep work areas clean, tidy, and uncluttered
    - Remove trip hazards
    - Clean up wet floors from leaks, spills, etc.
    - Keep egress routes unblocked
    - Store tools and equipment to avoid falling
    - Keep living areas clean
    - Use proper and visible (auto luminescent) signage board, wherever required
    - Implement fall prevention measures for workers exposed to the hazard of falling more than two meters. For fall prevention:
        - Install guard rails if appropriate
        - Use ladders and scaffolds properly
        - Install prevention devices including safety belts, etc.
- Additionally for offshore operations, consider the following in the design of facilities
    - Environmental conditions at the offshore location (e.g., seismicity, extreme wind and wave events, currents, ice formations)

  - Proper selection of materials and development of a monitoring plan to ensure the protection of equipment and structures from corrosion
  - Adequate living accommodations appropriate to outside environmental conditions, plus related policies that consider the physical and mental strain on personnel living on production or drilling facilities; space for recreation and social activities and/or consideration of a limit to the number of consecutive days permitted on the offshore facility.
  - Limited accommodations in production and drilling facilities for staff related to asset operation only
  - Temporary refuges or safe havens located in a protected area at the facility for use by personnel in the event of an emergency
  - A sufficient number of escape routes leading to designated personnel muster points and escape from the facility
  - Handrails, toe boards, and nonslip surfaces on elevated platforms and walkways, stairways, and ramps to prevent person overboard incidents
  - Crane and equipment lay down area positioning to avoid moving loads over critical areas and reducing the impacts from dropped objects. Alternatively, structural protection measures should be provided.

- For community health and safety hazards
  - Locate project facilities based on risk assessment. Maintain an adequate safety zone around the facilities.
  - Develop a community emergency preparedness response plan that considers the role of communities and community infrastructure.
  - To prevent public contact with dangerous locations and equipment and hazardous materials, install access deterrents such as fences and warning signs around permanent facilities and temporary structures
  - Provide public training to warn of existing hazards, along with clear guidance on access and land use limitations in safety zones or pipeline rights of way
  - The potential for exposure of members of the community to facility air emissions should be carefully considered during the facility design and operations planning process
  - All necessary precautions in the facility design, facility sitting and / or working systems and procedures should be implemented to ensure no health impacts to human populations and the workforce will result from activities
  - When there is a risk of community exposure to hydrogen sulfide from activities, the following measures should be implemented:

- Install a hydrogen sulfide gas monitoring network with the number and location of monitoring stations determined through air dispersion modelling, taking into account the location of emissions sources and areas of community use and habitation.
- Continuous operation of the hydrogen sulfide gas monitoring systems to facilitate early detection and warning.
- Emergency planning involving community input to allow for effective response to monitoring system warnings.

- For security purposes:
  - Unauthorized access to facilities should be avoided by perimeter fencing surrounding the facility and controlled access points (guarded gates). Public access control should be applied.
  - Adequate signs and closed areas should establish the areas where security controls begin at the property boundaries
  - Vehicle traffic signs should clearly designate the separate entrances for trucks / deliveries and visitor / employee vehicles
  - Means for detecting intrusion (for example, closed-circuit television) should be considered. Facilities should have adequate lighting to minimize trespassers.

8.2.3 References

1. Environmental, Health and Safety General Guidelines. International Finance Corporation, World Bank Group. 2007.
2. Environmental, Health and Safety Guidelines for Offshore Oil and Gas Development. International Finance Corporation, World Bank Group. (2014 draft version).
3. Environmental, Health and Safety Guidelines for Onshore Oil and Gas Development. International Finance Corporation, World Bank Group. 2007.
4. Recommended Practice for Occupational Safety for Onshore Oil and Gas Production Operation; API Recommended Practice 74, 2001, 2007.
5. United States National Fire Protection Association (US NFPA) Code 30.
6. OSHA Regulations (Standards -29 CFR),
7. United Kingdom Statutory Instrument (UKSI) 2005, The Control of Noise at Work Regulations 2005

8.3 *International Timelines for Various Permissions Related to Environmental Clearances*

8.3.1 Discussion

The type and number of “Environmental Permits” required for exploration and production activities, e.g. drilling, testing, and construction, vary for the activity type and the location, offshore or onshore. Some of the permits are listed below:

- Environmental Impact Assessment Permit (EIA) - documentation includes state of the environment before operations, effect on the environment from the planned operations such as risks of possible contaminants or other issues and contingency plans for mitigating these effects. Output is a robust EMP and reliable environmental Monitoring plan to implement and assess for effectiveness and continual improvement. Environment is all inclusive: wildlife (plants and animals), water, air, soil, and communities that might be affected.

- Water well permit from CGWA or State GW Board usually includes water use related documentation. Building permits usually include environmental assessment documentation or would require EIA depending on size of project construction activity

- Movement permits - permission grants for movement of trucks, ships or rigs. These require environmental assessment of the effects of this activity, including contingency plans to mitigate risk of major accidents and to clean up any such accidents to minimize the environmental impact. These types of permits can come from the defence, Forestry & Wild Life, City, Port Authority, Highway Department or some branch of the local government.

- Dumping/Disposal permits - for waste from drilling activities such as cuttings, produced sand, drilling fluid etc. This permit requires documentation of the properties of the waste, its effect on the biosphere, recommended disposal method, any cleanup required and contingency plans for uncontrolled release of drilling waste. Permit issued by State and/or Central regulatory agencies.

- Disposal permit - for sewage and trash from operations. This permit applies to garbage and sewage generated by personnel carrying out the operations. The environmental impact of the disposal plan must be documented and approved by statutory agencies

- Chemical storage permit - for chemicals used during drilling and completion operations. This permit requires environmental impact documentation of the chemicals (MSDS), storage, usage and contingency plan for accidents. Permit issued by statutory agencies

- Explosive permit - for explosive used during drilling and completion operations. This permit requires environmental impact documentation of the explosives, storage, usage and contingency plan for accidents. Permit issued by statutory agencies

- Noise permit - documentation of the noise of the operations and reasons for allowing over the suggested limits for the affected area. This permit is usually necessary where it might adversely impact wildlife or nearby communities or dwellings.

- To ensure safety and security of public and property from fire and explosion, the approval of the Chief Controller of Explosives (CCoE) is mandatory for all electrical equipment installed in potentially explosive atmospheres. The approval of such equipment is therefore limited to only such areas falling within the jurisdiction of the Petroleum and Explosives Safety Organization.

- Radioactive materials permit - this permit is needed for handling radioactive material needed for some logging operations and is the responsibility of the electric logging contractor; however, the PSC Contractor may need it to ensure no stoppage of operations.

- Hazardous materials permit - additional permits may be needed if other hazardous materials are used or anticipated to be encountered during drilling. Permit requires environmental impact documentation of the hazardous materials, storage, usage, disposal plan and contingency plan for accidents.

- Permits from other ministries may include forestry, fisheries, agricultural, heritage, transport, communications, police, defence, etc. These permits often require environmental impact assessment.

- Each country has a different set of requirements specific to their environmental restrictions. As such, no published universal timelines were found. However, a range of timelines for approval of various permissions and permits has been given in best practices below.

8.3.2 Best Practices

- Follow relevant laws, rules and regulations to safeguard the environment and community.

- Complete EIA documentation addressing all relevant aspects of the environment.

  - Detailed discussion of the baseline or pre-environmental status with relevant data on biosphere of the PSC block. Data to be included, depending on the location of the operations, on wildlife habitat status, weather data, surface water quality data, well water quality data, soil data, air quality data, ecology & biodiversity and community data such as gender, age, occupation, housing, health and other pertinent statistics. Additional data could be required for some operations.

  - Potential effects of all operational phases on any wildlife, air, surface and subsurface water, soil, and communities.

  - Contingency plans including management responsibilities, technologies to be utilized, timelines, onsite cleanup facilities.

  - Regular monitoring plan to measure effectiveness of controls and assuring regulatory compliance.

- Permitting time from presentation of the documents to the issuance of the permit can vary greatly from country to country and permit to permit. It is essential to follow checklists provided for different permits from various governmental agencies and to make sure these checklists are current with applicable laws, rules and regulations.

  The potential permits and the variance seen worldwide for approval time are given below:

  - Building permits - 3 weeks to 3 months
  - Environmental Assessment Permit - 1 to 6 months
  - Water well permit - 2 to 6 weeks
  - Movement permits - 1 week to 3 months
  - Dumping/Disposal permits - 3 to 12 months
  - Disposal permit - 1 week to 2 months
  - Chemical storage permit - 1 to 3 months
  - Explosive permit - 1 to 3 months
  - Noise permit - 1 to 6 weeks
  - Drilling permit - 1 to 6 weeks
  - Flaring permit - 3 days to 2 weeks
  - Radioactive materials permit - 1 to 4 weeks
  - Hazardous materials permit - 1 to 3 months
  - Other ministry permits - 2 to 4 weeks

- A clear standardized approval process and all needed permits with clear checklist of required documentation or studies among the various ministries (MoPNG, MoEF & CC, etc.) with maximum time of approvals (TOAs) for obtaining required permits is recommended to smooth the transition from exploration to production.

8.3.3 References

1. API RP 51R - Environmental Protection for Onshore Oil and Gas Production Operations and leases
2. API RP 67 - Oilfield Explosives Safety
3. Timeline estimates from personal knowledge of US, EU, British, Indonesian and Oman permitting times

8.4 *Preparation of Contingency Plan, Emergency Response Plan (ERP) and Disaster Management Plan (DMP) for Oil Spills, Fires, Blow-Outs, Accidents and Emergencies in Accordance with International Practices*

8.4.1 Discussion

Oil spills, fires, disasters, and blowouts are, unfortunately, events that could occur in the process of oil and gas exploration and development. These are mostly accidental and consequently cannot be predicted. They can occur onshore or offshore and could be affected by weather conditions which by themselves are unpredictable. While these events may not be completely prevented, their impact can be mitigated through planning and preparedness. As such, contingency plans, emergency response plans, and disaster management plans must be in place before, during and after company activities are initiated. These plans must be specific to the different stages of the Contractor's/Operator's operations including:

- Seismic exploration activities
- Exploratory/appraisal drilling activities
- Production/development drilling activities
- Field development and production activities
- Offshore and onshore pipeline activities
- Offshore and onshore transportation activities
- Tanker loading and unloading
- Ancillary and support services
- Decommissioning, abandonment and restoration

Contingency plans are tools that assist in the effective response to any incident and comprise the actions that the company has to implement to mitigate/minimize the impact of the incident. A contingency program looks critically at all the possibilities of what could go wrong and how, then develops a plan that includes step by step details of the strategies that have to be implemented before, during, and after an emergency/incident.

An essential part of Contingency planning is hazard identification. It is impossible to know when incidents such as oil spills happen and how much oil is likely to be spilled. However, it is possible to identify the corridors through which the oil travels and/or is stored, the potentials for spills, and the maximum potential spill volume. Different situations can affect the ability of response personnel to contain and/or clean up an oil spill, such as weather conditions, geographic isolation, and spill size. It is thus important to employ realism and lateral thinking in hazard identification.

The next step in Contingency planning is vulnerability analysis. The vulnerability analysis section of a contingency plan provides information about resources and communities that could be impacted in the event of a spill. This information is designed to help personnel involved in responding to a spill to make reasonable, well-informed choices about protecting public health, wild life, and the environment. This information could also be used to prioritize the containment and cleanup effort.

Contingency planning uses hazard identification and vulnerability analysis to develop a risk assessment. The risk assessment is then used as the basis for planning specific response actions and strategies to the incident. The plan addresses those problems by determining how best to control the spill, how to prevent/protect certain populations or environments from exposure to oil, and what can be done to repair the damage done by the spill. NEBA(Net Environmental Benefit Analysis) is the tool to be used to prioritize the action plan in responding any such contingencies.

The last step of Contingency planning is to develop response actions to address the risks that are identified under risk assessment. A carefully designed contingency plan will describe major actions that need to be taken when a spill occurs. The plan should have strategies, roles and responsibilities, action plan and description of resource mobilization. These actions should take place immediately following a spill so as to minimize hazards to human health and the environment. The response strategies designed for implementation should carefully balance the ecological, social and commercial concerns and should aim to minimize further adverse impact to the environment. In selecting response strategies, consideration should also be given to occupational health and safety risks, response times and other constraints that may limit the ability of the response teams to undertake specific tasks. The plan should be an actionable plan, not general in nature. It should provide the specific actions that need to be taken in the case of a given specific incident.

Once the Contingency Plan is in place, the plan must be tested through training and exercises. Lessons learned through testing of the plan should be used to review and update the plan. Consistent practice and improvement can lead to more effective future responses.

The main objective of emergency response planning is to establish a common framework for developing local response/intervention plans for the various operations carried out by companies. The final plan provides recommendations, guidelines and technical documentation, based on industry best practices, to assist the company in developing specific emergency response plans for its operations.

8.4.2 Best Practices

- Contingency Planning
    - Developing and Managing the Contingency Plan
        - Contingency plans vary with operations, location, and incidents. Company must develop/adopt and maintain contingency plans for incidents that are related to all aspects of its operations. For each operation, a well-designed contingency plan should be quite comprehensive, fully documented and easy to follow. References to external documents should be minimized.

- A well designed and documented contingency plan should have all the essential components including, but not limited to:
    - Hazard identification
    - Vulnerability analysis
    - Risk assessment (perceived risk)
    - Response actions/strategies
    - Test through training and exercises
    - Review/Improve/Update
- Contingency planning uses hazard identification and vulnerability analysis to develop a risk assessment. The risk assessment is then used as the basis for planning specific response actions and strategies.

- Hazard Identification
    - The Contractor/Operator should identify likely hazardous events and look for potentially complex hazardous events. The Contractor/Operator should evaluate all hazards related to all phases of operations. To have an appropriate contingency plan, the Contractor/Operator should demonstrate that it has a sufficient level of preparedness to mitigate the consequences of all the identified hazards.
    - The following information should always be collected as part of the hazard identification process for the case of an oil spill hazard:
        - Types of oils (physical and chemical properties) and volumes frequently transported through/or stored in that area. The impact of prevailing weather conditions on the oil in the event of a spill.
        - The mode of transportation used to move the oil, such as pipelines, trucks, railroads, or tankers and the potential for related hazards
        - Locations where oil is stored in large quantities
        - Extreme weather conditions that might occur in the area during different times of the year that have the potential to trigger an oil spill hazard
        - The location of response equipment and personnel trained to use the equipment and respond to the spill

- Early warning, alert systems and triggers

- Vulnerability Analysis

  - Determine who or what is at risk for harm in the event of an incident. Use this information to design the appropriate response factoring in protection of public health, wild life, and the environment. This information could also be used to prioritize the containment and cleanup effort.

  - Vulnerability analysis information should include, but not be limited to the following:

    - List of public safety facilities in the community
    - List of facilities such as schools and hospitals
    - List of recreational areas, such as campgrounds and parks
    - Residential communities in the immediate area
    - Identification of parts of the environment that are particularly susceptible to oil or water pollution
    - List of vulnerable wild life species and habitats. Predominant species at risk
    - Effects of oil on wildlife at risk
    - Priority species for protection and/or rehabilitation

- Risk Assessment

  - To properly characterize the risk and the impact of the spill/incident to the environment under normal and emergency conditions, a detailed knowledge of the existing environment (baseline) is required. In compiling the risks assessed, the Contractor/Operator should thus describe the existing environment that may be affected by the incident, as well as any relevant cultural, social and economic aspects of the environment in sufficient detail to enable adequate evaluation of the environmental impacts and risks from the incident.

- Response Actions/Strategies

  - Describe the actions that should be taken in the event of an incident. These actions should factor in ecological, social and commercial concerns and take place immediately so as to minimize adverse impacts to human health and the environment. The response actions should be developed to address the risks identified under the risk assessment step. The response strategy should be an actionable plan with specific actions needed to be taken in the case of a specific incident.

- The following response actions should be included in a contingency plan:
    - Oil spill response quick guide. A short and clear step by step plan of action in the event of an oil spill emergency
    - Members of the response team and the responsibilities of each member of the spill management and spill response operating team
    - Initial response actions to be undertaken before accessing external resources as necessary
    - Clear documentation of how the company response team interfaces with other community/state emergency response teams including search and rescue, fire suppression, wildlife managers, etc.
    - Notification of all private companies or government agencies that are responsible for the cleanup effort.
    - Getting trained personnel and equipment to the site quickly
    - Spill assessment. Defining the size, position, and content of the spill; its direction and speed of movement; and its likelihood of affecting sensitive habitats
    - Protocol for ensuring the safety of all response personnel and the public
    - Source control. Stopping the flow of oil from the ship, truck, or storage facility, if possible, and preventing ignition
    - Containing the spill to a limited area
    - Recovery of the oil spill. Removing the oil and properly disposing of the oil once it has been removed from the water or land
    - Tier level response actions for minor, moderate, and major spills
    - Environmental rehabilitation
    - Wildlife protection and rehabilitation
    - Response management. Efficient use of resources and proper coordination is vital to response management

- Response plan distribution. The response plan must be distributed in a way that it is easily accessed when needed and especially during an emergency

- Reporting and record keeping

- Testing the Plan

  - After the plan has been developed, it is important to test it to see if it works as anticipated. Testing usually takes the form of an exercise or drill to practice responding to a spill. A contingency plan cannot be considered adequate unless it has been intensively tested in some form and declared adequate.

  - Testing also has additional benefits including:

    - Training of the response staff in the procedures developed for the plan. It is not possible to fully comprehend the functioning of the plan without practicing. Testing is a form of practice and should be carried out regularly.

    - Testing provides a means to isolate and to improve on what is not working properly.

    - Testing also allows for an emergency response in a low-stress environment where new techniques and procedures may be tried without adverse consequences

- Improving the Plan

  - Lessons learned during oil spill drills and actual oil spills provide opportunities to improve on the plan. Contingency planning should be a dynamic process. Oil spills and/or other disasters could take any form or shape. As such, consistent practice and improvement can lead to more effective future responses.

Emergency Response Planning/Disaster Management

- It is essential that a functional emergency response plan program be in place prior to starting any activity. The adopted emergency response program should be in compliance with the Contractor's/Operator's HSE Contingency and Emergency Planning protocols, as well as local and state regulations.

- It is equally essential that the plan be fully tested and declared adequate prior to actual implementation. Testing in the form of regular drills provides training and opportunities for improvement and refinement.

- It is recommended that a specific emergency response plan be developed for each potential hazardous activity or incident that the Contractor's/Operator's operations might encounter. Such plans will provide specific guidelines for each specific emergency.

- While the specifics of an emergency response plan may differ with incident and operations, an adequate emergency response plan should include:
    - The list and the responsibilities of each member in the emergency response team
    - An "Initial Response Quick Guide"
    - Guidelines for strategic control plans for a particular emergency
    - Guidelines for daily tactical action plans during emergency operations
    - Critical response resource requirements and availability
    - Issues that may adversely affect response and recovery and how to address them
- Objectives of the Emergency Response Plan
    - The main objective of an emergency response plan is to provide specific guidelines, compatible with the Contractor's/Operator's other emergency programs (HSE, Contingency Plan, etc.), and with local/state regulations for intervening in the event of an emergency.
    - The emergency response plan should provide a working methodology to safely and effectively manage the emergency and to regain control of operations.
    - Developing an effective/appropriate emergency response plan will require a comprehensive assessment of potential risks and hazards associated with the company's operations within a specific environment. The risks and hazards assessment should thus incorporate weather conditions and other seasonal conditions that are prevalent in the region.
    - Upon development and testing, the plan should clearly:
        - Identify the members of the Contractor's/Operator's emergency response team (local team) and how the local team interfaces with the city, state, and/or national emergency response teams as applicable. Resource utilization and management should be clearly identified.
        - Provide a 'quick guide' of the specific tasks for each member of the emergency response team. Members are to be familiar with their specific tasks through drills.
        - Define the initial response actions to be taken before accessing external resources if necessary so as to ensure human safety and/or

minimize damage to the environment. Quick initial responses can prevent an emergency from escalating.

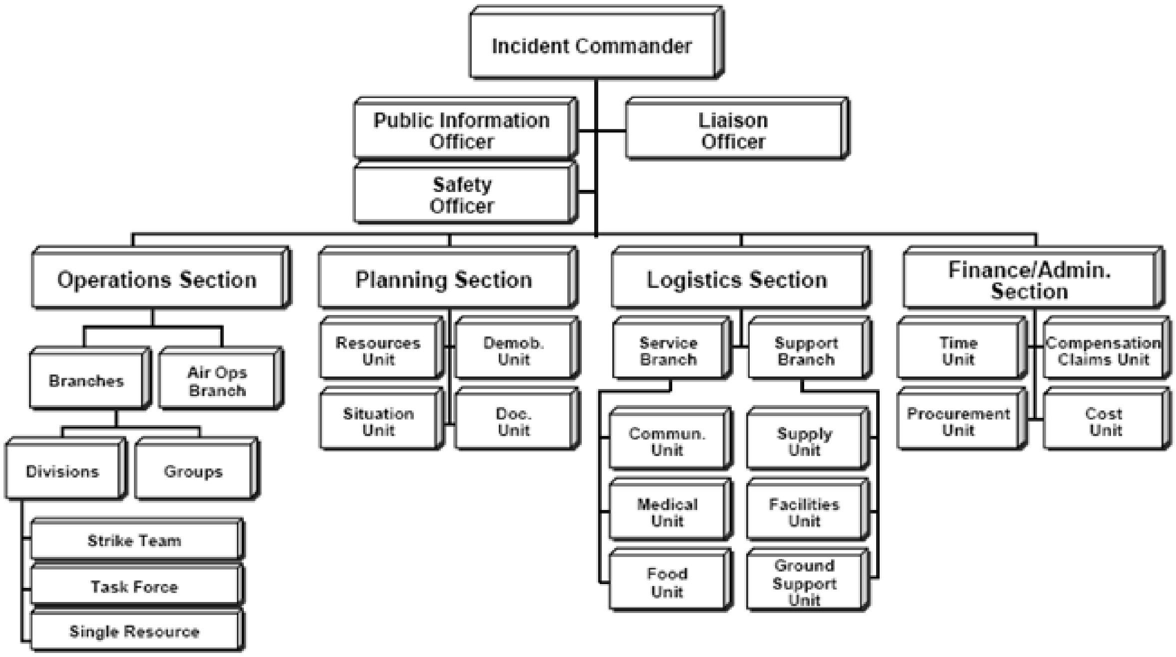
- Address issues related to security during an emergency.
- Address issues related to HSE and access to healthcare facilities during an emergency.

- Emergency Response Communication
    - In the event of an emergency, effective communication enables employees, stakeholders, the community, etc. to be informed of the current situation and allows all parties to set realistic expectations of a response. Communicating timely and accurate information to emergency response teams (local/state/national), facility managers, critical decision makers, stakeholders, vendors and contractors, and the general public is an important element to any emergency management.
    - According to the United States' Federal Emergency Management Agency (FEMA), an effective emergency/disaster communication approach should:
        - Be community centred
        - Have leadership commitment
        - Be included in planning and operations
        - Have media partnership
    - If and when an emergency occurs, clear communication is crucial to protect lives, the environment, the surrounding community, as well as the Contractor's/Operator's operations and reputation. Effective emergency communications should:
        - Result from accurate data collection
        - Clarify initial emergency response initiatives
        - Be timely, current, and consistent
        - Remain concise to accurately define necessary tasks
        - Include time parameters and follow up procedures
        - Be strategic in how tasks should be accomplished

- Testing and Updating the Plan

- The efficiency of the emergency response plan needs to be systematically tested and improved through periodic drills. Drills also have additional benefits including training of staff, isolation of problem areas, and providing an avenue to implement new techniques and procedures without adverse consequences. An effective emergency response plan is updated as necessary to incorporate changes and lessons learned. In addition, newly nominated personnel and all contact information on the plan should be updated regularly especially before any hazardous activities such as drilling. The plan needs to be updated each time that members of the response team are changed. It is recommended that the plan be updated on a regular schedule so as to maintain its usefulness in mitigating emergency situations.

- Incident Command System
  - The incident command system (ICS) is a standardized on-scene incident management concept designed specifically to allow responders to adopt an integrated organizational structure equal to the complexity and demands of any single incident or multiple incidents without being hindered by jurisdictional boundaries.
  - The ICS provides a framework for responders to efficiently work together thus eliminating/minimizing some of the problems inherent with responding to emergencies including:
    - Too many people reporting to one supervisor
    - Different emergency response organizational structures
    - Lack of reliable incident information
    - Inadequate and incompatible communications
    - Lack of structure for coordinated planning among agencies
    - Unclear lines of authority
    - Terminology differences among agencies
    - Unclear or unspecified incident objectives
  - The ICS is recommended for managing emergencies. A typical ICS structure is as given in this figure:



Typical Incident Command System Structure

- Recommended preparation procedures for Contingency Planning, Emergency Response Planning and Disaster Management have been included in the best practices listed above.
- Several agencies (IFC, IPIECA, OGP, API, NDMA etc.) have developed detailed and relevant guidelines to address oil and gas development issues related to contingency planning, emergency response planning and disaster management. Such agency guidelines are recommended for a more exhaustive discussion of international guidelines.

8.4.3 References

1. Environmental, Health and Safety General Guidelines. *International Finance Corporation*, World Bank Group. 2007.
2. Environmental, Health and Safety Guidelines for Offshore Oil and Gas Development. *International Finance Corporation*, World Bank Group.(2014 draft version).
3. Environmental, Health and Safety Guidelines for Onshore Oil and Gas Development .*International Finance Corporation*, World Bank Group. 2007.
4. Guidelines for Offshore Oil Spill Response Plans; API Technical Report 1145, 2013.
5. Emergency response planning in the oil field; International fire fighter, 2010.
6. IPIECA/OGP Contingency Planning for Oil Spills on Water. 2015.
7. National Disaster Management Policy 2009; NDMA.

9 Procurement Procedure

9.1 *Overview of Procurement Procedures*

9.1.1 Definitions and Discussion

Oil and gas companies that purchase goods or services under a Production Sharing Contract, have standard procurement procedures that guide the methods they use to acquire those goods and services.

9.1.2 Best Practices

- The procurement procedure duly approved by the MC or by OC as the case may be, will continue to be implemented as it is.
- Procurement procedures are developed by a Procurement Committee made up of specialists designated to that effect and whose responsibilities include:
    - Procurement identification and valuation
    - Confirmation of funding availability
    - Advertising of tenders
    - Organizing pre-bid conferences
    - Receipt and opening of bids
    - Evaluation of tender proposals
    - Selection of the supplier
    - Issue of letter of award
    - Contract negotiations
    - Award of contract
    - Order placement
    - Payment
- The provision of all necessary information that prospective bidders need to prepare their bids starts with the issuance of bidding documents that include:
    - The objectives, scope and expected results of the proposed contract
    - The technical specifications of Goods and Services to be procured
    - Expected contract duration and delivery schedule
    - The obligations, duties and functions of the winning bidder

- (In large complex projects, it is not possible to define minimum eligible criteria at EOI stage)The Procurement Document may contain:
    - Invitation to Bid
    - Instruction to Bidders including:
        - Bid Rejection Criteria (BRC)
        - Bid Evaluation Criteria (BEC)
        - Bidder's Qualifying Requirements
    - Bid Data Sheet
    - General Conditions of Contracts
    - Special Conditions of Contract
    - Schedule of Requirements
    - Scope of Work including technical specifications of the Goods and Services to be delivered
    - Sample forms as annexed
- Bid Evaluation Criteria generally stipulate that bids from the tenderers shall conform to the technical specifications, including the Scope of Work provided in the tender documents. Bids may be rejected by the procuring agency at its sole discretion in the event the goods or services offered do not conform to minimum required parameters or technical specifications. The technical evaluation and the financial evaluation are part of the Bid Evaluation Criteria.
    - During technical evaluation, the following shall be considered:
        - Compatibility of bids to technical requirements;
        - Execution methods;
        - Alternative options offered by bidders;
        - Information and/or procedures on bidders' goods or services;
        - Information on bidders' technical experience, equipment and employee's skills.
    - During evaluation of financial offers/bids, the following shall be considered:
        - Offered price, taxes, tariffs and other alternatives;
        - Timing of delivery;
        - Any conditions with regards to contract's terms;

- The specification for goods must be clear and unambiguous so that both the procuring agency and the tenderer are certain that the same product is being considered. In some cases, when goods cannot be described in a detailed way, reference to trademarks, patents or brands may only be made provided the words “or equivalent” are used.

