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Project Management Methodology and Tools for Oil Field Development: from investor point of view

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Dissertação de Mestrado

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Abstract

Energy is a critical source for global economy as its availability is required at almost in every industry. In order to match the energy global demand, companies are investing a massive capital in the execution of multinational projects. These projects if not properly planned, organized, executed and controlled may pose a high degree of risks to the shareholders. Besides compromising the success of a project, failures in addressing the projects risks can leave a company with serious consequences such as loss of competitive advantage or reputation damage.

Today oil and gas companies are facing many kinds of risks and uncertainties what makes execution of projects increasingly complex. The ultimate goal that companies are trying to reach is the production of hydrocarbon products in effective and cost efficient manner. This can be achieved by ensuring that reservoir performance is enhanced, production is optimized and project risks are reduced or eliminated.

The purpose of this work was to generate a methodology and tools that will help Partex Oil and Gas Group to improve the current risk management process of their hydrocarbon ventures. Being an investor of international projects, Partex does not have a direct project management control. As a result, the project operators often follow an unstructured methodology to risk management, which negatively impacts performance of the project and revenues of Partex shareholders. To facilitate Partex success, a following solution was proposed: an economic modeling framework to manage risks effectively, a structured risk management methodology that will ensure the sustainability of projects performance and KPIs to monitor project performance toward the target goals.

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Contents

List of Abbreviations

API	American Petroleum Institute
APM	Association for Project Management
BBL	Barrel
BG	British Gas
BOE	Barrel of Oil Equivalent
BP	British Petroleum
BSI	British Standards Institution
CAPEX	Capital Expenditures
E&P	Exploration and Production
EOR	Enhanced Oil Recovery
FDP	Field Development Plan
FEED	Front-End Engineering Design
FERMA	Federation of European Risk Management Associations
FEUP	Faculdade de Engenharia da Universidade do Porto
IEC	International Electrotechnical Commission
IRM	Institute of Risk Management
IRR	Internal Rate of Return
ISO	International Organization for Standardization
JMC	Joint Management Committee
JOA	Joint Operating Agreement
JOC	Joint Operating Committee
KPI	Key Performance Indicator
MAUT	Multi-Attribute Utility Methodology
MBOPD	Thousand Barrels of Oil per Day

MBSPD	Thousand Barrels of Steam per Day
MESG	Mestrado em Engenharia de Serviços e Gestão
MG1	Middle Gharif, different geological correlation tops used to subdivide the Gharif.
MMBO	Million Barrels of Oil
MVC	Mechanical Vapour Compressors
NPV	Net Present Value
OGP	International Association of Oil and Gas Producers
OPEX	Operational Expenditures
PDRI	Project Definition Rating Index
PMBOK	Project Management Body of Knowledge
PMI	Project Management Institute
PSA	Production Sharing Agreement
R&D	Research and Development
RIMS	Risk and Insurance Management Society
RUMP	Risk and Uncertainty Management Process
UG2A, UG2B	Upper Gharif, different geological correlation tops used to subdivide the Gharif. UG1 and UG2A are two significant layers that are typically separately produced.

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Introduction

This dissertation project was executed according to the academic curriculum of the MESG program in collaboration with the enterprise Partex Services Portugal in Lisbon. This chapter provides the insights of the hosting institution and the project itself, research problem and research objectives, applied methodology, limitations of research and the study report structure.

1.1 Presentation of Partex Oil and Gas Group

Partex Services Portugal is a management unit of the Partex Oil and Gas Group (referred in this report as simply Partex) which main objective is to provide technical, organizational and managerial support to the Group on oil and gas related activities, its participations in venture projects and partners. Today, staff seconded to the operations has become a very important element of the presence and involvement of the Group[1].

Partex was established in 1938 by Calouste Gulbenkian to manage his interests in the Middle East. Nowadays the Group along with its presence in Abu Dhabi and Oman diversified the operations to other countries such as Kazakhstan, Brazil, Algeria, Angola and Portugal. Along the years the Group developed partnerships with industry majors like ExxonMobil, Shell, BP, Total, Repsol, BG, Petrobrás, Sonatrach, Sonangol, and others.

1.1.1 Strategy and activities

Partex strategy is in targeting critical know-how and technologies in its core business areas.
The Group is carrying the following activities:

- Geosciences and seismic interpretation;
- Optimization of hydrocarbon recovery;
- Reservoir characterization and simulation;
- Reservoir management;
- Field development planning;
- Production operations;
- Facilities integrity and efficiency.

Also, company undertakes some R&D programs with a purpose to develop specific knowledge and technologies in critical areas of the industry such as:

- Acoustic and Elastic Seismic Inversion: through the development of algorithms for geostatistical seismic inversion aiming the improvement in reservoirs characterization.
- Enhanced Oil Recovery (EOR): application of compositional simulation and fluid characterization techniques on the implementation of EOR projects.

1.1.2 Group organizational structure

[1] Partex Corporate brochure, January 2008

Partex is organized mainly by geographical areas. It participates in joint ventures and concession agreements related to the oil and gas industry particularly in upstream activities: exploration, development, production and sales.

The Group is structured in sub-holding companies, management units, concession companies and service companies that provide to the joint ventures and operating companies, in which Partex participates, all the necessary advice and financial, technical, management and human resources support that they require, in accordance with the strategy and guidelines defined by the Holding.

Figure 1 shows the organizational structure of Partex Oil and Gas Group, its sub-holding companies and management units.

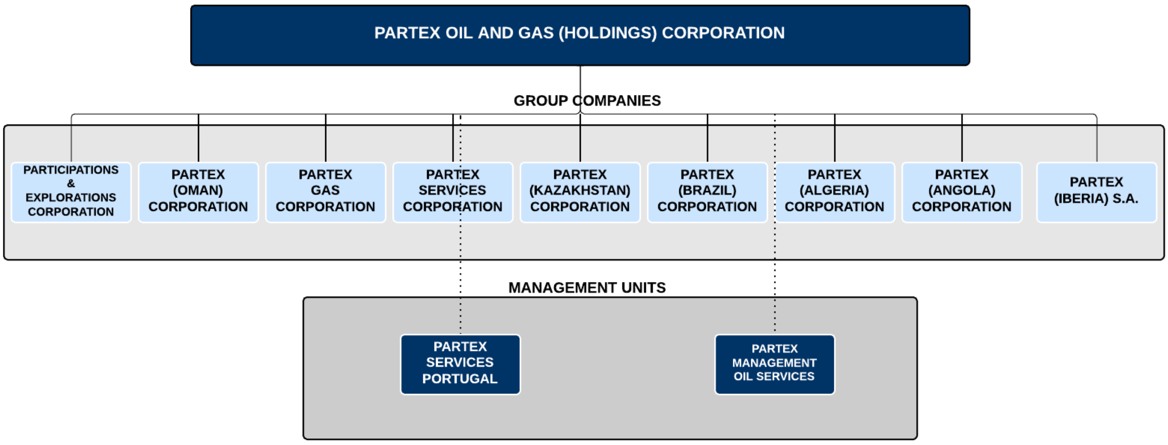

Figure 1 – Organizational structure of Partex Oil and Gas Group

1.2 Presentation of the dissertation project

This subchapter provides a brief description of dissertation project and outlines the main objective.

1.2.1 Project description

Due to the global grow in the energy demand, it can be assumed that the oil and gas industry will continue to develop through the increase in the number of exploration and production activities and joint ventures around the globe. Success in petroleum projects will require a combination of evolving technologies, human resources expertise and strong project management methodologies to provide investors with tools to manage and response to unforeseen changes.

Partex goal is to engage oil and gas businesses in an efficient, responsible and profitable manner. Company participates in a number of oil and gas concessions and joint ventures as an investor where a main project operator selected by the government is in charge with project planning, estimation and execution[2].

In such participations, “Partex” does not have a direct control over the execution of the project, providing only technical support activities to its partnerships and relies on the methodology and data provided by the operator. Such approach could bring a lot of uncertainties and risks from the investor perspective and may affect the success in the projects performance. This problem identified the interest and motivation to execute the current dissertation work.

In order to understand project management, and in particular, risks management processes of ventures where Partex acts as an investor, a case study from a project in the Sultanate of Oman was studied. This case study allowed to analyze the implemented risk management methodology, its advantages and disadvantages, identify the major areas of improvements and propose the respective solutions.

1.2.2 Project objective

The objective of the current work was established together with the advisor of Partex to address shareholders concerns in a most comprehensive manner.

The ultimate goal of the work was to generate a set of recommendations that can help to improve the effectiveness of Partex risk management process for its ventures in oil and gas projects and guarantee the sustainability of the business.

This objective was accomplished through the development of a methodology that aimed to provide a solution to the problem identified in the above section (Section 1.2.1). The description of the methodology is provided in the following section.

1.3 Method followed in the project

The methodology, applied in the project and developed collaboratively with the advisor of FEUP, was found as the most appropriate in order to successfully execute the research work. The dissertation project was accomplished in the following order:

1. Familiarization with the project and the hosting institution, interviews with project experts;
2. Development of a project schedule and a working plan;
3. Literature review of existing methodologies, standards and practices;
4. Case study analysis;
5. Application of the solution to the case study;
6. Reviews and feedback from the project experts;
7. Discussion of results, conclusions and recommendations for the upcoming project updates and future projects.

1.4 Limitations of research

[2] With the exception of Brasil where company operates an onshore small oil field

1. The execution of this research was dependent on data from the project operator submitted to investors through the various workshops and meetings. The documentation provided a narrow range and information outside of the range limit was not available for analysing.
2. The practical application of the proposed solution was not possible due to the large scope of the oil and gas projects and limited time to execute a dissertation work. The implementation of the recommended framework would require time to obtain the concrete results.

1.5 Topics discussed and how they are organized in this report

During this work all respective information and findings were structured and compiled into the following chapters:

- Chapter 1 – introducing the hosting institution where the dissertation study was carried out, its strategy, activities and organizational structure; brief introduction of the research project, research objectives and methodology for project execution;
- Chapter 2 – this chapter is dedicated to the literature review of the risk and risk management;
- Chapter 3 – description of the research problem and case study analysis;
- Chapter 4 – presentation of the proposed solution;
- Chapter 5 – application of the proposed solution to the case study;
- Chapter 6 – conclusions and recommendations for projects updates and future projects.

2. State of art

This chapter dedicates to a literature review of the risk and risk management concepts: definition and evolution of the risk management, existing standards and frameworks, description of the risk management process, and application of risk management tools in the oil and gas industry[3].

2.1. Definitions of *risk* and *risk management*

Risk can be found almost in any industry, project or organization. Petroleum industry usually deals with exploration and field development risks that brings uncertainties associated with an income and "life-cycle cost factors such as potential reserves, capital expenditures (CAPEX), operating expenditures (OPEX), production rate, oil and gas pricing and geological success ratios" (Sholarin, 2007). The management of risks in oil and gas projects is often a complex subject, and for petroleum companies it is important to study how to deal with exceeding budgetary spending and significant schedule delays.

The project objectives, or the measure of project success or failure, are often defined in terms of cost, schedule, and technical performance. Risk management, on the other hand, is intended to increase the likelihood of attaining these objectives by providing a systematic approach for analyzing, controlling, and documenting identified threats during both the planning and execution of a project (Sholarin, 2007).

Risk

Literature provides many definitions of *risk*. Though various authors formulate a risk differently, a common context of all definitions can be expressed as an "uncertainty of outcome" (Heinz-Peter Berg, 2010).

Willet (1951) identified risks as "the objective uncertainty as to the occurrence of an undesirable event. It varies with uncertainty and not with the degree of probability the greater the probable variation of the actual loss from the average, the greater the degree of uncertainty".

However, we found that this definition is quite arguable as authors like Crichton (1999) stated that "*risk* is the probability of a loss, and this depends on three elements, hazard, vulnerability and exposure. If any of these three elements in risk increases or decreases, then risk increases or decreases respectively".

For the current research work, the most appropriate is the definition proposed by Sayers (2002) "*risk* is a combination of the chance of a particular event, with the impact that the event would cause if it occurred. Risk therefore has two components – the chance (or probability) of an event occurring and the impact (or consequence) associated with that event. The consequence of an event may be either desirable or undesirable. In some, but not all cases, therefore a convenient single measure of the importance of a risk is given by: *Risk* =

[3] It was a deliberate choice to focus on a risk management as it addresses the objective of the current research work.

