Data Acquisition and Characterization

Reservoir Management | Data Acquisition and Characterization

Reservoir management requires a deep knowledge of the reservoir that can be achieved only through its characterization by a process of acquiring, processing and integrating several basic data.

In detail the main steps of this process are:

1.Data acquisition, involving the gathering of raw data from various sources, i.e.

- *Seismic surveys*
- *Well logs*
- *Conventional and special core analyses*
- *Fluid analyses*
- *Static and flowing pressure measurements*
- *Pressure-transient tests*
- *Periodic well production tests*
- *Records of the monthly produced volumes of fluids (oil, gas, and water)*
- *Records of the monthly injected volumes of IOR/EOR fluids (water, gas, CO2, steam, chemicals,…).*

2.Data processing based upon:

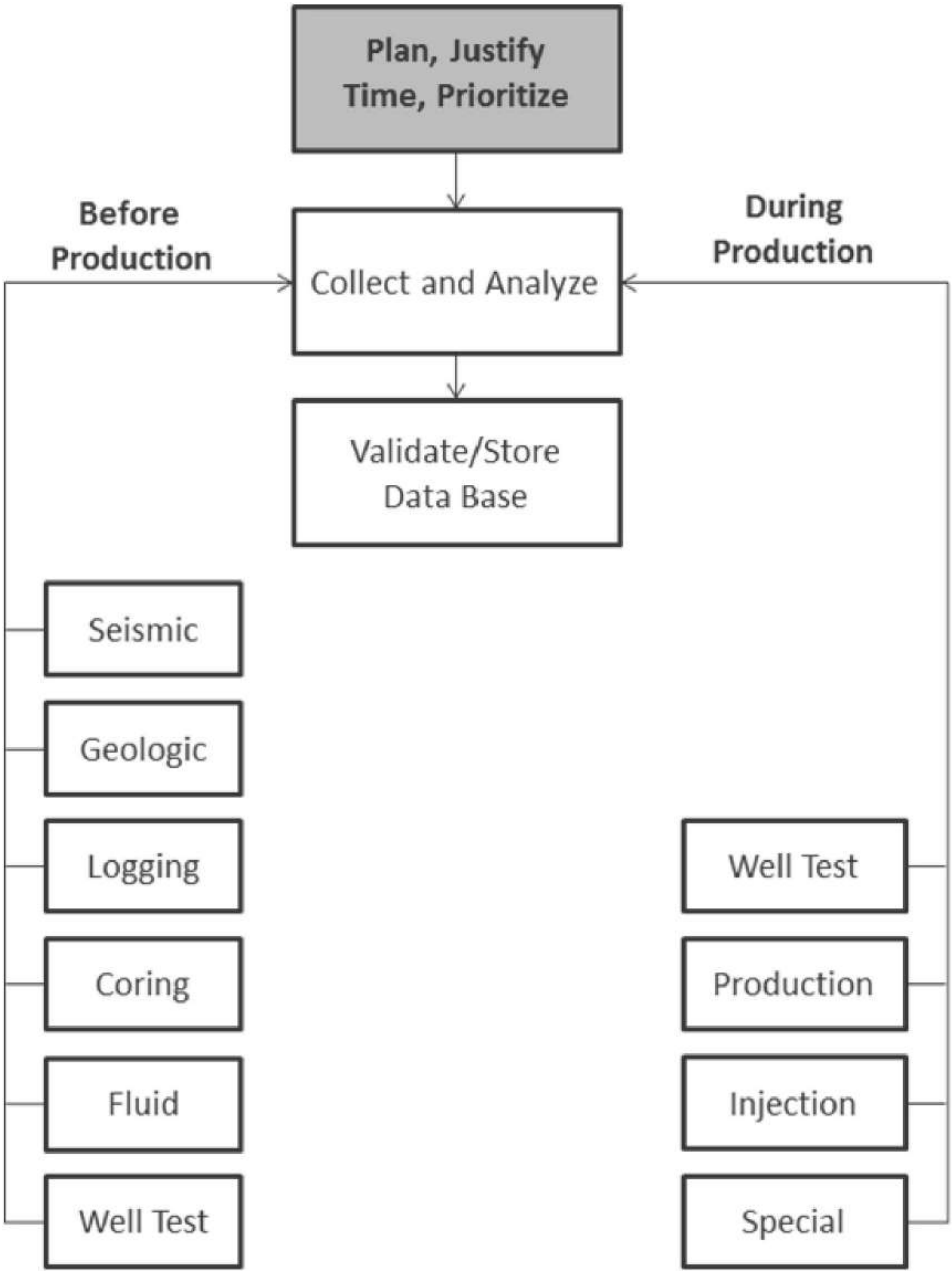
- *Seismic time maps*
- *Seismic conversion of time-to-depth maps*
- *Seismic attribute maps*

- *Log analyses*
- *Structural maps*
- *Cross sections*
- *Geologic models*
- *Reservoir fluids modeling (e.g. by EOS)*
- *Simulation models*

3.Data integration and Reservoir Characterization

The characterization of a reservoir aims at producing the best detailed geological reconstruction both of its geometry and of its internal structure. The overall process is, therefore, the first basic step in the development of a reservoir model, and it must consider all the available data, processed and interpreted with the best technologies always caring to be consistent with the observed historical reservoir performance.

Geophysical, geological, and engineering characterization provides also information on the initial distribution of the fluids, as well as on the hydraulic connectivity between different zones of the reservoir rocks.



Reservoir characterization aims at the detailed description of the reservoir

Typical information produced by the reservoir characterization process are for example:

- *Field and regional structure maps, including fluid-contact depth and shape and size of aquifers*

- *Isopach and porosity maps*
- *Flow units or individual producing zones; location of vertical and horizontal flow barriers*
- *Description of the depositional environment and evaluation of the effect of the diagenesis on rock transmissibility*
- *Variations in fluid saturations and permeabilities.*

The following activities are normally performed for the acquisition of the data required by the reservoir characterization.

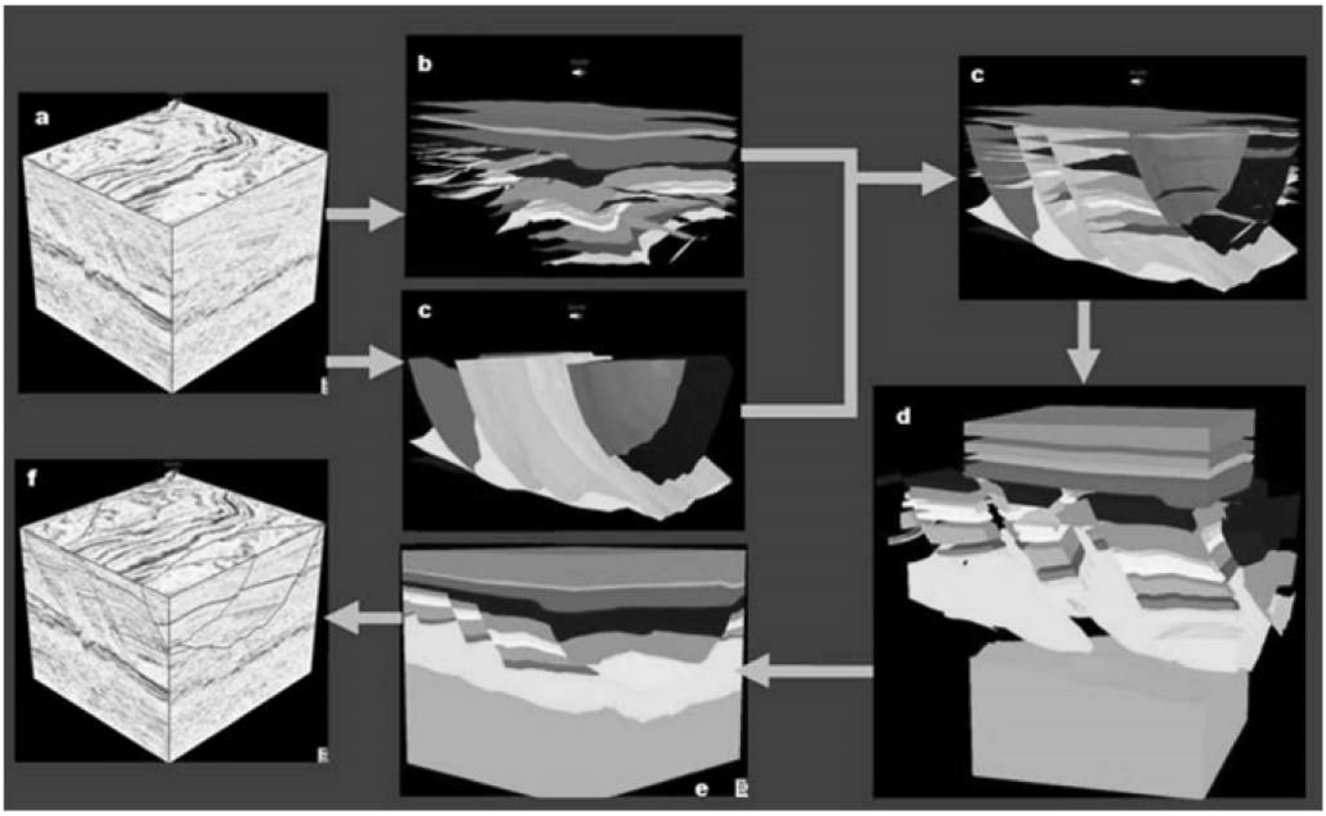
Seismic

Seismic data acquisition is fundamental for the definition of the reservoir architecture.

