Methodology to estimate future production of oil and natural gas, 2020-2033

September 2019

CNH

Comisión Nacional de Hidrocarburos

1. Introduction

The National Hydrocarbons Commission (herein referred to as the Commission) creates a future projection of oil and natural gas production for 2020-2033.

In this document, the Commission utilized available information up to July 5th, 2019 regarding development plans and profiles presented by operators, both from entitlements and contracts. In case of areas without plans or commercial discoveries, the Commission undertook a future projection of productions based on reserves data and the Exploratory Opportunities Database (BDOE, for its initials in Spanish), latest update December 31st, 2018.

This document is a methodology summary, based on the aforementioned information. The components of this methodology are described below, according to the following classification of areas:

- Fields with certified reserves under entitlements and contracts;
- Exploratory entitlements under Pemex;
- Fields with certified reserves under State management; and,
- Exploratory areas under State management.

2. Components of the methodology

2.1 Fields with certified reserves under entitlements and contracts

The extraction component is comprised of fields with discovered reserves, where there is certainty regarding the existence of resources in the subsoil. This list includes areas under entitlement regime, and contractual areas with an approved development plan or production estimates.

In total, 404 areas exist that are operated by Pemex as an entitlement that are currently in the production phase. To model the development of these field, we used development profiles of certified reserves through January 1, 2019, except for in a Development Plan (with respect to the Development Plan approved in Round Zero).

Through July 5, 2019, the Commission has approved 37 Development Plans[1]. For these fields, the profile presented to the Commission is used, except for one of them, which current production levels did not correspond to the observed production to date. Similarly, the Commission has received three Appraisal Reports that were used in this methodology.[2]

[1] Abkatún, Amatitlán, Ayatsil, Ayocote, Bellota, Cahua, Cinco Presidentes, Che, Cheek, Chipilín, Chocol, Cibix, Esah, Guaricho, Homol, Hok, Ixachi, Ixtal, Ixtoc, Kambesah, Ku, Kuil, Madrefil, Manik, Maloob, Miahuapan, Mulach, Octli, Onel, Rabasa, Terra, Teekit Profundo, Tlacame, Uchbal, Xanab, Xikín and Zaap. Xanab is the field which profile was not used in this estimation.

[2] Koban, Tetl and Tlacame

It is assumed that Petróleos Mexicanos has sufficient resources to invest in these fields, regardless of the total investment amount.

For fields with discovered reserves and operated under contracts, the estimation considered the available information up to July 5th, 2019 and includes the development plan presented to CNH by operators.[3]

For those contracts without development plan, the Commission used the development profiles originally calculated the year the field was awarded, only adjusting the period of beginning.

2.2 Exploratory entitlements under Pemex

The exploration component for Pemex consists of two mechanisms:

- Discoveries made by Pemex through 2019
- Estimate of potential discoveries

For the component of discoveries made by Pemex through 2019, seven reported discoveries are considered.[4] The Commission estimated a development profile based on estimated ultimate recovery (EUR) of a well located in the same region, and the profile of 2P reserves, certified through January 1, 2019. It is assumed that Pemex will develop all these 7 discoveries.

For the component estimate of potential discoveries, on each of these areas, a probability analysis was performed, according to the methodology in Annex 1.[5]

In this exercise, an annual budgetary limit of US$2.5 billion is considered. In order to prioritize exploration entitlements, they are sorted from most to least expected value of the potential recoverable volume, in terms of crude oil equivalent estimates for each entitlement, after probability analysis was performed.

In the case of exploratory well success in an area, a production and investment profile has been modelled based on table 1 of Annex 2.

Once a development profile for each project is obtained, an estimate of the Net Present Value (NPV) of income flow subtracting costs is made for each project on a monthly basis, with an annual discount rate of 10%.

If the area does not have a positive NPV, development and production profile investments are not considered and only investment made in exploration and the number of wells drilled is considered. Projects that do have a positive NPV are included in the production base.

