Senate Standing Committee on Economics
Inquiry into Australia's Oil and Gas Reserves
Response received from Robert Cook

Further to your email of 13th September 2021, the following responses are provided to the following Questions on Notice

1. Is there a mechanism or ability to get an assessment of the resources remaining in an ageing tenement/field?

Resource Assessment Mechanisms

There are mechanisms available for evaluating the residual resources in a declining oil field.

The attached Chemical Tracers, Inc., paper by Scott Badham ("The Single-Well Chemical Tracer Test as an Oil Reserves Evaluation Tool") provides details current methods employed for estimating oil reserves.

With an extensive production history, a great reliance in estimating the recoverable reserves of a field is placed on declining curve analyses which plot actual decline curves to a predicted economic cut off of a well or field. Declining curves can be prepared for each of the three phases of production of a field. For many of Australia's oil fields with strong aquifer support, a single decline curve tracks the life of the primary and secondary recovery phases. Decline curve analysis for the tertiary recovery phase of production has not been possible in Australia because tertiary recovery has not been implemented in Australia with the exception of Santos' experience with the successful EOR production from of its Tirrawarra field.

The mechanism for evaluating the proven reserves possible from tertiary recovery technology is addressed in Section 5 of the Chemical Tracer, Inc., paper. By conducting a single well chemical tracer test (SWCT test) to determine the residual oil concentration at the end of the secondary production phase of a well and then flooding that well with the enhanced oil recovery proposed for the field followed by a further SWCT test, the tertiary recovery potential of the field can be estimated and the incremental proved reserves established. Implementation of the EOR production will lead to those reserves being certified as valuable 1P reserves.

As an example of where SWCT testing is being applied, Abu Dhabi National oil Company (ADNOC) has recognized that the global average oil recovery stands at around 35% and ADNOC is looking to increase recovery rates to 70% at its fields by, implementing EOR technologies and to that end, is carrying out extensive SWCT testing of fields as a precursor to developing its EOR program.

SWCT testing eliminates most of the variability associated with other technologies and encountered in a field's geology and it can also be more cost effective and quicker to achieve a more reliable result.

None of Australia's oil fields abandoned to date or those planned to be abandoned in the foreseeable future have been SWCT tested to determine their residual oil concentrations or their EOR potential.

Santos planned to undertake the first SWCT test in 2018 and mobilized equipment from the USA to test Gidgealpa wells but cancelled the test and demobilized the equipment.

Resource Assessment Methodology

It is also possible to evaluate the potential of the remaining resources of an ageing field and to estimate how much of those resources could become recoverable reserves.

Bridgeport's approach to the evaluation of the EOR potential of the Moonie oil field in the Surat Basin in Queensland started with the knowledge that 25 million barrels had been produced from a field that its previous owner, Santos had estimated had an original oil in place (OOIP) of between 79 and 124 million barrels (OOIP estimating is anything but a precise science). A historic recovery of either 32% or 20% resp., provided plenty of scope to consider the tertiary recovery (EOR) options for the field.

Bridgeport's approach to considering the EOR options for Moonie was to first look for analogues based on the field's properties and its production history. This was achieved through a USA consultant specializing in EOR technology and produced an encouraging match for Moonie. The possible range of analogue recoveries applied to Bridgeport's OOIP estimate of 88 million barrels for the Moonie field, indicated it would be an excellent EOR candidate and warranted the time and cost commitment to generate a reservoir model for simulating the EOR development of the field.

The history matched reservoir model of the Moonie oil field was used to simulate the injection of carbon dioxide ($CO_{2)}$ into the Moonie oil field. The simulation work produced positive recovery forecasts and further work then concentrated on an initial project involving the injection of a quantity of CO_2 into a central well and forecasting the subsequent oil recovery from the surrounding producing wells. The concept of an initial CO_2-EOR project was dictated by the limited volume of anthropogenic CO_2 to be available locally and also it provided a means of confirming the viability of CO_2-EOR at Moonie and the justification for the large capital investment required for a full field development, assuming a larger source of CO_2 could be found for such a development.

It is worth noting that the oil fields in the Gippsland, Cooper-Eromanga, and Carnarvon basins unlike those in the Surat basin (Moonie), each has a ready supply of relatively pure natural CO_2 near to their oil fields.

2. Are you able to provide any assessment of the remaining potential of the Laminaria or Corallina fields?

   - ***a. Can OFM provide advice on the outcome of these assessments?***
   - ***b. Can OFM recommend a course of action to assess the fields?***

An assessment has been made of the Corallina oil field. The work was undertaken on a voluntary basis by colleagues in the USA and was possible because Corallina had only two producing wells enabling a relative quick means of history matching a generated reservoir model. Preparation of the Corallina model was made possible because NOGA management provided historical production data for the individual wells of the Laminaria and Corallina oil fields. This data is normally held as confidential between leaseholders and NOPTA and as such, unavailable for third parties.

a. Assessment of Corallina

Once the model was history matched, it was then used to simulate possible tertiary recovery (enhanced oil recovery or EOR) outcomes. Simulating the injection of nitrogen into the Corallina field indicated an incremental recovery in excess of 30 million barrels was possible. This was a conservative outcome based on a simple reservoir model and could be expected to be improved with an in-depth study.

A reservoir model was not prepared for Laminaria. The results from the simulation of EOR of Corallina was meant to be indicative of what could be expected from Laminaria should Minster Pitt or the Northern Endeavour Task Force wish to commission a more detailed study of the EOR potential of the fields.

It should also be recognized that producing 100 million barrels from Corallina oil field with only two wells provides scope for technology to improve the sweep of oil from the reservoir and for tertiary recovery. The fact that Corallina #3 produced 77 million barrels of the 100 million barrels from the field, possibly made it Australia's most prolific oil well. The March 2019 reserve report by RISC Advisory Pty. Ltd., commissioned NOGA, had conventional 2P proven reserves of 8.7 million barrels and conventional 2C contingent resources of 16.8 million barrels the latter mostly from a Laminaria South development.

The results from the Corallina EOR simulation were provided to Minister Pitt and to the Northern Endeavour Taskforce on 9th September 2020 and 9th November 2020 respectively together with a recommendation for a more detailed simulation of both fields. The cost of the studies was expected to be less than US$1 million and could have been completed in less than six months particularly if existing reservoir models of the fields held by the Northern Endeavour Task Force were made available.

An earlier response from the Minister was that the Taskforce was receiving industry advice on the future of the LamCor project. Apart from NOGA, Woodside appeared to be the only member of the industry with access to the necessary data and information to evaluate the upside potential of the fields for the Taskforce. Woodside on the 20th June 2020, advised (email from CEO Perter Coleman) that it was only advising NOPTA on abandonment options and not on the upside potential of the fields.

The attached animated simulation (viewed in Power Point presentation mode) of the Corallina field made possible by data supplied by NOGA, covers its production history and followed by an EOR production phase achieved by the injection of gas. This is a possible future for the field and how additional reserves can be recovered from both Corallina and Laminaria, well before their abandonment needs to be considered.

b. Recommended Course of Action

It appears that the Australian Government has no appetite for anything but abandonment of LamCor. The decommissioning including the plug and abandonment of the wells, will mean the irreversible loss of the reserves that otherwise could have been recovered by tertiary recovery technology as demonstrated above by the Corallina simulation.

Rather than plug and abandon the wells, it is recommended that the Australian Government enter discussions with the Timor Leste Government with the aim of transferring ownership of the fields to Timor Leste with the wells and facilities in their current condition. Additionally, it is also recommended that Australia continue to collect the levy recently imposed on Australian offshore operators and hold those funds on behalf of Timor Leste for its future EOR development and ultimate abandonment of the fields. This would appear to be a just and fitting approach to rectifying past perceived inequities while honouring the terms of the 2018 Maritime Boundary Treaty.