Probability × Consequence" (Kelman, 2003).

Risk management

Douglas W. Hubbard (2009) described *risk management* as a process of "identification, assessment, and prioritization of risks followed by coordinated and economical application of resources to minimize, monitor, and control the probability and/or impact of unfortunate events or to maximize the realization of opportunities".

This definition implies the existence of the process that will help to identify risks as early as possible to restrain the negative impact on the project performance that might occur.

Another description of risk management found in IEC 50 (191) (1990) and British Standards 8444 (1996) that was applied in this work is "the systematic application of management policies, procedures and practices to the tasks of analyzing, evaluating and controlling risk (Baker, 1997)".

For better understanding the origin of risk management, the following section will provide insights of the risk management evolution.

2.2. Evolution of risk management

Though risk management concepts originated from Roman and Greek times (Baker,1997), the era of a modern risk management started after 1955 when the term was first used by two American authors (Mehr and Hedges, 1963) in the title of the insurance manual. This predefined that the risk management has been long associated with the market insurance to protect individuals and companies from losses associated with accidents (Dionne, 2013). In this period, large companies started to use self-insurance against small risks that was covering the financial consequences of an adverse event or losses from an accident (Erlich and Becker,1972). Risk mitigation was a form of self-insurance to reduce the financial impact from natural catastrophes.

Risk management in the oil and gas industry also started to evolve after the World War II. The first study where risk of exploration was formally analyzed using the probability theory and modeling of sequential stages of exploration was the work of Allais (1956). In the study, he demonstrated how to use computer simulation, in particular Monter Carlo methods, and how to apply these methods to the complex probability analysis, instead of simplifications of risk estimation of large area (Suslik, Schiozer, Rodriguez, 2009). During this period governmental agencies also started to apply the analysis of risks in their assessments of oil and gas resources.

In 1960's, risk management concepts were quite new to the oil and gas industry and started to be explored by the academic world. In 1970's several authors argued that decision analysis could not reduce or eliminate the risk and replace a professional judgment of geoscientists, managers and engineers (Suslik, Schiozer, Rodriguez, 2009). Throughout of 1980's and 1990's several risk estimation methods were evolved such as: (1) lognormal risk resource distribution (Attanasi and Drew, 1985), (2) pareto distribution applied to petroleum field-size data in a play (Crovelli, 1995) and (3) fractal normal percentage (Crovelli et al., 1997)

(Suslik, Schiozer, Rodriguez, 2009).

In 1995, Walls made an important challenge by using multi-attribute utility methodology (MAUT) that was concerned with effects of including corporate goals and risk strategy into investment alternatives. This methodology was recognized and explored later in work of several authors such as Nepomuceno (1999), Suslick and Furtado (2001).

Recent studies such as Schiozer (2004) proposed to incorporate geological and economic risks with production strategy in order to 1) quantify the impact of decisions on the risk of the projects, (2) calculate the value of information, as proposed by Demirmen (2001) and (3) quantify the value of flexibility.

Schiozer (2004) strategy served as a base for techniques that today apply computer technologies to run simulations of complex reservoir models. Today techniques emphasize the importance of the following concepts: 1) quantification of value of information and flexibility, (2) optimization of production under uncertainty, (3) mitigation of risk and (4) treatment of risk as an opportunity (Suslik, Schiozer, Rodriguez, 2009).

2.3 Risk management frameworks and standards

Due to the increased interest of the academic world in improving companies' abilities to deal with risks and uncertainties, a lot of tools, standards and methodologies were developed in last decades.

In RIMS report a *standard* is defined as "an established norm or requirement, usually a formal document that establishes criteria, methods, processes and practices under the jurisdiction of an international, regional or national standards body". Along with the term "standard", the term *framework* is also used as 1) a structure for supporting the organization's strategic and operational objectives, and as 2) a system or group of interacting, interrelated, or interdependent elements, such as ideas, principles, methods or procedures, that form a complex whole (RIMS Executive report, 2011).

Table 1 presents selected standards and frameworks that are globally recognized and have in common a universal understanding of what risk management methodology should cover.

Table 1 – Selected risk management standards and frameworks

Year	Author/Institution	Name of the standard/framework
2000	British Standards Institution (BSI)	BS 6079-3:2000 Project Management - Guide to the Management of Business-related Project Risk
2002	The Institute of Risk Management (IRM)	Risk Management Standard
2002	Federation of European Risk Management Associations (FERMA)	Risk Management Standard
2004	Standards Australia/Standards New Zealand	AS/NZS 4360:2004: Risk Management

2004	Association for Project Management (APM)	Project Risk Analysis & Management (PRAM) Guide
2004	Project Management Institute (PMI)	Guide to the Project Management Body of Knowledge (PMBOK), Chapter "Project Risk Management"
2009	International Organization for Standardization (ISO)	ISO 31000:2009 Risk management – Principles and guidelines

Though standards mentioned in the Table 1 are highly adopted by many industries, we will highlight one that was applied to the current work, which is a Guide to the Project Management Body of Knowledge (PMBOK) issued by Project Management Institute.

Guide to the Project Management Body of Knowledge (PMBOK)

PMI identifies standard as "a document, established by consensus and approved by a recognized body, which provides, for common and repeated use, rules, guidelines or characteristics for activities or their results, aimed at the achievement of the optimum degree of order in a given context" (PMI, 2004).

This standard provides a diversified approach and a foundation to implementation of the project management tools and practices in organizations. The approach provides guidelines for ten (10) project management processes, namely: 1) Integration Management; 2) Scope Management; 3) Time Management; 4) Cost Management; 5) Quality Management; 6) Human Resources; 7) Communications Management; 8) Risk Management; 9) Procurement Management, and 10) Stakeholders Management. As the focus in this study was made on a risk management methodology, the reason for selection of the current standard was its clear and standardized structure, easy guidelines and variety of universal tools that can be applied to oil and gas projects.

2.4 Risk management process

The risk management process can be identified as a sequence of steps that if followed should lead "to the beneficial results and stable risk environment" (Baker, 1997). Due to the different perceptions of risk, steps of risk management process can vary from author to author.

For example, Mehr and Hedges (1963) in their study used five steps of risk management; also, five steps were applied in British Standards BS 8444 (1996); Bostwick (1987) reduced the process to four steps; Buchan (1994) in his work proposed three steps of managing the risk (Baker, 1997).

Project Management Institute risk management framework (2004) proposed the six-steps process (Figure 2), which was applied in this research.

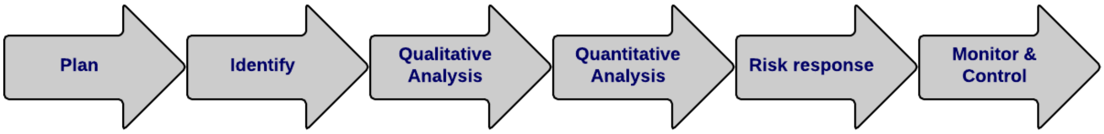

Figure 2 - Risk management process, PMI

The risk management methodology proposes the systematic execution of the following steps:

1. Plan Risk Management – the step of identifying how to conduct risk management activities for a project;

2. Risks Identification —the step of determining which risks may affect a project and documenting their characteristics;

3. Qualitative Risk Analysis— the step of prioritizing risks for further analysis or action by assessing and combining their probability of occurrence and impact;

4. Quantitative Risk Analysis— the step of numerically analyzing the effect of identified risks on project objectives.

5. Plan Risk Responses – the step of developing options and actions to enhance opportunities and reduce threats to project objectives.

6. Monitor and Control Risks – the step of implementation a risk response plan, tracking risks and evaluating risk process effectiveness throughout of a project (PMI, 2004).

2.5 Application of risk management tools in oil and gas industry

In a literature, a little of studies were found about application of standards and frameworks in oil and gas projects. This can be explained by the fact that petroleum industry a long time "have not been a traditional area for the conventional practice of project-management techniques" (Sholarin, 2007). It was discovered that in the oil and gas industry *risk management* is commonly associated with application of the specific standards that concerned with prevention of hazard risks[4] such as oil spills, fatal accidents, workforce injuries, etc. Usually standards applied to petroleum operations are the ones from International Association of Oil and Gas Producers (OGP), American Petroleum Institute (API) and others that are concerned with health, safety and environmental regulations. Also, the oil and gas industry applied to their projects only selected risk management tools rather than the complete frameworks. Below is a review of several tools that are commonly used in the oil and gas projects and related to the execution of current work.

Sensitivity analysis through Monte Carlo simulation

A Monte Carlo Simulation used by petroleum experts in order to estimate oil and gas volumes that can be extracted from reservoirs and the expenditures need to produce these volumes. This approach implies to test how sensitive the economic indicators are to a particular

[4] According to "Driver of Key Risks" of the Risk Management Standard, IRM

variable when all others are fixed at their baseline values. The ultimate goal of this technique is to provide "a visual representation of the impact the variables are expected to have on a given economic indicator" (Sholarin, 2007).

Economic analysis and economic modeling

Economic model is a support tool for the economic analysis. The example of this tool is PetroScope developed by Deloitte, which offers a framework for economic analysis calculations.

Economic analysis implies development and evaluation of several case scenarios for future investment decisions and budget estimations in a project. Scenarios aimed to quantify the impact of uncertainties from oil and gas development activities on project economics. Though it is difficult to predict "what the actual development pattern would be, but the scenarios provide a reasonable basis to begin thinking about potential effects".

3. Research problem

This chapter provides description of the problem, case study analysis and description of the current situation in the area of project management. The analysis of the case study is an important part of this work as it helps to analyze in depth the problem through a real life project.

3.1 Description of the problem

Capital projects in today's oil and gas industry has a certain degree of complexity and to manage them effectively is a critical and complicated task. Since oil and gas projects usually need significant investments, project management tools should have a focus on predictability and reliability, and also provide a certain degree of control over an execution of a project schedule and budget according to the plan and shareholders expectations.

If a project has a poor project management framework, it can cause unfavorable consequences such as loss of the project value and damage of business relationships with partners and governments. On a contrary, adequately used project management tools can increase the chance of project success and shareholders satisfaction.

Partex currently has a participating interest in eighteen (18) ventures around the world. These projects are usually managed via joint venture agreements between national and international companies. The combination of different geographies, political regimes, large capital investments and multi-party governance is exposing the Group to the risks in terms of cost, schedule and project management.

As it was mentioned in Section 1.2.1, in most of its ventures Partex acts as investor and not as operator. Schlumberger online dictionary identifies *operator* as "the company that serves as the overall manager and decision-maker of an E&P project. Generally projects have partner input and potential to override clauses" (Schlumberger, 2013).

As was already mentioned, one of the major concerns of Partex as an investor is the effectiveness of the current project management process in its ventures. This concern has been raised from a need to account and mitigate unforeseen challenges and unfavorable performance in some of the Group investments, and ineffective cost management.

Failure to address the aforesaid issues in a proactive and realistic manner may generate a negative impact on projects economics and Partex revenues. It is hereby assumed that such problem is a result of an inadequate project management methodology from the side of the operator, which will be analyzed later in this work.

3.2 Presentation of the case study

In order to investigate a risk management process and understand the roots of projects underperformance, we analyzed a Partex case study that includes the abovementioned pitfalls.

The case study presented in this work is dedicated to the analysis of a Partex investment in the Sultanate of Oman. Located in a Middle East, Oman is a country with complex geology what makes the undertaken subsurface projects an expensive and difficult challenge. Oil was first discovered in Oman in 1964 and currently Omani fields are being explored by the national and international oil companies.

The structure of this section is as follows: firstly, we provided background of oil field and oil extraction technology; then we presented contractual arrangement and organizational structure of Oman project; after we described a project management process and outlined a current risk management methodology; finally, the case study problem was explained.

3.2.1 Oil field characteristics

The Oman oil field[5], comprising a main North structure and a smaller South structure, was discovered over 30 years ago by one of Oman companies and has a long history of field appraisal and development study activity. The field contains viscous, low gravity crude oil in the shallow Permian-age sands. Eleven appraisal and delineation wells were drilled in a period between 1985 and 1998. In addition to delineation of the field structure and reservoir development, a number of the early vertical and horizontal appraisal wells were tested to evaluate reservoir productivity. On the basis of these well results, an initial field development plan (FDP) was issued in 1994 by the operator of the field, which proposed further study work and a limited development drilling.

