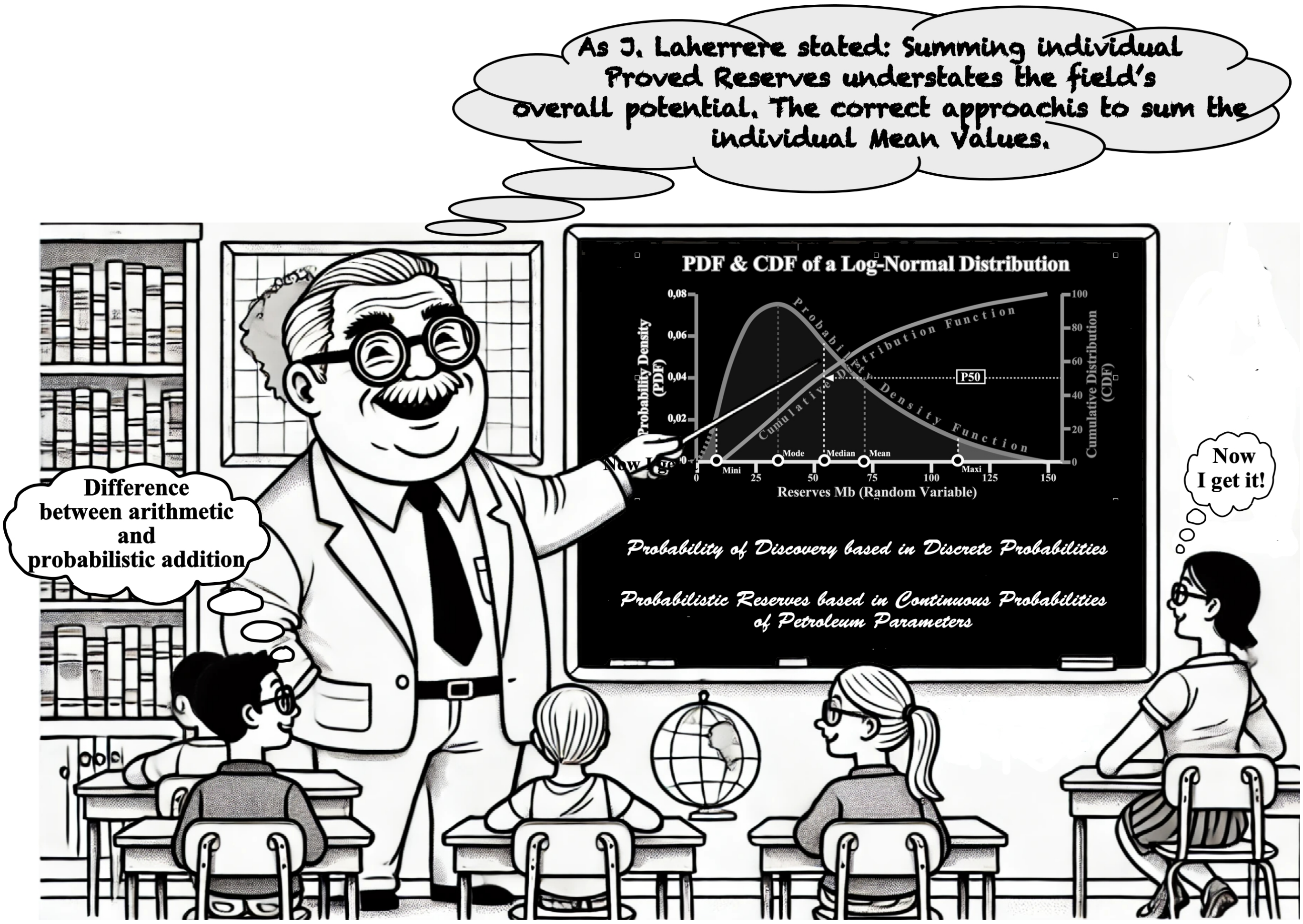
Chance and Certainty: Assessing Volumetric Probabilities in Petroleum Exploration"



Ccramez, 2024

Abstract:

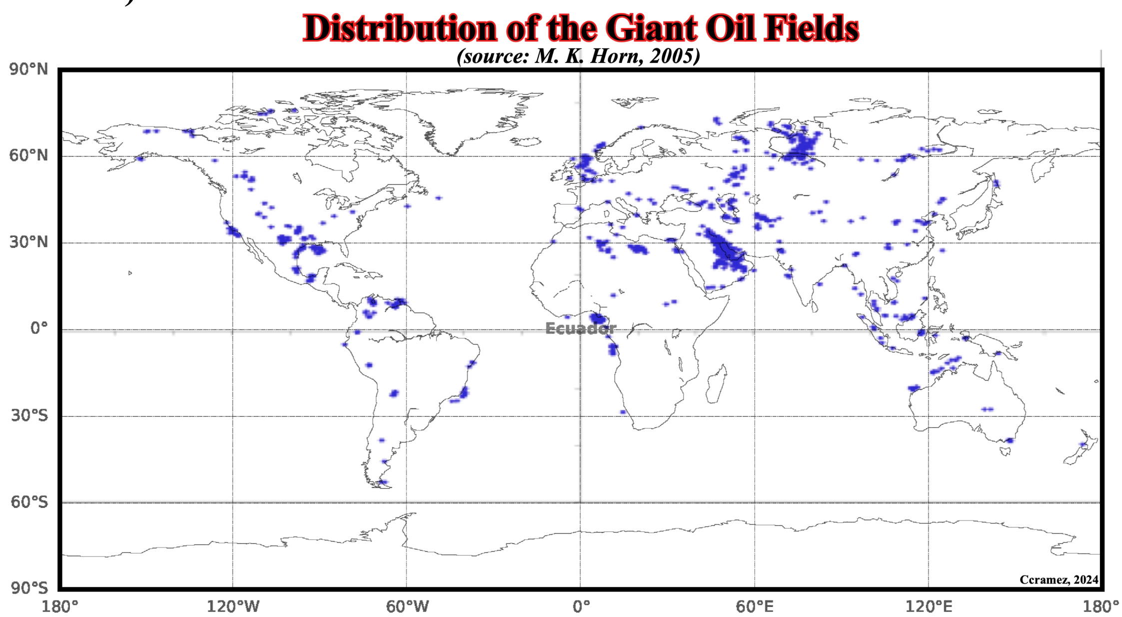
Probabilities of Hydrocarbon Discovery
and
Discovered Volume Uncertainty

The probability of hydrocarbon discovery, also known as the geological probability, corresponds to the likelihood of encountering hydrocarbons in a prospect located, generally, within a hydrocarbon-bearing sedimentary basin, all of which are practically known. This probability focuses on the binary outcome of exploration, i.e. success (hydrocarbon discovery) or failure (a dry well).

