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Research Article

Hydrocarbon Resource Evaluation: Risk, Volumetric and Economic Assessment Methodology: A Case Study in the Norwegian Barents Sea

Joel Ben-Awuah[a], Spariharijaona Andriamihaja[a], Abdullah Ali[a,] *

[a] [1]Department of Geosciences, Universiti Teknologi PETRONAS, Perak, Malaysia
* Corresponding author: +60169165850
E-mail address: alicorp10@gmail.com

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The petroleum exploration industry is cost intensive and requires detailed risk and economic evaluation of prospective areas to promote adequate investment. The objective of this study is to demonstrate the methodology (workflow) involved in assessing the potential profitability of a prospect using the GeoX software. The Nordkapp Basin of Norwegian section of the Barents Sea was used as a case study. The three stage evaluation approach applied in this study comprises risk evaluation of petroleum system elements, estimation of hydrocarbon volume and economic assessment of forecasted revenues from the sale of oil and gas. The results showed that geologic risk evaluation is an important input for volumetric estimates, which in turn is one of the main input parameters of the economic assessment. In addition, all three stages of the evaluation need to be carried out for an effective decision to be made on whether to drill a prospect.

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1. Introduction

The petroleum exploration industry is cost intensive and requires detailed risk and economic evaluation of prospective areas to promote adequate investment. Companies carry out a series of risk and economic analysis to determine the viability of a prospect. Geologic concepts are uncertain with respect to structure, reservoir, seal, and hydrocarbons; on the other hand economic assessments of the potential profitability of a venture are uncertain with respect to total costs [1]. These intertwined uncertainties of the geologic and economic models make for high-risk decisions with no guarantee of successfully striking hydrocarbons at any given drill site [1]. A decision on whether to drill a prospect or not is often made based on the outcome of geologic, volumetric, economic and risk evaluation. The outputs of the prospect analysis are therefore an estimate of the dry hole risk and an estimate of the likely quantities of hydrocarbons. Oil and gas companies often develop their own in house methodologies for such evaluation using available commercial softwares. The objective of this study is to demonstrate the methodology involved in hydrocarbon resource assessment from risk analysis through volumetric analysis to economic analysis using commercial software known as GeoX. Block 7231/1 in the Nordkapp Basin of Norwegian section of the Barents Sea was used as a case study (Fig.1).

GeoX has two separate but integrated tools for prospect analysis. gProspectR is used for doing a technical analysis of the prospect, while gFullCycle is used for analyzing prospect economics. The main output of gProspectR, estimates of recoverable resources and risk is a key gFullCycle input. Geologic uncertainty assessment is done by classifying the risk factors into two main groups. Risk factors that are common (marginal risks) to all prospects in the play and conditional risk factors that can vary from prospect to prospect in a play.

2. Geologic setting

The Barents Sea is part of the Arctic Ocean situated between the Norwegian-Greenland Sea, Noraya-Zemlya, the Arctic Ocean Margin and the Norwegian-Soviet mainland (fig.1) [2]. By the end of 1989 some 22 and 45 exploration wells had been drilled in the Soviet and Norwegian parts of the Barents Sea respectively with 250,000km of seismic acquired in Soviet waters and 423,000 in Norwegian waters [2]. The Barents Sea region has an intracratonic setting and has been affected by several episodes of tectonism since the Caledonian Orogenic movements terminated in Early Devonian times [3]. The Triassic to Early Jurassic is regarded as a tectonically relatively quiet period, however, the Stappen and Loppa Highs experienced tilting, and the Early Triassic was characterized by subsidence in eastern areas and sediment influx from the east [3]. Block faulting started again in the Mid Jurassic and increased during the period from Late Jurassic into Early Cretaceous, terminating with the formation of the now well-known major basins and highs and finally reaching maximum inversion and folding in the Eocene to Oligocene times [3].

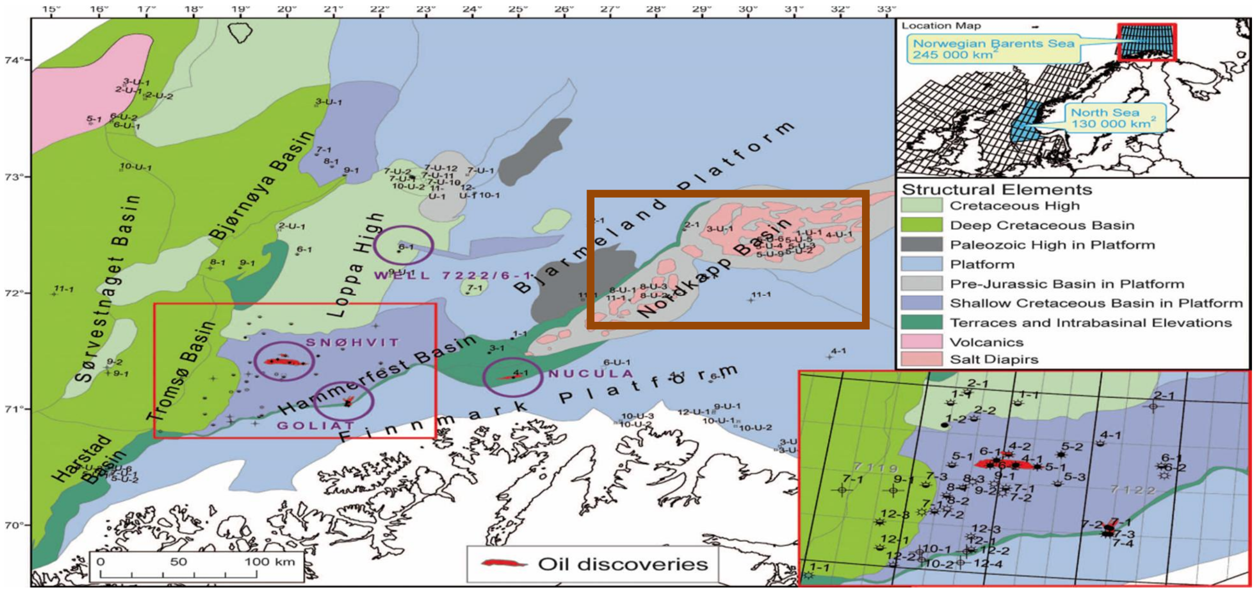


Fig.1: Location map of the Nordkapp Basin in the Norwegian Barents Sea [4]

The Norwegian portion of the Barents Sea has multiple petroleum systems representing an example of an overfilled petroleum system. However, several episodes of uplift and erosion from the Paleocene until the Pliocene-Pleistocene have caused the depletion of hydrocarbon accumulations in the region [4]. These episodes of uplift have increased the risks associated with hydrocarbon exploration in the Barents Sea making the area suitable for the risk assessment analysis. The petroleum system in the block is of Triassic age [5]. The Triassic sandstones belong to the Sassendalen Group consisting of the Havert, Klappmyss and Kobbe Formation and also the Snadd Formation which belongs to the Kapp Toscana Group that have been deposited in fluvial, deltaic, shallow marine, tidal and estuarine environments [5]. The source rocks are mainly Upper Devonian- Lower Carboniferous shale, Lower Carboniferous coal and Upper Permian shale with the petroleum traps being dominantly stratigraphic and structural (rotated fault blocks and halokinetic) (fig.2) [5]. The lack of success in finding commercial hydrocarbon accumulations in the Norwegian Barents Sea and by extension the Nordkapp basin has been linked to the uplift in the basin by several researchers. These factors include low pressure in the reservoirs due to the uplift and erosion [6], tilting as a result of differential uplift resulting in spillage from pre-uplift hydrocarbon accumulations [7], failure of seals [8], cooling of the source rocks with subsequent cessation in hydrocarbon generation [9] and lower reservoir quality than expected because of it having been buried deeper than present day depth [10; 11].

