SECOND PART: DEVELOPMENT, CONCLUSIONS AND RECOMMENDATIONS

7. Discussion on the recovery factor Dry vs. Wet Tree

One of the most important technical data when the economical evaluations are done is the ***recovery factor***. The recovery factor either of gas or oil expresses the fraction of the hydrocarbons that rely in the subsoil and that is expected or is brought to the surface, this of course will give estimates of the amount of the production and consequently of the profit that is expected to be obtained from the development.

When a volumetric analysis is performed the first step is the creation of geological maps (structure, fault contours and Isopatch maps), once they are prepared the next step is to obtain the expected amount of hydrocarbons recoverable either oil and/or gas (Roebuck, 1992).

The recoverable oil in stock tank barrels:

$$The\ recoverable\ oil\ in\ stock\ tank\ barrels = \frac{6.2898(\varphi)(1-S_w)}{B_o} \times R.F. \times Vol$$

Where:

- 6.2898 = the volume of barrels per cubic meter.
- φ = Porosity, decimal
- S_w =Connate water saturation decimal
- Bo= Oil formation volume factor, reservoir barrel/stock tank barrel
- R.F.= Recovery Factor
- Vol = The reservoir bulk volume from planimetric survey in cubic meters.

The recoverable dry gas in thousands of cubic feet (MCF):

$$The\ recoverable\ dry\ gas\ in\ MCF = 35.3146(\varphi)(1-S_w)\left(\frac{PT_{sc}}{P_{sc}TZ}\right) \times R.F. \times S.F. \times Vol$$

- 35.3146 = the volume of cubic feet per cubic meter.
- φ = Porosity, decimal
- S_w =Connate water saturation decimal
- P = Reservoir pressure
- T = Reservoir temperature in Kelvin
- P_{sc} = Pressure in standard conditions (depending on the required pressure base)
- T_{sc} = Temperature standard. *Usually a temperature of fifteen (15) Celsius degrees.*
- Z =Gas deviation factor (compressibility factor)
- R.F.= Recovery Factor
- S.F. Shrinkage factor.
- Vol = The reservoir bulk volume from planimetric survey in cubic meters.

The conventional discussions relate the recovery factor to the recovery methods which are classified in primary, secondary and tertiary and in particular for the oil fields also named IOR

(Improved oil recovery), EOR (Enhanced oil recovery for Oil). The table 7.1 shown the relation between recovery factors, technologies and their classifications.

Recovery methods	***Also referred as:***	***Technologies***	***Recovery Factor Associated by Roebuck (1992).***	***Recovery Factor Associated by Odland (2000-2008)***
Primary	Primary	Gas: Gas expansion	50-90%	
		Oil: Oil depletion		15-20%
Secondary	IOR (Improved oil recovery) For oil reservoirs	Gas: Water flodding and non miscible gas cap.	40-75%	
		Oil:		15-45% in addition
		Dissolved gas,	5-20%	
		Gas cap,	20-40%	
		Water drive	30-60%	
		Gravity drainage.	25-80%	
Tertiary	EOR (Enhanced oil recovery) for Oil reservoirs.	Oil. Thermal EOR CO2 EOR Other gases EOR Chemical/microbial EOR		2-8% in addition.

Table 7.1 Relation between recovery factors, technologies and its classifications with data from (Odland 2000-2008) and (Roebuck 1992).

A further discussion on these topics is out of the scope of this work, if is desired to complement knowledge on this topic it is suggested to take a look into the following references:

- *Design engineering aspects of waterflooding (Rose et. al, 1989).*
- *Enhanced oil recovery (Green and Willhite, 1998).*
- *Reservoir engineering aspects of waterflooding (Craig Jr., 1993).*
- *Waterflooding (Ganesh, 2003).*

The discussion in this work will be focused to know if there is evidence to differentiate the recovery factor when a development is designed by using dry tree or alternatively wet tree solutions and to find the best fitted probability distributions for different types of fields; non associated gas reservoir, undersaturated oil reservoir, saturated oil reservoir.

7.1 Empirical analysis of recovery factors in deepwater US Gulf of Mexico for dry tree vs. wet tree field development solutions.

Historically the recovery factor of the subsea production systems is perceived to be not as good as the one observed in the solutions that use dry trees. The reasons for this difference might be related to:

1. The cost of the well interventions in subsea production systems is considerable higher compared to fixed or floating platforms with work over systems since they require the mobilization of MODU's (Mobil offshore drilling units) or drilling ships for each well location.
2. The subsea wells operate with a continual high backpressure which causes that the energy that could be used to deplete more efficiently the reservoir is instead, lost in the flow line and in the choke valves of the system. (Scott, 2004).
3. Costs of subsea developments are more sensitive to the number of wells than platform developments.
4. Recoverable reserves depend on incremental costs (Odland, 2000-2008)

Hence for modeling the recovery factor there are two ways that are suggested according to data available and the level of complexity in which the modeling is intended to be performed:

- **Empirical probability distributions of the recovery factors by general analogy** for rapid tests.
- **Recovery factor by factorial model analogy** for deeper analysis.

7.1.1. Purpose

The model here proposed would consider that the recovery factor can be forecasted by analogy to historical values using the recovery factors reported to the MMS of the USA for the fields in deep water. These probability distributions will differentiate the recovery factor when a field is developed with subsea or dry trees in the case of dominant reservoir types:

- Non associate gas reservoir.
- Undersaturated oil reservoir.
- Saturated oil reservoir.

This model is intended to be used for analysis on the Mexican side of the Gulf of Mexico; hence the historical evidence that can be inferred from the statistics of the North of the Gulf of Mexico is considered to be a suitable analogy.

7.1.2 Methodology

The methodology to obtain the probability distributions will be shown next.

1. The information analyzed was taken from the data set “Atlas of Gulf of Mexico Gas and Oil Sands Data Available for Downloading” (MMS, 2006). The data used correspond to the fields of the worksheet:

    a. ***“MMS Field”*** MMS field name.
    b. ***“WDEP”*** Water depth (feet).
    c. ***“RESTYP”*** Dominant reservoir type: Nonassociated gas (N), Undersaturated oil (U), Saturated oil (S).
    d. ***“ORF”*** Oil recovery factor (decimal).
    e. ***“GRF”*** Gas recovery factor (decimal).

2. The data was filtered excluding the sands with associated water depth shallower than 1800 ft. (≈550 m).

3. The sands associated to the dry tree TLP’s and SPAR’s projects listed below were identified (See tables 7.2 and 7.3).

FIELD MMS DENOMINATION	FIELD DEVELOPMENT NICK NAME
GB426	Auger
GC158	Brutus
GB783	Magnolia
GC608	Marco polo
VK915	Marlin
MC807	Mars-ursa
MC243	Matterhorn
VK956	Ram-powell
GC654	Shenzi

Table 7.2 TLP’s Projects located in Gulf of Mexico in water depths deeper than 1800” ft .

4. If the “ORF” or the “GRF” for each observation was found to be “0”, cero, it was assumed that it was not intended to produce and hence those observations were eliminated from the data set.

5. Then the data were filtered and subsets were created according to the dominant reservoir type (Non associated gas (N), Undersaturated oil (U), Saturated oil (S), afterwards subordinate subgroups, with subsets of data related to dry tree and wet tree were also created. A list of those groups and the number of observations for each of them is shown in table 7.4. and figure 7.1.

FIELD MMS DENOMINATION	FIELD DEVELOPMENT NICK NAME
EB643	Boomvang north
GC680	Constitution
MC773	Devils tower
EB945	Diana
GC339	Front runner
GC205	Genesis
GB668	Gunnison
GC644	Holstein
AC025	Hoover
GC826	Mad dog
MC582	Medusa
EB602	Nansen
VK825	Neptune
AT063	Telemark

Table 7.3. SPAR Projects located in Gulf of Mexico in water depths deeper than 1800" ft.

6. From the previous list, subgroup "2. General oil recovery factor from non associate gas fields" (10 observations) and the subordinate groups "2.1 Dry tree oil recovery factor from non associate gas fields"(8 observations) and "2.2 Wet tree oil recovery factor from non associate gas fields"(2 observations) were found not to be statistically valid as reference due the few number of observations and consequently considered just as general reference. See figure 7.1.

7. The data sets were analyzed to find the best suitable probability distribution. The program "@Risk for Excel, Risk Analysis Add-in for Microsoft Excel Version 5.5.1 Industrial Edition" was used. From that program the tool "Distribution fitting" and the method "parameter estimation" were used. The possible probability distribution to be compared by the program were:

- Beta general
- Exponential
- Extreme value distribution
- Gamma
- Inverse Gauss
- Logistic
- Log-Logistic
- Log- Normal
- Normal
- Pareto
- Pearson 5
- Pearson 6
- Triangular
- Uniform
- Weibull

The goodness of fit was evaluated by calculation of the statistic χ2.

8. The probability distributions shown above were compared considering the goodness of fit and in case that the statistic χ2 were close for two or more distributions, the probability distribution that was comparatively more simple to model for further use was preferred.

9. A test was also done to test the hypothesis: $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$ vs. $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets created in this methodology.

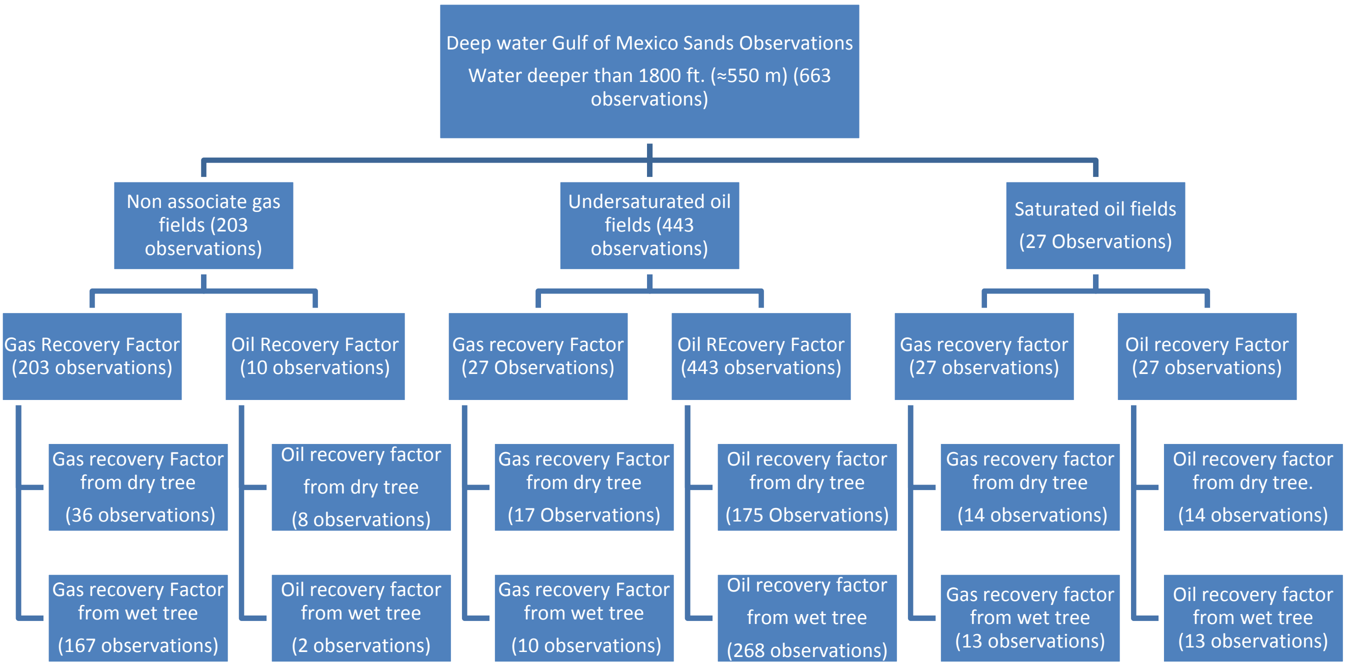

Figure 7.1 Subgroups and subordinate groups with number of observations from sands in projects located in Gulf of Mexico at water depths deeper than 1800" ft.

7.1.3 Results and inferences

The oil and gas recovery factors listed in this data set correspond to the estimated values declared by the operator companies to the MMS for each sand, and are subject to change due to different factors including technology improvements, operations management philosophy and refinement of calculations as more information from the reservoirs become available

The class of fields most exploited in deepwater in Gulf of Mexico corresponds to undersaturated oil fields (≈ 65%) followed by the non associated class (≈ 30%) and finally saturated oil fields class (≈ 4%).

