Chapter 6
Work Classification and Selection of Working Units

As reviewed in the previous chapter, there are different types of working units employed for permanent P&A operations depending on the well location and type of production facility. When considering onshore wells, the site space is not a concern, except for mountainous areas and swamps. However, site space for offshore wells may be a concern. Selection of working units for offshore wells is a concern as the daily rate of working units highly affect the final cost of permanent P&A operation. Generally speaking, there are some critical factors to be considered for the selection of the optimal working unit for the P&A job including: well location (either onshore or offshore), depth of operation/hole, required horsepower, availability of working unit, type of production facility, type of well completion, unit capacity (offshore wells) and availability of space (offshore wells). Unit capacity is the maximum load which a unit, production facility or platform, can support without collapsing.

When considering offshore wells, more than one type of working unit may be employed when performing different phases of P&A operation, depending on the type of production facility and availability of units. Generally, if a working unit is supposed to fully conduct the permanent P&A operation, the following systems are necessary: power system, fluid-circulating system, hoisting system, rotary system, well control system, well-monitoring system, and special marine equipment. At first glance, the required systems may suggest a drilling rig to be convenient, however, this might not be correct. A drilling rig is designed for the purpose of drilling. It has a high daily rates and needs to have all the mentioned systems at the same time. A P&A working unit may not need all the available systems at the drilling rig. For example: a multipurpose modular working unit could be an example of such a unit whereby different systems can be integrated at the required time. A modular rig may be used when either the existing drilling rig is not properly maintained or when there is no existing drilling rig onboard the platform. A P&A unit requires much lower drilling fluid pit volume compared to a drilling rig. However, it should be mentioned that a modular rig has a significant mobilization and demobilization cost and relies on existing infrastructure such as cementing system, mud system, utility, etc. to a large extent.

6.1 P&A Code System

Consider a situation where you wish to briefly explain the complexity of permanent abandonment of a well or several wells. Perhaps, it would be time consuming to explain the well location and complexity of each abandonment phase. A P&A code system can address their challenge. A P&A code system aims to classify wells for abandonment cost estimation. The P&A code system classifies wells according to three factors [1]:

- Well location
- Abandonment phases
- Abandonment complexity.

The well location is presented by two letters and followed by three digits, where each digit represents the complexity of abandonment operation for each abandonment phases.

6.1.1 Well Location

The Well location defines the physical location of well; land, platform, or subsea. So, the first two letters are as following:

- LA—Land well,
- PL—Platform well,
- SS—Subsea well.

6.1.2 Abandonment Phases

A P&A operation, can be divided into three different phases: Phase 1—reservoir abandonment, Phase 2—intermediate abandonment, and Phase 3—wellhead and conductor cut and removal. These phases are regardless of well location. The main goal in P&A is to perform the full operation as possible without a rig and removing as little steel as possible. The footprint should also be kept small. Therefore, experienced personnel should be involved with a good knowledge of what is required.

6.1.2.1 Phase 1—Reservoir Abandonment

This phase includes the following activities: wellhead is checked, waste handling system is prepared, wireline investigations are conducted and if possible, cement is squeezed into the reservoir perforations. If the squeezed cement is extended across

the cap rock and is qualified, it is counted as a primary permanent barrier. So far, these activities are performed with XMT in place and it is a rigless operation. If the squeezed cement is not qualified, the primary and secondary permanent barriers shall be established to secure the reservoir. This step may be carried out rigless or using a rig. When a rig is required, the well control system needs to be established. There are circumstances which require the use of a rig during the operation of Phase 1. These circumstances include: restricted access through the tubing to the barrier depth, lack of technology to log casing cement through the production tubing, poor cement or no cement behind the production casing, retrieval of production tubing due to presence of control lines at the barrier depth, a permanent packer set above cap rock, presence of an Annulus Safety Valve (ASV), and experiencing SCP due to hydrocarbon or overpressures.

6.1.2.2   Phase 2—Intermediate Abandonment

In this phase, all the identified zones with flow potential in the overburden need to be isolated. All the hydrocarbon flow potentials are secured by primary and secondary permanent barriers. Hydrocarbon zones with no flow potential and water bearing zones are isolated by establishing one permanent barrier. If the water bearing zone is a pressurized zone, then two permanent barriers, primary and secondary, are required. In the last part of Phase 2, a top plug often called and environmental plug, is installed. This phase may be carried out with a rig or rigless. The circumstances which dictate the use of a rig, in Phase 2, include: SCP due to hydrocarbons or overpressure at barrier depth which originates from the reservoir, restricted access to the casing, no isolated fresh water aquifers or zones, and non-isolated shallow gas. In addition, poor cement or uncemented casing at barrier depth, lack of technology to log casing cement behind the second casing string, and the presence of control lines (if not retrieved during Phase 1) can dictate the use of rig.