- Generally, the factors describing the goods should include:

    - Any design requirements
    - Any performance requirements
    - Size, color, materials, etc.
    - Quantity
    - Quality
    - Maintenance requirements
    - Delivery date

- Specifications for services should, wherever possible, be based on deliverables (output). Under this approach, the desired outcome including quality, performance and reliability levels, is described in the Scope of Work and the tenderer may suggest the best ways in which this can be achieved.

- wherever possible, specifications for Goods and Services should be based on International or National Standards. The advantages of using such standards are that they:

    - Represent the views of the whole market
    - Ensure that a product will meet a minimum standard of performance in defined areas
    - Can help avoid lengthy written specifications
    - Can help ensure compatibility of equipment

- The provision of goods and services is based on threshold values. The procurement can be done in one of the following three methods depending on the technical requirements and the thresholds based on the tender value relating to the cost for these goods and services, and the desired number of bidders:

    - Sole source procurement or purchasing on a nomination basis
    - Limited procurement procedure
    - Open competitive procurement

- Sole Source Procurement (Purchasing on a Nomination Basis)

    - (already addressed in the PSCs)Purchasing on a nomination basis or sole source procurement procedure may be used under the following circumstances:

    - No bid proposals have been received in response to an open or limited procurement method
    - Procurement of items of proprietary nature which can only be obtained from the proprietary source or for reasons tied to exclusive rights or intellectual property rights
    - Procuring maintenance and repair parts for machinery/equipment from the original supplier
    - For reasons of urgency due to emergency response situations or unforeseeable causes, such as earthquakes, floods, other natural disasters, etc. and when time limits provided for open or limited procurement cannot be complied with.
    - Repeat order, when prices are the same or lower than those in the original contract, provided that those prices are still the most advantageous after price verification.
    - Sourcing from fully state-owned enterprises explicitly created for that purpose
    - For new works or services, consisting in the repetition of similar works or services entrusted to the contractor to whom the original award was granted on the basis of open or limited procurement method, provided that such works or services are in conformity with the project for which the original award was granted
    - Hiring of specialized manpower
    - Purchase of specialized software
    - Location specific services
    - Procuring small-value items
    - During periods of war

  - Purchasing on a nomination basis should be effected after a survey of the oil and gas industry to determine the supply source from available global data banks, prior to the commencement of the procurement process, with the exception of original equipment manufacturer or annual maintenance contract and emergency purchase/services. There are numerous online resources providing access to pre-qualified suppliers of goods and services for the oil and gas industry. The survey should confirm the market price and the exclusivity of the source of goods or services to be procured.

  - The procuring agency should justify:

    - The necessity for the item to be procured under nomination basis only; and

    - That there is no suitable substitute in the market that can be obtained at more advantageous terms.

- Limited Procurement Procedures
  - Limited tender is a method of procurement of goods and services that involve a prior assessment of the technical, commercial, and financial capabilities (qualification criteria) of potential suppliers and bidders.
  - This method allows the establishment of a list of pre-qualified suppliers and bidders who are invited to submit proposals and is generally used under the following conditions:
    - Only few suppliers of goods and services are known to be available;
    - When there is a need to limit the bidding to qualified bidders in order to maintain uniform quality and performance.
- Open Competitive Procurement
  - Open competitive tendering procedures generally target contractors who are interested and meet the minimum qualification (technical and financial) criteria set out in the contract notice.
  - There are different types of open competitive bidding procedures based on the required technical specifications of the contract, the characteristics and the cost of goods and services to be provided.
  - In the case of open competitive procurement, if only one bidder submits a bid, the procuring agency should consider a rebidding process and increase the number of potential suppliers and tenderers to be contacted. The contractor has to use his business acumen to achieve the best possible commercial result keeping in view of the timeliness of the work.
  - In the case of only one qualified bidder, the procuring agency should have the option to accept the bid, pending Management Committee approval.
- Some of these procurement procedures include single-part bid system and two-part bid system.
  - Single-Part Bid System
    - Under the single-part bid system, both the Techno-Commercial bid and Price bid are submitted in one envelop.
  - Two Part Bid System
    - The two-part bid system is generally used for the procurement of specialized goods and services valued more than the single-part system.

    - The two-part system requires the submission of the Un-Priced Techno-Commercial Bid including all required compliance documents and the Price Bid in two separate envelops. The envelope containing the Price-Bid is opened after the evaluation of the Un-Priced Techno-Commercial Bid in conformity with the Bid Evaluation Criteria (BEC).

- Joint Ventures
  - In case of a Joint Venture, an Operating Committee should be established in conformity with the Joint Operating Agreement, and an Operator should be designated to carry out petroleum operations in conformity with the PSC.
  - The Operator's procurement procedures should be approved by the Operating Committee and submitted to the Management Committee.
- The above best practices are recommended as guiding principles for establishment of operator's procurement procedures.
- In order to maintain consistency, transparency and fairness, the same tender information, instructions and guidance during the tendering process should be given to all suppliers and bidders. Procedures, rules and bid evaluation criteria need to be applied consistently to the different bids to prevent any actual or perceived discrimination or preferential treatment. Consistency of this kind can be maintained when clear procedures are documented in advance, when staff are fully trained in them, and when there is strong continuity in the people who make up the tender project and advisers.

9.1.3 References

1. Various tender documents and project experience.

10 Other Areas

10.1 *International Requirements for Reporting of Details of E&P Activities to Ensure Ethical Operations / Share Market Compliance Definitions and Discussion*

10.1.1 Definitions and Discussion

Reporting of oil and gas activities is a requirement in the oil and gas industry. Companies are expected to report on a regular basis all activities related to Exploration, Reserves, Drilling, Field development, Production, Well testing, Well stimulation, Well abandonment, EOR, Environmental impact, Accidents, etc. These reports provide governments and their regulators information (including compliance information) concerning the activities of their oil and gas contractors and/or operators. Reporting guidelines differ somewhat from nation to nation and from state to state for the case of the USA. A summary of some reporting guidelines are provided below.

- **Norway**
    - Exploration activities
        - Detailed plans should be submitted at least 5 weeks before commencement of exploration activity
        - Weekly reporting of implementation of exploration activities should be done
        - Any changes from proposed activities should be submitted as soon as possible
        - Reporting about seismic data, gravimetric, magnetic, electromagnetic data, analysis results, maps and profiles and results from other geophysical and geological surveys should be submitted as soon as possible but no later than three months of completion of the individual activities
    - Drilling activities
        - Overall plan must be submitted with Plan for Development and Operations (PDO)
        - Drilling program and registration of well paths must be done no later than 15 days before the commencement of drilling
        - Daily reports from drilling and wells activities should be submitted
    - Testing
        - Plan for formation testing must be submitted in advance but no later than 72 hours before testing

    - Cuttings, cores, fluid samples and preparations from individual exploration wells should be submitted as soon as possible but not later than six months after completion of drilling of the well
    - A final geological and reservoir technical report with respect to the well should be submitted no later than six months after individual drilling and well activity has been completed
- Well plugging
    - Information on plugging and detailed logs must be submitted as soon as possible but no later than 24 hours before start of operations
- Production
    - Information on important production parameters such as gross/net production shall be made available on a daily basis during the production phase
    - The following volume data shall be reported on a monthly basis
    - Production
        - per well/well path and facility
        - allocated marketable products per facility/field (value adjusted)
        - import/export per facility/structure
        - consumption per facility/structure
    - Injection
        - per well/well path and facility
    - Stock
        - quantities at the end of month
    - Sales
        - gas per owner and buyer
        - oil, NGL and condensate per vessel
- Annual status report for fields in production should be submitted covering
    - General field status
    - Activity report
    - Plans for the period ahead

- Reserves
  - Reserves should be reported by October 15 of each year according to Norway's resource classification system

- **United Kingdom**
  - Exploration
    - Well and survey data including geophysical surveys, seismic data, well logs, samples, gravity, magnetic data should be made available as soon as they are ready
  - Drilling
    - Positioning of the well requires approval from department of energy and climate change
    - A minimum of 30-day notice is required for consent to straightforward drilling operations. Earlier notice will be required for operation in busy shipping areas
    - Well must be drilled within one year of consent date
    - Basic well data, seismic depth map, synopsis describing geologic rationale and objective of drilling the well should be provided
  - Testing/Sampling
    - Secretary of State's consent should be obtained in advance before flaring the gas
    - Well test exceeding 4 days is considered as long term test
    - Frequency of cutting samples, objective of coring program, mud type, details of well testing program should be provided in graphical or tabular form
  - Production
    - Oil production, associated gas production, condensate production, gas injection, water production, water injection, gas utilized, gas sold, etc., should be reported partially by the 16th of the following month or fully by the 30th of the following month
  - Loss/dumping of material at sea from oil and gas installations
    - All loss excluding material legally deposited in accordance with regulations or unregulated dumping of solid materials should be reported within six hours of the incident
  - Reserves

        - UK reserves are classified using Statement of Recommended Practices (SORP) published in 2001

- **United States of America**
    - Well Testing
        - Oil wells: File report either within 30 days of well completion or within 10 days of the test showing 24 hour production capability and GOR whichever is earlier date
        - Gas wells: File report either within 30 days of well completion or within 15 days of the test showing absolute open-flow potential test, whichever is earlier date
    - Production
        - Oil wells:
            - File monthly report of production , disposition and/or storage of both oil and casing head gas
            - File annually a well status report showing a 24 hour test
        - Gas wells:
            - File monthly report of production and disposition of gas and condensate
            - Semi-annually file a 72 hour deliverability test results
        - After initial testing, wells with production and deliverability under 100 Mcf per day are exempt from testing unless commingled
    - Dry holes/Inactive wells
        - At least five days before plugging operations, file a request for approval. If rig is on location, then telephone approval may be sought
        - Notify district office at least four hours prior to start of plugging operations
        - File completed plugging report within 30 days of plugging
    - Clean-up of all wells sites
        - Reserve/mud pits with chloride concentration of
            - 6100 mg/L or less: Dewater and backfill within one year of completing drilling
            - over 6100 mg/L: Dewater within 30 days and backfill within one year of completing drilling

        - Completion pits: Dewater within 30 days and backfill within 120 days of well completion

    - Accidents/Blowouts/H2S

        - Immediately notify district office by telephone

        - Write a letter explaining in detail the problems encountered and steps taken to resolve situation

    - Reserves

        - Every year all publicly listed companies are required to file a 10-K report classifying reserves according to SEC rules before the end of the year

10.1.2 Best Practices

- Based on the reporting standards adopted by the Agencies/Nations mentioned above, the following reporting guidelines are suggested:

    - Exploration Activities

        - A detailed exploration plan should be submitted before commencement of exploration activities

        - Monthly or Quarterly reporting of implementation of exploration activities is suggested

        - Any changes from proposed activities should be submitted as soon as possible

        - Reporting on seismic data, gravimetric, magnetic, electromagnetic data, analysis results, maps and profiles and results from other geophysical and geological surveys should be submitted no later than three months of completion of the individual activities

    - Exploration Drilling and Formation Testing

        - Submit a request for approval no later than 60 days prior to drilling an exploration well. Provide information regarding well positioning and trajectory including detailed information to support the drilling action.

        - Submit cuttings, cores, and fluid samples for testing and evaluation within 6 months after drilling completion for each well.

        - Submit formation test results/report within 60 days of completion of the test. Provide details regarding the maximum well potential.

        - Submit a comprehensive geological and reservoir technical report/s for each well after drilling and well testing activities have been completed.

        - Such “End of Well” report/s should summarize drilling process and activities, formations encountered and geology, logging, well test results, well schematic, well suspension activities, etc.

- Production Drilling Activities

    - Submit a comprehensive Field Development Plan (FDP) prior to any production drilling activities

    - Submit a drilling program within 60 days before the commencement of drilling. Provide information regarding well positioning and trajectory including detailed information to support the drilling program.

    - Provide updates on production drilling activities weekly.

    - Submit a detailed report of well drilling and completion results within three months of completion of each well.

- Injection and Production Activities

    - Oil production, associated gas production, condensate production, gas injection, water production, water injection, gas utilized, gas sold activities, etc., should be reported monthly.

- Well Plugging

    - Information related to well plugging and detailed logs should be submitted at least one week before starting of the plugging operations.

    - Provide completed plugging report within 30 days of plugging.

- Accidents/blowouts/H2S

    - Immediately notify State Agency by telephone and activate emergency plan.

    - Submit details regarding the problems encountered and steps taken to remedy the situation within 30 days of resolving the problem.

- Reserves Reporting

    - File annual report of reserves following SPE PRMS guidelines at the end of each year.

- Annual Field Report

    - Annual field report for fields in production should be submitted covering

        - General field status

        - Activities report

        - Future plans

10.1.3 References

1. http://www.rrc.state.tx.us/oil-gas/forms/oil-gas-filing-checklist-from-prospect-to-production/
2. http://www.npd.no/global/engelsk/5-rules-and-regulations/npd-regulations/ressursforskriften_e.pdf
3. http://www.npd.no/Global/Engelsk/5-Rules-and-regulations/Forms/RNB/General_Guidelines_RNB2012.pdf
4. https://www.gov.uk/oil-and-gas-petroleum-operations-notices
5. http://www.oiac.co.uk/resources/SORP.pdf

10.2 *Sharing of Infrastructure*

10.2.1 Definitions and Discussion

Most production facilities and pipelines are designed to handle peak production rates and will have excess capacity as rates decline. This creates an opportunity for new fields to access infrastructure without the high capital cost of constructing new facilities. The owners of the existing facilities benefit by collecting processing or transportation fees and possibly by extending the economic life of their original fields. All parties, including the government, benefit from development of otherwise uneconomic fields and from increased recovery from the original fields. The impact on the environment is less when existing infrastructure can be used. Project development timelines can also be greatly accelerated when new permitting, design, and construction of facilities can be avoided.

Although all parties can benefit from facility sharing, shared processing facility agreements have been most common when the new fields were also owned by one or more of the existing facility owners. One reason for this may be related to the lack of transparency of fees when the third party does not have access to information about the original fields and facility costs, particularly relating to capital recovery fees and compensation of deferred production, or “backout”. This compensation is usually calculated using reservoir models that the third party does not have. One area of shared infrastructure that is very successful and common is sharing of oil and gas pipelines. The sharing of oil spill response equipment and waste disposal sites within a region is also quite common. Examples of shared infrastructure and contractual mechanisms are provided below.

- North Slope of Alaska Facility Sharing, United States
    - Facility sharing agreements were developed as new fields use the Prudhoe Bay, Kuparuk, and Endicott processing facilities and flowlines. The majority of the agreements involved new fields owned by one or more of the original facility owners, although field ownership percentages vary. The agreements were developed to take advantage of excess oil production capacity that occurred when Prudhoe Bay and Kuparuk production declined. The facilities were limited by water and gas handling capacity. In 2013, Hilcorp purchased North Slope fields from BP, making Hilcorp a true third-party.

- The framework for facility sharing negotiations was that the facility sharing process must:
  - Be fair, equitable, and understandable to all parties
  - Result in net increase in production, improve resource conservation, and reduce waste
  - Not result in any new government regulation
  - Preserve and promote operational integrity
  - Preserve the integrity of unit rights/obligations, and tax partnerships
  - Reduce financial and operational risk
  - Introduce no significant adverse impact to existing production
  - Provide timely access to indicative fee structure for bona fide inquirers
  - Create a level playing field for all producers, where the “best” barrels are produced
  - Allow for resolution of conflicts
  - Compensate the facility owners for their historical capital costs and lost or deferred production
  - Provide equitable sharing of ongoing costs among all users
- Components of the facility sharing agreements:
  - Identification of Facility Owners and their intentions
  - Identification of Third Party Owners and their intentions
  - Definitions of Terms
  - Definition of Facilities that are and are not included in the agreement
  - Definition of Third Party Facilities that are third party sole responsibility
  - Standards of Produced Fluids (fluid compatibility and physical limitations)
  - Priorities Governing Production Processing: This section states that the facility sharing agreement will maximize the total oil production. In order to maximize oil production, high GOR and/or high WOR wells will be curtailed first regardless of ownership. Wells of the facility owner could be shut-in or curtailed, thereby decreasing the facility owner’s total production. The volume not produced by the facilities owners is “backed out” to make room for the third party production. To compensate the owners for this backout, the backout volume is calculated via a defined process, and

transferred to the facility owners from the third party owners. The third party owners do not pay fees on the barrels they must give up as backout compensation.

- Produced Water and Seawater: Facility owners will provide to each third party a volume of water, for water injection that is equal to the volume of water delivered to the facilities by the third party production.
- Excess Water Volumes: To the extent that additional produced water or seawater volumes are available and desired, facility owners will provide third party facilities with water volumes in excess of their water production where needed to maximize and optimize field development. A fee may apply for this excess volume.
- Facility Access Fees, which compensate facility owners for their investment and ongoing costs incurred to provide facilities and processing of the third party fluids.
- Capital Access Fee, which compensates the facility owners on an adjusted per barrel processed basis for their past capital investment. This fee recognizes that the facility owners have invested large sums in the past for the equipment and facilities that are available to the third party. Generally this fee would have a depreciation component and a rate of return component.
- Capital Access Fee Surcharge which compensates the facility owners for capital costs incurred after third party processing begins. This would apply if the third party does not participate in a joint capital project but the third party benefits from the project. This fee could be a per barrel charge which is imposed following increments of capital expenditure.
- Abandonment Fee, which compensates facility owners for future abandonment costs of the facilities.
- Abandonment Fee Surcharge, which covers abandonment costs for capital added after third party processing begins.
- Accounting: For purposes of determining volumes of third party oil processed, the volumes in the monthly production and injection reports filed with the Alaska Oil and Gas Conservation Commission will be used less any adjustments caused by backout. Allocation among the owners will be determined by the parties.
- Operating and Maintenance Costs, which compensate the facility owners for operating and maintenance costs. The costs for any facilities not benefiting the third party shall be excluded from the calculations.
- Plant Liquid Processing Fee, which is a per-barrel fee, determined by dividing the O&M costs by the volume of total liquid production (oil plus

water) processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross liquid processing operations but do not include any O&M costs not benefiting the gross liquid processing operations.

- Plant Gas Processing Fee, which is a per-mcf fee, determined by dividing the O&M costs by the volume of total gas production and lift gas processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross gas processing operations but not include any O&M costs not benefiting the gross gas processing operations. The fee shall be applied to the allocated volume of fuel gas, flare gas, take-in-kind, shrinkage and lost gas attributable to third party fluids.

- Common Drillsite fee, which is a per barrel fee, determined by dividing the O&M costs by the volume of total liquid production (oil plus water) processed in the facilities. The O&M costs can include total drillsite labor, direct operating costs and allocated field support costs that are attributed to all drillsite operations but shall exclude charges for operations which do not benefit the third party. The fee shall be applied to third party gross liquid production (oil plus water) processed through the facilities less any adjustments.

- Water Fee, which is a per-barrel fee, determined by dividing the O&M costs by the total make-up water volume made available and used for injection in all reservoirs. The O&M costs can include total labor, direct operating costs, and allocated field support costs that are attributed to seawater treatment plant operations and associated pipelines which carry seawater to the injection plants. This fee shall be applied to each barrel of make-up water injected into the third party reservoir.

- Ad Valorem Tax Fee: The annual ad valorem taxes chargeable to the third party shall be determined by multiplying the total annual ad valorem taxes by the third party adjusted gross liquid production (oil plus water) processed in the facilities divided by the total liquid production (oil plus water) processed in the facilities.

- Fluids Associated with Backout Oil: The adjusted backout volumes have an associated volume of water and gas. These volumes of water shall be the gross third party water production times the adjusted third party backout volume divided by the gross third party oil production. The gross third party gas production times the adjusted third party backout volume divided by the gross third party oil production is the associated gas volume.

- Routine Field CAPEX Share: Routine field CAPEX shall be allocated to the third party owners on third party’s gross liquid production (oil plus water) processed through the facilities less any adjustments divided by the total liquid production processed through the facilities.

- Joint Capital Projects: A joint capital project may be proposed by either the facility owners or the third party owners. The percentage voting and procedure for proposing the projects can be negotiated by the parties and set forth in this agreement. All construction and modifications shall be owned solely by the facility owners.

- Volume Adjustments

  - Backout of production from the facility owners' production caused by the introduction of third party production.

  - Quality adjustment due to differences in the characteristics of the oil production from the facilities and the oil production from the third parties. These differences could be caused by API gravity differences, compositional differences and impurities. The compensation will be a transfer of barrels between the parties. The exact procedure and calculation would be negotiable after the determination of the Quality effect.

  - Tax and Royalty: To calculate the net backout share allocated to each party, the backout volume is adjusted for severance tax and royalty to keep the receiving parties whole on an after severance tax and royalty basis.

- Allocation and Metering: Third party owners shall pay for all metering investments required for their fluids. Facility operator will prepare and maintain all information necessary for the filing of any reports required by governmental regulatory authorities relating to volume, quality, and disposition of produced fluids. The unit operator will conduct well tests or metering as required for the allocation of production and provide information to all parties.

- Gas Supply: Third party owners shall be responsible for fuel gas consumed by its equipment and a proportionate share of the fuel gas used in the facilities.

- Gas Use and Reinjection: Any gas not used and consumed shall be taken in kind, reinjected into the third party reservoir or injected into the facility owners' (FO) reservoir. The gas injected into the FO reservoir will be considered indigenous to the FO reservoir and no compensation for the gas will be given.

- Warehouse Sharing: The third party facilities will be permitted to use facility materials. The material and costs will be negotiated.

- Legal and Accounting Rights, which define each party's legal rights, indemnity and auditing procedures.

- Trans Alaska Pipeline System (TAPS) transports all North Slope production to Valdez, where it is loaded onto tankers.
- Other shared services:
  - Camp and services
  - Security checkpoints
  - Shuttle services
  - Grind and Inject Plant for drilling waste disposal

- Gulf of Mexico Facility Sharing
  - Almost all Gulf of Mexico pipelines are common carriers and regulated as such. As the fields continue to mature and new prospects are identified, satellite fields and deepwater prospects may be tied to common processing facilities, as is done in the North Sea.
  - Common carrier oil pipelines
    - Activities regulated by Federal Energy Regulatory Commission (FERC)
      - Rates and charges
      - Terms of service
      - Tariffs
      - Accounting
      - Reporting
      - Disclosure of shipper identity
    - Activities not regulated by Federal Energy Regulatory Commission (FERC)
      - Construction and abandonment of oil pipelines
      - Lease of pipeline assets
      - Securities transactions
      - Provision of non-transportation services
    - Types of rates
      - Settlement rates – any rate agreed to in writing by all users of the service.

        - Market rates- carrier has to demonstrate that it lacks significant market power to set rates in both the origin and destination markets. Carrier may set rates at what the market will bear.
        - Cost of service rates – guideline formulas exist for setting rates, based on accounting principles.
    - Common carrier gas pipelines
        - Regulated as a public utility
        - Construction, operation, and abandonment are regulated by FERC.

- North Sea (UK, Norway)
    - The United Kingdom's "Indicative Tariff" Code of Practice for offshore oil and gas infrastructure is a cooperative industry document on the rules and procedures governing third party access to these facilities. This document provides a framework for easy, fair and non-discriminatory access to offshore oil and gas facilities. The process is supported by the oil and gas industry. It is not mandated or enforced by a government agency, however if a dispute over access does arise, there is a government body that has the legal authority to settle the differences. The framework for third party facility access is a combination of the Offshore Infrastructure Code of Practice for conducting commercial negotiations and the legal backstop of appealing to the UK Secretary of State for Trade and Industry to settle disputes over access.
    - UK facility owners maintain a database of offshore infrastructure, capacity projections, and indicative fees. The Code of Practice sets guidelines for a negotiation timetable that begins when a potential user expresses interest in that infrastructure. The process is industry-driven and continues to evolve as conditions change.
    - The Norway Petroleum Act establishes a third party access regime to pipelines and other infrastructure. The relevant parties agree on the terms for such third party access. The Ministry of Petroleum and Energy (MPE) can, however, decide that a third party is entitled to use another licensee's installations and other facilities and provide tariffs and other terms for that use, including if the parties fail to agree within a reasonable time. However, this forced third party access is subject to the MPE finding that the use of the asset by a third party does not unreasonably restrict the needs of the owner or other users of the infrastructure.
    - Most of the infrastructure for transportation and processing of natural gas produced on the Norwegian continental shelf has been merged into an unincorporated joint venture called Gassled which is currently owned by six exploration and production (E&P) companies and five pure infrastructure owners. The Gassled pipeline system is operated by an independent, state-owned company called Gassco AS. New pipelines that are subject to third party access will, as a starting point, be merged into the Gassled system. For the Gassled transportation and processing

infrastructure, a regulated third party access system has been established. Under this system, processing and transportation capacity is made available for booking in auctions. The tariffs are set by the government in the Tariff Regulations and the transportation agreements are standardized.

- The main offshore Norwegian common carrier oil pipelines are owned by Norpipe Oil AS, a consortium which includes ConocoPhillips Skandinavia AS (35.05%), TotalFinaElf Exploration Norge AS (34.93%), Statoil (18.5%), Eni Norge AS (6.52%), and SDFI (5%). It is operated by ConocoPhillips Skandinavia AS.

- Canada
  - A framework for infrastructure sharing has been developed, known as the Jumping Pound formula. The most current formula is given in JP-05. This document provides a detailed guideline for fee negotiations under a variety of different circumstances and examples of negotiated fee arrangements.
  - Ideally, the fees are successfully negotiated without regulatory intervention or the need for a prescribed formula. When the parties cannot successfully negotiate an agreement, the recommended JP-05 fee formula is

    20% * Rate Base + Operating Costs + Lost GCA

    Where:

    Rate base is a negotiated number from original cost to replacement cost.

    Operating costs are the same as for facility owners.

    Lost GCA reflects the reduced royalty credits on unused capacity capital.
  - The formula applies to:
    - Fees negotiated between producing (E&P) companies needing or holding unused facility capacity, where such capacity was originally constructed for a producer's own use rather than for custom processing
    - Fees developed by companies that offer midstream processing services
    - Fees required by CAPL Joint Operating Agreement partners that elect non-participation in a production facility and elect the fee option under a CAPL operating agreement
    - Fees required by freehold mineral rights owners where the fees have not been specified in the lease agreements
    - Fees required by parties that elect non-participation in a new facility development to be the subject of a CO&O Agreement

- Brazil
    - Sharing of offshore facilities in the Campos basin has been proposed and appears to be inspired by the success of the UK facility sharing agreements.