3. Are you able to provide any assessment of the remaining potential of the tenements in Bass Strait?

Without access to the data from each of the Bass Strait oil fields it is not possible to assess the remaining reserve potential of each field. However, based on a cumulative oil production of 4 billion barrels for the Gippsland Basin Joint Venture oil fields and a range of assumed recovery factors, the corresponding range of tertiary reserve recoveries possibly from the injection of carbon dioxide (CO_2) could be as follows:

Assumed Recovery (% of OOIP for 4 billion bbls cum. prodn.)	OOIP (billion bbls)	EOR Recovery 17% of OOIP (billion bbls)
65%	6.2	1
60%	6.7	1.1
55%	7.3	1.2
50%	8	1.4
45%	8.9	1.5
40%	10	1.7
35%	**11.4**	**1.9**
30%	13.3	2.3
25%	16	2.7

The 17% recovery factor (applied to the OOIP) for enhanced oil recovery (CO_2-EOR) is often applied by the industry for a miscible CO_2 flood of an oil field.

A 65% recovery factor would be an exceptional outcome from any oil field that has been limited to only secondary production operations. Any claim for such an achievement would warrant verification particularly if tertiary recovery technology was not to be employed to maximize recoveries and particularly with the limited well spacing inherent in offshore operations.

As more approvals are granted for the Gippsland Basin Joint Venture to plug and abandon the Bass Strait oil fields with no detailed evaluation of their EOR potential undertaken, so will more oil reserves be lost to Australia. The only parties able to assess how big those losses will be, are the Gippsland Basin Joint Venture partners and NOPTA since they are the parties with access to the necessary information to carry out the assessments. The above table and the CO2CRC study are indicative of the magnitude of the potential loss to Australia.

CO2CRC Study

A recent study by CO2CRC assisted by Geoscience Australia, screened and ranked Australian basins for their CO_2-EOR potential. The study estimated CO_2-EOR could increase Australian oil recovery by 3 billion barrels. Without access to the CO2CRC methodology or details of how this figure was derived but based on APPEA published figures to 2014 which reveal 67% of Australia's cumulative crude oil production came from the Gippsland fields, it is not unreasonable to believe 2/3rds of the 3 billion additional barrels of CO2CRC's CO_2-EOR reserves were from the Gippsland Basin.

Another interesting outcome of the CO2CRC study was its selection of the Cooper-Eromanga and Surat basins for an in-depth study of their CO_2-EOR potential. The Cooper-Eromanga and Surat basins are believed to have the potential of recovering between 248 and 518 million additional barrels of reserves from the application of CO_2-EOR technology and thereby achieving recoveries in the order of 50% and 70% respectively while sequestering between 116 to 128 million tonnes of CO_2. An issue arising from such a finding is sourcing sufficient natural CO_2 from the Cooper-Eromanga gas fields since they are in decline and approximately 80 million tonnes of CO_2 from the gas fields has already been vented leaving a lesser volume to be produced. Recycling CO_2 from depleted CO_2-EOR projects may be necessary or importing captured anthropogenic CO_2 another option.

The Single-Well Chemical Tracer Test as an Oil Reserves-Evaluation Tool

Document Revision Record

REVISION	DATE	DESCRIPTION	WRITTEN BY	CHECKED BY	APPROVED BY
A	2020/05/22	Issued for Comments	S. Badham		
B	2021/09/21	Revised for clarity	S. Badham		

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1 Introduction and Definitions

"Oil reserves" are the remaining volume of oil that can be expected to be recovered from an individual well or field based upon reservoir characteristics, production history, engineering efforts undertaken to produce the oil, and the prevailing economic conditions under which the oil is being produced. A "reserves estimate" is an estimate of the size of oil reserves which has been generated by some scientifically reliable method. The primary purpose of a reserves estimate is to provide operators and investors with an understanding of the potential profitability of an oil or gas company. By law, publicly traded companies that do business in the United States (either through field operations or through the selling of company shares) must perform reserves estimates annually and disclose the information to the public. Public disclosure of reserves estimates is facilitated by the Securities and Exchange Commission (SEC). Companies that are not publicly traded will also often perform reserves evaluations for the sake of understanding their own profitability, although they are not required by law to disclose the information to the public.

Because oil is, in most cases, constantly being produced from a well, the oil reserves estimate for any one well or field should generally be expected to decrease over time as oil is removed from the reservoir. However, it is also true that other factors that influence the size of oil reserves (e.g., oil price, operational expenses, advances in technology, etc.) are also constantly changing, such that oil reserves may occasionally increase, irrespective of continuous production.

Generally speaking, an oil well will remain on production so long as the net profit from its production exceeds the cost of its operation. When the net profit generated by producing oil from a well decreases to the point that it equals (or is less than) the well's operational costs, the well is said to have reached its "economic limit". In virtually all cases, wells will reach their economic limits long before they stop producing oil. For example, if the total operating cost of a well is 200 USD/day, and furthermore, if the net profit to the operator is 20 USD/bbl (after all expenses have been paid), the economic limit for the well, which is measured as a production rate, will be 10 bbl/day. Once the production rate of the well has reached the economic limit, the well will, in most cases, be shut in or abandoned. Net profits are calculated after all expenses have been paid, including, taxes, royalties, capital expenditures, and operating expenditures. In many cases, companies will only own a certain percentage of the oil produced from the well based on contracts that specify the company's "net working interest," wherein the company is responsible for paying a certain percentage of the capital and operational expenses, and in return, is entitled to a certain percentage of the net production.

1.1 "Resource" Versus "Reserves"

The term "oil reserves" should not be confused with "oil resource". Oil resource, sometimes referred to as "original oil-in-place" (*OOIP*) or "petroleum initially in-place" (*PIIP*), is the total volume of oil contained in the pore space of a reservoir or producing interval. Similarly, reserves should not be confused with "estimated ultimate recovery" (*EUR*) or "cumulative recovery". These are all distinctly different terms, the relationships of which are illustrated in **Fig. 1**.