6.1.2.3   Phase 3—Wellhead and Conductor Cut and Removal

This phase is the last stage of a permanent P&A operation whereby the well control system is dismantled and wellhead and conductor are cut and pulled. When the wellhead is removed, re-entry to the wellbore would be almost impossible as the well control system cannot be installed. The cut and removal can be performed by use of a rig, conductor jack, vessel (subsea wells), or heavy lift vessel (offshore wells). The circumstances which may require the use of a rig, in Phase 3, may include: poor conductor integrity, platform may not be able to support the conductor load during pulling (offshore wells), water depth is beyond the limitation for cutting by anchor handling vessels or LWIV for subsea wells. Poor integrity of conductor may be caused by corrosion, weak connectors or shallow damage.

6.1.3 Abandonment Complexity

The well abandonment complexity is shown by a digit from 0 to 4, which is distinguished for each abandonment phases.

Complexity 0: **No work is required**. The abandonment phase has already been accomplished and no further work is required.

Complexity 1: **Simple rig-less operation**. A wireline unit, pumping, crane and jacks are utilized for the operation. Riser-less LWIV will be employed for subsea wells.

Complexity 2: **Complex rig-less operation**. Wireline unit, coiled tubing unit, hydraulic work-over unit (HWU), crane, and jacks are utilized during the operation. A heavy duty well intervention vessel with riser may be used for subsea wells.

Complexity 3: **Simple rig-based operation**. Operation requires retrieval of tubing and casing.

Complexity 4: **Complex rig-based operation**. Due to limited access to barrier depth, poor casing cement, or no casing cement, tubing and casing are required to be retrieved, and section milling and cement repair are necessary.

To figure out the complexity of each phase, it is recommended to consider some criteria, which are based on experience. These criteria are presented in Tables 6.1, 6.2 and 6.3. Sustained casing pressure related to hydrocarbons or overpressure is an indication of a well integrity issue associated with failure of the primary cement. The cement failure needs to be mitigated at cap rock level and there are risks associated with well control. Therefore, the operation is highly complex and well control equipment is required. Uncemented casing or poor casing cement means that the annulus needs to be accessed and a new annular barrier needs to be established. In a conventional P&A operation, section milling or an alternative technique is required. Therefore, the operation is of high complexity and HSE issues are associated with it. One of the main concerns, especially at the first stage of the P&A operation, is access downhole to below the estimated minimum setting depth where permanent barriers are required to be established. Drift diameter can be limited due to collapse or deposits of downhole minerals or chemicals. Such circumstances may be mitigated by injecting chemicals or it may require retrieval of the production tubing, either by a cut and pull operation or milling. There are situations where due to restricted access, the production tubing is milled from near surface to all the way down to the required depth of barriers. High torque and circulation gives the operation a complexity level of 4. The production tubing can also create a challenge if it is leaking, as the circulation of fluid or cement cannot be done. If a coiled tubing unit cannot be utilized for circulating or pumping cement, then the production tubing needs to be retrieved. Even though tests have shown that zonal isolation is possible, most authorities do not accept the presence of control lines and downhole gauges as a part of the permanent barrier. Because the control lines are attached to the production tubing, the tubing needs to be retrieved which requires a high pulling capacity. It should be noted that retrieval of production tubing means a higher cost of pipe pulling and handling, HSE issues for personnel and transportation to a location for disposal.

Table 6.1 The considered criteria for classifying complexity of Phase 1 of a permanent P&A operation [1]

×: Not feasible, √: Required, O: Optional	Well abandonment complexity			
	Type 1	Type 2	Type 3	Type 4
	Simple rigless	Complex rigless	Simple rig-based	Complex rig-based
1 Sustained Casing Pressure (SCP) due to hydrocarbons or overpressure	×	×	×	√
2 Uncemented casing or liner at barrier depth (cap rock)	×	×	×	√
3 Restricted access to tubing	×	×	√	O
4 Deep electrical or hydraulic lines present at barrier depth	×	×	√	O
5 Annular Safety Valve (ASV) present	×	×	√	O
6 Packer set above cap rock	×	×	√	O
7 Site does not allow CT/HWU pumping operations	×	×	√	O
8 Multiple reservoirs to be isolated	×	√	O	O
9 Tubing leak (e.g. corrosion, accessories)	×	√	O	O
10 Inclination >60° above packer (wireline access)	×	√	O	O
11 Well with good integrity, no limitations	√	O	O	O

Table 6.2 The criteria considered for classifying the complexity of Phase 2 of a permanent P&A operation [1]