Seismic allows reconstructing the reservoir geological setting through different level observations:

- *On large scale: reservoir geometry, identification of main structural features (e.g. faults), , etc*
- *On small scale: detailed structural and stratigraphycal features, fluid contacts, etc.*

Seismic response of a reservoir depends on petro-acoustic properties of the volume of rock investigated; such properties can be obtained by the interpretation of specific field data.



From seismic to structural reservoir modeling

Well Logging

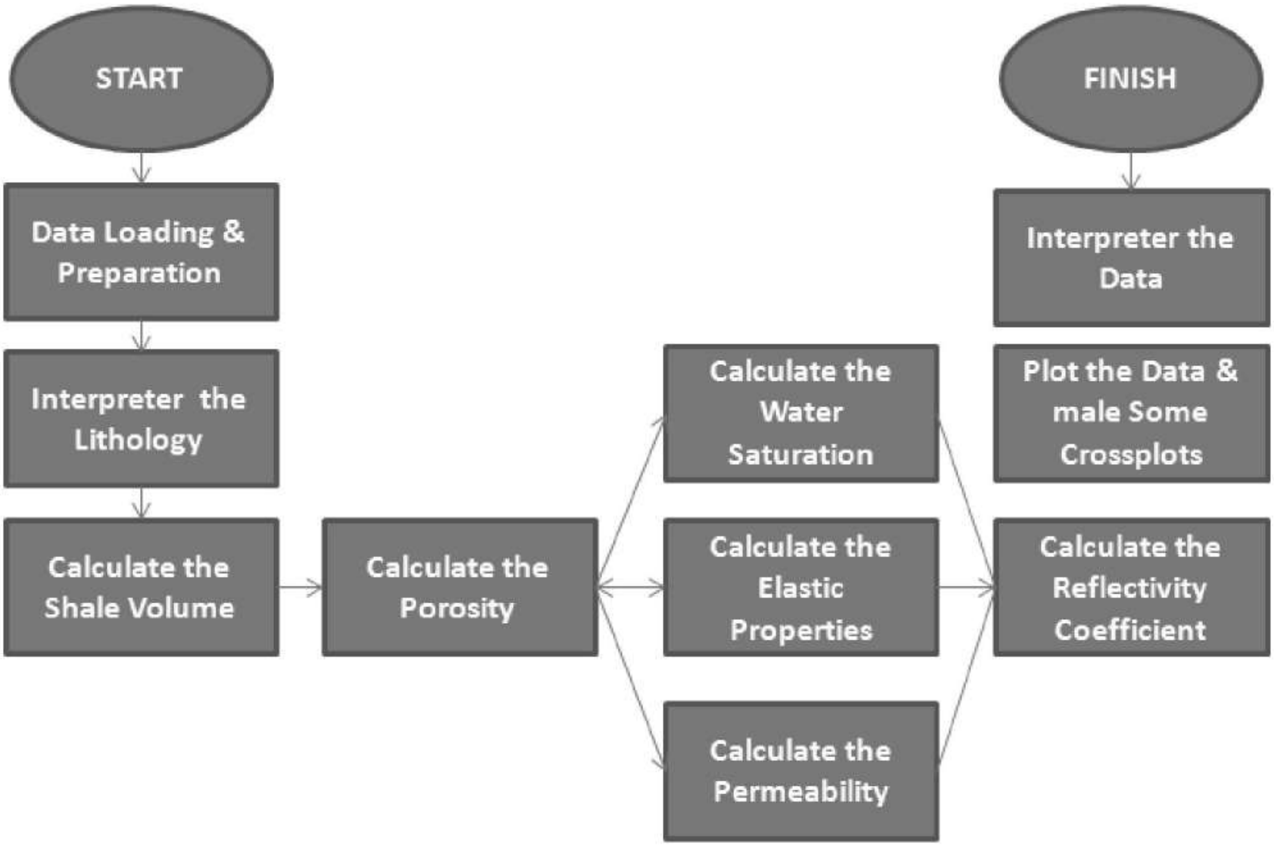
Well logging plays a fundamental role for the formation evaluation process and for the assessment of production potential of a hydrocarbon process.

The log interpretation, in fact, gives a quantitative evaluation of the "in-situ" value of some important petrophysical parameter, such as:

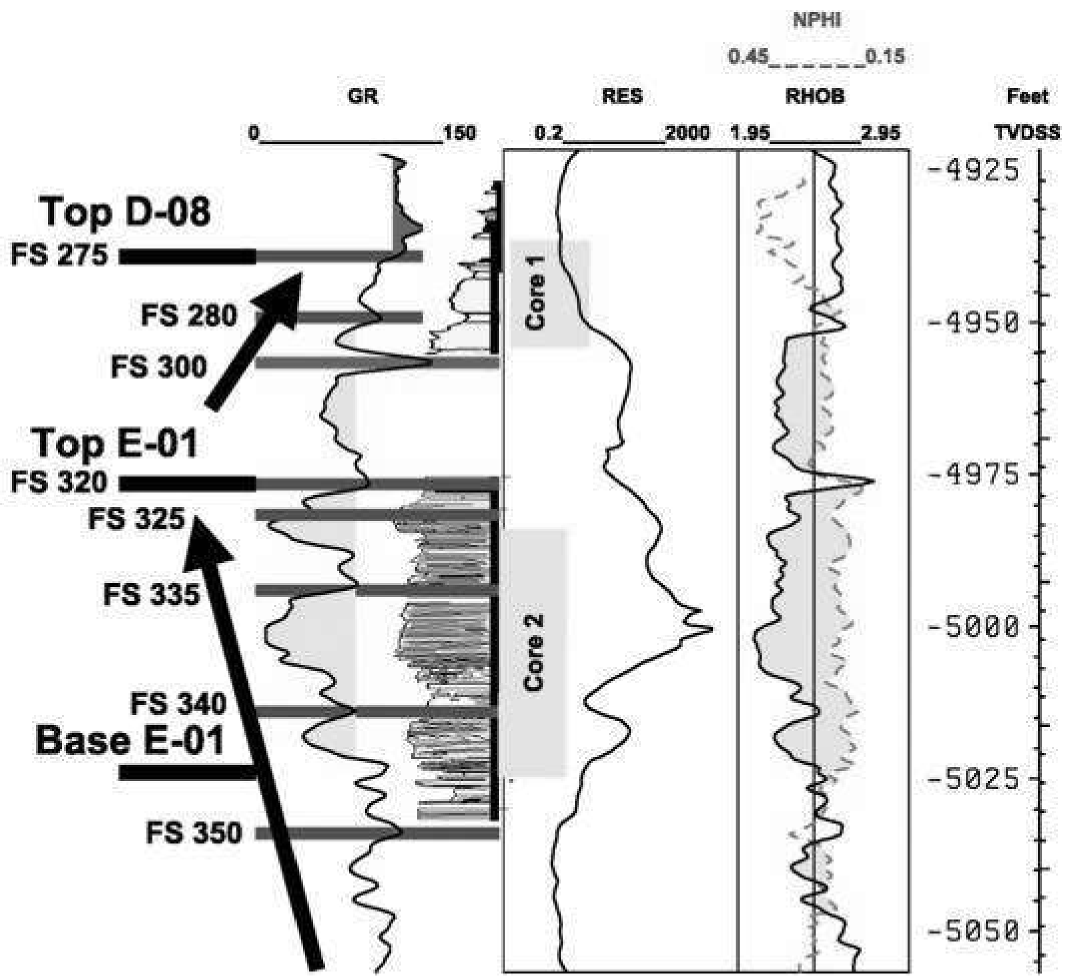
- *Shale volume (Vsh)*
- *Gross and net thickness of the drilled layers (h_G, h_N)*
- *Depth of the fluid contacts (gas-oil, gas-water, oil-water)*
- *Porosity (φ)*
- *Water saturation (Sw)*
- *Residual hydrocarbon saturation (Sor, Sgr)*
- *Rock elastic moduli (E, G, ν, etc.).*

Depending on the wellbore status, the logs are classified as:

- Open Hole Logs:
    - *Resistivity, Induction, Spontaneous Potential, Gamma ray*
    - *Density, Sonic Compensated Neutron, Sidewall neutron*
    - *Porosity, Dielectric, and Caliper*
    - *Gamma Ray, Neutron (except SNP), Carbodoxygen*
- Cased Hole Logs:
    - *Chlorine, Pulsed Neutron and caliper.*



A flowchart to analyze well logs for reservoir characterization



Well logs and flow units, connectivity, and reservoir characterization in a wave-dominated deltaic reservoir

Core Analysis

Lab analysis on reservoir rock samples (e.g. cuttings, bottom-hole or sidewall cores) are a traditional and well-established way to obtain basic data for formation evaluation and reservoir characterization. It is common practice to carry out these analyses according to two different approaches:

Routine Core Analysis that are usually performed on thin sections and on large number of small size samples (e.g. cuttings, plugs taken from a full size core) to characterize the texture of the reservoir rock and some of its basic petrophysical properties. Among the more important properties routinely measured we can here mention:

- *Chemical and mineralogical composition*
- *Petrographic properties (e.g. grain size, sorting, rounding, and grain shape, etc.)*
- *Volume and type of residual fluid (water, mud filtrate, oil) extracted*
- *Grain density*
- *Porosity*
- *Formation factor*
- *Absolute permeability both in horizontal and vertical direction*
- *Others (e.g. Klinkenberg permeability).*

Special Core Analysis (i.e. SCAL) that are usually carried out on a limited number of samples because of the lab time and costs involved with this type of analysis. The samples are chosen in such a way to be representative of the main rock types found in the reservoir.