3.2.2 Oil extraction technology

The particular characteristics of the oil (heavy oil with very high viscosity) imply the application of special technics for its extraction. Due to the high degree of viscosity, the oil should be heated prior to its production, otherwise it will not flow.

Steam flood implementation is considered to be one of the best options for development of heavy oils and it consists on the following: surface facilities are implemented to heat water and produce high temperature steam. At the same time the field is covered with well patterns composed by both producers and injectors. The steam is then injected into the oil bearing geological formations (oil reservoirs) through the injection wells to heat the oil presented in the porous space. Due to the temperature increase, the viscosity is significantly reduced, enabling fluids to flow towards the production wells. The horizontal producers and vertical injectors used in this technological approach are shown at Figure 3.

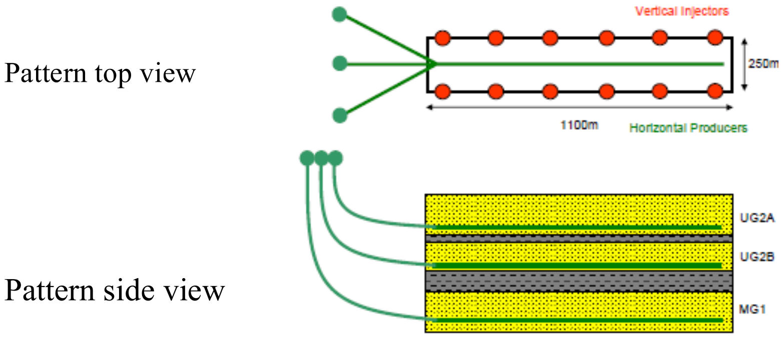

Figure 3 – Schematic well pattern

[5] Due to the confidentiality, the real name of the field is omitted in the text

Figure 3 illustrates the typical geometry of the patterns used in this technological approach:

- Three dedicated horizontal producer wells, one for each oil reservoir (3 reservoirs vertically stacked);

- Twelve vertical steam injector wells, evenly distributed around the injectors (6 on each side). The vertical steam injector wells cross all the three reservoirs.

3.2.3 Contractual arrangement

One of the distinctive features of the Oman oil field project is its contractual arrangement (fiscal regime). The oil and gas companies are usually operating in accordance with several types of agreements such as production sharing agreements (PSA), concessions, risk agreements and service contracts. In this work it will not be explained the details of the different contracts but rather some insights on the current project PSA will be given.

In general terms, the PSA implies that the state, which is usually represented by the government of the country or the national oil company, is the owner of the oil and gas resources. The state contracts the foreign oil company (or companies) that provides technical and financial services to execute the project. The foreign oil company is taking the exploration risks and responsibility for making all the necessary investments and as a reward is getting an entitlement to a share of the produced oil. Additionally, PSA terms frequently stipulate the establishment of a Joint Committee with representatives of all parties to oversee the implementation of the project.

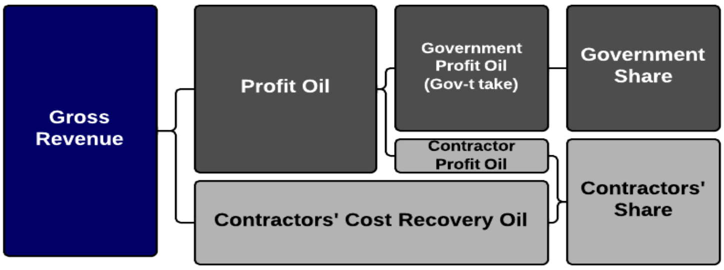

Figure 4 – PSA fiscal regime

The fiscal regime of a PSA is shown in Figure 4 and can be summarized as follows:

- Gross revenues of the project are divided by the government and foreign oil company by shares defined under the PSA terms;
- Foreign company has a pre-specified portion from the gross revenues as *cost recovery oil* to reimburse project expenditures up to a specified cap;
- Unrecovered costs in any year are being accrued to the following year;
- The remaining of the gross revenues is called *profit oil* and then to be split between the government and foreign oil company by a share specified in the PSA.

In 2005, the Government of the Sultanate of Oman decided to carve the Oman Oil field out of the previous concession and firmed a PSA with the following companies (contractors) presented in Figure 5.

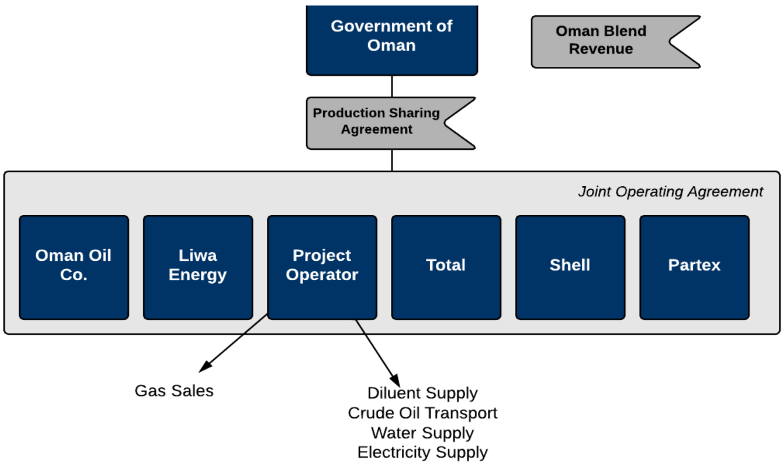

Figure 5 – Case study, PSA structure

3.2.4 Organizational structure

The Joint Management Committees Board and the constituent technical provide appointed members from the government and the operator company assigned governance of the PSA, finance, human resources and tender board.

Joint operations under the PSA are conducted under the terms and conditions of a Joint Operating Agreement (JOA) between all partners and supervised and directed by a Joint Operating Committee (JOC) and constituent technical committee composed of representatives from all partners.

The governance structure is primarily guided by the following:

- Production sharing agreement;
- Joint operating agreement;
- Oman laws and regulations;
- Operator´s Government laws and regulations;
- Operator corporate and Oman policies and procedures.

As you can see in the Appendix A, the organizational structure includes company supervision teams, direct project teams and business support teams. Overall responsibility for the delivery of project objectives is vested in the vice-president of field operations, within the operator and authorities approved framework. He is supported by functional managers with key responsibilities and accountabilities in the areas of subsurface, facilities, and operations.

The company supervision teams are in charge with supervising and managing the project and presented by:

- The *Joint Management Committee* board consists of six voting members. The JMC board is comprised of four representatives appointed by the government of Oman and two representatives appointed by the operator. One of the government-appointed members is the chairman. The committee's executive role is to oversee the implementation of the PSA.

- The *Joint Operating Committee* includes the Partex representative as well as representatives from all the other partners that hold a participating interest in the Oman oil field. The purpose of the JOC is to provide for the overall supervision and direction of joint operations.
- The *Joint Technical Committee and Joint Financial Committee* include as well members of Partex and other partners and the objective of these committees is to provide the overall supervision and direction of the technical and financial operations, respectively.

The direct project team includes:

- *Vice-President Field Operations* is responsible for delivery of the project objectives, development and operations, within the framework of Operator of Oman delegations of authority. He is supported by functional managers with key responsibilities and accountabilities in the areas of subsurface, facilities, and operations.
- *Operations Team* is responsible for all field operations personnel required to manage the well servicing rigs, artificial lift equipment, produced fluid treating, power generation, and steam generation. The operations team is also responsible for the completion of all the wells.
- *Facilities and Construction Team* is responsible for coordinating the design, procurement, and construction of all surface facilities including electrical generation, steam generation, fluid treating, and well hookup.
- *Subsurface Development Team* is generally responsible for the field development plan, reservoir surveillance, reservoir and fluid characterization, and gross reserve calculations. In addition, some field studies and support activities are provided by the major projects group (Phase II) in Houston.
- *Centralized Services and Support Team* is in charge with drilling which is a centrally managed function within the project operator, with dedicated field operations and engineering teams responsible for designing and drilling all wells needed to meet the requirements of the development plan.

The project team is also supported by the field *Business Support Teams*, which are: Finance and Business Support Team; Health, Environment and Safety Team; Legal/Contract and Supply Chain Management Team; Human Resources and Administration Support Team; Planning and Analysis Team; Houston Technical Support Team. The description of main key activities is shown in Appendix A.

3.2.5 Project management process

The process, shown in Appendix B, reveals the steps that were undertaking in the project from opportunity identification through its final approval and project execution. The process consists of four phases:

1. *Initiation phase* – this phase included several steps such as opportunity identification and outline of technical and economic studies to define a scope. At this initial stage of the project, the project opportunity to obtain the oil production of 150 MBOPD by 2012 was assessed and feasibility was studied and evaluated.

2. *Definition phase* – this phase was dedicated to the analysis of project requirements and development of project work programs, execution of technical, economical and risk management studies that would be later compiled in a single field development plan. This phase includes the following steps: review of well design, drilling and facilities plan; outline of risk and uncertainty management; development of work programs; review of geological model and the field development plan workshop.

During this phase cost planning, estimating and budgeting was made as well as the integrated project schedule. Cost planning began with a basis of design that included wells, facilities, and infrastructure requirements to meet the planned production forecast. For cost estimating the Operator used the results from front-end engineering design (FEED) studies to develop cost estimations for the facilities and infrastructure. Drilling well construction requirements, contract rates, and equipment quotes provided the basis of capital cost requirements to meet project objectives. In cost budgeting - cost estimates, project schedule, and production goals were the critical inputs to develop a project budget forecast. The project budget and specific work packages were approved by operator management according to the delegation of authorities outlined in authority document.

The current dissertation objective concentrated on this phase, in particular the *Risk and Uncertainty Management*.

3. *Execution phase* – after reviewing the project documentation and final project approval of the implementation plan and budget by project supervision teams (JMC and JOC), the start was given to the execution phase of the project and particularly to the following steps: start of the drilling program; procurement and construction; commissioning, handover and start-up.

4. *Operation and Maintenance phase* - this phase includes the project review which implies monitoring the project execution and project performance according to the original plan by adjusting and mitigating any deviations. During this phase a comprehensive reporting program was established to ensure that the project is on schedule and on budget. A number of tools, including the Primavera scheduling tool, were used to create reports that examine the health of the project. Project communication is organized through the quarterly project management reports. The project team also provides updates during the scheduled budget meetings that are part of the PSA agreement. These communications and scheduled meetings with partners are another method by which the project receives assurance and support.

3.2.6 Risk management methodology

The current subchapter describes the risk management tools and techniques that were implemented by the project operator in the analysing case study.

Risk planning

At the planning stage, due to the technical complexity of the project, partners anticipated that the major uncertainties would be associated with technical implementation of the project. This encouraged the operator to implement methods of *technical peer assistance and peer reviews* to monitor the technical feasibility of the project execution. The purpose of this technique was to provide an independent internal and external expert assessment of the technical and commercial strength of the project. The peer reviews were designed to examine the current plan, evaluate alternatives, and quantify risks through an open interaction between all participants.

Additionally, the project team implemented a *Project Definition Rating Index* (PDRI) to track the project facilities and a *Risk and Uncertainty Management Process* (RUMP) to track the overall project performance. The PDRI aimed to clarify risks to the project as it pertains to schedule and cost. The RUMP was designed to acknowledge risks to the projects ultimate goals. This was done by creating a list of potential problems, likely causes, probability and seriousness for each identified risk.

Risk identification

The existing approach of risk identification in Oman project includes identification of the risks through the workshop. The project team leaders and shareholder representatives meet at a workshop to identify the critical risks of the project. Then, potential risks are listed and ranked based on a risk identification matrix (Figure 6). The ranking of the risks are based on how they could impact the project goal of achieving 150 MBOPD. For estimations three qualitative categories are used: high medium and low.

LIKELIHOOD	H	Medium Risk	High Risk	Very High Risk
	M	Low Risk	Medium Risk	High Risk
	L	Low Risk	Low Risk	Medium Risk
		L	M	H
		SERIOUSNESS		

Figure 6 – Risk identification matrix

The next step is listing risks in a table and assigning the respective ranks (Figure 7).