The mean recovery factors for the different types of reservoir are summarized in table 7.5. According to the test of hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$ vs. $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets created in this methodology, there is not statistical evidence that suggest that a field developed with dry tree has a better recovery factor than one developed with wet tree solutions.

Subgroup or subordinate group		Number of observations
1. Gas recovery factor from non associate gas fields		***203***
	1.2 Dry tree gas recovery factor from non associate gas fields	*36*
	1.3 Wet tree gas recovery factor from non associate gas fields	*166*
2. Oil recovery factor from non associate gas fields		***10***
	2.1 Dry tree oil recovery factor from non associate gas fields	*8*
	2.2 Wet tree oil recovery factor from non associate gas fields	*2*
3. Gas recovery factor from undersaturated oil fields		***27***
	3.1 Dry tree gas recovery factor from undersaturated oil fields	*17*
	3.2 Wet tree gas recovery factor from undersaturated oil fields	*10*
4. Oil recovery factor from undersaturated oil fields		***443***
	4. 1 Dry tree oil recovery factor from undersaturated oil fields	*175*
	4.2 Wet tree oil recovery factor from undersaturated oil fields	*268*
5. Gas recovery factor from saturated oil fields		***27***
	5.1 Dry tree gas recovery factor from saturated oil fields	*14*
	5.2 Wet tree gas recovery factor from saturated oil fields	*13*
6. Oil recovery factor from saturated oil fields		***27***
	6.1 Dry tree oil recovery factor from saturated oil fields	*14*
	6.2 Wet tree oil recovery factor from saturated oil fields	*13*

Table 7.4. Subgroups and subordinate groups with number of observations from sands in projects located in Gulf of Mexico at water depths deeper than 1800" ft.

With exception of the gas recovery factor from saturated oil fields, all the other test fail to reject the null hypothesis $\mu_{\text{dry tree}}$- $\mu_{\text{wet tree}}$ = 0. This means that the inferred mean value of recovery factor is the same either for dry tree vs wet tree solutions.

In the only exception (gas recovery factor of the saturated oil fields) is perceptibly a difference in favor of the dry tree. Despite the oil recovery factor from the same type of reservoirs is larger for dry tree than for the wet tree, the pooled variance for both samples is too large to make a differentiation on their means.

It is inferred that a criteria that prefer a dry tree with the argument of a better recovery factor must be evaluated further, extending the analysis to consider the specific characteristics of the reservoir and the exploitation concept that is part of the field to be developed.

Subgroup	***Best fitted probability distribution dry tree***	***Mean recovery factor dry tree from best fitted probability distribution***	***Best fitted probability distribution wet tree***	***Mean recovery factor wet tree from best fitted probability distribution***
Gas recovery factor from non associate gas fields	*Triangular*	*0.5340*	*Triangular*	*0.4989*
Gas recovery factor from undersaturated oil fields	*Triangular*	*0.5348*	*Logistic*	*0.5586*
Oil recovery factor from undersaturated oil fields	*Gamma*	*0.3083*	*Log Normal*	*0.3207*
Gas recovery factor from saturated oil fields	*Normal*	*0.585*	*Normal*	*0.43846*
Oil recovery factor from saturated oil fields	*Triangular*	*0.3459*	*Exponential*	*0.2510*

Oil recovery factor from non associate gas fields (Referencial)	***Best fitted probability distribution combined dry and wet tree***	*Weibull*	***Mean recovery factor combined dry and wet tree***	*0.3057*

Table 7.5. Summary of the results of the recovery factor according to the subgroups and subordinate groups from sands in projects located in Gulf of Mexico at water depths deeper than 1800" ft.

7.2 Multifactorial models for the prediction of the recovery factor.

The prediction of the recovery factor based on models that consider a number of factors is popular among operator companies and regulatory authorities. Both Operator companies and regulatory entities are interested in getting the most of the extraction of hydrocarbons, however it could be an alternative for the operator companies to select a field development solution focusing on just one fraction of the feasible recovery in order to save investment costs. For the regulatory authorities this is not tolerable since considerable volumes that could be extracted and count for tax purposes as a future income are instead abandoned in the subsoil.

An example of a regulatory authority is the Norwegian Petroleum Directorate. Extracted from its Resource Report 2005 we can have a view of what is the point of view of this institution regarding to the recovery factor.

> *The objective of the authorities is that as much as possible of the resources that are proven on the Norwegian continental shelf are recovered in a manner that creates the highest possible value for society.The Norwegian Petroleum Directorate strives to make this feasible, partly by helping the petroleum industry choose the best recovery methods, encouraging the various players to work together to gain benefit from coordination, and putting focus on the framework conditions where it considers this to be necessary. To ensure a high recovery factor, good utilization of the resources and value creation from the fields, access to appropriate technology, sufficiently qualified personnel and ability to take decisions are essential. [NPD, P.p. 30, 2005]*

7.2.1 The Reservoir Complexity Index from the Norwegian petroleum directorate.

Regarding the calculation of the recovery factor, the proposal of the NPD is to bench mark the recovery factor as a function of the Reservoir Complexity Index (RCI). This Index has fundament in the fact that the reservoirs have unique characteristics but if there is a way to assess the quality of the reservoirs, the complexity indicated by one measure (the reservoir complexity index, RCI) will have a strong correlation with the recovery factor expected from a development.

The parameters that describe the reservoir quality according to the proposal by NPD include:

- General permeability.
- Contrasts in permeability
- Vertical and horizontal communications in the reservoir (influenced, for example, by faults),
- Impervious strata,
- Density,
- Tendency for water or gas to be drawn towards the production wells (coning) and the like.

For each parameter are given a value based on objective limits and subjective assessments. The factors are pondered and the possible value result of the index is normalized to be between 1 and 0. High values of the index mean a more complex reservoir. (NPD, 2005).

Bygdevoll (Bygdevoll, 2010) did show the most important parameters found by NPD for the Norwegian fields. The scope of the study by NPD and oil companies of the Norwegian Continental Shelf considered the factors that had better correlation for its area of interest. It should not be understood that the same factors have the same relevance for all the fields around the globe. Table 7.3 reproduce the data contained in the lecture by Bygdevoll, regarding the RCI complexity attributes, its description and complexity scores.

7.2.2 Inferences about the Reservoir Complexity Index from the Norwegian petroleum directorate on the performance of dry and wet tree solutions.

From the same presentation a data set was extracted for the fields encompassed by the study differentiating the dry tree and the wet tree developments. The results of the analysis of this data set are shown graphically in figure 7.2.

What can be inferred from the figure 7.2 is that on the Norwegian Continental Shelf, depending of the complexity of the reservoir, there is:

A linear trend on the recovery factor for fields developed with dry tree to decrease as the reservoir becomes more complex.

An exponential trend on the recovery factor for fields developed with wet tree to decrease as the reservoir becomes more complex. A linear trend was also tested but is not shown because the exponential regressed function has a better R^2 (R^2 = 0.5891 in linear regression vs R^2 = 0.6672 in exponential regression).

When the reservoir has a low complexity (up to 0.4) it seems that there is not an evident difference between the performances of dry vs wet tree solutions. As the complexity increases however the dry tree solutions become a better option based on the recovery factor registered.

Many oil companies worldwide employ methodologies similar to the RCI as a common basis. Although the calculation of this index is out of the scope of this work it could be useful for the reader to take a look on the patented work of Harrison (Harrison, 2004) who propose *"A method for computing complexity, confidence and technical maturity indices for the evaluation of a reservoir."*

	Complexity attribute	***Description***	***Complexity score***				
			Low complexity				***High complexity***
			1	***2***	***3***	***4***	***5***
1	*Average permeability*	*Describes the pore volume weighted average permeability in the main flow direction of the defined reservoir. mD*	*>10*	*1000-10000*	*100-1000*	*10-100*	*<10*
2	*Permeability contrast*	*Describes the permeability contrast between geological layers/facies types, and is calculated as log 10 [Kmax/Kmin]*	*<1*	*1-2*	*2-3*	*3-4*	*>4*
4	*Structural complexity*	*Describes how fluid flow between wells is affected by fault density, fault throw, fault transmitability.*	*The fault properties does not restrict fluid flow*				*The fault properties restrict fluid flow significantly. (High density of faults with throw larger than reservoir thickness and/or zero transmissibility).*
5	*Lateral statigraphic continuity*	*Describes the statigraphic continuity of the flow units in the main flow direction within the defined reservoir.*	*High degree of continuity*				*Highly continuous. Difficult to predict/describe injector/producer connecting flow units.*
9	*Stock Tank Original Oil in Place (STOOIP) density*	*Describes the areal concentration of STOOIP and is defines as STOOIP/area (mill Sm^3/km^2)*	*<4.5*	*2-4.5*	*1-2*	*0.5-1*	*<0.5*
11	*Coning tendency*	*Describes the conning problems associated with a gas cap or aquifer support. Large complexity only in cases where the oil band is thin*	*No conning tendency*		*Some coning problems from gas cap or aquifer*		*Thin oil zone and production severely restricted by gas or water coning problems*

Table 7.3 RCI complexity attributes, their description and complexity scores [Bygdevoll, P.p. 7, 2010].

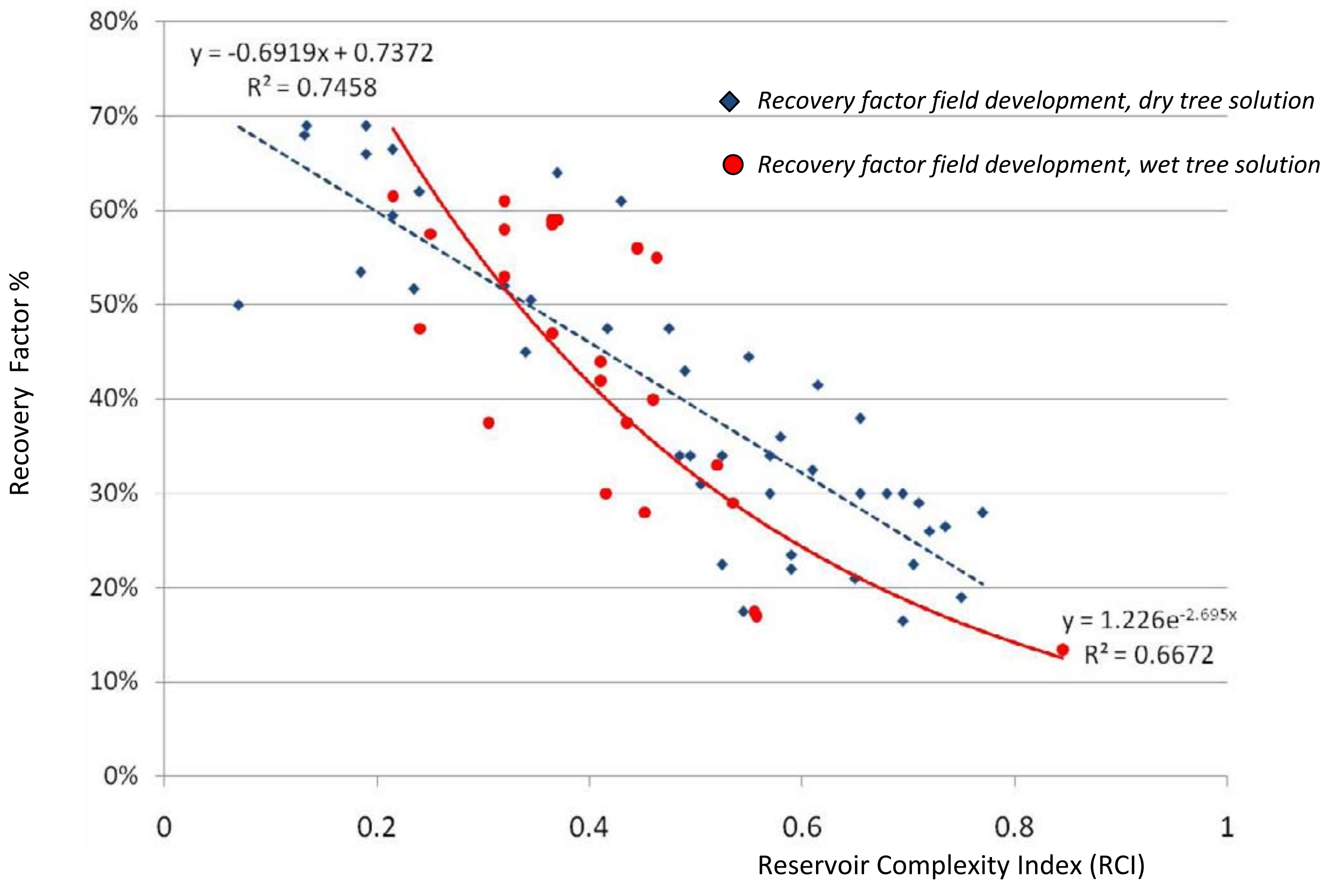

Figure 7.2 Scatter plot and a regression line showing the correlation between the recovery factors for oil from various deposits in relation to the reservoir complexity index (RCI), inferred data set from Bygdevoll, (Bygdevoll, P.p. 10, 2010]

8. Models presentation

Most of the calculations were made using the "Oil and Gas Exploration Economic Model" of the Nova Scotia Department of Energy (Nova Scotia, 2008), see annex F, and the results obtained were adjusted where necessary by the "Empirical cost models for TLP's and SPARS´s " (Jablonowsky, 2008), and the "Models of Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, System Description & FMEA" (Goldsmith, 2000).