3. Methodology

3.1. Geologic Risk Analysis

Risk analysis using the GeoX software mainly involves identifying the individual play elements and classifying them into conditional and marginal risks. According to the Coordinating Committee for Coastal and Offshore Geoscience Programs in East and South East Asia (CCOP) Guidelines for Risk Assessment of Petroleum Prospects [12], nine petroleum system elements that need to be risked in the evaluation of petroleum prospects were identified. The petroleum system elements include:

- Reservoir facies presence
- Reservoir quality
- Source rock presence
- Source rock maturity
- Migration pathways
- Migration timing
- Trap closure
- Trap seal
- Hydrocarbon recovery

The GeoX software however, allows the grouping of these nine petroleum system elements into three conditional risk factors: probability of adequate trapping, probability of reservoir quality and probability of hydrocarbon accumulation. These conditional risk factors are estimated assuming that the common factors are all adequate. Only four marginal (common) risk factors can be entered into the GeoX software: probability of hydrocarbon source, probability that hydrocarbon migration from source rock to the trap has occurred, probability of the presence of potential reservoir facies and probability that the trap was in place before generation, migration and accumulation of hydrocarbons. This classification therefore requires the nine petroleum system elements listed above to be reclassified into three conditional risk factors and four marginal risk factors.

Since the focus of this work is to demonstrate the workflow, a detailed evaluation of the play elements will not be carried out. Risk values from previous workers such as Nybo [13] have been used.

3.2. Volumetric Analysis

The result from risk analysis is an input parameter for volumetric analysis. The most important parameters needed for volumetric analysis include net to gross ratio, porosity, hydrocarbon saturation, reservoir thickness and trap fill. These parameters were obtained from previous literature such as Bugge *et al.,* [14] and Nybo [13]. The trap fill was set as 40% and not 100% because migration from the source to the trap was not perfect. As seen from the risk assessment, migration is assigned a marginal risk of 0.6. This is because uplifts and subsequent tectonic activities (sealing faults that act as permeability barriers) did not allow for migration of all generated hydrocarbons and so the trap is not filled to its maximum capacity. The reservoir thickness was calculated from taking the thicknesses of the Snadd formation in different wells drilled in the Barents Sea and then taking the average. The Snadd formation is the sandstone reservoir in the block. The average reservoir thickness calculated was 654.24m. The geometric factor was adjusted based on the shape of the trap. Information on the gas formation factor and oil formation factor were sourced from the United States Geological Survey.

3.3. Economic Analysis

Economic evaluation is the last stage of assessing the profitability of a prospect. Inputs from both the risk and volumetric assessment are used in the economic assessment. Other important inputs in the economic assessment include oil and gas prices, infrastructure already present in the basin and the tax regimes of the country. The gFullCycle module in GeoX is used for analyzing prospect economics. This work was carried out in Norway so the Norwegian petroleum tax laws and economic fiscal regime has been used. Oil and gas prices have been forecasted to the year 2049 with price predictions in the International Energy Outlook [15] from the U.S. Energy Information Department (figs.3 and 4). Discount rate of 7% and internal rate of return of 12% have been used (fig.2). Cost of seismic acquisition, exploration wells, development wells, production wells and infrastructure have been estimated using examples from other petroleum fields in the basin (figs.5-8).