×: Not feasible, √: Required, O: Optional		Well abandonment complexity			
		Type 1	Type 2	Type 3	Type 4
		Simple rigless	Complex rigless	Simple rig-based	Complex rig-based
1	Sustained Casing Pressure due to hydrocarbons or overpressure	×	×	×	√
2	Restricted access to tubing	×	×	×	√
3	No isolated fresh water aquifers/zones	×	×	×	√
4	Uncemented casing or liner at barrier depth (cap rock)	×	×	×	√
5	No isolated shallow gas	×	×	×	√
6	Site does not allow CT/HWU pumping operations	×	×	√	O
7	Poor primary casing cement	×	×	√	O
8	No tubing in well	×	√	O	O
9	Inclination >60° above barrier depth (wireline access)	×	√	O	O
10	Well with good integrity, no obstacles, tubing in place	√	O	O	O

An annulus safety valve may represent a restriction and limit the maximum flowrate required when circulating fluids or cement through tubing, which may demand retrieval of the production tubing. When the permanent packer is above the estimated minimum setting depth, and the workstring cannot pass through it

Table 6.3 The criteria considered for classifying the complexity of Phase 3 of a permanent P&A operation [1]

×: Not feasible, √: Required, O: Optional		Well abandonment complexity			
		Type 1	Type 2	Type 3	Type 4
		Simple rigless	Complex rigless	Simple rig-based	Complex rig-based
1	Poor conductor integrity	×	×	×	√
2	Platform unable to manage conductor load during retrieval	×	×	√	O
3	Water depth beyond limitation for cutting by LWIV (Subsea well)	×	×	√	O
4	Conductor cutting/rigless retrieval	√	O	O	O

to establish the primary and secondary permanent barriers, the packer needs to be milled.

As discussed in Chap. 5, that actual offshore facilities may not be able to accommodate crews, store equipment, use cranes or withstand load capacity. A support vessel may therefore be required. A typical situation is the need to isolate multiple reservoirs or multiple high pressure zones which may require a rig to remove the downhole completion and packers. Permanent plug and abandonment of multiple reservoirs or flow potential sections means a higher complexity of the operation.

When the permanent barriers are to be installed in depths with inclinations greater than 60°, a tractor is necessary for conducting wireline operation such as setting wireline plugs. Even at high inclinations, punching casing or running a wireline operation can be almost impossible. Therefore, high inclination at the barrier depth introduces multiple challenges.

Permanent P&A operation of wells with good integrity can be done rigless as internal plugs only need to be installed across the qualified annular barrier. Such operations can be done utilizing a coiled tubing unit.

Fresh water zones, abnormally pressured water bearing zones, and shallow gas zones need to be isolated by installing cross-sectional barriers. If such zones are poorly isolated or the corresponding annular space is uncemented, access to the formation should be achieved to establish permanent barriers. Such an operation may require section milling and well control systems.

Poor integrity of the conductor caused by corrosion, weak connectors, leaking connectors, etc. requires program with contingency plans. There are circumstances

where a platform or mobile offshore unit is not able to manage the conductor load during conductor removal. The situation is amplified when the inner casing is cemented. For subsea wells, the wellhead and conductor are usually cut and retrieved using an anchor handling vessel or LWIV. However, if the water depth is beyond the operational water depth for the LWIV, a heavy offshore unit may be required. Water depth can create challenges for the cut and removal of the wellhead. As an example, currently 500 m water depth is the limit for abrasive cutting of the wellhead or conductor due to the limit for compressor capacity.

Example 6.1 A subsea well, which is located in an ultra-deep water area, is going to be permanently plugged and abandoned. The well suffers from sustained casing pressure in A- and B-annulus. Logging data shows a shallow gas zone, which has not been isolated properly. What is the P&A code for the well.

Solution As the well is a subsea well, the first two letters are SS. The well suffers from SCP which means well integrity issue at cap rock level. By refereeing to Table 6.1, the P&A complexity of operation for Phase 1 is 4. The shallow gas zone needs to be secured and as there is uncemented casing at the depth of the gas zone, by referring to Table 6.2, the complexity of operation for Phase 2 is 4. The well is located in ultra-deep water area which is beyond conventional vessels. By referring to Table 6.3, the operation complexity is 4. Therefore, the P&A code system for the well is: SS-4-4-4.

6.2 Time and Cost Estimation of a P&A Operation

As a candidate well for permanent P&A is not going to be profitable, and all the P&A cost associated with it are not going to be recovered, cost estimation is an important process. To understand necessary time and cost of a P&A operation, it is necessary to identify the factors affecting the operation and to quantify their interaction. However, it is impractical to identify all the characteristics of a P&A operation. Therefore, in practice it is important to consider those factors that adequately represent the P&A operation. The contributing factors can be classified as either *observable* or *unobservable* factors. Observable factors are measured and quantified directly such as well characteristics, or may need to be represented by a proxy variable, such as operator experience. Unobservable factors are those kinds of factors which also affect the P&A operation, but are impossible to quantify, such as project management skills, communication skills, and readiness level of personnel. The observable and unobservable factors can be either dependent variables or independent variables. When time for a P&A operation is estimated, then cost of operation is consequently estimated.