In this work is also proposed a way to calculate the added value of an offshore structure acting as a hub, see point 8.4.

Tax calculations are out of the scope of this work, consequently, the results will show just values before taxes.

8.1 Oil and Gas Exploration Economic Model of the Nova Scotia Department of Energy

The description of the model as given on the web page is reproduced in the next two paragraphs.

> *The Oil and Gas Exploration Economic Model is an excel based model designed to provide screening economics for the evaluation of oil and gas exploration prospects and discoveries on the Nova Scotian shelf in the shallow waters around Sable Island, either as tie-ins to existing infrastructure or as stand-alone developments, and in deep water either as stand alone or with subsea tie back to existing infrastructure.*
>
> *The model provides full cycle calculations, from exploration to abandonment, and includes Nova Scotia offshore royalty and provincial and federal corporate income taxes. The government share is therefore incorporated into the cash flow and economic indicator calculations. [Nova Scotia,, P1, 2008].*

A full description of the model is shown in Annex F. Since the aim of this work is to evaluate a region that is different than this model is tailored for, a modification of the input costs was necessary. Tables 8.1, 8.2 and 8.3 show the assumptions used in the economical calculations of the investments in the field developments scenarios.

8.2 Empirical Cost Model for TLP's and SPAR's CAPEX.

Jablanowsky (Jablonowsky, 2008) presented a paper which estimates costs for SPAR's and TLP's projects using public and private data on 24 major projects. Besides, to provide an analysis of the variables that affect costs, the paper investigates the complexity of regression model specification in a decision-making setting. He also evaluates the sensitivity to modeling assumptions, sample selection bias, and other model specification issues.

When the models from point 8.2 and also 8.3 were used, a simple update in the costs was made using the "***IHS CERA Upstream Capital Costs Index (UCCI)".*** *The IHS CERA UCCI tracks the costs of equipment, facilities, materials, and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of twenty eight onshore, offshore, pipeline and LNG projects. It is similar to the consumer price index (CPI) in that it provides a* *clear, transparent benchmark tool for tracking and forecasting a complex and dynamic environment. The UCCI is a work product of CERA's Capital Costs Analysis Forum for Upstream (CCAF-U)."* [IHS Indexes, P1, 2010].

General Cost & Time Assumptions			
Estimate Date		1-Jan-09	
Deepwater Limit	Metres	200	
		Shallow Water	Deep Water
Seismic & Fixed Times			
Seismic Program Time	Days	90.0	90.0
Seismic Program Cost	KUSD	7,500.0	7,500.0
Seismic Processing Time	Days	180.0	180.0
Seismic Processing Cost	THOUSAND USD	3,500.0	3,500.0
Processing to Wildcat Time	Days	120.0	120.0
Wildcat Review Time	Days	90.0	90.0
Widcat Review Cost	THOUSAND USD	500.0	500.0
Wildcat to Appraisal Time	Days	120.0	120.0
Appraisal Review Time	Days	30.0	30.0
Appraisal Review Cost	THOUSAND USD	350.0	350.0
Time Between Appraisal Wells	Days	90.0	90.0
Appraisal to Preliminary Engineering	Days	180.0	180.0
Prelim Eng & Regulatory Prep	Days	300.0	300.0
Regulatory Approval	Days	180.0	180.0
Rig Rate	USD/day	250,000.0	500,000.0
Exploration / Appraisal Well Drilling			
Fixed Cost per well	THOUSAND USD	4,000.0	15,000.0
Fixed Cost per metre	USD/metre	2,300.0	3,400.0
Variable Cost per day (non-rig)	USD/day	180,000.0	250,000.0
Fixed days	Days	4.0	10.0
Average metres / day	metre/day	60.0	50.0
Development Well Drilling			
Fixed Cost per well	THOUSAND USD	3,000.0	6,000.0
Fixed Cost per metre	USD/metre	2,300.0	3,200.0
Variable Cost per day (non-rig)	USD/day	90,000.0	230,000.0
Fixed days	Days	2.0	4.0
Average metres / day	metre/day	40.0	40.0
Well Completion			
Fixed Cost per well	THOUSAND USD	700.0	700.0
Fixed Cost per metre	USD/metre	900.0	900.0
Variable Cost per day (non-rig)	USD/day	50,000.0	200,000.0
Fixed days	Days	2.0	3.0
Average metres / day	metre/day	600.0	600.0
Reenter & clean keeper	Days	4.0	4.0
Renenter predrill	Days	2.0	2.0
Preliminary Engineering			
Fixed Cost	THOUSAND USD	5,000.0	5,000.0
Variable Cost	USD/mcf	3.0	3.0

Table 8.1 Assumptions used in the economical calculation of the investments in field developments scenarios.

Gas Facilities			
Fixed Platform Fixed Cost	THOUSAND USD	7,000.0	
Fixed Platform Cost / Metre Water	THOUSAND USD/metre	320.0	
Fixed Platform Topside Fixed Cost	THOUSAND USD	25,000.0	
Fixed Platform Variable Cost	THOUSAND USD/MMSCFD	850.0	
Production Jack-up Fixed Cost	THOUSAND USD	190,000.0	
Production Jack-up Topside Fixed Cost	THOUSAND USD	5,000.0	
Jack-up Topside Variable Cost	THOUSAND USD/MMSCFD	600.0	
Tehtered Structure Fixed Cost	THOUSAND USD		300,000.0
Tethered Structure Cost /Metr e Water	THOUSAND USD/metre		5.0
Tethered Structure Topside Fixed Cost	THOUSAND USD		5,000.0
Tethered Structure Variable Cost	THOUSAND USD/MMSCFD		1,000.0
Additional Fixed Process Cost Sour Gas	THOUSAND USD	20,000.0	20,000.0
Additional Variable Process Cost Sour Gas	THOUSAND USD/MMSCFD	300.0	300.0
Subsea Well Surface Equipment	THOUSAND USD	2,000.0	10,000.0
Subsea Well Flowline Bundle	THOUSAND USD/Km	1,500.0	10,000.0
Subsea Manifold Fixed Cost	THOUSAND USD	9,000.0	25,000.0
Subsea Manifold Cost	THOUSAND USD/well	300.0	600.0
Oil Facilities			
FPSU Fixed Cost	THOUSAND USD	250,000.0	350,000.0
FPSU Platform Cost /MetreWater	THOUSAND USD/metre	5.0	5.0
FPSU Platform Topside Fixed Cost	THOUSAND USD	200,000.0	250,000.0
FPSU Platform Variable Cost	THOUSAND USD/MMBBL	1,200.0	1,200.0
Rented FPSU Fixed Cost	THOUSAND USD/day	170.0	200.0
Rented FPSU Variable Cost	THOUSAND USD/MMBBL/day	2.5	2.5
Export			
Export to Shore Pipeline Fixed Cost	THOUSAND USD	10,000.0	20,000.0
Export to Shore Pipeline Variable Cost	THOUSAND USD/km	1,000.0	1,200.0
Satellite Pipeline Fixed Cost – Sweet	THOUSAND USD	12,000.0	27,000.0
Satellite Pipeline Variable Cost – Sweet	THOUSAND USD/km	1,200.0	2,700.0
Satellite Pipeline Fixed Cost – Sour	THOUSAND USD	14,000.0	31,500.0
Satellite Pipeline Variable Cost – Sour	THOUSAND USD/km	1,400.0	3,150.0
Subsea Export Bundle Fixed Cost - Sweet	THOUSAND USD	7,000.0	15,750.0
Subsea Export Bundle Variable Cost – Sweet	THOUSAND USD/km	2,500.0	5,625.0
Subsea Export Bundle Fixed Cost – Sour	THOUSAND USD	10,000.0	22,500.0
Subsea Export Bundle Variable Cost - Sour	THOUSAND USD/km	3,500.0	7,875.0
Engineering and Project Management	%	0.1	0.1
Facilities Contingency	%	0.2	0.2

Table 8.2 Assumptions used in the economical calculation of the investments in field developments scenarios.

Abandonment Cost			
Fixed Platform Fixed	THOUSAND USD	3,000.0	
Fixed Platform per depth	THOUSAND USD/metre	30.0	
Jack-up Fixed Cost	THOUSAND USD	5,000.0	
Tethered Structure Fixed Cost	THOUSAND USD		5,000.0
FPSU Fixed Cost	THOUSAND USD		5,000.0
Subsea Manifold	THOUSAND USD	2,000.0	3,000.0
Cost per Surface Well	THOUSAND USD	2,000.0	2,000.0
Cost per Subsea Well & Flowline Bundle	THOUSAND USD	3,500.0	3,500.0
Export Pipeline variable cost	THOUSAND USD/km	100.0	100.0
Satellite Pipeline variable cost	THOUSAND USD/km	150.0	250.0
Operating Costs			
Platform & Jack-up Facilities			
Fixed Cost /Year			
Subsea	THOUSAND USD	2,000.0	2,000.0
basic process, water knock out	THOUSAND USD	7,000.0	7,000.0
full process, sweet	THOUSAND USD	19,000.0	19,000.0
full process, sour	THOUSAND USD	25,000.0	25,000.0
Fixed Cost /Year / Capacity			
Subsea	USD/MMSCFD	200.0	200.0
basic process, water knock out	USD/MMSCFD	280.0	280.0
full process, sweet	USD/MMSCFD	370.0	370.0
full process, sour	USD/MMSCFD	530.0	530.0
Variable Cost			
Subsea	USD/MCF	0.1	0.1
basic process, water knock out	USD/MCF	0.1	0.1
full process, sweet	USD/MCF	0.2	0.2
full process, sour	USD/MCF	0.2	0.2
Oil Costs			
Fixed Cost/Year	THOUSAND USD	10,000.0	12,000.0
Fixed Cost /Year / Capacity Sweet	USD/MBOPD	250.0	250.0
Fixed Cost /Year / Capacity Sour	USD/MBOPD	300.0	300.0
Variable Cost Sweet	USD/BBL	2.5	2.5
Variable Cost Sour	USD/BBL	3.2	3.2
Transport & Process Tariff			
Direct Pipeline Tie-in	USD/MCF	0.4	0.4
Satellite to Main Platform – Sweet	USD/MCF	0.6	0.6
Satellite to Main Platform – Sour	USD/MCF	0.8	0.8
Subsea Process & Transport – Sweet	USD/MCF	1.0	1.0
Subsea Process & Transport – Sour	USD/MCF	1.2	1.2
Shuttle Tankers	USD/BBL	0.7	0.7
Pipelines			
Fixed Cost /Year	THOUSAND USD	2,000.0	2,000.0
Variable Cost	THOUSAND USD / km	40.0	40.0

Table 8.3 Assumptions used in the economical calculation of the investments in field developments scenarios.

8.3 Goldsmith Models for OPEX, RAMEX and RISKEX.

Reference is made to paragraph 5.3 and "Models of Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, System Description & FMEA" (Goldsmith, 2000). The RAMEX results from this report are used to correct the calculations presented in chapter 9. The RISKEX are not included because every concept development has a particular and unique set of characteristics that cause considerably different outcome scenarios and consequently different results, too complex for a first initial screening as the scope of this work considers.

8.4 Value added of a floating structure acting as a Hub

As it is show in appendix G, the activity in deep water offshore Mexico is having place in a region with an evident lack of preexisting infrastructure. This fact makes it important to develop a network of facilities that should increase the feasibility of development in the future.

Hence it is proposed here that additional offshore structures shall have an added value for comparison purposes. This added value will be calculated by doing an evaluation of NPV for the prospects that could be developed if the facility would be in place already.