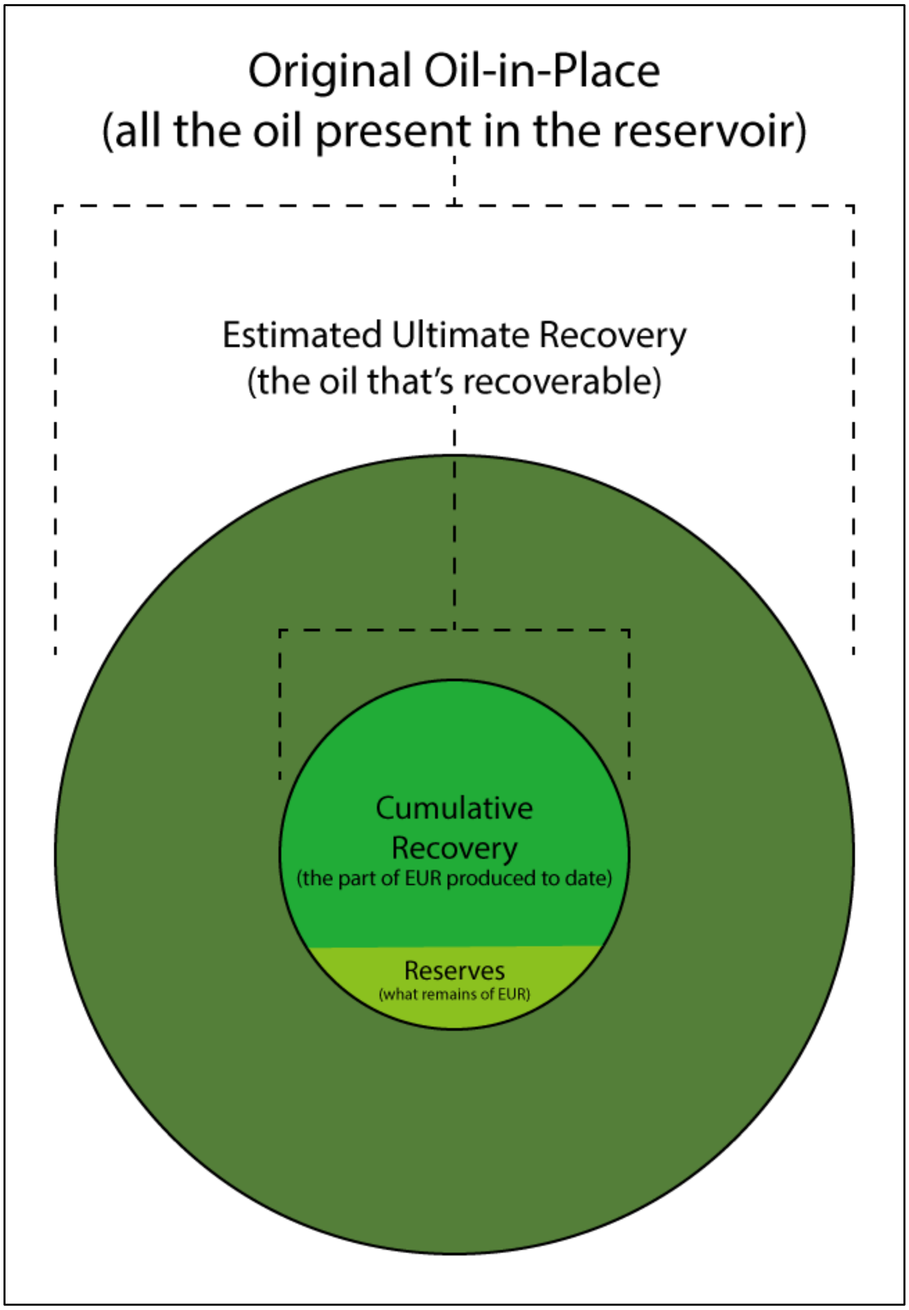

Fig. 1 – Relationship between OOIP, EUR, cumulative recovery, and reserves in an oil or gas reservoir (not necessarily drawn to scale).

To summarize:

- *Oil resource* (also "OOIP" or "PIIP"): The total volume of oil contained within the drainage volume of an individual well or reservoir. Due to economic and technological limitations, only part of this oil is recoverable.
- *Estimated ultimate recovery* (*EUR*): The volume of oil that, under current geologic, economic, and technological conditions, is expected to be produced from a well or reservoir during its operational lifetime (i.e., by the time it reaches its economic limit).
- *Cumulative recovery*: The volume of oil that, as a portion of *EUR*, has already been produced from the well or reservoir.
- *Oil reserves* (also "remaining oil reserves"): The volume of oil that, as a portion of *EUR*, is expected to be recovered but which still resides in the well or reservoir.

OOIP and *EUR* are related by way of the recovery factor *RF*, which varies between 0 and 1:

$$EUR = OOIP \cdot RF \tag{1}$$

Where:

EUR = estimated ultimate recovery (bbl)

OOIP = original oil-in-place (bbl)

RF = recovery factor (fraction).

In practice, *OOIP* is always larger than *EUR*, which is simply a reflection of the fact that some oil in a reservoir is unrecoverable due to technological and economic limitations. The relationship between *EUR*, cumulative recovery, and oil reserves is mathematically defined in Equation 2.

$$EUR = Cumulative\ Recovery + Reserves \tag{2}$$

When oil companies report reserves for a well or field, they report only that volume of oil that remains in the reservoir and which they believe, with "reasonable certainty," can be recovered given existing economic and operational conditions. Barring any changes in those economic or operational conditions, the reserves for a well or field should decrease from one year to the next. If, however, certain conditions change – e.g., the price of oil increases, the company's operational expenses decrease, or technological innovations improve the recovery factor for the well or field – the associated reserves may periodically increase. The general trend in reserves, however, will be downward over time.

1.2 Reserves Reporting Laws in the United States

By law, oil and gas reserves must be reported annually to the SEC by any publicly traded oil company in the United States. The guidelines for how these reserves are calculated are maintained and periodically updated by the SEC, but with considerable input from professional organizations within the oil and gas industry. The Society of Petroleum Engineers (SPE) has historically played a critical role in offering guidance to the SEC, largely by way of the Petroleum Resource Management System (PRMS). The PRMS is a document written and updated every few years by SPE to propose best practices for how reserves should be calculated. In large part, the SEC guidelines are taken almost verbatim from PRMS, but with certain exceptions. Generally speaking, the PRMS document is much more thorough than the SEC guidelines and tends to be more reflective of on-the-ground realties within the industry (particularly with regard to advances in technology). The last revision to the SEC rules was issued in 2009 and was based largely on the 2007 revision to PRMS. The most recent revision of PRMS was issued in 2018.

For reference, the SEC rules for reporting oil and gas reserves are found in two sections of the U.S. Code of Federal Regulations (CFR):

- Regulation S-X (found in CFR Title 17, Chapter II, Part 210, Section 4-10), "*Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975*".
    - This regulation provides financial accounting and reporting standards, largely by way of defining several oil reserves-relevant terms, for oil and gas companies.
- Regulation S-K (found in CFR Title 17, Chapter II, Part 229, Subparts 1200-1208), "*Disclosure by Registrants Engaged in Oil and Gas Producing Activities*".
    - This regulation provides a few general instructions and clarification of certain definitions.

Fig. 2 shows the "resource classification framework" assembled by SPE and published in the PRMS. This classification framework is the basis for how the SEC classifies different categories of oil and gas resources. By law, only the volumes of petroleum classifiable as "Proved Reserves" need be reported to the SEC. This volume represents only a small part of the actual petroleum resource present in a reservoir (e.g., see Fig. 1).