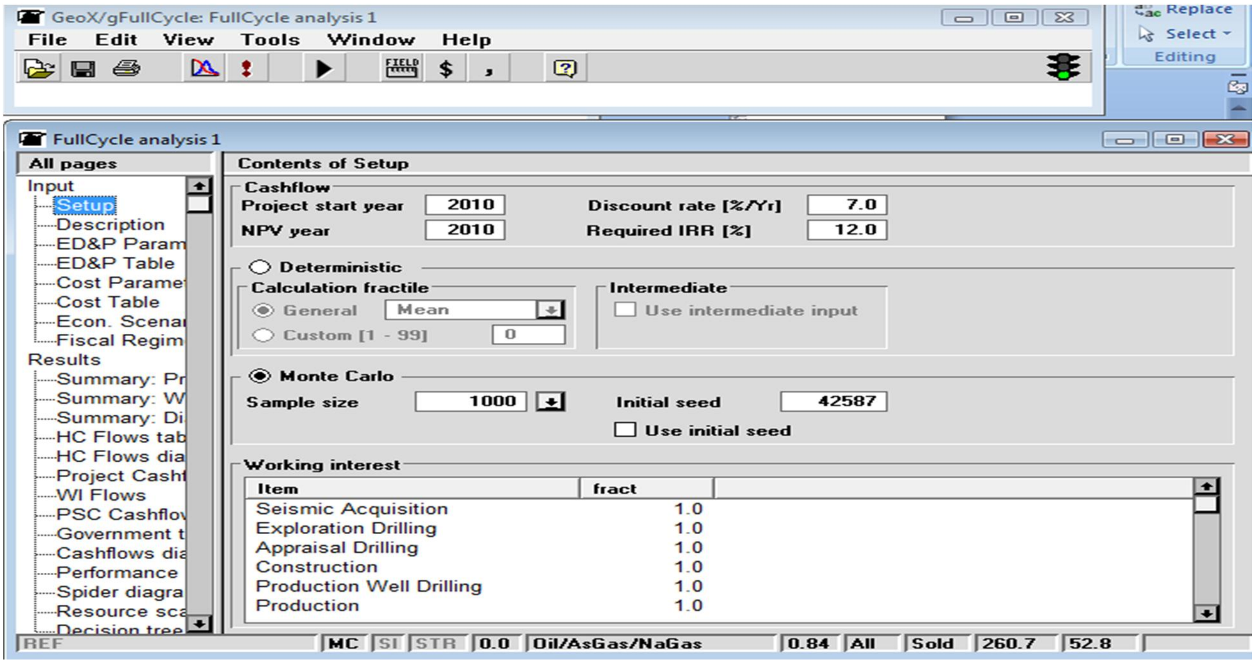


Fig.2: Project setup

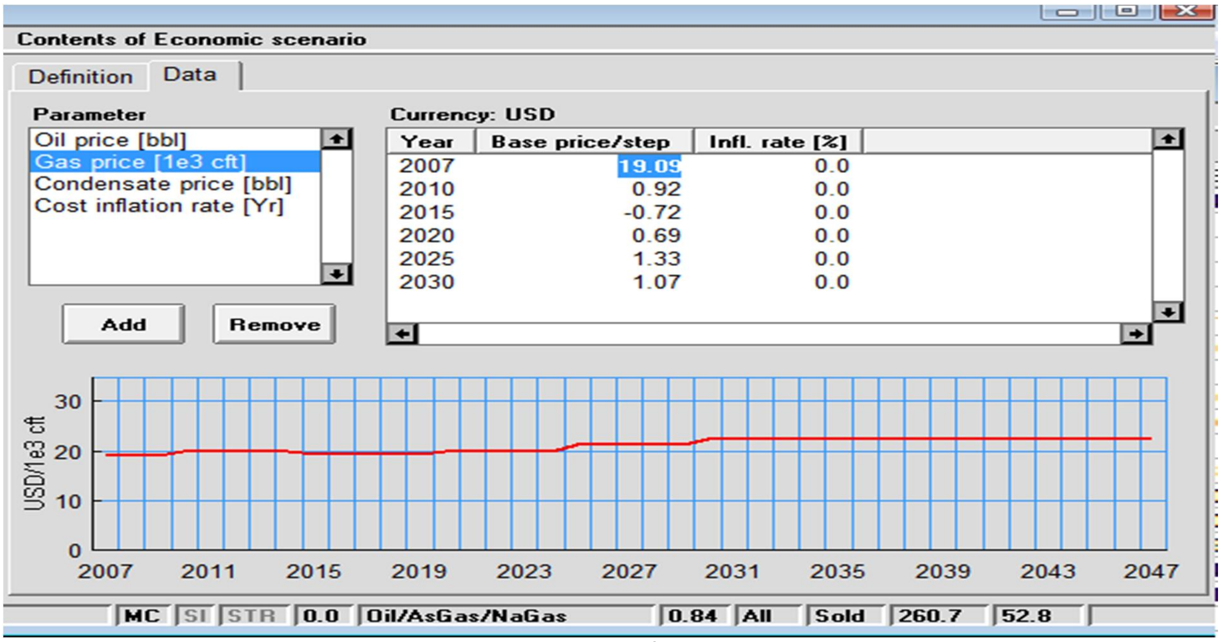


Fig.3: Gas price forecast

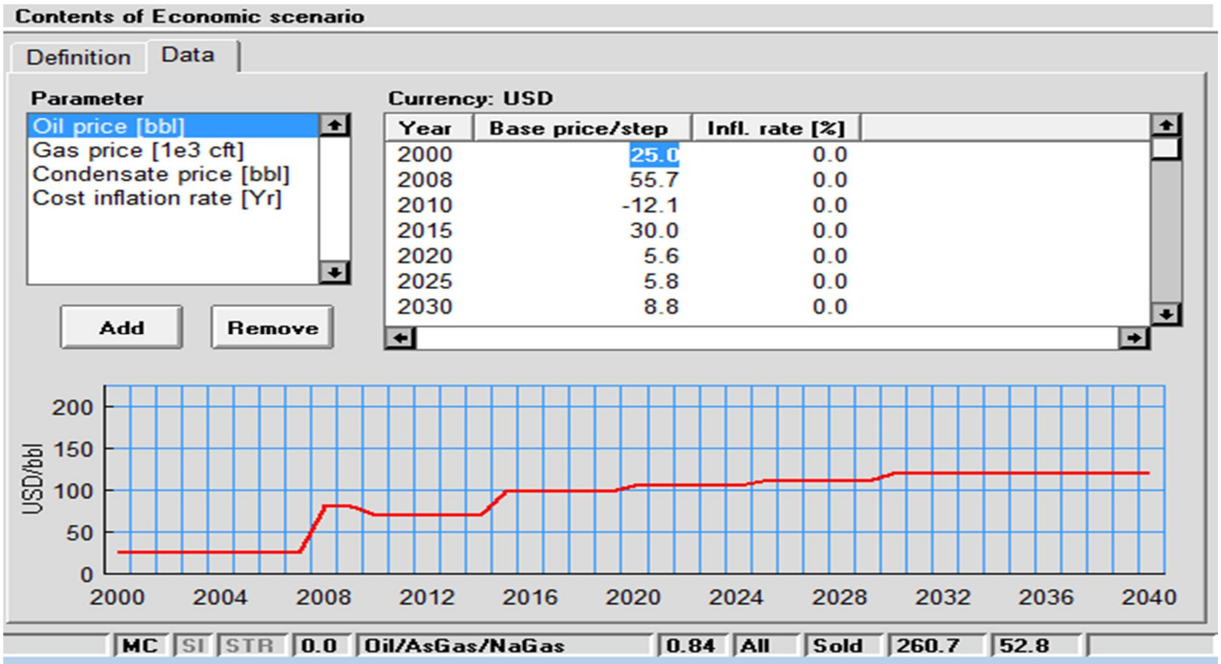


Fig.4: Oil price forecast