To account for this added value, a series of assumptions have been considered:

1. It will be assumed that the estimated prospective resources are the real original volume in place.
2. The net present value will also be discounted by some assigned probabilities representing discovery, appraisal and development in the way that:

Accounted added value =

NPV (Development the field X Overall Chance of success)

When apply…	*- NPV(Cost for planning development the field X Probability of pass an appraisal, given a discovery)*
When apply…	*- NPV (Cost for appraisal X Probability of a discovery)*
When apply…	*- NPV (Cost for wildcat)*

Where:

Overall Chance of Success = (Probability of discovery) X (Probability to pass to appraisal given a discovery) X (Probability of develop, given an appraisal, given a discovery)

These formulas are intended to discount the uncertainty of the discovery and also the uncertainty related to pass the different decision gates mentioned in chapter 4. It will also discount the irreversible investments that occur in the field development process.

3. The criteria to add prospects to the analysis was the distance to the proposed facility; when it was identified that there was less than 90 km in a slightly curved route, the prospect was allowed to be included in the calculations.

4. It should not be understood that all the included prospects are proposed to be tied back to the host facility since there are capability restrictions in every structure; it is just an assumption to calculate the added value of new infrastructure in the region of interest.

5. The parameters of the NPV calculation will be shown in chapter 9. As a general case, for calculation purposes, we will assume a subsea field development with a tie back to processing and a production stream induction through the offshore. In some cases an array in “daisy chain” is proposed. For many of the prospects a low probability and low forecasted resources were assumed since there was not a clear expectation related to them in the literature listed in chapter nine.

9.0 Case Analysis.

The scenarios to be studied in this thesis are based on the prospective areas of development of the National Company PEMEX Exploración y producción.

According to Morales (Morales, 2009) Nine areas were defined as the most important for Mexican deep water. The most relevant characteristics to be considered were economical value, prospective resource size, hydrocarbon type, geological risk, distance to production facilities, and environmental restrictions. Figure 9.1 shows the prospective hydrocarbon fluids in Mexican offshore areas as well as the relative position of some of the exploratory wells and US developments for reference. Figure 9.2 shows the location of the areas listed in table 9.1. Table 9.1. lists the areas with its associated geological risks and water depth.

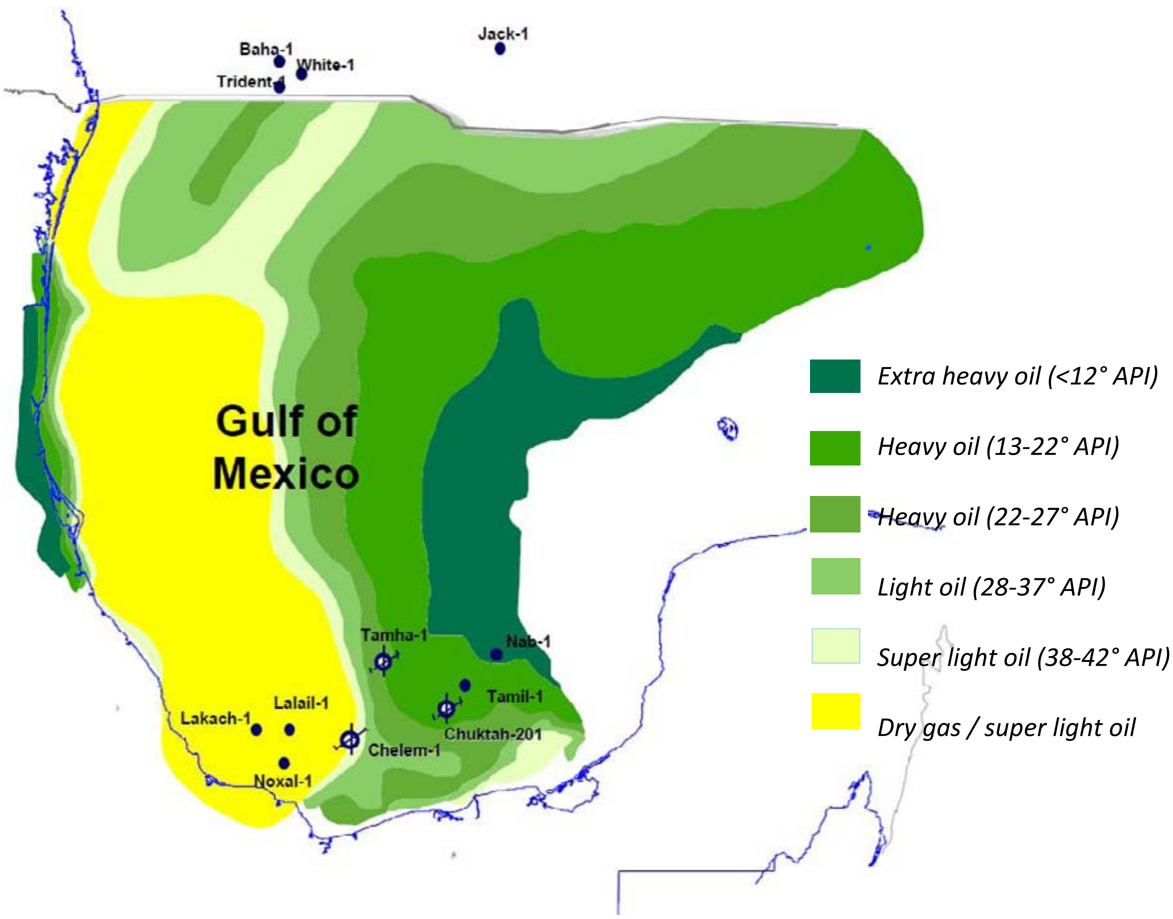

Figure 9.1 Prospective hydrocarbon fluids in Mexican offshore areas (Morales, 2009)

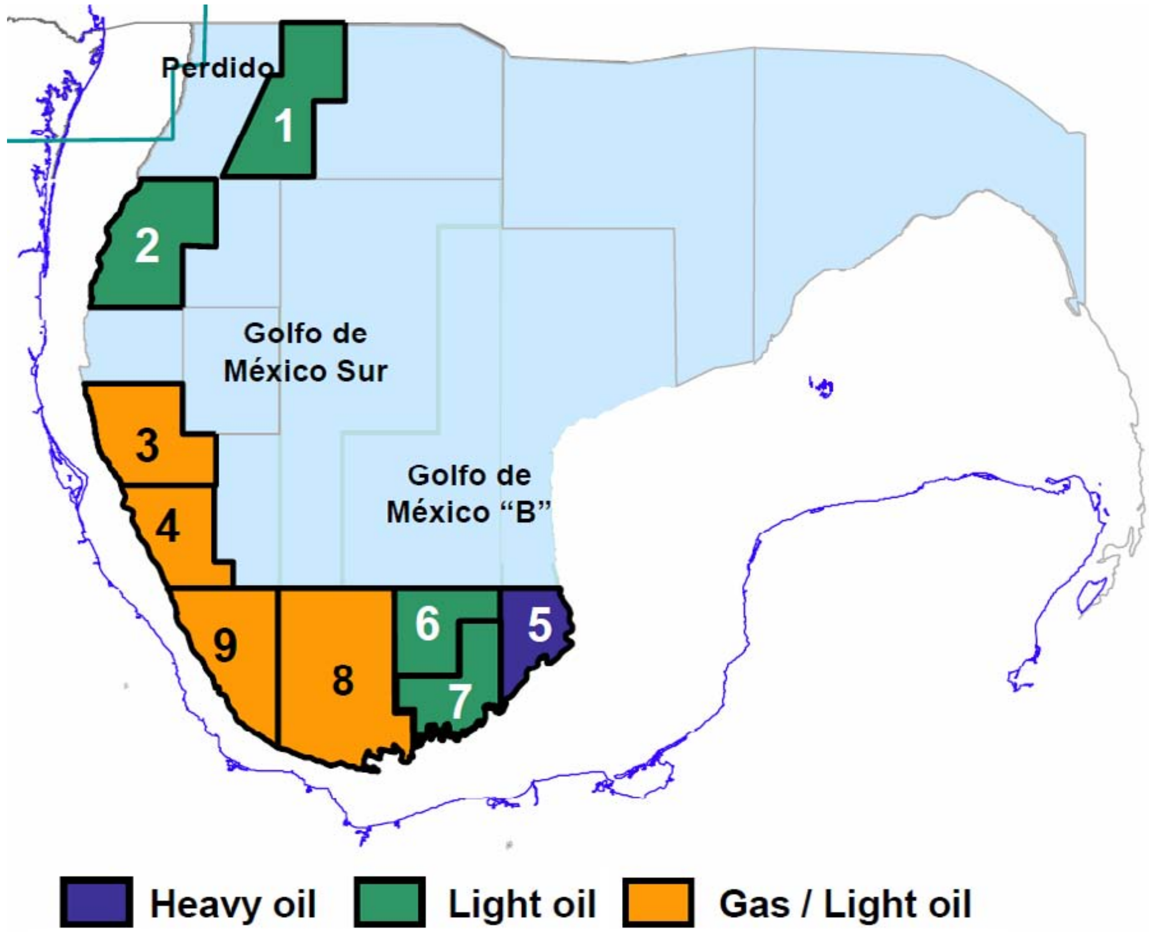

Figure 9.2 Mexican deep water areas after PEMEX (See table 9.1).(Morales, 2009)

Area	*Risk*	*Water depth (m)*
1. Perdido folded belt	*Low-Moderate*	*>2,000*
2. Oreos	*Moderate-High*	*800-2,000*
3. Nancan	*High*	*500-2,500*
4. Jaca-Patini	*Moderate-High*	*1000-1,500*
5. Nox-Hux	*Moderate*	*650-1,850*
6. Temoa	*High*	*850-1,950*
7. Han	*Moderate – High*	*450-2,250*
8. Holok	*Low-moderate (Western)*	*1,500-2,000*
	High (Eastern)	*600-1,100*
9. Lipax	*Moderate*	*950-2,000*

Table 9.1: Prospective deepwater areas defined by PEMEX in Mexican offshore. (Morales, 2009)

Table 9.2 lists the exploratory wells drilled by Pemex in deep waters (more than 500 meters water depth):

YEAR	*WELL*	*WATER DEPTH*	*TOTAL DEPTH*	*RESULT*	*Original Volume in place*	
					MMMcf	*MM B.O.E.*
2004	*Chukta-201*	*513 m*	*4901 m*	*Dry hole*	*-------------*	*------------------*
2004	*Nab-1*	*679 m*	*4050 m*	*Extra heavy oil, non commercial*		*408*
2006	*Noxal-1*	*936 m*	*3640 m*	*Gas, non comercial*	*583.60*	*85.9*
2007	*Lakach-1*	*988 m*	*3813 m*	*Gas, under development*	*1,732.70*	*255.1*
2007	*Lalail-1*	*805 m*	*3815 m*	*Gas, non comercial*	*1,181.30*	*173.9*
2008	*Chelem-1*	*810 m*	*3125 m*	*Dry hole*	*-------------*	*------------------*
2008	*Tamha-1*	*1121 m*	*4083 m*	*Dry hole*	*-------------*	*------------------*
2008	*Tamil-1*	*778 m*	*3598 m*	*Heavy oil, may be developed*		*200 (Prospective resources not incorporated as reserves)*
2009	*Leek-1*	*851 m*		*Gas, under evaluation*	*156.1*	*18*
2009	*Catamat-1*	*1230 m*	*5025 m*	*Gas, non-commercial*	*-------------*	*------------------*
2009	*Etbakel-1*	*681 m*	*4525 m*	*Oil, non-commercial*	*-------------*	*------------------*
2009	*Holok-1*	*n/a*	*---------*	*Non-productive, water*	*-------------*	*------------------*
2009	*Kabilil*	*n/a*	*-----------*	*Dry hole*	*-------------*	*------------------*

Table 9.2: Exploratory wells drilled by Pemex in deep waters (more than 500 meters water depth) from 2004-2009.

9.1 General basis for analysis.

As a result it was selected for study the set of deep water fields formed by Noxal, Lakach, Lalail, and Leek, incorporating also the shallow water discovery Tabscoob due its close location to the deep water fields.

The analysis will not include Tamil and Nab fields, located in the Campeche bay region “Nox-Hux”, however they will be commented at the end of this chapter. These deep water heavy oil fields of Mexico are in a status of not commercially feasible, is possible that they are not technically feasible at this moment.

A summary of the initial assumptions projects evaluation are depicted in table 9.3. The projects of field development considered are Lakach (Lakach Field) and Holok (Noxal, Lalail, Leek and Tabscoob fields). The name of the projects is just a proposal for the analysis in this study and should not be understood that are the real denomination of the projects.