This concept is fundamentally different from the probability of the discovered volumes, which refers to the uncertainty in the amount of hydrocarbons that could be discovered, if a discovery were to occur. While the probability of discovery addresses the likelihood of finding hydrocarbons compared to the drilling dry wells, the probability of the discovered volume focuses on the potential variability in the size of the resource. The latter concept is critical in assessing the commercial viability of a prospect, as the size and quality of the discovery directly influence its economic potential.

A) Probabilities of Hydrocarbon Discovery

There are over 800 sedimentary basins in the Earth's crust. Of these, only 226 have been identified as oil and gas basins. These basins collectively host about 50000 oil and gas fields, with proven reserves estimated at about 150 Gt (giga tonnes) of oil equivalent (a standardised measure that includes for both oil and gas reserves). This is equivalent to about 1,1 Tb (terabarrels, where 1 Tb = 10^{12} barrels of oil).



As shown in the map of giant field distribution (figure above), the Northern Hemisphere, particularly regions such as the Middle East, Western Siberia, the North Sea and the Gulf Coast, has a high concentration of giant fields. In contrast, the Southern Hemisphere, which has fewer sedimentary basins overall, has significantly fewer giant fields.

From a geological perspective, foredeep sedimentary basins and Atlantic-type divergent margins, associated with rift-type basins, appear to be the most prolific geological environments for giant field formation. These geological settings provide the necessary conditions for significant hydrocarbon accumulation, including adequate source rocks, reservoirs and trapping mechanisms.

In any given oil and gas-bearing sedimentary basin, the subsurface geological conditions vary widely, and this variability means that identifying areas with significant hydrocarbon potential requires a detailed evaluation of critical geological factors.

Within a petroleum sedimentary basin, geoscientists typically begin their evaluation of prospective hydrocarbon opportunities by considering five key parameters:

1) ***Source Rock:*** **The presence of organic-rich rocks that produce hydrocarbons under suitable thermal conditions.**

2) ***Reservoir Rock:*** **Rocks with sufficient porosity and permeability to store and transmit hydrocarbons.**

3) ***Trapping:*** **Geological structures or stratigraphic features capable of accumulating hydrocarbons.**

4) ***Migration:*** **The movement of hydrocarbons from the source rock to the reservoir rock.**

5) ***Retention:*** **The ability of the trap to prevent hydrocarbons from escaping over geological time.**

Evaluation of these factors helps geoscientists identify the most promising areas for hydrocarbon exploration. However, due to the inherent uncertainty in subsurface data, probabilistic assessments play a crucial role even at this early stage. Probabilities in this context, are discrete probabilities. They refer to the likelihood of certain outcomes occurring in a discrete probability distribution, where the possible outcomes are distinct and countable. Unlike continuous probabilities (which deal with ranges or intervals of values, as we will see in probabilistic reserve estimation), discrete probabilities focus on finite or countable sets of outcomes. The main characteristics of discrete probabilities are:

➡ ***Countable Outcomes:***

The possible outcomes are finite or can be listed (rolling a die, flipping a coin).

➡ ***Assigned Probabilities*:**

Each outcome is assigned a probability, and the sum of all probabilities equals 1 (100% certainty that one of the outcomes will occur).

➡ ***No Intervals between Outcomes*:**

Unlike continuous probabilities, discrete probabilities do not consider intermediate values between outcomes.

➡ ***Calibration of Probabilities*:**

Based on empirical studies and standard conventions, discrete probabilities can be categorised as:

Certainty	**means ≥**	**0,99 probability**
Very likely	**approximately**	**0,90 probability**
Likely	**approximately**	**0,70 probability**
No preference	**(don't know)**	**0,50 probability**
Inlikely	**approximately**	**0,30 probability**
Very unlikely	**approximately**	**0,10 probability**
Excluded	**means ≤**	**0,01 probability**

NB- In the oil industry, reporting any data with more than two significant digits is statistically incorrect because the accuracy of the reported values varies by more than 10% and shows the author's incompetence.

Examples of Discrete Probability:

☑ **Rolling a Die:**

- ➡ **Possible outcomes: 1, 2, 3, 4, 5, 6.**
- ➡ **Each outcome has an equal probability of ⅙ or ≈ 16,6 %.**

☑ **Flipping a Coin:**

- ➡ **Possible outcomes: Heads, Tails.**
- ➡ **Each outcome has a probability of 0,5 if the coin is fair.**

☑ **Hydrocarbon Presence in a Basin or Prospect:**

- ➡ **Possible outcomes for each parameter (e.g. source rock, reservoir rock, trap, migration, retention) either "present" or "absent," with probabilities based on geological evidence.**

To assess the likelihood of finding hydrocarbons in a sedimentary basin or prospect, geoscientists use discrete probabilities for each critical parameter of the petroleum system, such as source rock, reservoir rock, trap, and so on. Each para-

meter represents an event with its own probability of occurrence. These probabilities are usually assumed to be independent, meaning that the presence or absence of one parameter does not directly affect the others.

Because these probabilities are independent, they are multiplied to calculate the overall probability of hydrocarbon occurrence. Multiplication is used because the overall probability depends on all the necessary conditions occurring simultaneously. In probability theory, the joint probability of independent events is the product of their individual probabilities.

If the probability of having a source rock is P(A) = 0,5 and the probability of having a reservoir rock is P(B) = 0,7, then the probability of having both a source rock and a reservoir rock is:

$$P(A \cap B) = P(A) \times P(B) = 0{,}5 \times 0{,}7 = 0{,}35\ (35\%).$$

This approach ensures that the overall probability reflects the requirement that all conditions must be present for hydrocarbons to accumulate. Adding probabilities, by contrast, would imply that any single parameter being present is sufficient, which is not the case in hydrocarbon exploration. Even with a perfect trap, hydrocarbons cannot accumulate without a source rock.

Therefore, the multiplication of probabilities is the correct method to take into account the dependence on the simultaneous fulfilment of all the necessary conditions for the development of a petroleum system.

B) Calculation of Hydrocarbon Discovery Probabilities

Suppose that for a given oil prospect, the discrete probabilities for the key exploration parameters have been evaluated in the following as:

Parameter	Value	Unit	Description
Area (A)	25	km²	The mapped area of the reservoir
Gross-Thickness (h)	20	m	The total vertical thickness of the reservoir
Net to Gross Ratio (N/G)	0,8	(unitless)	The proportion of the gross thickness that contributes to hydrocarbon storage
Porosity (φ)	0,20	(fraction)	The proportion of the reservoir rock that consists of pore spaces
HC Saturation (S_h)	0,75	(fraction)	The proportion of pore space filled with hydrocarbons (oil or gas)
Formation V- Factor (FVF)	1,2	(unitless)	The ratio of reservoir conditions to surface conditions for hydrocarbons
Recovery Factor (RF)	0,30	(fraction)	The proportion of hydrocarbons that can be produced from the reservoir

- **Source Rock: 0,5 probability**

  (the likelihood that sufficient organic-rich rock is present).