Basically the SCAL aim at obtaining information on

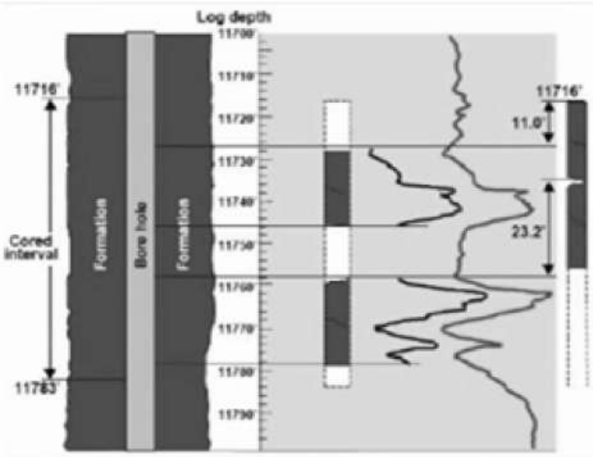
- the petrophysical properties of the reservoir rock in presence of two or three different fluids.
- the displacement efficiency of the IOR/EOR processes
- the effect of reservoir pressure decline on porosity and absolute permeability of the reservoir rock.

Among the most important SCAL usually performed we can here list:

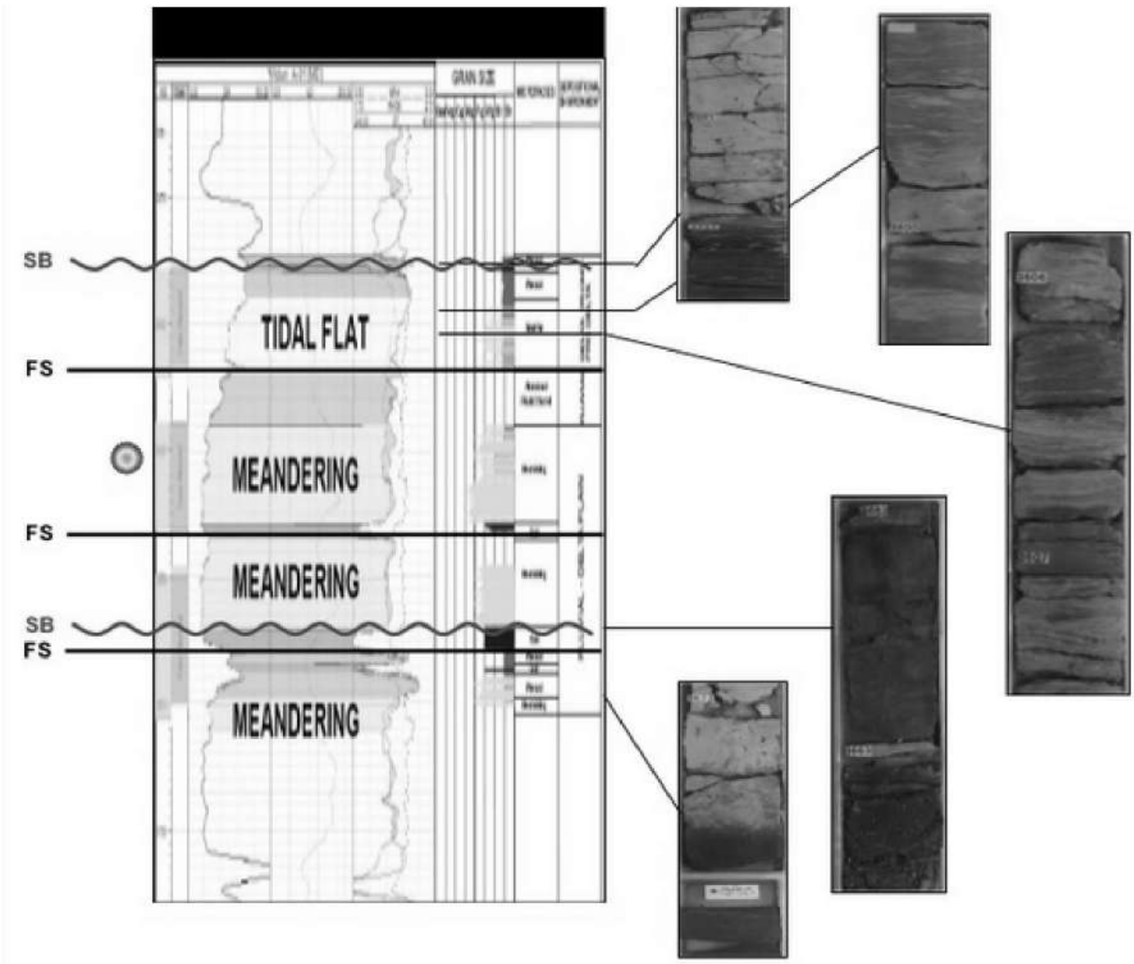
- *Wettability evaluation (e.g. by Amott or USBM method)*
- *Capillary pressure curves*
- *Resistivity index (e.g. for Archie exponent)*
- *Two-phase relative permeability curves by steady state methods (e.g. Hafford or Penn State)*
- *Two-phase relative permeability curves by unsteady state methods (e.g. Welge)*
- *Displacement experiments (e.g. to optimize WAG cycles)*
- *Porosity and absolute permeability at varying reservoir*

overburden pressure

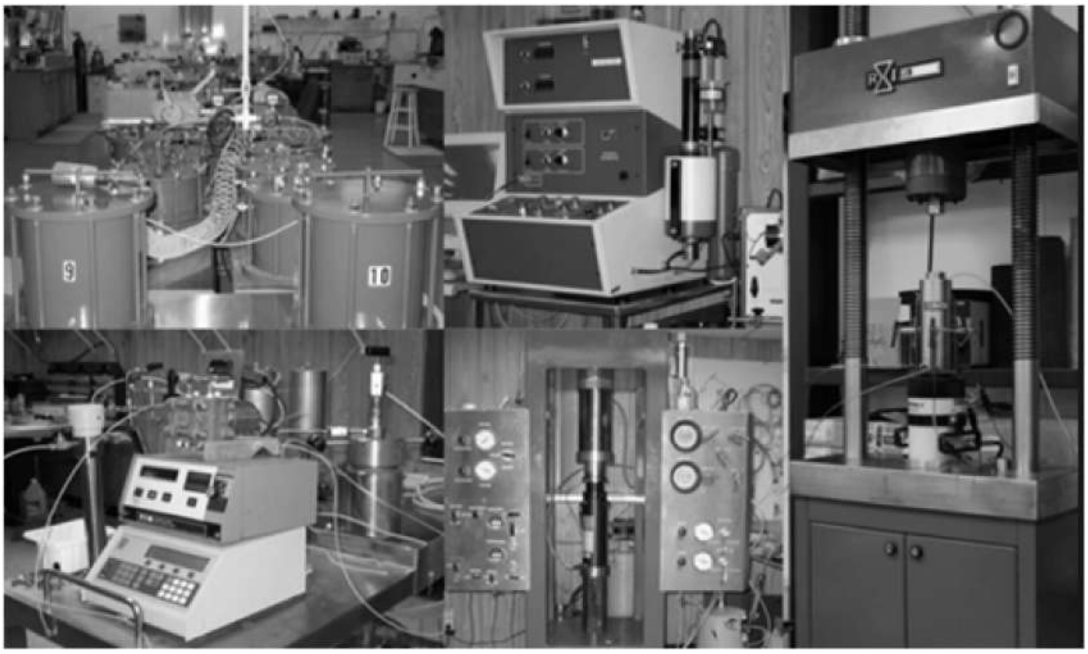
- Others (e.g. NMR imaging of displacement processes).



Logs and core correlation



Core data and sequence stratigraphy



SCAL laboratory equipment and apparatus

Fluid Properties

The phase and volumetric behavior of hydrocarbon systems is commonly characterized through a set of lab experiments known as “PVT study”. The type of experiments and the physical quantities to be measured depends on whether the hydrocarbon system is on liquid or gaseous phase at the initial reservoir conditions.

In the first case the system is identified as“oil” and will undergo to a “differential liberation test” in a PVT cell, where the pressure is gradually lowered by steps, keeping the temperature constant and discharging the gas volume liberated in each step.

The following basic quantities are measured during the study:

- *Initial system composition*
- *Bubble point pressure (p_b)*
- *Volume of oil both for $p>p_b$ and $p<p_b$*
- *Volume and composition of the gas liberated at each step*

- *Oil viscosity*
- *Separation tests.*

Moreover, a special set of experiments (“separator tests”) is performed flashing a certain volume of oil from the initial reservoir conditions to the stock tank conditions, so as to simulate the separation process that will occur through the surface facilities.

All the data measured in a PVT study are furthermore processed to obtain the thermodynamic functions to be used in the reservoir engineering studies, i.e.: B_o, R_s, B_g, γ_g, μ_o, etc.

If the system is on gaseous phase at the initial reservoir conditions and a retrograde condensation will occur in the reservoir during the production, it is identified as “gas condensate”.