10.2.2 Best Practices

In National Interest, Regulator should outline in the FDP Approval process, evaluation of any potential sharing of Facilities/ Infrastructure (including independent 3rd party evaluation and recommendation) to optimize utilization of resources for faster and economic development of domestic hydrocarbon resources and in case there is possibility of utilization of facilities/ infrastructure, same should be mandated. Similar practice exists in T&T and Brazil (Document to be submitted by AOGO)

- Facility Sharing Agreements
    - The facility sharing process must:
        - Be fair, equitable, and understandable to all parties
        - Result in net increase in production, improve resource conservation, and reduce waste
        - Not result in any new government regulation
        - Preserve and promote operational integrity
        - Preserve the integrity of unit rights/obligations, and tax partnerships
        - Reduce financial and operational risk
        - Introduce no significant adverse impact to existing production
        - Provide timely access to indicative fee structure for bona fide inquirers
        - Create a level playing field for all producers, where the “best” barrels are produced
        - Allow for resolution of conflicts
        - Compensate the facility owners for their historical capital costs and lost or deferred production
        - Provide equitable sharing of ongoing costs among all users
    - Components of the facility sharing agreements:
        - Identification of Facility Owners and their intentions
        - Identification of Third Party Owners and their intentions
        - Definitions of Terms

- Definition of Facilities that are and are not included in the agreement
- Definition of Third Party Facilities that are third party sole responsibility
- Standards of Produced Fluids (fluid compatibility and physical limitations)
- Priorities Governing Production Processing: This section states that the facility sharing agreement will maximize the total oil production. In order to maximize oil production, high GOR and/or high WOR wells will be curtailed first regardless of ownership. Wells of the facility owner could be shut-in or curtailed, thereby decreasing the facility owner's total production. The volume not produced by the facilities owners is "backed out" to make room for the third party production. To compensate the owners for this backout, the backout volume is calculated via a defined process, and transferred to the facility owners from the third party owners. The third party owners do not pay fees on the barrels they must give up as backout compensation.
- Produced Water and Seawater: Facility owners will provide to each third party a volume of water, for water injection that is equal to the volume of water delivered to the facilities by the third party production.
- Excess Water Volumes: To the extent that additional produced water or seawater volumes are available and desired, facility owners will provide third party facilities with water volumes in excess of their water production where needed to maximize and optimize field development. A fee may apply for this excess volume.
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- Capital Access Fee, which compensates the facility owners on an adjusted per barrel processed basis for their past capital investment. This fee recognizes that the facility owners have invested large sums in the past for the equipment and facilities that are available to the third party. Generally this fee would have a depreciation component and a rate of return component.
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- Abandonment Fee, which compensates facility owners for future abandonment costs of the facilities.

- Abandonment Fee Surcharge, which covers abandonment costs for capital added after third party processing begins.

- Accounting: For purposes of determining volumes of third party oil processed, the volumes in the monthly production and injection reports will be used less any adjustments caused by backout. Allocation among the owners will be determined by the parties.

- Operating and Maintenance (O&M) Costs, which compensate the facility owners for operating and maintenance costs. The costs for any facilities not benefiting the third party shall be excluded from the calculations.

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- Plant Gas Processing Fee, which is a per-mcf fee, determined by dividing the O&M costs by the volume of total gas production and lift gas processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross gas processing operations but not include any O&M costs not benefiting the gross gas processing operations. The fee shall be applied to the allocated volume of fuel gas, flare gas, take-in-kind, shrinkage and lost gas attributable to third party fluids.

- Common Drillsite fee, which is a per barrel fee, determined by dividing the O&M costs by the volume of total liquid production (oil plus water) processed in the facilities. The O&M costs can include total drillsite labor, direct operating costs and allocated field support costs that are attributed to all drillsite operations but shall exclude charges for operations which do not benefit the third party. The fee shall be applied to third party gross liquid production (oil plus water) processed through the facilities less any adjustments.

- Water Fee, which is a per-barrel fee, determined by dividing the O&M costs by the total make-up water volume made available and used for injection in all reservoirs. The O&M costs can include total labor, direct operating costs, and allocated field support costs that are attributed to seawater treatment plant operations and associated pipelines which carry seawater to the injection plants. This fee shall be applied to each barrel of make-up water injected into the third party reservoir.

- Ad Valorem Tax Fee: The annual ad valorem taxes chargeable to the third party shall be determined by multiplying the total annual ad valorem taxes by the third party adjusted gross liquid production (oil plus water) processed in the facilities divided by the total liquid production (oil plus water) processed in the facilities.

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- Volume Adjustments

    - Backout of production from the facility owners' production caused by the introduction of third party production.

    - Quality adjustment due to differences in the characteristics of the oil production from the facilities and the oil production from the third parties. These differences could be caused by API gravity differences, compositional differences and impurities. The compensation will be a transfer of barrels between the parties. The exact procedure and calculation would be negotiable after the determination of the Quality effect.

    - Tax and Royalty: To calculate the net backout share allocated to each party, the backout volume is adjusted for severance tax and royalty to keep the receiving parties whole on an after severance tax and royalty basis.

- Allocation and Metering: Third party owners shall pay for all metering investments required for their fluids. Facility operator will prepare and maintain all information necessary for the filing of any reports required by governmental regulatory authorities relating to volume, quality, and disposition of produced fluids. The unit operator will conduct well tests or metering as required for the allocation of production and provide information to all parties.

        - Gas Supply: Third party owners shall be responsible for fuel gas consumed by its equipment and a proportionate share of the fuel gas used in the facilities.
        - Gas Use and Reinjection: Any gas not used and consumed shall be taken in kind, reinjected into the third party reservoir or injected into the facility owners' (FO) reservoir. The gas injected into the FO reservoir will be considered indigenous to the FO reservoir and no compensation for the gas will be given.
        - Warehouse Sharing: The third party facilities will be permitted to use facility materials. The material and costs will be negotiated.
        - Legal and Accounting Rights, which define each party's legal rights, indemnity and auditing procedures.
    - Other shared services:
        - Camp and services
        - Security checkpoints
        - Shuttle services
        - Grind and Inject Plant for drilling waste disposal
- Additional Offshore Facility Sharing
    - Common carrier oil pipelines
        - Activities regulated
            - Rates and charges
            - Terms of service
            - Tariffs
            - Accounting
            - Reporting
            - Disclosure of shipper identity
        - Activities not regulated
            - Construction and abandonment of oil pipelines
            - Lease of pipeline assets
            - Securities transactions

        - Provision of non-transportation services
      - Types of rates
        - Settlement rates – any rate agreed to in writing by all users of the service.
        - Market rates– carrier has to demonstrate that it lacks significant market power to set rates in both the origin and destination markets. Carrier may set rates at what the market will bear.
        - Cost of service rates – guideline formulas exist for setting rates, based on accounting principles.
  - Common carrier gas pipelines
    - Regulated as a public utility
    - Construction, operation, and abandonment are regulated

- Establishment of "Code of Practice" (UK Example)
  - The United Kingdom's "Indicative Tariff" Code of Practice for offshore oil and gas infrastructure is a cooperative industry document on the rules and procedures governing third party access to these facilities. This document provides a framework for easy, fair and non-discriminatory access to offshore oil and gas facilities. The process is supported by the oil and gas industry. It is not mandated or enforced by a government agency, however if a dispute over access does arise, there is a government body that has the legal authority to settle the differences. The framework for third party facility access is a combination of the Offshore Infrastructure Code of Practice for conducting commercial negotiations and the legal backstop of appealing to the UK Secretary of State for Trade and Industry to settle disputes over access.
  - UK facility owners maintain a database of offshore infrastructure, capacity projections, and indicative fees. The Code of Practice sets guidelines for a negotiation timetable that begins when a potential user expresses interest in that infrastructure. The process is industry-driven and continues to evolve as conditions change.
- Sharing of infrastructure may aid in monetization of marginal fields by lowering the costs of bringing the fields on production. It is therefore important to have a system in place to inform operators of the infrastructure near them and to facilitate access and utilization.

10.2.3 References

1. The UK Department of Energy and Climate Change (DECC) lists requirements for onshore oil and conventional gas field development plans in their document "Guidance Notes for Onshore Oil and Gas Field Development Plans (October 2009)". The section on "Annual Field Reports" addresses issues related to deviations from the agreed FDP.

2. "North Slope of Alaska Facility Sharing Study" prepared for Division of Oil and gas, Alaska Department of Natural Resources. Bob Kaltenbach, Chantal Walsh, Cathy Foerster, Tom Walsh, Jan MacDonald, Pete Stokes, Chris Livesey and Will Nebesky, Petrotechnical Resources Alaska. May 2004.

    a. http://dog.dnr.alaska.gov/publications/Documents/OtherReports/NorthSlope_Facility_Sharing_Study.pdf

3. United States Federal Energy Regulatory Commission (FERC)http://www.ferc.gov

4. Norway http://uk.practicallaw.com/6-529-5206#a466457

5. "JP-05: A Recommended Practice for the Negotiation of Processing Fees", Joint Industry Task Force Report, prepared by Canadian Association of Petroleum Producers, Gas Processing Association Canada, Petroleum Joint Venture Association, Small Explorers and Producers Association of Canada. October, 2005.

    a. https://www.aer.ca/documents/reports/JP05.pdf

6. Pedroso, D. C., Abdala, D. C., & Pinto, L. A. G. (2012, April 30). Infrastructure Sharing: Creating Value for Brazilian Deepwater Offshore Assets. Offshore Technology Conference. doi:10.4043/23004-MS

10.3 *Are there any Unidentified Gaps and Ambiguities in the Indian PSCs / Contracts?*

In review of the NELP-VIII Model Production Sharing Contract, the following observations and recommendations were made:

- In regards to non-associated natural gas discoveries, the impact of imposing price restrictions on natural gas should be weighed against the potential increase in domestic natural gas production resulting from more favorable project economics, especially with marginal fields. Gas prices more reflective of import prices or more favorable production splits to the Contractor for non-associated gas production scenario are a few examples of ways to improve project economics. By allowing for marginal fields to be developed, investment into the country should increase, resulting in local jobs and community benefits, and lower reliance on foreign gas/LNG import. Perhaps this should be done on a case by case basis, inserting an article allowing for revisions to terms and conditions with respect to marginal fields (similar to contract extension policy for mature fields).

- Article 21.5.12 states that the Contractor has 10 years from the date of discovery to commence development of a gas field else the Discovered Area shall be excluded from the Contract Area; however; there is no such provision in the case of oil. A similar clause for oil scenario has been suggested.

- In the case of assignment of Participating Interest, the date of govt approval may be the date of issuance of approval letter by MOPNG. In case of CBM Contract, the commencement of the Development Phase (Phase III and IV) may be considered from the date of issuance of Mining Lease by the State Government.

- References

1. Model Production Sharing Contract (NELP-VIII), Republic of India, 2009.

10.4 *International Norms for Insurance for Petroleum Operations Taken by Contractor to Provide for Liabilities and Indemnify the Government*

10.4.1 Definitions and Discussion

The oil and gas industry is one with inherent risks to both people and equipment. While operators should take all reasonable measures possible to prevent dangerous situations that may result in damage to people or equipment, unforeseeable and unpredictable events of loss do occur. It is important to have a plan for these events as well as a means of repairing, mitigating and/or resolving their consequences. In addition to the many tools and mitigation techniques for health, safety and environmental events discussed elsewhere in this document, a robust insurance program can provide companies of all sizes the means to deal with these events. Further, a fully underwritten insurance policy will enable a covered event to be mitigated completely, largely removing counterparty risk and the potential risk of underfunding.

Insurance policies are generally written with general conditions policy, declarations and endorsements. The general conditions will set forth the basic coverages of the policy, including high level terms and definitions. Declarations generally include the limits of coverage, retention (or “deductible”), and the named insured. Endorsements are basically additional language modifying the general conditions. These can include additional coverages, terms of mitigation (such as indemnification, pay on behalf of, cut through, etc.), and/or additional terms of coverage. Each policy is different and has endorsements specific to the underwriter group.

10.4.2 Best Practices

There are many types of insurance available to international oil and gas operators, a few of the most common are:

- Commercial General Liability (“CGL”)
    - CGL, also called third-party liability, covers liability for bodily injury and property damage to third parties. Operators commonly get claims from the employees of a contractor, such as a drilling or well service company. The contractor’s employee gets hurt at the well site, makes a claim for workers compensation and then sues the operator for “not furnishing a safe place to work”. Before the CGL responds to such a claim, the contract should be reviewed to make sure a mutual hold harmless agreement making each employer liable for injury to his employee, regardless of

fault. If so, the claim is passed to the other party. If there is no mutual hold harmless, the operator's policy will respond.

  - The CGL should include an endorsement for liability to Underground Resources and Equipment. This endorsement would cover damage to adjacent reservoirs, water tables, or equipment owned by a nearby operator. This coverage is commonly available for CGL policies.

  - It is common to find Sudden and Accidental Pollution Liability included on the CGL, subject to the operative clause of the policy requiring Bodily Injury and/or Property Damage to a third party; but operators should be careful of the discovery period—the time allowed to discover the loss. Liabilities arising solely from any obligations imposed by or on behalf of a government authority are typically excluded.

    - A separate pollution policy that includes strict clean-up and/or gradual coverage can be purchased and it is usually written on a claims-made basis. This is commonly referred to as "Environmental Impairment Liability" and is provided by a number of specialist International Insurers. This is a recommended practice for operations in environmentally sensitive areas.

  - The CGL should also include several broadening endorsements if not included in the form: Waiver of Subrogation if required by contract; Additional insured where required by contract; Primary and Non-contributory; Cross liability, etc.

  - The CGL will exclude control of well costs (blow out, etc.) as this is placed under a separate policy called Control of Well (COW) or now often referred to as Operators Extra Expense (OEE).

- Control of Well ("COW")

  - The largest exposure for oil and gas operators in terms of severity is covered by this policy. It is widely accepted that a well shall be deemed out of control when there is an uncontrolled flow from the well above the surface of the ground or water bottom, albeit this can be widened by endorsement.

  - Coverage to mitigate this risk generally has three major parts: Coverage for expenses in controlling a well that has gotten out of control; re-drilling or restoring the well to the depth at which control was lost; and liability for pollution damage caused by such loss of control. Operators can also provide a sub-limit for damage to property in the care, custody and control of the operator, or for which it has contractually agreed to be responsible e.g. drill string.

  - There are other endorsements to broaden coverage for this policy as well. Such endorsements may include: Cut-through (where the operator is reimbursed directly for claims), pay-on-behalf-of (where the underwriter will retain a company such as Boots and Coots to bring the wells under control and redrill to depth), evacuation of people, underground blowout, extended redrill, unlimited redrill, making wells safe or other terms specific to the policy.

- Control of Well events related to labor unrest are generally covered in most policies at no additional charge, but operators are recommended to check the endorsements for policy specifics.

- Automobile Insurance
  - Automobile insurance is often required by law for all road-legal vehicles and written in the standard manner. All autos owned by the company should carry liability insurance at a minimum, not forgetting that some rigs and oilfield equipment such as mobile rigs, cranes and forklifts may be operated on state roadways. Coverage for hired and non-owned autos should also be considered if employees will be driving non-owned vehicles. This enables the employees of an operator to be covered if they are operating leased vehicles. There are broadening endorsements that can be added onto this policy as well.
- Workers Compensation and Employers Liability
  - Workers' compensation covers for land operations is standard fare. If there is maritime exposure make sure there are coverages extended to that as well.
- Property Insurance
  - This is required and written in the standard manner to cover operational facilities (including removal of debris/wreck) including but not limited to buildings, equipment, furniture, contents, etc.
  - Operators should pay particular attention to the "basis of valuation" clause of their policy and ensure that they declare values appropriate to the type of coverage being purchased.
  - A special type of property coverage applies to oil companies called Crude Petroleum in Tanks Coverage that covers oil while it is being stored.
  - While Property Insurance does not generally cover any liability, it is important to keep in order to maintain equipment that might be damaged or stolen.
  - Other types of insurance may also include coverage on loss of production income / business interruption.
- Excess Umbrella (also called as 'Excess Liability Umbrella'):
  - This is typically provided by International Insurers to sit in excess of primary insurances provided by the domestic marketplace.
  - This coverage extends the limits of liability for other coverages. It is important to make certain there are no exclusions or wording that will inhibit the policy from being as broad as or broader than underlying coverages.

- Other Types of Insurance
    - As with any business operation, other coverage that is not specific to oil and gas operators should also be considered. Note that this report does not suggest these coverages as PSC requirements, but rather informs and recommends their consideration by operators. Some of these policies are::
        - Directors and Officers
        - Employment Practices Liability
        - Fiduciary Liability
        - Crime
        - Network Security Liability
        - Trade Credit insurance
- Insurance Process
    - Insurance is generally obtained through a broker that will assist an operator in contacting various marketplaces or underwriters to create a policy tailored to the needs of the Working Interest Parties. Policies should be chosen that reduce liability and indemnify the Government.
    - It is common for governments to require operators to use a local agent to underwrite the coverage. Depending on the market capacity, it is typically expected that the domestic marketplace be utilized to procure primary coverage for the smaller exposures such as workers compensation, automobile liability, D&O insurance, corporate travel, etc.
    - However, in the case of many large exposures such as COW, physical damage or umbrella liabilities, the domestic marketplace does not contain the sufficient capital to provide the limits required. As a result these risks are generally reinsured by international syndicates such as Lloyds of London. In these circumstances a Reinsurance broker will typically be appointed to arrange the required reinsurance protection on behalf of a domestic ceding company that will in turn, and upon confirmation of such protection, be able to issue the relevant policy to the operator. It is typically a requirement that such reinsurance protection be provided by those Reinsurers with a financial security rating of A- or above from Standard & Poor's and/or AM Best.
    - It is highly recommended that Operators carry GCL insurance with a limit sufficient to cover damage to people, property or equipment reasonably within their sphere of influence.
    - COW coverage is almost universally required. As a rule, the limit for COW insurance should be sufficient to cover foreseeable remediation (which will vary depending on the remoteness of the location, operating environment, depth and well

type), re-drilling of the entire well, and cleanup of a sudden event of pollution (which will depend on the local environment). Careful consideration should be given to the particular well in question, but COW limits are commonly 3-5 times the estimated cost of the completed well.

  - Additional insurance is recommended for the specific areas of liability and property that an insured might require for the reasons stated above. Special attention should be given to insurance which protect people, such as workers compensation.

- The above best practices detail the more common types of insurance available to international oil and gas operators and contain various recommendations. It is the considered view of this report that at a minimum, operators shall carry, CGL, COW and property insurance for owned equipment. Other policies should be maintained as required by law and as appropriate for the operating environment.

- In addition to the above practices, it is important to mention that Article 24 of the (NELP-VIII) PSC for India states that insurance policies shall include the Government as additional insured and shall waive subrogation against the Government. This is generally permissible but requires written agreement to do so with the assured and the waived party. Furthermore, Article 24 states that the Contractor shall indemnify, defend and hold the Government, and the State Government harmless against all claims, losses and damages of any nature. These practices are mandated by the PSC and are therefore recommended.

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3. Model Production Sharing Contract (NELP-VIII), Republic of India, 2009.

10.5 *Accounting Procedures; Inventories and Records of Assets*

10.5.1 Definitions and Discussion

Accounting is the language of business. It is used by the business world to communicate the business transactions that have occurred in the operations. Due to the complexity of the business, culture, taxation and legal systems, there is diversification of accounting policies throughout the world. Due to the diverse nature of the accounting policies worldwide, it becomes difficult to make comparison between companies that reside in different parts of the world. It makes it difficult and more tasking for the investor and other interested parties to make financial and non-financial decisions.

The US GAAP used to have four alternative accounting methods:

- Full Cost Method
- Successful Efforts Method

- Discovery Value Accounting Method
- Current Value Accounting Method

The amended SFAS 19 rejected the use of the Discovery Value Accounting and Current Value Accounting methods in 2008. Thus, only two methods viz, Successful Efforts Method and Full Cost Method are recommended for use in accounting for the oil and gas companies.

Definition of terms used in accounting are given below:

- Costs
    - Pre-license costs - Cost that is incurred in the period prior to the acquisition of a legal right to explore for oil and gas in a particular location.
    - License acquisition costs - Costs that are incurred to purchase, lease or otherwise acquire a property.
    - Exploration and appraisal costs - Costs incurred after obtaining a license or concession but before a decision is taken to develop a field or reservoir.
    - Development costs - Costs incurred after a decision has been taken to develop a reservoir
    - Operating costs - Costs of producing oil and gas including costs of personnel engaged in the operation, repairs and maintenance and materials, supplies and fuel consumed and services utilized in such operations.
- Decommissioning
    - The process of plugging and abandoning wells, dismantlement of wellhead, production and transport facilities and restoration of producing areas in accordance with license requirements and/or relevant legislation.
- Full cost accounting
    - A method of accounting for oil and gas exploration and development activities whereby all costs associated with exploring for and developing oil and gas reserves are capitalized, irrespective of the success or failure of specific parts of the overall exploration activity. Costs are accumulated in cost centers known as ‘cost pools’ and the costs in each cost pool are written off against income arising from production of the reserves attributable to that pool.
- Impairment
    - Capitalized development costs - a change in circumstances leading to a conclusion that the recoverable amount from reserves associated with capitalized development costs is likely to be less than the amount at which those costs are carried in the books.

- Costs capitalized whilst a field is still being appraised - a change in circumstances leading to a conclusion that there is no longer a reasonable prospect that commercial reserves will result and will be developed.

- Successful efforts accounting

  - A method of accounting for oil and gas exploration and development activities whereby exploration expenditure which is either general in nature or relates to unsuccessful drilling operations is written off. Only costs which relate directly to the discovery and development of specific commercial oil and gas reserves are capitalized and are depreciated over the lives of these reserves. The success or failure of each exploration effort is judged on a well-by-well basis as each potentially hydrocarbon bearing structure is identified and tested.

10.5.2 Best Practices

- Accounting Theory

  - The accounting choice is any decision whose primary purpose is to influence the output of the accounting system in a particular way. Three major factors that influence the accounting choices are the size of the firm, the level of capital intensive nature of the firm and the competition in the industry that the firm faces.

  - Oil and gas E&P activities have several distinctive features:

    - High risk
    - High cost of investment
    - Time lag between exploration and production
    - No necessary correlation between the capital expenditure for exploration and development and the value of the oil and gas reserves discovered as a result of the activities

  - These and other factors make the accounting for oil and gas operations complex and specialized and thus have led to development of a wide range of accounting practices in the industry. The two most commonly used and recommended historical cost methods in accounting for oil and gas industry is:

    - Successful Efforts Method
    - Full Cost Method

  - Oil and Gas accounting can be related to three basic activities carried out by oil and gas exploration and production companies.

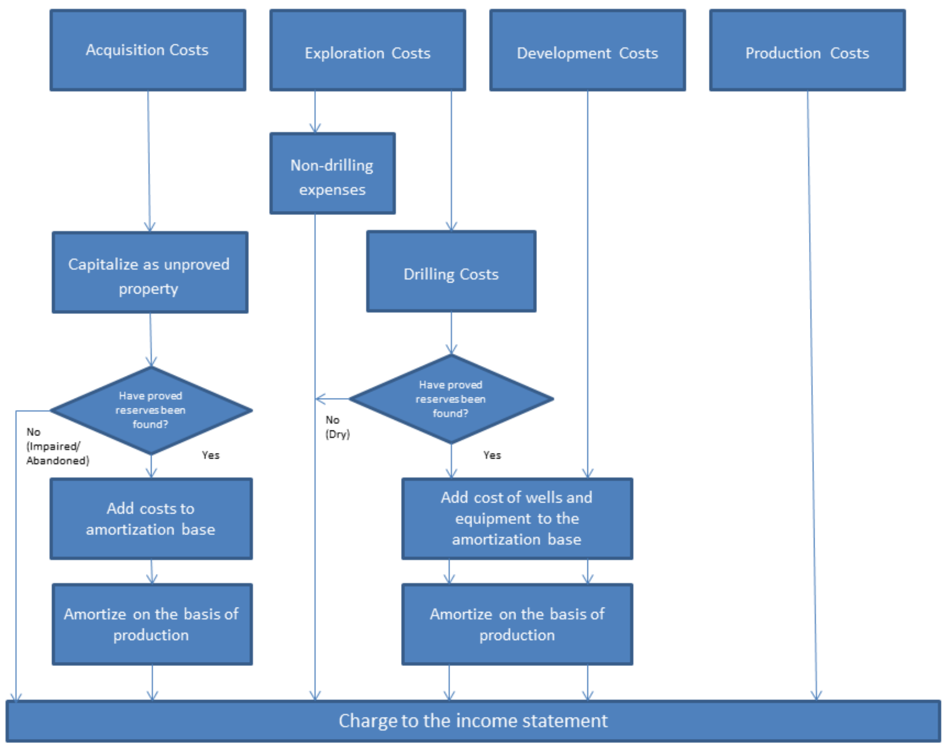
    - Pre-production and development activities
    - Production activities

  - ▪ Decommissioning activities

- o These three basic types of activities must be accounted for using one of the two above named generally accepted historical cost methods. These methods of accounting have been described in the sections below.

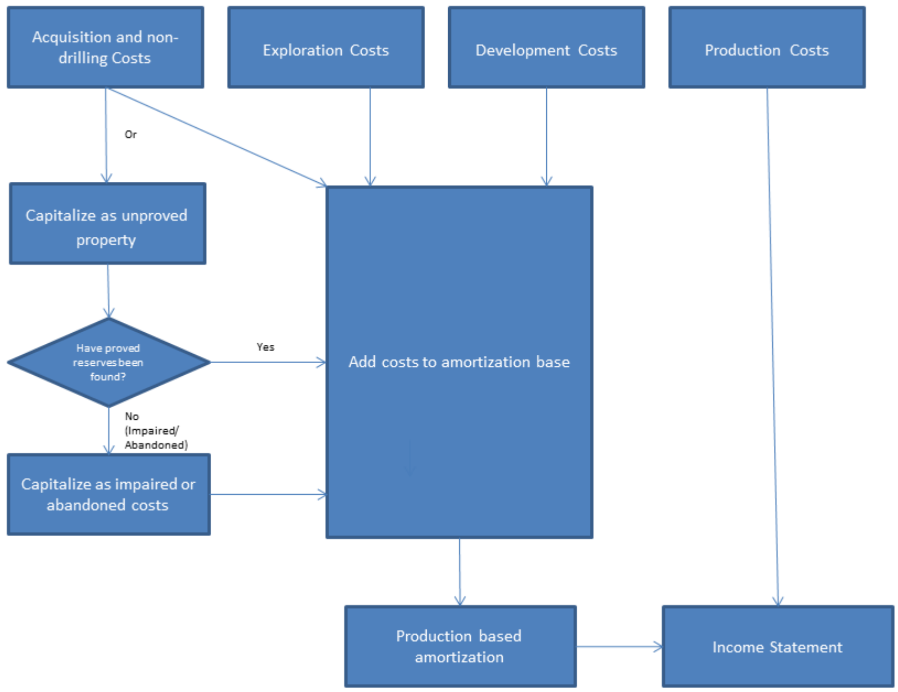
- Accounting Systems
  - o Successful Efforts Method

    The chart below describes the functioning of the Successful Efforts Method



  - o Full Costs Method

    The chart below describes the functioning of the Full Costs Method



- The primary difference between successful efforts and the full cost is in whether a cost is capitalized or expensed when incurred. Thus the difference is in the timing of expense or loss charge against the revenue.

