Dynamic Uncertainties Appraisal throughout a Development Project, Applying PRMS Indicators of Resource and Reserves Categorization

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Abstract

In general, Oil Companies need a contract with the government to have legal rights to carry out Exploration and Production (E&P) projects. In this work, we discuss contractual and economic issues in the E&P sector in Brazil and the dynamics of uncertainties throughout the stages of an E&P project. This study uses Petroleum Resource Management System - PRMS (SPE, et al., 2007) concepts, its reserve categorization and indicators to measure uncertainty in oil and gas projects. First, we analyze complexities resulting from different contractual regimes and their limits—time, area and cumulative production—as well as the impact on the management of Field Development Plans (FDP). Under these limits, not all production and resources are included in the contract, affecting volume amount, property rights and fiscal regime. Time limits affect decisions about the remaining reserves after the end of contract, while area issues occur when reservoirs extend beyond the geographical boundary of an exploratory block. Cumulative production limit appears in the Transfer of Rights Agreement (TRA), which authorized the Brazilian Government to assign 5 billion barrels of oil equivalent to Petrobras in 2010. The National Agency of Petroleum (ANP) promoted technical studies that indicated the recoverable volume in the area of TRA exceeds the limits originally agreed.

In the second part, we use the 12-step integrated decision analysis methodology by Schiozer, et al. (2015) and PRMS reserve indicators to describe the dynamics of uncertainties throughout exploration, development and production phases. Through reservoir simulation and the optimization of a production strategy, we measured the key reserve indicators in different phases of a project. The increment of developed reserves due to the introduction of wells, in the development, and the reclassification of resources, in the management phase, are assessed probabilistically.

The novel information of this work is the use of the PRMS international standard and the 12-step methodology to not only calculate reserves, but also describe the dynamics of uncertainties throughout a Development Project and to qualify complex contractual and economic issues.

1. Introduction

The motivation for this work is to discuss uncertainties that affect an E&P project and the dynamics of reserve categorization, evaluating not only production strategy optimization, but also contractual and economical aspects. The PRMS guidelines can contribute to generating differentials of attractiveness, predictability and reliability, indicating risk and uncertainty measures throughout a development plan.

The objectives of this work are (i) to analyze contractual and economic issues in real cases in the Brazilian E&P sector and (ii) to use PRMS indicators, along with the 12-step methodology by Schiozer, et al. (2015), to evaluate the dynamic of uncertainties throughout the successive stages of an E&P project (Figure 1).
In the first two phases (defining of areas and bidding rounds), the evaluation is mainly qualitative. In the following phases – exploration, discovery, appraisal and declaration of commerciality – we consider quantitative aspects (Figure 2). Finally, in the development and production phases, through numerical simulation of reservoirs, quantitative indicators can describe the dynamics of uncertainties.

Each decision moves the project along the stages from the choice of area to the end of development activities.

To address this theme, we divided the work into key parts. First, to discuss specific complexities in real Brazilian projects, we integrate PRMS concepts with decision-making management methodology, Front-End-Loading (FEL). We then use numerical simulation of the reservoir in a hypothetical field, and loops of the 12-step methodology, to estimate uncertainties throughout a development project. Previous work discussed an approach for assessing a reservoir-simulation, but with the goal of evaluating a simulation model and propose requirements for simulation predictions to be considered as proved reserves model for use in estimating reserves (Jones, et al., 2016).

2. Methods, Procedures, Process

2.1. Fundamental Concepts of PRMS and FEL Methodology

One of the advantages of PRMS is that it considers technically possible projects to maximize recovery, even if some projects are unfeasible when originally evaluated. These projects remain part of the portfolio, and the correct identification and rating ensures that they are visible as potential investment opportunities in the future.

A critical point to understand the PRMS classification is that the designation of estimates of recoverable amounts such as (i) Prospective Resources, or (ii) Contingent Resources, or (iii) Reserves, is based only on the maturity of a project.

The distinction between these three classes is based on the definitions of (i) discovery and (ii) commerciality. The classification of the oil recoverable quantities depends on individual interpretation in the decision-making process, but the concept of increasing likelihood of commercialization should be a key point in the overall ranking of the system and support portfolio management.

The increasing likelihood of commercialization in classifications of resource classes and subclasses is not intended to represent a linear scale, nor is it necessarily sequential. A Contingent Resource project, for example, classified as "Non-Viable Development" may have a lower commercialization chance than a low-risk prospect. In general, however, quantitative estimates of the likelihood of commercialization will increase as the project moves from the exploration phase to the execution of the development and production plan.

It is important to note that - while the goal is to move projects to higher project maturity levels, and eventually to production - a change in circumstances (results from dry holes, changes in fiscal regime, etc.) can hold the project development.

A key portfolio management goal is to identify all possible incremental development options for a reservoir. It is recommended that all technically feasible projects for the reservoir be identified, even though some may not currently be economically feasible.

This approach highlights the extent at which incremental development projects could achieve in terms of recovery efficiency, which should be at least comparable to similar reservoirs. When analog reservoirs achieve significantly better recovery efficiency than the reservoir under consideration, there may be incremental development options...
that are not being considered.

The structure of the PRMS was designed to clarify uncertainty in the quantification of reserves. This is clearly demonstrated in the separation between (i) project maturity and (ii) range of uncertainty.

Uncertainty in any estimation attributed to a project can only be published, in the final Reserve Report, either by a complete distribution of results derived from probabilistic methodologies, or by selected results (low, best and high estimates) of this distribution, using deterministic methods.

The subdivision of Reserves in uncertainty range (1P, 2P and 3P) is based only on uncertainty in the project recovery, as it occurs for Contingent Resources and Prospective Resources. Whether a deterministic or probabilistic method is used, for comparable results the premises must be the same.

2.1.1. Chance of commerciality and range of uncertainty

The PRMS categorizes recoverable amounts of hydrocarbons into two main axes. The first, vertical in Figure 3, is the chance of commerciality. With this concept, the recoverable amounts are categorized in increasing order of commerciality chances as (i) Prospective Resources, (ii) Contingent Resources, or (iii) Reserve.

The second axis, horizontal in Figure 3, is the range of uncertainty, which categorizes quantities into (i) low, (ii) best and (iii) high estimates. The interaction of these two axes results in the classification:

1. Reserves: Proved (1P), Probable (2P) and Possible (3P);
2. Contingent Resources: 1C (low), 2C (best) and 3C (high);
3. Prospective Resources: low, best and high estimates.

![Figure 3: Resources classification framework. (SPE, et al., 2007).](image)

Development projects (and associated recoverable amounts) may be sub-classified according to (i) the project’s maturity level and (ii) the associated business decisions to move the project to commercial production. This approach is interesting as it allows the management of portfolios of opportunities at various stages of exploration and development.