- **Reservoir Rock: 0,7 probability**

  (the likelihood of suitable storage and flow properties in the rock).

- **Trap: 0,90 probability**

  (the likelihood of a geological structure or feature capable of trapping hydrocarbons).

- **Migration: 0,7 probability**

  (the likelihood that hydrocarbons have migrated from the source to the reservoir).

- **Retention: 0,8 probability**

  (the likelihood that the trap has successfully retained hydrocarbons over time).

The overall probability of hydrocarbon occurrence is calculated by multiplying these individual discrete probabilities, as the petroleum parameters considered are independent:

$$0{,}5 \times 0{,}7 \times 0{,}9 \times 0{,}7 \times 0{,}8 =$$

$$= 0{,}17 \text{ or } 17\%$$

This approach highlights the importance of carefully assessing each factor and understanding how small changes in one parameter can significantly affect the overall probability.

C) Discovered Volume Uncertainty

In this chapter, we focus on the evaluation of hydrocarbon reserves, acknowledging that the two distinct methods for assessing the reserves of a prospect or field - deterministic and probabilistic - serve complementary roles in the process.

These methods are integral to accurately estimating reserves and supporting informed decision-making.

C.1) Deterministic Approach

The deterministic method is often used as a preliminary approach to estimating the amount of recoverable hydrocarbons.

In this method, geoscientists assign single, fixed values to key reservoir parameters such as (i) Area, (ii) Gross Thick-ness, (iii) Net to Gross Ratio, (iv) Porosity, (v) Hydrocarbon Saturation, (vi) For-mation Volume Factor (FVF) and (vi) Recovery, which values are typically derived from geological data, geophysical surveys and analogs from nearby fields.

This approach provides a single point estimate that is useful for gaining a rough understanding of potential reserves. However, because it does not account for variability or uncertainty in the input parameters, the deterministic method can oversimplify the complexity of subsurface conditions.

Example of Deterministic Reserves Evaluation

(i)- Reservoir Volume (Bulk Volume or BV):

The total physical volume of a reservoir rock, including both pore spaces and the solid matrix. It is typically expressed in cubic metres (m^3) or barrels and represents the gross volume of the reservoir.

$$BV = A \times h =$$
$$= 25\ km^2 \times 20\ m =$$
$$= 500\ M.m^3$$

(ii) Net Reservoir Volume (NRV):

The portion of the bulk volume of a reservoir that consists of rock with sufficient porosity and permeability to store and transport hydrocarbons. It excludes non-productive zones and is typically expressed in cubic metres (m^3) or barrels.

$$NRV = BV \times N/G =$$
$$= 500\ M.m^3 \times 0{,}8 =$$
$$= 400\ M.m^3$$

(iii) Pore Volume (PV):

The total volume of all the pore spaces within the reservoir rock, representing the space available to store fluids (hydrocarbons, water, or gas). It is calculated as the product of the bulk volume and the porosity of the reservoir and is typically expressed in cubic meters (m^3) or barrels.

$$PV = NRV \times \phi =$$
$$= 400\ M.m^3 \times 0{,}20 =$$
$$80\ M.m^3$$

(iv) Hydrocarbon Pore Volume (HCPV):

The portion of the pore volume within a reservoir that is filled with hydrocarbons, excluding water or other fluids. It is calculated as the product of the pore volume and the hydrocarbon saturation and is typically expressed in cu-bic meters (m^3) or barrels.

$$HCPV = PV \times Sh =$$
$$= 80\ M.m^3 \times 0{,}75 =$$
$$= 60\ M.m^3$$

(v) Stock Tank Oil Initially in Place (STOIIP):

The total volume of oil estimated to exist in a reservoir initially, at standard surface conditions (stock tank conditions). It is calculated using the reservoir's bulk volume, porosity, hydrocarbon saturation, and a formation volume factor that accounts for the reduction in volume as oil is brought to the surface. It is typically expressed in barrels (STB) or cubic meters (m^3).

STOIIP = FVF x HCPV=

= 1260 $M.m^3$ =

= 50 $M.m^3$

(vi) Recoverable Reserves (RR):

The portion of hydrocarbons initially in place (oil or gas) that can be technically and economically recovered using current technology and operational practices. It accounts for recovery efficiency and is typically expressed in bar-rels (for oil) or cubic meters (for gas).

RR = STOIIP × RF (recovery factor) =

= 50 $M.m^3$ × 0,30 =

= 15 $M.m^3$ of oil

Thus, using the deterministic method, the recoverable reserves for this reservoir are estimated to be:

15,0 $M.m^3$ or 94,5 Mb of oil
(assuming that 1 m^3 = 6,3 barrels).

C.2) Probabilistic Approach

As exploration progresses and more data becomes available, a more robust and realistic probabilistic approach becomes essential. This method accounts for the inherent uncertainty in subsurface parameters by assigning probability distributions to each variable rather than relying on single point estimates.

C.2.1) Key Concepts

☑ Parameter Distributions

- ✳ Surface Area: Might follow a triangular or normal distribution.
- ✳ Porosity: Defined by Mini, Mode, and Maxi values.
- ✳ Net-to-Gross Ratio: Varies due to geological heterogeneity.

☑ Combining Distributions

Using tools such as Monte Carlo simulations, these probability distributions are combined to calculate a range of possible hydrocarbon reserve outcomes. The results are typically expressed as:

- **P10: The optimistic case (10% chance of exceeding the associated reserves).**
- **P50: The most likely case (50% chance of exceeding the associated reserves).**
- **P90: The conservative case (90% chance of exceeding the associated reserves).**

C.2.2) Transition from Discrete to Continuous Probabilities

a) Discrete Probabilities

- ☑ **Used in earlier stages of exploration to estimate the probability of binary outcomes, such as**
  - **Is the source rock present? (Yes / No)**
  - **Have hydrocarbons migrated? (Yes / No)**
- ☑ **The probabilities are multiplied to estimate the overall probability of hydrocarbons being present.**

b) Continuous Probabilities:

- ☑ **Used in detailed reserve evaluations where parameters such as area, thickness, porosity, hydrocarbon saturation, etc. are treated as ranges.**
- ☑ **Normal, triangular or log-normal distributions, the ranges of which are modelled using probability density functions (PDFs).**

c) Example:

Rather than asking a discrete probability question such as *"Is the reservoir rock present?"*, geoscientists often explore continuous probabilities to better understand the variability of reservoir properties. For example, they ask:

"What is the probable thickness of the reservoir?"