- The second difference between the two methods is the size of the cost center over which the costs are accumulated. For the successful efforts method the cost center is the lease, field or reservoir whereas for the full costs method the cost center is the country.

- Under the successful efforts method only exploratory drilling costs that are successful are considered to be a part of the cost of finding oil and gas and thus capitalized. Unsuccessful exploratory drilling costs do not result in any economic benefit and thus are expensed. In contrast full cost method considers both unsuccessful and successful costs incurred in search for reserves as a necessary part of finding oil and gas. Thus, both successful and unsuccessful costs are capitalized even though the unsuccessful costs have not future economic benefit.

- A comparison of the accounting treatment between the various costs under both successful efforts method and full costs method is shown in the table below:

Item	Successful Efforts Method	Full Cost Method
Acquisition Costs	Capital	Capital
G&G Costs	Expense	Capital
Exploratory Dry Hole	Expense	Capital
Successful Exploratory Well	Capital	Capital
Development Dry Hole	Capital	Capital
Successful Development Well	Capital	Capital
Production Costs	Expense	Expense
Amortization Cost Center	Property, Field or Reservoir	Country

- Application of Accounting Systems
    - Pre-production activities and development activities
        - Successful Efforts Method
            - All pre-license, license acquisition, exploration and appraisal costs should initially be capitalized in well, field or general exploration cost centers as appropriate. Expenditure incurred during the various exploration and development phases should be written off unless commercial reserves have been found.
            - Any expenditure which is incurred prior to the acquisition of a license and the costs of other exploration activities should be written off in the accounting period itself.
            - Exploration and appraisal costs should be accumulated on a well-by-well basis in case the evaluation of the resources is pending.
            - If any commercial reserves are found after the appraisal, then the net capitalized costs which were incurred in the process of discovering the field should be transferred into a single field cost center. Any subsequent development costs, should be capitalized in this cost center.
            - All successful exploration and development expenditure should be capitalized as additions to fixed assets in the period in which it is incurred.
            - When the existence of commercial reserves is established, directly related exploration and appraisal expenditure should be capitalized and reclassified in the financial statements as tangible assets. Subsequent field development costs should be classified as tangible assets.
            - Subsequent expenditure should be capitalized where it enhances the economic benefits of the tangible fixed assets.

- Full Cost Method

    - All the expenditure on pre-license, license acquisition, exploration, appraisal, and development activities including enhanced oil recovery and extended life projects should be capitalized.

    - Pre-license acquisition, exploration and appraisal costs of individual license interests may be held outside cost pools until the existence or otherwise of commercial reserves is established. These costs will therefore remain undepreciated pending determination, subject to there being no evidence of impairment.

    - The accounting policy of the firm should provide the basis under which cost pools are established, for example geographic area, region or country.

    - The aggregate net book value of full cost pools should be disclosed, together with the aggregate of costs held outside cost pools.

- Production activities

    - All the expenses under the production activities are expensed under both Successful Efforts and Full Cost methods of accounting.

    - Inventory Valuation

        - Inventories should be stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses.

        - Supplies should be valued at cost to the firm mainly using the weighted average cost method or net realizable value,whichever is the lower.

    - Pipeline fill

        - Crude oil which is necessary to bring a pipeline into working order should be treated as a part of the related pipeline on the basis that it is not held for sale or consumed in a production process, but is necessary to the operation of a facility during more than one operating cycle, and its cost cannot be recouped through sale (or is significantly impaired). This shall apply even if the part of inventory that is deemed to be an item of property, plant and equipment (PP&E) cannot be separated physically from the rest of inventory. Valuation should be at cost and it should be depreciated over the useful life of related asset.

- Decommissioning activities

- Decommissioning describes the process of plugging and abandonment of the wells, and stoppage of production and of restoration of producing areas in accordance with license requirements.
- The firms should make provision for a present obligation whether that obligation is legal or constructive.
- In most of the cases these provisions should be recorded at the present value of the expenditures expected to be required to settle the decommissioning obligation.
- The decommissioning liabilities should be provided for the facilities where a damage that will need to be rectified has been caused, for example production platforms that are already in place.
- This means that cost reductions expected to arise from increased experience of current technology or from applying the technology to larger projects can be considered. However, completely new technologies should not be anticipated.
- Where there is an adjustment to the provision as a result of a change in estimate, there should be a corresponding equal and opposite adjustment to the related ‘decommissioning asset’.
- A uniform group accounting policies should be used for determining the amounts to be reported in a company’s consolidated accounts, if necessary by adjusting for consolidation the amounts which have been reported by subsidiary undertakings in their own accounts, so that the consolidated accounts reflect the group’s accounting policies applied to the exploration and development activities of the group as a whole. A consistent definition of commercial reserves and consistent application of either full cost or successful efforts accounting policies should be applied throughout.

- Financial Statement Presentation & Disclosures
  - Accounting Policies
    - The financial statements should have disclosures related to the methods of accounting for oil and gas activities. Some of the items which should normally be included in the disclosures are:
      - accounting for pre-production costs
      - amortization of capitalized costs
      - impairment tests
      - future decommissioning costs
      - deferred taxation

        - turnover and royalties
        - interest

    - Capitalized Costs
        - The aggregate capitalized costs relating to a company's oil and gas exploration and production activities and the related depreciation, depletion and amortization should be disclosed as at the balance sheet date
    - Decommissioning
        - Provisions for decommissioning costs should be separately disclosed in the balance sheet
        - Pre-production costs are incurred or provided
        - Each of the following types of costs should be disclosed in total and by geographical area for the accounting period:
            - License or concession acquisition costs
            - Exploration and appraisal costs
            - Development costs
    - Results of Operations
        - The results of operations of oil and gas exploration and production activities should be disclosed in total and by geographical area
    - Commercial Reserve Quantities
        - The net quantities of a company's interest in commercial reserves of crude oil and natural gas should be reported as at the beginning and end of each accounting period in total and by geographical area

- Inventories and Records of Assets
    - Inventory is defined as assets held for sale in the ordinary course of business, in the process of production for such sale, or to be consumed in the production of goods or services.
    - The permitted techniques for cost measurement, such as standard cost method, are similar under most of the accounting systems.
    - The cost of inventory includes all direct expenditures to ready inventory for sale, including allocable overhead, while selling costs are excluded from the cost of inventories, as are most storage costs and general administrative costs.
    - Virtually all E&P companies have oil in lease tanks, but the volumes and changes in inventory are typically immaterial to financial statements so most E&P

companies do not bother to recognize the inventory of crude oil in lease tanks when preparing financial statements. Some companies have substantial crude oil inventories, such as in remote foreign locations or on large ocean-going tankers; inventories of these types should be reflected in the financial statements.

  - Oil and gas inventory is recorded at the lower of cost or market (LCM). Immaterial inventory may be carried for simplicity at posted field price or similar market price.
  - Changes in inventory carrying values are often recorded as an adjustment to lease operating expense rather than to revenues.

- The inventory should be recorded using the lower of cost or market method of inventory valuation.

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10.6 *Information Security for the E&P Industry*

10.6.1 Definitions and Discussion

Organizations operating in the E&P sector face enormous challenges, including the pressing need to find and exploit new energy supplies, greater regulatory pressures, new workflow requirements, and the demands of a changing professional labor force. At the same time, E&P companies face a serious and growing risk from cyber-attacks, malicious software, and other threats against their IT infrastructure and intellectual property, and via property employees bring into the workplace like smartphones and tablets.

E&P organizations can measurably improve their security posture – not by deploying sophisticated technologies or strategies – but instead by simply following the basics of common-sense cybersecurity. That means deploying modern versions of operating systems, productivity tools and other applications, restricting workstation users to Standard User privileges, and adopting the Security Development Lifecycle.

The E&P sector is susceptible to cybercrime, and particularly where it uses newer technologies that may be vulnerable to sophisticated probes or attacks. Newer technologies – such as computer-controlled drilling rigs, condition monitoring, dynamic positioning systems, cloud-based services, and even USB sticks – may be vulnerable to sophisticated probes or attacks. The increasing dependency on automation to optimize drilling and production operations in the context of the "big crew change," with fewer available experts, is another. Once-isolated plant and drilling control systems are now increasingly integrated with corporate networks, vendor, and service company systems, and those connections can be doorways for potential threats. Other such doorways include:

- The heterogeneous infrastructure that is rapidly assembled at the wellsite, transiently supporting multiple service vendors for drilling and completing wells, or permanent field IT infrastructure, supporting digital oilfield initiatives - either of which create potential portals into corporate production data management systems through cellular, satellite, WiMax and other channels.

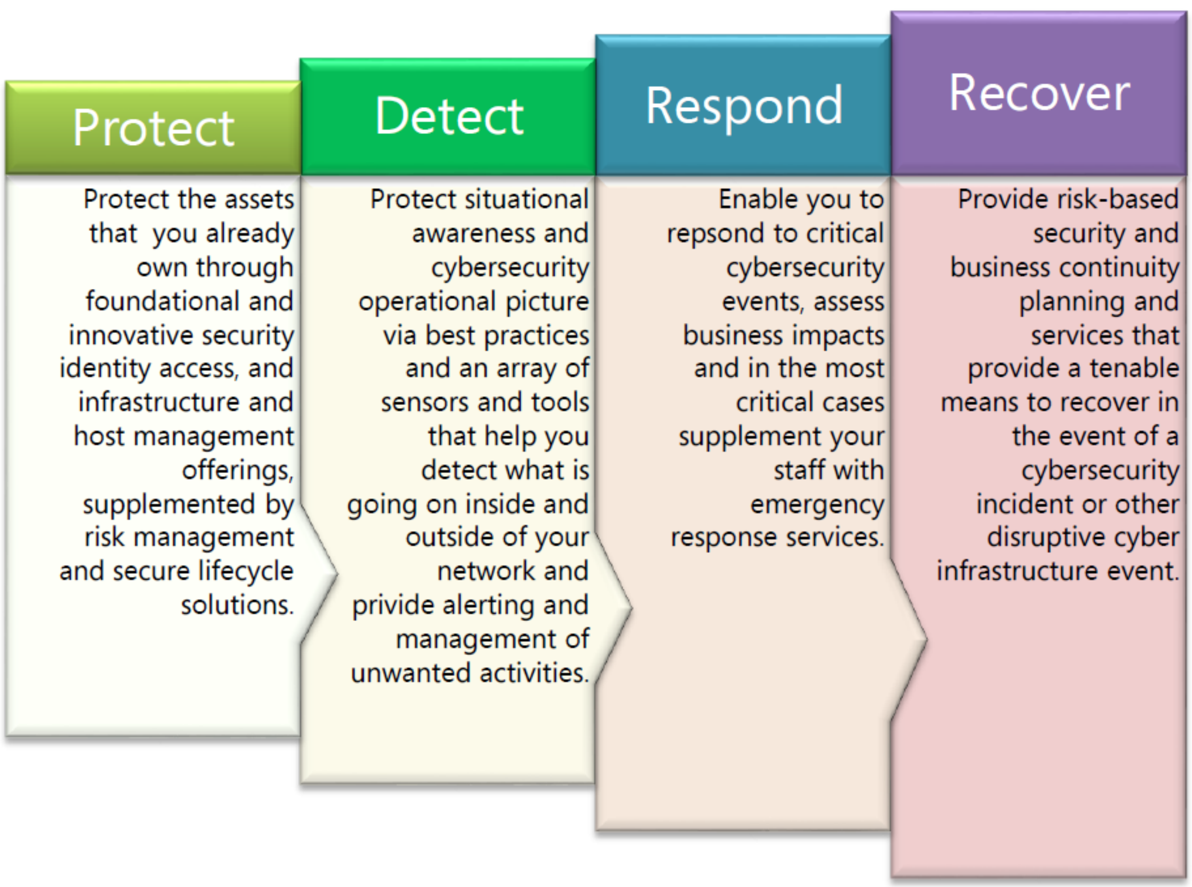
- A global, mobile workforce carrying unmanaged devices that grant access to corporate control and management networks.

In many energy-related firms, rapid growth has introduced greater risk to corporate information, while increasing IT workloads, and complicating regulatory compliance. The sheer volume of data now captured and stored by digital oilfield technologies creates real value and significant challenges. Workflow requirements have changed dramatically. A shrinking workforce means that fewer skilled professionals and experts are tasked with sharing information across global projects, a trend that can expose organizations to greater risk. More available data supports improved collaboration and better insights, but it also raises dramatic new security issues.

E&P firms often have tens of thousands of computers, many of which are now mobile devices carried all over the globe. Digital IP is easier to transport, which is both a benefit and a risk. Production and export units must carefully guard project documentation, while meeting technical reporting requirements for exploration projects. Across the industry, increasingly connected, collaborative employees need faster access to sensitive systems and data.

10.6.2 Best Practices

- A logical and proven three-step strategy for countering threats in the enterprise IT environment is recommended:
    - Protect - This critical first stage of the security management life-cycle focuses on stopping potential attacks before they can breach an oil and gas business IT infrastructure.
    - Detect - To effectively recognize and deter cyber threats, oil and gas organizations need monitoring and analytic tools capable of providing a comprehensive view of their security environment. Those tools must monitor potential threats, from suspicious activities or system weaknesses, both at the network perimeter and from within the organization.
    - Respond and Recover - Even in the most secure environments, incidents can and do occur and thus it is recommended to initiate the pre-deployment of contingency plans, processes, tools, and competencies that can help oil and gas organizations better contain, analyze and eradicate a threat.



A lifecycle approach treats cybersecurity as a continuum rather than as individual, isolated, network-defense components.

- The model described in the above steps provides the following guidelines to ensure IT security by E&P Industry:
  - Collaborative Security - Oil and gas organizations can protect their IT infrastructure and IP assets by deploying advanced security for their key collaborative systems and data stores.
  - Endpoint Protection - Firms should take great care to secure laptops, desktops, mobile devices such as tablets, and other endpoint systems.
  - Hardened Desktops - To ensure desktop security in remote locations, organizations deploying these systems should follow the best practices for desktop security prior to sending them up in the field.
  - Secure operating systems - A secure OS should build upon a structurally proven base, while incorporating next-generation technologies, such as solutions for auditing, user account controls, powerful applications control, and drive- and device-level encryption controls.
  - Server-level protection - The organization must implement servers that are designed and built to deliver maximum reliability, flexibility, control, and security.
  - Data protection - Organizations can better protect data stored on IT operating systems, with advanced drive-level data encryption.
  - Application-level protection - Organizations must ensure the control and security of mission-critical systems in order to ensure the overall protection of a complex, high-volume IT infrastructure.
  - Access control - Oil and gas companies relying on email, intranet web sites, and other collaborative systems to manage production, projects, and the work output of often far-flung employees and partners must secure these systems.
  - Active Directory - The organization must ensure the centralized security of the active directory which would basically be used to manage corporate identities, credentials, information protection, system and application settings.
  - Configuration - To help prevent risks associated with out-of-date hardware, software, and security systems, oil and gas organizations must carefully manage configurations throughout their IT reference architecture.
  - Compliance - IT administrators need fast, automated systems to configure and manage computers, data centers, and private cloud environments. They should be able to compare their internal standards to both industry best practices and international standards in order to easily create new policies and configurations and to customize group policies using rich knowledge-based tools.

- Network Access Protection - The best access protection combines device-level security with corporate governance policy compliance. Administrators should be able to define granular levels of access based on client identity, group policies, and pre-access compliance. Automatic controls should quarantine non-compliant devices, and then apply remediation and updates to ensure full compliance before network access is allowed.

- Security audits - In complex, exploration and production environments, and particularly in organizations that have strict security requirements, a centralized database should be used to store and consolidate security logs, and to filter and evaluate events using robust data analysis and reporting tools.

- Secure virtualization - The organization should follow a reliable virtualization approach to provide live migration capabilities and cluster-shared volumes for improved storage flexibility. Oil and gas organizations can also achieve secure, centralized administration and management of virtual environments thus increase server utilization, and more quickly provision new virtual machines and authorized self-service end users.

- Desktop optimization - To ensure maximum performance and security from desktops, oil and gas firms can now deploy powerful optimization technologies to improve compatibility and management, reduce support costs, and improve asset management and policy control at the desktop level.

10.6.3 References

1. Microsoft Best Practices for IT Security

10.7 *Appropriate Physical and Environmental Security Controls for the Information Assets to Ensure Proper Safeguards for the E&P Industry*

10.7.1 Definitions and Discussion

The security aspect includes the physical and environmental measures that can be implemented to secure the Assets. This section does NOT deal with the software security aspects and a separate section is dedicated for the Confidentiality, Integrity and Availability of the devices and the software residing within them.

10.7.2 Best Practices

- Physically secure your hardware – All devices including but not limited to laptops, desktops, servers, routers, switches etc. must be physically secured. The physical security medium used includes racks, elevations, etc. must ensure that the device is IP Code proof as well as maintains the allowed operating temperature.

- Protect against unauthorized administrators – Ensure all employees have the authorized access to a particular hardware. Personnel with an access to a particular hardware must operate that particular hardware only.

- Fire Proof – The environment where the device is located must be safe and not have any incendiary materials close to the device. The environment must also follow standard fire protection standards by installing smoke detection alarms, sprinklers and all other required tools.

- Use strong codes/passwords – Though the internal system and the software housed in the device must have a password on its own, the particular location where the device is accessed must also have a passcode in the form of several forms such as a room door code, rack door code etc.

- Monitoring – Install the latest cameras and sensors for monitoring personnel access within the room where the device is housed.

- Cable Security – Cables must be secured, properly color coded, named, & insulated to ensure not only personnel safety but also device safety.

- E&P Hazard Proof – Environment where the device is kept must not be susceptible to the following:

    - Vehicle Accidents
    - Struck-By/Caught-In/Caught-Between
    - Explosions and Fires
    - Falls
    - Confined Spaces
    - Chemical Exposures

10.7.3 References

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10.8 *Protection of Information Assets Based on their Confidentiality, Integrity and Availability (CIA) Requirements for the E&P Industry*

10.8.1 Definitions and Discussion

Confidentiality is defined as the Privacy or the ability to control or restrict access so that only authorized individuals can view sensitive information. One of the underlying principles of confidentiality is "need-to-know" or "least privilege". In effect, access to vital information should be limited only to those individuals who have a specific need to see or use that information.

Integrity is when information is accurate and reliable and has not been subtly changed or tampered with by an unauthorized party. Integrity includes: Authenticity: The ability to verify content has not changed in an unauthorized manner. Non-repudiation & Accountability: The origin of any action on the system can be verified and associated with a user.

Availability is when information and other critical assets are accessible to customers and the business when needed. Note, information is unavailable not only when it is lost or destroyed, but also when access to the information is denied or delayed (i.e. information is available on a web site, but the server is overwhelmed by a denial of service attack and no one can access it).

10.8.2 Best Practices

- Confidentiality
    - Secure package source files
    - Password protect all systems
    - Use a higher RAID level with encryption
    - Encrypt all important communication by means of HTTPS (SSL/TLS)
    - Block-Filter external IP addresses on Routers and Switches using Access lists or Route maps
    - Install Anti-Virus and SPAM Filter
- Integrity
    - Data encryption, which locks data by cipher
    - Data backup, which stores a copy of data in an alternate location
    - Access controls, including assignment of read/write privileges
    - Input validation, to prevent incorrect data entry
    - Data validation, to certify uncorrupted transmission
- Availability

- Reliability – Using redundant clustering of devices
- Proactive monitoring for monitoring examines every completed drive I/O and tracks the rate of drive reported error returned by the drives as well as drive performance and degradation often associated with unreported internal drive issues.
- Background detection and repair drive errors to scan proactively to check drives for defects and initiate repairs before they cause a problem.
- Advanced Protection features such as local key management and drive-level encryption.
- Advanced notification for reporting low health devices.
- Replication services – Local replication features to protect against accidentally deleted files and data corruption, while remote mirrors to duplicate primary site data to an off-site location.

10.8.3 References

1. http://ishandbook.bsewall.com/risk/Methodology/CIA.html
2. https://technet.microsoft.com/en-us/library/bb735870.aspx
3. http://www.zdnet.com/article/10-security-best-practice-guidelines-for-businesses/
4. http://www.cyberciti.biz/tips/raid5-vs-raid-10-safety-performance.html
5. https://www.veracode.com/blog/2012/05/what-is-data-integrity
6. http://www.thedatachain.com/articles/2011/4/top_considerations_for_ensuring_99999_data_availability_in_mid_range_storage

10.9 *Appropriate Following Technical Controls during the Lifecycle (Create, Process, Store, Archive, and Destroy) of Information as per its Valuation and Associated Risk for the E&P Industry*

10.9.1 Definitions and Discussion

The data lifecycle includes the following stages – Create, Process, Store, Archive and Destroy. The entire process is managed through Data Lifecycle Management. Data lifecycle management is the process of managing business information throughout its lifecycle, from requirements through retirement. The lifecycle crosses different application systems, databases and storage media. By managing information properly over its lifetime, organizations are better equipped to deliver competitive offerings to the market faster and support business goals with less risk.

10.9.2 Best Practices

- Creating data

- Design research
- Plan data management (formats, storage, etc.)
- Plan consent for sharing
- Locate existing data
- Collect data (experiment, observe, measure, simulate)
- Capture and create metadata

- Processing data
  - Enter data, digitize, transcribe, translate
  - Check, validate, clean data
  - Anonymize data where necessary
  - Describe data
  - Manage and store data
- Storing data
  - Estimate capacity and ensure proper capacity planning
  - Have multiple mediums of storage such as hard disk drives, tapes and even the cloud
  - Ensure timely and scheduled backup of important data
  - Ensure all communication channels of backup and DR are up and running
  - Ensure spatial as well as geographic replication
- Archiving data
  - Identify data to be archived
  - Create and maintain deletion policies plus data lifecycle management
  - Creating an archive policy for the ages
  - Implement archiving criteria: search, automation, flexibility
- Destroying data
  - When drafting written agreements with third parties, include provisions that specify those data that was provided to the third party must be destroyed when no longer needed
  - Ensure accountability for destruction

- Organizations should manage non-electronic records in a similar fashion to their electronic data
- Depending on the sensitivity of the data being shared, be specific in the written agreement as to the type of destruction to be carried out
- When destroying electronic data, use appropriate data deletion methods to ensure the data cannot be recovered
- Avoid using file deletion, disk formatting, and "one way" encryption to dispose of sensitive data
- Destroy CDs, DVDs, and any magneto-optical disks by pulverizing, cross-cut shredding, or burning
- Address in a timely manner sanitization of storage media which might have failed and need to be replaced under warranty or service contract
- Create formal, documented processes for data destruction within your organization and require that partner organizations do the same

10.9.3 References

1. http://www-01.ibm.com/software/data/lifecycle-management/
2. http://www.bu.edu/datamanagement/background/data-life-cycle/
3. http://searchstorage.techtarget.com/feature/Data-archiving-best-practices-Policies-planning-and-products
4. http://ptac.ed.gov/sites/default/files/Best%20Practices%20for%20Data%20Destruction%20%282014-05-06%29%20%5BFinal%5D.pdf

10.10 *Establishment and Implementation of Appropriate Controls to Ensure than Employees and Third Parties Understand their Responsibilities and Risk of Theft, Fraud and Misuse of Information*

10.10.1 Definitions and Discussion

Insider threats are influenced by a combination of technical, behavioral, and organizational issues and must be addressed by policies, procedures, and technologies. Accordingly, best practices to mitigate insider threats involve an organization's staff in management, human resources (HR), legal counsel, physical security, information technology (IT), and information assurance (IA), as well as data owners and software engineers. Decision makers across the enterprise should understand the overall scope of the insider threat problem and communicate it to all the organization's employees.

10.10.2 Best Practices

- Clearly document and consistently enforce policies and controls.

- Incorporate insider threat awareness into periodic security training for all employees.
- Beginning with the hiring process, monitor and respond to suspicious or disruptive behavior.
- Anticipate and manage negative issues in the work environment.
- Know your assets.
- Implement strict password and account management policies and practices.
- Enforce separation of duties and least privilege.
- Define explicit security agreements for any cloud services, especially access restrictions and monitoring capabilities.
- Institute stringent access controls and monitoring policies on privileged users.
- Institutionalize system change controls.
- Use a log correlation engine or security information and event management (SIEM) system to log, monitor, and audit employee actions.
- Monitor and control remote access from all end points, including mobile devices.
- Develop a comprehensive employee termination procedure.
- Implement secure backup and recovery processes.
- Develop a formalized insider threat program.
- Establish a baseline of normal network device behavior.
- Be especially vigilant regarding social media.
- Close the doors to unauthorized data exfiltration.

10.10.3 References

1. https://www.cert.org/insider-threat/best-practices/

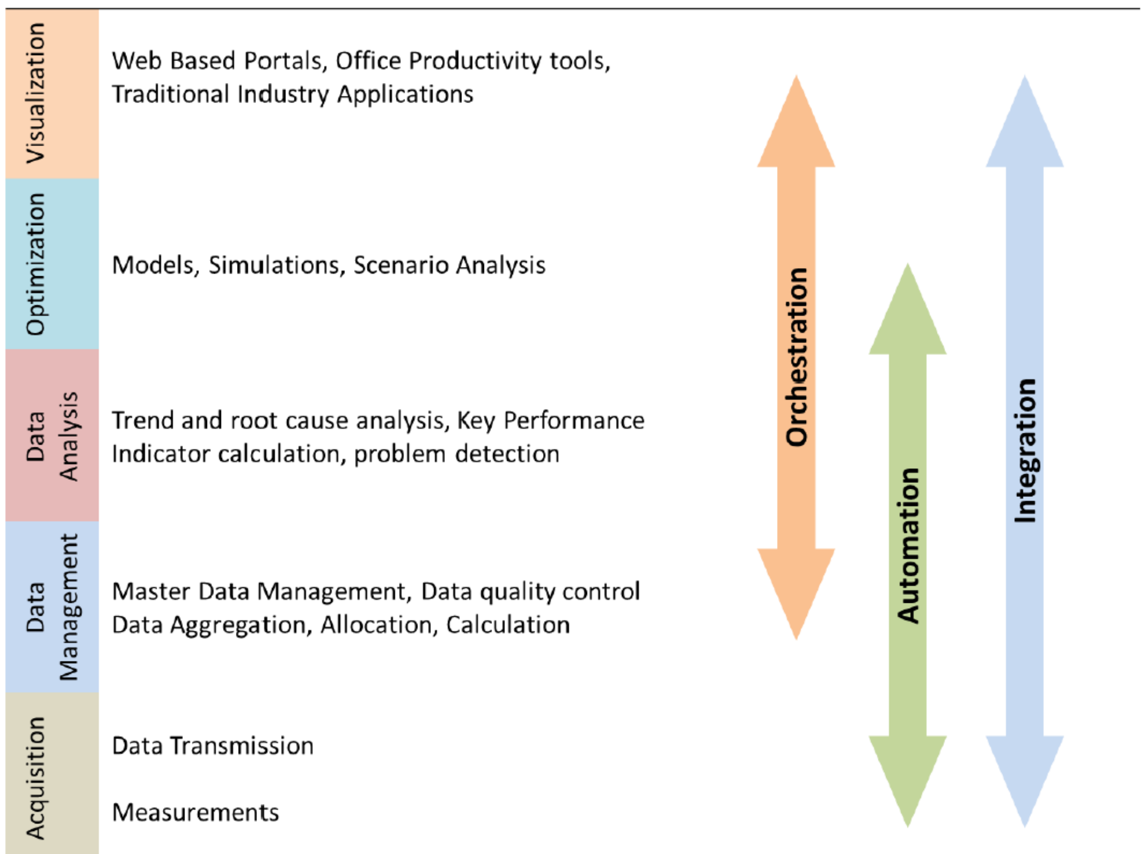
10.11 *Standards for IT and Data Management Infrastructure*

10.11.1 Definitions and Discussion

Oil and gas exploration and production (E&P) is a vast, complex, data-driven business, with data volumes growing exponentially. These organizations work simultaneously with both structured and unstructured data.