Other sub-divisions are optional and three are presented in the System, which can be used together or separately to identify project characteristics and their associated recoverable quantities.

The options for sub-classifications are (i) project maturity, (ii) reserve status, and (iii) economic status, which add important information about the type of risk and uncertainty in a project.

2.1.2. Project maturity

The project maturity subclass subdivides the volume estimates as follows (Figure 4):

1. Reserves: On Production, Approved for Development and Justified for Development
2. Contingent Resources: Development Pending, Unclarified or on Hold, and not viable
3. Prospective Resources: Prospectus, Lead, and Play

The boundaries between different levels of project maturity can be aligned with internal corporate project management tools, such as “decision gates”, creating a direct link between the decision-making process and the characterization of the portfolio through the classification of resources. This alignment may also facilitate the designation of appropriately quantified risk factors.
The next two subclasses – Reserve and Economic Status – may be used alone or in combination with project maturity subclasses.

Figure 4: Subclasses based on project maturity (SPE, et al., 2007).

### 2.1.3. Reserve Status

Another subclass of PRMS is Reserve Status, which is applied only to volumes classified as Reserves and adds information to the level of development and stage of production. In this subdivision the Reserves are classified:

1. On Production: (i) Developed Producing; (ii) Developed Non-Producing and (iii) Not Developed
2. Approved for Development: (ii) Developed Non-Producing and (iii) Not Developed
3. Justified for Development: (iii) Not Developed

Figure 5 shows a combination of project maturity and reserve status.

Figure 5: Project Maturity versus Reserve Status, adapted from (SPE, et al., 2007).

Estimated recoverable amounts for projects that fully meet the requirements for Reserves can be subdivided according to their operational and budget status.

Although the definition of these subdivisions, prior to 1997, was associated only with Proved Reserves, PRMS now explicitly allows the application for all categories of Reserves (Proved, Probable, and Possible).

Reserves Status has been used in certain environments, and it is mandatory for some regulatory authorities, such as the ANP in Brazil, to categorize the Proved Reserves into Developed and Not Developed.

This approach requires caution as it is possible to confuse the subclass of project maturity that is linked to the status of the project, while reserve status considers the level of implementation of the project, essentially well to well. Unless each well constitutes a separate project, reserve status is a subdivision of Reserves within a project.

Reserve Status is not project-based, with no direct relationship between (a) reserve status and (b) chance of commerciality, which is the maturity level of the project.

Applying reserve status in the absence of a subclass of project maturity can mix two different types of not developed reserves and disguises that they can be of two different levels of project maturity, which are:

1. Not developed simply because implementation of the development project (approved, committed and budget) is ongoing and drilling of wells, for example, is in progress at the time of the evaluation;
2. Not developed because the final investment decision has not yet been made and/or other approvals or contracts are waiting to be confirmed.

For portfolio analysis and decision making it is clearly important to distinguish between these two types of not developed reserves.

Using the project maturity classification, a distinction can be made between a project that was Approved for Development and one that is Justified for Development but not yet approved.

Finally, it is very important to clearly understand the difference between (i) the definition of a project and (ii) the classification of Reserves based on Reserve Status. Reserve Status is a subdivision of the recoverable quantities within a project and does not reflect the classification by chance of commerciality, in fact, it is a subdivision only of the quantities that are Reserves. The two definitions equate to the special case where each well is defined as a project.

2.1.4. Economic Status

Another PRMS classification for Contingent Resource subdivide volumes based on economic status (Table 1). The two main options are marginal or submarginal contingent resources, but where evaluations are incomplete with uncertainties about the ultimate chance of commerciality, the recommendation is to use the economic status “undetermined.”

<table>
<thead>
<tr>
<th>Project Maturity Subclass</th>
<th>Additional Sub-Classification</th>
<th>Economic Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Development Pending</td>
<td>Pending</td>
<td>Marginal Contingent Resources</td>
</tr>
<tr>
<td>Development Unclarified or On Hold</td>
<td>Unclarified</td>
<td>Undetermined</td>
</tr>
<tr>
<td>Development Not Viable</td>
<td>Not Viable</td>
<td>Sub-marginal Contingent Resources</td>
</tr>
</tbody>
</table>

Table 1: Economic Status Classification (SPE, et al., 2007)

2.1.5. Integration with Front-End-Loading management methodologies

The project definition in the FEL methodology (BARSHOP, 2009) and in the classification of resources and reserves of the PRMS is summarized here. The sequential decision making through the decision gate methodology (Figure 6) can be used for any relevant set of activities within the Field Development Plans (FDP), for example the inclusion of a production facility in the project, or an additional well. Also, the complete FDP decision making can be supported in the FEL methodology.

The PRMS classification applies to the E&P project with all the initiatives for the production and commercialization of hydrocarbons, generally described in the FDP.

Figure 6: FEL Methodology - Decision Gates in E&P projects (IPA Global, 2009)
In summary, "Project" in the PRMS classification refers to the set of activities for the production and commercialization of hydrocarbons. The FEL methodology is a decision-making tool for enterprises, be it intermediate activities or a complete FPD.

2.2. 12-Step Methodology by Schiozer et al.

The 12-step methodology is used for integrated decision analysis for petroleum field development and management considering reservoir simulation, risk analysis, history matching, uncertainty reduction techniques, representative models, and selection of production strategy under uncertainty.

In this methodology, reservoir simulation is used directly to reproduce field performance. It can be used in complex reservoirs and in different field stages such as development, management or both. The focus is the use of static and dynamic data to reduce uncertainties allowing risk analysis. Thus geological, economic, operational, and other uncertainties yield a decision analysis based on reservoir simulation and risk-return techniques.

Figure 7 shows a schematic representation of a loop of the 12-step methodology.

Detailed information and references may be found in Schiozer, et al. (2015). A simplified description of the steps is presented below:

1. Reservoir characterization under uncertainties (to build models, develop scenarios and estimate probabilities);
   - The uncertainties of the model were composed by: (1) Geostatistical realizations of facies, porosity, NTG, permeability and east structural model; (2) Properties: water relative permeability (krw), PVT, water-oil contact depth (WOC), rock compressibility (CPOR), and vertical permeability multiplier (kz) are considered during the reservoir modeling and; (3) Economic and Technical (operational) uncertainties are also included.

2. Build and calibrate simulation model;

3. Verify inconsistencies of the Base Case with dynamic well data;

4. Generation of scenarios considering all possible scenarios;
   - The use of Discretized Latin Hypercube technique to consider the efficient combination of uncertainties is one option to generate a set of scenarios.