"What is the probable porosity?"

Each parameter is represented as a Probability Density Function (PDF), which quantifies the range of possible values and their probability. This approach allows geoscientists to model and incorporate the inherent uncertainty of geological properties, providing a more nuanced understanding of the reservoir characteristics.

C.2.3) Monte Carlo Simulation

A Monte Carlo Simulation generates thousands of possible scenarios by randomly sampling values for each parameter based on their probability distributions.

There are different steps in Monte Carlo Simulation:

a) Define Input Distributions

➡ **Assign Mini, Mode, and Maxi values to each parameter.**

➡ **Convert these into a log-normal distribution:**

☑ **Mean (μ) in log space =**

ln(Mode)

☑ **Standard Deviation (σ) in log space =**

Parameter	Mini	Mode	Maxi	Log Mean (μ)	Log Std Dev (σ)
Surface Area (km²)	10	50	100	ln(50) = 3,91	0.49
Porosity (%)	0.10	0.20	0.25	ln(0,20) = −1,61	0.30

[ln(Maxi) − ln(Mini)] ÷ (2 × 1,645)

(The term 2×1.645 in the formula refers to statistical confidence intervals in a normal distribution, specifically within the context of lognormal distributions)

Example Conversion:

Parameter	Range	Most Likely	Probability Distribution
Surface Area (km²)	10 to 100	50	Symmetric Gaussian-like
Reservoir Thickness (m)	10 to 50	30	Symmetric Gaussian-like
Net-to-Gross Ratio (fraction)	0,6 to 0,9	0,75	Right-skewed (favoring higher values)
Porosity (fraction)	0,1 to 0,25	0.2	Symmetric Gaussian-like
HC Saturation (fraction)	0,6 to 0,9	0,75	Right-skewed (favoring saturations)
Formation V Factor (ratio)	1 to 2	1,2	Slightly left-skewed

b) Generate Random Samples

Parameter	Mini	Mode	Maxi
Surface Area (km²)	10	15	25
Gross Thickness (m)	60	70	85
Net to Gross Ratio	0,80	0,85	0,90
Porosity	0,12	0,15	0,20
HC Saturation	0,70	0,75	0,80
Formation V. Factor	0,60	0,62	0,65

➡ Use random sampling (e.g., Python's `numpy`) to simulate values for each parameter.

Reservoir Parameter Ranges and PDFs

c) Calculate Oil in Place

➡ Apply the volumetric equation:

$$\text{Oil in Place} = 7758 \times A \times h \times [(N/G \times \phi \times Sh) \div FVF]$$

(7750 is the constant of convertion the reservoir rock volume into stock tank barrels (STB)

d) Repeat for Many Iterations

➡ Run **10000 iterations or more to capture the full range of variability.**

e) Aggregate Results

➡ Analyse the results to derive P90, P50, and P10 estimates.

C.2.4) Analytical Methods

Overview:

Analytical methods directly calculate the parameters of the output distribution directly, without random sampling. These are faster than Monte Carlo simulations for log-normal distributions.

Steps in Analytical Methods:

a) Define Input Distributions

➡ Assume all parameters follow log-normal distributions.

b) Combine Distributions Mathematically

➡ The product of independent log-normal variables is itself log-normal.

➡ Compute:

Mean (μ) :

$$\mu = [\ln(Mini) + \ln(Maxi)] \div 2$$

Variance (σ^2):

$$\sigma^2 = [\{ \ln(Mini) + \ln(Maxi) \} \div \ln 2] - \ln(Mode)$$

c) Output Parameters:

➡ Directly calculate the Mean, Variance and Mode of the log-normal distribution.

e) Example Calculation

The following assumptions and steps are used to calculate the probability distribution for oil in place:

1- Parameter Distributions

- ➡ Each parameter (e.g. area, thickness, porosity) is modelled as an independent variable with a lognormal distribution.
- ➡ The lognormal distribution reflects the positive and multiplicative nature of reservoir parameters (values cannot be negative).

2- Mini-Mode-Maxi Values for Each Parameter

3- Lognormal Law for Total Oil in Place

- ➡ The product of independent lognormal variables is itself lognormal.
- ➡ The Mode of the product is calculated as the product of the Mode values of the parameters:

Parameter	Mini	Mode	Maxi
Area (km²)	10	50	100
Thickness (h)	10	30	50
Net-to-Gross (N/G)	0,75	0,85	0.90
Porosity (ϕ)	0,1	0,2	0,25
Saturation (Sh)	0,6	0,75	0,9
Formation Volume Factor (FVF)	1,2	1,4	2

Mode $_{\text{(Oil in Place)}}$ =

[Mode (A) × Mode (h) × Mode (N/G) × Mode (ϕ) × Mode (S_h)] ÷ Mode (FVF)

4- Full Lognormal Distribution:

A Monte Carlo simulation or analytical method is used to calculate the full distribution of oil in place, including Mini, Mode and Maxi values for each parameter.

a) Mode Calculation:

Mode (Oil in Place) =

$$= (50 \times 30 \times 0,75 \times 0,2 \times 0,75) \div 1,4 \approx$$

$$\approx 161 \text{ Mb (STB)}$$

b) Log-Normal Parameters:

$$\mu = [\ln(2327,4) + \ln(3920375)] \div 2 = 11,47$$

$$\sigma^2 = 11,47 - \ln(93162,6) = 0,03$$

$$\sigma = \sqrt{0,03} = 0,173$$

c) Mean Reserves:

$$\text{Mean (Oil in Place)} = e^{\mu+[(\sigma 2)\div 2]} =$$

$$= 97{,}626 \text{ Mb (STB)}$$

In summary, the probabilistic approach provides:

- ☑ **A comprehensive view of reserve uncertainty with P90, P50, and P10 values.**
- ☑ **Tools for risk-based exploration and decision-making under uncertainty.**
- ☑ **Optimisation of exploration and development strategies.**

By moving from deterministic to probabilistic methods, companies gain a deeper understanding of the risks and rewards associated with hydrocarbon exploration.

C.2.5) Comparison of Methods

➡ **The analytic methids are faster than Monte Carlo simulations and provides direct parameters for the output distribution.**

Aspect	Monte Carlo Simulation	Analytical Method
Complexity	Computationally intensive	Requires mathematical derivation of distribution
Flexibility	Can handle any type of input distribution	Assumes specific input distributions (e.g., log-normal)
Output	Simulated data and full empirical distribution	Parameters of the resulting distribution
Applications	Preferred when input distributions are non-standard or complex	Ideal for cases where input variables are log-normal

C.3) Reserves Assessment Using Log-Normal Distributions

Since the product of independent log-normal distributions is itself a log-normal distribution, the probability distribution of oil in place can be calculated by multiplying the relevant petroleum parameters. These parameters are assumed to be independent and are defined by their Mini, Mode, and Maxi values, which are calibrated to follow a log-normal distribution.