In this case the PVT study will be a “Constant Volume Depletion” during which the initial pressure of a certain volume of “gas” in “ad hoc” cell will be gradually lowered by steps, keeping constant the temperature and the cell volume. The total mass of hydrocarbons in the cell, of course, is decreased during each pressure depletion step

The following basic quantities are measured during the study:

- *Initial system composition*
- *Dew point pressure (p_d).*

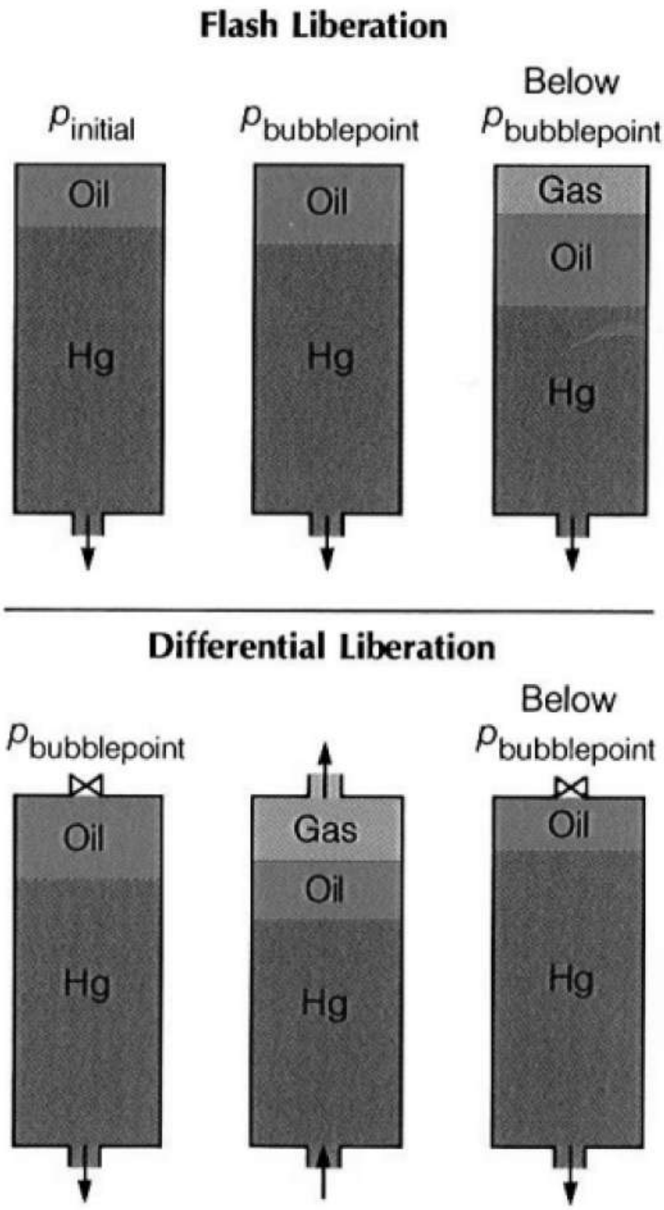
And for each depletion step:

- *Volumes of gas and condensate retrograde liquid*
- *Chemical composition of produced gas phase*
- *Equilibrium gas phase deviation factor (Z)*
- *Equilibrium gas phase density*
- *Chemical composition of remaining liquid at abandonment pressure.*

All the data measured in a PVT study are furthermore processed to obtain the thermodynamic functions to be used in the reservoir engineering studies, such as:

- *Calculated cumulative produced fluid*
- *Potential liquid content of the produced gas phase*
- *Cumulative volume of liquid components produced in the well stream fluid*
- *Equilibrium gas phase density*
- *Viscosity of the Equilibrium gas phase.*

Special PVT experiments can also be performed for the reservoir engineering studies of IOR/EOR projects. For instance, in case of (miscible or not miscible) natural gas or “exotic” gas (N_2, CO_2) injection the execution of a “swelling study” is usually recommended.



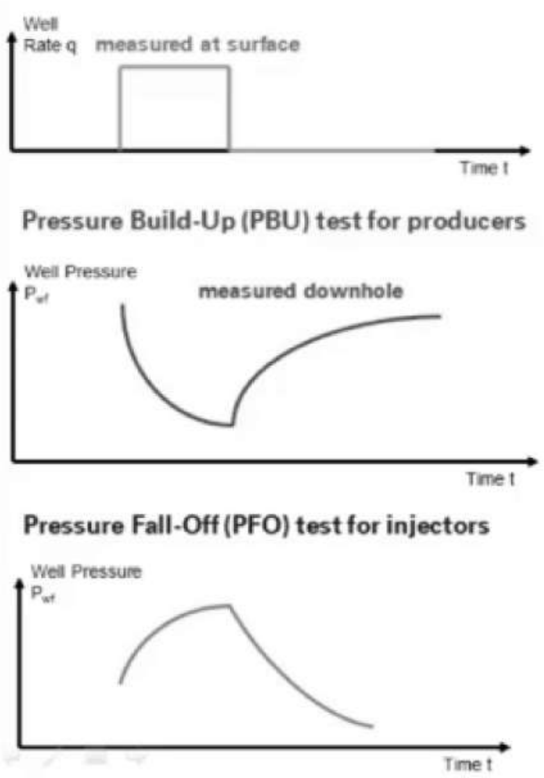
Fluid analysis for fluid properties determination

Comparison between PVT experiments: flash liberation and differential liberation experiments

Well Testing

Well test is a well-established and really powerful technique for characterizing some of the basic transport properties of a porous rock, and for evaluating the performance and the potential productivity of a well.

Pressure build-up, falloff tests, interference and pulse tests can provide a good assessment of the in situ value of the effective permeability-thickness of a reservoir in addition to its pressure, as well as information on stratifications, and on the possible presence flow barriers such as sealing or partially sealing faults, strong permeability-thickness variations, etc.



Well test analysis

This short review of the data necessary for a good reservoir characterization and the techniques employed to get them, has shown that a huge amount of data is usually collected and analyzed during the life of a reservoir.

An efficient data management program-for collecting, analyzing, storing and retrieving them is, therefore, required for good reservoir management. An efficient data management system is, hence, a key issue for storing and retrieving raw and processed data into a readily accessible form.

The amount of acquired data can vary based on

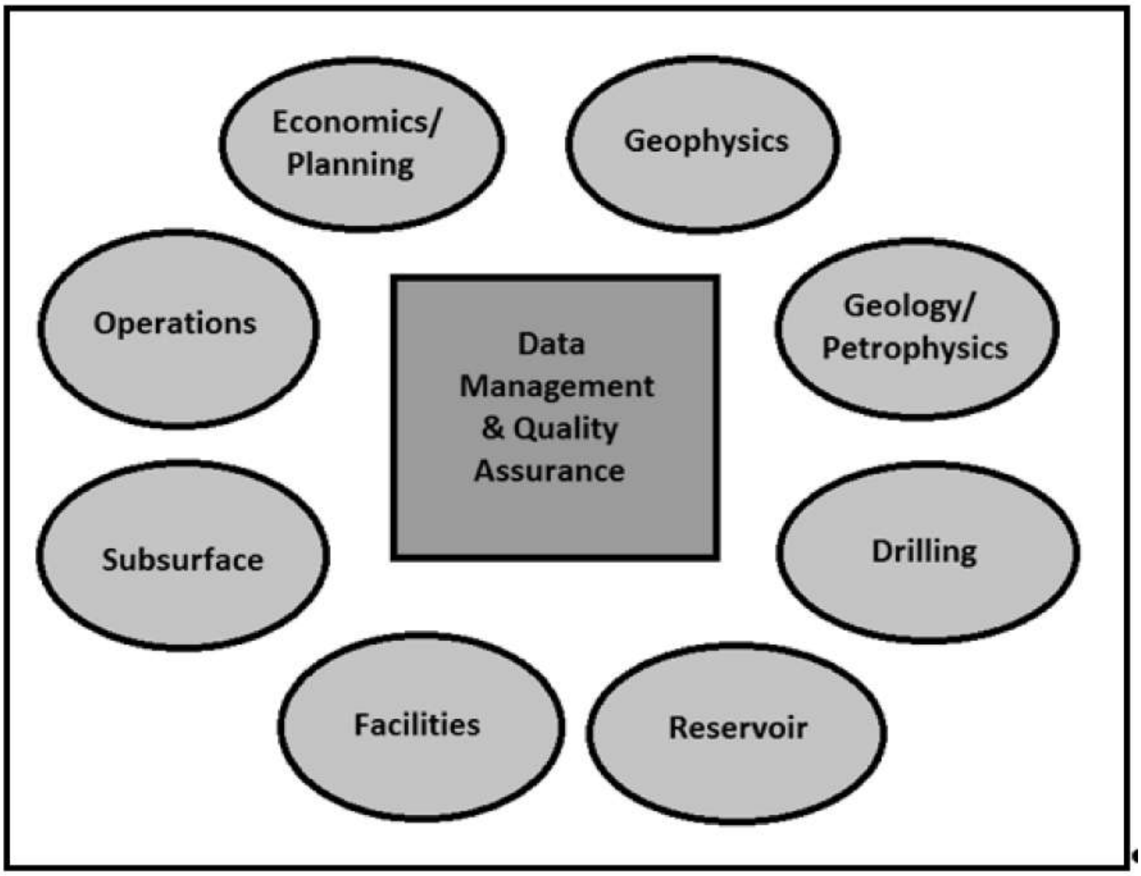
- *Size of the database*
- *Size of the resource*
- *Remaining life of the resource.*

Moreover, the acquisition and interpretation of the data requires a robust quality assurance process for their validation and correct interpretation.

The validated data must be stored in a common computer database accessible to all interdisciplinary end users.

The evident benefits of readily available, high-quality data is

- Saving of time spent in reorganizing, checking, and reinterpreting data each time a study is conducted.