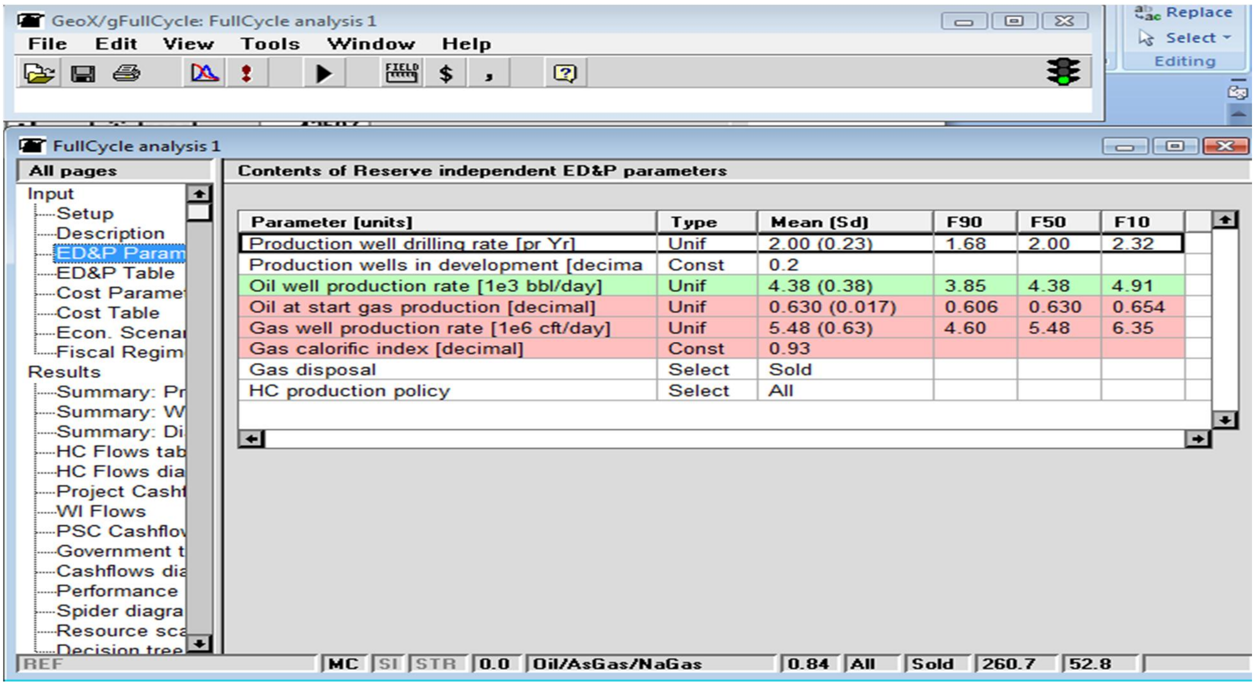


Fig.5: Exploration, development and production parameters

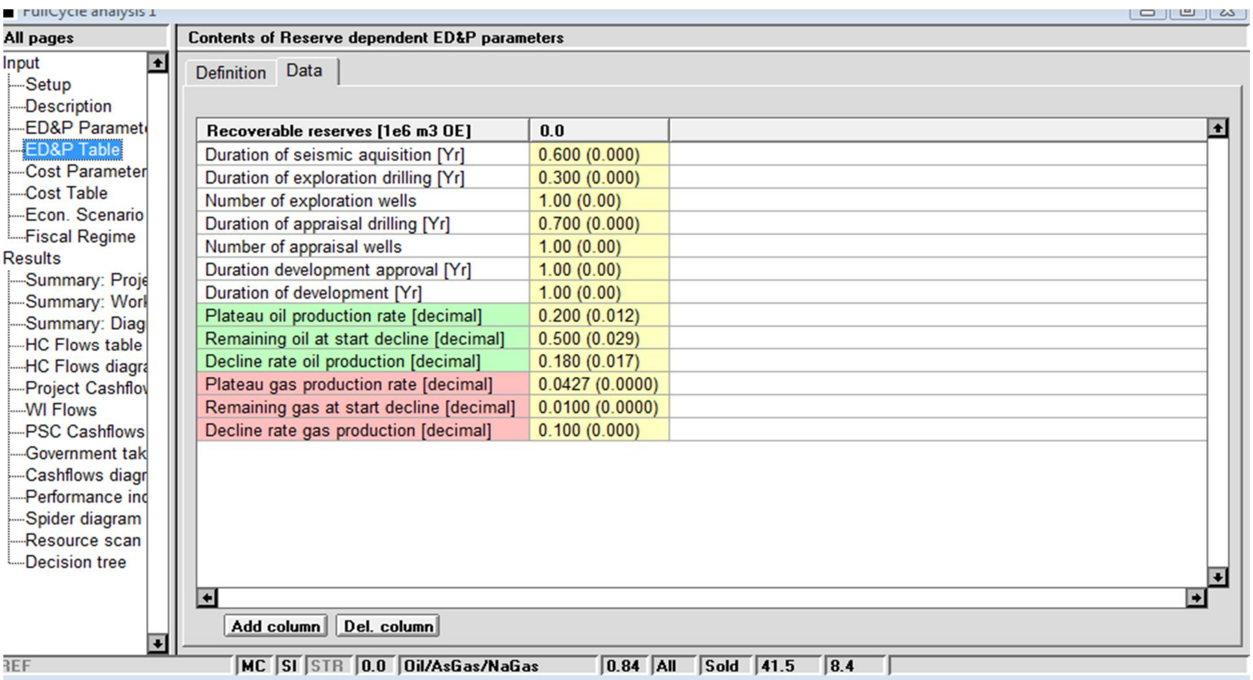
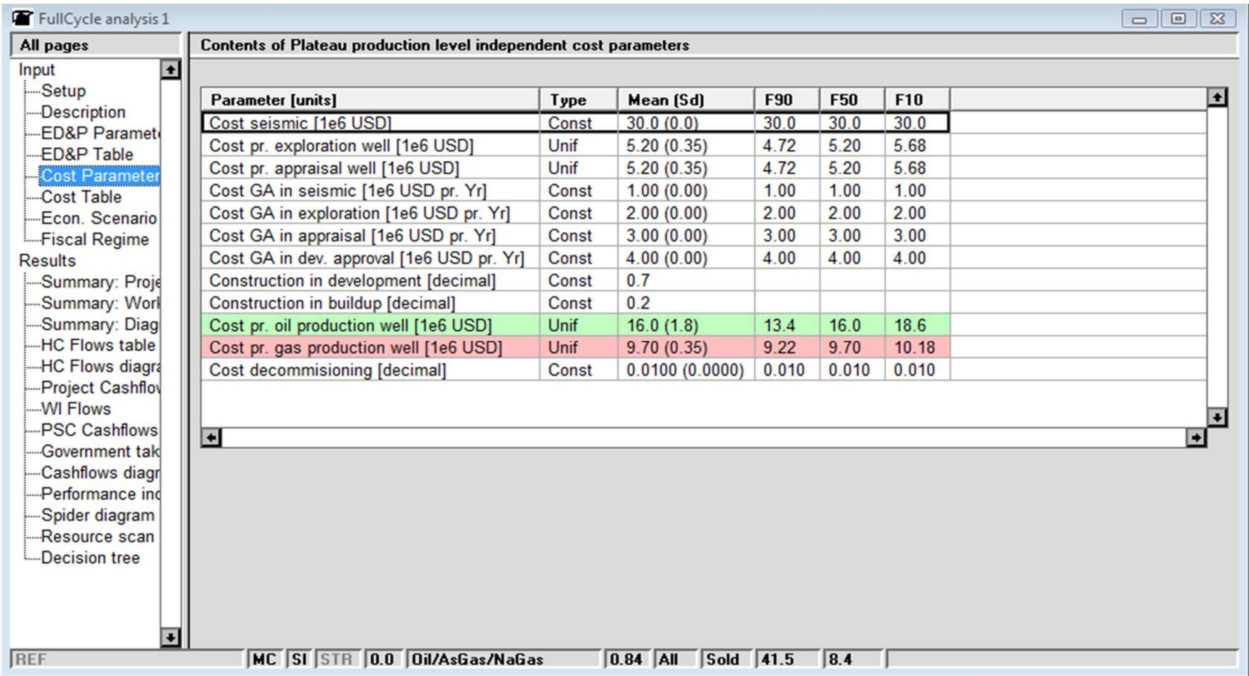
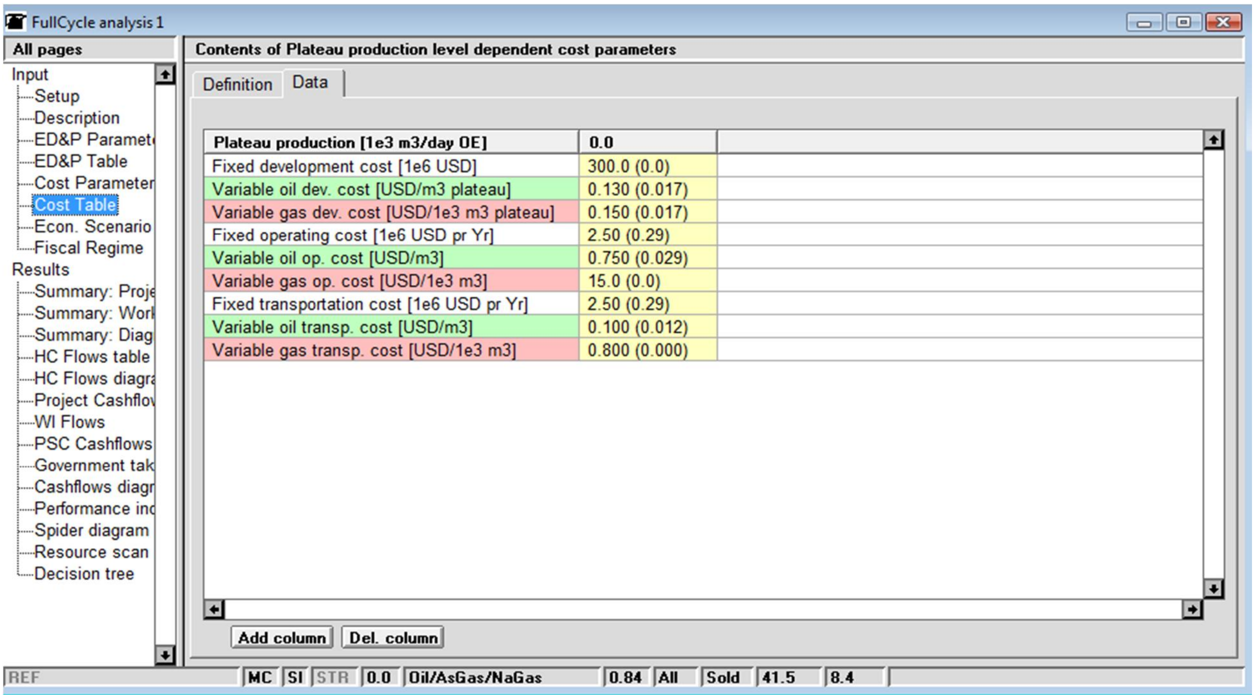