[3] Includes all contracts in Round 1.2 and one contract in Round 1.3
[4] Discoveries catalogued as contingent resources: Exploratus-1EXP, Nat-1, Hem-1; discoveries catalogued as certified reserves: Maximino-1DL, Doctus-1; discoveries catalogued as exploratory opportunities: Kokitl-1EXP
[5] Through July 5, 2019. On August 27, 2019, the Energy Ministry issued new titles for 64 exploration entitlements.

2.3 Fields with certified reserves under State management

40 fields with certified reserves are reserved by the State.[6] It is the government's decision to tender these areas in new bidding rounds or award directly to Petróleos Mexicanos for their development.

The present exercise uses the following procedure to estimate the year when production might begin in these blocks, as well as the investment required for their development, assuming operator designation processes, starting June 2020:

1. The blocks are sorted from largest to smallest volume of crude oil equivalent.
2. One bidding round per year where 5 blocks are tendered is assumed, beginning June 2020, auctioning the blocks with largest volumes first.
3. An award rate of 60% is used for each round.
4. If a block is awarded, it is assumed the operator will develop and invest in the field using the certified 2P reserves profile through January 1, 2019, beginning the year of the bidding round.
5. Economic evaluation of Net Present Value is not made, in order to reflect development potential of these fields.

2.4 Exploratory areas under State management

To estimate the potential recoverable hydrocarbons in Mexico, an Exploratory Opportunities Base is used, which was last updated by the Commission on December 31, 2018. This Base includes the number of exploratory opportunities, estimated recoverable volume in different scenarios (P90, P50, Media, P10) for each opportunity, and composition by hydrocarbon type.[7]

In addition, the Five-Year Plan for Exploration and Extraction of Hydrocarbons 2015-2019 is used, last updated in January 2018.

The present exercise uses the following procedure to estimate the year when production might begin in these blocks, as well as the investment required for their development, assuming operator designation processes, starting June 2020.

The award rate of these blocks varies according to location. In this exercise, the following rates are used, presented in Annex 2's Table 3.

[6] These fields are: Akpul, Aluk, Anguilas, Arroyo Zapana, Baksha, Chapabil, Chukua, Citam, Enispe, Gurumal, Hap, Kamelot, Kanche, Kay, Kayab, Kix, Kopo, Las Canas, Lem, Men, Mene, Misón, Mixtán, Nak, Nueva Colonia, Palmaro, Panal, Pit, Pitahaya, Pohp, Ribereño, Toloc, Tsón, Tunich, Uchak, Után, Veinte, Wayil, Zapotal and Zazil-Ha.

[7] Super light, light, heavy, and extra heavy oil, wet gas and dry gas.

Once a block has been awarded, the number of exploratory wells attempted is estimated, as well as the period between the drilling of new wells, as presented in Annex 2's table 2.

Once a development profile is obtained for each of the projects, an estimate of Net Present Value (NPV) of income flow after project costs is taken on a monthly basis, with an annual discount rate of 10%. This process allows to determine the incorporation (or not) of such projects in our estimation.

Annex 1

Probabilistic exercise

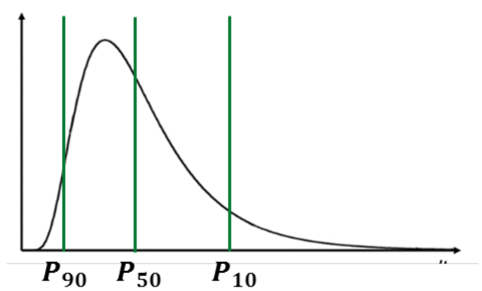
The goal of the exercise is to locate the opportunities with the best prospects around the centroid of each block in the Five-Year Plan. The number of development opportunities is defined by the user.

Once the opportunities with the best prospects in each block are identified, a Montecarlo simulation model is used to determine the distribution of prospective resources in each of the developable opportunities in a block, assuming independence among opportunities. 10,000 iterations are made using the following model:

1. Simulate success or failure of the opportunity using a Bernoilli-type distribution, using as a parameter the probability of geological success. That is, for an opportunity with a 30% probability of success, the simulation will generate 3,000 successes and 7,000 failures.