The central and vital role of data management and quality assurance

Integrated Reservoir Modeling

Reservoir Management | Integrated Reservoir Modeling

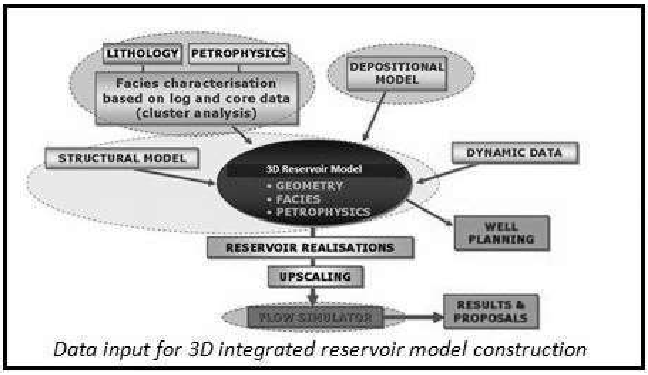
Reservoir Models

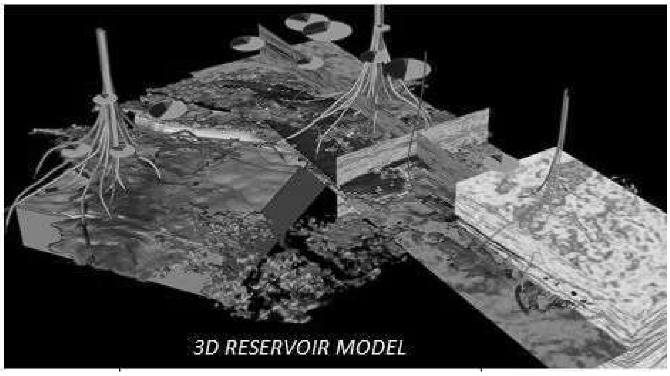
A ”reservoir model” is a mathematical representation of a specific volume of rock incorporating all the “characteristics” of the reservoir under study. It can be considered as a conceptual 3D construction of a single reservoir or in some cases of an oil/gas field.

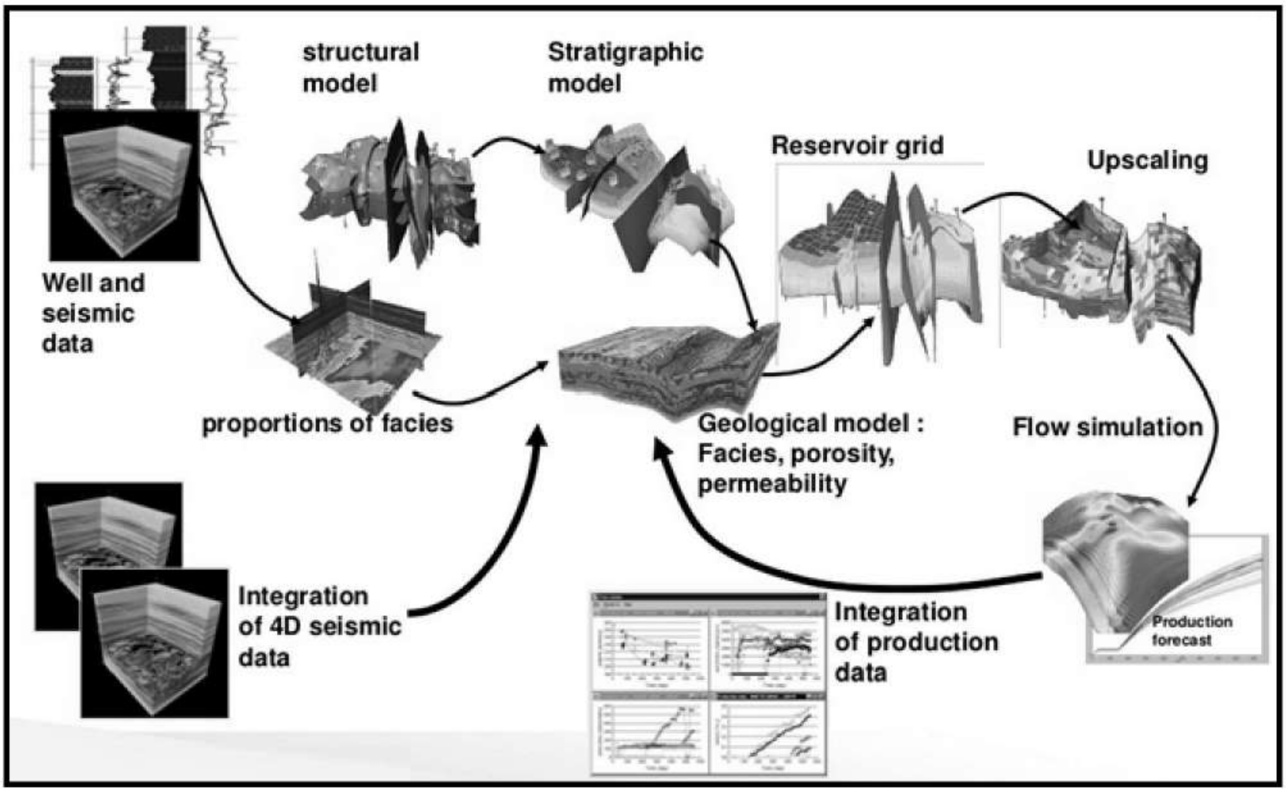
Data derived from various sources are integrated by deterministic or geostatistical methods, or a combination of both, to construct the model. Its setting up, however, is a dynamic process, since a reservoir model must be continuously up-to-dated and revised when new data become available or inconsistencies between the predicted and real reservoir behavior are found.

The reservoir model is, therefore, the result of studies whose main objective is to understand and describe the dynamic behavior of a hydrocarbon reservoir in order to predict its future performance under different development and production strategies.

From practical point of view, the integrated reservoir modeling represents now the most valuable technical approach for estimating the oil/gas reserves and computing the future production profiles, reducing the uncertainties always associated with the static and dynamic reservoir descriptions.







Workflows for integrated reservoir modeling

There are several reasons why an integrated reservoir modeling has found a strong and rapid development:

- For a reliable evaluation of the bulk and net rock volumes, and the original hydrocarbons in place – which are of utmost importance in
  - assessing the economics of a reservoir development project

- selecting the development schemes and exploitation strategy
- selecting the basic design and size of the production facilities
- allocating equity shares with partners

- For an assessment of the minimum well number required to produce the reservoir economically, as well as for the optimal selection of well type (e.g. vertical, slant, horizontal, multilateral, etc.) and locations
- For an economic/technical evaluation of implementing IOR/EOR processes to increase the final recovery
- For verifying the consistency of all static and dynamic data reducing the uncertainties always present in a reservoir model.

The integrated reservoir modeling finds application in different stages and phases of the reservoir life cycle.

In the case of field development it is used for:

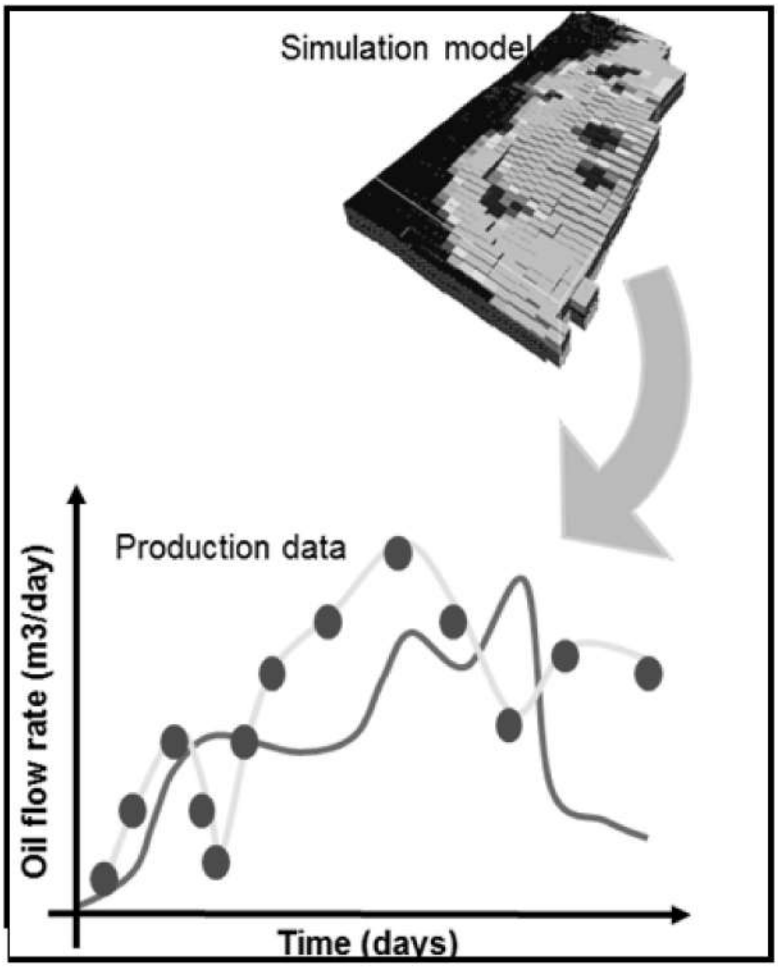
- Estimating the HOIP
- Selecting the field development strategy
- Selecting the optimal number and locations for injector and producer wells
- Computing the production profiles (oil, gas, and water)
- Estimating the oil and gas technical reserves
- Obtaining some basic data required by the economic evaluation
- Identifying and quantifying the key uncertainties.

In the case of producing field it is used for:

- Calibrating the geological model by matching the past production history (fluid rates, GOR, WC, pressures, etc)
- Identifying the undrained oil/gas bearing zones
- Optimizing the production rate and the final recovery
- Keeping the right injection rate for the optimal

reservoir pressure maintenance and/or for the maximum sweep efficiency of the displacement processes

- Locating infilling wells
- Modifying the well patterns
- Selecting the best well construction and completion design
    - vertical vs. horizontal, completions
- Updating production profiles and economics.