Adverse Risks	Probability	Seriousness	Risk
Gas supply delayed/insufficient	H	H	VH
Facilities construction schedule delayed	H	H	VH
Insufficient/inadequate human resources early enough	H	H	VH
Reservoir does not respond as well as expected	M	H	H
Water supply for steam delayed/not available	M	H	H
Selected water treating does not work	M	H	H
Well construction schedule delayed	M	H	H
Delays due to external approval	M	H	H

Figure 7 - Risk ranking

Risk monitoring

Project management responsibilities are assigned to the *Planning and Analysis* business support team (Appendix A), which is responsible for managing identified risks related to the project.
The operator tracks the project performance execution on a monthly basis through a dashboard illustrating the progress of critical project indicators, such as oil rate, new wells, milestones, OPEX and CAPEX.

Major Findings

Review of the current risk management methodology revealed that it is not comprehensive and Partex participation is insufficient. Applied risk management reflects in implementation of *four* processes, namely: (1) Risk planning; (2) Risks identification; (3) Qualitative risk analysis; (4) Risk monitoring.
According to the Project Management Institute (PMI), a complete risk management methodology consists of *six* processes, which are: (1) Risk planning; (2) Risks identification; (3) Qualitative risk analysis; **(4) Quantitative risk analysis; (5) Risk response planning;** (6) Risk monitoring.
Tools implemented in risks management processes by the operator also lack standardization and can be enhanced using the standardized approach that will be performed in the next chapter, revealing a need to improve the current process followed by the operator.

Another conclusion made after analysis of risk factors for periods 2006-2010 (Appendix C) and 2010-2013 (Appendix D) is that the key risks considered by the project operator as *high* and *very high* are narrow and mostly technical risks. Considered few external and organizational risks, the operator didn't take into account any of project management risk factors.

3.2.7 Case study problem

Underpinning the PSA is a commitment by the project operator and the Joint Operating Agreement (JOA) partners to implement a massive steam flood on an Omani onshore oil field. An initial FDP was submitted by the operator to the Joint Management Committee (JMC) Board in August 2005.

The FDP proposed to achieve a field production plateau rate of 150 MBOPD by 2012. The development plan outline included construction of a core facility capable of generating a daily steam injection rate of 550-650 MBSPD (with 100% quality) and handling a daily oil production of 150 MBOPD.

Figure 8 shows the three periods of the project execution, defined by the operator in 2005, and a blue line is showing the targeted daily oil rate. The initial forecasted target was 150 MBOPD of oil production by 2012 and maintain such production plateau for almost 10 years. After that, operator was expecting a production decline in 2021 with abandonment of the field by 2035.

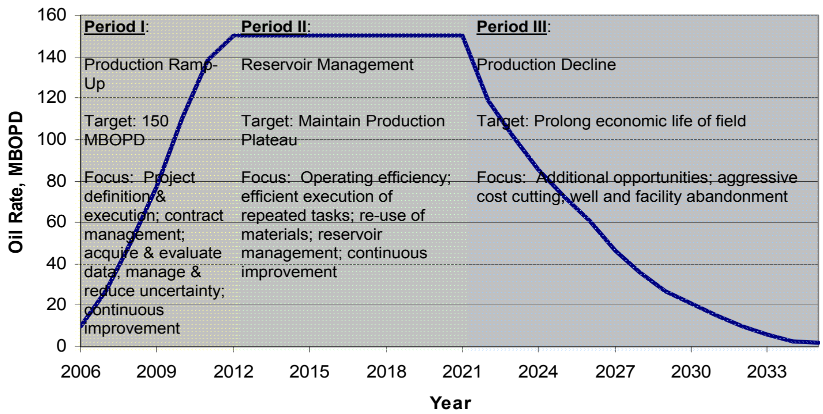

Figure 8 – Original FDP, 2006

At the planning phase, the operator was confident in its ability to operate the field in an expedient and cost-efficient manner. However, at the start of project implementation, the operator faced difficulties primarily with the generation of the needed volumes of quality steam, which affected oil extraction from the field. As a consequence, the oil production started to lag the forecasted value.

After the early startup delays of the facilities and the operator adjustments of the reservoir performance, the oil production did not approach the expectation of the original forecast.

The commitment to achieve the 150 MBOPD production target needed a large initial capital investment in facilities, but delays in production required immediate corrective actions that increased the planned project budget. As a result, the deviations from the original plan were reflected on the project economics, particularly caused a negative effect on project Net Present Value (NPV), Internal Rate of Return (IRR), gross revenue and shareholders cash flow.

In 2010, the operator issued a revised FDP with new assumptions, production rates and budget profiles. Figure 9 shows the increased Period I forecasting to achieve the production target only in 2013, the decrease on the length of Period II aiming to maintain the plateau of 150 MBOPD from 2013 to 2018 (only 6 years) and the increase length of Period III (early decline).

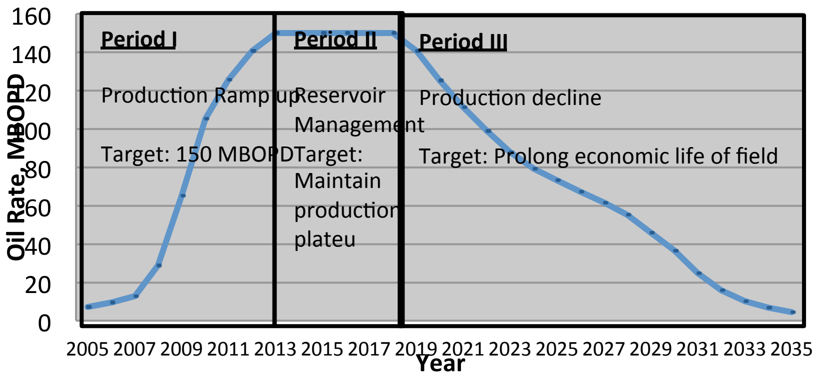

Figure 9 – Revised FDP, 2010

Unsuccessful, due to the continued deviations in costs, schedule and inability to achieve project targets, led the operator to review and update again the FDP during 2013. Detailed analysis of deviations, respective root causes and their impact on economic parameters is provided in Section 5.2.

Main conclusions of the case study analysis

Partex participates as an investor in an ongoing venture in the Sultanate of Oman and shareholders faced unforeseen difficulties during the project execution due to the complexity of the oil field and inadequate project management:

- In general, project estimation (assumptions) in terms of production volume proved to be inaccurate, which led to the negatiave deviations in oil production, schedule and project costs;
- The planning of the project was too optimistic as there were no alternative plans;
- A monthly dashboard shows the past project performance and results are not future-oriented dimensions;
- Lessons learned in project management are poorly practicing;
- Risk management methodology is not comprehensive (*four* risk management processes were implemented instead of *six*);
- Risks management tools are lack of standardization;
- Partex involvement is insufficient.

4. Proposed solution

This section presents a proposed solution that was developed to address the research work main objective. Firstly, it proposes "Partex" to use an economic modeling framework to test project performance and be aware of the impact of risks and uncertainties on the project outcomes. Secondly, to implement a standardize risk management framework and performance measurement metric to align the processes according to the internationally recognized standards.

4.1 Economic modeling framework

In line with the current research work, the main tool that was developed to address the project objective was the economic model (Figure 10). This is a reasonable tool for Partex to monitor its projects performance according to the project plan and shareholders' expectations.

Before making a decision of investing in capital projects, Partex should have a clear view of the project's profitability. When calculating profitability, economists are often ignoring the uncertainties in input values. However, the profitability of the project can be misleading if uncertainties are being ignored.

Developed in Microsoft Excel, the proposed economic modeling framework provides automatic calculations of project input data (Appendix E) and intuitive user-interface (Appendix F) that can be used in project updates and future work to screen economical prospects and evaluate the impact of key uncertainties and risks. The output results of the model (Appendix G) will allow Partex to be more aware of project uncertainties and be more prepared for negotiations with the operator using model outcomes as a basis for improvements recommendations.

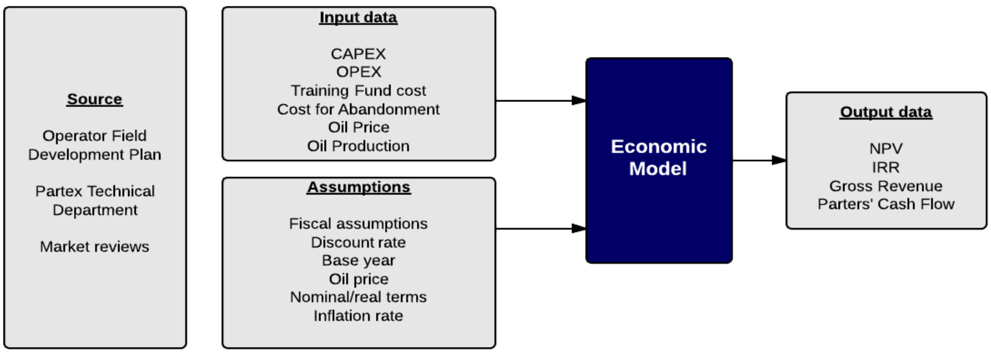

Figure 10 – Economic modeling framework

The economic model can be used for:

- *Quick screening and evaluation of project parameters* – model allows to get a quick idea about the project current performance providing automatic calculations of input data submitted by the project operator;

- *Scenarios analysis* – scenarios provide a framework with different ways to execute a project and have a greater flexibility for decision-making process rather than one path without alternatives;
- *Sensitivity testing* – assessment of project parameters to identify which ones have a greater impact on project performance; evaluation and quantification of project risks.

However, this framework would not be a comprehensive tool without the aligned risk management structure and performance measurement metric, which are described below.

4.2 Risk management framework

One of the standardized project management frameworks is the framework of the Project Management Institute (PMI) - A Guide to the Project Management Body of Knowledge (PMBOK Guide).

Partex will benefit from the implementation of this methodology for several reasons:

- This methodology is a part of a globally accepted standard, and can be applied to complex industrial projects aligning the project management processes with the international standards.
- Risk management tools will be more easily to apply to the project updates and to the future projects, being of a greater value for the company.
- The framework has already proved its effectiveness. Tools of this framework were implemented by oil and gas companies, in particular, Shell International Exploration and Production, in its Brutus project. Shell applied a work breakdown structure and a new financial software system to have a common language in its operations for better communication between project members. This approach gave better understanding of objectives to the project team and efficiently improved shareholders expectations.

4.3 Performance measurement metric

Key Performance Indicators (KPI) is a metric tool that aims to measure how well a project performs in terms of “operational, tactical or strategic activity that is critical for the current and future success of an organization”.

The objective of performance measurement is to improve effectiveness of managing the project and KPIs address this goal showing progress of the project towards the target results for a specific period. Monitoring of KPIs should be done *on a daily or weekly basis* as quarterly, monthly or annual measurements show the past project performance and results are not the future-oriented dimensions. Daily or weekly monitored KPIs will allow managers and shareholders to receive the warning signs about areas that pose a danger to the project performance and need an immediate attention through the implementation of mitigation actions.

The application of the proposed solution is presented in the next section.

5 Application of the proposed solution to the case study

This section demonstrates the proposed solution by applying it to the case study described in the Section 3.2. Firstly, deviations in project parameters are analyzed using different case scenarios. Secondly, the impact of such deviations is translated on project economics. Then, a sensitivity analysis is performed. Finally, the application of risk management framework and the project performance measurement are presented.

5.1 Economics and fiscal regime modeling

Oil and gas industry poses a lot of uncertainties in the volume of oil that can be developed, the oil market price, and the time needed for development and production activities. Thus, the output of the economic model depends on assumptions of oil production, oil price, project expenditures and a fiscal regime (in this case a PSA). The framework of the economic model in this research is shown in Figure 10.

This section describes the projected approach of applying an economic model for a certain fiscal regime modeling in the oil and gas industry.

The fiscal regime that is applied to the current case study was discussed in Section 3.2.3. Example of fiscal calculations is provided in Appendix H. The developed economic model incorporates features of the fiscal regime of the analyzed case study, however model can be easily adjusted to other fiscal regimes.

Model Case Scenarios

Generally, the operator of Oman field should have accounted for alternative plans or scenarios to explore ways that the project can perform in the future, which would prepare the base for different decisions.