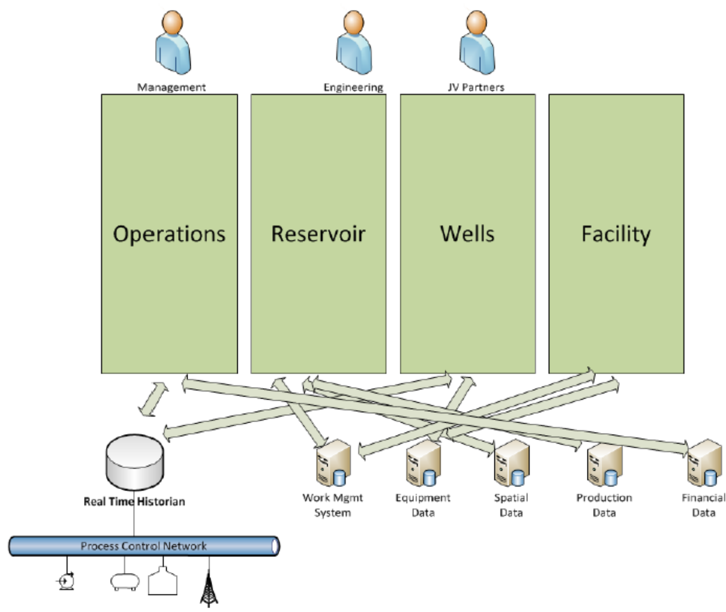
Structured data is handled in the domain-specific applications used to manage surveying, processing and imaging, exploration planning, reservoir modeling, production, and other upstream activities. At the same time, large amounts of information pertaining to those same activities are generated in unstructured forms, such as emails and text messages, word processing documents, spreadsheets, voice recordings, and others.

The figure below shows the broad spectrum of structured and unstructured data oil and gas organizations use to orchestrate, automate, integrate, and execute integrated upstream operations and management activities.



Business activities use a broad range of structured and unstructured data

The current state of IT infrastructure in most oil and gas businesses is unable to adequately support and respond to analysis, operations, and business needs. In most organizations, the volume of information is increasing exponentially because digital sensors are deployed in more exploration and production plays, more data sources are connected to IT systems, and growing volumes of information are captured and stored in enterprise databases. Large volumes of domain-specific information are also embedded in various upstream applications. This data situation means it's difficult or impossible to use that data to quickly and efficiently get the information and answers needed.



Current Architectures

Existing IT architectures in the upstream oil and gas sector are often limited by applications in silos, poor integration, and barriers to collaboration. Paradoxically, the most common activities across all of these domains are word processing, spreadsheet, email, and other basic business applications.

Current state of IT architectures for the oil and gas sector

A few basic issues define the requirements of an upstream IT architecture.

Some of the current known issues in the E&P industry are:

- Data Management
- Integration
- Collaboration
- Performance Management

10.11.2 Best Practices

- General Best Practices:
    - Reduced implementation and support costs - Oil and gas companies can do this by maximizing their use of existing technology investments when purchasing new solutions from vendors and making extensive use of cloud solutions so that capital investment on data centers can be reduced as can the support costs of running them thus maximizing business agility and lowering IT costs.
    - Ability to deliver more with less - The organization must be able to deliver more throughput with fewer resources and severely time-constrained work teams by spending more time doing domain-focused work—and less time searching for and preparing the data needed for that work. Workflows, data-driven events, and automated analysis should help drive their efforts to identify risks and help manage the exploration portfolio or production operations.

    - Integrated views - Workers need integrated views that reveal all relevant data, both structured and unstructured, for a particular situation.

    - Easily accessible KPIs - Management needs to implement up-to-date KPIs to fully understand the current status and overall health of an organization.

    - Plug-and-play technology - The industry needs an architectural approach that allows upstream organizations to use more flexible and cost-efficient cloud-based plug-and-play business logic. If a technology supplier comes up with a better web-based seismic viewer, the architecture should allow that solution to be deployed quickly and economically to other cloud-based solutions that could make use of it.

    - Integration of structured and unstructured data - Upstream organizations need the ability to connect and integrate the large volumes of unstructured data generated and used by non-domain-specific sources, such as word processing and email programs, unified communications, and collaborative applications. This requirement recognizes that much of the information needed to manage upstream projects is in fact hosted in non-domain applications and environments, both on-premises and increasingly, in the cloud.

    - Standards - The organization can implement XML standards-based technologies such as WITSML, PRODML or RESQML, curated and supported by Energistics to provide common data interfaces thus providing the foundation needed to ensure plug-and-play access to best-in-class hardware and software solutions that run both in the private data center and in the cloud. Further, standard industry database schemas like the PPDM can be implemented to further support the above.

- Technology Related Best Practices:

    - Cloud computing - Upstream companies can implement Cloud-enabled standards such as the OData standard and industry data standards such Energistics in combination with technology such as secured web services, permit easy, secure integration between different instances of cloud-hosted services, even those provided by different vendors.

    - Mobility - IT department should be able to support the flexibility of enabling mobile devices for end users.

    - Big Data -The E&P company must implement Big Data platform to manage data of any type, whether structured such as sensor data from rigs, or unstructured such as raw seismic data - and of any size: from gigabytes to petabytes. This ‘Big Data’ solution should also manage data at rest or in motion, and support modern tooling like Hadoop. Finally, when only a portion of a given set of data needs to be accessed by analytical tools upon this platform, there should be ways of temporarily storing the rest of the data in low-cost, secure cloud storage to lower on-premise data center costs for these huge data sets.

    - Social - The industry also is now embracing social media capabilities such as status updates and notifications from social networks, messages, instant messaging, blogs, and wikis. As upstream professionals can use these technologies to manage their personal connections better to foster cross-discipline collaboration and to better understand and manage the upstream operations environment.

10.11.3 References

1. Microsoft Best Practices for Data & IT Management

10.12 *Dispute Resolution Process*

10.12.1 Definitions and Discussion

The oil and gas industry involves complex, risky and expensive operations which usually last for a very long time. Special contracts are employed in governing relationships among various parties engaged in these operations. Owing to the complexity of operations and relations between various entities, the oil and gas industry is prone to various types of disputes.

Given the complexity of oil and gas contracts, the oil and gas industry is one of the most dispute-intensive industries in the world and the types of disputes arising from negotiated contracts include disputes among operators, non-operators, and joint ventures in property acquisition, exploration developments, supply and marketing arrangements, and construction projects, among others. Disputes may also arise in areas such as international maritime boundary claims, equipment-related claims, claims over jurisdiction, claims relating to quantity and quality of goods, and insurance issues. In order not to interfere with the progress of operations, it is essential that appropriate means of resolving such disputes are agreed by parties, prior to any engagement.

- **Oil and Gas Contracts and Related Disputes**
    - Based on the nature of oil and gas contracts, oil and gas industry disputes can be classified into four main categories, namely government vs. government disputes, government vs company disputes, company vs company disputes and individual vs company disputes.
    - Government vs government disputes are primarily boundary disputes concerning oil and gas fields that cross international borders, most of which are located in maritime waters. They mostly involve governments, since only governments are able to claim sovereign title and resolve boundary disputes with the neighboring countries. However, oil and gas companies could get indirectly involved in these disputes if they are granted concessions that straddle disputed boundary lines. Companies could also be asked by the government to fund the dispute costs, and to provide data and legal expertise to aid in resolving the boundary dispute. As such, both company and government need to be familiar with these disputes and be able to manage them properly when they find themselves in the middle of one.
    - Government vs. company disputes usually occur when governments significantly change the terms of an original contract or expropriate an investment, hence violating the terms of the original contract. Typical contracts between oil companies

and the government include production sharing contracts, joint venture contracts, joint operating contracts, farm out contracts, etc. When original contracts/agreements are violated, oil and gas companies or the consortium of oil and gas companies can initiate a claim based on violations to the investment contract and/or violations to an investment treaty or convention. In the oil and gas industry, cross-border contracts and claims are mostly guided by conventions agreements and/or treaties including the Energy Charter Treaty (ECT), the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (also called the New York Convention), the Washington Convention of 1965 that provided for the establishment of the International Center for the Settlement of Investment Disputes (ICSID).

  - Host states wishing to attract foreign investment often advertise their willingness to resolve foreign investment disputes using these channels. Foreign/International companies are encouraged to invest taking comfort from the fact that they will not be compelled to submit disputes to an unfamiliar panel.
  - It is recommended that appropriate dispute resolution clauses be included in the contracts to allow for the use of these treaties or convention agreements to resolve potential disputes.

- Company vs. company disputes usually occur between two or more companies. These disputes usually occur due to contracts violations including, but not limited to joint operating agreements, unitization agreements, farm out agreements, study and bid agreements, sale and purchase agreements, and confidentiality agreements. One prevalent subcategory of company vs company disputes occurs between operators and service contractors in agreements such as drilling and well servicing, seismic related activities, construction, equipment and facilities, transportation, and processing agreements. These disputes make up the majority of disputes in which oil and gas companies find themselves.
- Individual vs. company disputes usually occur when an individual initiates a claim against an oil and gas company or contractor for a variety of reasons including personal injury, contract violations, legal fees, etc.
- During contract negotiations, it is recommended that dispute resolution clauses be included in the contract to address the prevalent disputes between the parties involved. An inadequate dispute resolution clause can produce much delay, expense, and inconvenience. When writing a dispute resolution clause, keep in mind that its purpose is to resolve disputes, not create them. Whenever disagreements arise over the meaning of a dispute resolution clause, it is often because it failed to address the particular needs of the parties. Use of standard, simple and straight forward language may avoid difficulties. Drafting an effective dispute resolution agreement is the first step on the road to successful dispute resolution.

- Dispute Resolution Methods

- Disputes in the oil and gas industry are generally resolved either through litigation or through alternative dispute resolution (ADR) channels. Alternative dispute resolution channels include arbitration, mediation, expert determination, reconciliation, etc. Of these dispute resolution techniques, dispute resolution through litigation and arbitration are binding. Dispute resolution through arbitration is currently considered the principal method of dispute resolution in the oil and gas industry, especially when there is an international contract spanning many countries.

- Dispute Resolution through Litigation

  - Dispute resolution through litigation usually results when the disputing parties are unable to resolve the dispute through ADR channels. Under these circumstances one party, the claimant/plaintiff, files a lawsuit against another party, the defendant, to enforce a particular right or action. The litigation process is presided over by a judge or jury who listens to the arguments and witnesses of both parties and then passes a judgment which becomes binding, subject to appeal.

  - Oil and gas dispute resolution through litigation are most frequently used in the domestic energy business with parties from the same jurisdiction (for example in the U.S., in Canada, the in the UK, in Australia, and in India). It is, however, not the preferred forum for international disputes for a number of reasons including problems in enforcing court judgments in foreign jurisdictions, cost and length of trials, and antipathy to local courts by foreign investors. As a result, it is rarely chosen as a dispute resolution mechanism in international oil and gas agreements. Litigation is sometimes chosen in oil and gas agreements when all the parties come from the same jurisdiction and they are all comfortable with the courts of their home country.

  - As in the other industries, litigation in the oil and gas industry is a formal process in which both sides to the dispute provide their version of the dispute and are given enough time to provide evidence to support their argument. As indicated, dispute resolution through litigation often results if the disputing parties are unable to resolve their disputes through arbitration. In certain instances, the process starts with arbitration and ends up in the courts. Under these circumstances, the process could be lengthy and expensive depending also on the complexity of the conflict, with no way to fast track the process. The duration of the process could also depend on the case load of the court assigned to the case. In some countries, including India for example, dispute litigation through the court could experience significant delays due to backlogs within the court system.

- Dispute Resolution through Arbitration

  - Arbitration involves the resolution of disputes between two or more parties through a voluntary or a contractually required hearing with determination by an impartial third party. The third party arbitration can either be institutional or ad-hoc arbitration.

- Arbitration is considered as the most widely accepted and used dispute resolution method in the international energy sector. It is a legally binding process that provides the most flexibility to parties in how they want to resolve their dispute.

- Arbitration provides many advantages including allowing parties to choose their arbitrators, selecting the kind and extent of their arbitration process, and choosing the venue and forum where the arbitration will be held. It also has the advantage of the recognition and enforcement of arbitral awards in foreign jurisdictions, which court judgments generally do not have.

- Unfortunately, along with that flexibility comes a number of problems, including the fact that adverse parties can make the process look a lot like litigation resulting in high costs and time consuming processes. Companies or the state can adopt a number of strategies to manage time and cost concerns in international arbitration. Despite some of its shortcomings, when given a choice between litigation and arbitration, international contracts always lean towards international arbitration.

- Some of the main attractions for opting for arbitration include the following:

    - Party autonomy. Parties can decide in which country the arbitration will take place and the language to be used for the purpose of the dispute hearing. In other words, arbitration provides the parties with neutrality and relative flexibility to resolve the disputes privately outside a national court system, although this flexibility is limited by the extent that it needs to be associated with a legal system. The parties will decide whether to follow an ad hoc arbitration or an institutional arbitration. Institutional arbitration will be administered by an arbitral institute such as the International Chamber of Commerce (ICC) in Paris or the London Court of International Arbitration (LCIA).

    - Choice of arbiter. Arbitration is attractive to those in the oil and gas industry as the parties can choose a neutral arbiter or tribunal or arbiters based on their specialist knowledge. In litigation there is always the worry that a court will not have the necessary expertise and experience. The tribunal's decision will be binding on the parties and is final, so there is no right of appeal unless otherwise agreed by the parties.

    - Privacy and confidentiality. Privacy and confidentiality are of paramount importance to the industry, not only with respect to the final award, but also in relation to information generated or produced in the course of proceedings. In some cases, parties may wish by the very existence of arbitration to be protected by an obligation of confidentiality.

- Enforceability. It is generally seen that an arbitral award is more enforceable for international contracts than a court award, because these international arbitrations are backed up by multiple international conventions and treaties. These conventions and treaties provide an effective and enforceable legal framework for international arbitration.

- Overlapping commercial interests and long term contractual relationships between oil and gas companies (both international and state) militate against litigation which is often expensive, time consuming, adversarial and destructive of good relationships. The international nature of the operations of multinational oil and gas companies and cross border oil and gas fields, favor arbitration as a mode of dispute resolution.

- Arbitration is generally perceived to be faster and less expensive than litigation and can lead to a more tailored and creative conclusion to suit the parties' interests than litigation.

▪ Though arbitration is considered less costly and less time consuming, it can quickly become just as expensive and time consuming as litigation (or more), if one party strongly disagrees with the arbitration outcome and decides to prolong the proceedings through the court. Court involvement or intervention tends to increase the duration and the cost of the dispute resolution. As such, arbitration has the potential to become as formal as litigation in the case of adverse parties. Arbitration can also be drawn out if recourse is consistently being made to the courts to resolve potentially conflicting issues.

- Dispute Resolution Clauses

  - Adopting clear, unambiguous dispute resolution clauses can contribute to the efficiency of the dispute resolution process. Arbitration agreements should clearly state the intent of the parties to arbitrate. However, it is not enough to simply state that “disputes arising under the agreement shall be settled by arbitration.” While the language indicates the parties’ intention to arbitrate and may authorize a court to enforce the clause, it leaves many issues unresolved. Issues such as when, where, how and before whom a dispute will be arbitrated are subject to disagreement once a controversy has arisen, with no way to resolve them except to go to court.

  - Some of the important elements to keep in mind when drafting, adopting or recommending a dispute resolution clause include the following:

    ▪ The clause could be drafted to cover all disputes that may arise, or only certain types of disputes that tend to arise.

  - The clause could specify the specific method(s) of dispute resolution. For example, it could specify only arbitration – which yields a binding decision – or also provide an opportunity for non-binding negotiation or mediation.

  - The dispute resolution clause should be signed by as many potential parties (e.g. contractors) to a future dispute as possible.

  - To be fully effective, “entry of judgment” language in domestic cases is important.

  - It is normally a good idea to state whether a panel of one or three arbitrator(s) is to be selected, and to include the place where the arbitration will occur.

  - If the contract includes a general choice of law clause, it may govern the arbitration proceeding. The consequences should be considered.

  - The parties are free to customize and refine the basic arbitration procedures to meet their particular needs.

- International Arbitration Conventions and Treaties

  - International arbitration conventions and treaties, including bilateral international treaties, provide a legal framework for the enforcement of international arbitrations. These include the New York convention of 1958, the Washington convention of 1966, the Energy Charter Treaty of 1998, as well as thousands of bilateral investment treaties and several regional conventions that replicate the benefits of the international conventions.

  - The New York Convention

    - Recognizing the growing importance of international arbitration as a means of settling international commercial disputes, the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention) seeks to provide common legislative standards for the recognition of arbitration agreements and court recognition and enforcement of foreign and non-domestic arbitral awards. The Convention's principal aim is that foreign and non-domestic arbitral awards will not be discriminated against and it obliges parties to ensure such awards are recognized and generally capable of enforcement in their jurisdiction in the same way as domestic awards. An ancillary aim of the convention is to require courts of parties to give full effect to arbitration agreements by requiring courts to deny the parties access to court in contravention of their agreement to refer the matter to an arbitral tribunal.

    - The New York Convention is considered as the most important international treaty in respect of international commercial arbitration which is also regarded as a major factor in the development of arbitration as a means of resolving international trade disputes. This is the primary convention used to recognize, enforce, and challenge international arbitral awards. There are currently over 150 parties to this convention. This makes the enforcement of arbitral awards easier and more widespread in the sense that a party to a dispute is able to enforce an award rendered in one contracting state into any of the other contracting states. To access the benefits of this convention the seat of the arbitration should be in a country that is a signatory to the convention and the counter-party (or its assets) against whom an agreement or award is to be enforced should be from a country that is a party to the New York Convention.

- The Washington Convention
  - The Washington Convention of 1965 also addressed issues related to the settlement of investment disputes between nation states and citizens of other countries. The Convention created the International Centre for Settlement of Investment Disputes (or ICSID). The ICSID, an autonomous international organization and a member of the family of World Bank Institutions, provides facilities for the arbitration of investment disputes between host governments and foreign investors. ICSID jurisdiction is limited to disputes occurring between a contracting state and a national of another contracting state. Although parties must consent in writing to submit disputes to the ICSID, such consent may be expressed in bi-lateral treaties and foreign investment laws as well as in contracts. The Convention was primarily designed to create investor confidence, and to promote inward investment into developing countries.
- The Energy Charter Treaty (ECT)
  - The ECT is an international agreement which establishes a multilateral framework for cross-border co-operations in the energy industry. The treaty covers all aspects of commercial energy activities including trade, transit, investments and energy efficiency. The treaty is legally binding, including dispute resolution procedures. Companies and states should structure their investments and negotiate their contracts to take advantage of the investment protection provided by the ECT and other related treaties.
- International Arbitration Institutions
  - There are many arbitral institutions in the world but the major ones are three namely, the International Chamber of Commerce (ICC) International Court of Arbitration, the American Arbitration Association's International Center for the Dispute Resolution (ICDR), and the London Court of International Arbitration(LCIA).
  - The rules of the ICC, LCIA and ICDR are all suitable for use around the world and for arbitrations conducted in various languages and under various governing laws. In each case, it is for the arbitrators to resolve the dispute, with the institutions simply administering the arbitrations. In this capacity, the ICC, LCIA and ICDR each receive and distribute the parties' initial submissions, assist with the appointment of the tribunal (with or without

party-nominations) and resolve any challenges that a party may make against an arbitrator. The arbitration rules of each institution are broadly similar. All three institutions leave a considerable degree of flexibility with the parties and the tribunal. What distinguishes these institutions from each other are the degree of administration (or supervision) their rules entail and their fee structure. The procedures of the LCIA and the ICDR are lightly administered, with the role of the LCIA and the ICDR limited primarily to the appointment of (and challenges to) the tribunal. On the other hand, the ICC procedure is more actively administered. In addition to tribunal appointment and resolving challenges to the tribunal, the ICC procedure includes the preparation of Terms of Reference (TOR), and the scrutiny of awards.

- International Chamber of Commerce (ICC) International Court of Arbitration
    - The ICC is one of the leading providers of dispute resolution services for individuals, businesses, states, state entities and international organizations seeking alternatives to court litigation. The ICC, which is based in Paris, was established in 1923.It is probably the best known international commercial arbitration institution.
- The London Court of International Arbitration (LCIA)
    - The LCIA, which is based in London, was established in 1892. It is Europe's second leading international arbitration institution (after the ICC)and is very well known internationally. The LCIA has affiliated arbitral institutions in Dubai (DIFC-LCIA), India(LCIA India) and Mauritius (LCIA-MIAC).
- The International Center for Dispute Resolution
    - The International Center for Dispute Resolution (ICDR) is a division of the American Arbitration Association (AAA) which provides international arbitration and other dispute resolution services. ICDR is headquartered in New York and has other offices in Ireland, Mexico, Singapore and Bahrain.

- Ad hoc Arbitrations
    - Ad hoc arbitrations are non-institutional arbitrations that often arise because parties do not agree upon (or simply fail to provide for) any institutional arbitration. Parties sometimes believe that, by avoiding the fees of arbitral institutions, ad hoc arbitration might prove cheaper than institutional arbitration. Whilst this is possible

in theory, in practice, the benefits of the institution's administrative services and the lower charges of arbitrators under institutional rules can easily outweigh the costs involved, especially in connection with large and complex disputes, where many procedural issues are likely to arise. Ad hoc arbitration significantly increases the likelihood of court intervention and these potentially significant costs must also be considered. Prior to selecting ad hoc arbitration, parties should satisfy themselves that they would not be better served by an institutional form of arbitration.

- The Indian “Arbitration and Conciliation Act, 1996”
    - The Indian “Arbitration and Conciliation Act, 1996” (the Act) was formulated based on the United Nations Commission on International Trade Law (UNCITRAL) Model Law on International Commercial Arbitration (1985) and the United Nations Commission on International Trade Law (UNCITRAL) Conciliation Rules (1980). As a result of the Arbitration and Conciliation Act, 1996, arbitration emerged in India as a ‘fast track’ approach to conflict resolution. The Act included the essential dispute resolution provisions within UNCITRAL Model Law and UNCITRAL Conciliation Rules, with certain refinements. Some of these refinements, though appearing positive from the onset, do not appear to have produced significant results in terms of reducing resort being made to courts, or in terms of reducing the time taken for resolution of disputes. In formulating the Act, for example, recourse was given to the courts in limited circumstances where the parties to arbitration were unable to find common ground. Arbitration following the Act has, however, been plagued by significant delays in arbitration cases involving the courts as seen below.

The Act contemplates only three situations where courts may intervene in arbitral proceedings. These are:-

(a) appointment of arbitrators, where the procedure for the appointment of arbitrators as envisaged by the parities has failed;
(b) ruling on whether the mandate of arbitrator stands terminated due to *de jure* or *de facto* inability to perform his functions or failure, for other reasons, to act without undue delay [s. 14(2)]; and
(c) providing assistance in taking evidence (s 27).

In fact, the Indian law is far more restrictive in laying down the extent of judicial intervention (compared to the UNCITRAL Model Law). Section 5 of the Act provides that notwithstanding anything contained in any other law for the time being in force, in matters governed by (this) Part (i.e., Part I Arbitration), no judicial authority shall interfere except where so provided for. Section 8 of the Act, further provides that a judicial authority before which an action is brought in a matter which is the subject matter of an arbitration agreement shall, on application of a party to the arbitration agreement, or a person claiming through or under him, refer the parties to arbitration unless it finds that *prima facie* no valid arbitration agreement exists. These departures made by the Indian law demonstrate the legislative intent to minimize judicial intervention in arbitration matters. By and large the Indian courts have well understood the spirit and intent behind the principle of non-intervention. [Pl. see **CDC Financial Services (Mauritius) Ltd v BPL Communications: 2003 (12) SCC 140].** The Act, as seen above, allows full freedom to the parties in the matter of appointment of arbitrators. However, if the parties fail to reach an agreement, recourse is made to the court. The Act also enables parties to adopt an appointment procedure under which any institution may be given specific roles in such appointment. However, in practice, resort is seldom made to such institutional arrangements in the matter of appointment of arbitrators. The process of ‘running to the court’ has proven to be a stumbling block in Indian arbitration. The process has impacted significant delays to Indian arbitration based on the availability of the court. The Arbitration and Conciliation (Amendment) Ordinance, 2015, seeks to address this issue by insertion of a new sub-section (13) in section 11 of the Act to the effect that an application made under the said section for appointment of an arbitrator or arbitrators shall be disposed of by the Supreme Court or the High Court or the person or institution designated by such Court, as the case may be, as expeditiously as possible and an endeavour shall be made to disport of the matter within a period of sixty days from the date of service of notice on the opposite party..

- As a result of the full flexibility to appoint arbitrators given by the Act, the tendency has been to use ad hoc arbitrators in Indian arbitration. The use of institutional arbitration is yet to take off in any significant measure in India. Arbitration has more or less been essentially relegated to the arbitrators themselves, without an established time frame to conclude the arbitration or an established fee structure. The arbitrators essentially control the arbitration time table and the fees, thus leading to additional unnecessary delays and cost.

The recent amendments introduced in the Act through the Arbitration and Conciliation (Amendment) Ordinance, 2015, seek to address only one of these two issues, namely, the lack of a time-frame for making of arbitral award, by insertion of a new section 29A. which now specifies a time limit for making the arbitral award (twelve months extendable by six months by consent of the parties) and also provides for automatic termination of the mandate of the arbitral tribunal upon expiry of the time period unless the Court has extended the period. However, as regards management/administration of the arbitration process, concerted efforts are needed towards creation and promotion of effective institutional mechanisms, so that the arbitral process becomes streamlined and cost effective to parties. With the ICC, LCIA and ICDR, and similar institutions, the institution essentially appoints the arbitrators, defends the arbitrators (in the case of a challenge) and simply administers the arbitration process, which saves both time and costs for the parties. The need to promote institutional arbitrations without having resort to court intervention seems to be the need of the hour in order to achieve the purpose behind the relevant provisions of the Act.

- The Act is equally plagued by certain sections that render arbitral awards more or less unenforceable. Challenges to arbitration awards can equally be tied up within the court system for years. These delays and other technicalities have handicapped the functioning of the Act significantly. There is thus the need to reform certain sections of the Act

- It is recommended that an institutional arbitration structure be promoted and/or implemented. Any adopted reform should also seek to implement a fee structure with a potential ceiling to fees. With sufficient reforms, the entire arbitration process will once again play the role it was meant to play.