5. Reduction of scenarios with dynamic data;
   - As the case has initial production from 4 wells, the index NQDS (Normalized Quadratic Deviation with Sign) indicator is used to filter the scenarios (to select a set of scenarios that best reproduce well dynamic data). With the selected model, an initial strategy (E0) must be used to select a base case. This initial strategy is not critical because it will be improved in the next steps; it is just used to select the Base1 case.

6. Selection of deterministic production strategy for Base Case;
   - After choosing an intermediate case (P50 named as Base1) a deterministic production strategy is then selected.
   - To select the Base1 production strategy we considered the following optimization activities: (1) number and type of wells, and capacity constraints; (2) well schedule; (3) location of wells and capacity constraints (fine tune); (4) well schedule and; (5) water-cut, maximum liquid production and water injection of wells.

7. First estimative of risk curve, considering E1 (the selected production strategy after optimization for Base1 case) with all possible scenarios from Step 5;

8. Selection of Representative Models (RM);
   - Strategy E1 is optimized for Base1 model so it is necessary to verify other possibilities.
   - Some representative models (RM) are selected and other strategies are checked if they are good for other scenarios.
   - A set of RM is then selected.

9. Selection of production strategy for each RM repeating Step 6 for each RM;
   - After selecting the RM set, the production strategy of each RM is defined. This step repeats the optimization procedure described in Step 6 for each RM obtained the set of optimized strategies [E2, E3, ...E9], where E is the optimized strategy defined for each RM.

10. Selection of production strategy under uncertainty including economic and other uncertainties;
    - Considering all 9 production strategies optimized in Step 9, the best alternative can be selected in different ways.
    - Risk indicators are used to estimate risk (standard deviation, P10-P90, probability of having the
NPV below a tolerance and others).

11. Identification of potential for change in the production strategy to improve chance of success:
   - Step 11 analyzes in detail the strategy selected in the previous step.
   - This step is necessary because there are several improvements that can be made to the strategy considering the uncertainties and the risk aversion of the companies.
   - The most common studies included in this step are: information, flexibility, and robustness, which can reduce risk or improve the objective functions (OF) of the projects but they have some associated investments and costs. Integration with production systems is also considered.

12. Final risk curve and decision analysis.
   - After passing through all the steps detailed above, we have a robust process to be used in the decision analysis yielding a strategy that is appropriate to the case, honoring the history data and considering all uncertainties mapped for each particular case.
   - The 12-step procedure has to be repeated whenever new important information is obtained and, therefore, it is a continuous process that must be used by the company.
   - It is unnecessary to perform all the steps, only those relevant for the study.

3. Applications
   3.1. Contractual and economic issues in real cases in the Brazilian E&P sector.

This part of the work discusses the Brazilian regulatory framework for oil and gas, which adds distinctions to the categorization of resources and reserves. This discussion allows an application of PRMS concepts to practical and sometimes exclusive cases in the Brazilian E&P sector.

Since the classification of resources and reserves is a technical-economic concept, besides the optimization of reservoir recovery, which determines the performance of the production curve, we include topics that have a significant impact. In this section, we discuss (i) contractual and (ii) economic issues.

The contractual topic covers situations in which the outcome of the project - production, resources, or reserves - is only partially covered by the contract. This situation impacts the ownership of existing resources or reserves and the applicable tax system. These aspects are discussed in the presentation of contractual regimes in Brazil and their resource categorizations are affected by (i) time, (ii) area, and (iii) cumulative production limits.

In the economic topic, items that directly impact the cash flow analysis are discussed, such as the characteristics of the different tax systems. In addition, we evaluate the incentive of Royalty reduction, established by Resolution 17/2017/CNPE (CNPE, 2017), and show that using PRMS classification of economic status, the Royalty incentive could be expanded to more situations.

Contractual Issues
Allocation of quantities, costs and sales revenues to a project is governed by applicable contracts between owners of mineral resources (lessors) and contractors (lessees), 3.3 Law and recognition of resources (SPE, et al., 2007).

3.1.1. Contractual Regimes and the Fiscal System in Brazil

Until 1995, according to Article 177 of the Federal Constitution (BRASIL, 1988), the research and development of oil and natural gas deposits and other fluid hydrocarbons was monopolized by the Union. However, Constitutional Amendment 9/1995 (BRASIL, 1995), which allows the Union to contract state or private companies to carry out these activities, subject to the conditions established by law.

Concession

In 1997, Law 9,478 (BRASIL, 1997), called the Petroleum Law, established the National Council for Energy Policy (CNPE), The National Petroleum, Natural Gas and Biofuels Agency (ANP), and the Concession Agreement for research and mining of oil and gas.

Transfer of Rights Agreement – TRA / Onerous Assignment

In 2010, within the initiatives to establish a new regulatory framework for the exploration of the Pre-salt, Law No. 12,276 (BRASIL, 2010) authorized the Union to assign 5 billion barrels of oil equivalent (boe) to Petrobras on a costly basis. This onerous assignment, in non-granted areas located in the Pre-salt, shall take effect until Petrobras extracts the equivalent number of barrels of oil defined in the Onerous Assignment Agreement. CNPE issued Resolution 2 (CNPE, 2010) in September 2010 and approved the Onerous Assignment Agreement in accordance with Law 12,276/2010. National Agency of Petroleum (ANP) promoted technical studies that indicate the recoverable volumes in the areas exceed the limits of 5 billion barrels of oil equivalents.

Production Sharing

In 2010, two laws established the new regulatory framework. Law 12,304 (BRASIL, 2010b) authorized the Executive Power to create the state company Pre-Sal Petróleo SA - PPSA, which would be responsible for the management of the new modality of contract, PSC. This contract was introduced by Law 12,351 (BRASIL, 2010c), which deals with the exploration and the production of hydrocarbons, under the production sharing regime, in areas of the Pre-salt and other strategic areas, in addition to creating the Social Fund and changing provisions of Law 9,478.

Transfer of Rights Surplus

Technical studies of ANP identified volumes that exceed the limits of the amount contracted under the onerous assignment contract. These additional volumes will be offered in a Transfer of Rights Surplus Bidding Round at the Production Sharing regime (ANP, 2018). Besides the 5 Billion boe already contracted, the six blocks have a potential volume estimated to be between 6 to 15 Billion boe of surplus. The Brazilian Government set up transfer of rights commission, which has 60 days to reach a final agreement on terms between the government and Petrobras. If an agreement is reached, surplus bidding round may occur in June 2018.