Based on a case study problem described in the Section 3.2.7, the economic model was developed incorporating three distinct case scenarios for comparing the outputs of original plan with the two following ones (2010 and 2013) and analyzing the impact of deviations on the project economics. The first scenario used the input data of the 2006 FDP, the second scenario is based on the input data of 2010 FDP and the third scenario is based on the latest data and a forecast from a project workshop conducted in 2013 prior issuing the 2013 FDP (pre-2013 FDP).

Case Scenario 1

The first case scenario was developed using the original forecasted data the operator provided at the project planning stage (2006 FDP). This scenario includes a forecast for the project life cycle (2005-2035) and includes assumptions of the volume of oil production and project expenditures (CAPEX, OPEX, costs for training fund and abandonment).

The first scenario, as the original plan from the operator of the field, has the following distinctive characteristics:

- Oil production will meet the targeted volume (150 MBOPD) in 2012;

- Operator will maintain the desired oil production during the next 10 years;
- Expenditures (CAPEX, OPEX and abandonment cost) for the project life cycle are budgeted as 11 billions US$.

Case Scenario 2

The second case scenario is based on the input data of the 2010 FDP. This scenario includes historical data (2005-2009) and updated forecast of oil production rate and project expenditures for the following years (2010-2035).

The second scenario has the following distinctive features:

- Oil production will reach the target volume (150 MBOPD) in 2013;
- Operator will maintain the plateau for the 6 following years;
- Expenditures for the project life cycle will reach 17 billions US$.

Case Scenario 3

The third scenario provides the recent forecast from the operator that includes historical data for 2005-2012 years and forecasted project data for the 2013-2035 period.

The main features of this scenario are as follows:

- Oil production peak (150 MBOPD) is assumed to be reached at 2014;
- Plateau will be maintained for 2 years;
- Total expenditures are assumed to reach 18 billions US$.

Model Assumptions

Model assumptions are provided in Appendix I.

Model Inputs

Input data is a set of variables that is used as an input for the economic model calculations. The following variables were considered:

Capital Expenditures (CAPEX) – investments made in the project. The major expenditures include facilities construction costs and drilling costs.

Operational Expenditures (OPEX) – costs for operating a project that include costs for maintenance, field support, manpower, etc.

Training Fund Cost – costs for training program of project's workforce that include oil field induction program, on-the-job training, foundation training (math, science, computer skills). This cost was defined by PSA as non-recoverable.

Cost for Abandonment – costs that associated with closure of the project like shut down of wells, removal of facilities and equipment, environment clean up operations, etc.

Oil Production – the volume of oil that can be extracted from oil field reservoirs.

Oil Price – field realized price based on the assumptions explained in Appendix I.

Model Outputs

The output of the economic model is a set of calculated economic variables, which are the following:

Net Present Value (NPV) – is one of the most important measurements for a project as it evaluates the viability of the investment by calculating the difference between cash inflows and cash outflows using a discount rate (10%). In the model, NPV was calculated using the following formula:

$$NPV\ (i, N) = \sum_{t=0}^{N} \frac{R_t}{(1+i)^t}$$

where

i – a discount rate; N – the total number of periods; t - time of the cash flow; R_t - net cash flow.

Internal Rate of Return (IRR) – is a rate of return that makes NPV of the project equal to zero. This is another measurement of the project economic performance, which evaluates the desirability of the project. The higher project IRR - the better performance it is showing.

Gross Revenue – is a total revenue that project receives from selling crude oil before deducting any project expenditures.

Partners Cash flow – is an amount of cash generated by partners of Joint Operating Agreement from the project gross revenues deducted of project expenditures and government cash flow.

Analysis of root causes of project deviations and their impact on the project economics is explained in the next section of the work.

5.2 Economic model as a tool to analyze project's deviations

A project deviation is any deviation from the project plan, from a way in which the project has been expected to be accomplished. In other words it means any discrepancy between the project results and the original plan agreed by all parties. Deviations might be positive and negative. Positive deviations can result from increase in oil selling price or increase in volume of oil extraction. Negative deviations, like increase in project expenditures or decrease in oil production, should play for parties the role of an alert and be the reason to the implementation of corrective actions.

This section provides an analysis of deviations in project parameters, reasons for those deviations and undertaken corrective actions as well as evaluation of the economic model outputs. The first part of the section compares deviations in forecasted and actual values of Case Scenario 1 with Case Scenario 2; Case Scenario 2 with Case Scenario 3. The first step was to analyze deviations in the input parameters of the economic model scenarios, namely in oil production, CAPEX and OPEX. The second step was to study the impact of occurred deviations on project economics by comparing actual output parameters such as gross revenue, cash flow, NPV and IRR with the target values. Finally, the NPV sensitivity analysis was performed to measure the effects of input parameters changes on the project economic outputs.

Oil Production

Oil production refers to the amount of oil that can be extracted from an oil field. Figure 11 shows a comparison of the oil production profile between Case Scenario 1 and Case Scenario 2 of economic model and deviations in a volume of oil production that happened from 2006 to 2009.

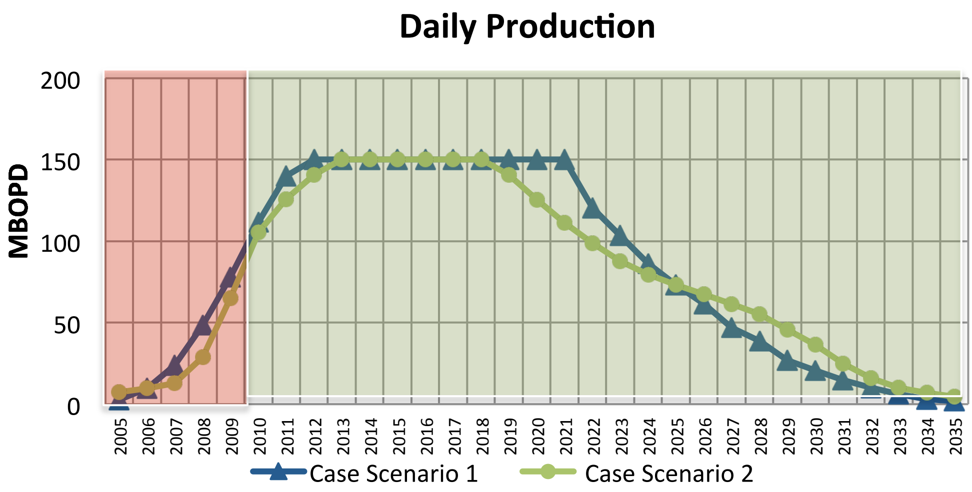

Figure 11 – Production profile[6] (Case Scenario 1 vs. Case Scenario 2)

As can be seen from the Figure 11, the actual oil production of Case Scenario 2 started to deviate from the target Case Scenario 1 in 2007. Figure 11 is showing that the operator updated its forecast of reaching the target oil production only in 2013 and reduced the plateau length to 6 years.

The production targets have not been reached due to the several reasons:

- Delay in the startup and operation of steam generation facilities;
- Oil reservoir response was not as expected;
- Scarcity of data of the operating field and unexpectable field conditions;
- Optimistic assumptions made during the planning process that did not reflect the reality.

Field production forecasts were obtained based upon dynamic simulation model results. At the ignition of the project, the operator *could build full field dynamic simulation model* covering the entire field area in detail and encompassing all reservoirs. However, this approach was not followed due to the large volume of work needed to get accomplish this task in due time. Hence, production profiles were calculated using a methodology that encompassed smaller dynamic simulation tools, namely: type curve analysis and sector

[6] The red area in a diagram constitutes to the analyzed project data; the green area – forecasted data

models simulation. These models refer to "typical" good, medium and low quality smaller areas of the field, which were afterwards extrapolated to the full field scale.

The main disadvantage of this approach is that no well-by-well history match was attempted. Rather, operator was attempting to determine how best to setup a sector model so that the overall performance of the model would be a reasonable approximation of the actual performance. Hence, no modifications were made to the geologic description, and no historical rate data were entered into the model. All production and injection rates were derived in a prediction mode and were applied to sectors of the field that had no performance data prior to the construction of the model.

After project initiation and first drilling it was noticed that reservoir was not responding as expected and actual oil production was lagging with the forecasted one. The corrective actions that were undertaken by the operator after observing undesirable reservoir performance was *accelerating well construction* in order to increase the number of immature patterns and allow production at a lower steam/oil ratio than predicted.

The comparison in the production profile of Case Scenario 2 and Case Scenario 3 are shown in Figure 12.

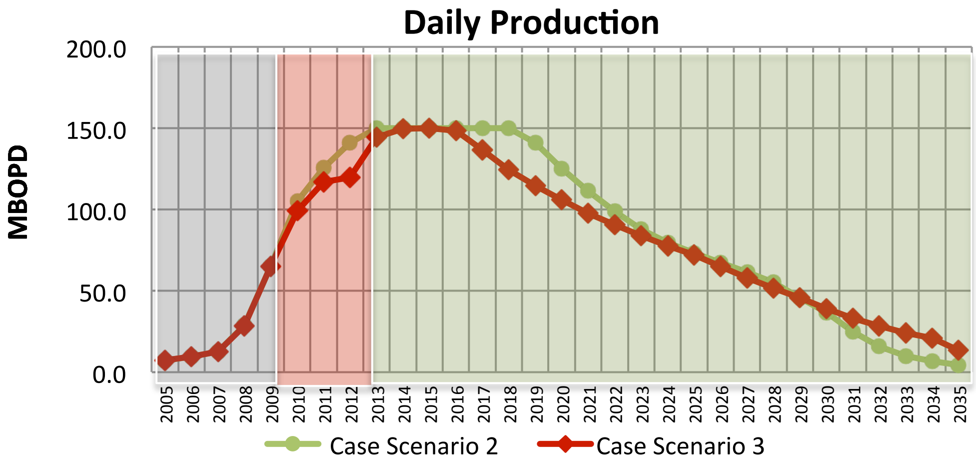

Figure 12 – Production profile[7] (Case Scenario 2 vs. Case Scenario 3)

The diagram shows that the peak oil production, as it was forecasted in the Case Scenario 2 for the year 2013, was postponed in Case Scenario 3 until 2014. The length of maintain the target volume of 150 MBOPD have been reduced to 2 years.

The key reasons of these deviations were as follows:

- Lower steam injected than forecasted;
- Reservoir pressure higher than assumed;
- New field area poorer in reservoir quality than initially assumed.

According to the provided reasons for the deviations, operator during 2010-2012 years was expecting shortage of steam due to the delay in facilities implementation and also some

[7] The grey area constitutes to the past historical data; red area – analyzed data; green area – forecasted data.

technical problems such as poor performance of mechanical vapour compressors (MVC) needed to extract steam as well as poor reservoir vertical conformance. The field performance and the quality of the new areas was not as expected due to the high water saturation in outer areas of the field and the presence of thin shale layer in the reservoir that was diminishing the efficiency of steam injection.

The corrective actions that the operator was undertaken during this period were concentrated around implementation of an aggressive drilling work program that implied to drill replacement wells for patterns that have suffered wellbore failure and drill Kahmah[8] wells in order to extract additional oil.

Again, the operator assumptions did not materialise. In 2013 the operator felt the need to evaluate the project, considering improvement wedges that will push forward project expenditures.

Expenditures Deviations

Expenditure deviations refer to deviations in Capital Expenditures that include facilities and drilling costs and Operating Expenditures.

Capital Expenditures (CAPEX) are funds that partners of Joint Operating Agreement investing in the project in order to maintain or increase the scope of operations. Capital costs include costs for exploration and appraisal, development drilling, production facilities, pipelines and general property. In Oman project, due to the fact that the field was previously explored, the major part of the CAPEX investments constitute to facilities costs and drilling costs.

Operating Expenditures (OPEX) refers to ongoing costs of running a project and they include costs to manage oil production (maintenance of wells operations), steam injection, campus and infrastructures, direct and support staff, chemicals and materials, rental power, etc.

Case Scenario 1 vs. Case Scenario 2

As it was mentioned before, the shortage in oil production caused implementation of corrective actions which consequently increased project expenditures, both CAPEX and OPEX. In order to quantify occurred deviations, parameters for Case Scenario 1 and Case Scenario 2 were compared. Then the percentage of each factor contribution to the total deviations for each year was computed (Figure 13).