It is important to note that while the Mode of the resulting distribution is derived by multiplying the Mode values of the each parameter, this is not the case for the Mean or Variance, which require a different calculation approach.

Suppose the following set of hypothetical parameters, characterised by their Mini, Mode, and Maxi values, is used to calculate the probability distribution of oil in place for a hydrocarbon prospect.

The product of the Mini values (x) is 24, the product of the Mode values (y) is 62 and the product of the Maxi values (z) is ≈200, which allows the μ (Mean) and σ (Standard Deviation) to be calculated:

$$\mu \text{ (Mean)} = \tfrac{1}{2} (\text{Ln } x + \text{ Ln } z) = 4{,}24$$

$$\sigma^2 \text{ (Variance)} = \tfrac{1}{2} (\text{Ln } x + \text{Ln } z) - \text{Ln } y = 0{,}10$$

$$\sigma \text{ (Standard Deviation)} = 0{,}31$$

The Mean (μ) and the Standard Deviation (σ) of the lognormal distribution are very well approximated by Bourdeaire's two rules of thumb:

$$\mu \text{ (Mean)} = \tfrac{1}{3} (\text{Mini + Mode +Maxi})$$

$$\sigma \text{ (Standard Deviation} = \tfrac{1}{3} (\text{Maxi - Mini})$$

Using the above reservoir parameters, let's look at a hypothetical example:

Step 1: Calculate Mini, Mode, and Maxi Reserves

Volumetric Equation

$$\text{Oil in Place} = 7758 \times A\times h \times [(N/G\times\phi\times Sh) \div FVF]$$

(7750 is the constant of convertion the reservoir rock volume into stock tank barrels (STB)

1.1) Mini Reserves:

$$\text{Mini} = 7758 \times 10 \times 60 \times [(0{,}8 \times 0{,}12 \times 0{,}7) \div 0{,}65]$$

$$\text{Mini} = 7758 \times 10 \times 60\times (0{,}0672 \div 0{,}65) =$$

$$= 7758 \times 10 \times 60 \times 0{,}1034 =$$

$$= 48164{,}6 \text{ Mb STB} =$$

48164,6 Mb Stock Tank

1.2) Mode Reserves:

$$\text{Mode} = 7758 \times 15 \times 70 \times[(0{,}85 \times 0{,}15 \times 0{,}75) \div 0{,}62)]$$

$$\text{Mode} = 7758 \times 15 \times 70\times (0{,}095625 \div 0{,}62) =$$

$$= 7758 \times 15 \times 70 \times 0{,}1541 =$$

$$= 126473{,}2 \text{ Mb STB} =$$

126473,2 Mb Stock Tank

1.3) Maxi Reserves:

$$\text{Maxi} = 7758 \times 25 \times 85 \times [(0{,}9 \times 0{,}20 \times 0{,}8) \div 0{,}60]$$

$$\text{Maxi} = 7758 \times 25 \times 85 \times (0{,}144 \div 0{,}60) =$$

$$7758 \times 25 \times 85 \times 0{,}24 =$$

3971880,0 Mb STB

Step 2: Calculate Log-Normal Parameters

2.1) Natural Logarithms

$$\ln(\text{Mini}) = \ln(48164{,}6) = 10{,}78$$

$$\ln (\text{Mode}) = \ln(126473{,}2) = 11{,}75$$

$$\ln(\text{Maxi}) = \ln(3971880{,}0) = 15{,}19$$

2.2) Mean (μ) in Log Space:

$$\mu = \tfrac{1}{2}\,[(\ln(\text{Mini}) + \ln(\text{Maxi})]]$$

$$\mu = \tfrac{1}{2}\,(10{,}78 + 15{,}19) =$$

$$= 12{,}99$$

2.3) Variance (σ²) in Log Space:

$$\sigma^2 = \tfrac{1}{2}\,[(\ln(\text{Mini}) + \ln(\text{Maxi})] - \ln(\text{Mode})$$

$$\sigma^2 = 12{,}99 - 11{,}75 =$$

$$= 1{,}24$$

2.4) Standard Deviation (σ):

$$\sigma = \sqrt{\sigma^2} = \sqrt{1{,}24} =$$

$$= 1{,}11$$

Step 3: Calculate Mean and Mode Resrerves

3.1) Mean Reserves (log-normal mean):

$$\text{Mean}_{\text{(Oil in Place)}} = e^{\mu+(\sigma 2 \div 2)} = e^{12{,}99 + (1{,}24/2)} =$$

$$= e^{13{,}61} \approx 893110{,}76 \text{ Mb (Stock Tank Barrels)}$$

893110,76 Mb (STB)

3.2) Mode Reserves:

Mode (Oil in Place) = 126473,2 Mb (STB) =

= 126473,2 Mb (STB)

3.3) Standard Deviation:

$$\sigma = 1{,}11 \text{ (log space)} =$$

$$= 1{,}11$$

NB- Log space means that calculations are performed using the natural logarithm (ln) of the values, rather than the values themselves. This approach is specific to distributions such as the log-normal distribution, which assumes that the logarithm of the variable (e.g. oil in place) is normally distributed.This example shows how Mini, Mode and Maxi values are combined to analytically compute a log-normal distribution for reserves.

Executive Summary

(i) The probabilistic approach is essential because it provides a more accurate and realistic assessment, especially when making decisions under uncertainty.

(ii) Unlike the deterministic method, which provides a single estimate, the probabilistic approach gives decision makers a comprehensive view of the potential risks and rewards:

a) Assess the likelihood of success or failure.

b) Evaluate potential economic outcomes.

c) Optimise exploration and development strategies.

(iii) By moving from a deterministic to a probabilistic framework, companies can better navigate the complexities of hydrocarbon exploration and make decisions that are consistent with their risk tolerance and strategic objectives.

Multi-Reservoirs or Multi-plays Scenario

In geological scenarios or exploration contexts involving multiple hydrocarbon-bearing zones (or reservoirs) within a single area, basin, or field, two main cases often arise: (i) Multi-plays and (ii) Multi-reservoir rocks.