Fig.6: Exploration, development and production table



Parameter [units]	Type	Mean (Sd)	F90	F50	F10
Cost seismic [1e6 USD]	Const	30.0 (0.0)	30.0	30.0	30.0
Cost pr. exploration well [1e6 USD]	Unif	5.20 (0.35)	4.72	5.20	5.68
Cost pr. appraisal well [1e6 USD]	Unif	5.20 (0.35)	4.72	5.20	5.68
Cost GA in seismic [1e6 USD pr. Yr]	Const	1.00 (0.00)	1.00	1.00	1.00
Cost GA in exploration [1e6 USD pr. Yr]	Const	2.00 (0.00)	2.00	2.00	2.00
Cost GA in appraisal [1e6 USD pr. Yr]	Const	3.00 (0.00)	3.00	3.00	3.00
Cost GA in dev. approval [1e6 USD pr. Yr]	Const	4.00 (0.00)	4.00	4.00	4.00
Construction in development [decimal]	Const	0.7			
Construction in buildup [decimal]	Const	0.2			
Cost pr. oil production well [1e6 USD]	Unif	16.0 (1.8)	13.4	16.0	18.6
Cost pr. gas production well [1e6 USD]	Unif	9.70 (0.35)	9.22	9.70	10.18
Cost decommisioning [decimal]	Const	0.0100 (0.0000)	0.010	0.010	0.010

Fig.7: Cost parameters



Plateau production [1e3 m3/day OE]	0.0
Fixed development cost [1e6 USD]	300.0 (0.0)
Variable oil dev. cost [USD/m3 plateau]	0.130 (0.017)
Variable gas dev. cost [USD/1e3 m3 plateau]	0.150 (0.017)
Fixed operating cost [1e6 USD pr Yr]	2.50 (0.29)
Variable oil op. cost [USD/m3]	0.750 (0.029)
Variable gas op. cost [USD/1e3 m3]	15.0 (0.0)
Fixed transportation cost [1e6 USD pr Yr]	2.50 (0.29)
Variable oil transp. cost [USD/m3]	0.100 (0.012)
Variable gas transp. cost [USD/1e3 m3]	0.800 (0.000)

Fig.8: Cost table

4. Results and Discussion

Table 1 summarizes the reclassification of the nine petroleum system elements into conditional and marginal risk factors. Several factors need to be considered in assessing the risk associated with each play element. For example, in the evaluated block, factors that affect the integrity for traps and trap seals like the several episodes of uplift that occurred in the basin need to be considered. Another important factor is the fact that some hydrocarbon prospects have already been discovered in nearby basins and are producing, e.g. Snohvit field in the Hammerfest Basin (fig.1). Such discoveries reduce the risks in the basin tremendously because it proves the presence of a mature source rock, a working trap and presence of good quality reservoir rocks.

Table 1: Classification of petroleum system elements into marginal and conditional risk

	MARGINAL RISK-COA				CONDITIONAL RISK-SR		
	Hydrocarbon source	Timing	Migration	Reservoir Facies	Trap Occurrence	Effective Porosity	HC Accumulation
Facies Presence				0.9			0.85
Reservoir Quality				1		1	
Source Presence	1						0.9
Source Maturity	1						1
Migration Paths			0.6		0.6		
Migration Timing		1			1		
Trap Closure			1		0.9		
Trap Seal			1		0.7		
HC Recovery				1			1
	1	1	0.6	0.9	0.378	1	0.765

Risk calculations in table 1shows a marginal play probability of 0.54, conditional prospect probability of 0.29 and unconditional probability of 0.156 (fig.9). It can be concluded from table 1 that the risk of drilling a dry hole is as high as 0.843 (fig.9). This high dry hole risk can be attributed to some of the factors enumerated above in the basin. However, a decision on whether to drill the prospect or not cannot be made based on only the geologic risk analysis.

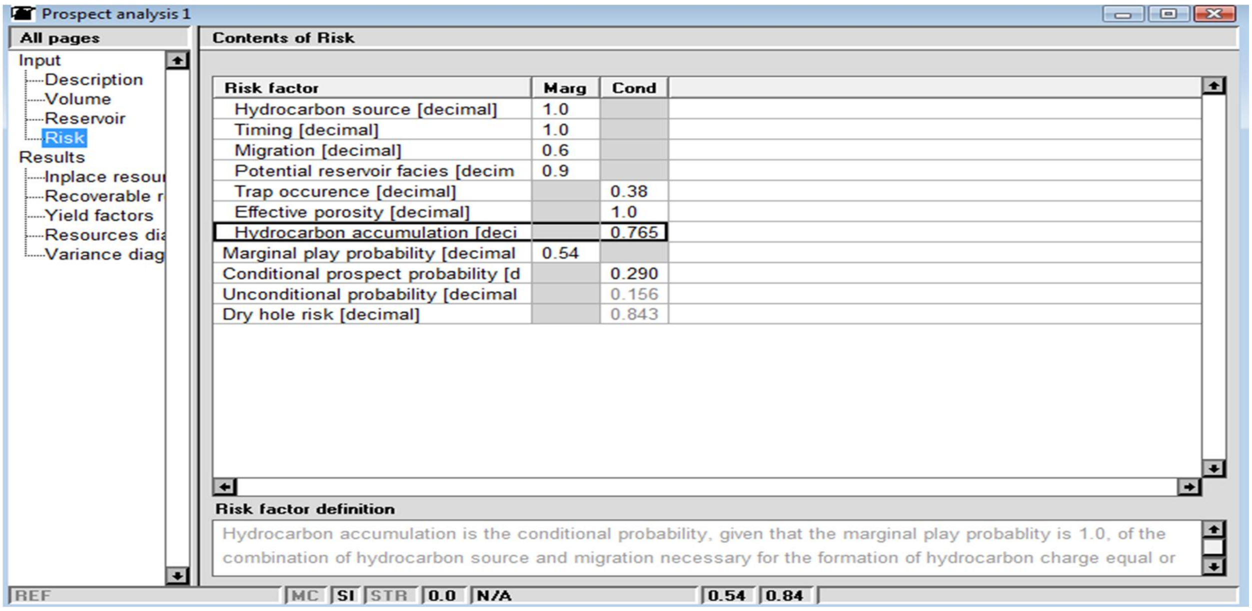


Fig.9: Risk parameters

4.1. Volumetric Analysis

The presence of uncertainties in prospect evaluation means that hydrocarbon volumes are estimated from the optimistic, pessimistic and conservative views (figs.10 and 11). Total recoverable resources are the sum of the accumulation size of recoverable oil, recoverable non associated gas and recoverable associated gas. GeoX estimates these volumes as P10, P90 and P50 respectively. P10 represents the highest hydrocarbon volumes with a 10% chance of obtaining such volumes. P90 represents the lowest hydrocarbon volumes with a 90% chance of obtaining such volumes. P50 values usually represent a more conservative estimate with 50% chance of success. From figs. 12 and 13, the total recoverable hydrocarbon resources can be calculated in cubic metres (m^3) as:

For oil:

P10- 11.45 million cubic metres

P50- 6.27 million cubic metres

P90- 3.43 million cubic metres

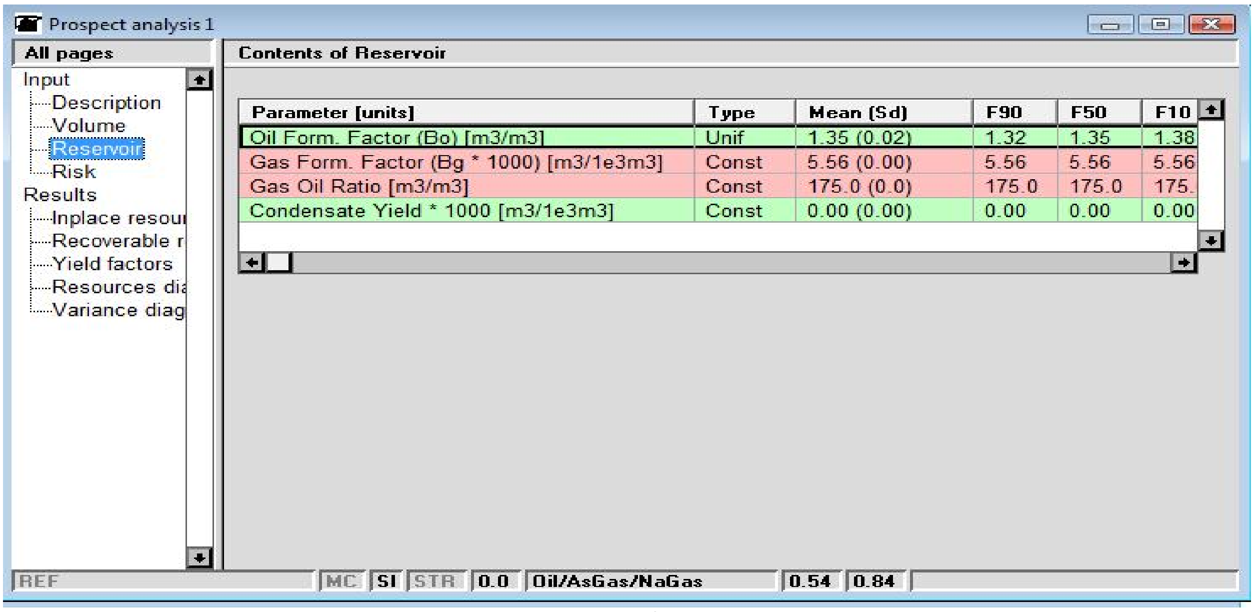
For gas:

P10- 54.0+2.0= 67.45 billion cubic metres

P50- 29.9+1.10= 37.27 billion cubic metres

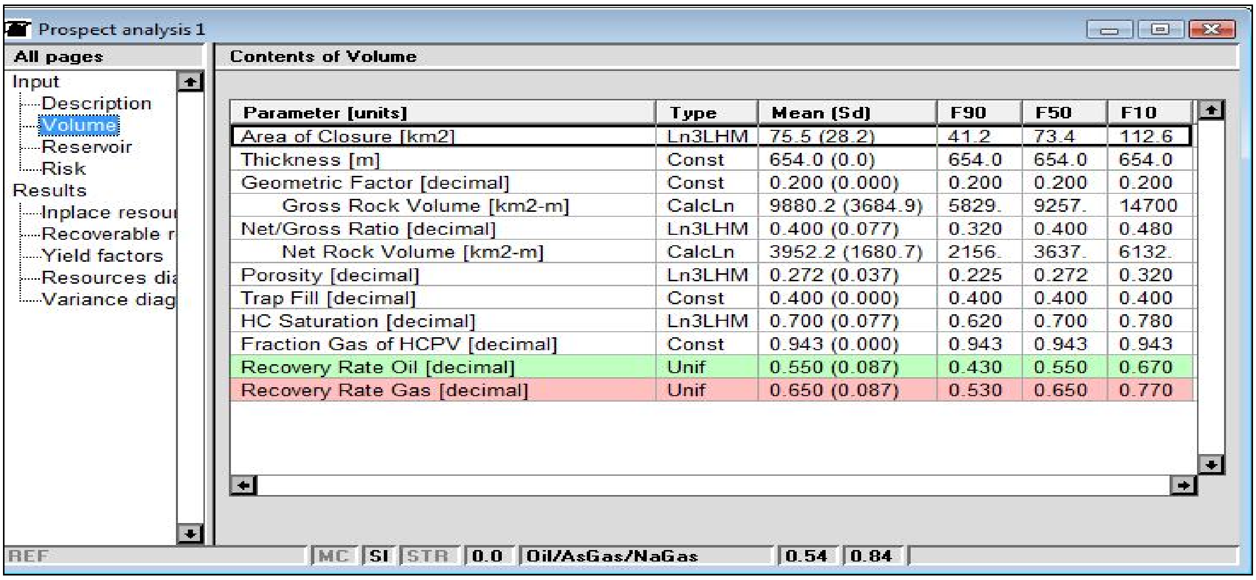
P90- 16.5+ 0.60 =20.53 billion cubic metres

From the volumetric calculations, the main type of hydrocarbon in the prospect is gas. These volumes have been validated with previous results by Nybo (2009) with an error margin of +/- $3m^3$. Sources of error are usually due to uncertainties in the data used.



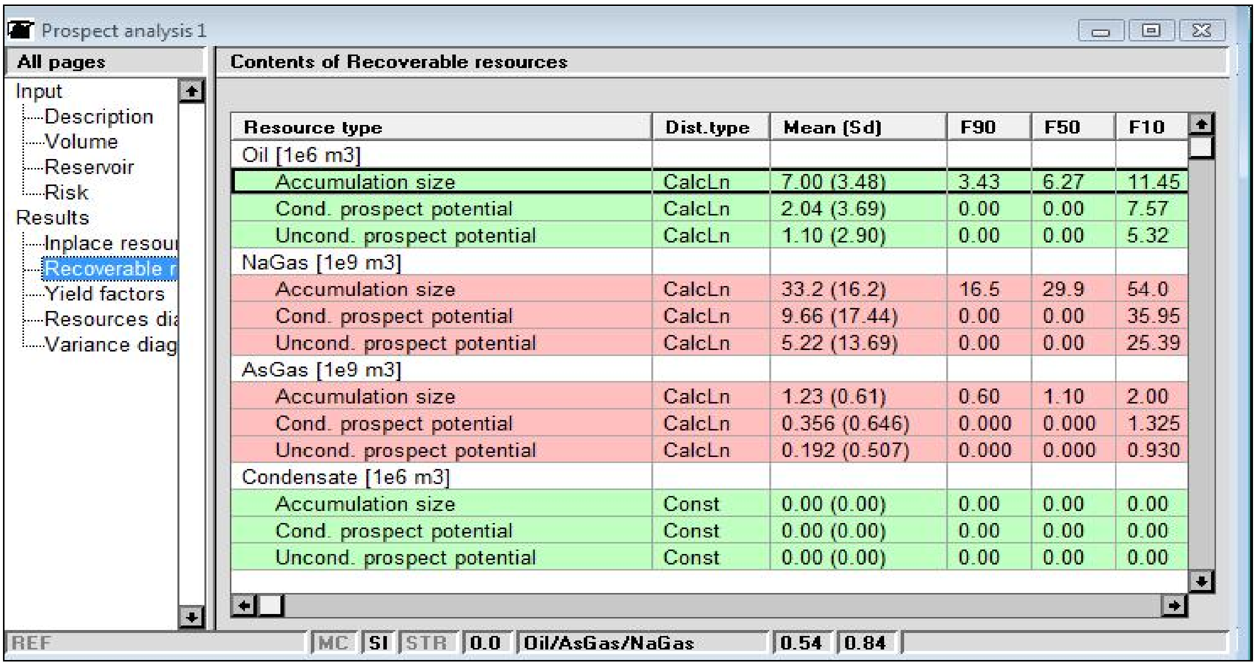
Parameter [units]	Type	Mean (Sd)	F90	F50	F10
Oil Form. Factor (Bo) [m3/m3]	Unif	1.35 (0.02)	1.32	1.35	1.38
Gas Form. Factor (Bg * 1000) [m3/1e3m3]	Const	5.56 (0.00)	5.56	5.56	5.56
Gas Oil Ratio [m3/m3]	Const	175.0 (0.0)	175.0	175.0	175.
Condensate Yield * 1000 [m3/1e3m3]	Const	0.00 (0.00)	0.00	0.00	0.00