10.12.2 Best Practices

- Host states wishing to attract foreign investment or foreign contractors, while resolving contract related disputes judiciously, are recommended to advertise their willingness to resolve contract related disputes using any of the channels described above. With that, foreign/international oil companies and contractors are also encouraged to do business taking comfort from the fact that they will not be compelled to submit disputes to an unfamiliar channel/court. These recommendations equally apply to independent oil and gas operators doing business with the state. By clearly stating the channels for dispute resolution up front, unnecessary disputes on how to resolve disputes can be avoided.

- Based on the advantages presented, dispute resolution through arbitration is highly recommended over litigation. Appropriate dispute resolution clauses should be included into contracts to enable smoother and faster resolution of potential conflicts.

- Provided below are sample international dispute resolution through arbitration clauses that can be considered for inclusion as part of a contract. These clauses can also be customized for inclusion into contracts between national oil and gas operators and the state.

    - Any controversy or claim arising out of or relating to this contract shall be determined by arbitration in accordance with the rules of Arbitration contained in the Arbitration & Conciliation Act, 1996[].

    - Any dispute, controversy, or claim arising out of or relating to this contract, or the breach thereof, shall be finally settled by arbitration administered by Indian Council of Arbitration, The International Centre for Alternate Dispute Resolution (ICADR) or any other body functional under the Arbitration & Conciliation Act, 1996 in India.[………..].

    - Any dispute, controversy, or claim arising out of or relating to this contract, or the breach, termination, or invalidity thereof, shall be settled by arbitration under the UNCITRAL Arbitration Rules in effect on the date of this contract. The appointing authority shall be as decided by the parties under the respective contract []…………... The case shall be administered by Indian Council of Arbitration, The International Centre for Alternate Dispute Resolution (ICADR) or any other body functional under the Arbitration & Conciliation Act, 1996 in India .[…………] under its Procedures for Cases under the UNCITRAL Arbitration Rules.

- During contract negotiations, it is recommended that dispute resolution clauses be included in all contracts to address the prevalent disputes between the parties involved. An inadequate dispute resolution clause can produce so much delay, expense, and inconveniences. When writing a dispute resolution clause, keep in mind that its purpose is to resolve disputes, not create them. Whenever disagreements arise over the meaning of a dispute resolution clause, it is often because it failed to address the particular needs of the parties. Use of standard, simple and straight forward language may avoid difficulties. Drafting an effective dispute resolution agreement is the first step on the road to successful dispute resolution.

- Disputes in the oil and gas industry are generally resolved either through litigation or through alternative dispute resolution (ADR) channels. Alternative dispute resolution channels include arbitration, mediation, expert determination, reconciliation, etc. Of these dispute resolution techniques, dispute resolution through litigation and arbitration are binding. Dispute resolution through arbitration is currently considered the principal method of dispute resolution in the oil and gas industry, especially when there is an international contract spanning many countries. In some cases, an informal resolution from technical experts is advisable before pursuing arbitration.

10.12.3 References

1. Dispute resolution in oil and gas; Muhammad Waqas, Oil and Gas Financial Journal, January 13, 2015.
2. International dispute resolution; Tim Martin, Independent Petroleum Association of America & Association of International Petroleum Negotiators.
3. Dispute resolution in oil and gas industry: Why Do Participants in the Oil and Gas Industry Prefer International Commercial Arbitration to Litigation; Raphael Bahati Tweve Mgaya, Tanzania Petroleum Development Corporation (TPDC).
4. Drafting Dispute Resolution Clauses, A Practical Guide; The American Arbitration Association.
5. Guide to International Arbitration; Latham and Watkins, 2014.
6. Alternative Dispute Resolution Guidelines; The World Bank Group, 2011.

10.13 *Practices Regarding Obligations of Govt. / Regulator in Contract Management*

10.13.1 Definitions and Discussion

The objective of the host Government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity. In order to accomplish this, governments must design a fiscal system that:

- Provides a fair return to both Government and Contractor;
- Avoids undue speculation;
- Limits undue administrative burden;
- Provides flexibility; and
- Creates healthy competition and market efficiency.

One of the most widely used contractual documents in the oil and gas industry between state governments and oil and gas companies or contractors is the Production Sharing Contract (PSC). A PSC is a common type of contract signed between a government and a resource extraction company (or group of companies) concerning how much of the resource extracted from the country each will receive. An essence of the PSC is that the state government or its representing agency engages a competent contractor to carry out all petroleum operations on assigned acreage. The contractor undertakes the initial exploration risks and recovers costs if and when oil is discovered and extracted. These contracts need to be managed carefully with specific obligations from all parties.

10.13.2 Best Practices

In general the host Government's role is to:

- Evaluate the progress of the PSC, ensuring all deliverables are satisfactorily completed
- Follow up on monitoring reviews, audits, and investigations
- Provide approvals/permits for timely execution of the contract

The host Government's role is explained in detail in the provisions of the PSC contract; many Government related provisions are highlighted below.

General PSC Contract Guidelines

- Scope of the Contract
    - The Contract is a production-sharing arrangement with respect to the Contract Area, whereby the GOVERNMENT has the right to regulate and oversee the Petroleum Operations within the Contract Area.
    - The purpose of the Contract is to define the respective rights and obligations of the Parties and the terms and conditions under which the CONTRACTOR shall carry out all the Petroleum Operations.
    - By entering into the Agreement, the GOVERNMENT grants the CONTRACTOR the exclusive right and authority to conduct all Petroleum Operations in the Contract Area.
    - Upon the CONTRACTOR's request, the GOVERNMENT shall provide all required Permits relating to the Petroleum Operations required by the CONTRACTOR to fulfil its obligations under this Contract, including those relating to any extension and renewal periods and including those required by the Government.
    - The government further
        - represents and warrants to the CONTRACTOR that it has not done and has not omitted to do anything that would cause the cancellation or suspension of this Contract or any Permit granted pursuant to this Contract; and
        - covenants that it will not do, or omit to do, anything that would cause the cancellation or suspension of this Contract or any Permit granted pursuant to this Contract.
- Government's Participating Interest
    - The GOVERNMENT shall through a Public Company duly authorized by the GOVERNMENT (and notified to the CONTRACTOR) have the option of

participating in the Contract, in respect of the entire Contract Area, as a CONTRACTOR entity, with an undivided interest in the Petroleum Operations and all the other rights, duties, obligations and liabilities of the CONTRACTOR, under the Contract in respect of the Contract Area, or certain percentage (the "Government Interest", for example, 25%), such option being referred to herein as the "Option to Participate". The Public Company shall be entitled to exercise the Option to Participate by notifying the CONTRACTOR in writing of such election at any time in the period commencing on the Effective Date and ending one hundred and eighty (180) days after the date on which CONTRACTOR declares the first Commercial Discovery (which date of declaration is referred to as the "First Commercial Declaration Date"). If the Public Company does not notify the CONTRACTOR of such election within such period, the Option to Participate shall be deemed to have been waived.

- Management Committee
    - A Management Committee shall be established in a timely fashion (usually 30 days) following the Effective Date for the purpose of providing orderly direction on all matters pertaining to the Petroleum Operations and Work Program. Within such period each of the GOVERNMENT and the CONTRACTOR shall by written notice nominate its respective members of the Management Committee and their deputies.
    - The Management Committee shall comprise an equal number of members designated by each Party. For example: two (2) members designated by the GOVERNMENT and two (2) members designated by the CONTRACTOR. Upon ten (10) days' notice, each Party may substitute any of its members of the Management Committee. The chairman of the Management Committee shall be one of the members designated by the GOVERNMENT (the "Chairman"). The vice chairman of the Management Committee shall be one of the members designated by the CONTRACTOR (the "Vice-Chairman"). In the absence of the Chairman, the Vice-Chairman shall chair the meeting. Each Party shall have the right to invite a reasonable number of observers as deemed necessary to attend the meetings of the Management Committee in a non-voting capacity.
    - The Management Committee shall review, deliberate, decide and give advice, suggestions and recommendations to the Parties regarding the following subject matters:
        - Work Programs and Budgets;
        - the CONTRACTOR's activity reports;
        - production levels submitted by the CONTRACTOR, based on generally accepted practice in the international petroleum industry;
        - accounts of Petroleum Costs;
        - procurement procedures for potential Subcontractors, with an estimated subcontract submitted by the CONTRACTOR;

  - Development Plan and Budget for each Petroleum Field;
  - any matter having a material adverse effect on Petroleum Operations;
  - any other subject matter of a material nature that the Parties are willing to consider.

- Each Party shall have one (1) vote in the Management Committee. The Management Committee cannot validly deliberate unless each Party is represented by at least one (1) of its members or its deputy. The Management Committee shall attempt to reach unanimous agreement on any subject matter being submitted. In the event the Management Committee cannot reach unanimous agreement, a second meeting shall be held usually within fourteen (14) days to discuss the same subject matter and attempt to reach a unanimous decision. Except the provisions below, in the event that no agreement is reached at the second meeting, the Chairman shall have the tie-breaking vote.

- In the event that, during the Exploration Period, no agreement is reached at the second meeting of the Management Committee, or unanimous approval is not obtained, the proposal made by the CONTRACTOR shall be deemed adopted by the Management Committee.

- Unanimous approval of the Management Committee shall be required for:

  - approval of, and any material revision to, any Exploration Work Program and Budget prepared after the first Commercial Discovery in the Production Area relating to such Commercial Discovery (unless such Exploration Work Program and Budget has been deemed approved by the Management Committee);
  - approval of, and any material revision to, the Development Plan, the production schedule, lifting schedule and Development and Production Work Programs and Budgets;
  - establishment of rules of procedure for the Management Committee;
  - approval of, and any material revision to, procurement procedures for goods and/or services, submitted by the CONTRACTOR (unless such procedures have been deemed approved by the Management Committee);
  - approval of, and any material revision to, any proposed pipeline project, submitted by CONTRACTOR;
  - approval of a first rate bank in which to place the Decommissioning Reserve Fund;
  - approval of, and any material revision to, any proposed Decommissioning Plan;

- any terms of reference which are required to be prepared and agreed for the purposes of expert determination; and
- any matter having a material adverse effect on Petroleum Operations.

- Either Party may call an extraordinary meeting of the Management Committee to discuss important issues or developments related to Petroleum Operations, subject to giving reasonable prior notice, specifying the matters to be discussed at the meeting, to the other Party. The Management Committee may from time to time make decisions by correspondence provided all the members have indicated their approval of such decisions in such correspondence.

- Supervision by the Government- Government Obligations
  - The CONTRACTOR shall at all times provide reasonable assistance as may reasonably be requested by the GOVERNMENT during its review and verification of records and of any other information relating to Petroleum Operations at the offices, worksites or any other facilities of the CONTRACTOR.
  - Upon giving reasonable prior notice to the CONTRACTOR, the GOVERNMENT may send a reasonable number of representatives to the work-sites or any other facilities of the CONTRACTOR to perform such reviews and verifications. The representatives of the GOVERNMENT shall at all times comply with any safety regulations imposed by the CONTRACTOR and such reviews and verifications shall not hinder the smooth progress of the Petroleum Operations.
- Government Assistance
  - To the extent allowed by the State law and at the specific request of the CONTRACTOR, the GOVERNMENT shall take all necessary steps to assist the CONTRACTOR in, but not limited to, the following areas:
    - securing any necessary Permits for the use and installation of means of transportation and communications;
    - securing regulatory Permits in matters of customs or import/export;
    - securing entry and exit visas, work and residence permits as well as any other administrative Permits for CONTRACTOR's and its Subcontractors' foreign personnel (including their family members) during the implementation of this Contract;
    - securing any necessary Permits to send Abroad documents, data or samples for analysis or processing for the Petroleum Operations;
    - relations with federal and local authorities and administrations;
    - securing any necessary environmental Permits;

        - obtaining any other Permits requested by the CONTRACTOR for the Petroleum Operations;
        - access to any existing data and information, including data and information relating to the Contract Area held by previous operators or contractors; and
        - providing all necessary security for Petroleum Operations.

- Government Responsibility – Case of the USA
    - US Federal Oil and Gas Regulations: 43 C.F.R. § 3161 - Jurisdiction and Responsibility - Establishes the authority and jurisdiction of the appropriate local authorized officer to direct and oversee oil and gas operations, to require that all operations be conducted in a manner which protects other natural resources and the environmental quality.
        - § 3161.2 Responsibility of the authorized officer
            - The authorized officer is authorized and directed to approve unitization, communitization, gas storage and other contractual agreements for Federal lands; to assess compensatory royalty; to approve suspensions of operations or production, or both; to issue Notice to Lessees (NTL's): to approve and monitor other operator proposals for drilling, development or production of oil and gas; to perform administrative reviews; to impose monetary assessments or penalties; to provide technical information and advice relative to oil and gas development and operations on Federal and Indian lands; to enter into cooperative agreements with States, Federal agencies and Indian tribes relative to oil and gas development and operations; to approve, inspect and regulate the operations that are subject to the regulations in this part; to require compliance with lease terms, with the regulations in this title and all other applicable regulations promulgated under the cited laws; and to require that all operations be conducted in a manner which protects other natural resources and the environmental quality, protects life and property and results in the maximum ultimate recovery of oil and gas with minimum waste and with minimum adverse effect on the ultimate recovery of other mineral resources. The authorized officer may issue written or oral orders to govern specific lease operations. Any such oral orders shall be confirmed in writing by the authorized officer within 10 working days from issuance thereof. Before approving operations on leasehold, the authorized officer shall determine that the lease is in effect, that acceptable bond coverage has been provided and that the proposed plan of operations is sound both from a technical and environmental standpoint.
        - § 3161.3 Inspections

    - The authorized officer shall establish procedures to ensure that each Federal and Indian lease site which is producing or is expected to produce significant quantities of oil or gas in any year or which has a history of noncompliance with applicable provisions of law or regulations, lease terms, orders or directives shall be inspected at least once annually. Similarly, each lease site on non-Federal or non-Indian lands subject to a formal agreement such as a unit or communitization agreement which has been approved by the Department of the Interior and in which the United States or the Indian lessors share in production shall be inspected annually whenever any of the foregoing criteria are applicable.

    - In accomplishing the inspections, the authorized officer may utilize Bureau personnel, may enter into cooperative agreements with States or Indian Tribes, may delegate the inspection authority to any State, or may contract with any non-Federal Government entities. Any cooperative agreement, delegation or contractual arrangement shall not be effective without concurrence of the Secretary and shall include applicable provisions of the Federal Oil and Gas Royalty Management Act.

- In general, the Government's role is to:
    - Evaluate the progress of the PSC, ensuring all deliverables are satisfactorily completed
    - Follow up on monitoring reviews, audits, and investigations
    - Provide approvals/permits for timely execution of the contract
- Additionally, the Government should create conditions for the industry to be self-regulating

10.13.3 References

1. US Federal Oil and Gas Regulations
2. PSC for Kurdistan Regional Government of Iraq
3. Model Production Sharing Contract (NELP-VIII), Republic of India, 2009
4. Johnston, Daniel. 1994. International Petroleum Fiscal Systems and Production Sharing Contracts. Tulsa, OK. PennWell Publishing Company.

10.14 *Enabling Regulations for Unconventional Hydrocarbons*

10.14.1 Definitions and Discussion

Unconventional hydrocarbons refer to oil and natural gas which must be extracted using techniques different from those for extracting conventional hydrocarbons. Unconventional oil consists of liquid sources including shale oil (also known as light tight oil), oil sands and extra heavy oil while unconventional gas typically includes shale gas, tight gas, gas hydrates and coalbed methane (CBM). Specialized techniques are needed to recover unconventional resources because they are often trapped in reservoirs with very low permeability where oil or natural gas has little to no ability to flow through the rock and into a wellbore. Petroleum industry uses horizontal drilling and hydraulic fracturing to extract oil or natural gas from low permeability unconventional reservoirs.

10.14.2 Best Practices

- Exploration and production contract for unconventional hydrocarbons (Colombia)
  - Initially Proposed Definitions
    - The definition of Unconventional Hydrocarbons needs to be refined to ensure that it does not overlap with Conventional Hydrocarbons contracts. This is relevant because areas of Unconventional Hydrocarbons contracts can overlap areas of Conventional Hydrocarbons contracts.
    - Note that the rights granted under a typical E&P contract do not exclude Unconventional Hydrocarbons. As a matter of fact, they are covered, and there is an express provision in the current agreements to increase the exploration period for up to 2 years (from an initial 6 years) in case of a discovery of Unconventional Hydrocarbons.
  - Scope
    - Scope is limited to the right to explore and exploit Unconventional Hydrocarbons.
    - As a result, conventional liquid hydrocarbons and free gas will be excluded from the scope of the contract. Also excluded are undeveloped reservoirs that had already been discovered and were known to the contractor at the time of entering into the agreement.
  - Term
    - Exploration.8years (extendable for 1 additional year), divided in sub-phases. Right to relinquish the area subject to meeting minimum obligations of sub-phase.
    - In case of a Discovery that may be commercial, the contractor must develop a Pilot Program that can last 2 years, extendable for another year. The program must involve at least the drilling of 5 wells.

- Additional Exploration Program. At the end of the exploration period, and to the extent there is an Area of Evaluation (Discovery + Decision to conduct a Pilot Program), an Area of Production or a Discovery has been made in the last exploration sub-phase, the Contractor can conduct an Additional Exploration Program with a maximum of 2 sub-phases of 2 years each.

  In this case, the Contractor must relinquish 50% of the contracted area (excluding Areas of Evaluation and Areas of Production).

  After completion of the first sub-phase, 25% of the retained areas must be relinquished in order to access to the second sub-phase.

- Pilot Program. In case of a Discovery that may be commercial, the contractor must develop a Pilot Program that can last 2 years, extendable for another year. The program must involve the drilling of at least 5 wells.

- Production.30 years

  Extensions for successive periods of up to 10 years, until the economic limit of the commercial field, provided that the production area has been producing unconventional hydrocarbons for the last 5 years before the application, and that the contractor agrees to pay an additional 10% of production of Unconventional Hydrocarbons, or 5% in case of [extra] heavy oils.

- New Incentives to Foster Investment in Oil and gas Sector in Argentina
  - The Argentine government established a hydrocarbon investment promotion mechanism aimed at attracting investment to develop the nation's vast unconventional resources. The Decree 929/2013, published on July 15, will allow companies to freely sell 20% of their production in the international market (or in the local market at international price) without paying export retentions and without currency or repatriation restrictions.
  - If the plan meets the requirements set forth by the Commission (these have not been published yet), the beneficiary company will enjoy the following benefits:
    - Possibility of selling 20% of production in the international market without currency/repatriation restrictions: On the 5th year of the project, companies will be entitled to freely sell 20% of their production in the international market without paying any export retentions. As long as the investment threshold has been met, the total proceeds from such operation shall be free from currency or repatriation restrictions.
    - Possibility of selling 20% of production in the local market at the international price and freely exchange and repatriate proceeds: If the national production of hydrocarbon does not meet the national demand, the company must sell such 20% in the local market but at the same reference price that could be obtained in the international market. For the purpose of

selling such 20% in the national market, the international reference price shall not be reduced by computing any export restriction. The Commission shall establish a compensation mechanism between the local price and the international price which shall be payable in Argentine pesos. When the sale of such 20% is performed in the national market, the producer seller will have a "priority right" to freely exchange proceeds to any other currency in the government regulated exchange market.

- Possibility of extending the life of concessions: The decree creates the category of "Non-conventional Hydrocarbon Exploitation" which consists of extraction of liquid or gas hydrocarbons through non-conventional stimulation techniques in formations, which are characterized by low permeability. This category includes shale gas or shale oil, tight sands, tight oil, tight gas and coal bed methane. Companies that are holders of exploration permits or exploitation concessions and which have been included in the Regime for the Promotion of the Investment for Hydrocarbon Exploitation shall be entitled to a concession of "Non-conventional Hydrocarbon Exploitation."

- Any exploitation concession allows the company to exploit both conventional and non-conventional resources within the concession area. A current concession holder may apply for a non-conventional concession and thus be shall be entitled to a new concession for a term of 25 years. This 25 year term may be extended for an additional 10 years. Such 10-year extension may be granted during the initial authorization of the concession.

- Additionally, if the concession holder proves geographic continuity of the conventional and non-conventional fields, the concession holder may request that the areas be unified in the single new non-conventional concession, thereby extending the life of the original concession for up to 35 years. If the areas are unified, the concession holder must exploit the non-conventional resources and but also has the right to develop the conventional resources.

- If it is not possible to unify the areas into a single non-conventional concession, the area of the original concession shall be subdivided into a conventional concession and a non-conventional concession. The conventional part of the concession shall expire on the date originally stipulated.

- Unconventional Oil and Natural Gas Production Tax Rates in US

  - The table below summarizes the state tax incentives for unconventional oil in the United States. The states include Colorado, Montana, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming. For example, Oklahoma has a four-year production tax "holiday" that reduces the tax rate for newly completed horizontal wells from seven to one percent.

State Tax Policy Related to Unconventional Oil

State	Base Tax Rate	Incentives for Unconventional Production	Timing of Collections
Colorado	Graduated tax rate based on gross income of producer: 2% under $25,000; $500 + 3% for $25,000 to $100,000; $2,750 + 4% for $100,000 to $300,000; $10,750 + 5% for production over $300,000. Net production value is gross production value less transportation and processing costs.	87.5 percent of property taxes paid to local governments are deducted from the state severance tax liability.	Annual. Payment is due on the 15th day of the fourth month after the close of the taxable year (April 15 following the tax year beginning January 1).
Montana	Working interest 9.0%; Royalty interest 14.8%. Total gross value is computed as the product of the total number of barrels produced each month and the average wellhead value per barrel. Producers are allowed to deduct any oil produced that is used in the operation of the well.	0.5% for first 18 months from new horizontal wells and 12 months on new vertical wells on working interest only.	Quarterly. Tax payments are due within 60 days following the close of each calendar quarter.
New Mexico	3.75% of net production value, defined as gross production value less royalties paid to federal, state, or tribal governments, and transportation costs.	N/A	Monthly
North Dakota	A 5% rate is applied to the gross value at the well of all oil produced, except royalty interest in oil produced from a state, federal or municipal holding and from an American Indian holding within the boundary of a reservation.	N/A	Monthly
Oklahoma	7% (4% if price drops below $17/bbl, and 1% if price drops below $14/bbl)	Horizontal wells pay 1% for first 48 months or until costs recovery	Monthly

Texas	7.5% of gross production value, including royalty and other interests.	N/A	Monthly
Wyoming	6% of gross production value.	N/A	Monthly

- The table below summarizes the state tax incentives for unconventional Natural Gas in US. The states include Arkansas, Louisiana, New Mexico, Oklahoma, Pennsylvania, Texas and Wyoming.

State Tax Policy Related to Unconventional Natural Gas

State	Base Tax Rate	Incentives for Unconventional Production	Timing of Collections
Arkansas	5% on natural gas.	1.5% on high-cost gas wells for 36 months. If cost recovery is not achieved by 36 months, the incentive is extended an additional 12 months or until cost recovery.	Monthly
Louisiana	$0.148/Mcf for the period 7/1/12 to 6/30/13. Works out to a 4.1% tax rate when the price is $3.58/Mcf.	No tax for two years or until the well cost is paid, whichever comes first on wells drilled to a true vertical depth of more than fifteen thousand feet.	Monthly
New Mexico	3.75% of net production value, defined as gross production value less royalties paid to federal, state, or tribal governments, and transportation processing costs.	N/A	Monthly
Oklahoma	7% (4% if price drops below $2.10/mcf, and 1% if price drops below $1.75/Mcf).	1% for first 48 months or until cost recovery for horizontal wells.	Monthly
Pennsylvania	Annual fee schedule set by the Public Utility	N/A	Annually, due in April following the calendar year

	Commission. Fees are based on the price of natural gas		for which the fee is assessed.
Texas	7.50%	0% to 7.4% for high cost gas wells for 120 months or until the value of the incentive exceeds 50 % of well completion costs. The incentive tax rate is calculated as the relationship between wells costs and the average of all high costs wells from the previous year. The median cost well pays exactly half the base tax rate (or 3.75 percent).	Monthly
Wyoming	6%	N/A	Monthly

- Based on the Colombian example, it is proposed to allow for an extended exploration period in the case of discovery of unconventional hydrocarbons.
- It is recommended to prove commerciality of unconventional hydrocarbons through a pilot program.
- PSC extensions should be utilized for producing unconventional hydrocarbons for maximum recovery of hydrocarbons throughout the commercial production life.
- Allow Contractors to freely sell a percentage of their unconventional hydrocarbon production in the international market (or in the local market at international prices) without paying export retentions and without currency or repatriation restrictions.
- A variety of fiscal incentives could be utilized to promote development of unconventional hydrocarbon discoveries. Such incentives could be reduced taxation, reduced royalty payments, more favorable production splits to the contractor, etc.

10.14.3 References

1. Regulatory Framework of Unconventional Hydrocarbons in Colombia
2. Argentina: Amendment of the Hydrocarbons Law
3. Argentina Announces: New Incentives to Foster Investment in Oil and gas Sector
4. Unconventional Oil and Natural Gas Production Tax Rates

10.15 *General Guidelines on Tight Oil/Gas, CBM, Shale Oil/Gas Exploration and Exploitation Strategies*

10.15.1 Definitions and Discussion

- Tight oil/gas is crude oil or natural gas that is contained in petroleum-bearing formations of low permeability, often shale or tight sandstone.

- Shale oil/gas is crude oil or natural gas trapped within shale rock formations underground. Advances in hydraulic fracturing or "fracking" – the process of forcing fluids at high pressure into wellbores to fracture the shale rock, allowing the oil/gas to escape.

- Coalbed methane (CBM) refers to methane that is found in coal seams and is widely considered as an unconventional source of natural gas. Typical recovery entails pumping water out of the coal to allow the gas to escape. Methane is the principal component of natural gas. Coalbed methane can be added to natural gas pipelines without any special treatment. Numerous regulations designed to regulate conventional natural gas development can and do apply to CBM exploration and exploitation. However, due to the differences in produced water volumes and quality, well spacing, and utility infrastructure, specific CBM regulations have been drafted by federal, state and local regulating agencies to meet various concerns.

- The environmental impacts of CBM development are considered by various governmental bodies during the permitting process and operation, which provide opportunities for public comment and intervention. Operators are required to obtain building permits for roads, pipelines and structures, obtain wastewater (produced water) discharge permits, and prepare Environmental Impact Statements. As with other natural resource utilization activities, the application and effectiveness of environmental laws, regulation, and enforcement vary with location. Violations of applicable laws and regulations are addressed through regulatory bodies and criminal and civil judicial proceedings.

10.15.2 Best Practices

- Shale Oil Exploration and Exploitation Guidelines in the USA

    - Key federal regulations governing shale development include: Clean Water Act; Clean Air Act; Safe Drinking Water Act; National Environmental Policy Act; Resource Conservation and Recovery Act; Emergency Planning and Community Right to Know Act; Endangered Species Act and the Occupational Safety and Health Act.

    - Effective hydraulic fracturing regulation can only be achieved at the state level as state regulations can be tailored to geological and local needs. Key state regulations include: review and approval of permits; well design, location and spacing; drilling operations; water management and disposal; air emissions; wildlife impacts; surface disturbance; worker health and safety; and inspection and enforcement of day-to-day oil and gas operations.