(i) Multi-Plays

Refers to multiple hydrocarbon exploration opportunities within a sedimentary basin, often targeting different geological settings. Each "play" represents a unique combination of source rock, reservoir rock, trap, and migration pathway that has the potential to yield hydrocarbons. Examples include:

- ☑ **Different stratigraphic layers in a basin (e.g. shallow versus deep reservoirs).**
- ☑ **Plays in different geological formations with different depositional environments.**
- ☑ **Different trap types within the same area (e.g. structural traps and stratigraphic traps).**

(ii) Multi-Reservoir Rocks

Refers to the presence of multiple reservoirs (rock formations capable of storing hydrocarbons) within the same prospect or field. These reservoirs may located at:

- ☑ **Different stratigraphic levels (e.g. a field with oil in a sandstone reservoir at one depth and gas in a carbonate reservoir deeper down).**
- ☑ **Lateral compartments due to geological variations such as faults or lithological changes.**
- ☑ **Reservoir rocks separated by non-reservoir layers (e.g. shale or tight carbonates acting as a barrier between stacked reservoirs).**

In such contexts, geoscientists must avoid penalising the expected total reserves by simply summing the proved reserves of each reservoir or field when estimating total reserves, because the proved value (P90, representing the conservative estimate with a 90% probability of being met or exceeded) of total reserves is not equal to the sum of the proved values for each individual reservoir or play.

In fact, when assessing total reserves in a multi-play field or across multiple reservoirs, it is important to understand that the sum of individual Proved Reserves understates the total potential of the field. This is because each reservoir or field has its own probability distribution and the summation of P90 values does not reflect the probabilistic nature of the whole system, which includes contributions from less conservative (but still realistic) outcomes.

To obtain a more accurate and representative estimate of expected recoverable reserves, the correct approach is to sum the Means (expected values slightly above the P50) of each reservoir or play. Mean values incorporate the full range of possible outcomes for each reservoir and better capture the overall potential of the field by considering both high and low probabilities. Aggregate Proved Reserves underestimate total potential of an hydrocarbon accumulation not only because of the conservative nature of P90:

- **Proved Peserves are deliberately conservative estimates, often used for regulatory or financial reporting purposes. They are intended to represent the minimum level of reserves with a high degree of certainty.**

Reservoir	P90 (Conservative)	P50 (Median)	P10 (Optimistic)	Mean Reserves (Expected Value)
Reservoir 1	25	54	117	65
Reservoir 2	20	45	110	58
Reservoir 3	15	50	105	57
Reservoir 4	10	40	90	46
Reservoir 5	12	35	85	44
Reservoir 6	18	48	100	55

- **By aggregating these conservative estimates, the overall result is skewed towards the lower end of the potential range and excludes significant upside potential.**

This is not only due to the uncertainty of the estimates, but also to the possible independence of the reserves:

- **Each reservoir has its own geological characteristics and associated uncertainties. Simply summing the P90 values ignores the proba-**

bilistic interaction between the reservoirs, which could lead to a more favourable overall result.

To accurately assess expected recoverable reserves, the correct method is to sum the Mean of reserves from each reservoir or play. The Mean, often derived from probabilistic methods such as Monte Carlo simulations, represents the average outcome over the entire probability distribution and provides a realistic estimate of total recoverable reserves.

This approach takes into account both risk and upside potential, providing a more balanced and useful estimate for decision making:

- Investment Decisions

  Summing mean values provides a more realistic basis for planning exploration, development, and production activities.

- Portfolio Management

  In multi-country, multi-field or multi-reservoir scenarios, summing Proved Reserves can lead to overly cautious valuations, whereas summing Mean values allows better comparison and optimisation.

- Risk Assessment

  A probabilistic approach that considers the Mean provides a fuller understanding of potential risks and rewards.

Dice Game Analogy

An analogy with a game of dice may help to illustrate why summing the Mean values for each reservoir is the correct method of calculating the total expected reserves of a field. Imagine rolling a series of dice, each representing a reservoir with its own possible outcomes (analogous to its probability distribution).

- Each die produces a range of possible values, with the Mean value representing the average result over many rolls.
- If we focus only on the minimum guaranteed results (analogous to summing Proven Reserves or P90 values), we ignore the full range of possibilities and underestimate the overall potential.
- By summing the Meanvalues of all the dice, we get a more accurate picture of the overall expected outcome, which reflects the most likely overall outcome.

This analogy demonstrates that the summation of Mean values takes into account both risks and rewards and provides a balanced and realistic estimate of total recoverable reserves, rather than a conservative floor value.

- In petroleum geology, a "Proved" value is a high confidence estimate that represents the minimum result we can reasonably expect.

- Apply this concept to dice, if you like:

"What is the lowest number I can confidently expect to get?

The answer is not simply the lowest possible outcome (e.g. 1 for a standard six-sided die). Instead, it refers to a value that reflects a high probability of occurrence. This distinction highlights the difference between the absolute minimum outcome and a more likely or representative outcome based on probability.

- For example, on a single roll, you can be reasonably confident of getting a at least a 2, because the probability of rolling a 2 or higher is 5 out of 6 (about 83%).
- This makes 2 a conservative minimum, or "proven value". Although a 1 is possible, it's less likely, so 2 is a more reliable threshold.
- When rolling multiple dice, let's say six (6) as the number of petroleum parameters (see page 5), the cumulative "Proved" value will not simply add up to a simple multiple of the individual "Proved" values.
- If we roll 6 dice, simply summing the individual Proved values ($6 \times 2 = 12$) underestimates the likely cumulative result. Due to the reduced likelihood of each die rolling less than 2 at the same time, the cumulative Proved value for 6 dice could be higher, closer to 21, reflecting a more realistic minimum threshold.
- This adjusted cumulative Proved value takes into account the increased probability that at least some dice will roll above the individual threshold, and is therefore a better representation of a conservative floor in multi-reservoir scenarios.
- The "Expected" or Mean value is the average of all possible outcomes. For a single six-sided die, this is calculated as:

$$(1+2+3+4+5+6) / 6 =$$

$$= 3{,}5$$

- This is the average result of many dice throws and provides a balanced view of possible outcomes rather than a conservative minimum. In petroleum geology, the expected value represents the average expected reserves, taking into account all recovery options and their probabilities.
- For 6 dice, the Expected (Mean) value is:

$$6 \times 3{,}5 =$$

$$= 21$$

- This represents the typical outcome over many trials, in contrast to the Proved value, which represents a conservative minimum.

- The Proved value (6 x 2 = 12) is a conservative, probabilistic floor reflecting a high confidence minimum for reserves.
- Mean (Expected) value (6 x 3,5 = 21) is the average result over an infinite number of repetitions, providing a balanced view of possible outcomes.

These concepts help us to set realistic expectations and prepare for different scenarios when estimating oil reserves. By analysing probabilistic distributions across multiple reservoirs, we gain a clearer understanding of the range of total reserves and can make more informed planning decisions.