[8] Underground formation contained oil and discovered during the drilling operations

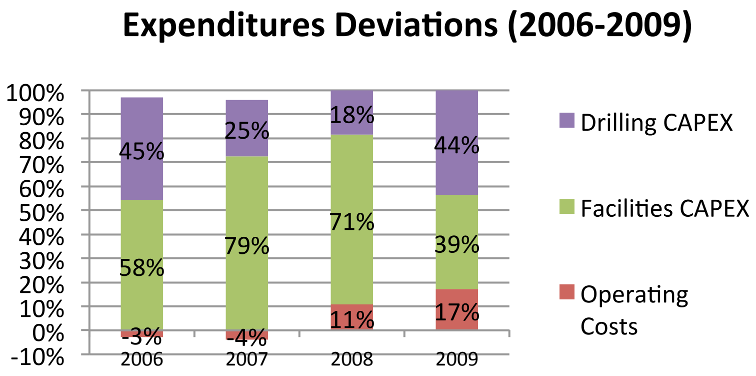

Figure 13 – Expenditure deviations (Case Scenario 1 vs. Case Scenario 2)

It can be seen from the figure above that CAPEX was the main variable that pushed total expenditures forward.

Deviations in CAPEX facilities costs, that constitute to the major part of deviations for the period 2006-2008, can be explained by the following reasons:

- Increase in materials costs;
- Change in facility project scope as a result of adjustment for campus infrastructure, power distribution system and steam generation system;
- Poor contractor performance and missed deadlines.

Deviations in CAPEX drilling costs happened due to the shortage in oil production that consequently changed drilling schedule, increased the number of wells and drilling unit costs.

The undertaken corrective actions to reduce CAPEX deviations were mainly focused on the continuous improvement on well delivery and well cost reduction. It led to the identification and implementation by the operator the following actions: stabilization and continuous improvement of drilling services contractors; operator strived to continue reducing well durations and costs by continuously reviewing engineering and operations in conjunction with the various contractors; efficiently tender and manage contracts for supply of trucking services, water delivery, and other logistic services.

In Figure 13, it can be noticed that actual operating costs started to increase earlier in the project life (2008) due to the increased number of wells and increased manpower costs.

The key issues of increase in OPEX that occurred in the 2008 - 2009 period were as follows:

- Additional costs were needed to manage steam injection (largest cost of production) such as well servicing costs to replace steam injection equipment; injection profile surveys required to measure steam distribution effectiveness; increased expenditures forecast for seismic work. These operations reflected in an increase in the number and cost of manpower to maintain the project pace.
- Increase in chemicals cost that were estimated in the original Case Scenario 1 based on analog assumptions or generally accepted oilfield practices. Case Scenario 2 chemical costs assumptions were made based on actual and observed field conditions.
- Additional rental power cost that was not forecasted in Case Scenario 1.

- Additional cost anticipated due to plant start-up activity and infrastructure. These costs had not been anticipated in 2006 FDP forecast. The assumption was that new facilities would require very little maintenance. That assumption has proven inaccurate to date.

Among the *corrective actions* that the operator applied to respond to the operating cost challenges were attempts of reducing the cost uncertainty by calibration of the cost model with the continued calibration of estimated costs with actual observations. Also started in 2009, a new cost management process was implemented to help in monitoring and reporting of all expenses associated with the oil field cost centers.

Case Scenario 2 vs. Case Scenario 3

Figure 14 shows the capital costs comparison between revised budget of the year 2010 and the actual project budget for the period 2010-2012. The negative percentage of CAPEX in 2010 means that operator did not exceed the budget limit and saved part of the capital costs.

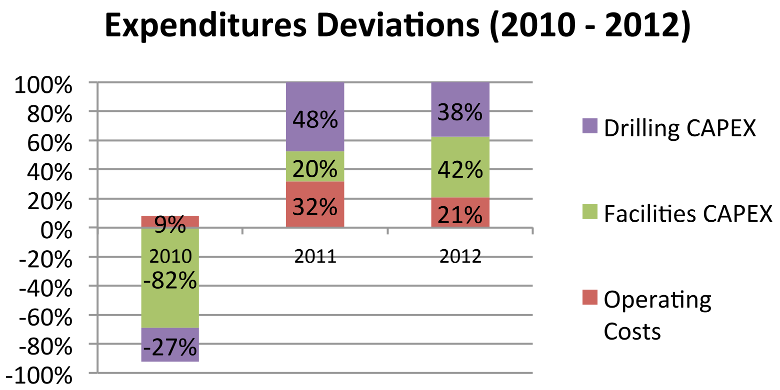

Figure 14 - Expenditure Deviations (Case Scenario 2 vs. Case Scenario 3)

The savings in CAPEX that occurred in 2010 was due to less drilling and completion activities. But the deviations that occurred in the period between 2011 and 2012 were mainly due to:

- Increase in overall well servicing activities as a result of increase in well count and adjusted well costs;
- Additional budget estimated for activities associated with Kahmah operations, including well operations and survey data and additional costs associated with the Steam Injector profile control installations.

Corrective actions included increased focus at subsurface steam conformance, which implies effective redistribution of the steam across all targeted zones at the injection level, and downhole steam quality for improving current assumed field average surface.

The key issues that made OPEX deviate from the planned budget were the following:

- An increase in manpower cost was required to maintain the project that included raising salaries, hiring employees from local communities and changes in industry labor directives due to the political instability in the Middle East.

- Additional materials and services required for water quality enhancement.

5.3 Analyzing impact of deviations on project economics

The project economics refers to the performance of project economic parameters such as gross revenue, partners' cash flow, NPV and IRR. When developing an economic model, the output parameters were computed for all three case scenarios. First, the target parameters were identified using the input data of the original project plan (Case Scenario 1). Then two other sets of output variables were calculated using input data of Case Scenario 1 and Case Scenario 2. In this section a comparative analysis of planned and actual outputs will be provided.

Gross revenue

Gross Revenue is the total revenue of the project generated by the amount of the oil production sold by the respective field price, before deductions of any expenses. Figure 15 presents the comparison of the gross revenue for the three case scenarios. The Case Scenario 1 is planned gross revenue from the project initiation and used as a target.

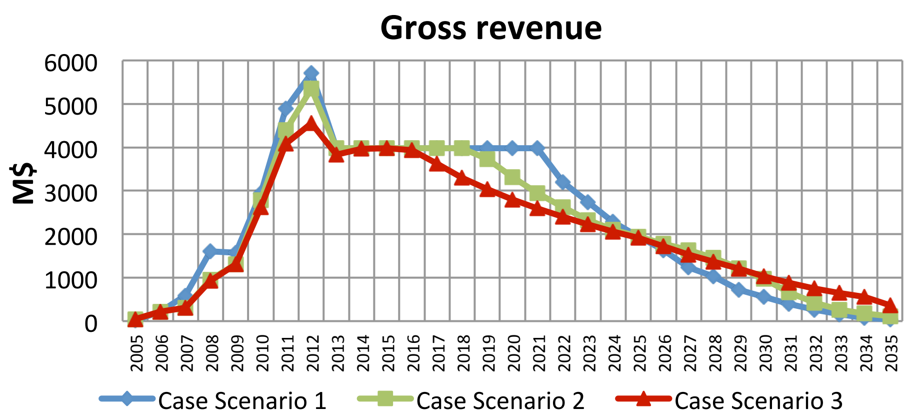

Figure 15 – Gross revenue profile

Figure 15 shows that operator did not achieve the desired results due to the deviations in oil production. As gross revenue is calculated as

*Gross Revenue = Oil Production * Oil Price,*

it can be concluded that the loss in production caused a consequent loss in project revenues. Note, that for all case scenarios there are identical oil price assumptions as discussed in Appendix I and in this case price is not a factor of gross revenue deviations.

Partners' Cash Flow

The cash flow is generated from

Partners Cash Flow = (Cost recovery oil + Partners' profit oil) – Total costs.

According to the original plan, the forecasted cash flow (Case Scenario 1) should become positive in 2008, but due to the increase in the investments and drop in gross revenues, the actual cash flow turned positive only at 2010. Unforeseen negative cash flow that occurred in the period 2008-2009 is a consequence of an increased project expenditures and less than expected project income. It means that partners received the positive cash flow 2 years later than initially estimated (Figure 16).

Though it can be explained as a common practice in the first years of the large capital projects as Oman oil field, operator should be more accurate in its estimations in order to maintain the reputation of a trusted operator among the project partners.

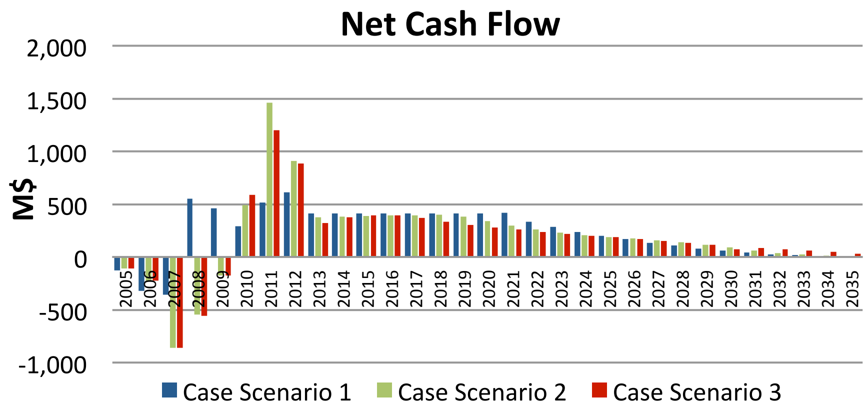

Figure 16 – Partners cash flow profile

Net Present Value

Net Present Value (NPV) is the indicator that incorporates the time value of money. NPV indicates whether the future cash flow stream generated by the project will yield a positive net present value when the cash flows are discounted using the assumed discount rate of 10%. The discount rate is partners' cost of capital and when NPV is positive, investments returns made in the project will be greater than the cost of capital. All the three case scenarios were ranked at a single discount rate of 10%, allowing the comparison of NPV results.

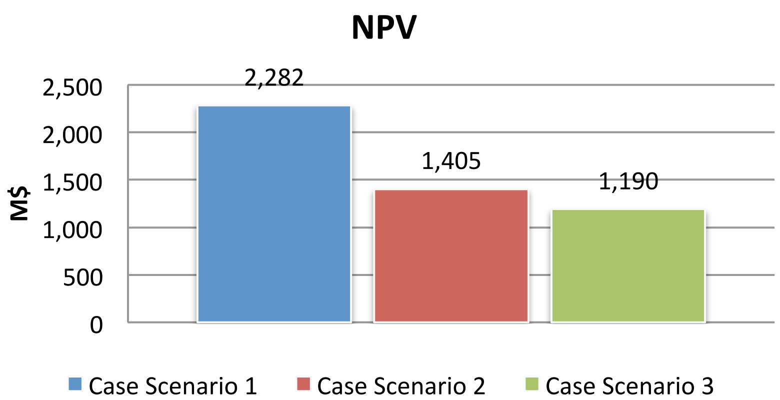

Figure 17 – NPV profile

Figure 17 shows the target NPV (Case Scenario 1) which calculations were based on the inputs of the original 2006 FDP. The deviations that occurred in input variables of Case

Scenario 2 and Case Scenario 3 impacted NPV in a negative manner greatly reducing the value of the project.

Internal Rate of Return

The Internal rate of return (IRR) is another indicator of time value of money and it computes in percentage terms. It is the discount rate that is required in order to generate NPV of zero. In the projects, the higher the IRR rate the better is the investment and it can be useful as this rate is compared to the cost of capital to indicate if investment is profitable. The discount rate of the project was assumed as 10%, which meant that if calculated IRR would be lower than 10%, the investment would not be made, since the project would not be rentable and attractive for investors.

The IRR computed for the original Case Scenario 1 yield 44%, however due to the negative deviations of input parameters the actual IRR dropped to 22% and then to 20% in 2013 (Figure 18).