Dynamic reservoir model for production forecasts

In addition, the 3D integrated reservoir modeling:

- Helps the integration in a quantitative model of soft information such as sedimentological and depositional models, faults transmissibility etc.

- Enables and promotes the joint team work of geoscientists and engineers
- Reduces the inconsistencies that can be generated by the different geo-modeling workflows
- Allows a good and reliable volumetric evaluation of fluids initially in place even in case of complex reservoir geometries
- Allows the most advanced 3D gridding techniques and the upscaling the geological models
- Helps to select in a real time the optimal final well target while drilling.

Static Model

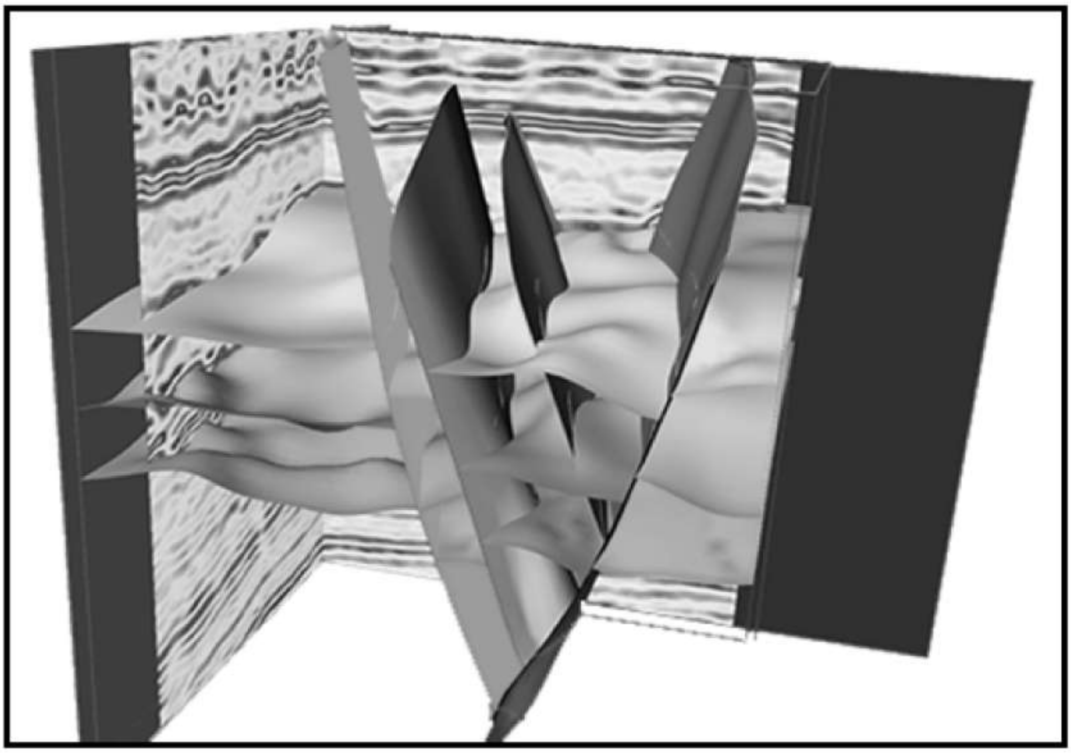
A static reservoir model is the one incorporating all the geological features (i.e. structural, sedimentological, petrophysical, etc.) of an underground volume of rock that can store fluids (hydrocarbons and/or water) and can allow their movement.

In general, the static model of a reservoir is the final integrated product of the structural, stratigraphic and lithological modeling activities, where each of these steps is developed according to its specific workflow.

A static reservoir study typically proceeds through four main stages.

1. Structural modeling

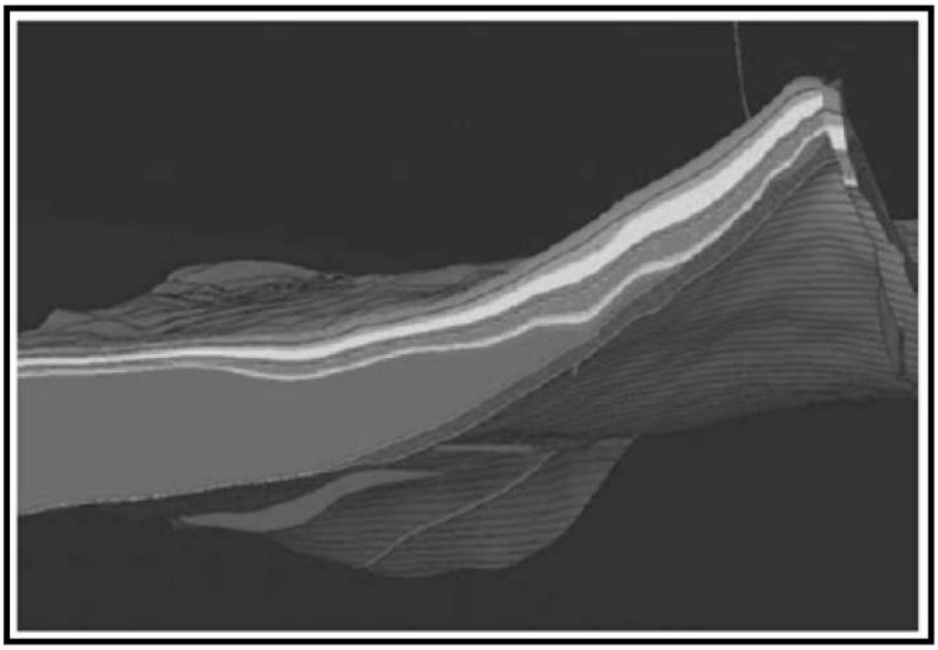
- Reconstruction of the geometrical and structural properties of the reservoir, by defining a map of its structural top and the set of faults running through it. This stage of the work is carried out by integrating interpretations of the geophysical surveys with the available well data.



A structural model showing faults and layering

2. *Stratigraphic modelling*

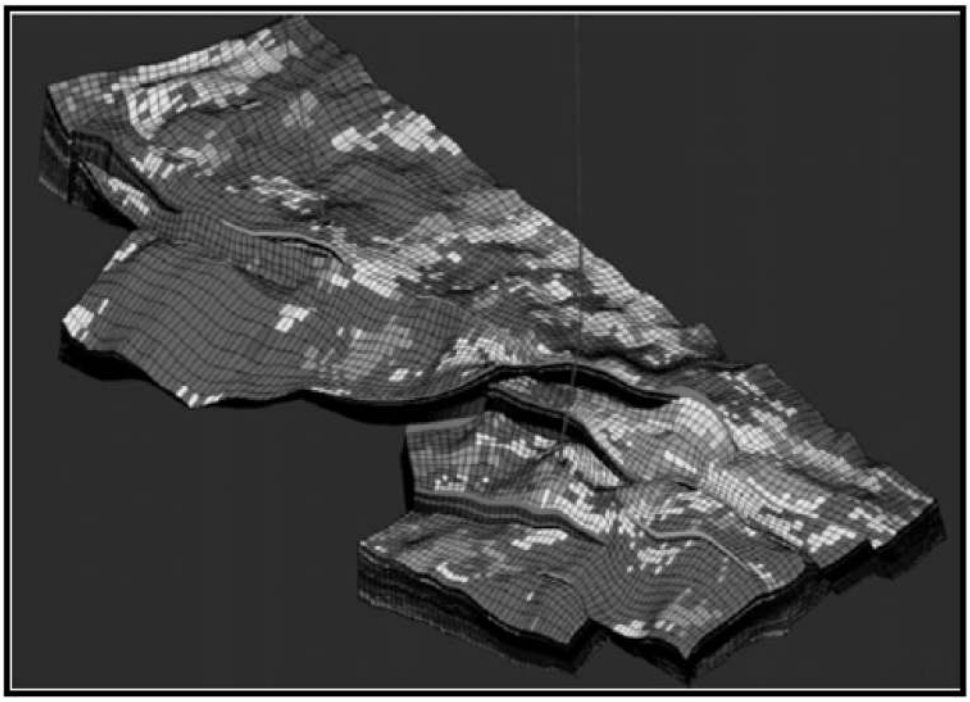
- Definition of a stratigraphic scheme using well data, which form the basis for well to well correlations. The data consist of electrical, acoustic and radioactive wireline logs, and of results of core analysis, integrated where possible with information from specialist studies and production data.