Methodoloy & Example of Probabilitic Reserve Evaluation

(Oil field with six reservoir rocks)

The P90, P50, and P10 values are derived from the Probability Distribution Function (PDF) of reserves for each reservoir. This distribution represents the probability of different reserve volumes based on geological, geophysical, and engineering data.

The specific steps to obtain these values are:

1- Data Collection and Analysis:

- Collect input data for key reservoir parameters (e.g. surface area, thickness, porosity, saturation, recovery factor).
- Define the range of possible values for each parameter, typically using minimum, most likely, and maximum estimates.

2- Probability Distribution:

- Assign a probability distribution to each parameter (e.g. triangular, normal, or log-normal) to reflect the uncertainty.
- Combine these distributions using Monte Carlo simulations or analytical methods to generate a PDF for the reserves.

3- Cumulative Probability:

Reservoir	Mean Reserves (Expected Value)	Standard Deviation (in Mb)
Reservoir # 1	65	20
Reservoir # 2	58	18
Reservoir # 3	57	20
Reservoir # 4	46	15
Reservoir # 5	44	
Reservoir # 6	55	17

- **Convert the PDF into a Cumulative Distribution Function (CDF), which shows the cumulative probability that the reserves are less than or equal to a given value.**
- **The Complementary Distribution Function (CCDF) shows the cumulative probability reserves being greater or equal to a given value.**

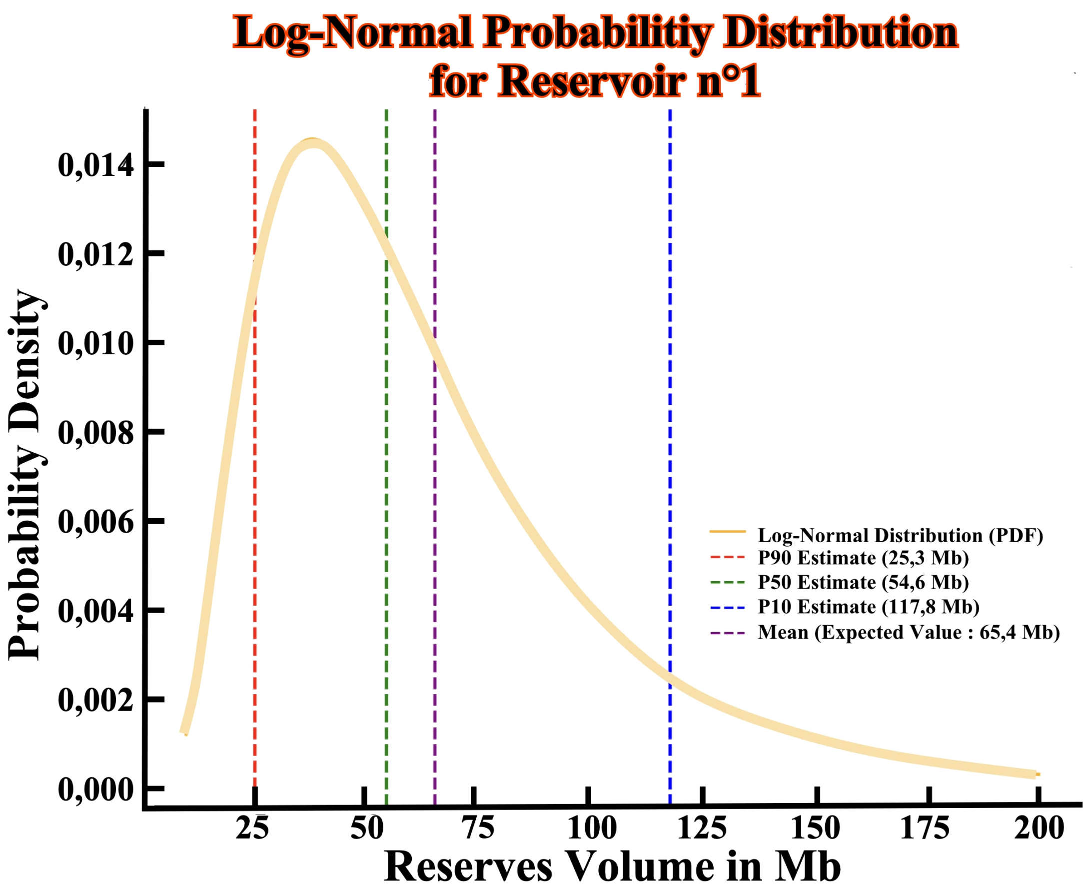
4- Extract Key Probabilities:

- **P90 (Proven): The volume that has a 90% probability of being met or exceeded.**
- **P50 (Median): The volume with a 50% probability, representing the most likely reserves.**
- **P10 (Optimistic): The volume with a 10% probability, representing the upper end of the stimate.**

Using the log-normal distribution, the reserves for each reservoir are expressed in terms of their P90, P50, and P10 values, with the Mean (Expected) reserves calculated from the distribution, as shown below:

For Reservoir #1, the Probability Distribution Function (PDF) shown in the next figure shows the reserve volumes corresponding to the P90, P50 and P10 values - 25.3 Mb, 54.6 Mb and 17.8 Mb respectively.

The P90, P50 and P10 values are derived from the Probability Distribution Function (PDF) of Reserves for Reservoir #1 shown in the figure below.



The P90 (conservative, red line) is approximately 25,3 Mb and represents a conservative estimate, with a 90% probability of meeting or exceeding this reserve volume.

The P50 (median, green line) is approximately 54,6 Mb and represents the median (most likely) estimate, with a 50% probability of meeting or exceeding this reserve volume.

The P10 (optimistic, blue line) is approximately 117,8 Mb and represents an optimistic estimate, with only a 10% probability of meeting or exceeding this reserve volume.

The Mean (expected value, purple line) is approximately 65,4 Mb and represents the expected value, which is the average of all possible reserves weighted by their probabilities and is the most useful value for decision making under uncertainty.

Since the P90, P50 and P10 values for each reservoir are used to fit a log-normal distribution, the log-normal parameters (log mean, μ, and log scale standard deviation, σ) can be determined. Once these parameters have been calculated, the standard deviation in linear space (σ) is derived using the formula:

$$\sigma = (e^{\sigma 2} - 1) \times e^{2\mu + \sigma 2}$$

where

σ is the shape parameter (the standard deviation in log space), and

μ is the log-mean (the mean in log space).