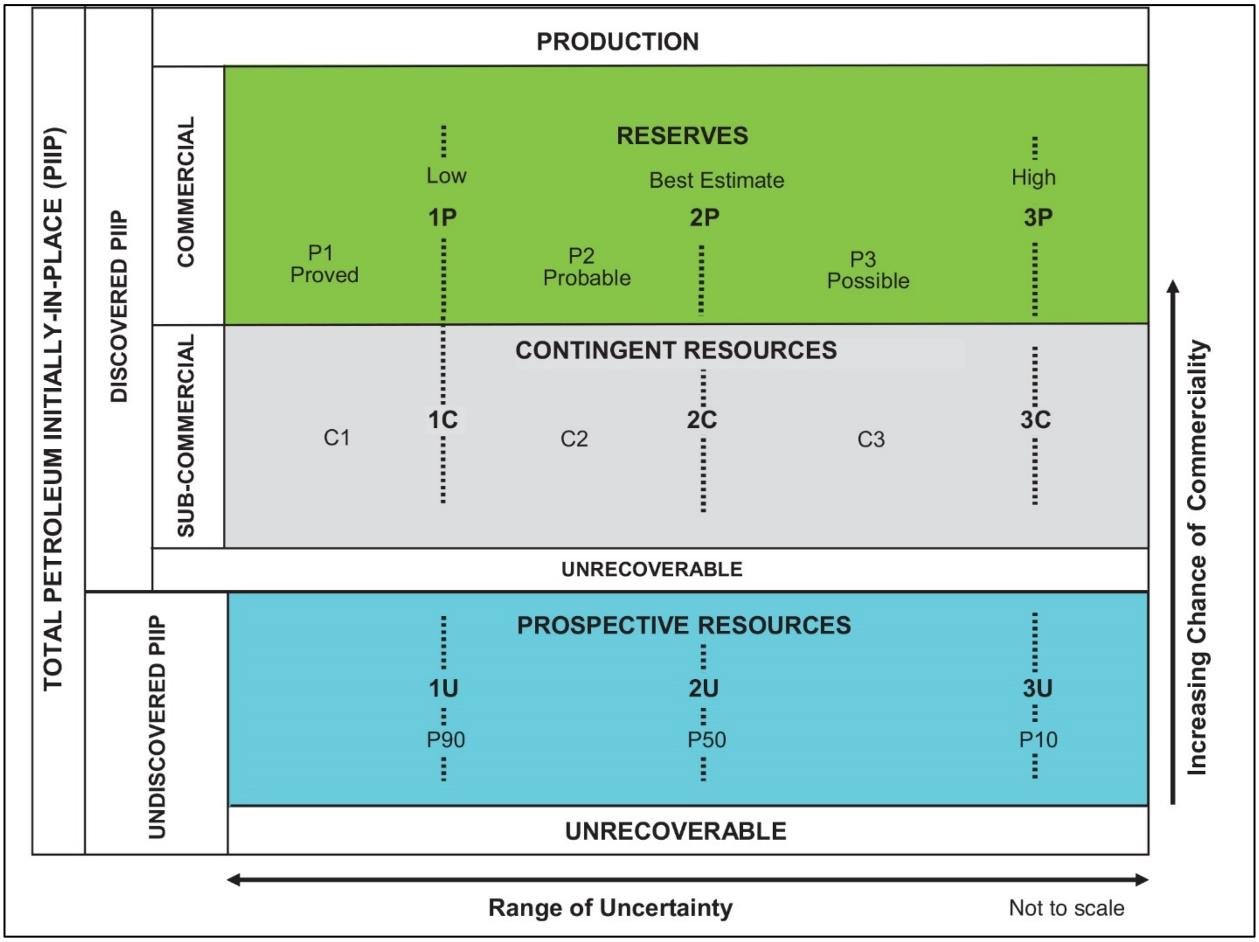

Fig. 2 – "Resource classification framework," from the Petroleum Resource Management System (SPE 2018).

1.3 Reserves Categories

"Oil reserves" may be classified as "proven," "probable," or "possible" based on the statistical likelihood of their recovery. "Proven reserves," also known as "1P reserves," are a volumetric estimate that has a high likelihood of being met or exceeded during the life of the well (this estimate must meet a 90% likelihood threshold in a probabilistic estimate). "Probable reserves," also known as "2P reserves," are a volumetric estimate that's as likely as not to be met (this estimate must meet a 50% likelihood threshold in a probabilistic estimate). "Possible reserves," also known as "3P reserves," are a volumetric estimate that has a low likelihood of being met or exceeded during the life of the well (this estimate must meet a 10% likelihood threshold in a probabilistic estimate).

Of these three categories, "proven reserves" is the most conservative estimate – i.e., this reserves class is characterized by a smaller volume, but one which is much more likely to be produced (or exceeded) during the life of the well. Put another way, a proven reserves estimate for a well or field is likely to be met or exceeded in the vast majority of cases (e.g., 90% of cases), which illustrates its conservative nature. By comparison, the "probable" and "possible" classes of reserves are comparatively riskier estimates. As mentioned previously, proven reserves is the number that publicly traded oil companies are required to report annually to the SEC. Consequently, the SEC rules have a low tolerance for risk built into them. Oil companies may also choose to report "probable" and "possible" reserves, but they are not required by law to do so.

In practice, reserves are most often calculated for *individual wells* due to the fact that the relevant data required to perform a reserves estimate is almost always based on individual well performance and/or well characteristics. According to the SEC rules, a company must itemize its reserves estimates for each geographic region in which it operates (e.g., country, continent, etc.).

2 Methods of Reserves Estimation

There are many methods of estimating oil reserves, including volumetric analysis, decline curve analysis, material balance calculation, and reservoir simulation. The SEC's primary stipulation with regard to these various methods is that they be based on "reliable technology," which it defines thusly:

> *Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.*

Ultimately, these methods all work by utilizing some kind of model (e.g., a set of equations) that relies upon various input parameters to calculate a reserves estimate. These methods may either be "deterministic" or "probabilistic".

2.1 Deterministic Versus Probabilistic Methods

The fundamental distinction between a "deterministic estimate" and a "probabilistic estimate" is that a deterministic estimate uses a single value for each input parameter required by the model, whereas a probabilistic estimate uses a statistical distribution of values for each input parameter. To illustrate this difference, consider the hypothetical "model" in Equation 3, with which we are attempting to estimate the value of some output parameter *y* as a function of input parameters *a*, *b*, and *c*:

$$y = a + b^c \tag{3}$$

(To clarify, the Equation 3 is merely a mathematical abstraction, not an actual model for calculating oil reserves estimates.)

The deterministic approach to solving *y* in Equation 3 is quite straightforward. It requires only that we identify a fixed value for each of the variables *a*, *b*, and *c* and use them in Equation 3 to arrive at a single, "deterministic" estimate for *y*.

While the deterministic approach is perfectly valid in many circumstances, there are certain situations in which knowing exact values for the input parameters (e.g., *a*, *b*, and *c*) may not be feasible. This is commonly the case in oil reservoirs, where the various input parameters required by a reserves estimation model may not be definitively known. In other words: We may know values for certain input parameters, like porosity or decline rate, for *some* wells, but not for the wells we're currently trying to generate reserves estimates for. In this situation, we would be relegated to making educated guesses about the input parameters for the wells we're interested in.

For example, imagine that you've collected data on input parameters *a*, *b*, and *c* (see Equation 3) from a dozen previous field observations or lab experiments, such that you now have 12 unique estimates for each of the three parameters. Furthermore, suppose you wanted to use that data to estimate the next outcome for parameter *y*. One option for doing so would be to simply calculate the average value for each of the parameters *a*, *b*, and *c* and use those averages in the new calculation of *y*. Because this approach ultimately relies upon using a single, fixed value for each parameter in Equation 3 (in this case, an average), the approach would be classified as a deterministic one. A potential downside to this kind of deterministic approach is that the data used to calculate the averages may contain outliers that skew the averages for one or more parameters.

The probabilistic approach aims to avoid the problem of outliers. In the probabilistic approach, the available data for each input parameter (e.g., the 12 previous observations in the example above) is used to create, not mere averages, but statistical distributions that describe the range and likelihood of possible values for each input parameter. These distributions mathematically describe the chance that some value within the distribution might be randomly sampled. Values that frequently occur within the distribution are more likely to be randomly sampled from the distribution, while values that are rare (i.e., the outliers) are less likely to sampled. The benefit of this approach is that the distribution accurately biases the data toward the more frequently encountered values while still allowing for the occasional occurrence of an outlier.

The distributions used to characterize the input parameters may be of any statistical type – e.g., a normal distribution, a log-normal distribution, a triangular distribution, etc. Whatever distribution type is used, it should be a good match to the real-world data. As an example, consider **Fig. 3**, which shows results from a hypothetical study of reservoir thickness conducted on 30 different wells located in the same field.