Example of a 3D Stratigraphic Model – L. Cosentino

3. Lithological modeling

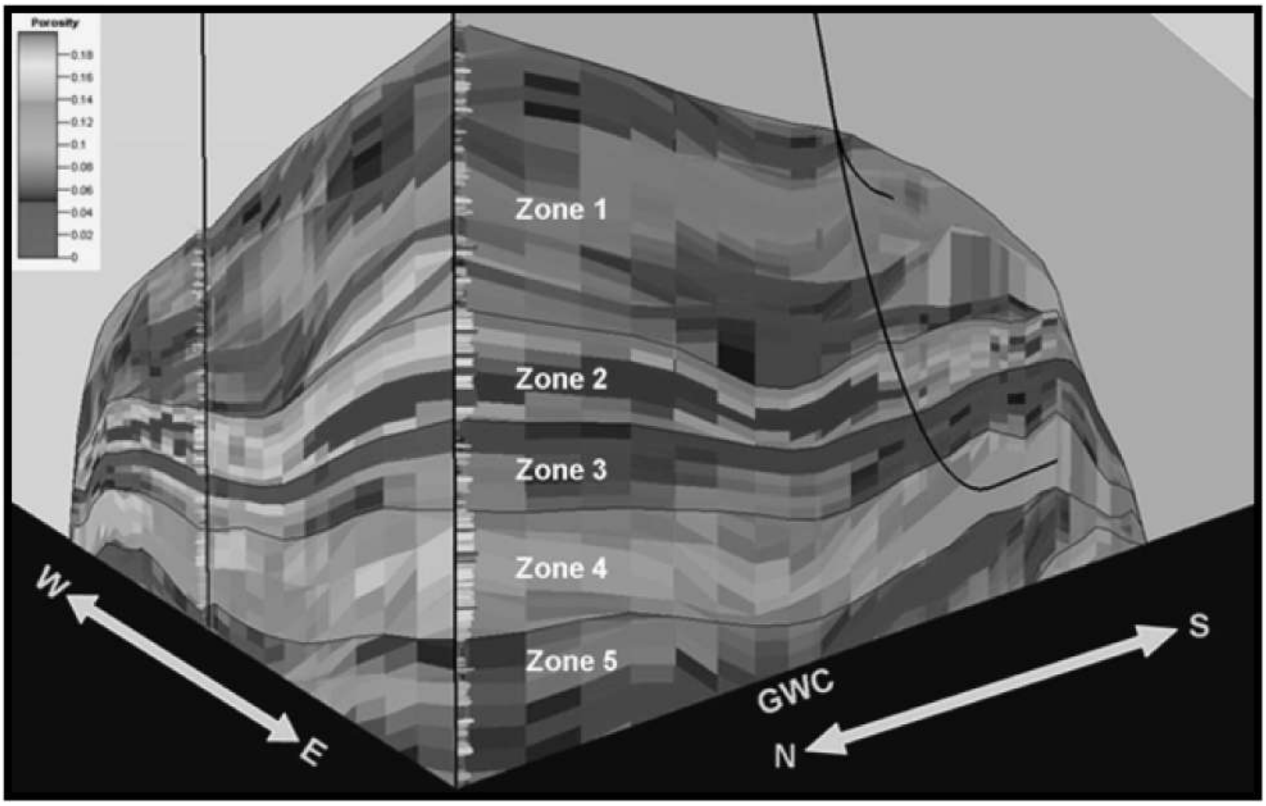
- Definition of the lithological types (basic facies), which are characterized on the basis of lithology, sedimentology, and petrophysics. This classification into facies is a convenient way of representing the geological characteristics of a reservoir, especially for the purposes of subsequent three-dimensional modelling.



Example of a stochastic model of facies – L. Cosentino

4. Petrophysical modeling

- A quantitative interpretation of well logs to determine some of the main petrophysical characteristics of the reservoir rock, (porosity, water saturation, and permeability). Core data represent the essential basis for the calibration of interpretative processes.



A petrophysical model showing porosity distribution and values

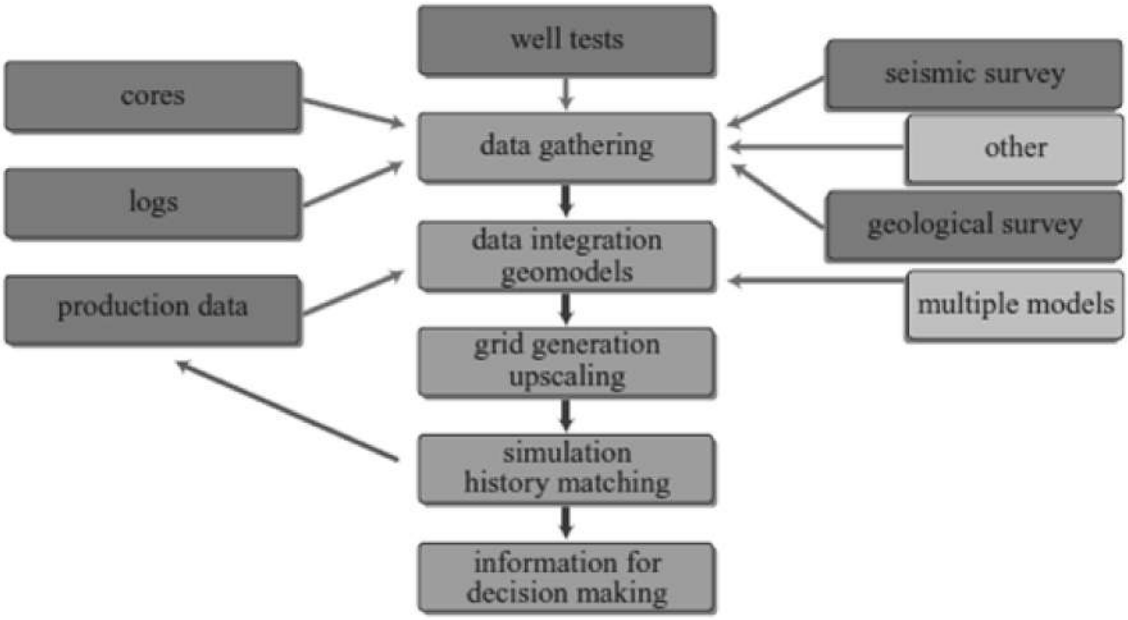
The results of these different stages are integrated in a two (2D) or three-dimensional (3D) context, to build an integrated geological model of the reservoir.

This model represents the reference frame for calculating the quantity of hydrocarbons in place, and on the other, forms the basis for the initialization of the dynamic model.

Dynamic model

The *dynamic model* combines the static model, pressure- and saturation-dependent properties, well locations and geometries, as well as the facilities layout to calculate the pressure/saturation distribution into the reservoir, and the production profiles vs. time.

A dynamic model can be used to simulate several times the entire life of a reservoir, considering different exploitation schemes and operating conditions to optimize its depletion plan.



Integrated reservoir modeling and simulation

Reservoir simulation is a branch of petroleum engineering developed for predicting reservoir performance using computer programs that through sophisticated algorithms numerically solve the equations governing the complex physical processes occurring during the production of an oil/gas reservoir.

Basically, a reservoir simulation study involves five steps:

1. Setting objectives
2. Selecting the model and approach
3. Gathering, collecting and preparing the input data
4. Planning the computer runs, in terms of history matching and/or performance prediction
5. Analyzing, interpreting and reporting the results.

Factors to consider in selecting the simulation model are

- The recovery process of the reservoir

- the model must be able to reproduce the main reservoir drive mechanisms
- Quality and type of the available information- which influence the level of detail to use in the modeI
- Type of answer required
  - The desired accuracy of the expected results will influence the design of the simulation model
- Available resources
  - human, economic and technological resources

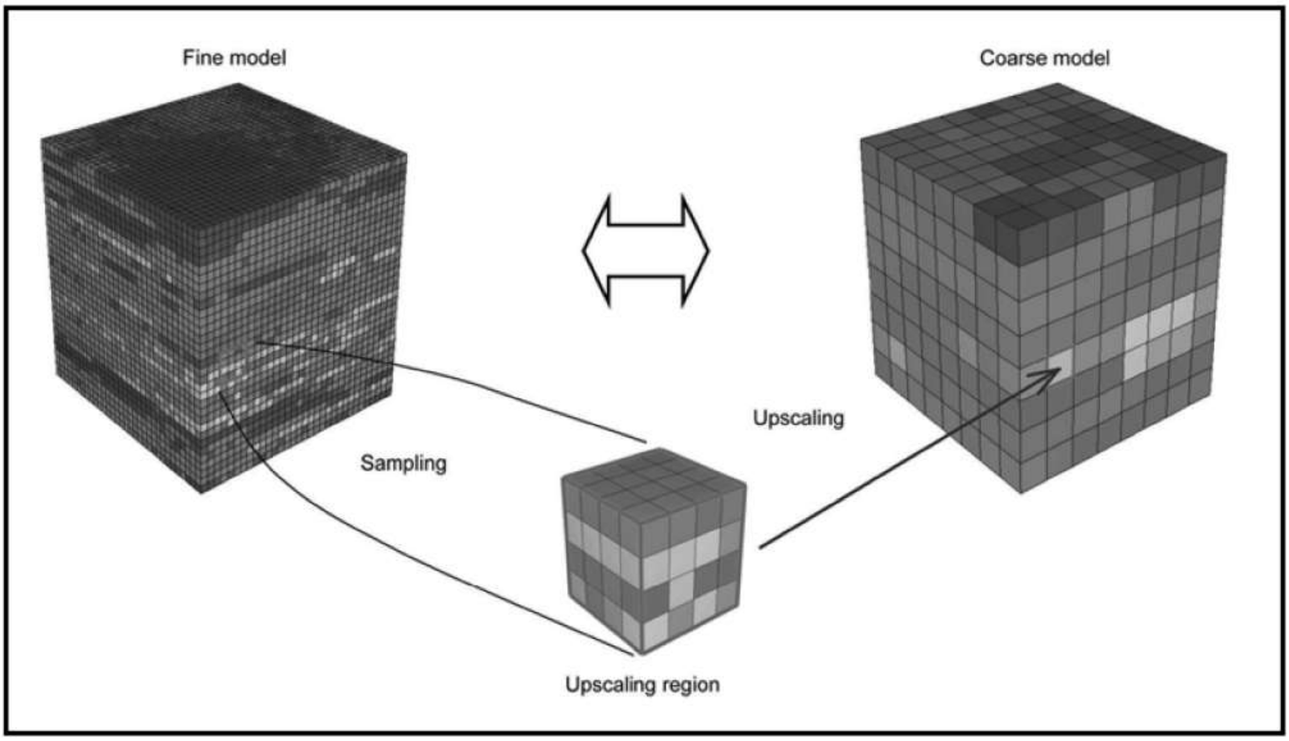
Different types of simulators are used to represent the drive mechanisms of different types of reservoirs, and the selection depends on the type and behavior of the original reservoir fluids and on the predominant process controlling the reservoir production and hydrocarbon recovery:

- Black-oil model
  - It assumes that the thermodynamic behavior of the reservoir hydrocarbon system can be well represented only by two components: the ”stock-tank oil” and the “separator gas”. The classical PVT studies supply all the data required by this approach.
- Compositional model
  - It assumes that the reservoir hydrocarbon system can be well represented only by a number of components and pseudocomponents (C_1+N_2, C_2, …, C_{7+}, …). The thermodynamic behavior of such system is described by the use of an EOS (equation of state) that is usually calibrated with the data of PVT studies.
- Thermal model
  - It is used in case of reservoirs where an EOR process based on thermal recovery techniques is applied. This is the case of heavy oil, extra heavy oil, and bitumen reservoirs, in which the oil viscosity is so high that does not allow any

primary production or the implementation of any conventional injection process (cold water, gas).