6.2.1   Description of Factors

There are many factors and events that impact time and cost associated with P&A operations. The factors can include well characteristics, well complexity, site characteristics, working unit, operator philosophy, local regulations, exogenous events, dependent variables, and unobservable variables.

6.2.1.1   Well Characteristics

In P&A operations, characteristics of the well such as well length, hole diameter, and well inclination contribute to time, cost, and HSE risk. For example, hole diameter and length of the required plug determine the P&A material volume, and the material to be removed from the well.

6.2.1.2   Well Complexity

The well complexity can be increased because of different reasons, including but not limited to: limited access to the desired interval, type of completion, high-pressure and high-temperature condition, and well integrity issues. Consequently, increase of well complexity can increase the duration and cost of P&A operation. Well complexity can also directly influence the type of required working unit.

6.2.1.3   Site Characteristics

Geographical location, distance from the well to the nearest service station, and water depth at the site for offshore well are some of the main site characteristics.

6.2.1.4   Working Unit

Type of working unit and personnel on board, directly contribute to a large part of the total P&A cost. Selection of the working unit depends on other factors such as well complexity, site characteristics, vessel availability for offshore wells, environmental criteria, etc. Therefore, this factor is a dependent factor.

6.2.1.5   Operator Philosophy

The operator decides when to permanently P&A a well, what type of contract is necessary, and how to carry out the operation. In addition, duration, P&A design, job

specification (single well or campaign P&A), and strategies are the main parameters, which are based on operator preferences, for determining time and cost of P&A.

6.2.1.6   Local Regulations

As discussed in Chap. 1, different authorities have their own requirements with respect to permanent P&A of wells. Local regulations may impact the time and cost of the operation. Consider the North Sea where the UK regulation requires 30 (m) of a continuous qualified plug whereby the Norwegian regulation requires 50 (m) of a continuous qualified plug.

6.2.1.7   Exogenous Events

There are situations where the P&A operation may be subject to delays. Equipment failure is an example of such circumstances. If a spare part is not available, then activities are delayed. Sometimes, equipment or equipment's parts may be lost in the well. Fishing or a multiple fishing operation may be necessary to retrieve these elements. For offshore P&A, activities may be significantly delayed due to weather. Weather downtime can become an important factor in the total time and cost of an operation. Severe weather conditions can cause delays for supply boats to deliver equipment or material which are of a critical stock level. Weather can also impact anchoring and moving time of floating working units. In some geographical locations, such as the North Sea, the weather can be too severe and cause the operation to be suspended. Therefore, weather conditions and waiting on weather time needs to be considered for P&A.

6.2.1.8   Dependent Variables

The number of days spent to accomplish Phase 1 to Phase 3, is defined as time to P&A a well. It includes, mooring and demooring (if applicable), time to survey the well condition, tripping, time spent on barrier installation and its verification, weather time, and cut and removal of the wellhead.

6.2.1.9   Unobservable Variable

There are many factors known to be difficult to quantify and incorporate directly into time and cost analysis. Of these one can refer to unique P&A design, incidents during preparation, project management and leadership skills, availability of technology and technique, and personnel skills.

P&A design and preparation—Evaluation of well condition and careful planning is required to complete a P&A project successfully. The first step in P&A design is

to identify the different permeable zones that needs to be isolated. There are two different approaches with respect to the number of plugs to be installed: traditional approach or risk-based approach. In a traditional approach, each hydrocarbon zone requires its permanent barriers. However, in a risk-based approach, the consequence of combining formations which contain fluid is carefully studied. If the risk of any harm to environment or failure of barrier is low, the two or more formations are grouped and a barrier is installed for them. The installed barrier consists of a primary and a secondary permanent barrier. Each approach has its impact on time and cost. In addition, a multidisciplinary team should design the P&A efficiently to deal with objectives of the operation.

Project management and leadership skills—Appropriate project management and leadership has to have comprehensive and integrated engineering planning, with coordinated skills and well defined contingencies. The project is to be executed in the shortest possible time in collaboration with all team members.

Technology and technique—The impact of technology and technique on performance of a P&A operation is extensive. New technology can be enabling or enhancing or both, and will shift from enabling to enhancing over time, due to learning effects. Generally, new technology is expensive, but if the performance of the operation and safety is improved, then costs will decline. It is difficult to find out the impact of new technologies on estimation of time and costs of an operation. A kind of such tool is perforate, wash and cement technique which reduces the time of P&A operation by eliminating section milling (see Chap. 8).

Personnel skill—Another factor which is part of unobservable variables is skill and experience. During P&A design, experienced engineers can include their learnings from other operations which can significantly influence the time and cost. During the operation, experienced personnel, crossed trained, can implement their experiences to solve the challenges on site instead of awaiting personnel to arrive from another site. Hence, the cost can be significantly reduced by suing properly trained personnel.