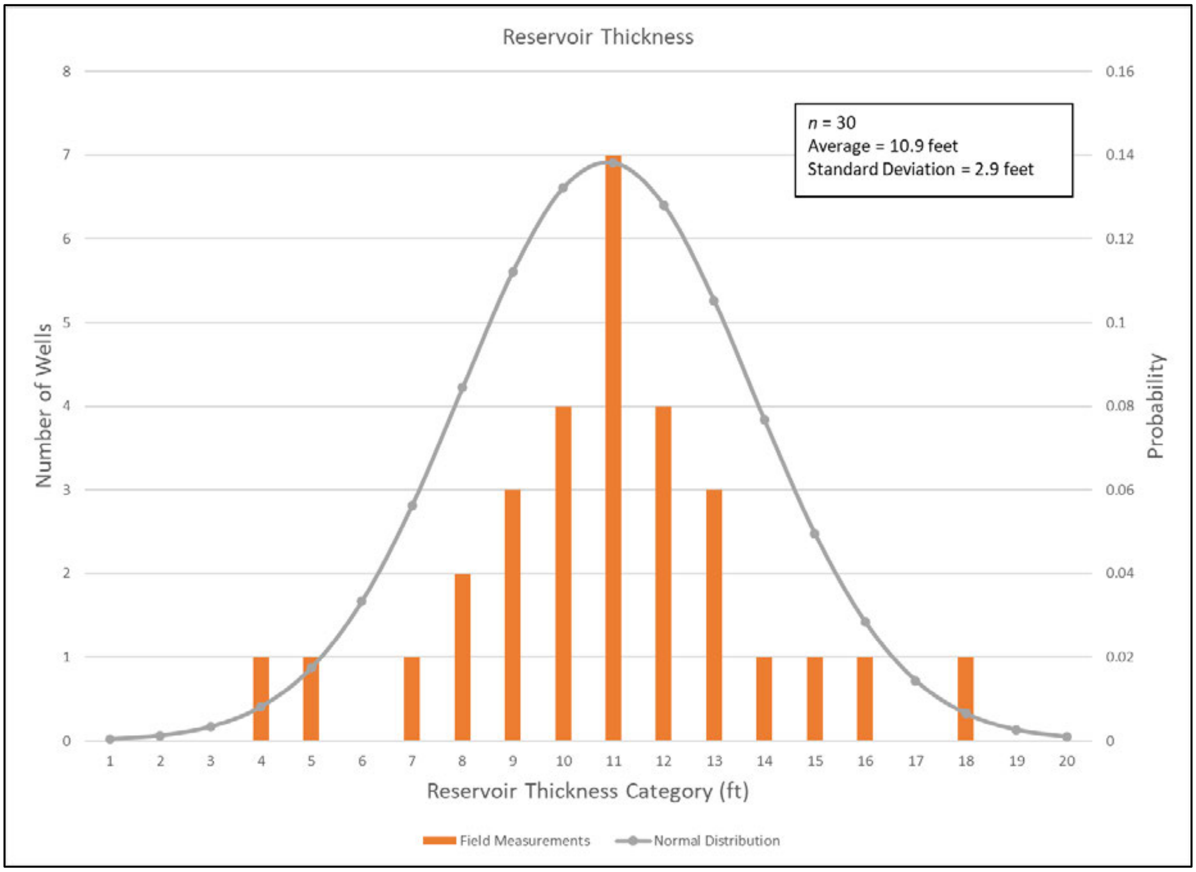

Fig. 3 – Field-measurements of reservoir thickness for 30 hypothetical wells. The data are overlaid with a normal distribution that approximates the field data.

In Fig. 3, data for reservoir thickness (measured in feet) have been collected by evaluating 30 different wells and presented as a histogram. Most of the wells exhibit a reservoir thickness in the range of 10 to 12 feet (average = 10.9 feet), but there do exist some statistical outliers at the higher and lower ends of the field measurements. Using the average thickness and standard deviation calculated for the real-world data, a normal distribution can be constructed that approximates the shape of the histogram. Note that the normal distribution (the gray line) is plotted as a probability of occurrence for the 30-well data set. For example, the normal distribution in Fig. 3 predicts a roughly 14% chance that a well will have a reservoir thickness of exactly 11 feet and roughly 1% chance that it will have a reservoir thickness of 4 feet. *(Note: the normal distribution is generated only for whole-number values of reservoir thickness, e.g., 3 ft, 8 ft, 14 ft, etc. As such, there is no statistical probability calculated for fractional values, e.g., 12.4 ft.)*

The benefit of distributions like the one shown in Fig. 3 is that they are relatively easy to construct (usually only requiring an average value and a standard deviation) and can be easily used in computer models to make predictions about certain phenomena, including oil reserves. Once the distributions are mathematically generated for each parameter required by the model, the model (e.g., Equation 3) is typically run multiple times by randomly sampling values for each of the input parameters from their respective distributions.

The result of this process is that instead of getting a single, fixed value for the parameter of interest (*y*), we end up with a statistical range of likely outcomes, each characterized by a percent likelihood of occurring. The benefit of this approach is that the model still allows for the possibility that outliers may occur in nature, but the outliers do not unduly bias the model in one direction or another. Instead, the range of possible outcomes for the output parameter (e.g., *y*) is primarily controlled by the most likely occurrences of the input parameters (e.g., *a*, *b*, and *c*). Such probabilistic reserves estimates in the oil industry are commonly accomplished through a computer method called Monte Carlo simulation, in which the model is run thousands of times by randomly sampling each input parameter from its respective distribution (in other words, calculating output parameter *y* in Equation 3 thousands of times by randomly sampling input parameters *a*, *b*, and *c* from their respective distributions). The results of these thousands of trials are then plotted as a distribution of possible outcomes, like those shown in **Fig. 4**.

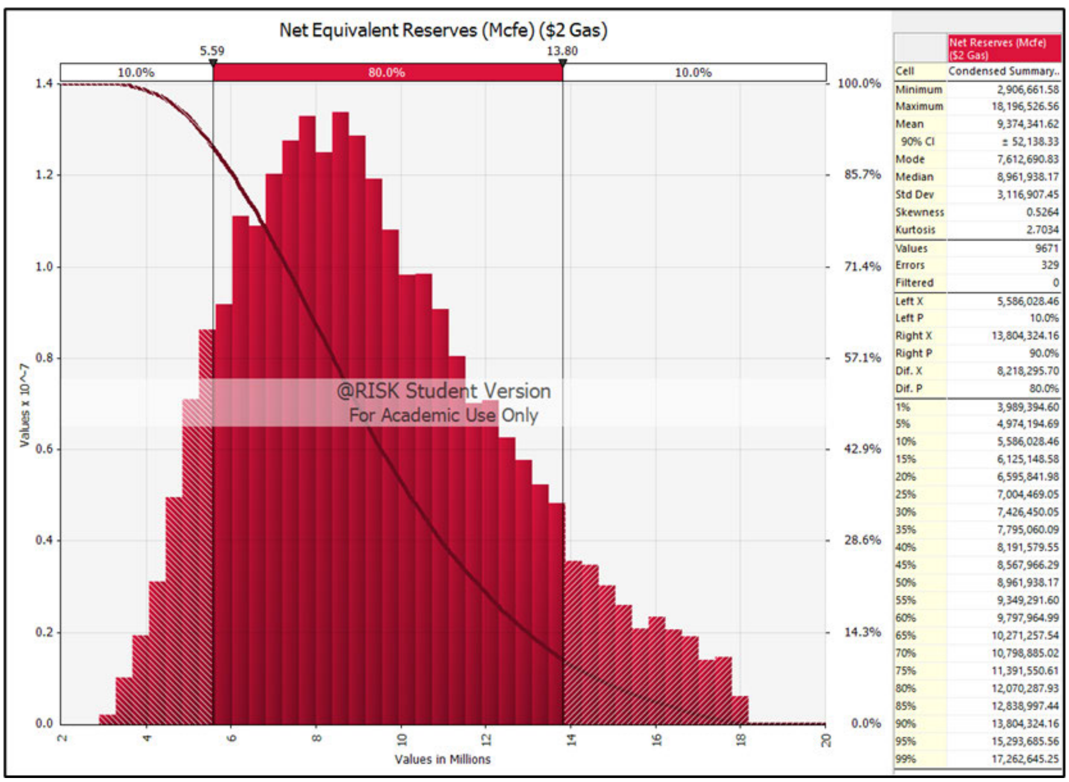

Fig. 4 – Monte Carlo simulation results of gas reserves from a single gas well.