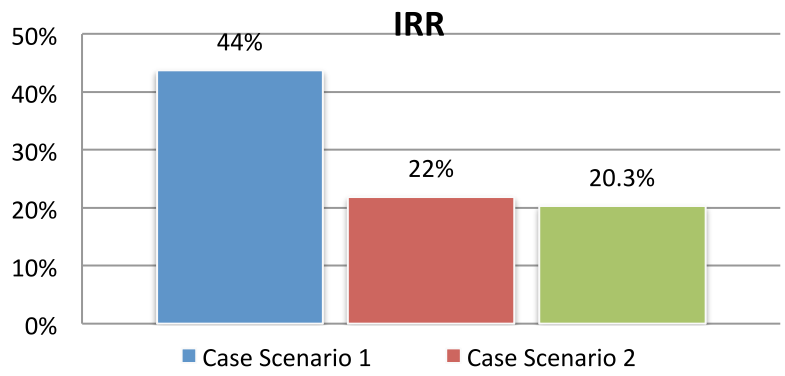

Figure 18 – IRR profile

Summary of deviations in input and output parameters for three Case Scenarios is shown in Appendix J.

5.4 Economic model as a tool to perform a sensitivity analysis

In order to determine the level of impact for the input variables on project NPV and also identify if the project is more dependent on a certain variable, a sensitivity analysis was conducted. This analysis was performed using input data of Case Scenario 3 and was taking into consideration the full life cycle of the project (2006-2035). The NPV sensitivity was tested to the following variables: CAPEX, OPEX, Oil Brent price and Production volume. A change in key input variables will cause the NPV to change. Sensitivity analysis measures the percentage change in NPV that results from a given percentage change in an input variable when other inputs are held at their expected values (Eugene F. B., Michael C. E., 2010).

The base case scenario (variation 0%) assumed that the project NPV does not increase or decrease by any value. Then, each input variable was increased by 10% and 20% and then decreased by 10% and 20% from the base case, holding other variables constant at the base case level. Respective NPV then was calculated (Table 2).

Table 2 – NPV sensitivity analysis

Variation in OPEX	Result on NPV	Variation in CAPEX	Result on NPV	Variation in Brent price	Result on NPV	Variation in Production Volume	Result on NPV
%	$M	%	$M	%	$M	%	$M
-20%	1217	**-20%**	1176	**-20%**	819	**-20%**	851
-10%	1190	**-10%**	1170	**-10%**	991	**-10%**	1007
0%	1164	**0%**	1164	**0%**	1164	**0%**	1164
10%	1137	**10%**	1158	**10%**	1336	**10%**	1320
20%	1111	**20%**	1152	**20%**	1509	**20%**	1477

Finally, the set of NPV results was plotted into graphical representation of NPV sensitivity to changes in input variables (Figure 19).

The fluctuations of the bars in the Figure show the range of NPV sensitivity to each input. The larger the range, the wider the variable's bar and the more sensitive NPV is to this variable (Eugene F. B., Michael C. E., 2010).

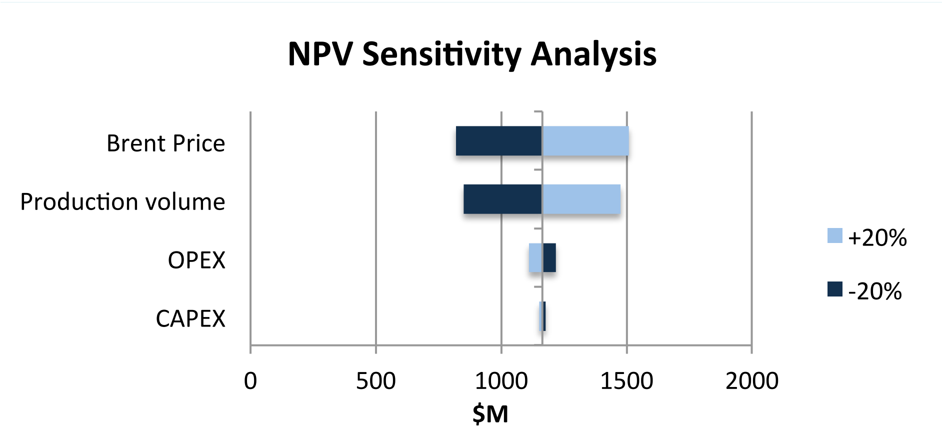

Figure 19 – NPV sensitivity analysis

One of the obvious observations is that NPV, in the analyzed case study, was not very sensitive to the changes in CAPEX and OPEX. It can be explained by the contractual arrangement of the project. The cost recovery mechanism defined by PSA terms implies that all costs that invested in the project can be recovered. That means that increase or decrease in capital and operating costs did not significantly influence the NPV of the project. On the contrary, NPV was very sensitive to changes in oil price and production volume.

*This, eliminating the impact of oil price due to the single oil price scenario used in the economic model, lead to a conclusion that negative deviations in **oil production volume** negatively impacted the economics of the project.*

This can be a result of poor project management techniques in particular planning, estimation, control and implementation of lessons learned to the project.

5.5 Risk management framework

This section is dedicated to the demonstration of risk management framework that can be applied to enhance the effectiveness of risk management process of Partex ventures. The framework includes consequent implementation of the six risk management processes that were discussed in Section 2.4.

5.5.1 Plan risk management

Plan Risk Management is the process of defining how to conduct risk management activities for a project. This process can increase the probability of success for the five other risk management processes if it carried out carefully and explicitly. For ventures with multiple investors, planning activity is important in order to ensure the visibility of the plan and establish an agreed-upon basis for evaluating risks.

Plan Risk Management has only one tool - meetings and analysis of risks, which should include representatives of project team, investors, stakeholders or other persons who is involved in the process of risk planning. These meeting should help to determine potential risks and establish a common understanding among all parties involved in a project.

The ultimate goal of the Plan Risk Management process should be an establishment of a risk management plan, which describes how shareholders will define, monitor, and control risks during the project life cycle.

Therefore, after planning meetings and workshops Partex should request the risk management plan from the operator and ensure that this plan contains the following information:

- *Methodology* - description of how operator will perform risk management plan, including elements such as methods, tools, and where risk data might be found that shareholders can use in the later processes;
- *Roles and responsibilities* - description of people who will be responsible for managing the risks;
- *Budgeting* – assignment of resources and estimation of costs for risk management procedures that should be included in the project cost baseline;
- *Timing* – information about when and how often processes and activities associated with risk management in the project schedule will be performed;
- *Revised stakeholder tolerances* - as operator proceeds through the risk management processes, it might find that risk tolerances have changed and should be documented in the risk management plan;
- *Reporting formats* – description of how risk management information will be maintained, updated, analyzed, and reported to project shareholders;
- *Tracking* - description of how operator will document the history of the risk activities for the project and how the risk processes will be inspected.

5.5.2 Risk identification

Risk identification is the process of determining which risks may affect the project and documenting their characteristics. This is an iterative process because new risks may evolve or become known as the project progresses through its life cycle. The frequency of iteration and who participates in each cycle will vary by situation (PMI, 2004).

Authors of Project Management Institute proposed a comprehensive approach in risk identification process that can incorporate several tools and techniques:

- Documentation reviews;
- Information-gathering techniques;
- Checklist analysis;
- Assumptions analysis;
- Risk categories;
- Diagramming techniques;
- SWOT analysis;
- Expert judgment.

To carry out the internal analysis, Partex is recommended some of these tools particularly documentation reviews, assumptions analysis, risk breakdown structure and additional tool - benchmarking.

Documentation reviews

This technique involves review of project plans, project assumptions and historical information of the project. The review can be done internally by the Partex team and will help the Group to validate the quality and consistency of deliverables from the operator. Also, this review can lead to the creation of the complementary risks from Partex standpoint.

Assumptions analysis

Assumptions analysis is a process of validating the assumptions as they apply to a project. Also, the process examines if assumptions are accurate, complete, and consistent. All assumptions should be tested against two factors:

- The strength of the assumption or the validity of the assumptions;
- The consequences that might impact the project if the assumption turns out to be false.

All assumptions that turn out to be false should be evaluated and scored just as risks (Heldman K., 2009).

In oil and gas projects assumptions are an important part of technical studies and simulation models and the results are being used for the project production and budget forecasts. Thus, Partex can make its own test of assumptions that are provided by the operator to ensure that results are matching with operator outcomes and the Group internal expectations.

Risk Breakdown Structure

Risk Breakdown Structure (RBS) is a new concept that aims to structure project risks arranging them by categories and sub-categories which helps to identify areas and causes of potential risks. RBS is a hierarchical representation of risks that splits four major risk categories such as technical, external, organizational and project management into the finer risk levels (Figure 20).

Currently, the operator is not categorizing the project risks and Partex can internally apply this tool, as RBS serves as a checklist to ensure that all risks are covered. The tool will assist in identifying generic and specific project risks that can help to create a proper risk response plan. The results of RBS can also be used later in qualitative risk analysis to understand dependencies and correlations between risks, risk exposure types, and roots caused the risks.

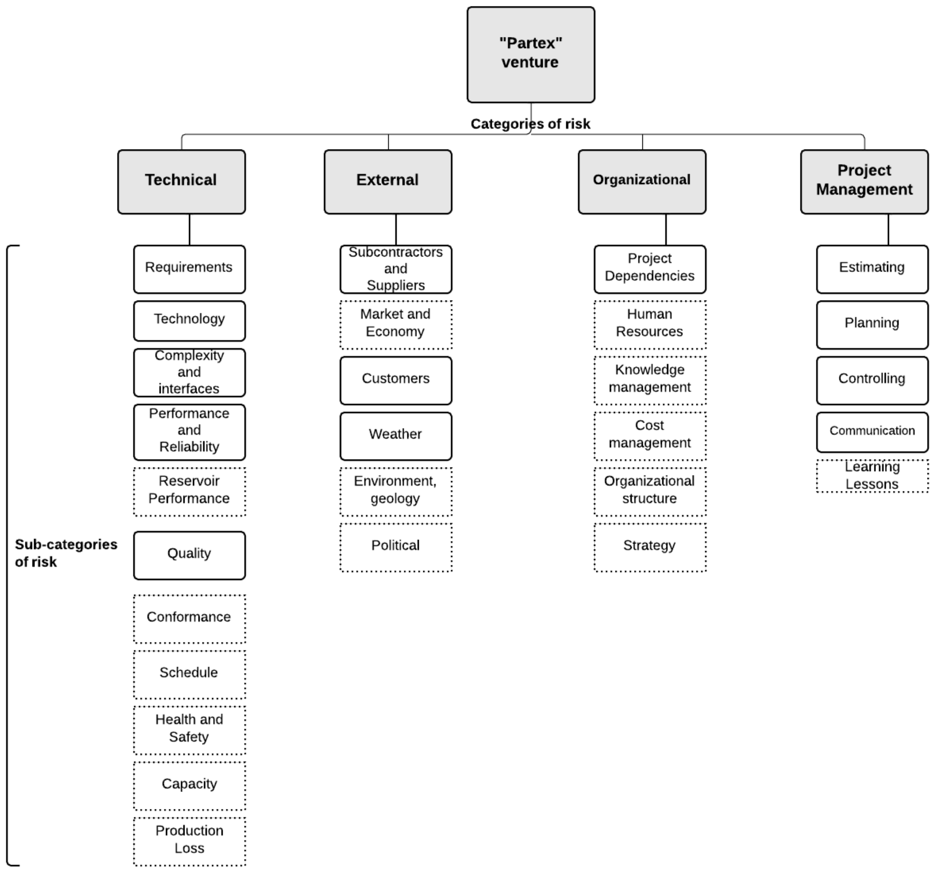

Figure 20 – RBS for Partex ventures

An example of the application of RBS tool is provided in Appendix K.

Benchmarking

This is an additional tool that Partex can use to compare risks identified by the operator with risks of the oil and gas majors such as BP, Shell, ExxonMobil etc. This will allow to understand what risks the industry is currently facing and if the operator risks list should be complemented. The example of risk benchmarking is shown in Appendix L.

The ultimate outcome of the risk identification process is the Risk Register that should contain:

- The list of identified risks (Appendix M);

- The list of potential responses.

This tool sufficiently helps to document, track, review, and manage risks throughout the project. The example is provided below.

Table 3 - Sample Risk Register

Risk	Trigger	Cause	Impact	Owner	Response Plan
Name and description of a risk	The warning sign that a risk will occur	The origin of a risk	The effect on project objectives or overall project performance	The person who is responsible for a risk	Corrective actions that were undertaken to reduce or eliminate a risk

5.5.3 Qualitative risk analysis

The Project Management Institute identified that "qualitative risk analysis as the process of prioritizing risks for further analysis or action by assessing and combining their probability of occurrence and impact". In other words, this process considers the impact that identified risks will have on the project performance and the probability that they will occur. This process is the one of the most common processes when prioritizing project risks because it is fast, relatively easy to perform, and cost effective (Heldman, 2009).