2. Simulate the distribution of prospective resources, reconstructing the distribution function according to P_{10}, P_{50} and P_{90} and assuming that the variables are distributed in Lognormal form (see Figure 2).

Figure 2. Lognormal Distribution of probability



3. Multiply the simulation of successes and failures for observed prospective resources to obtain a distribution of prospective resources conditional to opportunity success.

The guiding principle for determining blocks to be auctioned each year is the following:

a) Sort blocks in descending order according to the value of prospective resources in risk (VPrR).

b) For each bidding round, the 5 blocks per conventional area, and 10 blocks per unconventional area with the highest VPrR are offered.

c) Subsequently, a random draw with success conditional on the percentage specified in Annex 2’s table 3 is made of the blocks to determine awarding. Blocks that are not awarded will be auctioned in following rounds, comparing once again their VPrRs against those of the new blocks.

d) Once all blocks are awarded, a random draw with uniform distribution is made to evaluate which in blocks production is initiated. For this draw, the probability of geological success of each block is taken into account.

e) If in this draw none of the opportunities in an awarded block are determined for production start, said block is included in the following bidding round to be offered again, respecting the methodology presented in this chapter.

Annex 2

Table 1. Cost and development assumptions for exploratory blocks

Location	Cuenca	EUR of well type (MMBOE)	Exploratory Well (million USD)	Development Well (million USD)	Opex ($USD/bbl PCE)	Infrastructure ($USD/BOE)
Deepwater	Perdido	9.320	$93.8	$84.4	$6.6	$1.0
Deepwater	Mexican Ridges	24.006	$86.5	$77.9	$6.6	$2.0
Deepwater	Salina Basin	9.320	$94.8	$85.3	$6.6	$2.0
Shallow waters	Southeast Basins	24.841	$42.0	$31.0	$4.4	$1.0
Shallow waters	Tampico-Misantla	3.486	$48.0	$21.3	$6.6	$2.0
Shallow waters	Burgos	4.300	$44.0	$13.6	$5.5	$2.0
Onshore Conventional	Burgos	0.442	$6.2	$5.8	$2.1	$1.0
Onshore Conventional	Sabinas	1.821	$6.2	$5.4	$2.1	$1.0
Onshore Conventional	Southeast Basins	7.222	$5.9	$4.0	$5.4	$1.0
Onshore Conventional	Tampico-Misantla	0.223	$5.9	$16.0	$2.0	$1.0
Onshore Conventional	Veracruz	1.945	$5.6	$3.5	$2.1	$1.0
Onshore Unconventional	Burgos	1.878	$7.0	$5.9	$6.0	$2.0
Onshore Unconventional	Sabinas	1.878	$7.0	$5.9	$6.0	$2.0
Onshore Unconventional	Tampico-Misantla	0.405	$5.8	$5.2	$8.2	$2.0

EUR: Estimate Ultimate Recovery
MMBOE: million barrels of oil equivalent
USD: American dollars
BOE: barrel of oil equivalent

Notes:

- Using historic information from wells drilled in Mexico, the location of drilled wells is proposed by basin. The first 180 monthly observations of all wells are used to estimate a decline curve using linear regression, controlling for fixed effects of the well. Recoverable volume and the production profile of wells in analogous basins is taken into account, using information from Questor and Wood Mackenzie.
- For conventional projects, an average cost for exploratory wells was calculated from the costs presented in Exploration Plans by oil operators, through July 5, 2019. For unconventional projects, costs from analogous basins Niobrara Chalk and Southwest Eagle Ford are used.

Table 2. Number of exploratory wells for blocks in Five-Year Plan

Location	Number of exploratory wells	Months between drilling of each well
Deepwater	2	12
Shallow waters	2	8
Onshore conventional	3	6
Offshore unconventional	3	8

Table 3. Number of blocks offered by year and corresponding award rate

Location	Number of contracts offered by year	Award rate
Deepwater	5	60%
Shallow waters	5	50%
Onshore conventional	5	80%
Onshore unconventional	10	60%