The aggregation of the reserves values (P90, P50, P10 and Mean) for all reservoir intervals (1 to 6) can is a s follows:

- ★ **P90 Total (Conservative Estimate):**

  Sum of P90 values: 25 + 20 + 15 + 10 + 12 + 18 =

  = 100 Mb

- ★ **P50 Total (Median Estimate):**

  Sum of P50 values: 54 + 45 + 50 + 40 +35 + 48 =

  = 272 Mb

- ★ **P10 Total (Optimistic Estimate):**

  Sum of P10 values: 117 + 110 + 105 + 90 + 85 + 100 =

  = 607 Mb

- ★ **Mean Total (Expected Value):**

  Sum of Mean Reserves: 65 + 58 + 57 + 46 + 44 + 55 =

  = 325 Mb

We can aggregate the mean reserve values of all the reservoirs and generate a corresponding Probability Distribution Function (PDF). To do this, we sum the mean reserves of all reservoirs (representing the expected value for each reservoir) and take into account the probabilistic contributions from each reservoir. This aggregation assumes that the reserves of individual reservoirs are independent and can be combined probabilistically to derive an overall distribution for the total reserves.

Assuming the reservoirs are independent, their means can be summed, and the aggregate uncertainty can be approximated using statistical methods.

Step1- Example Data for Individual Reservoirs

Total Mean Reserves:

$$T_{Mean}\ (65 + 58 + 57 + 46 + 44 + 55) =$$

$$= 325\ Mb$$

Step 2- Estimate Total Standard Deviation

2.1 - Input Data

From the example, the standard deviations of the individual reservoirs are:

$$\sigma_1 = 20,\ \sigma_2 = 18,\ \sigma_3 = 19,\ \sigma_4 = 15,\ \sigma_5 = 16,\ \sigma_6 =$$

$$= 17\ Mb$$

2.2 - Calculate Variance (σ^2) for Each Reservoir

$$\sigma_1^2 = 400,\ \sigma_2^2 = 324,\ \sigma_3^2 = 361,\ \sigma_4^2 = 225,\ \sigma_5^2 = 256,\ \sigma_6^2 =$$

$$= 289\ Mb$$

2.3 - Sum the Variances

$$\text{Total Variance} = \sigma_1^2 + \sigma_2^2 + \sigma_3^2 + \sigma_4^2 + \sigma_5^2 + \sigma_6^2$$

$$T_{\sigma^2} = 400 + 324 + 361 + 225 + 256 + 289 =$$

$$1855\ Mb^2$$

2.4 - Calculate the Total Standard Deviation

The standard deviation is the square root of the total variance:

$$\sigma_{total} = \sqrt{1855} \approx$$

$$\approx 43{,}07\ Mb$$

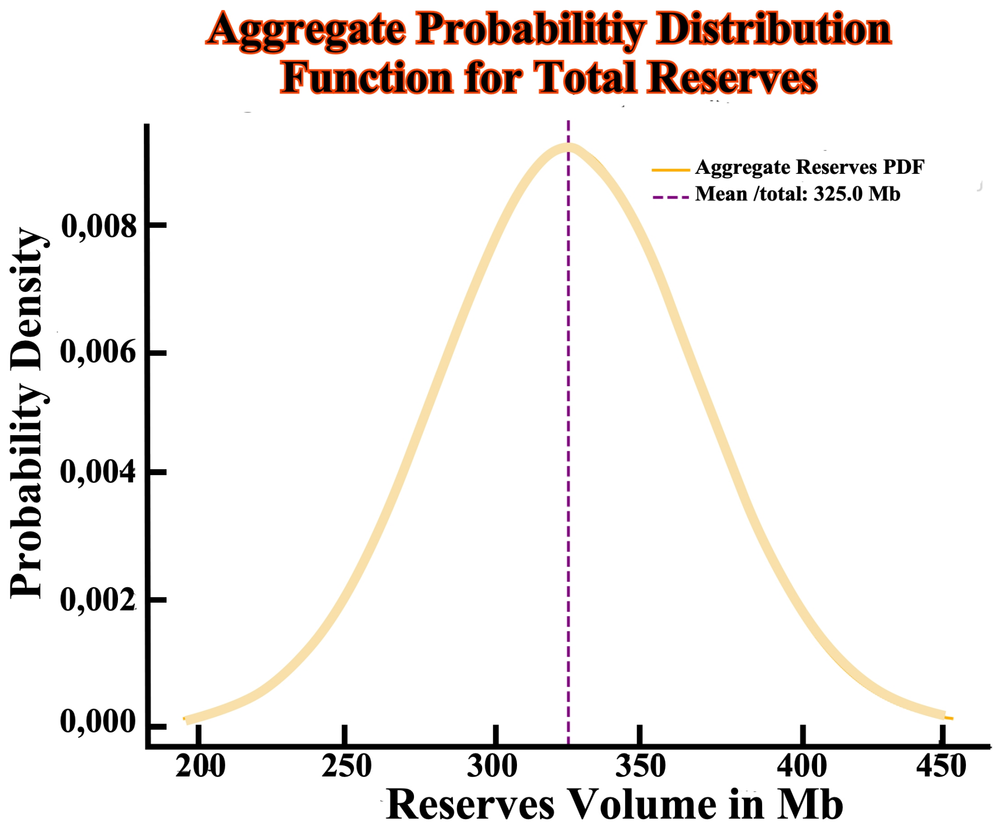
This calculation assumes the reservoirs are independent in terms of uncertainty. If dependencies exist (e.g. correlations between reservoirs), a more advanced method would be required.

Assuming independence, the total standard deviation can be approximated as:

$$\sigma_{total} = \sqrt{(\sigma_1^2 + \sigma_2^2 + \sigma_3^2 + \sigma_4^2 + \sigma_5^2 + \sigma_6^2)}$$

Step 3- Construct the Aggregate PDF

The aggregate reserves will follow an approximate normal distribution due to the Central Limit Theorem, as it's the sum of independent variables. We will now calculate and plot the aggregated PDF.



This Probability Density Function (PDF) provides a probabilistic estimate for the total recoverable reserves of the field:

☑ **Total Mean Reserves:**

$$R_{\text{Total Mean Reserves}} = 325 \text{ Mb}$$

☑ **Total Mean Reserves with Uncertainty:**

$$R_{\text{Total Mean Reserves with Uncertainty}} = 325 \pm 43{,}1 \text{ Mb}$$

(where the standard deviation σ is approximately 43,1 Mb).

Explanation:

- **The yellow curve (PDF) represents the aggregated uncertainty in the total reserves, under the assumption that the individual reservoirs are independent.**

- **The vertical purple line indicates the mean (expected value) of 325 Mb, which is calculated as the sum of the mean reserves of all individual reservoirs.**

- **The standard deviation (σ) quantifies the combined uncertainty from all reservoirs, resulting in the broader spread of the aggregate reserves distribution.**