To generate Fig. 4, a reserves estimation model comprised of economic and geologic input parameters was run 10,000 times, where each of the input parameters were randomly sampled for every run. The red bars of the histogram each represent different reserves estimates (thousands of cubic feet of gas-equivalent, or Mcfe, on the x-axis) plotted as a percent likelihood of outcome (left-hand-side of the y-axis). The red curve, which corresponds to the right-hand-side of the y-axis, is a decumulative probability plot, which tells us the cumulative likelihood that a certain reserves estimate will be met or exceeded. For example, Fig. 4 shows that there's a 90% likelihood (high probability) that the *EUR* for this well will be at least 5.59 Mcfe. Similarly, there's a 10% likelihood (low probability) that the *EUR* will be 13.8 Mcfe or more. As the reserves estimate gets higher, there's a lower and lower chance of that particular outcome actually occurring.

The advantage of probabilistic estimates like the one shown in Fig. 4 is that they allow different reserves estimates to be quantified with a numerical probability (i.e., percent likelihood of outcome). By comparison, deterministic estimates can only ever be qualified *verbally* (e.g., "highly likely of occurring," "unlikely to occur," etc.). Both types of estimate are allowed by the SEC, but probabilistic estimates tend to be favored by investors because of their perceived greater precision. Despite this, deterministic estimates are far more common due to the relative ease with which they can be generated.

2.2 The Volumetric Method

The volumetric reserves model is arguably the simplest and most widely used reserves-estimation method in the oil and gas industry. This model is based primarily on the geometry of the reservoir (or individual well drainage) and the fluid saturations present in the pore space. In other words, it attempts to calculate reserves by simply looking at the size of the reservoir and the type of fluid the reservoir contains. Using the volumetric method, we can derive equations for *OOIP* and *EUR* for an oil-water reservoir:

$$OOIP = 7758\frac{Ah\varphi(1 - S_{wi})}{B_{oi}} \tag{4}$$

$$EUR = 7758\frac{Ah\varphi(1 - S_{wi})}{B_{oi}} \cdot RF \tag{5}$$

where:

OOIP	= original oil-in-place (STB)
7758	= conversion factor (reservoir bbl/acre·ft)
A	= Drainage area (acres)
h	= reservoir thickness (ft)

φ = reservoir porosity (fraction)

S_{wi} = initial water saturation (fraction)

B_{oi} = initial formation volume factor for oil (reservoir bbl/STB)

EUR = estimated ultimate recovery (STB)

RF = recovery factor (fraction).

Most of the terms in Equations 4 and 5 (A, h, φ, S_{wi}, and B_{oi}) can be determined via logging, laboratory testing, or other field methods. However, the recovery factor *RF* poses two problems. First, *RF* is generally only acquirable after a well has been produced to its economic limit, which effectively eliminates using *RF* to calculate reserves for the well in question (i.e., a reserves estimate would no longer be required if the well has already been produced to its economic limit). Secondly, applying the *RF* to other, still-producing wells is difficult if the reservoir is not homogenous (i.e., different wells with different reservoir characteristics may exhibit widely different *RF* values). An additional problem is that the *RF* value also fails to give any useful information about why a well reached its economic limit at a specific point in time. Specifically, the *RF* value alone does not tell us anything about what percentage of the unrecovered oil is represented by residual oil and how much is represented by bypassed oil. A single-well chemical tracer test (SWCTT) may help to resolve these problems.

3 An SWCTT-Based Method of Reserves Evaluation

The SWCTT method for reserves evaluation presented in this document is based upon a mathematical expansion of how the recovery factor *RF* is defined. The method utilizes the SWCTT to first measure waterflood residual oil saturation (S_{orw}) in a handful of wells that have reached their economic limit and for which *RF* values are already known. It then uses this information to make a reserves estimate for a newly drilled well in which a separate S_{orw} measurement has been made. There are two primary advantages to this method over the traditional *RF*-only approach:

1. Measuring S_{orw} (via SWCTT) for each of the wells that have reached their economic limits gives useful information about how much of the remaining oil in each well is comprised of residual oil (i.e., S_{orw}) and how much is comprised of oil that is technically mobile but remains unrecovered due to inefficient waterflooding or economic constraints. By itself, the *RF* value cannot distinguish between these two types of remaining oil resource.

2. By mathematically decomposing *RF* into multiple, unique fluid saturations that are field-measurable, it becomes possible to generate more precise reserves estimates for new wells.

3.1 Expanded Definition of Recovery Factor, *RF*

Here, I propose an expanded definition of *RF* in terms of parameters that may be directly measured or inferred through SWCT testing:

$$RF = \frac{(1 - S_{wi} - S_{ob} - S_{orw})}{(1 - S_{wi})} \tag{6}$$

where:

S_{ob} = bypassed oil saturation (fraction)

S_{orw} = waterflood residual oil saturation (fraction).

The bypassed oil saturation (S_{ob}) in Equation 6 is intended to represent all of the mobile oil that remains in a reservoir after the well has reached its economic limit. This volume of oil is separate from and in addition to the oil that remains in the pore space as a waterflood residual phase (S_{orw}), i.e., when the fractional flow of water in the drainage volume of the well reaches 100%.

The numerator in Equation 6 represents the total volume of oil that is theoretically recoverable during the productive lifetime of a well that undergoes waterflooding. This numerator assumes that some oil is left behind in the reservoir after waterflooding as either bypassed oil (S_{ob}) or residual oil saturation (S_{orw}). The denominator represents all oil originally present in the pore space (*OOIP*). Substituting Equation 6 into Equation 5 gives:

$$EUR = 7758 \frac{Ah\varphi(1 - S_{wi})}{B_{oi}} \cdot \frac{(1 - S_{wi} - S_{ob} - S_{orw})}{(1 - S_{wi})} \tag{7}$$

Equation 7 may be further simplified to:

$$EUR = 7758 \frac{Ah\varphi(1 - S_{wi} - S_{ob} - S_{orw})}{B_{oi}} \tag{8}$$

Equation 8 is the essence of the SWCTT method for estimating oil reserves in a new well via the volumetric model. Instead of relying on a sometimes difficult-to-measure parameter like *RF* (see Equation 5), this modified approach makes use of one parameter (S_{orw}) that can be directly measured from the well in question and another parameter (S_{ob}) that can be calculated from older analog wells and for which the range of uncertainty may be lower (i.e, as compared to the range of uncertainty in estimates of *RF*).

Equation 8 is applicable for estimating reserves in oil reservoirs that are expected to undergo waterflooding (i.e., secondary recovery) at some point in their productive lifetime. Equation 8 can also be modified for application to wells slated for enhanced oil recovery (EOR; see later discussion).

In practice, the objective of using the SWCTT method for reserves evaluation is to refine an estimator's understanding of *RF*. Values for *RF* that are used in reserves estimates traditionally come from one or more analog wells from the same field that have already been produced to their economic limits. Once the *RF* values for those older wells are known, the estimator would calculate an average *RF* and apply it to Equation 5 to make an *RF*-based deterministic estimate. Or similarly, a distribution of *RF* values could be generated from the field data and applied to a probabilistic estimate using Monte Carlo simulation. However, these traditional approaches don't guarantee that the *RF* values acquired from the older analog wells are necessarily applicable to a new well, particularly in cases where older wells have been drilled in higher-quality portions of the reservoir.