6.2.2   Traditional Method for Time Estimation

Traditionally time of a P&A operation is estimated using deterministic values. This statistical approach, also known as the deterministic method, uses a mathematical model to estimate the outcomes precisely. In deterministic methods, a deterministic model governs the outcomes through known relationships among the factors, observable and quantifiable factors, Fig. 6.1. However, there is no room for unobservable and variable factors. In this method, a given input will always produce the same output which means that the model defines an exact relationship between the variables. This defined relationship allows prediction of the impact of one variable on the other. The traditional method assumes certainty in its solution.

The deterministic approach has its advantages and limitations. The advantages include simplicity of approach, clear assumptions, and transparent communication

Fig. 6.1 A deterministic model precisely estimates the outcome based on the input factors

$$X_1, X_2, X_3 \rightarrow \text{Deterministic model } f(x) \rightarrow Y_1, Y_2$$
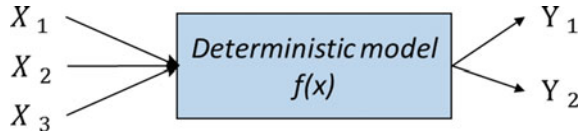
of results [2]. The limitations are the prediction's optimistic bias on good results, not presenting the full range of possible outcomes. Uncertainty associated with sub-operations are not included in the final results [2].

6.2.3   Probabilistic Method for Time Estimation

The probabilistic approach, also known as the stochastic method, uses a mathematical model which presents probability of a random phenomenon. In this method, the probability of an event occurring again is estimated based on historical data and governing statistical analysis models. The probabilistic model is likely to produce different outcomes even with the same initial conditions. So, variation and uncertainty of data on each event are considered in the probabilistic model, Fig. 6.2. In fact, a probabilistic model includes both deterministic components and random error components.

The advantages of the probabilistic approach are addressed as: reflecting uncertainties, presenting a range of possible outcomes, including unexpected events, providing the opportunity to apply sensitivity analysis, possible to include learning effects, the interaction between sub-operations can be analyzed, and decision making process of the operation can be improved [2]. Although the probabilistic approach introduces advantageous features, there are also limitations and subjectivity associated with it. A probabilistic model will not and should not be expected to identify and
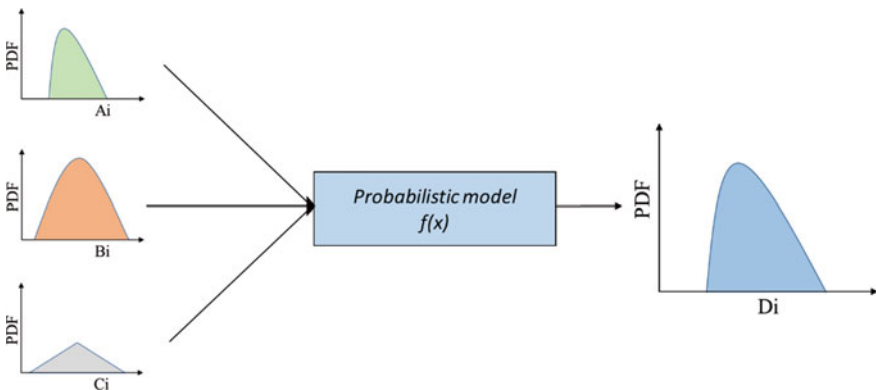
Fig. 6.2 A probabilistic model includes uncertainty of input data and includes uncertainty in the outcome values

capture all risks as the presence of unknowns are always part of the story. Considering the results of a probabilistic approach without the accompanying philosophy behind them has limited value. Defining the relationship of inputs is not straight forward [3].

6.2.3.1 Refreshing Statistics

It is important to avoid any misinterpretation or misconstruction of results obtained by probabilistic estimates. Therefore, there are terms which need to be elaborated and be properly used. The most common terms are *percentiles*, *mode*, *mean* and *median* [4].