Fig.10: Contents of reservoir



Parameter [units]	Type	Mean (Sd)	F90	F50	F10
Area of Closure [km2]	Ln3LHM	75.5 (28.2)	41.2	73.4	112.6
Thickness [m]	Const	654.0 (0.0)	654.0	654.0	654.0
Geometric Factor [decimal]	Const	0.200 (0.000)	0.200	0.200	0.200
Gross Rock Volume [km2-m]	CalcLn	9880.2 (3684.9)	5829.	9257.	14700
Net/Gross Ratio [decimal]	Ln3LHM	0.400 (0.077)	0.320	0.400	0.480
Net Rock Volume [km2-m]	CalcLn	3952.2 (1680.7)	2156.	3637.	6132.
Porosity [decimal]	Ln3LHM	0.272 (0.037)	0.225	0.272	0.320
Trap Fill [decimal]	Const	0.400 (0.000)	0.400	0.400	0.400
HC Saturation [decimal]	Ln3LHM	0.700 (0.077)	0.620	0.700	0.780
Fraction Gas of HCPV [decimal]	Const	0.943 (0.000)	0.943	0.943	0.943
Recovery Rate Oil [decimal]	Unif	0.550 (0.087)	0.430	0.550	0.670
Recovery Rate Gas [decimal]	Unif	0.650 (0.087)	0.530	0.650	0.770

Fig.11: Volumetric parameters



Resource type	Dist.type	Mean (Sd)	F90	F50	F10
Oil [1e6 m3]					
Accumulation size	CalcLn	7.00 (3.48)	3.43	6.27	11.45
Cond. prospect potential	CalcLn	2.04 (3.69)	0.00	0.00	7.57
Uncond. prospect potential	CalcLn	1.10 (2.90)	0.00	0.00	5.32
NaGas [1e9 m3]					
Accumulation size	CalcLn	33.2 (16.2)	16.5	29.9	54.0
Cond. prospect potential	CalcLn	9.66 (17.44)	0.00	0.00	35.95
Uncond. prospect potential	CalcLn	5.22 (13.69)	0.00	0.00	25.39
AsGas [1e9 m3]					
Accumulation size	CalcLn	1.23 (0.61)	0.60	1.10	2.00
Cond. prospect potential	CalcLn	0.356 (0.646)	0.000	0.000	1.325
Uncond. prospect potential	CalcLn	0.192 (0.507)	0.000	0.000	0.930
Condensate [1e6 m3]					
Accumulation size	Const	0.00 (0.00)	0.00	0.00	0.00
Cond. prospect potential	Const	0.00 (0.00)	0.00	0.00	0.00
Uncond. prospect potential	Const	0.00 (0.00)	0.00	0.00	0.00

Fig.12: Recoverable hydrocarbon resources

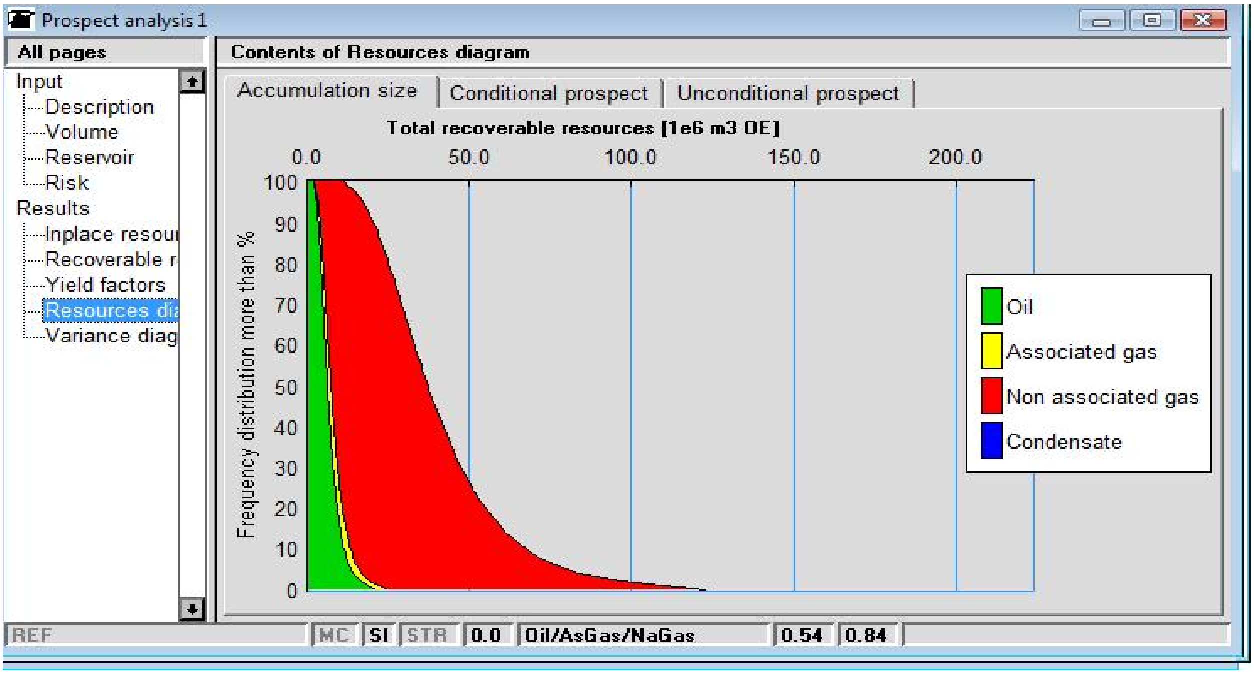


Fig.13: Resource diagram

4.2. Economic Analysis

The economic analysis is the most complicated of the entire GeoX prospect evaluation workflow. The main outputs of the economic evaluation are the operational costs (OPEX), capital cost (CAPEX) and gross revenue from the sale of oil and gas in the field. Calculations of gross revenues use the life span of the project, current oil and gas prices and forecast of the oil and gas prices of the project. Another important output is a decision tree based on net present values (NPV) of different scenarios based on which a decision can be made whether to drill the prospect or not. Results from the economic evaluation are summarized in figs.14 and 15. A decision on whether to explore the prospect or not and the cash flows associated with a discovery or dry well are represented by probabilities and discounted NPV's in the decision tree in fig.15.