By performing an SWCT test for S_{orw} on these older, shut-in or abandoned wells, it becomes possible to determine what proportion of the *RF* value is due to bypassed oil and what proportion is due to residual oil. Once a measurement for S_{orw} is in-hand, a value for S_{ob} can be calculated by rearrangement of Equation 6:

$$S_{ob} = RF \cdot (S_{wi} - 1) - S_{wi} - S_{orw} + 1 \qquad (9)$$

Ideally, multiple SWCT tests could be conducted on several wells that have reached their economic limits and for which *RF* values have previously been determined. In so doing, a more refined, average S_{ob} value for the reservoir can be attained and may be used deterministically to make a reserves estimate on a new well. Conversely, a statistical distribution of S_{ob} values (e.g., a normal distribution, a triangular distribution, etc.) may be generated and used to generate a probabilistic reserves estimate for the new well using Monte Carlo simulation.

Once the estimate(s) for S_{ob} (either deterministic or probabilistic) have been made for the older wells, *EUR*s for newly drilled and/or on-production wells may be calculated via Equation 8 after performing an SWCTT to measure S_{orw}.

4 Example Applications

The hypothetical scenarios presented in Sections 4.1 and 4.2 illustrate the two advantages of the SWCTT method.

4.1 Improved Understanding of Bypassed Oil and Waterflood Efficiency

In this first hypothetical field application, an operator has production data for five wells that have reached their economic limits. Measurements of other parameters required by the volumetric model have been made for each well (e.g., via previous logging and lab work) or have been estimated based on well spacing. For the sake of simplicity, we assume things like drainage area, interval thickness, and porosity have been measured previously and are shown to be uniform across the five wells. The data available to the operator are summarized in **Table 1**.

Well #	*A* (acres)	*h* (feet)	*φ* (fraction)	S_{wi} (fraction)	B_{oi} (res bbl/STB)	*EUR* (STB)
1	40	20	0.22	0.15	1.1	475,000
2	40	20	0.22	0.15	1.1	500,000
3	40	20	0.22	0.15	1.1	525,000
4	40	20	0.22	0.15	1.1	550,000
5	40	20	0.22	0.15	1.1	575,000

Table 1 – Logging, PVT, and production data for five hypothetical wells in the same field that have reached their economic limits. For the sake of simplicity, the geological parameters and PVT fluid characteristics have been assumed to be the same for each of the five wells.

Rearrangement of Equation 5 allows *RF* values to be calculated for the wells in Table 1. This is given by:

$$RF = \frac{EUR \cdot B_{oi}}{7758 \cdot Ah\varphi(1 - S_{wi})} \tag{10}$$

Using Equation 10, *RF* values for each of the five wells are calculated and summarized in Table 2.

Well #	*EUR* (STB)	*RF* (fraction)
1	475,000	0.450
2	500,000	0.474
3	525,000	0.498
4	550,000	0.521
5	575,000	0.545

Table 2 – Calculation of RF values for each of the five hypothetical wells.

By performing an SWCTT on each well to measure S_{orw}, it becomes possible to resolve how much of the recovery factor is due to residual oil and how much is due to bypassed oil (S_{ob}). Using Equation 9, Sob values are calculated for each well and summarized in Table 3.

Well #	***EUR*** **(STB) [known from production history]**	***RF*** **(fraction) [calculated via Equation 10]**	S_{orw} **(fraction) [measured via SWCTT]**	S_{ob} **(fraction) [calculated via Equation 9]**
1	475,000	0.450	0.26	0.207
2	500,000	0.474	0.26	0.187
3	525,000	0.498	0.25	0.177
4	550,000	0.521	0.25	0.157
5	575,000	0.545	0.23	0.157

Table 3 – Hypothetical results of field measurements for S_{orw} made via SWCTTs and their corresponding S_{ob} values. For wells drilled in the same producing interval and in the same field, S_{orw} will typically be similar due to the fact that they share similar geological and chemical characteristics.

Table 3 demonstrates that by performing SWCTTs on each of the five wells to measure S_{orw}, an operator may gain additional information regarding bypassed oil that helps understand how efficiently an individual well is draining and how waterflooding operations may be differentially impacting different parts of the field.

4.2 Reduced Uncertainty in Reserves Estimates

In this second hypothetical field application, we'll use the same well data from the previous example in Section 4.1 to show how the SWCTT method can reduce uncertainty in reserves estimates for newly drilled wells. Recall that in Table 2 we calculated *RF* values for each of the five analog wells that were produced to their economic limits. In a conventional approach to making a reserves estimate via the volumetric method, one or more *RF* values from analog wells would be used in conjunction with logging and PVT data acquired from the new well to make the reserves estimate. For example, we could calculate low, average, and high *RF* values from the data in Table 2 and use those to make a range of deterministic estimates for the new well. The low, average, and high RF values from the five analog wells are summarized in **Table 4**.

Well #	*EUR* (STB)	*RF* (fraction)
1	475,000	0.450
2	500,000	0.474
3	525,000	0.498
4	550,000	0.521
5	575,000	0.545
	Low:	**0.450**
	Average:	**0.498**
	High:	**0.545**

Table 4 – Low, average, and high RF values for each of the five hypothetical wells.

Table 4 shows that the average *RF* for the five older wells was calculated to be 0.498, but may be as low as 0.450 or as high as 0.545 depending on S_{orw} and the effectiveness of waterflooding (as inferred from S_{ob}). The variance in these *RF* values contributes to the uncertainty in any reserve estimate for which they are used.

For example, let's assume we have a new well (Well #6) that has been drilled and completed to the same producing interval in the same field. Logging and PVT work show that this well has similar characteristics to the previous five analog wells, as summarized in **Table 5**.

A (acres)	40
h (feet)	18
φ (fraction)	0.21
S_{wi} (fraction)	0.15
B_{oi} (res bbl/STB)	1.1

Table 5 – Characteristics of hypothetical Well #6.

Using the traditional *RF* method (Equation 5), we could calculate low, average, and high *EUR*s for the new well using the low, average, and high values of *RF* observed in the five analog wells (Table 4) and the logging and PVT data measured for the new well (Table 5). These low, average, and high estimates are calculated in Equations 11-13.

$$EUR_{lowRF} = (7{,}758 \text{ res bbl/acre} \cdot \text{ft}) \left[\frac{(40 \text{ acres})(18 \text{ ft})(0.21)(1-0.15)}{(1.1 \text{ res bbl/STB})}\right](0.450) = 407{,}887 \text{ STB} \tag{11}$$

$$EUR_{avgRF} = (7{,}758 \text{ res bbl/acre} \cdot \text{ft}) \left[\frac{(40 \text{ acres})(18 \text{ ft})(0.21)(1-0.15)}{(1.1 \text{ res bbl/STB})}\right](0.498) = 451{,}395 \text{ STB} \tag{12}$$

$$EUR_{highRF} = (7{,}758 \text{ res bbl/acre} \cdot \text{ft}) \left[\frac{(40 \text{ acres})(18 \text{ ft})(0.21)(1-0.15)}{(1.1 \text{ res bbl/STB})}\right](0.545) = 493{,}997 \text{ STB} \tag{13}$$

These results are summarized in **Table 6**:

	Low (*RF* = 0.450)	**Average (*RF* = 0.498)**	**High (*RF* = 0.545)**
New Well *EUR*	407,887 STB (-9.6% from avg.)	451,395 STB	493,997 STB (+9.4% from avg.)

Table 6 – Low, average, and high estimates for new well EUR using the traditional RF method. The variance from the average estimate is given for both the low and high estimates, and is approximately +/- 9.5%.

Using the traditional method (which normally uses only the average *RF* value), the "probable" *EUR* for the new well would be calculated as 451,395 STB. However, if we assume that *RF* values for the field vary between 0.450 and 0.545 (as has been previously observed in the abandoned wells), the *EUR* for the new well may be as much as 9.5% higher or lower.