Percentiles (also known as the "P" number)—In probabilistic methods, the range of outcomes produced by models are divided into 100 parts and presented by 99 percentiles, P_1–P_{99}. Each percentile contains 1% probability of the outcomes. Of these percentiles, three percentiles are the most common to be used when discussing the results. These include P_{10}, P_{50}, and P_{90} (see Fig. 6.3). P_{10} is the percentile whereby 10% or less of outcomes have the probability to fall in the range of P_1–P_{10}. P_{90} is the percentile whereby 10% or less of outcomes have the probability to fall in the range of P_{90}–P_{99}. In other words, P_1–P_{10} and P_{90}–P_{99} are less likely outcomes. P_{50}, also known as *median*, is the probability of having 50% of the outcomes equal to or exceeding the best estimate. Similarly, 50% of the outcomes equal or less than the best estimate. The distribution curve of outcomes can be symmetric or asymmetric (skewed), Fig. 6.4. For an asymmetric distribution, the P_{50} and mean value are unequal.
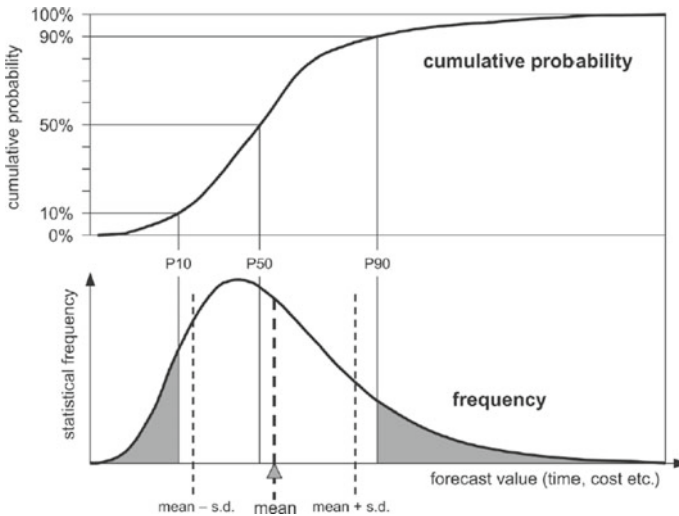

Fig. 6.3 Distribution outcome with statistical terms used in probabilistic method of estimation
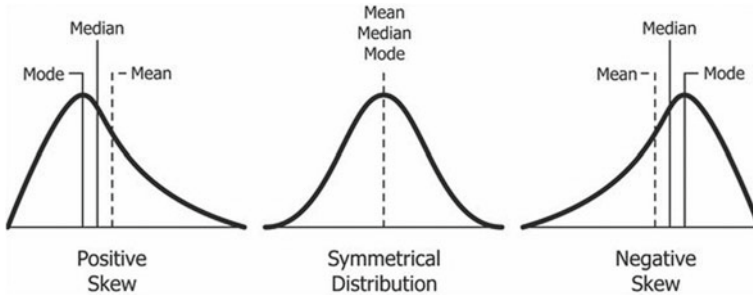
Fig. 6.4 Symmetric and a symmetric distribution with mode, median and mean values

Mode (also known as the Most Likely Value)—This is the most frequent value in the data set which occurs during thousands of iterations of time or cost estimation. On a probability frequency chart, the mode is the value at the highest point, see Fig. 6.4.

Mean (also known as the Expected Value)—This is the arithmetic average, sum of values of a data set divided by number of values, of all the outcomes of simulation iterations. If mean values are summed up together, a meaningful result is obtained which is commonly used for Authority for Expenditure (AFE) or analysis of a single well.

Median (also known as the "P$_{50}$")—This is the middle value which separates the greater and lesser outcomes of a data set.

6.2.3.2 Probability Distributions

In the probability approach, an offset data is a value which indicates the distance between the beginning of the value and a given point. Probability distributions are used to characterize the behavior of random variables. To fit offset data, there are several probability distributions to choose: normal, triangular, lognormal, and uniform [5]. Of these, the two widely accepted probability distributions are uniform distributions and triangular distributions (the two lower left distributions shown in Fig. 6.2). The uniform distributions are the simplest of all and are described by a minimum and a maximum value. The triangular distributions are an extended form of uniform distributions by adding the mode, the most likely value.

When considering probability distributions three terms are distinguished: Probability Mass Function (PMF), Probability Distribution[1] Function (PDF) and Cumulative Distribution Function (CDF). To clarify the difference between these terms, it is necessary to understand two main types of random variable distribution: *discrete* or *continuous*. A continuous random variable distribution is a curve with an infinite number of values on it which characterizes the distribution of a random variable.

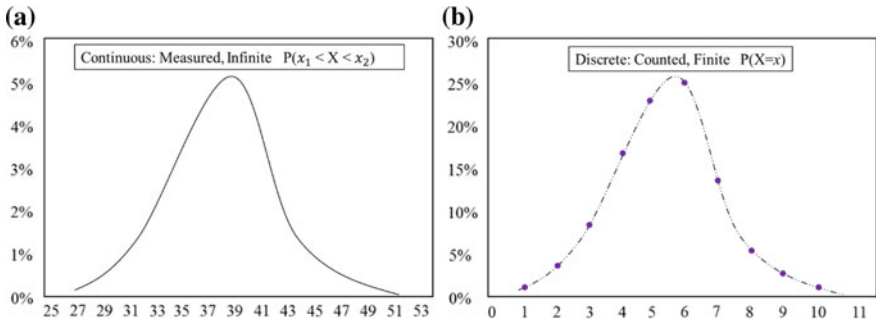[1]Distribution is also noted as Density in some references.