3.1.2. Time Limit - Duration of Contract

The first contractual question is related to the time limit. The duration of the contracts imposes the need to decide the best use of resources between the options (i) to exhaust the recoverable volume in the contractual period, or, if this does not occur, (ii) the possibility of renewal, or even (iii) a replacement of the operator by another contractor to explore the available Reserves under a new contract. Table 2 summarizes the limits and possibilities of contractual renewal for the main types of contracts available in Brazil.

Concession

The duration of Contract Round 13 (BRASIL-ROUNDS, 2016) was defined as "five years for the exploration phase and 27 years for the production phase, extendable by clauses and conditions set forth in the concession agreement."

Onerous Assignment

The Onerous Assignment Agreement (PETROBRAS, 2010) determines that: "5.2. The Term of this Contract is 40 years counted from the Date of Signature. 5.3. The Term of this Contract may be extended by the Seller for a maximum of five years, upon request of the Assignee."

Production Sharing Agreement

The PSA (BRASIL-ROUNDS, 2013) determines the "Term: 35 years, non-extendible by means of the clauses and conditions set forth in the Production Sharing Agreement."
Table 2: Time limits in Brazilian contracts.

<table>
<thead>
<tr>
<th>Limits</th>
<th>Renewal</th>
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</thead>
<tbody>
<tr>
<td><strong>Concession</strong></td>
<td>Time: 5 + 27 years</td>
</tr>
<tr>
<td><strong>Transfer of Rights/ Onerous Assignment</strong></td>
<td>Volume: 5 Billion boe</td>
</tr>
<tr>
<td></td>
<td>Tempo: 40 + 5 years</td>
</tr>
<tr>
<td><strong>Prod. Sharing Contracts</strong></td>
<td>Time: 35 years</td>
</tr>
<tr>
<td><strong>Surplus of Onerous Assignment</strong></td>
<td>Time: 35 years</td>
</tr>
</tbody>
</table>

Figure 8 shows production rate vs time and the split of volume in and out of contract. The amount of volumes in and out and the property rights of these reserves, in general, are defined in the contracts. Some contracts have renewal clauses, others do not. The optimization of production strategy is a key issue to deal with contracts without renewal clauses.

Contract renewal

The classification after the end of the contract would depend on the Field Development Plan (FDP). We can therefore estimate some possibilities from scenarios for this situation.

1. As long as there is no contractual definition after the end of the contract, clearly the quantities estimated by the current FDP may be classified as follows: (a) until the end of the contract they are owned by the Company or the Consortium contracted and have their classification according to uncertainty and maturity of the project; (b) after the termination of the contract, are owned by the Union, the classification will be as Contingent Resources until a new FDP is defined.

2. Some possibilities for definition of new contract:
   a. Contract renewal with the same company or consortium. Some Brazilian contracts consider the possibility of renewal. In that case, the classification of quantities would be according to the uncertainties and maturity of the project or additional projects in the renewal, maintaining ownership with the current Company or Consortium. This option seems to be the simplest;
   b. If, for any reason, contractual renewal does not occur, if the quantities are relevant, the Union may bid the area to hire a new Company or Consortium. The production assets present in the area, if still in operation, may be included in the agreement;
   c. There is a more flexible recommendation from the PRMS when there is reasonable certainty of contractual renewal. In this case, it would be possible to consider the volume estimative after the end of the first contract as Reserve to the current operator.

3.1.3. Area Limit - Extension of reservoirs beyond the limit of the contract area

Reservoirs or deposits may extend beyond the geographical boundary of an exploratory block contract (Figure 9). In these cases, the ownership of the resources is shared by the Companies that own the blocks reached by the mine, or with the Union if the mine reaches non-contracted areas. Good exploration practices recommend that different actors work together to produce the resources of these shared deposits in the most rational and efficient way possible.

Law 12351/2010 (BRASIL, 2010c) defines "Individualization of production: a procedure aimed at dividing the production result and rational use of the natural resources of the Union, by unifying the development and production of the extension beyond the block granted or contracted under the regime of production sharing."
Figure 9: Reservoir extension out of the contract area limit

Figure 9 shows a reservoir that extends to an area out of contract. The amount of volumes in and out and the property rights of these reserves, in general, are decided between the owner of exploration rights of the areas involved (Other companies or the Government).

3.1.4. Cumulative Production Limit - Transfer of Rights Agreement

Technical studies have been promoted by the National Agency for Petroleum, Natural Gas and Biofuels, which indicates that the areas contracted under the TRA have volumes that exceed the limits of 5 billion barrels of oil equivalent originally agreed. In these areas, Petrobras has already carried out the necessary exploratory activities, within the scope of the Contract.

These additional volumes will be offered in a Transfer of Rights Surplus Bidding Round at the Production Sharing regime (ANP, 2018).

As it will be presented, the coexistence of different contractual regimes, associated with specific issues of reservoir and contractual areas, creates a set of different reserve owners. The PRMS concepts provide some support to understand this question.

Figure 10: contractual limit of cumulative production.

Figure 10 shows a cumulative production rate vs time and the split of volume in and out of contract. The volumes in and out and the property rights of these reserves, in general, are decided between the owner of exploration rights of the areas involved (other companies or the Government).

3.1.5. Economic Issues

This topic will discuss issues that affect valuation, economics, and the reserve evaluation, such as (i) Royalty reduction incentive defined by CNPE (CNPE, 2017), (ii) the tax systems applied in Brazil, (iii) financial engineering in oil projects, (iv) cost of decommissioning, and (v) the fiscal incentive of REPETRO.

(i) Resolution CNPE (CNPE, 2017) established the Petroleum Exploration and Production Policy and granted an incentive to reduce Royalty as follows:

"Article 3. The ANP, [...] shall observe the following guidelines [...] : XII - grant, on the basis of pre-established criteria and provided that the economic benefit to the Union, within the scope of the extensions of the validity of the existing contracts, is confirmed, a reduction of royalties, up to 5% , on incremental production generated by the new investment plan to be executed, in order to allow the extension of the useful life, maximizing the recovery factor of the fields.

Single paragraph. The incremental production, which is dealt with in item XII, will be calculated considering the historical decline of the field."

The royalty refers to payments that are due to the government or mineral owner (lessor) in exchange for the depletion of the reservoirs by the producer (lessee / contractor) who has access to the petroleum resources, 3.3.1 Royalty (SPE, et al., 2007).

Many agreements allow the contractor/lessee to produce the volume of royalties and sell the production on behalf
of and pay the product to the owner/lessor of royalties. Some agreements provide for royalty to be taken only in kind by the owner/lessor. In both cases, royalty volumes are deducted from the lessee’s right to the resources. In some agreements, the royalties of the host government are treated as taxes to be paid in cash. In such cases, equivalent royalty volumes are controlled by the contractor who may (subject to regulatory guidance) elect to report such volumes as Reserves and/or Contingent Resources with appropriate offsets (increase in operating expense) to recognize the financial liability of the Royalty obligation.