- Hydraulic Fracturing – New York, USA

  - Currently, New York State does not allow hydraulic fracturing in its portion of the highly sought after Marcellus Shale. In December of 2010, then New York State Governor David Patterson issued an executive order banning the practice of "high-volume, horizontal hydraulic fracturing" in the Marcellus Shale region until the Department of Environmental Conservation (DEC) completed a review to certify that the practice was safe. At the time of the executive order, the DEC had already stopped issuing drilling permits in the Marcellus Shale until it completed its review of the practice. The "moratorium" enacted by the executive order is still under effect, as the DEC continues its review process.

- Hydraulic Fracturing – Texas, USA

  - In June 2011, Texas passed a law requiring the Railroad Commission to promulgate rules for the disclosure of chemicals used in hydraulic fracturing. The Commission approved a proposed rule in August that would apply to hydraulic fracturing treatments on wells drilled after the effective date of the rule. This proposed rule would require disclosure to the well operator of each chemical ingredient added to the hydraulic fracturing fluid. The well operator would then be required to submit this information to the "FracFocus" website.

- Hydraulic Fracturing – Louisiana, USA

  - The Louisiana Department of Natural Resources (DNR) Office of Conservation is responsible for regulating the exploration and production of oil and gas. An operator of a hydraulic fracturing well must obtain a work permit before commencing well construction operations. The work permit application must include a plan for the construction and stimulation of the fracking well. Before drilling can begin, the operator also needs to obtain a permit to drill. To protect fresh water sources, the DNR requires well casings of varying depths dependent on the depth of the well itself.

  - Flowback from hydraulic fracturing activities must be stored in tanks or lined pits, but are exempt from Louisiana Hazardous Waste Regulations. Pits must be constructed above the 100-year floodplain, and temporary containment pits must be closed within six months of well completion. Pits must be closed in a manner that protects the soil, surface water, ground water, and underground sources of drinking water. Before closing a pit, the pit contents are tested for multiple parameters, including pH, heavy metals, and oil and grease content.

  - The well operator is responsible for the proper handling and transportation of exploration and production waste taken offsite for storage, treatment, or disposal. Offsite disposal must be at an approved commercial facility. The operator may elect to dispose of such wastes at a DNR or Department of Environmental Quality (DEQ) permitted facility. Wastes received at a DEQ permitted facility becomes the sole responsibility of the DEQ. Furthermore, DEQ regulations require well operators to develop and implement a Spill Prevention and Control Plan.

- Recently, the Louisiana DNR adopted a new rule requiring oil and gas well operators to disclose the composition and volume of the fracking fluids they use, after completing the well. The rule requires disclosure to the Office of Conservation or a public registry, such as "FracFocus."

- Coalbed Methane Exploration and Exploitation Guidelines in the USA
  - Produced Water Regulations
    - Produced water quality varies depending primarily upon the geology of the coal formation. Typically, saltier water is produced from deeper coal formations. Produced water may contain nitrate, nitrite, chlorides, other salts, benzene, toluene, ethylbenzene, other minerals, metals and high levels of total dissolved solids.
    - Depending on which state you live in, produced water may be: discharged onto land, spread onto roads, discharged into evaporation/percolation pits, reinjected into aquifers, discharged into existing water courses (with the proper permit), or disposed of in commercial facilities. In some states, standards for produced water disposal are becoming more rigorous, and certain disposal practices are losing favor. Surface discharge, for example, is a controversial method of disposal, as it can lead to a build-up of salts and other substances in the soil, and affect the productivity of the land. In some states, re-injection is the only option for disposal.
    - Federal regulations apply to the two most common methods of handling CBM produced water, i.e., surface discharge and reinjection. If the water is discharged to a surface stream, it must be done under the provisions of state-specific Clean Water Act Section 402: National Pollutant Discharge Elimination System (NPDES). If CBM produced water is injected into deep, geologic formations as a means of disposal, it must be to a Class II Disposal Well.
  - Fiscal Incentives
    - An incentive for production of unconventional fuels was provided by the Windfall Profit Act (WPT) of 1980 (tax act) at a time of high oil prices. This incentive was a production tax credit intended for times when low oil prices would limit the competitiveness of unconventional gases. The tax credit for CBM became known simply as the Federal Sec. 29 tax credit when it was retained after the WPT act provisions expired.
    - For CBM production to qualify, the well must have been spudded between December 31, 1979, and January 1, 1993. The site must have been prepared, the drilling rig set up, and the initial borehole begun. Further, capital to drill

to total depth must have been committed. At the end of December 1992, Congress allowed Section 29 to expire.

- Shale Gas Exploration and Exploitation Guidelines in the USA
    - Site Development and Preparation
        - Setback Restrictions from Buildings
            - Setback restrictions regulate the distance between wells and other entities—such as schools, homes, streams, and water wells—that are thought to merit special protection and care. Most of the surveyed states (20 of 31) have building setback restrictions, ranging from 100 feet to 1,000 feet from the wellbore (the most common method of measurement), with an average of 308 feet. Some other states do not regulate building setback, but may require setbacks from other features or activities.
        - Setback Restrictions from Water Sources
            - Well setback from surface water (such as rivers) and water wells is widely regulated, though not as widely as building setback. Of the states surveyed, 12 have setback restrictions from some body of water or water supply source; 9 of those have setback restrictions from municipal water supplies (measured from the well) ranging from 50 feet to 2,000 feet, with an average of 334 feet.
        - Pre-Drilling Water Well Testing Requirements
            - Pre-drilling water well testing establishes the baseline water quality for an area prior to drilling activity. The majority of surveyed states (23) do not require baseline water well testing. In states that do require such testing, regulation usually requires testing of at least two wells within a specified radius from the proposed well location. This radius varies significantly among states, from 0.09 miles (Virginia) to 1 mile (North Dakota, Nebraska, and Oklahoma). The average radius is 0.44 miles. States that do require testing may do so only in some fields or under certain conditions.
            - Colorado and Ohio have zone-or well-specific conditions for pre-drilling water well testing. For instance, the Wattenberg field in Colorado, which is part of the Niobrara play, is the only zone in Colorado that requires pre-drilling water well testing. Ohio, on the other hand, decides on a permit-specific basis whether or not pre-drilling water well testing is necessary. API best practice is to test water samples from any source of water located near the well (determined based on anticipated fracture length) before drilling, or before hydraulic fracturing.

- Well Drilling and Production
  - Casing and Cementing Depth Regulations
    - Casing is steel pipe of varying diameter that separates the wellbore from surrounding rock. Cement is circulated within the gap (annulus) between each layer of casing. Almost all surveyed states regulate the depth to which well casing must extend and be cemented. Of those, 21 have specific casing and cementing requirements; 15 of these require casing to be set and cemented to a specified minimum depth below the base of layers or zones containing freshwater—between 30 and 120 feet, with an average of about 64 feet.
  - Cement Type Regulations
    - Cementing practices may be regulated in terms of compressive strength, type of cement, or circulation around casing. Eleven states use command-and-control regulation specifically to regulate cement type, characteristics, and practices. Another six states address cementing in their permit processes.
  - Surface Casing Cement Circulation Regulations
    - Twenty-eight states require surface casing, the outermost layer of casing, to be cemented all the way to the surface. All states that require such cementing do so explicitly in their statutes or regulations, not as part of their permitting process.
  - Intermediate Casing Cement Circulation Regulations
    - Use of intermediate casing is usually not mandatory, but if it is, cementing regulations often apply. Ten states use command-and control rules: in four (New York, Pennsylvania, Indiana, and Kentucky), cement must be circulated to the surface. The remaining six states specify a height above the shoe (the bottom of the casing string) or uppermost hydrocarbon zone to which intermediate casing must be cemented. This height ranges from 200 feet above the uppermost hydrocarbon zone (Colorado and Oklahoma) to 600 feet above the shoe (Texas).
  - Production Casing Cement Circulation Regulations
    - Only two states (Arkansas and New York) require production casing to be cemented to the surface. Twelve states have specific regulations for how much cement must be circulated. These rules vary and are measured from similar but slightly different points. An additional 10 states regulate cementing of the production casing in their permit processes.

- Venting Regulations

  - Venting occurs when gas escapes from the wellbore into the atmosphere. More than half of states surveyed (22) have some form of venting regulations, though these vary greatly across states. Some states have specific restrictions such as the number of days that venting may occur, the amount of gas that may be vented, or the development phases during which gas may be vented. That is, some states specify that venting may be allowed during well cleanup, well testing, and emergencies, but at no other time. Some states have "aspirational standards," which require operators to minimize gas waste or not to harm public health, but impose no effective requirement or standard. Louisiana prohibits venting unless it can be shown that the prohibition causes economic hardship. API suggests that all gas resources of value that cannot be captured and sold should be flared, but that any venting be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site.

- Flaring Regulations

  - Flaring is the process by which excess gas is burned off in stacks or flares. The majority of states surveyed (23) have some flaring regulations, though these vary greatly across states. Some states restrict the amount of gas that may be flared, the location of flares, or the development phases during which gas may be flared. That is, some states specify that flaring may be used during well cleanup, well testing, and emergencies, but at no other time. Several states mandate that gas be flared as opposed to vented. API suggests that all gas resources of value that cannot be captured and sold should be flared and recommends that flares be restricted to a safe location and oriented downwind considering the prevailing wind direction at the site.

o Waste Water Storage and Disposal

- Water Withdrawal Regulations

  - Water makes up by far the largest share of fracturing fluid, and the fracturing process requires several million gallons per job. Several states have discussed drafting water withdrawal restrictions specific to the shale gas industry, but none has yet passed such legislation. Of the states surveyed, 30 do generally regulate surface and groundwater withdrawals, however. Some require permits for water withdrawals, others require registration and reporting, and a few require both.

- Fracking Fluid Disclosure Regulations

- At the federal level, hydraulic fracturing is exempt from disclosure that would otherwise be required by the Safe Drinking Water Act, though the Department of the Interior recently passed rules requiring frack fluid disclosure for wells drilled on public lands. Less than half of states surveyed (14) require disclosure of fluids used in the fracturing process. At least three states have proposed rules, and two states have some form of fluid disclosure regulations but it is unclear if they pertain to hydraulic fracturing. Illinois' proposal would strengthen existing disclosure rules. The level of disclosure detail required also differs across states. Few states require disclosure of all chemicals used; even fewer states require disclosure of additive volume and concentration. Pennsylvania, for example, requires the disclosure of percent by volume of each additive in the stimulation fluid, whereas Arkansas requires additives to be expressed as a percent by volume of the total hydraulic fracturing fluids, and of the total additives used. All states with chemical disclosure requirements provide trade secret exemptions for chemicals considered "confidential business information." Wyoming requires prior approval for use of benzene, toluene, ethylbenzene, and xylene (BTEX) compounds. API suggests that operators be prepared to disclose information on chemical additives and their ingredients and that "the best practice is to use additives that pose minimal risk of possible adverse human health effects to the extent possible in delivering needed fracture effectiveness."

▪ Fluid Storage Regulations

- Fluid storage needs vary over the course of the shale gas development process. Fracking fluids must be stored before being used, and the post-fracturing wastewater, including flowback fluids and produced fluids, must also be stored before disposal. There are many different types of pits, including permanent and temporary pits, and different pits have distinct specifications, such as whether or not they require lining. Fluids are most commonly stored in pits and tanks; 9 surveyed states only specifically address pit storage and 19 specifically mention pits and tanks in their regulations. California mandates a closed-loop systems in which fluids are not exposed to the elements at any point. Michigan only allows pits to be used for drilling fluids, muds, and cuttings; tanks must be used for produced water, completion fluids, and other liquid wastes, and in all areas zoned residential. Other storage options include ponds, sumps, containers, impoundments, and ditches. API best practice stipulates that "completion brines and other potential pollutants should be kept in lined pits, steel pits, or storage tanks."

▪ Freeboard Requirements

- Most states that allow fluid storage in pits have a variety of specifications that must be met, including freeboard requirements-that is, the amount of space in the pit between the maximum water level and the top of the pit. Freeboard is important for preventing overflow of fluids, particularly during and after intense rain. Of the 27 states that allow storage of fluids in pits, 16 have freeboard regulations, ranging from 1 foot to 3 feet. New Mexico differentiates between permanent pits and temporary pits in the amount of freeboard required, 3 feet and 2 feet, respectively. Oklahoma requires 1.5 feet of freeboard for temporary pits, 2 feet of freeboard for noncommercial pits, and 3 feet of freeboard for pits capable of holding more than 50,000 barrels. Montana's requirements only apply to earthen pits or ponds that receive produced water containing more than 15,000 ppm total dissolved solids in amounts greater than five barrels per day on a monthly basis. California does not allow the use of pits for fluid storage, thus freeboard requirements are not applicable. API best practice is that pits should be constructed with sufficient freeboard "to prevent overflow under maximum anticipated operating requirements and precipitation."

- Pit Liner Requirements

  - Pit liners prevent fluids from seeping into the ground and potentially contaminating groundwater. Most of the states surveyed that allow fluid storage in pits (18) require pit liners. Of those states, 11 have specific regulations about the thickness of the liners and several states have other regulations such as permissible liner materials (for example. re-compacted clay liners, soil mixture liners, and synthetic liners). Alabama, Montana, and Wyoming all have conditional requirements for pit liners, such as Alabama's rule that liners are only required if the bottom of the pit is not above the seasonal high water table. Wyoming requires them only if it is "necessary" to prevent contamination of surrounding ecosystems. California does not allow the use of pits for fluid storage, thus pit liner requirements are not applicable. API best practice is that "depending upon the fluids being placed in the impoundment, the duration of the storage and the soil conditions, an impound lining may be necessary to prevent infiltration of fluids into the subsurface."

- Waste Water Transportation Tracking

  - Wastewater that is not reused, recycled, or disposed of on-site is transported off-site, usually in trucks. The tracking of transported wastewater can be enforced either by requiring transporters to have permits, by requiring detailed recordkeeping of shipments, or both. Recordkeeping requirements often include the names of the operator and transporter, the date the wastewater was picked up, the location at which it was picked up, the location of the disposal facility or destination of the shipment, the type of fluid being transported, and the volume. Many states also stipulate the number of years that such records must be kept available to inspectors. Slightly less than half of the states surveyed (15) do not require tracking of transported wastewater. The rest (16) use permits, recordkeeping, or both to track transported wastewater. Colorado and Kansas require records to be kept of wastewater shipments but do not require transporters to be approved or permitted. In some cases, the onus is placed on the operator to ensure that all information is tracked and reported, whereas in other cases, the burden is on the transporter to do so. API best practice is that wastewater is transported "in enclosed tanks aboard DOT compliant tanker trucks or a dedicated pipeline system."

▪ Underground Injection Wells for Flowback and Produced Water

- Arkansas, Colorado, Ohio, Oklahoma, and Texas have recently experienced an increase in seismic activity near deep underground injection sites. As a result, many deep injection wells have been closed while further research is conducted. Almost all of the states surveyed (30) allow deep well injection as a form of wastewater disposal. North Carolina prohibits underground injection of fluids produced in the extraction of oil and gas wells. Arkansas has a moratorium on deep injection in a 600-square-mile area of the state where there is a fault that may have been activated by wastewater injections in the area. Ohio has recently followed a similar course of action, temporarily closing down several injection wells in an area where seismic activity has occurred. Fort Worth, Texas, has a moratorium on deep injection wells. API best practice is that "disposal of flow back fluids through injection, where an injection zone is available, is widely recognized as being environmentally sound, is well regulated, and has been proven effective."

o Well Plugging and Abandonment

▪ Well Idle Time Regulations

- An idle well is one that is not currently producing oil or gas. Generally, wells are not permitted to remain idle indefinitely, but instead must be properly plugged to minimize the risk of damage or contamination. Of the 31 states surveyed, 28 regulate the duration over which a well is allowed to sit idle. Beyond this time period, operators must generally restart production at the well, convert it to a waste disposal well, or plug and abandon it. Maximum idle times range from 1 to 300 months, with a mean of 23.5 months.

▪ Temporary Abandonment Regulations

- Many states allow operators to temporarily abandon wells, allowing them to remain idle but—in most cases—requiring operators to take various measures to reduce the risk of damage to or contamination of the well. Of the states surveyed, 22 allow temporary abandonment. State law limits the amount of time wells can be kept in this status. These limits range from 3 to 60 months, with a national average of about 23 months. In those states without temporary abandonment regulation, the general well idle time rules (if any) apply: wells must be plugged once well idle time expires.

- Well Inspection and Enforcement

  - Accident Reporting Requirements

    - Most of the states surveyed (26) have regulations that require reporting of accidents (such as spills, leaks, and fires). The rest do not mention reporting requirements in their regulations but may stipulate such requirements in permits. The map shows the specific time or range of times in which accidents must be reported, which averages 14 hours. Several states offer different timelines depending on the severity of the spill. Louisiana and Virginia, for example, set a 24-hour timeline for spills that are not categorized as "emergencies." New Jersey has a 2-hour reporting requirement if potable water supplies are affected and a 24-hour requirement if an underground source of drinking water is impacted. West Virginia does not provide a timeline but states that in case of an accident the operator must give notice to the district oil and gas inspector or the chief. Typically, operators are then given a specific number of days thereafter to file a written report detailing the accident. On the map, a zero indicates that accidents must be reported immediately. API best practice is that "a spill or leak should be promptly reported."

- Other Regulations

  - State and Local Ban and Moratoria

    - Several state and local governments have passed bans and moratoria on various parts of the horizontal drilling and hydraulic fracturing process. New York State, in addition to a statewide moratorium, has more than fifty local bans and moratoria. Several states with local or municipal bans are currently in litigation over the legality of local regulation of shale gas extraction. Two New York judges recently upheld local ordinances banning the practice, whereas a judge in West Virginia ruled a local ordinance unconstitutional and unenforceable. Texas and Colorado do not allow local or municipal bans, but several local governments in these states have passed moratoria on the shale gas development process. On the map, the New Jersey and Maryland numbers indicate the number of years the moratoria are set to run, beginning in January 2012 and June 2011, respectively. As of June 2012 New Jersey has six months remaining and Maryland has two years.

- Severance Tax Calculation Method

    - Severance taxes are taxes imposed on gas production. Each state has a different rate, and states use one of two methods to calculate the tax-either a percentage of the market value of the gas extracted or a fixed dollar amount per quantity extracted. Some states use a hybrid approach in which the percentage tax varies between different levels based on the gas price. Rates may also vary based on production, well vintage, or other factors. For example, in Montana, the tax rate is 0.5 percent for the first 18 months of a well's operation (compared to 9 percent thereafter). In Utah, if the price of gas is below $1.51 per MCF the tax rate is 3 percent, and in Colorado the tax rate is set based on total net gross income, with the lowest rate (2 percent) pertaining to total net gross income less than $25,000 and the highest (5 percent) pertaining to total net gross income greater than or equal to $300,000. Some states (such as Maryland and Virginia) leave the question of severance taxes to local governments, though Maryland is debating a 4.5 percent statewide severance tax which would be imposed on top of any local taxes (currently Allegany County's 7 percent and Garrett County's 5.5 percent tax). Virginia limits local severance taxes to 1 percent. Several states offer incentive programs that can reduce severance tax burdens. Louisiana, for instance, offers discounts for "incapable" wells; Montana offers a decreased rate for "nonworking interests;" Oklahoma lowers the tax according to the price of gas at market; and Texas can lower taxes for high-cost wells and inactive wells. Pennsylvania recently passed an "impact fee" that provides funds to the communities where drilling is occurring to alleviate the cost of burdens, such as road repairs, environmental damages, and other issues. Georgia and Vermont do not have severance taxes but that is not surprising since they do not have production.

- Selected Federal Actions Related to Unconventional Oil and Gas Production (USA)

    - EPA: Clean Air Act (CAA)

        - Air emissions. In 2012, EPA issued regulations that revised existing rules and promulgated new ones to regulate emissions of volatile organic compounds (VOCs), sulfur dioxide, and hazardous air pollutants (HAPs) from many production and processing activities in the oil and gas sector that had not been subject previously to federal regulation.

        - Particularly pertinent to shale gas production are the New Source Performance Standards (NSPS), which require reductions in emissions of

VOCs from hydraulically fractured natural gas wells. The rules require operators to use reduced emissions completions (green completions) for all hydraulically fractured natural gas wells beginning no later than January 2015.

- Applying broadly across the sector, the NSPS require reductions of VOCs from compressors, pneumatic controllers, storage vessels, and other emission sources, and also revise existing standards for sulfur dioxide emissions from onshore natural gas processing plants, and HAPs from dehydrators and storage tanks.

- In September 2013, EPA updated its 2012 performance standards for oil and natural gas to address VOC emissions from storage tanks used by the crude oil and natural gas production industry. The updates are intended to ensure tanks likely to have the highest emissions are controlled first, while providing tank owners and operators time to purchase and install VOC controls. The amendments reflect recent information showing that more storage tanks will be coming on line than the agency originally estimated (thus, presumably, producers need more time to purchase and install emission controls).

- In July 2014, EPA proposed updates and clarifications to NSPS requirements for well completions, storage tanks, and natural gas processing plants. The proposal would not change the required emission reductions in the rules, including standards applicable to hydraulically fractured natural gas wells.

o EPA: Clean Water Act (CWA)

- Wastewater discharge. Produced water and flowback from hydraulic fracturing have high levels of total dissolved solids (TDS), largely chlorides, which can harm aquatic life and affect receiving water uses (such as fishing or irrigation). EPA is updating its chloride water quality criteria for protection of aquatic life.

- CWA Section 304(a)(1) requires EPA to develop criteria for water quality that reflect the latest scientific understanding of the effects of pollutants on aquatic life and human health. States use EPA-recommended criteria to establish state water quality standards, which in turn are used to develop enforceable discharge permits.

- If reflected in state water quality standards, the revised chloride water quality criteria could affect discharges of produced water from extraction of conventional and unconventional oil and gas.

- In 2011, EPA indicated that it was initiating two separate rulemakings to revise the Effluent Limitations Guidelines and Standards (ELGs) for the Oil and Gas Extraction Point Source Category to control discharges of wastewater from (1) coalbed methane (CBM) and (2) shale gas extraction.

Under CWA Section 304(m), EPA sets national standards for discharges of industrial wastewater based on best available technologies that are economically achievable (BAT).

- States incorporate these limits into discharge permits. Shale and CBM wastewaters often contain high levels of total dissolved solids (TDS—i.e., salts), and shale gas wastewater may contain chemical contaminants, naturally occurring radioactive materials (NORM), and metals.

- Discharges to surface water: Currently, shale gas wastewater may not be discharged directly to surface waters. CBM wastewater is not subject to national discharge standards; rather, CBM wastewater discharge permits are based on best professional judgments of state or EPA permit writers. EPA was working to develop regulatory options to control direct discharges of CBM wastewaters, but determined in 2013 that no economically achievable technology was available.

- Discharges to treatment plants: Current ELGs lack pretreatment standards for discharges of shale gas or CBM wastewaters to publicly owned wastewater treatment works (POTWs), which typically are not designed to treat this wastewater. EPA is developing national pretreatment standards that shale gas and CBM wastewaters would be required to meet before discharge to a POTW to ensure that the receiving facility could treat the wastewater effectively.

- EPA: Emergency Planning and Community Right-to-Know Act (EPCRA)

  - Chemical disclosure. EPA has been considering an October 2012 petition by nongovernmental organizations to subject the oil and natural gas extraction industry to Toxics Release Inventory (TRI) reporting under EPCRA. Section 313 of EPCRA requires owners or operators of certain industrial facilities to report on releases of toxic substances to the state and EPA. EPA and states are required to make nonproprietary data publicly available through the TRI website.

- EPA: Safe Drinking Water Act (SDWA)

  - Diesel fuels. EPA has issued UIC Program Guidance for Permitting Hydraulic Fracturing with Diesel Fuels in response to the revised SDWA definition of "underground injection" in the Energy Policy Act (EPAct) of 2005 to explicitly exclude the underground injection of fluids (other than diesel fuels) used in hydraulic fracturing. The guidance provides recommendations for EPA permit writers to use in writing permits for hydraulic fracturing operations using diesel fuels. The guidance applies in states where EPA implements the UIC program for oil and natural gas related (Class II) injection wells. States are not required to adopt the guidance, but may do so.

- EPA: Toxic Substances Control Act (TSCA)

        - Chemical reporting. In response to a citizen petition (TSCA Section 21), EPA published an Advance Notice of Proposed Rulemaking (ANPRM) to get input on the design and scope of possible reporting requirements for hydraulic fracturing chemicals. EPA is considering requiring information reporting under TSCA Section 8(a), and health and safety data reporting under Section 8(d). EPA is seeking comment on the types of chemical information that could be reported and disclosed, and approaches to obtaining this information for chemicals used in hydraulic fracturing.

    - EPA: Resource Conservation and Recovery Act (RCRA)

        - Storage/disposal pits and ponds. EPA has been considering developing guidance to address the design, operation, maintenance, and closure of pits used to store hydraulic fracturing fluids for reuse or pending final disposal. These wastes are exempt from regulation as a hazardous waste under RCRA.

    - Department of the Interior, Bureau of Land Management (BLM): Mineral Leasing Act, Indian Mineral Leasing Act

        - Hydraulic fracturing on public lands. BLM has proposed revisions to rules governing oil and natural gas production on federal and Indian lands. BLM proposes to (1) require public disclosure of chemicals used in hydraulic fracturing, (2) tighten regulations related to well-bore integrity, and (3) add new reporting and management/storage/disposal requirements for water used in hydraulic fracturing.

    - Department of Homeland Security, Coast Guard: 46 U.S.C. Ch. 37

        - Wastewater shipment. The Coast Guard regulates the shipment of hazardous materials on the nation's rivers. Because of the potential for shale gas wastewater in the Marcellus Shale region to contain radioactive materials (especially radium, which can form surface residues and may lead to radioactive surface contamination of the barges), the Coast Guard currently does not allow barge shipment of shale gas extraction wastewater. In 2013, the Coast Guard's Hazardous Materials Division issued a proposed policy letter establishing requirements for bulk shipment of shale gas extraction wastewater by barge for disposal.

- The above regulations and guidelines are practiced across the United States, one of the largest developers of unconventional hydrocarbons. Though these are recommended, any in-country regulations will supersede those discussed above.

10.15.3 References

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10.16 *Practices for Extension of PSCs to Extract Maximum Oil/Gas for Importing Countries*

10.16.1 Definitions and Discussion

In the event hydrocarbons are still producing by the end of the stipulated term of the production sharing contract or agreement, many government contracts around the world allow for a renewal/extension of the contract or agreement with equal or amended terms and conditions. For fields operating at economic production levels at the end of the PSC, an extension of the contract or agreement at equal terms and conditions may be sufficient. For mature fields where extraction of oil and gas has become costly as operating costs for the fields are high relative to resulting oil or gas production revenues, amendments to terms and conditions may be needed. Without proper economic incentive, these fields may be abandoned even though there is remaining production potential. Avoiding pre-mature field abandonment is especially important in oil and gas importing countries such as India and the United States.

Production Sharing Contract Examples

The following examples of contract extension policies have been summarized from various PSCs around the world:

- Oman – Contractor has the right to request a 5-yr extension to the production agreement subject to mutual agreement between contractor and government regarding the terms and conditions of such renewal.
- Indonesia – PSCs under the 2001 Oil and Gas Law are valid for 30 years, at which point the Contractor can request a maximum of 20-yr extension.
- Nigeria – Contract renewal allowed subject to the performance of the contractor's obligations; if granted, contract terms shall be revised and agreed to by contractor and NNPC for the duration of such renewal at the option of either party.