Fig. 6.5 Random variable distributions: **a** continuous, **b** discrete

To specify a local location on a continuous distribution, probability, one exact value cannot be given but an interval is presented. So to specify the interval on a continuous distribution, a PDF represents the interval (see Fig. 6.5a). Examples of continuous random variables are distance, time and asset returns in finance. A discrete random variable distribution is obtained by counting and is a finite measurement (see Fig. 6.5b). So the probability of a random variable is an exact value. Therefore, a PMF presents the outcome. Briefly, continuous random variables are measured, however, discrete distribution random variables are counted.

When considering a continuous distribution of a random variable, to present the probability of outcomes, approximately equally, of an input value, PDF is used. But to present the outcome probability of an input value, CDF is used.

Example 6.2 Figure 6.6 shows Monte Carlo simulation results of time estimation for a subsea single well which is going to plugged and abandoned. In one scenario, the entire operation is supposed to be carried out by a semisubmersible rig while in another scenario the operation is carried out partly by a semisubmersible unit and partly by a vessel.

(a) What will be the most likely value, the mode, for time of this operation when performing the operation entirely by deploying a semisubmersible unit and what will be the occurrence probability of the most likely value?
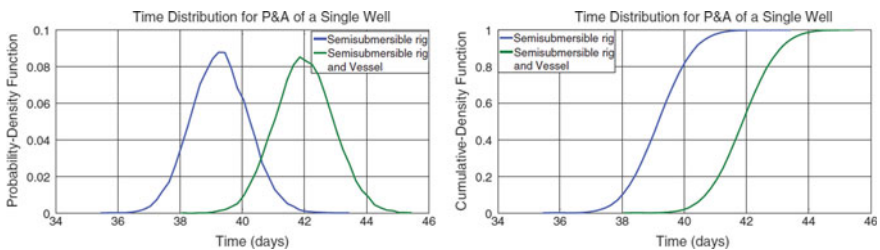

Fig. 6.6 Time distribution for P&A of a single well: **a** PDF, **b** CDF [2]

(b) What will be the most likely value, the mode, for time of this operation when performing the operation by deploying a combination of a semisubmersible unit and a vessel and what will be the occurrence probability of the most likely value?
(c) Interpret the outcomes of PDF and CDF of having 42 days when using a combination of a submersible and a vessel.

Solution The probability is presented by a value from 0 to 1.0 or in percentage, from 0 to 100%.

(a) By referring to the PDF curve, semisubmersible rig, the occurrence probability of the mode is approximately 85.7% and the associated time will be approximately 39 days.
(b) By referring to the PDF curve, semisubmersible rig and vessel, the occurrence probability of the mode is approximately 83% and the associated time will be approximately 42 days.
(c) By considering the probability of having the time of operation 42 days, when combination of semisubmersible and vessel are employed, the CFD is approximately 55%. In other words, having the expected time of the P&A operation being less or equal to 42 days is 55%.

Offset data analysis includes data gathering and analyzing the offset data. Although this planning procedure is time consuming it should be carried out properly as more accurate input results in a better quality of outcomes. Therefore, during data gathering, team members need to discuss and analyze the data. Non-Productive Time (NPT) should be split into predicted and unpredicted offset data and analyzed separately. It is important to document the analysis of offset data.

Considering time estimation of P&A operations, limited or poor offset data requires predominantly expert judgement. However, this might become a challenge as biased positive and negative experiences of experts may lead to an unrealistic understanding of their ability to assess uncertainties. In addition, poor handling of uncertainty may also be rooted in outdated methodology and poorly quantitative ideas about it.

6.2.3.3   Central Limit Theorem

When building a model for time estimation, the Central Limit Theorem (CLT) can be used. According to the CLT, when independent random distributions, of any distribution shape, are added, the sum of probability distribution tends toward a normal distribution.

To reduce the impact of the CLT and avoid unrealistically narrow results of estimations, three main ways have been suggested and addressed. These includes: restricting the number of input variables, avoid using too narrow input ranges and not underestimating uncertainty, and dependencies between input variables to be addressed by use of *correlation* [4].
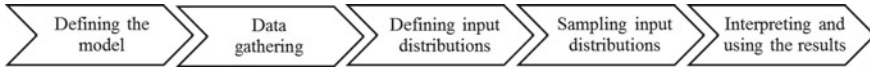
Fig. 6.7 Five general steps of Monte Carlo simulation

6.2.3.4 Monte Carlo Simulation of Time Estimation

The concept of the Monte Carlo was developed by a Polish-American mathematician, Stanislaw Ulam, in the late 1940s. Before Monte Carlo simulation was developed, statistical sampling was used to estimate uncertainties of deterministic simulations. Monte Carlo simulation is a method of estimating the value of an unknown quantity by deploying the principles of inferential statistics. The inferential statistics make inferences and predictions about population (a set of examples) and samples (a proper subset of a population). In other words, Monte Carlo is a numerical technique to forecast the outcomes based on the available evidences [6]. The predicted outcome depends on the size of input variables and the variance. Since the introduction of the Monte Carlo method and with advancement of computers, application of the technique has been adapted in different fields, including a wide variety of problems in the petroleum industry [2, 4, 7–11].