Alternatively, if a company owns a royalty or equivalent interest of any kind in a project, the related amounts may be included in the resource rights.

(ii) With the existence of different contracts and fiscal regimes in Brazil, the cash flow of the economic analysis can assume different configurations. In summary, it is possible to differentiate the following types:

1. The Concession Regime, in a simplified form, includes Royalty (10%), Special Participation - PE for fields with production above a minimum value, IRPJ and CSLL;
2. The Onerous Assignment contract differs mainly because it does not have PE;
3. The Sharing Agreement first considers Royalties of 15% and does not have PE but rather the sharing of production at a rate that depends on price and production per well. The oil sharing received by the Government is sold by Pre-Salt Petroleum S.A. (PPSA), and finally, the production costs (CAPEX and OPEX) are reimbursed in oil to the Operator under specific rules. Additional information on PSC in Brazil may be found in Nascimento and Schiozer, 2017.

(iii) Cash flow is also heavily impacted by project finance with CAPEX. It has been common to use Leasing of important CAPEX items, such as FPSO and subsea equipment. For the actual cash flow, the Leasing dilutes the costs in installments spread over the duration of the contracts, significantly altering the Net Present Value (NPV), in relation to the traditional depreciation of the CAPEX.

(iv) Another issue that impacts the cash flow, and consequently the economic limit and the Reserves is the cost of decommissioning. Not only in Brazil, but also in countries with many oil production structures, attention to estimating decommissioning costs has increased. These costs, estimated for the end of the project (sometimes 30 years ahead), have a real chance of underestimation. In addition, there is little experience, especially in Brazil, of decommissioning maritime field structures with production modules. Safety and environmental requirements reinforce the need for accurate cost estimation.

(v) REPETRO, established in Decree 6,759 (BRASIL, 2009), is an important fiscal incentive for the Oil Industry in Brazil. This incentive significantly reduces the cost of goods and services, where REPETRO rules apply, and should be considered for the preparation of cash flow. Most of the companies elaborate the economic analyses with costs already discounting the incentive of REPETRO.

3.2. Dynamic of uncertainties over time.

To present the PRMS quantitative indicators applied to a study of the dynamics of uncertainties over time, we used the 12-step methodology and UNISIM-I benchmark cases already published. Additionally, we developed a new simulation case, in an intermediate time, to measure the Reserve Status classification in the middle of the development phase.

UNISIM-I is the first model created by UNISIM-CEPETRO to provide a dataset to compare methodologies and performance of different techniques, simulators, algorithms, among others. Detailed information about UNISIM-I benchmark cases are found in:

- [UID]: UNISIM-I-D (GASPAR, et al., 2015);
- [UIX]: UNISIM-I-X, case developed in an intermediate time in this work.
- [UIM]: UNISIM-I-M (GASPAR, et al., 2016) and
- [UIH]: UNISIM-I-H (Maschio, et al., 2013).

3.2.1. Description of simulations

The UNISIM-I benchmark cases UID, UIX, UIM and UIH had their reference models selected through 12-step analyses. The UNISIM group developed these cases to identify models better adjusted to historic production under geological, operational, and economic uncertainties in the following stages of the project: 1461, 2313, 2618, and 4018 days.

We used the probabilistic distribution from these optimized models to measure reserve indicators in the times selected.

These benchmark cases have the following common characteristics:

- The reference model is based, with some modifications, on the structural, facies and petrophysical model
of the Namorado oil field, in Campos Basin, Brazil;

- They use, based on a geological model, a Discretized Latin Hypercube with geostatistical realizations to sample and combine different types of uncertainties (continuous and discrete attributes and realizations represented by geostatistical images) to generate possible scenarios;
- They assume the same characteristics from UNISIM-I-D (until t1=1461 days) and consider the same exploitation strategy for field development, a water-flooding project with 14 producers (4 vertical and 10 horizontal) and 11 horizontal injectors;
- They consider two approaches: (1) deterministic, without uncertainties and (2) probabilistic, considering geological, economic, and operational uncertainties;
- A probabilistic history-matching process was applied to reduce the number of scenarios;
- The misfit between the models and the production history data was evaluated by quantification and diagnostic procedures, considering acceptance levels and several objective functions simultaneously, including well-fluid rates and bottom-hole pressures;
- They have a dataset available online, which includes a reservoir simulation model, structural model, PVT table, water-oil contact, water relative permeability, vertical permeability multiplier, rock compressibility and images with petrophysical characteristics related to facies, porosity, horizontal and vertical permeability, and net-to-gross ratio.

UID study requires setting up a development oil strategy between t1 and tf (the final time of production). This yielded a set of 214 scenarios honoring the history data, considering all uncertainties.

UIX is a case in an intermediate time between “D” and “M”, which yield a set of 104 scenarios.

The goal of the UIM project is to optimize the revitalization (design and control) variables of the provided exploitation strategy during the reservoir management phase. UIM yielded a set of 48 scenarios.

The UIH model is used in post-development applications for production history matching and uncertainty reduction. UIH yielded a set of 407 scenarios.

Table 3 presents main information for each case.

<table>
<thead>
<tr>
<th>Benchmark case</th>
<th>Historic production data</th>
<th>Forecast</th>
<th># selected models</th>
</tr>
</thead>
<tbody>
<tr>
<td>UID</td>
<td>t1 = 1461 days (4 years)</td>
<td>26 years</td>
<td>214</td>
</tr>
<tr>
<td>UIX</td>
<td>tX = 2313 days (6 years)</td>
<td>24 years</td>
<td>104</td>
</tr>
<tr>
<td>UIM</td>
<td>tM = 2618 days (7 years)</td>
<td>23 years</td>
<td>48</td>
</tr>
<tr>
<td>UIH</td>
<td>tH = 4018 days (11 years)</td>
<td>19 years</td>
<td>407</td>
</tr>
</tbody>
</table>

Table 3: Details of Benchmark cases.

Through the reservoir simulation, the dynamic of uncertainty in the project life was measured. Figure 11 shows a summary of the simulation cases optimized by the 12-step methodology applied to a scenario reduction process in different phases of field life. The number of models obtained from each phase depends on the reduction scenario process/method applied to each phase. The increment of developed reserves due to the introduction of producer/injector wells, and the reclassification of resources over time is presented in the case study.