The association of the fields in the project Holok is also a proposal made in consideration of the relative proximity between the fields and type of crude that is expected to be produced. The amount of reserves introduced for each case was the original volume in place multiplied by the mean recovery factor obtained for non associated gas reservoirs, see table 7.5 in chapter 7. Annex G provide more detailed information about each one of the fields.

One main characteristic of the area is that there is not closer facility than the compression Station Lerdo, around 50 km from Lakach development. Second closer export option for gas is located at least 130 km from Lakach in Coatzacoalcos.

Project	***Lakach***	***Holok***			
Evaluation Parameters					
Discount Rate	*0.12*	*0.12*	*0.12*	*0.12*	*0.12*
Discount To	*Decision Date*	*Decision Date*	*Decision Date*	*Decision Date*	*Decision Date*
Economic Scenario	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*	*Scenario 1 : NYMEX*
Project Parameters					
Project Name	*Lakach*	*Noxal*	*Leek*	*Tabscoob*	*Lalail*
Current Project Stage	*Development*	*Appraisal*	*Appraisal*	*Appraisal*	*Appraisal*
Product Type	*Gas*	*Gas*	*Gas*	*Gas*	*Gas*
Original volume in place (Bcf)	*1732.7*	*583.6*	*156.1*	*140.9*	*1181.3*
Mean Reserves (Bcf) Wet tree design	*864.44*	*291.16*	*77.88*	*70.30*	*589.35*
Mean Reserves (Bcf) dry tree design	*925.26*	*311.64*	*83.36*	*75.24*	*630.81*
Water Depth (metres)	*988*	*936*	*848*	*234*	*806*
Reservoir Depth (m MSL)	*3150*	*2100*	*2200*	*1700*	*2450*
Reservoir Complexity	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*
Areal Extent Factor	*Medium*	*Medium*	*Medium*	*Medium*	*Medium*
Reservoir Pressure	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*	*Normally Pressured*
Gas Calorific Value (btu/scf)	*1086*	*1086*	*1086*	*1086*	*1086*
Liquid Yield (bbl/mmcf)	*59*	*59*	*59*	*59*	*59*
Gas Type	*Sweet*	*Sweet*	*Sweet*	*Sweet*	*Sweet*
Keep Appraisal Wells ?	*No*	*No*	*No*	*No*	*No*
Risk Parameters (Chance of Proceeding to Next Phase)					
Appraisal	*N/A*	*0.75*	*0.75*	*0.75*	*0.75*
Development Planning	*1*	*1*	*1*	*1*	*1*

Table 9.3: Initial assumptions for projects evaluation.

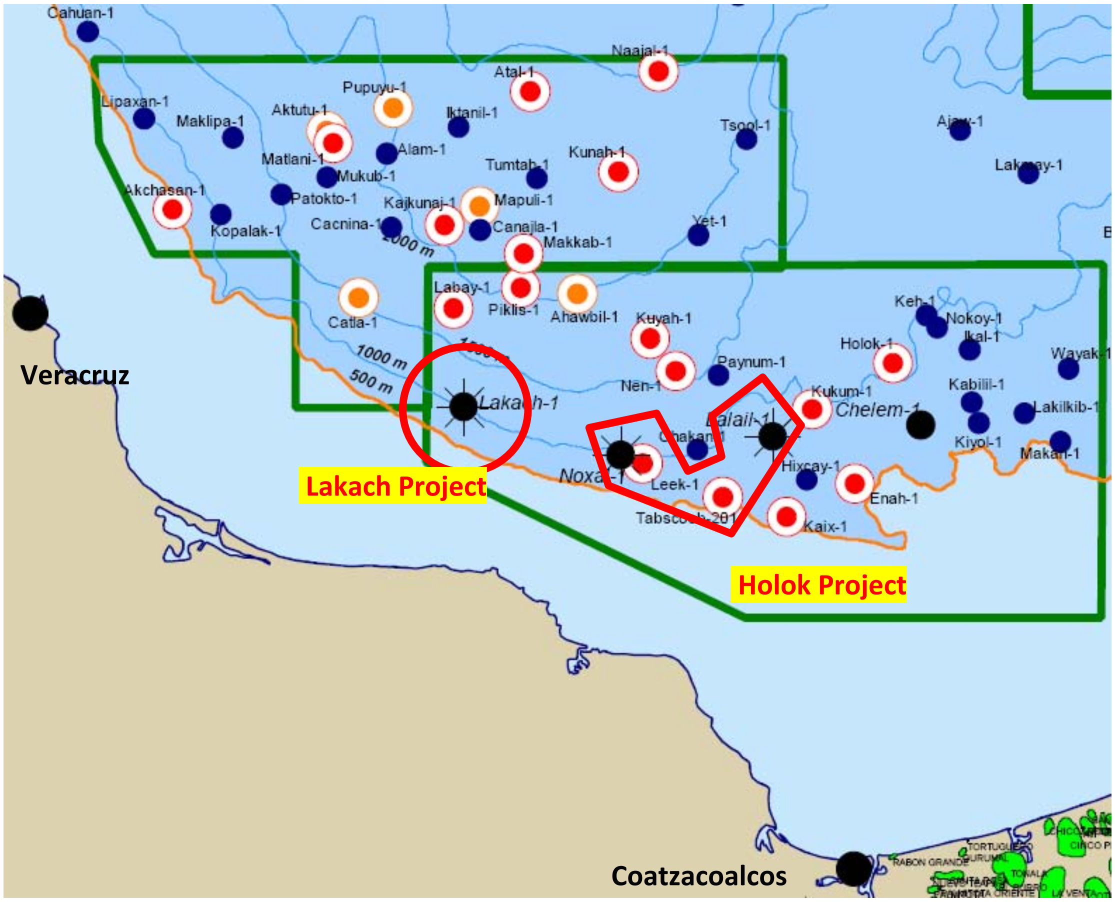

Figure 9.3: Location of deep water wild cats wells which lead to the definition of the fields listed in table 9.3.[Extracted from Hernandez, P. 15, 2009]

9.2 Scenario I: Deep water stand alone gas field

9.2.1 Basis for analysis

Refer to Annex G.

9.2.2 Alternative concepts to test

- ***Subsea Tieback to Shore***

This scenario is a 60 km subsea tie back to shore development. The field will be connected to installations onshore for processing and be recompressed and delivered to the network of pipelines of PEMEX onshore. It considers 8 development wells and modifications of the Compression Station Onshore, to process and induce the produced stream to the pipeline network of PEMEX. Its throughput capability should be no less than 360 MMSCFD/Day.

- ***TLP with dry tree, export pipeline for gas and off take through FSO for condensate.***

A TLP located in Lakach with a 60 km pipeline for gas export distance from the development to the compression Station Onshore. Offtake of oil and condensate will be possible trough and FSO. It considers 9 development dry wellhead wells with one single drilling center, the Facility also consider the inclusion of a full capability drilling package for drilling and workover.

It should have the possibility to become a Hub for future possible developments of prospects (See table 9.4 and figures 9.4 and 9.5) and to have a throughput capability not minor than 360 MMSCFD/Day.

Name of the prospects	***Water Depth (m)***	***Forecasted Resources (MMMSCF Dry Gas)***	***Estimated Reserves (MMMSCF Dry Gas)***	***Distance to Lakach Field development***	***Probability of discovery***	***Probability to pass to appraisal given a discovery***	***Probability to develop, given the appraisal, given the discovery.***
KAJKUNAJ-1	*2073*	*1400*	*698*	*43 km*	*35%*	*50%*	*80%*
LABAY-1	*1700*	*1100*	*549*	*24 km*	*55%*	*50%*	*80%*
PIKLIS-1	*1,945*	*2400*	*1197*	*31 km*	*38%*	*50%*	*80%*
MAKKAB-1	*1,945*	*600*	*299*	*34 km*	*55%*	*50%*	*80%*
KUNAH-1	*2,160*	*2100*	*1048*	*65 km*	*44%*	*50%*	*80%*
ATAL-1	*2,409*	*1600*	*798*	*72 km*	*41%*	*50%*	*80%*
NAAJAL-1	*2470*	*2600*	*1297*	*88 km*	*39%*	*50%*	*80%*

Table 9.4: Identified prospects located close to the Lakach development area with assumed resources reserves and probabilities of development for calculation of added value.

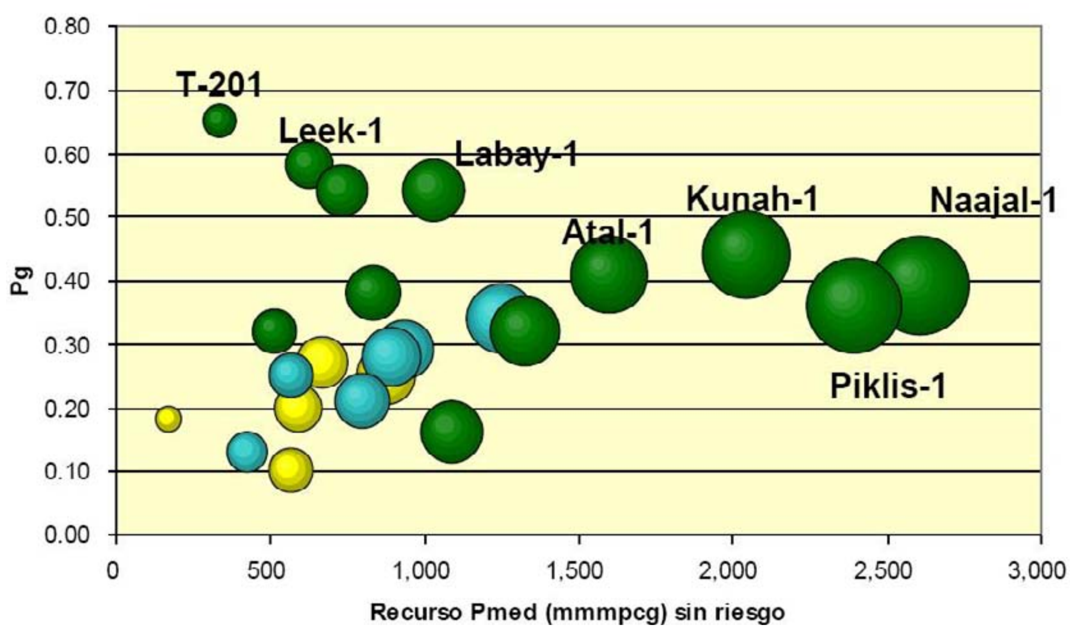

Figure 9.4: Identified prospects located close to the Lakach development area with assumed forecasted resources and geological probability of success after PEMEX [Hernandez, 2009]

- ***SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.***

A SPAR located in Lakach with a 60 km pipeline for gas export distance from the development to the compression Station Onshore. Offtake of oil and condensate will be possible trough and FSO. It considers 9 development dry wellhead wells with one single drilling center, the Facility also consider the inclusion of a full capability drilling package for drilling and workover.

It should have the possibility to become a Hub for future possible developments of prospects (See table 9.4 and figures 9.4 and 9.5) and to have a throughput capability not minor than 360 MMSCFD/Day.

Figure 9.5: Location of prospects and hypothetical paths of pipelines if Lakach would have been developed as a processing Hub for future field developments in this gas province.

9.2.3 Results

Tables 9.5 to 9.8 show the summary of calculations done for this scenario.

Project scenario	**Deep water stand alone gas field**
Concept	**Subsea Tieback to Shore**
Stage of the Project	**Development planning**
Overall Chance of Success	**100.0%**
First Production Date	**15-Dec-12**
Abandonment Date	**1-Mar-28**
Project Start Date	**1-Jul-10**

Risked Discounted Values		**Thousands USD**		**Millions USD**
Income				
Gas Revenue				3,342.5
Liquids Revenue				1,991.7
Total Revenue				5,334.1
Expenditures				
Seismic				-
Wildcat				-
Appraisal				-
Development Planning			**-**	**7.4**
Preliminary Engineering Cost		7,439.06		
CAPEX Facilities & Pipelines			**-**	**771.0**
MainStructure (Modification of Compression Station Onshore		368,800.00		
Topside Facilities		-		
Subsea Surface & Flowlines		29,800.00		
Export Pipeline / satellite bundle		353,250.00		
Engineering & Project Management		19,152.50		
CAPEX Development Drilling			**-**	**509.4**
8 New Subsea Wells (Driling & Completion)		509,400.76		
OPEX			**-**	**227.9**
Facilities		56,793.41		
Well intervention		134,220.99		
Export		36,910.77		
RAMEX			**-**	**540.0**
Abandonment Expenditures			**-**	**10.5**
		Total Costs	**-**	**2,066.3**
		NPV @ 12.0 % ($M)		**3,267.9**
Added value using the structure as a Hub.				**0**

Table 9.5: Calculation results for the Deep water stand alone gas field with a concept of development as Subsea Tieback to Shore.