The Monte Carlo simulation method can be divided into five steps (see Fig. 6.7): defining the model, data gathering, defining input distributions, sampling input distributions, and interpreting and using the results.

Defining the model—A Monte Carlo simulation begins with a model. The forecaster needs to clarify the scope of the analysis including the contingencies and possibilities, to be determined. Once done, appropriate input parameters are specified to the model. Then, the output values are calculated. Each of these parameters are viewed as random parameters [5].

Data gathering—In a P&A operation, the assumption is that the exact values of the model inputs are unknown, so offset data are used which means uncertainty in modeling. Data gathering is necessary to quantify this uncertainty. Offset data is the key step in Monte Carlo forecasting.

Defining input distributions—When offset data are ready, the probability distributions are defined and sampling of each uncertain input value to the model is accomplished. This process can be subdivided into two steps: selection of distribution shape (e.g. uniform, normal, lognormal, etc.) and distribution parameters (e.g. minimum, standard, deviation, P_{90} percentile, etc.).

Sampling input distributions—Monte Carlo simulation performs random sampling from input distributions and conducts a large number of trials. A trial is the process of selecting one value for each input and calculating the output or possible results. A simulation is a series of hundreds or thousands of repeated trials for which the outputs are stored. The selection of random numbers from the input distributions can have a significant effect on the outcomes.

A major driver of the final range of outcomes is correlation. A *correlation* is defined as any relationship or dependency between two input quantities which motivates their joint distribution to deviate from statistical independency [4, 11]. Correlation is part of physical reality and as the relationships between input quantities are often not amendable to quantification, correlations are quite subjective and amorphous [12]. Spearman's rank order, Pearson, and Kendall Tau are some common correlations to consider the dependency [13]. The dependency between inputs is assigned with a value between –1 and +1 whereas full independency is shown by –1 and full dependency by +1. Spearman's rank order correlation, also known as Spearman's rho, is a measure of statistical dependency between the rankings of two variables. For two data sets of X and Y, Spearman's rank order correlation coefficient is given by [13].

$$\rho = 1 - \frac{6 \times \sum \left(\Delta r^2 \right)}{n \times \left(n^2 - 1 \right)} \tag{6.1}$$

$$\Delta r = x - y \tag{6.2}$$

where *n* is the number of correlated data pairs between the data sets, and x and y correspond to ranks of the data sets. It should be noted that the Spearman's rank order correlation is independent of distribution of data.

Pearson correlation coefficient for two data sets is given by:

$$P = \frac{\sum_{i=1}^{n} \left(X_i - X' \right)\left(Y_i - Y' \right)}{\sqrt{\sum_{i=1}^{n} \left(X_i - X' \right)^2} \sqrt{\sum_{i=1}^{n} \left(Y_i - Y' \right)^2}} \tag{6.3}$$

where X_i and Y_i are a pair of the correlated data sets, X' and Y' are their mean values, and n is the number of correlated data pairs between the data sets. One of the main drawbacks of this correlation is that a non-linear transformation between two variables is not preserved. In addition, this correlation does not capture a non-linear relationship between the two variables.

Unlike the Spearman's rank order and the Pearson's correlations, the Kendall Tau rank correlation coefficient captures the dependency pattern between two variables. The Kendall Tau rank correlation coefficient is given by:

$$\tau = \frac{(number\ of\ concordant\ pairs) - (number\ of\ discordant\ pairs)}{\frac{n(n-1)}{2}} \tag{6.4}$$

where *n* is the size of samples, concordant pairs are the pairs that are moving in the same direction, and discordant pairs are the ones that are moving in the opposite direction. When the correlations are generated, they will be included in the model.

Interpreting and using the results—PDF and CDF are the basic outcomes of a Monte Carlo simulation, for each quantity [2]. In order to avoid any false outcome or misinterpretation, these must pass some quality-assurance or a sensitivity analysis

prior to being used. When the process is successfully completed, the distribution curves are ready to be used in a variety of processes of a P&A operation, including risk analysis and decision making, budget allocation, setting targets and expectations [4, 11].

6.2.4   Regression Method for Time Estimation

A regression approach uses a model in which deterministic and probabilistic models are applied. The contribution of the deterministic part in the regression model provides the opportunity that output results depend on input values. But the contribution of the probabilistic part in the regression model does not allow to produce an exact value for output values.

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