![Figure 11: Summary of simulation cases](image-url)

Wells and times
Figure 12 shows key stages of the project. The wells introduced in each stage are:

- $t_{UID} = 1461$ days: NA1A, NA2, NA3D, and RJS19;
- $t_{UID} = 2313$ days: INJ007, INJ017, PROD008, INJ003, INJ006, PROD010, INJ010, INJ019, PROD024A, INJ021, INJ015, and PROD005. (Minimum interval for connection (well-platform) of each well is 30 days);
- $t_{UID} = 2618$ days: INJ005, INJ023, PROD025A, INJ022, PROD012, PROD014, PROD021, PROD023A, and PROD009.

4. Discussion, Observation and Results

4.1. Brazilian E&P Cases

We discussed in previous sections three limits that bring special issues to reserve categorization. Figure 13 provides an overview of these limits.

Under these limits, the outcome of projects – production, resources and reserves – is only partially in the contract, affecting the size, property rights, and fiscal regime in and out of contract.

4.1.1. Time Limit

The concession contract, for example, allows five years for the exploration phase and 27 for the production phase. The first concession contracts were signed at the creation of the ANP in 1998. The so-called Round Zero included the existents fields in production and exploration phases, which were selected by Petrobras. Contracts that were in the production phase in 1998 are due to end in 2025, while those in exploration phase will finish around 2030.
Figure 14 and Figure 15 show the ranking of Brazilian fields with the highest production offshore and onshore in Dec, 2017.

The time limit is relevant because many of the highest production fields are from the Round Zero. Offshore areas are Roncador, Marlim Sul, Marlim, Marlim Leste, Albacora, Albacora Leste, Barracuda, Caratinga, and Voador while onshore areas are Canto do Amaro, Carmópolis, Leste de Uruçu, Estreito, Rio Uruçu, Alto do Rodrigues, Araçás, Buracica, Fazenda Alegre, Sirizinho, Fazenda Pocinho, Salina Cristal, Pilar, Miranga, Furado, and Socorro.

Moreover, by simple analysis of decline it is possible to estimate that some of these fields, mainly offshore, will have viable production after 2025.

In this specific example, the application of the PRMS classification recommendations contributes to the evaluation of issues about recovery amount and property rights. After the contractual period, if the area contract ends, there is no commerciality assurance.

Therefore, estimated recoverable quantities should only be classified as Reserve until the date of termination of the contract. The quantities estimated to be produced subsequently the end of the contract should be considered as Contingent Resources.

Recovery amounts in areas without a valid exploitation contract are property of the Brazilian Government until the definition of a new contract for the area. Since the Brazilian Government does not operate directly, a contractual renewal or a new bidding round to select a new operator is necessary.

Resolution 2/2016/CNPE (CNPE, 2016) guaranteed the possibility of contractual renewal under certain conditions. There are already cases of contractual renewal approved by the ANP and others are under evaluation (ANP, 2017b).

Extensions or renewals of the contract, section 3.3.3 in PRMS (SPE, et al., 2007), states that when projects approach the end of the contractual period, they may be extended (i) by negotiation to contract extensions, (ii) by
the exercise of options to extend, or (iii) by other means. Volumes that will be produced beyond the end date of the current contract should not be considered Reserve unless there is a reasonable expectation that an extension, renewal or new contract will be granted. This reasonable expectation may be based on historical treatment in accordance with regulatory standards. Otherwise, the expected production beyond the term of the contract should be classified as Contingent Resources with an associated reduced chance of commercialization.

4.1.2. Area Limits

When the deposit reaches only contracted areas, the solution to rationalize production is the process of individualization of production (ANP, 2017c). The contractors involved negotiate a Production Individualization Agreement (AIP), which establishes, among other things, the participation of each one in the production and who will be the operator, the responsible for conducting the unified planned activities. Article 27 of the Petroleum Law (later modified by Law 12,351/2010) was the first Brazilian legal standard focused on unitization.

The individualization of oil production is a globally adopted and effective legal institute to prevent the predatory production of petroleum deposits that extend beyond the area granted (CNPE, 2016). When a deposit reaches non-contracted areas, these areas of a shared deposit should be promptly contracted for the execution of joint operations, preferably before the date of declaration of commerciality of the shared deposit.

The space limit is relevant because areas involved have significant value and attract interest of major International Oil Companies (IOC). The 2nd PSC Bidding Round (2nd half of 2017) was dedicated to unitizable areas in the Pre-salt.

The 2nd Round offered four blocks with unitizable deposits, that is, adjacent to the fields or prospects whose reservoirs extend beyond the contracted area: South of Gato do Mato, North of Carcará and Surrounding of Sapinhoá (Santos Basin) and Southwest of Tartaruga Verde (Campos Basin) (Figure 16). The unitization occurs when one deposit extends to areas that belong to different operators or between contracted areas and those not contracted yet.

Figure 16: Unitizable Areas Offered for 2nd Pre-Salt Bidding (ANP, 2017d).

Figure 17 shows results of the 2nd PSC Bidding Round, which was dedicated to unitizable areas in the Pre-salt (ANP, 2017e).

Figure 17: 2nd PCS Bidding Round Results

In addition, most of the Pre-salt fields area involved in unitization processes (PPSA, 2018).

4.1.3. Cumulative Production Limit
Cumulative production limit is present in Transfer of Rights Agreement (TRA) (PETROBRAS, 2017). The TRA was signed between Petrobras and the Federal Government in 2010. Petrobras acquired the right to produce up to five billion barrels in pre-salt areas.

As a result of the activities under transfer of rights, commerciality has been declared for the fields of Búzios, Sêpia, Itapu, South of Lula, South of Sapinhoá, North and South of Berbigão, North and South of Sururu, and Atapu. The beginning of commercial production is set for the first half of 2018.

Over the past seven years, with the volume of information acquired through the drilling of more than 50 wells and long-duration production testing, plus the extensive knowledge acquired in the pre-salt layer of the Santos Basin, it was possible to conclude that the volumes exceed the five billion barrels of oil equivalent originally contracted.

4.1.4. Combination of different contractual types and limits

A very interesting example to discuss is the projects in the exploratory blocks Iara and Iara Surroundings.

Iara exploratory block was a concession contract in Santos Basin from Round 2, signed in 2000, and had a Discovery Assessment Plan - PAD from well 1-BRSA-618-RJS in the BM-S-11 Consortium.

Iara Surroundings exploratory block was the 4th area of the Transfer of Rights Agreement, signed in 2010, located in the surroundings of Iara.

Initially, there are two types of contract, Concession in Iara and TRA in Iara Surroundings, Figure 18. Since the surplus in volume of the TRA contract follows PSC regime, there will be three types of contracts in the same area.