Project scenario	**Deep water stand alone gas field**
Concept	**TLP with dry tree, export pipeline for gas and off take through FSO for condensate.**
Stage of the Project	**Development planning**
Overall Chance of Success	**100.0%**
First Production Date	**15-Dec-12**
Abandonment Date	**1-Mar-28**
Project Start Date	**1-Jul-10**

Risked Discounted Values	**Thousands USD**	**Millions USD**
Income		
Gas Revenue		3,125.9
Liquids Revenue		1,879.1
Total Revenue		5,005.0
Expenditures		
Seismic		-
Wildcat		-
Appraisal		-
Development Planning		- 7.4
Preliminary Engineering Cost	7,439.06	
CAPEX Facilities & Pipelines		**- 1,094.6**
Main structure	331,763.65	
Topside Facilities (Include a full capability Drilling Package)	612,560.30	
Subsea Surface & Flowlines	28,360.53	
Export Pipeline / satellite bundle	84,275.41	
Engineering & Project Management	37,636.36	
CAPEX Development Drilling		**- 362.9**
9 New dry wellhead Wells (Driling & Completion)	362,914.32	
OPEX		**- 344.5**
Facilities	85,841.02	
Well intervention	202,869.79	
Export	55,789.19	
RAMEX		**- 100.2**
Abandonment Expenditures		- 30.0
	Total Costs	**- 1,939.6**
	NPV @ 12.0 % ($M)	**3,065.4**
	Added value using the structure as a Hub.	**2533**

Name of the prospects	Accounted Added Value (Millions USD)
KAJKUNAJ-1	277
LABAY-1	315
PIKLIS-1	422
MAKKAB-1	152
KUNAH-1	440
ATAL-1	402
NAAJAL-1	525
Accounted added value of an offshore floating structure in Lakach location	2533

Table 9.6: Calculation results for the Deep water stand alone gas field with a concept of development as TLP with dry tree, export pipeline for gas and off take through FSO for condensate.

Project scenario	**Deep water stand alone gas field**
Concept	**SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.**
Stage of the Project	**Development planning**
Overall Chance of Success	**100.0%**
First Production Date	**15-Dec-12**
Abandonment Date	**1-Mar-28**
Project Start Date	**1-Jul-10**

Risked Discounted Values	**Thousands USD**	**Millions USD**
Income		
Gas Revenue		3,125.9
Liquids Revenue		1,879.1
Total Revenue		5,005.0
Expenditures		
Seismic		-
Wildcat		-
Appraisal		-
Development Planning		- 7.4
Preliminary Engineering Cost	7,439.06	
CAPEX Facilities & Pipelines		**- 1,031.2**
Main structure	515,369.52	
Topside Facilities (Include a full capability Drilling Package)	365,602.00	
Subsea Surface & Flowlines	28,360.53	
Export Pipeline / satellite bundle	84,275.41	
Engineering & Project Management	37,636.36	
CAPEX Development Drilling		**- 362.9**
9 New dry wellhead Wells (Driling & Completion)	362,914.32	
OPEX		**- 344.5**
Facilities	85,841.02	
Well intervention	202,869.79	
Export	55,789.19	
RAMEX		**- 104.2**
Abandonment Expenditures		- 32.0
	Total Costs	**- 1,818.3**
	NPV @ 12.0 % ($M)	**3,186.7**
	Added value using the structure as a Hub.	**2533**

Name of the prospects	Accounted Added Value (Millions USD)
KAJKUNAJ-1	277
LABAY-1	315
PIKLIS-1	422
MAKKAB-1	152
KUNAH-1	440
ATAL-1	402
NAAJAL-1	525
Accounted added value of an offshore floating structure in Lakach location	2533

Table 9.7: Calculation results for the Deep water stand alone gas field with a concept of development as SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.

Summary Evaluation Parameters	KAJKUNAJ	LABAY	PIKLIS	MAKKAB	KUNAH	ATAL	NAJAAL
Overall Chance of Success	14.00%	22.00%	15.20%	22.00%	17.60%	16.40%	15.60%
First Production Date	28/11/2014	17/12/2014	11/12/2016	23/06/2014	20/11/2016	12/11/2014	20/10/2016
Abandonment Date	01/03/2030	01/03/2030	01/03/2032	01/03/2024	01/03/2032	01/03/2030	01/03/2032
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Risked Discounted Values NPV @ 12.0 % ($M USD)							
Gas Revenue	319.6	392.2	493.9	236.2	503.2	430.9	557.6
Liquids Revenue	192.3	236.0	296.6	142.0	302.2	259.2	335.0
Total Revenue	512.0	628.2	790.5	378.2	805.4	690.1	892.6
Seismic	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wildcat	-48.8	-55.7	-51.2	-51.2	-47.2	-42.6	-41.5
Appraisal	-40.4	-71.3	-58.4	-46.6	-62.6	-41.3	-48.7
Development Planning	-1.0	-1.5	-1.3	-1.4	-1.5	-1.3	-1.4
Facilities & Pipelines	-35.7	-35.1	-117.2	-46.0	-120.2	-65.7	-134.8
Development Drilling	-38.6	-62.1	-60.1	-28.6	-50.9	-42.6	-50.0
Operations	-69.0	-86.7	-78.4	-50.5	-81.1	-93.2	-89.6
Abandonment	-1.0	-1.3	-1.4	-1.5	-1.6	-1.5	-1.9
Total Costs	-234.6	-313.7	-368.1	-225.8	-365.0	-288.3	-368.1
Accounted added value	277.4	314.5	422.4	152.3	440.3	401.9	524.5

Table 9.8: Summary of calculation results for the added value of the offshore floating structure in the location of Lakach.

9.3 Scenario II: Deep water array of gas and condensate fields in proximity

Table 9.3 lists the characteristics of the fields Noxal, Leek, Tabscoob and Lalail. All of them discoveries with probable and possible reserves in place. The small size and relatively large distance to infrastructure are the main factors to postpone their development. Based in the similarity of these issues with the *Canyon Express field development* (see chapter 6 and annex C.), it is proposed in this work, to address the challenge of the development proposing the concepts:

1. Subsea development with tiebacks to a platform of separation and recompression with off take in FSO for condensate.
2. Floating structure of separation and recompression with off take in FSO for condensate for tie back of the fields Noxal, Leek and Tabscoob based in Lalail.
3. Floating structure of separation and recompression with off take in FSO for condensate for tie back of fields Lalail, Leek and Tabscoob based in Noxal.

It will not be develop a comparison for dry and well tree in this scenario. The reasons are that the proposed concepts considered are only subsea developments and there was not found a significant difference in the comparison using dry vs well tree for the kind of hydrocarbons that are understood to be found in the prospects (See chapter 7).

9.3.1 Basis for analysis

Refer to Annex G.

9.3.2 Alternative concepts to test

- ***Subsea developments in tieback to a platform of separation and recompression with offtake in FSO for condensate.***

The Holok compression station offshore (HCSO) is a proposed new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and the Tabscoobs (101, 201). HCSO will take advantage of a shallow water location to become the structure for subsea tieback developments.

It is shown in the figure 9.6 the location of the structures and the fields and also a number of routes in red that might be considered for a further study (not included in this work) to give some hint about the added value of this offshore facility for the development of additional prospects.

A summary of the Technical parameters for evaluation are listed below.

- 65 km Export distance from HCSO to Compression Station Onshore.
- 100 m water depth.
- Offtake of oil and condensate trough FSO.
- Hub for future possible developments of prospects (See table 9.9 and figure 9.6).
- Throughput capability: 430 MMSCFD/Day

Name of the prospects	Water Depth (m)	Forecasted Resources (MMMSCF Dry Gas)	Estimated Reserves (MMMSCF Dry Gas)	Distance to HCSO	Probability of discovery	Probability to pass to appraisal given a discovery	Probability to develop, given the appraisal, given the discovery.
NOXAL	936	583.6	291.16	20 km	100%	75%	100%
LEEK	848	156.1	77.88	20 km	100%	75%	100%
LALAIL	806	1181.3	589.35	46 km	100%	75%	100%
TABSCOOB 101	234	140.9	70.30	29 km	100%	100%	100%
TABSCOOB 201	400	300	140	30 km	65%	75%	100%

Table 9.9: Complementary assumptions for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept "Subsea developments in tieback to a platform of separation and recompression with offtake in FSO for condensate".

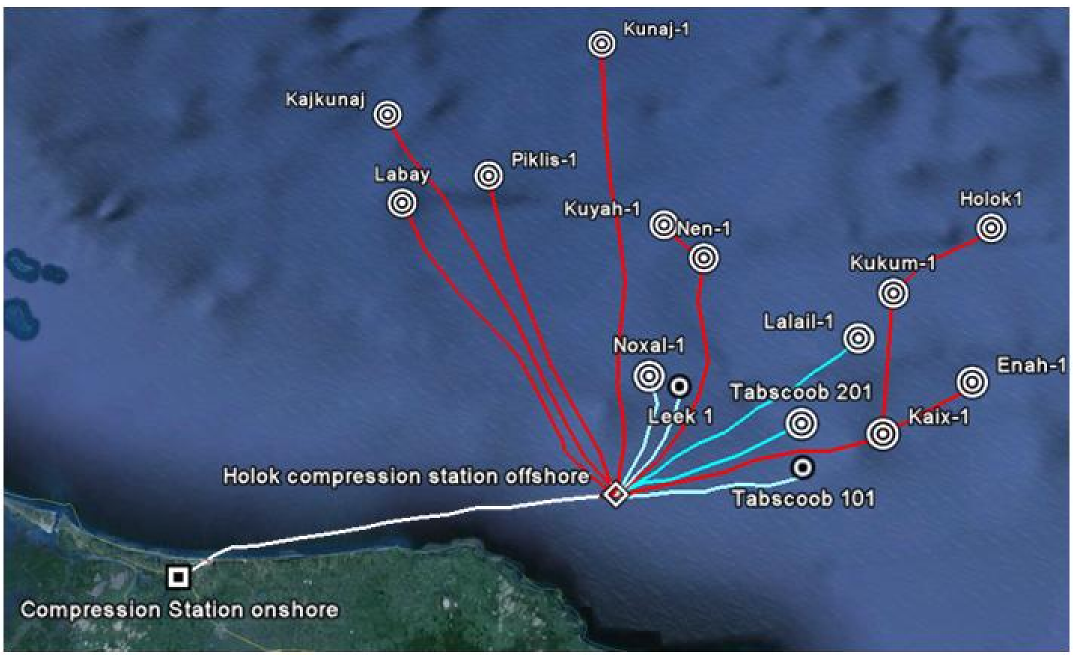

Figure 9.6: Hypothetical development for HOCS and the future field developments of this gas province.

- ***Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail.***

This concept proposes a semisubmersible or a floating structure with wet trees. Drilling considered to be done with semisubmersibles and drilling vessels. The facility would be a manned new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and also the Tabscoobs (101, 201).

The field Lalail is selected because of be the largest discovery with relation to the reserves estimated to be in place.

Figure 9.7 shows the relative location of the fields and also a number of routes in red that might be considered for a further study (not included in this work) to give more basis to estimate the added value of this offshore facility for the development of additional prospects.

A summary of the Technical parameters for evaluation are listed below.

- 110 km Export distance from Lalail floating hub to Compression Station Onshore.
- 806 m water depth.
- Offtake of oil and condensate trough FSO.
- Hub for future possible developments of prospects (See table 9.10 and figure 9.7).
- Throughput capability: 430 MMSCFD/Day

Name of the prospects	***Water Depth (m)***	***Forecasted Resources (MMMSCF Dry Gas)***	***Estimated Reserves (MMMSCF Dry Gas)***	***Distance to LALAIL***	***Probability of discovery***	***Probability to pass to appraisal given a discovery***	***Probability to develop, given the appraisal, given the discovery.***
LALAIL	*806*	*1181.3*	*589.35*	*-----------*	*100%*	*75%*	*100%*
NOXAL	*936*	*583.6*	*291.16*	*5 km*	*100%*	*75%*	*100%*
LEEK	*848*	*156.1*	*77.88*	*30 km*[1]	*100%*	*75%*	*100%*
TABSCOOB 201	*400*	*300*	*140*	*17 km*	*65%*	*75%*	*100%*
TABSCOOB 101	*234*	*140.9*	*70.30*	*7 km*[2]	*100%*	*100%*	*100%*

Table 9.10: Complementary assumptions for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept " Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail".