- The thermal EOR processes that can be simulated include: SAGD, cyclic steam injection, steam flooding, hot and cold water injection, and in situ combustion.

Upscaling of the geological models is key issue in the reservoir simulation. It is basically a process by which a very heterogenous region of the reservoir rock described with a huge amount of “fine grid cells” is replaced by an equivalent less heterogeneous region made up of a number of single coarse-grid cells. The “upscaled geological model” must, however, maintain the same storage and transport properties of the reservoir rock described with detail by the “fine geological model”. The upscaling process, therefore, is essentially an averaging procedure in which the static and dynamic characteristics of a fine-scale model are approximated by those of a coarse-scale model.

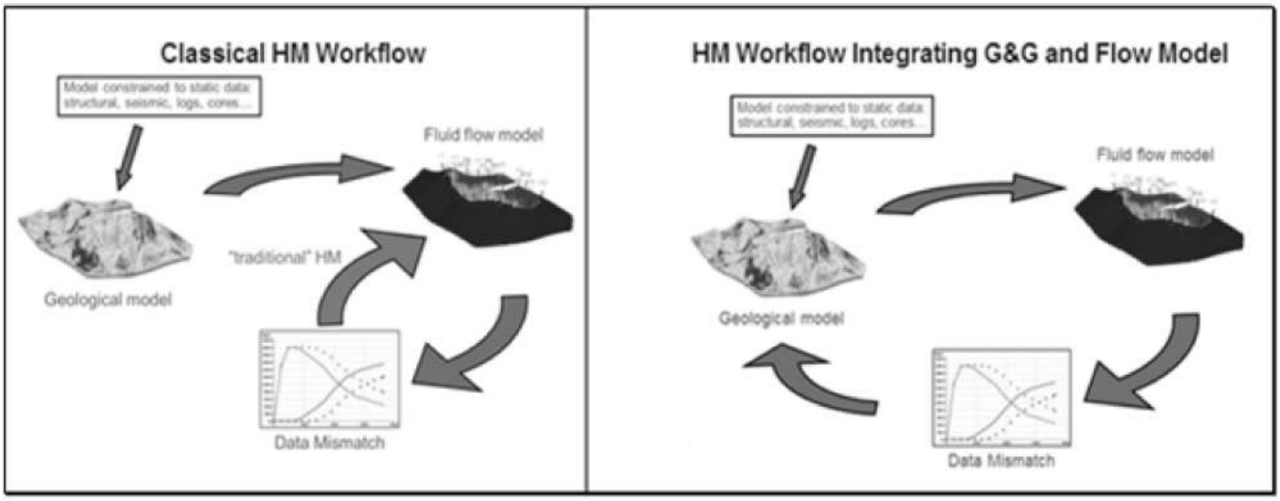


Conceptual illustration of the upscaling process

In a numerical simulation study historical production/injection data (oil, gas, and water rates) must be supplied to the mathematical model. Of course, good quality production/injection data are essential for a reliable simulation study, in terms of direct input data and reference data to evaluate the accuracy of the history match phase.

Past history matching is the most practical method for testing a reservoir model's validity and for calibrating the geological model. Basically history matching is a process of reservoir parameter adjustment in such a way that the simulated reservoir behavior reproduces the actual reservoir behavior.

History matching process should also help to identify possible points of weaknesses in the initial reservoir model, and should help to find and evaluate the most efficient ways to overcome them.



Two possible approach to History Matching

Once calibrated, the simulation models are then used to compute the production forecasts considering various hypotheses for the reservoir exploitation.

In simple cases, this prediction phase can be performed in a few days, while the in more complex cases it can take several months depending on:

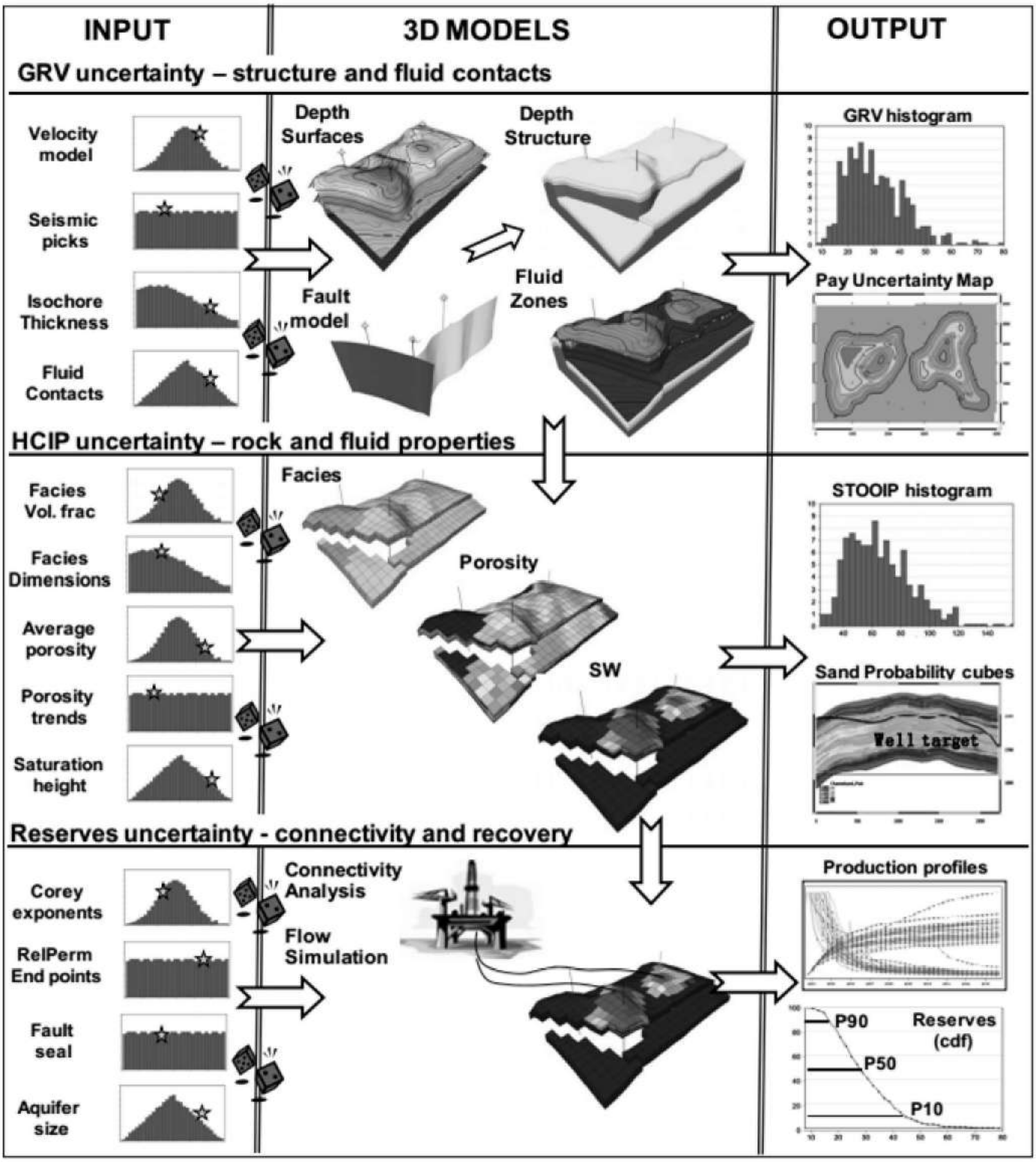
- the size (i.e. number of cells), the type (i.e. black oil, compositional) and geological features of the model,
- the complexity of the wellbore system and of the surface facilities layout
- the number of predictions to be run.

A general sequence for running the prediction phase can be summarized as follows:

- Input Data for predictions – definition of the cases to be run
- Setting guidelines and constraints – to simulate the future production performance of a field
- Inflow and outflow well performance
- Running the prediction cases
- Uncertainty assessment.

Field/group production and injection constraints
Max oil production
Max water production
Max GOR
Max water injection rate
Max water injection pressure
Min average reservoir pressure
Separator pressure

Well production and injection constraints
Max GOR
Max WOR
Max total liquid rate
Min and max oil production rate
Min and max water injection rate
Min bottom hole pressure
Max water injection pressure
Well head flowing pressure



Schematic of a 3D uncertainty workflow.

It shows the most common inputs, stages in the 3D modelling process and corresponding outputs