![Figure 18](image1.png)

Figure 18: Depth map with the contour of reservoir and Iara exploratory block limits (Lima, 2010).

In the declaration of commerciality of these areas, in December 2014, Petrobras reported that the region of these exploration blocks contained three unconnected reservoirs, but all three had reservoir extensions between the two contracts and even to the non-contracted area (PETROBRAS, 2014), Figure 19.

![Figure 19](image2.png)

Figure 19: shows a schematic drawing of the identified deposits

Therefore, Petrobras pointed to ANP eight different fields resulting from the original exploratory blocks, Figure 20. The motivation for so many fields is the separation of each part of the reservoir for each type of contract.
The example of the commercial declaration of the Iara and Iara Surroundings areas shows the complexity resulting from the coexistence of different contracts. Considering the contracted areas, there are cases of Individualization of Production between concession contract and TRA, as well as between TRA and PSC. In addition, there is also a reservoir extension for non-contracted areas.

Certainly, the economic analysis and the classification of resources and reserves are impacted by the complexity of the situation. The PRMS and local regulation present guidelines for evaluating the impact of this complexity as more exploration, development and production information is obtained.

4.1.5. Royalty Incentive for Sub-marginal Projects

As discussed in section 2.1.4 the economic status divides contingent resources into Marginal and Sub-marginal projects.

Additionally, we discussed in section 3.1.2 the Royalty incentive established by CNPE, which grants a reduction of royalties, up to 5%, on incremental production generated by the new investment plan, to extend the useful life and to maximize the recovery factor. The incremental production is calculated considering the historical decline of the field and within the scope of the extensions of current contract.

The Royalty incentive clearly brings Sub-marginal projects up in the chance of commerciality axes to marginal level.

So, this relevant incentive could be expanded not only to declining fields, but also to any Sub-marginal development project, which would become Marginal project (development pending) because of Royalty incentive.

The incentive would depend on pre-established objective criteria – certification of PRMS economic status classification, for instance - since identified clear economic benefit to the Union and/or maximization of the recovery factors.

4.2. Dynamic of uncertainties Evaluation

As summarized in Table 3, the benchmark cases resulted in 773 models selected through the 12-step methodology. UID, UIX, UIM, and UIH resulted in 214, 200, 48, and 407 models, respectively.

All cases used a period of dynamic data (production and pressure) to reduce uncertainties in production forecast. UID, UIX, UIM, and UIH used 1461 (4), 2313 (6), 2618 (7), and 4018 (11) days (years), respectively, of historic dynamic data.

Figure 21 presents the dynamic of reserve indicators and uncertainties until the economic limit, 10957 days. It is important to highlight some aspects of this chart:

1. Chart presents the result throughout time of four key reserve indicators: High, Best and Low estimates, as well as Cumulative Production.
2. The cumulative production line represents the volume produced to date estimated in the real model UNISIM-I-R in each time of the horizontal axis;
3. The High, Best, and Low lines, however, represent the estimate of cumulative production at the end of project \( t_f = 10957 \), which were measured in four times \( t_{UID}, t_{UIX}, t_{UIM} \) and \( t_{UIH} \).
4. The continuous line is just a representation since the data were collected in the times appointed.
Figure 21: Key reserve indicators – Probabilistic results on U1D, U1X, U1M and U1H benchmark cases - Volumes in Millions of m³.

Figure 22 presents the key stages of the project. A short description of information and uncertainty variation for each stage studied will be presented.

The issues for each period presented in Figure 22 are:

4.2.1. Period 1: Exploration and appraisal  \( t_0 \) to \( t_{UID} \)  0 to 1461 days

- \( t_0 = 0 \) (production start);
- Wells introduced: NA1A, NA2, NA3D, and RJS19;
- \( t_{UID} = 1461 \) days:
4.2.2. Period 2: Development \( t_{\text{UID}} \) to \( t_{\text{restart}} \) 1461 to 1857 days

- wells are drilled and completed;
- No production in this period;
- \( t_{\text{restart}} \): 1857 days:
  - date of incidence of investments on drilling, completion and platform/facilities;
  - no changes in reserves indicators;
  - starting date of the production system installation.

4.2.3. Period 3: Development and Production 1 \( t_{\text{restart}} \) to \( t_{\text{UIX}} \) 1857 to 2313 days

- In the date of opening each well:
  - incidence of investments on connection (well-platform).
- Wells introduced (4 producers and 8 injectors):
  - INJ007, INJ017, PROD008, INJ003, INJ006, PROD010, INJ010, INJ019, PROD024A, INJ021, INJ015, and PROD005;
  - Minimum interval for connection (well-platform) of each well: 30 days.
- \( t_{\text{UIX}} \): 2313 days:
  - 2nd measure of reserve indicators in case UIX.
- The structural model defined as uncertainty in UNISIM-I-D is now assumed to be known after drilling wells in the east block.
- A new set of petrophysical properties realizations was generated and updated the model for the post-development phase.
- Water-oil-contact uncertainty decreased.
- The main variation in the level and range of reserves was in 1P and 2P estimates. The recognition of the east block and the elimination of scenarios without the east block resulted in higher 1P and 2P estimates.
- Figure 23 presents a field map and start time for producer and injector wells, in which we highlight the wells already introduced in UIX time, 2313 days.

![Figure 23: Field Map and start time for producer and injectors – UIX time.](image)

- Additional dynamic data of the developed wells reduced uncertainties close to the wells. To compare developed and not developed performance – reserve status classification – uncertainties, we present in Figure 24 \( N_p \) normalized risk curves per well. We considered well developed those introduced by 2313 days. To compare the group of wells, we considered the difference \([P_{90} - P_{20}]\) for the dispersion in \( Z \) unit \((Z = [Npi - \mu] / \sigma)\). Figure 24 shows that not developed wells have a dispersion 50% higher.
4.2.4. Period 4: Development and Production 2

- Wells introduced (6 producers and 3 injectors):
  - INJ005, INJ023, PROD025A, INJ022, PROD012, PROD014, PROD021, PROD023A, and PROD009.
  - Additional dynamic data of the new wells reduced uncertainties close to the wells.
  - A new set of petrophysical properties realizations was generated and updated the model for the post-development phase.
  - t_{UX}:2618 days:
    - 3rd measure of reserve indicators in case UIM.
  - The level and dispersion of reserves (1P, 2P and 3P) were significantly reduced. The key factor for this variation was the new information added by new wells, not only static data from new reservoir images, but also new dynamic data from all wells in the field.

4.2.5. Period 5: Production and Management 1

- Operational uncertainties were evaluated, resulting in adjusted well parameters.
- A new set of petrophysical properties realizations was generated and updated the model for the post-development phase.
- t_{UX}:4018 days:
  - 4th measure of reserve indicators in case UIH.
  - The subtle variation in the level and range of reserves was due to adjusts in well parameters.