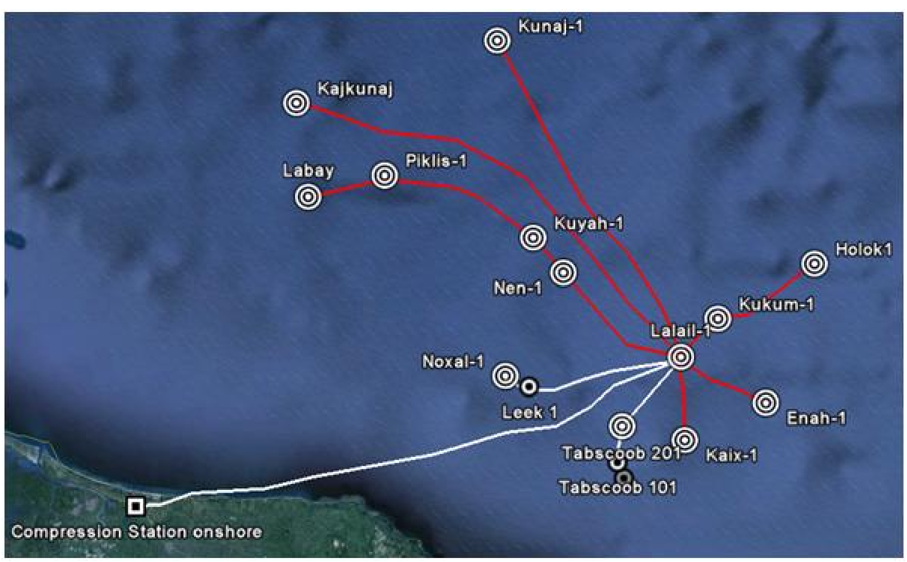

Figure 9.7: Hypothetical development for a Floating structure in Lalail also as a Hub for the future field developments of this gas province.

[1] *Note: It will be evaluated a daisy chain Noxal-Leek_Lalail*
[2] *Note: It will be evaluated a daisy chain Lalail - Tabscoob (101) – Tabscoob (201).*

- ***Floating structure of separation and recompression with off take in FSO for condensate for the fields Lalail, Leek and Tabscoob based in Noxal***

This concept proposes a semisubmersible or a floating structure with wet trees. Drilling considered to be done with semisubmersibles and drilling vessels. The facility would be a manned new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and also the Tabscoobs (101, 201).

The field Noxal is selected because of be the second largest discovery with relation to the reserves estimated to be in place and the relative proximity to the Leek project, which is expected to give a better economical result than other options not mentioned so far.

Figure 9.8 shows the relative location of the fields and also a number of routes in red that might be considered for a further study (not included in this work) to give more basis to estimate the added value of this offshore facility for the development of additional prospects.

A summary of the Technical parameters for evaluation are listed below.

- 72 km Export distance from Noxal floating hub to Compression Station Onshore.
- 936 m water depth.
- Offtake of oil and condensate trough FSO.
- Hub for future possible developments of prospects (See table 9.11 and figure 9.8).
- Throughput capability: 430 MMSCFD/Day

Name of the prospects	***Water Depth (m)***	***Forecasted Resources (MMMSCF Dry Gas)***	***Estimated Reserves (MMMSCF Dry Gas)***	***Distance to NOXAL***	***Probability of discovery***	***Probability to pass to appraisal given a discovery***	***Probability to develop, given the appraisal, given the discovery.***
NOXAL	*936*	*583.6*	*291.16*	*-----------*	*100%*	*75%*	*100%*
LEEK	*848*	*156.1*	*77.88*	*5 km**	*100%*	*75%*	*100%*
TABSCOOB 201	*400*	*300*	*140*	*19 km**	*65%*	*75%*	*100%*
TABSCOOB 101	*234*	*140.9*	*70.30*	*7 km**[3]	*100%*	*100%*	*100%*
LALAIL	*806*	*1181.3*	*589.35*	*34 km*	*100%*	*75%*	*100%*

Table 9.11: Complementary assumptions for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept: " Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Noxal".

[3] *Note: It will be evaluated a daisy chain Noxal-Leek-Tabscoob (101) – Tabscoob (201).*

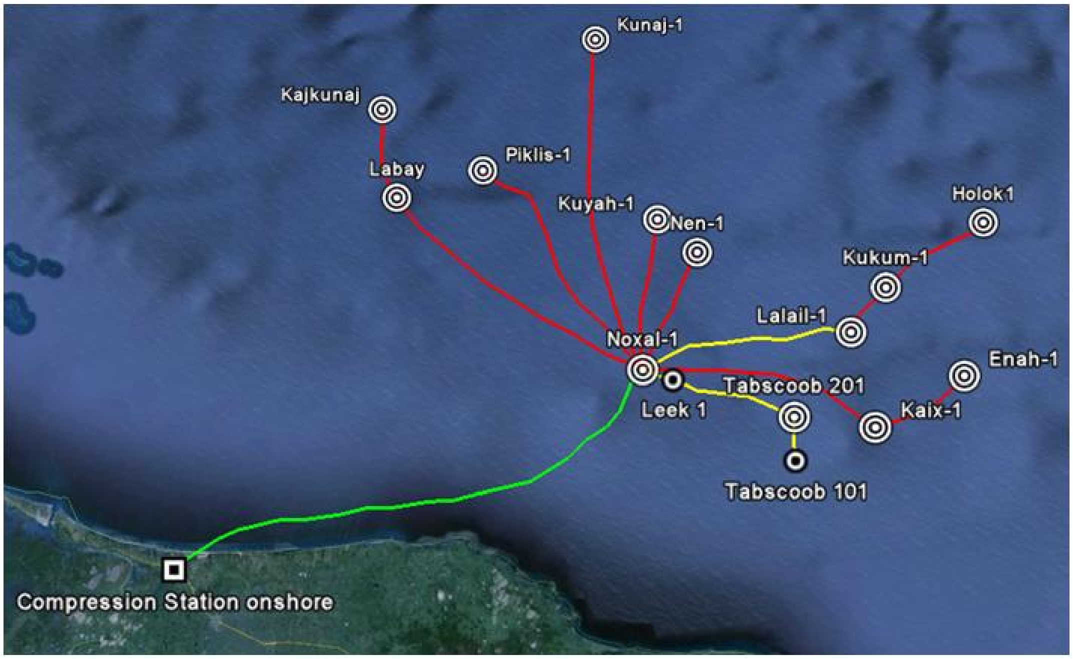

Figure 9.8: Hypothetical development for a Floating structure in Noxal also as a Hub for the future field developments of this gas province.

9.3.3 Results

Tables 9.12 to 9.14 show the summary of calculations done for this scenario.

Project scenario	Deep water array of gas and condensate fields in proximity					
Concept	**Subsea developments in tieback to a platform of separation and recompression with offtake in FSO for condensate.**					
	HOCS	LALAIL	NOXAL	LEEK	TABSCOOB 1	TABSCOOB 2
Overall Chance of Success	N/A	0.75	0.75	0.75	1	0.4875
First Production Date (Available from, for HOCS)	17/05/2012	26/03/2014	22/09/2013	25/05/2013	01/06/2013	21/01/2014
Abandonment Date	01/04/2029	01/03/2029	01/03/2024	01/03/2021	01/03/2021	01/03/2022
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Risked Discounted Values NPV @ 12.0 % ($M USD)						
Gas Revenue		1540.78	842.32	240.72	289.43	263.28
Liquids Revenue		925.13	503.98	143.52	172.60	157.98
Total Revenue		2465.91	1346.31	384.24	462.03	421.27
Seismic		0.00	0.00	0.00	0.00	0.00
Wildcat		0.00	0.00	0.00	0.00	-41.90
Appraisal		-142.58	-82.43	-47.42	-49.52	-25.76
Development Planning		-4.50	-4.07	-3.72	-4.93	-2.36
Facilities & Pipelines	-591.01	-214.04	-112.44	-113.18	-200.39	-99.25
Number of development wells to be drilled		6	3	1	1	2
Throughput capability: MMSCFD/Day	430.00	198.46	99.23	33.08	66.15	33.08
Development Drilling		-210.04	-84.66	-31.64	-44.96	-32.59
Operations	-504.07	-335.87	-177.46	-61.62	-78.71	-61.73
Abandonment	-7.69	-5.58	-4.42	-3.53	-5.63	-3.21
Total Costs	-1102.77	-691.61	-354.98	-224.28	-347.31	-151.24
NPV @ 12.0 % ($M USD)	**-1102.77**	**1774.30**	**991.33**	**159.96**	**114.71**	**270.02**
					NPV @ 12.0 % ($M USD)	**2207.55**

Table 9.12: Results for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept "Subsea developments in tieback to a platform of separation and recompression with off take in FSO for condensate.".

Project scenario	Deep water array of gas and condensate fields in proximity				
Concept	**Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail.**				
	LALAIL	LEEK	NOXAL	TABSCOOB 201	TABSCOOB 101
Overall Chance of Success	0.75	0.75	0.75	0.4875	1
First Production Date	30/11/2015	05/06/2016	22/09/2016	23/01/2017	19/05/2016
Abandonment Date	01/03/2030	01/03/2024	01/03/2027	01/03/2025	01/03/2024
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Risked Discounted Values; NPV @ 12% (USD $M)					
Gas Revenue	1317.79	170.81	599.96	187.27	205.84
Liquids Revenue	793.00	101.87	358.97	112.37	122.71
Total Revenue	2110.79	272.68	958.94	299.64	328.55
Seismic	0	0	0	0	0
Wildcat	0	0	0	-33.07	0
Appraisal	-186.23	-37.03	-58.67	-20.33	-35.39
Development Planning	-5.27	-2.65	-2.90	-1.68	-3.51
Facilities & Pipelines	-954.58	-109.78	-36.48	-46.10	-56.30
Number of development Wells	6	3	1	2	1
Throughput capability: MMSCFD/Day	430.00	99.23	33.08	66.15	33.08
Development Drilling	-270.55	-25.76	-60.26	-27.23	-32.19
Operations	-238.54	-44.72	-124.74	-43.15	-53.21
Abandonment	-6.71	-3.06	-2.51	-1.86	-2.41
Total Costs	-1661.88	-179.92	-257.30	-144.26	-155.56
NPV @ 12.0 % ($M USD)	**448.91**	**14.17**	**425.25**	**69.01**	**78.29**
				TOTAL NPV @ 12.0 % ($M USD)	**1035.64**

Table 9.13: Results for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept "Floating structure of separation and recompression with off take in FSO for condensate for the fields Noxal, Leek and Tabscoob based in Lalail".

Project scenario	Deep water array of gas and condensate fields in proximity				
Concept	**Floating structure of separation and recompression with off take in FSO for condensate for the fields Lalail, Leek and Tabscoob based in Noxal**				
	Noxal	Leek	Tabscoob 201	Tabscoob 101	Lalail
Overall Chance of Success	0.75	0.75	0.4875	0.75	0.75
First Production Date	01/07/2015	14/05/2016	24/01/2017	19/05/2016	26/03/2017
Abandonment Date	01/03/2025	01/03/2024	01/03/2025	01/03/2024	01/03/2032
Discount Date	01/07/2010	01/07/2010	01/07/2010	01/07/2010	01/07/2010
Risked Discounted Values; NPV @ 12% ($M USD)					
Gas Revenue	712.07	171.85	187.21	155.04	1096.70
Liquids Revenue	428.80	102.43	112.34	92.43	658.49
Total Revenue	1140.87	274.28	299.56	247.47	1755.19
Seismic	0.00	0.00	0.00	0.00	0.00
Wildcat	0.00	0.00	-33.07	0.00	0.00
Appraisal	-82.43	-32.60	-20.33	-35.25	-101.49
Development Planning	-4.07	-2.65	-1.68	-2.63	-3.20
Facilities & Pipelines	-779.95	-36.40	-49.87	-42.22	-118.00
Number of development Wells	4	1	2	1	6
Throughput capability: MMSCFD/Day	430.00	30.71	61.43	30.71	184.29
Development Drilling	-71.60	-21.38	-27.21	-24.00	-149.50
Operations	-119.85	-42.51	-43.26	-40.01	-237.45
Abandonment	-5.65	-1.69	-1.93	-1.80	-3.64
Total Costs	-1063.55	-137.23	-144.27	-145.92	-613.27
NPV @ 12.0 % ($M USD)	22.68	137.04	155.29	101.55	1141.91
				Total NPV @ 12.0 % ($M USD)	**1613.12**

Table 9.14: Results for the calculation of the project scenario "Deep water array of gas and condensate fields in proximity"; Concept " Floating structure of separation and recompression with off take in FSO for condensate for the fields Lalail, Leek and Tabscoob based in Noxal".