By comparison, let's now assume that SWCTTs have been performed on the five analog wells such that we've successfully measured S_{orw} and calculated S_{ob} for each well (as previously reported in Table 3). Instead of calculating low, average, and high values for *RF*, we'll now calculate low, average, and high values for S_{ob}. These are summarized for the five wells in Table 7.

Well #	***EUR* (STB) [known from production history]**	***RF* (fraction) [calculated via Equation 10]**	**S_{orw} (fraction) [measured via SWCTT]**	**S_{ob} (fraction) [calculated via Equation 9]**
1	475,000	0.450	0.26	0.207
2	500,000	0.474	0.26	0.187
3	525,000	0.498	0.25	0.177
4	550,000	0.521	0.25	0.157
5	575,000	0.545	0.23	0.157
			Low:	**0.157**
			Average:	**0.177**
			High:	**0.207**

Table 7 – Low, average, and high S_{ob} values for the five hypothetical analog wells.

Using the SWCTT approach (Equation 8), we can calculate low, average, and high *EURs* for the new well by using the high, average, and low S_{ob} values in Table 7, respectively. This requires that an SWCTT to measure S_{orw} on the new well be carried out. For this example, we'll assume that the new well was determined to have an S_{orw} of 0.24, which is consistent with what was previously measured in the analog wells. These low, average, and high EURs are shown in Equations 14-16:

$$EUR_{highSob} = (7{,}758 \text{ res bbl/acre} \cdot \text{ft})\left[\frac{(40 \text{ acres})(18 \text{ ft})(0.21)(1-0.15-0.207-0.24)}{(1.1 \text{ res bbl/STB})}\right] = 429{,}748 \text{ STB} \quad (14)$$

$$EUR_{avgSob} = (7{,}758 \text{ res bbl/acre} \cdot \text{ft})\left[\frac{(40 \text{ acres})(18 \text{ ft})(0.21)(1-0.15-0.177-0.24)}{(1.1 \text{ res bbl/STB})}\right] = 461{,}739 \text{ STB} \quad (15)$$

$$EUR_{lowSob} = (7{,}758 \text{ res bbl/acre} \cdot \text{ft})\left[\frac{(40 \text{ acres})(18 \text{ ft})(0.21)(1-0.15-0.157-0.24)}{(1.1 \text{ res bbl/STB})}\right] = 483{,}067 \text{ STB} \quad (16)$$

These results are summarized in **Table 8**:

	Low (S_{ob} = 0.207)	**Average (S_{ob} = 0.177)**	**High (S_{ob} = 0.157)**
New Well *EUR*	429,748 STB (-6.9% from avg.)	461,739 STB	483,067 STB (+4.6% from avg.)

Table 8 – Low, average, and high estimates for new well EUR using the SWCTT method. The variance from the average estimate is given for both the low and high estimates.

As can be seen by comparing Tables 6 and 8, the SWCTT-based method results in a smaller variance between the low, average, and high estimates of *EUR* compared with the traditional, *RF*-based method (e.g., approximately 5-7% variance versus 9-10% in this example). The reason for this is because any variance in *RF* among different wells is the combined result of the variances in S_{ob} and S_{orw}. By definitively measuring S_{orw} with an SWCTT, we effectively eliminate one potential source of variance in *RF* and are left with only the variance in S_{ob} (which can't be measured directly with any currently existing field test). As a result of using the SWCTT, the total uncertainty in *RF* is reduced such that a more accurate *EUR* value may be calculated.

It is worth noting that simulations of the SWCTT method described above show that it performs best when S_{orw} is the primary factor influencing recovery factor in a sample of identical analog wells (e.g., same interval thickness, same porosity, same S_{wi}, etc.). By contrast, there can exist some irregular or anomalous combinations of field parameters (e.g., high *RF* coupled with high S_{orw}) where the SWCTT method will appear to give *EUR* estimates that suffer from higher variance than the conventional *RF*-based approach. Even in these cases, however, the anomalous combination of parameters may suggest that the *RF*-based approach will, itself, give unreliable estimates of reserves, likely owing to uncertainties in other geologic or fluid parameters. Even in these unusual circumstances, the SWCTT method at least gives a reserves estimator additional options for what information to incorporate into his or her reserves estimate.

5 Reserves Evaluation for Enhanced Oil Recovery (EOR)

The SEC allows residual oil to be reported as proved reserves so long as a pilot program has demonstrated that such oil is economically and technologically recoverable. The passage from the SEC that's relevant to EOR-based reserves is found in Regulation S-X, Section 210.4-10:

> *(22) 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.*
>
> *…*
>
> > ***(iv) 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:***
> >
> > > ***(A) 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

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

With these rules in mind, it should be possible for an operator to use the results of a One-Spot EOR pilot to report reserves. We can slightly modify the volumetric reserves model (previously applied to waterflood-only wells) to account for any additional oil that may be recovered through EOR injection. Modification of Equation 8 gives:

$$EUR = 7758\frac{Ah\varphi(1 - S_{wi} - S_{orm})}{B_{oi}} \tag{17}$$

where:

S_{orm} = EOR-modified S_{or} (fraction).

Notice that in Equation 17, S_{ob} has been eliminated. The reason for this is because this method does not require prior knowledge of an *RF* value for the well or field. Instead, we assume that the oil saturation S_{orm} achievable by the EOR method of choice determines the economic limit, which eliminates the *a priori* need to know *RF* to perform the calculation.

Depending on the age of the well, the practical application of this method may look different. For a newly drilled well, an EOR pilot program may be carried out immediately to determine S_{orm} before the well even begins its life as a conventional oil producer. Once this endpoint oil saturation is known, a reserves estimator can calculate the *EUR* of the well using Equation 14. This, of course, assumes that the cost of EOR does not exceed the net profit generated from the improved oil recovery.

A more likely scenario is one in which a conventional oil producer has been on production for several years and for which an *EUR* has already been calculated (e.g., via the conventional *RF* method shown in Equation 5 or via the SWCTT method described by Equation 8). In this scenario, the existing *EUR* will likely have been calculated assuming that the economic limit will be reached during waterflooding. A One-Spot pilot may be used to show the difference in *EUR* between the waterflood-only and EOR scenarios. The amount of additional reserves achievable through EOR would be calculated as the difference between the two *EUR* estimates:

$$Additional\ Reserves = EUR_{EOR} - EUR_{waterflood} \tag{18}$$

More precisely, this would be calculated by:

$$Additional\ Reserves = 7758\frac{Ah\varphi}{B_{oi}}[(1 - S_{wi} - S_{orm}) - RF \cdot (1 - S_{wi})] \tag{19}$$

Again, an economic analysis would need to be conducted to ensure that the additional reserves could generate enough net profit to justify pursuing the EOR program.

Field Total	Oil	Gas	Water
	(MSTB)	(MMSCF)	(MSTB)
Cumulative Production	98994	29699	1026e3
Cumulative Injection	NA	0	0
Cumulative Gas Lift	NA	0	NA
Cumulative Water Influx	NA	NA	1130e3
Current Fluids In Place	110331	33099	322343
Production Rates	.29866	.08960	74.701
Injection Rates	NA	0	0

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Field Total	Oil	Gas	Water	Solvent	Polymer	Seawater
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MSTB)
Cumulative Production	131809	158249	841041	NA	NA	NA
Cumulative Injection	NA	179898	0	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Water Influx	NA	NA	936602	NA	NA	NA
Current Fluids In Place	77692	84327	313904	NA	NA	NA
Production Rates	.41943	1.2531	74.581	NA	NA	NA
Injection Rates	NA	0	0	NA	NA	NA