4.2.6. Period 6: Production and Management 2

- tf – 10957 days:
  - maximum simulation final time;
  - field abandonment cost.

For the production forecast, all the production strategy characteristics concerning operational restrictions and economic model were used.

Table 4 presents the evolution of three reserve indicators: [a] % of Project Time, [b] the range of uncertainty, Ind01 = (3P-1P)/3P, and [c] cumulative production, Ind02 = %Cum.Prod/2P.
OTC-28889-MS

<table>
<thead>
<tr>
<th>% of Time</th>
<th>UID</th>
<th>Restart</th>
<th>UIX</th>
<th>UIM</th>
<th>UIH</th>
<th>END</th>
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</thead>
<tbody>
<tr>
<td>13%</td>
<td></td>
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<tr>
<td>17%</td>
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<tr>
<td>21%</td>
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<td>24%</td>
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<td>37%</td>
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<tr>
<td>100%</td>
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</table>

<table>
<thead>
<tr>
<th>Ind01 = (3P - 1P)/3P</th>
<th>30%</th>
<th>30%</th>
<th>14%</th>
<th>7%</th>
<th>4%</th>
<th>0%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ind02 = % Cum. Prod/ 2P</td>
<td>8%</td>
<td>8%</td>
<td>11%</td>
<td>21%</td>
<td>53%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table 4: Reserve Indicators along project.

- In benchmark case UID, historic with 1461 days, 13% of project time, with 4 production wells, the range of uncertainty is 30% of high estimate and the cumulative production represents 8% of best estimate 2P.
- In the restart of production, 17% of project time, indicators kept constant, since no production was added.
- In UIX, 21% of project time, with additional 4 producer and 8 injector wells, the range of uncertainty is 14% of the high estimate and cumulative production represents 11% of the best estimate.
- In UIM, 24% of project time, with additional 6 producer and 3 injector wells, after the introduction of all strategy wells, the range of uncertainty is 7% of the high estimate and cumulative production represents 21% of the best estimate.
- In UIH, 37% of project time, the range of uncertainty is 4% of the high estimate and cumulative production represents 53% of the best estimate.
- Note that in UIM time, after the introduction of all production strategy wells, when cumulative production represents just 21% of the best estimate, the range of uncertainty dropped from 30% to 7%.

Evaluation of uncertainties along the project, based on risk curve of Np, is presented in the Figure 25.

![Figure 25: Risk curves of Np in successive stages of the project.](image)

5. Conclusions

We discussed in previous sections the application of PRMS concepts and indicators to analyze contractual and economic issues in E&P projects in Brazil and to measure uncertainty in oil and gas projects.

Chance of commerciality, range of uncertainty, project maturity, reserve and economic status are key concepts to analyze uncertainties in real complex cases and to measure variation throughout a development.

The 12-step methodology is a robust system for integrated decision analysis through reservoir simulation and when associated with PRMS indicators results in the quantitative evaluation of uncertainty in different stages of a project.

In the evaluation of time, area and cumulative production limits, using the methodology described, we discussed:

1) A set of fields, offshore and onshore, in Brazil, which will have contract end with relevant potential to produce after time limits.
2) Real unitization processes in relevant Brazilian fields, mainly in pre-salt, in which the production strategy selection determines the definition of property rights of the reserves between areas in and out ring fences;
3) A special contract, Transfer of Rights, in the regulatory Brazilian framework in which a cumulative production limit separates reserve rights in the same reservoir in and out contract.
4) The complexity of association of contractual limits and different fiscal system regimes.
The PRMS guidelines related to amount recognition and property rights, within and out contract limits provides possible directions for good practices. In the unitization cases, the 12-step methodology may be applied to select production strategy and a fair objective function to maximize recovery among areas involved, minimizing legal dispute.

When the contractual limits discussed are associated with different fiscal regimes, the complexity expands considerably. PRMS and the 12-step methodology may provide a direction to optimize results to the players, based on the objective criteria.

In the economic issues, we discussed Royalty reduction introduced in the Brazilian regulatory framework for brownfield in the decline phase. Based on the methodologies discussed, this incentive could be expanded for more cases, in which the incentive could transform sub marginal into marginal economic projects, in accordance with economic status classification. Considering clear economic benefit to the Government through accredited certification of economic reserve status, for instance, and/or maximization of the recovery factors.

In the evaluation of the dynamic of uncertainties, we used UNISIM benchmark cases – UID, UIX, UIM, and UIH – and simulated 773 models selected through the 12-step methodology. These cases used 1461, 2313, 2618, 4018 days, respectively, of historic dynamic data (production and pressure).

The results show a strong variation of the range of uncertainty from stages UID to UIX. The main causes are: (i) elimination of the uncertainty about of the existence of the east block, (ii) definition of water-oil contact and (iii) the new dynamic and static data acquired from new wells.

In the UIX stage, we observed a consistent difference in the range of uncertainty between developed and undeveloped wells. Based on the normalized risk curve per well and P90-P20 range, we noticed a range of uncertainty 50% higher in undeveloped wells in comparison with developed ones. The static and dynamic information added by each well significantly reduced uncertainty.

The analyses of key reserve indicators provide an important measure of the uncertainty reduction. From the initial stage (UID 13% of project life) to the end of the development (UIM 24% of project life) the range of uncertainty (Ind01 = [3P-1P]/ 3P) reduced from 30% to 7%, and the production (Ind02 = % cumulative production/ 2P) increased from 8% to 21%. In stage UIH, 37% of project life, Ind01 reduced to 4%, while Ind02 increased to 53%.

The use of 12-Step methodology, the UNISM benchmark cases, the real model, and PRMS indicators allowed dynamic uncertainty to be measured over time. Commonly, the reserve evaluation is carried out in the present time of the project, providing cumulative production estimate in the economic limit, in accordance with the Net Present Value (NPV).

Reservoir simulation with probabilistic scenarios permit forecasting, which may estimate reserve indicators not only in current time, but also in key stages of the project, creating an initial estimate to be tracked as a business plan. The continuous addition of new information and comparison with previous estimates, as recommended in the 12-Step methodology, is very good management practice, which improves attractiveness, predictability and reliability of development projects.

6. Acknowledgements

The authors wish to acknowledge the support of ANP and CEPETRO / UNICAMP, as well as CMG and Schlumberger for their software license and technical support.

Keywords: Uncertainties; Decision Making; Development Project; Resource Categorization; PRMS; Numerical Simulation, UNISIM-I Benchmark Cases.

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