9.4. Deep water heavy and extra heavy oil fields.

Table 9.2 list a large discovery (NAB-1) mentioned as extra heavy oil and accounted for 400 MM B.O.E. The original volume of 3P oil reserves is 408.0 million barrels, while the original 3P oil equivalent reserves are estimated at 32.6 million barrels.

The payzone is estimated to be at a total profundity of 2800 m at 679 m water depth. The API grade for the oil is estimated to be between 8 an 10 degrees.

These characteristics made the field, one of the most challenging fields in the world, in case that in some moment it would be indented to be developed. No historical reference exists for a commercial development for this depth and fluid properties.

Heavy oil, extra-heavy oil, and bitumen projects are large undertakings and very capital intensive. In addition to the production infrastructure, additional upgrading, refining, and transportation facilities are needed. Pipelines for heavy oil and possibly for CO2 sequestration would be needed. Another issue is obtaining a sufficient supply of diluent for pipelining heavy oil. These projects also have long operating and payback periods, so unstable oil prices can deter long-term investments.[NPC, P.p. 2,2007]

Additional information on this respect might be consulted in “Topic paper #22, heavy oil” (NPC, 2007).

9.5. Conclusions

On the first scenario, was found that the best Net Present Value assessment result for the development of the Lakach field is the concept of subsea tieback to shore. This is true when it is not considered an additional value for the development of infrastructure in the region. Although the concept has higher economical penalties in the RAMEX because of the higher cost for it maintenance, the savings in the CAPEX are notorious.

On the other hand, the potential of the Region of Holok-Temoa related to the prospects listed in the table 9.4 might increase considerably the strategic value of the investments in infrastructure. This infrastructure would be available when offshore structures and a network of pipelines will be developed in the region.

Lakach had an ample positive Net Present Value before taxes even when a floating structure was selected. Is notorious also the calculated added value that could be obtained by using the floating structure as a hub as shown in table 9.8. Lakach had also a geographical advantage since it is located at less than 1000 meters of water depth; much easier to develop when is compared to other identified prospects of development that go from 1700 m up to 2500 m water depth.

Figure 9.5 shows a hypothetical development that could have had Lakach as a processing Hub for the future field developments of this gas province.

Lakach Field development has already been committed to be developed as a subsea tieback to shore. Consequently for future concept selection is strongly recommended to keep in mind the fact that the development of infrastructure increase the feasibility of future developments and increase overall recoveries rates from the oil and gas fields.

On the second scenario, It was found that a series of medium-small size fields might be economically developed when are planned as a group of fields.

The best NPV concept assessed for this scenario was a “Subsea development with tiebacks to a platform of separation and recompression with off take in FSO for condensate”, meanwhile the higher investment cost for floating structures either in Lalail or Noxal make them not a sounded option for efficient investment of resources.

The platform of separation and recompression here named as “The Holok compression station offshore (HCSO)” is a proposed new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and the Tabscoobs (101, 201). HCSO will take advantage of a shallow water location to become the structure for subsea tieback developments.

This proposed structure will reduce the cost of the development and at the same time became a high added value for future developments since its reach is comparative equivalent against floating structures located in the Lalal and Noxal sites.

An additional advantage for the Mexican Industry as a whole is that these kind of shallow water facilities are in the scope of capability of national contractors. This is a high potential argument on behalf of the national content that PEMEX can encourage through its corporate decisions.

On the heavy and extra heavy oil discoveries is an opinion of this author that the Exploration activities in deep water should be focused in prospects potentially commercial instead to look after resources that can barely be produced (API-15 or minor). Although the diversification of opportunities for exploration should be encouraged, is the opinion of this author that it should be focused in the Region of Holok Temoa or others that could have a similar potential of development in the short run.

There is no doubt that additional discoveries in the Holok Temoa Integral Asset and in general in the deep water in Mexico will take place in the future, but there are some few recommendations that could be issued after the development of this study.

1. It is suggested to design, coordinate and follow a strategic plan for field development in all the regions in the domain of PEMEX, looking for maximize the possibilities of development and ensure efficient depletion of the natural resources located in Mexican territorial waters.
2. Encourage the investment in infrastructure since it makes feasible future field development and increase the capability of efficient depletion.
3. Encourage solutions that will make possible a gradual assimilation of technology for both the National Oil Company and for the national contractors. The economically feasible solutions that open the participation of national suppliers alone or in association with international contractors should have extra points in the formal assessment of concepts.
4. Exploration and appraisal should focus in prospects that are commercial in the short run. The drilling in deep water is not only expensive but it could be notoriously ineffective if it is not linked to the value chain of field development.

10. General Conclusions

10.1 On the discussion on the recovery factor Dry vs. Wet Tree

In order to give validity to the model of LCC analysis here proposed, an empirical comparison on the resulting recovery factor based on data of the US Gulf of Mexico was included in the scope of this work. This comparison was intended to answer ¿Is there a significant difference in the recovery factor when is used the dry tree vs. the wet tree concept solutions?

The oil and gas recovery factors listed in this data set analyzed correspond to the estimated values declared by the operator companies to the MMS for sands located in the US Gulf of Mexico. The values are subject to change due to different factors including technology improvements, operations management philosophy and refinement of calculations as more information from the reservoirs become available

The class of fields most exploited in deepwater in Gulf of Mexico corresponds to undersaturated oil fields (≈ 65%) followed by the non associated class (≈ 30%) and finally saturated oil fields class (≈ 4%).

The mean recovery factors for the different types of reservoir are summarized in table 7.5. According to the test of hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$ vs. $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} \neq 0$ with μ calculated from the data sets created in this methodology, there is not statistical evidence that suggest that a field developed with dry tree has a better recovery factor than one developed with wet tree solutions.

With exception of the gas recovery factor from saturated oil fields, all the other test fail to reject the null hypothesis $\mu_{\text{dry tree}} - \mu_{\text{wet tree}} = 0$. This means that the inferred mean value of recovery factor is the same either for dry tree vs wet tree solutions.

In the only exception (gas recovery factor of the saturated oil fields) is perceptibly a difference in favor of the dry tree. Despite the oil recovery factor from the same type of reservoirs is larger for dry tree than for the wet tree, the pooled variance for both samples is too large to make a differentiation on their means.

It is inferred that a criteria that prefer a dry tree with the argument of a better recovery factor must be evaluated further, extending the analysis to consider the specific characteristics of the reservoir and the exploitation concept that is part of the field to be developed.

Consecuently a model that include a reservoir complexity index was presented and analized. The Reservoir Complexity Index from the Norwegian petroleum directorate on the performance of dry and wet tree solutions was discussed.

From a presentation provided by the NPD a data set was extracted for fields encompassed by an study differentiating the dry tree and the wet tree developments. The results of the analysis of this data set are shown graphically in figure 7.2.

What can be inferred from the figure 7.2 is that on the Norwegian Continental Shelf, depending of the complexity of the reservoir, there is:

A linear trend on the recovery factor for fields developed with dry tree to decrease as the reservoir becomes more complex.

An exponential trend on the recovery factor for fields developed with wet tree to decrease as the reservoir becomes more complex. A linear trend was also tested but is not shown because the exponential regressed function has a better R^2 (R^2 = 0.5891 in linear regression vs R^2 = 0.6672 in exponential regression).

When the reservoir has a low complexity (up to 0.4) it seems that there is not an evident difference between the performances of dry vs wet tree solutions. As the complexity increases however the dry tree solutions become a better option based on the recovery factor registered.

Many oil companies worldwide employ methodologies similar to the RCI as a common basis. Although the calculation of this index is out of the scope of this work it could be useful for the reader to take a look on the patented work of Harrison (Harrison, 2004) who propose *"A method for computing complexity, confidence and technical maturity indices for the evaluation of a reservoir."*

10.2 On the Case Analysis

Two hypothetical projects (three different concepts for each project) of field development, based in public information released by PEMEX, are assessed.

Scenario I: Deep water stand alone gas field

- Concepts: Subsea Tieback to Shore; TLP with dry tree, export pipeline for gas and off take through FSO for condensate; SPAR with dry tree, export pipeline for gas and off take through FSO for condensate.

Scenario II: Deep water array of gas and condensate fields in proximity

- Concepts: Subsea development with tiebacks to a platform of separation and recompression with off take in FSO for condensate; Floating structure for separation and recompression with off take through an FSO for condensate for tie back of the fields Noxal, Leek and Tabscoob based in Lalail; Floating structure for separation and recompression with off take through an FSO for condensate for tie back of fields Lalail, Leek and Tabscoob based in Noxal.

In the first scenario, it was found that the best Net Present Value assessment result for the development of the Lakach field is the concept of subsea tieback to shore. This is true when an additional value for the development of infrastructure in the region is not considered. Although the concept has higher economical penalties in the RAMEX because of the higher costs for it maintenance, the savings in the CAPEX are notorious.

On the other hand, the potential of the Region of Holok-Temoa, related to the prospects listed in table 9.4, might increase considerably the strategic value of the investments in infrastructure. This infrastructure would be available when offshore structures and a network of pipelines will be developed in the region.

Lakach development has an ample positive Net Present Value before taxes even when a floating structure was selected. Also the calculated added value that could be obtained by using the floating structure as a hub as shown in table 9.8. Lakach has also a geographical advantage since it is located at less than 1000 meters of water depth; much easier to develop when is compared to other identified prospects of development that go from 1700 m up to 2500 m water depth.

Figure 9.5 shows a hypothetical development that could have Lakach as a processing Hub for the future field developments of this gas province.

The Lakach Field development has already been committed to be developed as a subsea tieback to shore. Consequently for future concept selection, it is strongly recommended to keep in mind the fact that the development of infrastructure increases the feasibility of future developments and increase the overall recoveries rates from the oil and gas fields.

On the second scenario, It was found that a series of medium-small size fields might be economically developed when they are planned as a group of fields.

The best NPV concept assessed for this scenario was a “Subsea development with tiebacks to a platform of separation and recompression with off take on an FSO for condensate”, meanwhile the higher investment costs for floating structures either in Lalail or Noxal make them not a sounded option for efficient investment of resources.

A platform for separation and recompression, here named as “The Holok compression station offshore (HCSO)” is a proposed new brand offshore structure with separation and recompression that will serve as a Hub for the development of the Fields, Lalail, Noxal, Leek, and the Tabscoobs (101, 201). HCSO will take advantage of a shallow water location to become the structure for subsea tieback developments.

This proposed structure will reduce the costs of the development and at the same time become a high added value for future developments since its reach is comparatively equivalent with floating structures located in the Lalal and Noxal sites.

An additional advantage for the Mexican Industry as a whole is that these kind of shallow water facilities are in the scope of the capability of national contractors. This is a high potential argument on behalf of the national content that PEMEX can encourage through its corporate decisions.

Regarding the heavy and extra heavy oil discoveries, the opinion of this author is that the Exploration activities in deep water should be focused on prospects potentially commercial instead of looking for resources that can barely be produced (API-15 or less). Although the diversification of opportunities for exploration should be encouraged, is the opinion of this author that it should be focused on the Region of Holok Temoa or others that could have a similar potential of development in the short term.

10.3 Recommendations

There is no doubt that additional discoveries in the Holok Temoa Integral Asset and in general in the deep water in Mexico will be made in the future, but there are some few recommendations that could be issued after the development of this study.

1. It is suggested to design, coordinate and follow a strategic plan for field development in all the regions in the domain of PEMEX, looking for maximizing the possibilities of development and ensure efficient depletion of the natural resources located in Mexican territorial waters.
2. Encourage the investments in infrastructure since it makes feasible future field development and increase the capability of efficient depletion.
3. Encourage solutions that will make possible a gradual assimilation of technology for both the National Oil Company and for the national contractors. The economically feasible solutions that open the participation of national suppliers alone or in association with international contractors should have extra points in the formal assessment of concepts.
4. Exploration and appraisal should focus on prospects that are commercial in the short run. The drilling in deep water is not only expensive but it could be notoriously ineffective if it is not linked to the value chain of potential field developments.

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