- Kurdistan, Iraq – Contractor has the right to extend the term of the PSC for 5 years under same terms and conditions.
- Brazil – Concessionaire may request an extension via written request and submission of a Development Plan or a Production Program if additional investments in the Field are not requested by ANP. Duration of extension appears to be dictated by ANP (the National Petroleum Agency) if extension is accepted. During the extension of the Production Phase, the Parties will be bound under the terms and conditions of the original contract with the exclusive exemption of any amendments agreed to by both Parties prior to granting of extension.
- India (NELP-VIII) - Extension by mutual agreement between Parties for (5) years or such period agreed upon after taking into account balance recoverable reserves and balance economic life; extension of (10) years or such period agreed upon in the event of Non-Associated Natural Gas. Consistent terms and conditions.

Production from Mature Fields in USA, a Major Importing Country

United States operates under a concessionary system as opposed to a PSC system, deriving their share of the revenues through taxes and royalties. Realizing the importance of production from marginal wells in mature fields, the government formed policies around incentivizing continued production from these fields in low oil or gas price environments. Tax credits and expedited recovery of project costs have helped maintain economic production from mature fields, extending the time till abandonment and increasing ultimate recoveries of hydrocarbons.

Benefits to the United States from enabling economic production from these fields are not only a reduction in imported oil and gas, but provisions of jobs and economic activity for local communities as well as additional tax dollars. By incentivizing continued development of these mature fields, premature abandonment of large quantities of oil and gas volumes is avoided.

The main incentives provided by the United States towards development of mature oil and gas fields are summarized below.

Enhanced Oil Recovery (EOR) Tax Credit

Section 43 of the Internal Revenue Code provides an enhanced oil recovery credit equal to 15 percent of the qualified enhanced oil recovery costs incurred in a tax year. The EOR credit phases out as the reference price of oil exceeds an annually adjusted threshold. For the 2008 tax year, the threshold price was $41.06 and the reference price was $66.52 based on 2007. Consequently, the EOR tax credit was phased out completely.

Marginal Well Tax Credit

Marginal oil wells are those with average production of not more than 15 barrels per day, those producing heavy oil, or those wells producing not less than 95 percent water with average production of not more than 25 barrels per day of oil. Marginal gas wells are those producing not more than 90 Mcf a day. The provision allows a $3 a barrel tax credit for the first 3 barrels of daily production from an existing marginal oil well and a $0.50 per Mcf tax credit for the first 18 Mcf of daily natural gas production from a marginal well. The tax credit phases in and out in equal increments as prices for oil and natural gas fall and rise. Prices triggering the tax credit are based on the annual average wellhead price for all domestic crude oil and the annual average wellhead price per 1,000 cubic feet for all domestic natural gas. The credit for a taxable year is based on the average price from the previous year. The phase in/out prices are as follows:

OIL – phase in/out between $15 and $18

GAS – phase in/out between $1.67 and $2.00

For producers without taxable income for the current tax year, the amendment provides a 5-year carryback provision allowing producers to claim the credit on taxes paid in those years.

In 2009, eighty-five percent of all American oil wells were marginal wells, and they provided ~20 percent of American oil production. Similarly, seventy-four percent of all American natural gas wells were marginal wells, providing ~12 percent of American natural gas production.

Expensing of Intangible Drilling Costs

The expensing of intangible drilling costs (IDCs) has been part of the federal tax code since 1913. Intangible drilling costs generally include cost items that have no salvage value, but are necessary for the drilling of exploratory or development wells. Intangible drilling costs cover a wide range of activities and physical supplies, including ground clearing, draining, surveying, wages, repairs, supplies, drilling mud, chemicals, and cement required to commence drilling, or to prepare for development of a well. IDCs can be either expensed in the year incurred or amortized over a 5-year period. The purpose of allowing current-year expensing of these costs is to attract capital to what has historically been a highly risky investment. Current expensing allows for a quicker return of invested funds through reduced tax payments.

Tertiary Injectants Deduction

Tertiary injection expenses, including the injectant cost, can be fully deducted in the current tax year. Supporters of the favorable current treatment of these expenses point to the importance of tertiary recovery methods in maintaining the output of older wells, as well as the environmental advantages of injecting carbon dioxide, a primary tertiary injectant, into wells.

10.16.2 Best Practices

- Contract extensions are typically allowed in many PSCs around the world. An extension of 5 years is most common; however, an extension of up to 20 years does exist. All extensions must be approved by the Host Government.

- In the case of mature fields where operating costs are becoming prohibitive to continued development, many countries allow a discussion between contractor and government regarding extension of the PSC under proposed amendments to terms and conditions so as to incentivize continued economic development of the field to extract maximum oil and gas from the area, to the benefit of both the contractor and government. Delaying field abandonment results in additional government revenues, lower reliance on foreign oil and gas (for importing countries such as India and USA), preservation of local jobs, as well as benefits to local communities.

- It is recommended to allow extension of the PSC for a period of 5 years or more (up to maximum 20 years) subject to Government approval. Government approval may be based on criteria such as prudent field operations, adherence to PSC guidelines, etc.

- In the case of mature fields where operating costs are becoming prohibitive to continued development, it is recommended to allow for a discussion between Contractor and Government regarding extension of the PSC under proposed amendments to terms and conditions so as to incentivize continued economic development of the field to extract maximum oil and gas from the area.

- The Contractor should request such extensions/revisions to the PSC in a manner that provides sufficient time for the Government to evaluate such request. The time required by the Government to evaluate such request should be clearly stated.

10.16.3 References

1. Independent Petroleum Association of America. 2009. Enhanced Oil Recovery

   http://www.api.org/~/media/files/policy/taxes/2009-03-enhancedoilrecovery.pdf

2. Independent Petroleum Association of America. 2009. Marginal Well Tax Credit

   http://www.api.org/oil-and-natural-gas-overview/industry-economics/tax-issues/~/~/media/Files/Policy/Taxes/2009-04-MarginalWellTaxCreditFactSheet.ashx

3. Pirog, Robert. 2012. Oil and Natural Gas Industry Tax Issues in the FY2013 Budget Proposal. Congressional Research Service, March 2, 2012.

   http://budget.house.gov/uploadedfiles/crsr42374.pdf

10.17 *Best Practices of the Governing Bodies of Different Fiscal Regimes with Regards to the Management Committee*

10.17.1 Definitions and Discussion

The "Management Committee" guidelines under Model Production Sharing Contract (PSC) from the Ministry of Petroleum and Natural Gas of the Government of India has been reviewed. This article contains detailed procedures regarding the responsibilities and the rights of the "Government" and "Contractor".

10.17.2 Best Practices

- After reviewing a wide range of PSCs from all over the world, a few additional guidelines relating to Management Committee that can be included into the Indian document are listed below. Some of these guidelines may be referenced in the Indian document but not explicitly stated. These guidelines may benefit in detailing and polishing some of the pre-existing guidelines in the Indian PSC.

- Each party (Government and Contractor) shall have the right to invite a reasonable number of observers as deemed necessary to attend the meetings of the Management Committee in a non-voting capacity.
- Each party (Government and Contractor) shall have the right to bring in expert advisors to any meeting to assist in the discussions of technical and other matters requiring an expert advice.
- The Minister shall be entitled to attend the Management Committee meetings as an observer in a non-voting capacity.
- With regards to Article 6.5 in the Indian PSC, it can be stressed that the unanimous approval of the Management Committee shall be required.
- According to Article 6.13 in the Indian PSC, "*In case, unanimity is not achieved in decision making process within a reasonable period as may be required under the circumstances, the decision of the Management Committee shall be approved by the majority Participating Interest of seventy percent (70%) or more with Government representative having a positive vote in favor of the decision.*" With regards to this, one of the PSCs, have listed that in the event that no agreement is reached at the second meeting, the Chairman shall have the tie-breaking vote.
- The Management Committee shall approve Contractor's insurance program and the programs for training and technology transfer submitted by Contractor and the accompanying budgets for such schemes and programs.
- Any change in Operator shall be subject to the prior approval of the Management Committee.

10.17.3 References

1. Model Production Sharing Contract (NELP-VIII), Republic of India, 2009
2. Production Sharing Contract, Kurdistan Region of Iraq
3. Model Production Sharing Contract, Republic of Kenya
4. Model Exploration and Production Sharing Contract, Republic of Cyprus, 2012
5. Model Production Sharing Contract, Timor-Leste
6. Model Production Sharing Contract, Republic of Tanzania, 2013

10.18 *If Subsequent to the Award of Contract, Access to the Area is Restricted Due to any Reason, What are the Best Practices Relating to Rights and Responsibility of Contractor?*

10.18.1 Definitions and Discussion

This particular category appears to relate to a "Force Majeure Event”. A “Force Majeure Event” shall mean any event or circumstance or combination of events or circumstances beyond the reasonable control of a Party occurring on or after the Effective Date of the Production Sharing Contract (PSC) that materially and adversely affects the performance by such affected Party of its obligations under or pursuant to the PSC provided, however, that such material and adverse effect could not have been prevented, overcome or remedied by the affected Party through the exercise of diligence and reasonable care. "Force Majeure Events" shall include the following events and circumstances, but only to the extent that they satisfy the above requirements:

- any act of war (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, civil commotion, or act of terrorism;
- lightning, earthquake, tsunami, flood, storm, cyclone, typhoon, or tornado; epidemic or plague; explosion, fire, blowout or chemical contamination; mechanical failure; down hole blockage; and
- strikes, works-to-rule, go-slows or other labor disputes, unless such strikes, works-to-rule, go-slows or labor disputes were provoked by the unreasonable action of the management of the affected Party or were, in the reasonable judgment of the affected Party, capable of being resolved in a manner not contrary to such Party’s commercial interests.

Force Majeure Events shall expressly not include the following conditions, except and to the extent that they result directly from force majeure: a delay in the performance of any contractor, including late delivery of machinery or materials; and normal wear and tear. Nothing in this shall relieve a Party of the obligations which arose prior to occurrence of a force majeure event.

Responsibilities of the Contractor in this particular event will include the General Notification Obligations already-in-place. At the same time, the Rights of the Contractor will also be non-obligations causes in-line with the "Force Majeure" event already-in-place.

10.18.2 Best Practices

- In addition to the above stated Force Majeure scenarios, access to the land can also be restricted due to blocks overlapping with the:
    - Special Economic Zone (SEZ)
    - Reserve forests
    - Naval Exercise Areas
    - Defense Research and Development Organization (DRDO) Danger zones

  - National Parks
  - Urban Areas
  - Firing Ranges of Police/ Armed forces, etc.
- This situation can arise in scenarios such as:
  - Delays in approvals on part of government securing No Objection Certificates (NOCs) from various government agencies
  - Permission denied to carry out operations against an earlier approval with respect to restricted areas e.g. Ministry of Environment and Forest (MoEF) can deny previously issued clearances for operations in the Reserve Forests.
- With this regard, a recent "Policy Framework for Relaxations, Extensions and Clarifications at the Development and Production Stage" issued by the Ministry of Petroleum and Natural Gas (MoPNG) outlines in detail the Reduction in Minimum Work Program (MWP). These guidelines list the rights and responsibilities of the Contractor for the above said situations.
- If any other reason, that is not listed above, occurs, which restricts the access to the area for the Contractor and is not of the scale of "Force Majeure" event (to be decided by the Management Committee) then the Contractor should immediately (e.g. within 3 days) notify the Management Committee and ask to convene a meeting. A joint meeting of Contractor and Management Committee shall decide the further responsibilities and rights of the Contractor in this event, depending on the restriction to access.
- It is recommended to follow the guidelines presented in the recent “Policy Framework for Relaxations, Extensions and Clarifications at the Development and Production State” issued by the Ministry of Petroleum and Natural Gas.
- The Contractor is recommended to immediately notify the Management Committee if there is restriction of access to an area for the Contractor that may or may not qualify as a “Forced Majeure” event.

10.18.3 References

1. Model Production Sharing Contract (NELP-VIII), Government of India, 2009
2. Production Sharing Contract, Kurdistan Region of Iraq
3. Model Production Sharing Contract, Republic of Kenya
4. Model Exploration and Production Sharing Contract, Republic of Cyprus, 2012
5. Model Production Sharing Contract, Timor-Leste
6. Model Production Sharing Contract, Republic of Tanzania, 2013
7. "Policy Framework for Relaxations, Extensions and Clarifications at the Development and Production Stage under the PSC Regime for Early Monetization of Hydrocarbon

Discoveries", O-22013/27/2012-ONG-D-V, Ministry of Petroleum and Natural Gas, Government of India, November 2014.

Glossary of Terms

.gslib - Geostatistical Software Library
.las - Log ASCII Standard file format
µgal - Microgal
µms-2 - Micrometer per second squared
1P, 2P, 3P - Highest, Medium and Lowest Certainty
2C - Best Estimate of Contingent Resource
4WD - Four-Wheel Drive
A - Area, sq. feet
A/D - Analog to Digital
AAA - American Arbitration Association
AAPG - American Association of Petroleum Geologists
ACGIH - American Conference of Governmental Industrial Hygienists
ADR - Alternative Dispute Resolution
AER - Alberta Energy Regulator
AFE - Authorization for Expenditures
AGA - American Gas Association
AIME - American Institute of Mining, Metallurgical, and Petroleum Engineers
ANP - Agência Nacional do Petróleo
AOFP - Absolute Open Flow Potential
API - American Petroleum Institute
APSG - Association of Petroleum Surveying and Geomatics
ASTM - American Society for Testing and Materials
AVA - Amplitude versus Angle
AVO - Amplitude versus Offset
BAT - Best Available Technologies
BEC - Bid Evaluation Criteria
BHP - Bottom Hole Pressure
BHT - Bottom Hole Temperature
BLM - Bureau of Land Management
BO - Barrel of Oil
BOP - Blowout Preventer
BPMIGAS - Badan Pelaksana Minyak dan Gas Bumi
BRC - Bid Rejection Criteria
BS&W - Basic Sediment and Water
BTEX - Benzene, Toluene, Ethylbenzene, and Xylene
CAA - Clean Air Act
CAPEX - Capital Expenditure
CAPL - Canadian Association of Petroleum Landmen
CBL - Cement Bond Log
CBM - Coalbed Methane
CCE - Constant Composition Expansion
CCL - Cased Colar Locator
CDP - Common Depth Point
CEC - Cation Exchange Capacity
CGL - Commercial General Liability

CGR - Condensate/Gas Ratio
CHS - Community Health and Safety
CMP - Common Mid Point
CO&O - Construction, Ownership and Operation Agreement
CO2 - Carbon dioxide
CoS - Chance of Success
COW - Control of Well
CPP - Contracting & Procurement Procedures
CRA - Corrosion Resistant Alloys
CS - Checkshot
ct - Total Compressibility
CWA - Clean Water Act
D&O - Directors and Officers
DEC - Department of Environmental Conservation
DECC - Department of Energy and Climate Change
DEQ - Department of Environmental Quality
DFS - Digital Field System (Texas Instruments)
DGH - Directorate General of Hydrocarbons
DGPS - Differential Global Positioning System
DHI - Direct Hydrocarbon Indicator
DIFC - Dubai International Financial Centre
DL - Differential Liberation
DLIS, LIS, LAS - Log Data Formats
DMP - Disaster Management Plan
DNR - Department of Natural Resources
DoC - Declaration of Commerciality
DP - Dual Porosity
DPDP - Dual-Porosity-Dual-Permeability
DPR - Department of Petroleum Resources
DR - Disaster Recovery
DRDO - Defense Research and Development Organization
DST - Drill Stem Test
E&P - Exploration & Production
EAGE - European Association of Geoscientists
EBCDIC - Extended Binary Coded Decimal Interchange Code
ECS - Elemental Capture Spectroscopy
ECT - Energy Charter Treaty
EDS - Energy Dispersive X-ray spectroscopy
EIA - Environmental Impact Assessment
EIR - Environmental Impact Report
ELGS - Effluent Limitations Guidelines and Standards
EM - electromagnetic
EMP - Emergency Response Plan
EOR - Enhanced Oil Recovery
EPA - Energy Policy Act
EPCRA - Emergency Planning and Community Right-to-Know Act
EPSA - Exploration and Production Sharing Agreement

ERD - Extended reach drilling
ERP - Emergency Response Plan
ESP - Electrical Submersible Pump
EUR - Estimated Ultimate Recovery
EWT - Extended Well Tests
FASB - Financial Accounting Standards Board
FBHP - Flowing Bottom Hole Pressure
Fcd - Dimensionless Fracture Conductivity
FDIS - Final Draft International Standard
FDP - Field Development Plan
FEED - Front End Engineering
FEMA - Federal Emergency Management Agency
FERC - Federal Energy Regulatory Commission
FO - Facility Owner
FRF - Formation resistivity factor
FTIR - Fourier Transform Infrared Spectroscopy
FVF - Formation Volume Factor
FWL - Free Water Level
G&G - Geological & Geophysical
GAAP - Generally Accepted Accounting Principles
GC - Gas Chromatography
GCA - Gas Cost Adjustment
GCF - Geological Chance Factor
GC-MS - Gas Chromatography-Mass Spectrometry
GEF - Gas Expansion Factor
GHG - Greenhouse Gas
GIF - Graphics Interchange Format
GIIP - Gas Initially-in-Place
GIP - Gas in Place
GIPIP - Good International Petroleum Industry Practices
GLV - Gas Lift Valve
GOC - Gas-Oil Contract
GOR - Gas to Oil ratio
GPoS - Geological Probability of Success
GPS - Global Positioning System
GR - Gamma Ray
GRV - Gross Rock Volume
GTO - Geo-Technical Order
gu - Gravity unit
GWC - Gas-Water Contract
H2S - Hydrogen Sulfide
HAP - Hazardous Air Pollutants
HCFC - Chlorodifluoromethane
HCPT - Hydrocarbon Pore Thickness
HD - High Definition
HFC - Hydrofluorocarbons
HG - Host Governments

HHR - Handler, Henning & Rosenberg
HIPPS - High Integrity Pressure Protection Systems
HKO - Highest Known Oil
HPHT - High Pressure and High Temperature
HR - High Resolution
HR - Human Resources
HSE - Health, Safety, and Environment
HTTPS - Hyper Text Transfer Protocol Secured
HUET - Helicopter Under-water Egress Training
Hz - Hertz
IA - Information Assurance
IADC - International Association of Drilling Contractors
IAGC - International Association of Geophysical Contractors
ICC - International Chamber of Commerce
ICDR - International Center for the Dispute Resolution
ICS - Incident Command System
ICSID - International Center for the Settlement of Investment Disputes
IDC - Intangible Drilling Costs
IFC - International Finance Corporation
IOC - International Ocean Color
IOC - International Oil Company
IOGP - International Association of Oil and Gas Producers
IOR - Improved Oil Recovery
IP - Internet Protocol
IPIECA - International Petroleum Industry Environmental Conservation Association
IPR - Inflow Performance Relationship
IRF - International Regulators Forum
IRP - Industry Recommended Practice
IS - Internal Standard
ISO - International Standards Organization
IT - Information Technology
IWCF - International Well Control Forum
JMC - Joint Management Committee
JPEG - Joint Photographic Experts Group
K - Reservoir Permeability
KNPC - Kuwait National Petroleum Company
KOC - Kuwait Oil Company
KOTC - Kuwait Oil Tanker Company
kpa - kilopascal
KPI - Key Performance Indicator
LACT - Lease Automated Custody Transfer
lat-long - Latitude-Longitude
lbm - Pound mass
LC&R - La Coste and Romberg
LCIA - London Court of International Arbitration
LCM - Lower of Cost or Market
LITH - Lithology

LKH - Lowest Known Hydrocarbons
LKO - Lowest Known Oil
LNG - Liquified Natural Gas
LWD - Logging while drilling
M&S - Monitoring and Surveillance
MARPOL - International Maritime Organization
MASP - Maximum Anticipated Pressure
MAWOP - Maximum Allowable Wellhead Operating Pressure
MAWP - Maximum Allowable Wellhead Pressure
MC - Management Committee
mcf - 1,000 cubic feet (cf) of natural gas
MCP - Minimum Collapse Pressure
MD - Measured Depth
MD RKB - Measured Depth Relative to Rotary Kelly Bushing
MDT - Modular Formation Dynamics Tester
MEC - Minimum Expenditure Commitments
MFA - Minimum Financial Amount
mgal - Milligal
MIAC - Mauritius International Arbitration Conference
MICP - Mercury Injection Capillary Pressure
MIYP - Minimum Internal Yield Pressure
ML - Mining Lease
MMP - Minimum Miscibility Pressure
MMS - Minerals Management Service
Mmscf - million metric standard cubic feet
MoEF - Ministry of Environment and Forest
MoEFCC - Ministry of Environment, Forest and Climate Change
MOG - Ministry of Oil and Gas
MoPNG - Ministry of Petroleum & Natural Gas
MPE - Ministry of Petroleum and Energy
MPMS - Manual of Petroleum Measurement Standards
MPP - Mid-Point Perforation
MPSC - Model Production Sharing Contract
MRC - Maximum Reservoir Contact
ms-2 - Meter per second square
MSDS - Materials Safety Data Sheet
MTC - Major Tender Committee
MWD - Measurement while Drilling
MWO - Minimum Work Obligation
MWP - Minimum Work Program
N/G - Net-to-Gross Ratio
NACE - National Association of Corrosion Engineers
NDMA - National Disaster Management Policy
NDR - National Data Repository
NELP - New Exploration Licensing Policy
NFPA - National Fire Protection Association
NGD - National Gravity Database

NGL - Natural Gas Liquid
NGS - Norwegian Geochemical Standard
NIGOGA - Norwegian Industry Guide to Organic Geochemical Analyses
NMR - Nuclear Magnetic Resonance
NNPC - Nigerian National Petroleum Corporation
NOC - National Oil Company
NOC - No Objection Certificate
NORM - Naturally Occurring Radioactive Materials
NPD - Norwegian Petroleum Directorate
NPDES - National Pollutant Discharge Elimination System
NR - Natural Remnant
NSPS - New Source Performance Standards
O&M - Operating and Maintenance
OBM - Oil Based Mud
OBQ - On Board Quantity
ODS - Ozone Depleting Substances
OEE - Operators Extra Expense
OEM - Original Equipment Manufacturer
OGIP - Original Gas-in-Place
OGRC - Oil and Gas Reserves Committee
OHS - Occupational Health and Safety
OIML - International Organization of Legal Metrology
OIP - Oil in Place
OISD - Oil Industry Safety Directorate
OML - Oil Mining Lease
OOIP - Original Oil-in-Place
OSHA - Occupational Safety and Health Administration
OSPAR - Convention for the Protection of the Marine Environment of the North-East Atlantic
OWC - Oil-Water Contract
PAHs - Polycyclic aromatic hydrocarbons
PBU - Pressure Build Up
PCI - Potential Commercial Interest
PCP - Progressive Cavity Pump
PDF - Portable Document Format
PDO - Plan for Development and Operations
PDS - Planetary Data System
PSDM - Pre-stack Depth Migration
PFO - Processed Fuel Oil
Pg - Geological Chance Factor
PHI - Porosity in Fraction
PHIE - Effective Porosity
PIO - Utilisation of Petroleum
PLT - Pipeline Logging Tool
PLT - Production logging tool
POTW - Publicly Owned Treatment Works
PP&E - Property, Plant and Equipment
PPDMA - Professional Petroleum Data Management Association

PPE - Personal Protective Equipment
PPS - Predictability vs. Portfolio Size
PRM - Permanent Reservoir Monitoring
PRMS - Petroleum Resources Management System
PRODML - Production Markup Language
PSA - Production Sharing Agreement
PSC - Production Sharing Contract
psi - pounds per square inch
PSS - pseudo-steady state
PSTM - Pre-stack/Post-stack Time Migration
PTA - Pressure Transient Analysis
PUD - Proved Undeveloped Reserves
PVT - Pressure/Volume/Temperature
Q - Absorption
QA - Quality Assurance
QC'd - Quality Controlled
RAID - Redundant Array of Independent Disks
RCI - Reservoir Characterization Tool
RCRA - Resource Conservation and Recovery Act
RESQML - XML Standards for Reservoir
RF - Recovery Factor
RFT - Repeat Formation Tester
ROB - Quantity Remaining on Board
ROP - Rate of Penetration
ROT - Remotely Operated Tool
ROV - Remotely Operated Vehicle
RP - Recommended Practice
RPG - Reverse Pressure Gauge
RPS - Renewable Portfolio Standard
RTA - Rate Transient Analysis
S&W - Sediment and water
S/N - Signal to Noise
SARA - Saturates, Aromatics, Resins, and Asphaltenes
SBHP - Static Bottom Hole Pressure
SCAL - Special Core Analysis
SDWA - Safe Drinking Water Act
SEG - Society of Exploration Geophysicists
SEM - Scanning Electron Microscopy
SEZ - Special Economic Zone
SFAS - Statement of Financial Accounting Standards
SGCR - Critical Gas Saturation
SGU - Maximum Gas Saturation
SIEM - Security Information and Event Management
SO2 - Sulfur dioxide
SOCAR - State Oil Company of Azerbaijan Republic
SOGCR - Critical Oil in Gas Saturation
SORP - Statement of Recommended Practices

SOWCR - Critical Oil in Water Saturation
SP - Spontaneous Potential
SPC - Partial Completion Skin
SPE - Society of Petroleum Engineers
SPEE - Society of Petroleum Evaluation Engineers
SPEREE - Society of Petroleum Engineers Reservoir Evaluation & Engineering
SRO - Surface Read-Out
SRP - Surface Rod Pump
SS - Steady State
SSL - Secure Socket Layer
STOIIP - Stock Tank Oil Initially in Place
Sw - Water Saturation
SWCR - Critical Water Saturation
SWL - Connate Water Saturation
SWU - Maximum Water Saturation
SYN - Synthetic
TAPS - Trans Alaska Pipeline System
TD - Total Depth
TDS - Total Dissolved Solids
TIFF - Tagged Image File Format
TKDN - Tingkat Komponen Dalam Negeri
TLS - Transport Layer Security
TOA - Time of Approvals
TOC - Total Organic Content
TOR - Terms of Reference
TPDC - Tanzania Petroleum Development Corporation
TRI - Toxics Release Inventory
TSCA - Toxic Substances Control Act
TVD - True Vertical Depth
TVDSS - True Vertical Depth Sub Sea
TWT - Two Way Travel Time
UIC - Underground Injection Control
UKCS - United Kingdom Continental Shelf
UKSI - United Kingdom Statutory Instrument
UNCITRAL - United Nations Commission on International Trade Law
UNEP - United Nations Environment Programme
USB - Universal Serial Bus
USBM - U.S. Bureau of Mines
UTM - Universal Transverse Mercator
VEFD - Vessel Experience Factor on Discharging
VEFL - Vessel Experience Factor on Loading
VOC - Volatile Organic Compounds
VP - Vibrator Point
VSP - Vertical Seismic Profile
WBS - Wellbore storage
WGS - World Geodetic System
WiMax - 802.11 standard (Wireless Metropolitan Area Network)

WISTML - XML Standard for Drilling
WOR - Water-Oil ratio
WPC - World Petroleum Council
WPT - Windfall Profit Act
XML - Extensible Markup Language