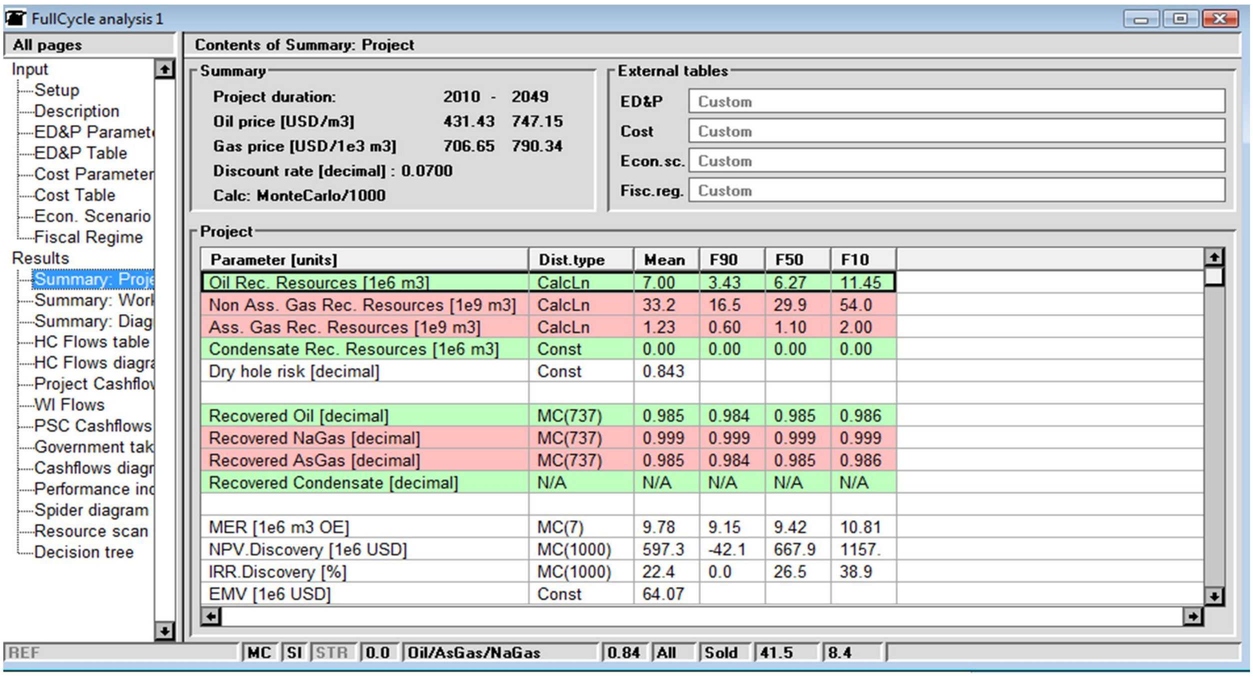


Fig.14: Project summary

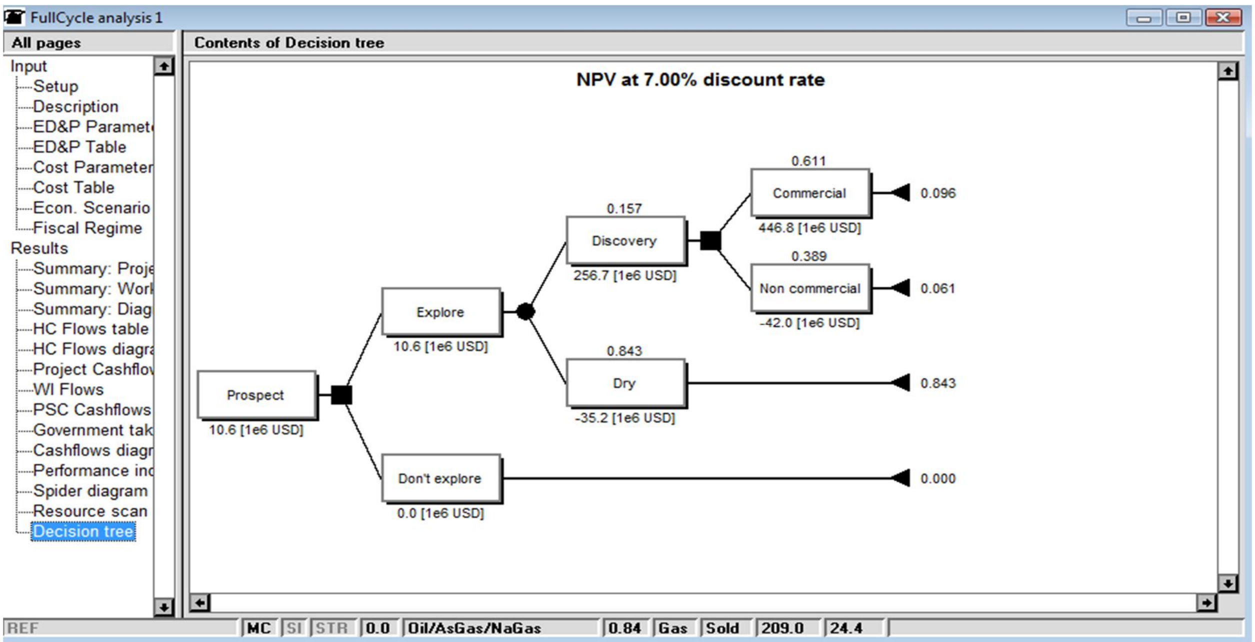


Fig.15: Decision tree with net present values (NPV) at 7% discount rate

The CAPEX of the project derived from the GeoX calculations is 1484.4 million United States Dollars (Table 2). The OPEX of the project is 1182.6 MUSD (Table 3). A pipeline should be constructed from the prospect to Snohvit field in order to transport the gas. The Snohvit field is a gas field and has the necessary facilities already in place for storage and processing of gas. The cost of construction of this pipeline has been estimated as 100MUSD and included in the fixed development cost for the project. If both oil and gas are produced, then a feasibility study should be carried out in order to determine how to transport and process the oil. The gross revenue of the project is 28,817.8 MUSD. This is mainly from the forecasted sales of oil and gas produced from the field.

Table 2: CAPEX of project

CAPEX	Amount (MUSD)
Seismic acquisition	30
Exploration drilling	5.2
Appraisal drilling	5.3
Construction development	353.2
Production well drilling	1090.4
Total CAPEX	1484.4

Table 3: OPEX of project

OPEX	Amount (106 USD)
General and Administration	7.5
Transportation	183.2
Field operation	976.9
Decommissioning	15.1
Total OPEX	1182.6

Table 4: Oil and gas gross revenues

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue (106 USD)	126.7	453.4	867.2	1036	985.7	887.1	813.5	283.5	287.7	342.5	397.3	452
Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Revenue (106 USD)	540.5	599	657.4	715.8	774.2	874.4	935.8	997.1	1041	1042	1042	1042
Year	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Revenue (106 USD)	1042	1042	1042	1042	1042	1042	1042	1042	1042	1042	1042	148

From Table 4, the gross revenue of the project exceeds the sum of OPEX and CAPEX by 26150.8MUSD. This means the project is economical and can be drilled. A decision then has to be taken on whether to produce only gas or both gas and oil. Table 5 compares the economics of the two different scenarios using the net present values (NPV). From table 5, it is more economical and profitable to produce both oil and gas. However, it has to be noted that presently there in no infrastructure for oil and so if both oil and gas will be produced then a further study is required to access the cost of providing that infrastructure. If the infrastructure cost for producing oil in addition to gas is more than the profits from the sale of oil, then it is recommended that only gas should be produced from the field. There is 73.7% chance that a commercial discovery will be made with an NPV of 825.4million dollars. There is a 26.3% chance of a non commercial discovery with an NPV of -42 million dollars. There is an 83.3% chance of getting a dry hole. The minimum economic reserve (MER) required for the prospect to be profitable is about 62bbloe.

Table 5: Comparison between producing both oil and gas and producing only gas

	PRODUCING OIL AND GAS	PRODUCING ONLY GAS
MER (10^6 bbloe)	62	194.41
COMMERCIAL NPV (MUSD)	825.4	446.7
DISCOVERY NPV (MUSD)	597.3	256.7

5. CONCLUSION

The methodology demonstrated in the study is a typical prospect evaluation work flow used in the evaluating the viability of a prospect. Since the focus of this study was to demonstrate methodology, a detailed analysis of the risk associated with each petroleum element has not been done, however, in actual evaluation of a prospect a more comprehensive risking of the petroleum system elements need to be done in order to assign risk factors to them. The process of evaluating a prospect is a three stage approach with each successive stage depending on the results of the previous stage. The three interdependent stages include risking of geologic parameters, volumetric estimates and economic assessment of the prospect. To determine the viability of a prospect, an evaluation of each of these three stages need to be carried out comprehensively. Important factors to consider in the risking and volumetric estimates include thickness of reservoir, hydrocarbon saturation, area of closure, mature and quality source rocks, migration and migration pathways, quality reservoir rocks and a working trap formed before migration of hydrocarbons. Important input for economic assessment include current and future oil and gas prices, exploration and development costs and the tax/ fiscal regime of the operating country.

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