The PMI recommends the following tools and techniques to perform the qualitative risk analysis:

- Risk Probability and Impact Assessment;
- Probability and Impact Matrix;
- Risk Data Quality Assessment;
- Risk Categorization;
- Risk Urgency Assessment;
- Expert Judgment.

In the Oman project, for performing a qualitative risk analysis the operator used the risk matrix tool. Qualitative rankings are assigned to the likelihood and seriousness of the risks and an overall risk ranking (high, medium, low risk) is based on the combination of the two. The ranking of the risks are based on how they could impact the project goal of achieving 150 MBOPD. After, establishing the list of risks and respective ranks, it is distributed among the shareholders. The qualitative methodology was discussed in Section 3.2.6.

To enhance the current methodology, Partex can use the same tool but in more comprehensive way. Below it will be discussed the implementation of two qualitative techniques – risk probability and impact assessment and probability and impact matrix.

Risk Probability and Impact Assessment

The purpose of this technique is to analyze and detect risks that need immediate attention and implementation of aggressive measures. This tool helps to assess the probability of occurrence of each risk factor that were identified and also analyze what impact these risks will have on project objectives.

The objectives of the Oman project were identified as follows:

- Production rate – meet the target production rate of 150 MBOPD;
- Capital and operating expenditures – meet the project budget for capital and operating costs;
- Time – meet the project target production (150 MBOPD) in the established schedule;
- Oil price changes – maintain the project with a desirable oil market price.

Most commonly this analysis is being accomplished using the expert judgment. To demonstrate the application of this technique on the Oman project, a review of the project historical data and series of interviews with Partex experts were carried out. Finally, the following estimations were made:

- Low impact on project objectives was assigned as 10%;
- Medium impact was assigned as 20%;
- High impact was assigned as 40%;
- Very high impact was assigned as 80%.

Project objectives and estimated impact were combined in the Table 4.

Table 4 - Defined conditions for impact scales of a risk on major Oman Oil Field project objectives

Project Objectives	Low /.10	Medium /.20	High /.40	Very High /.80
Production rate (150 MBOPD)	<5% volume decrease	5-10% volume decrease	10-15% volume decrease	>15% volume decrease
Capital Expenditures	<5% CAPEX increase	5-15% CAPEX increase	15-20% CAPEX increase	>20% CAPEX increase
Operating Expenditures	<5% OPEX increase	5-15% OPEX increase	15-20% OPEX increase	>20% OPEX increase
Time	<5% time increase	5-10% time increase	10-20% time increase	>20% time increase
Oil price changes	<5% oil price decrease	5-10% oil price decrease	10-20% oil price decrease	>20% oil price decrease

Every risk that is identified throughout the project should be carefully assessed using the table above. Failure in estimating the correct values will have an effect on the next technique that is assigning the overall risk score to identified probability and impact values.

Probability and Impact Matrix

Impact is the evaluation of consequences that risks posed to a project. The commonly used risk impact scale is a relative scale that assigns values such as high-medium-low (Heldman, 2009). Usually, these risk-rating rules are specified by the organization in advance of the project and included in organizational process assets. Evaluation of each risk's importance and, hence, priority for attention, is typically conducted using a look-up table or a probability and impact matrix. Such a matrix specifies combinations of probability and impact that lead to rating the risks as low, moderate, or high priority (PMI,2004).

Table 5 shows the proposed Probability and Impact matrix to execute a qualitative risk analysis. The red area represents Very High risk, orange area – High risk, yellow area – Medium risk and green area – Low risk.

Table 5 – Proposed Probability and Impact Matrix

	Impact on an objective			
Probability of occurrence	**Low /.10**	**Medium /.20**	**High /.40**	**Very High /.80**
0.90	**0.09** Medium	**0.18** High	**0.36** High	**0.72** Very High
0.70	**0.07** Medium	**0.14** Medium	**0.28** High	**0.56** Very High
0.50	**0.05** Low	**0.10** Medium	**0.20** High	**0.40** High
0.30	**0.03** Low	**0.06** Medium	**0.12** Medium	**0.24** High
0.10	**0.01** Low	**0.02** Low	**0.04** Low	**0.08** Medium

When probability of risk occurrence and impact on an objective are estimated, it is easy to find in a matrix a corresponding cell with numerical value and natural language expression of the risk. For instance, the project management team has estimated that a risk might occur with an impact on the volume of oil production. After brainstorming, it was decided that the risk would have a medium impact (5-10% volume decrease) on a project objective "Production rate (150 MBOPD)". Then, the team assumed that the probability of risk occurrence is 0.70 out of 1. Finally, two values were correlated in a Table 5 and the risk was ranked as "0.14 Medium".

This technique aimed to help in estimating proper risk responses: risks that have a negative impact on objectives if they occur (threats), and that are in the high-risk zone of the matrix, may require priority action and aggressive response strategies. Threats in the low-risk zone may not require proactive management action beyond being placed on a watchlist or adding a contingency reserve (Heldman,2009). Numerical values can be applied when prioritizing risks based on results of the matrix. The example of application of this technique is provided in Appendix N.

The ultimate goal of qualitative risk analysis is to prioritize the identified risks and determine which ones need the further analysis and, eventually, a risk response plan (Heldman,2009). The risk register has to be updated with the following inputs:

- *Relative ranking or priority list of project risks* based on the results of probability and impact matrix. Usually risks are classified by individual significance such as "high", "medium" and "low". Project management team has to focus on risks with "high" significance on project objectives that should lead to immediate response actions and as a result a prevention of a negative project outcome.
- *Risks grouped by categories.* This risk categorization can reveal the common root causes or areas of the project that need project management team attention. The concentration on a specific category can improve the risk response efficiency.
- *List of risks requiring response in the near-term*. The prioritization of risks by those that require an urgent response and those that can be handled at a later date (PMI, 2004).
- *Watchlists of low-priority risks*. Risks that during the Qualitative Risk Analysis were estimated of "low" significance should be put on a watchlist for the continuous monitoring.

5.5.4 Quantitative risk analysis

All capital projects have uncertainties. However, qualitative study of risk factors is not enough for reducing uncertainties and making good decisions. That is why nowadays oil and gas companies are widely using the quantitative risk analysis techniques. The main purpose of carrying such analysis is to ensure that the identified risks are below the tolerable limits. According to PMI, this study can be approached using several tools such as:

- Sensitivity Analysis;
- Expected Monetary Value Analysis;
- Decision Tree Analysis;
- Modeling and Simulation;
- Expert Judgment.

In order to quantify the impact of the project risks, it is recommended Partex to carry out its own internal analysis using developed economic model as a tool. The advantages of this analysis would be discussed below.

Sensitivity analysis

Sensitivity analysis is a quantitative tool that aims to determine which risk has the greater potential to impact a project performance. This technique can be explained as follows: the company chooses a set of variables that in its opinion will have an impact on a project. Then the performance of the project is being tested by increasing and decreasing the variables by identified range, for instance +20%/-20%. The results of this study will give the overview of how much the project performance can be affected by various risk elements. It also allows to see which risks might have the biggest impacts on the project and will require detailed response plans.

As an example, the sample sensitivity analysis was conducted and five project risks with different impact on objectives were selected and, creating the set of assumptions, applied to the developed economic model. Assumptions and outcome parameters, which are NPV, partners cash flow and partners revenue, are presented below.

Assumptions

1. Risks will affect the project during the five following years, including the current year, and will cover the period from 2013 to 2017. After that, the operator will be able to mitigate or eliminate the risks.
2. Risks will not affect the historical data that is covering the period from 2005 to 2012 of the project.
3. For calculations of outcome parameters the data of "Case Scenario 3" of the developed economic model was used.
4. For "time increase" variable it was assumed that Operator will not reach the production target in the following five years and average of 130 MBOPD was taken as an input for model calculations for a given period.

The base case is the case that is not impacted by any risk. The base case values are as follows:

Table 6 – Base case output values

	NPV	Partners Revenue	Partners Cash Flow
	$M	$M	$M
Base Case	2.642	15.095	4.711

Results of the risk sensitivity analysis are represented by the delta (difference) value between the base case and the case resulted from the change in risk variable.

Table 7 – Risks sensitivity analysis

Risk Factor	Consequences on the objective	NPV delta	Partners Cash Flow delta	Partners Revenue delta
		$M	$M	$M
Oil price changes	25% oil price decrease	534	639	639
Inability to achieve target bottomhole pressure	25% volume decrease	485	581	580
Well construction schedule slippage	10% time increase	214	253	252
Change in Oman Labor directives (recruitment, contract costs, etc.)	40% OPEX increase	125	148	-1085
Inability to achieve target vertical injection conformance	20% CAPEX increase	25	28	-202

The table above is presenting an approach that allows to quantify the impact of potential risks on a project performance. The diagram below is a graphical representation of the table, particularly impact of risks on project's NPV.

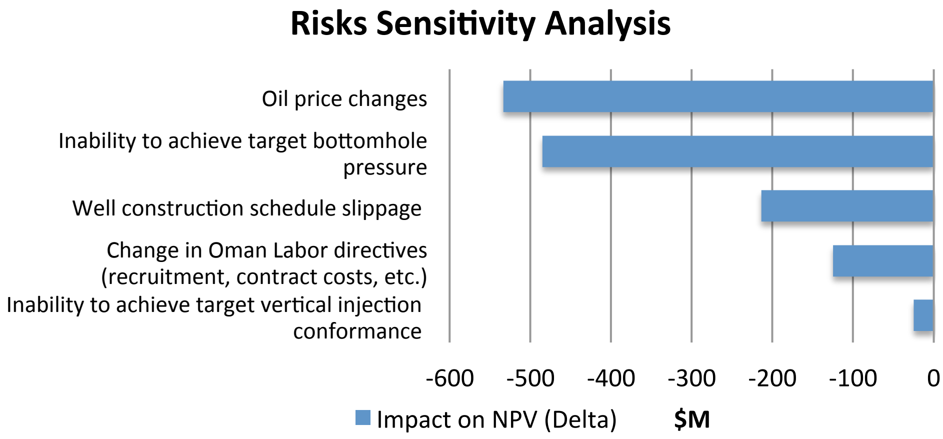

Figure 21 – Risks sensitivity analysis

It can be noticed that the greater impact will have the risks that have negative consequences on oil price, volume of oil production and time of the project; outcome parameters are not very sensitive to changes in expenditures due to the project contractual arrangement (PSA). The positive values mean "loss", whereas the negative mean "gain". The gain in partners revenue, despite the increase in expenditures, happened due to the specificity of the project contractual arrangement. By PSA terms costs can be recovered and assume that

Partners Revenue = Cost oil recovered + Profit oil,

and

Cost Oil Recovered = CAPEX + OPEX,

therefore, more costs are being invested in a project, more costs can be recovered (assuming that the project generate enough gross revenue to cover project expenditures) and benefit for partners net revenue.

The outcomes of quantitative analysis process is risk register updates that will incorporate the following new elements:

- Probabilistic analysis of the project – forecasted results of project schedule and budget as specified by the outputs of risk analysis. The results should contain projected completion schedule and expenditures along with a confidence level associated with each (Heldman, 2009);
- Probability of achieving the cost and time objectives;
- Prioritized list of quantified risks;
- Trends in quantitative risk analysis results.

5.5.5 Plan risk response

The objective of a plan risk response process is to develop risk responses for risks with significant threat or substantial opportunity for project objectives. For this process PMI proposes four techniques:

- Strategies for negative risks or threats;
- Strategies for positive risks or opportunities;
- Contingent response strategy;
- Expert judgment.

Each of these tools includes a strategy. Partex can implement all four strategies in risk response planning, however we would like to highlight one of them – Contingent Response Strategy.

Contingent Response Strategy

Contingent response strategy, or contingency planning, is a process of planning alternatives to cope with risk in case of its occurrence. This strategy is different from the mitigation planning as if mitigation aims to reduce the probability and impact of the risk then contingency planning is implying the development of response strategies in advance of the threat occurring. When risks were identified and quantified, response plans should be developed and be prepared for implementation.

The output of risk response planning process, according to PMI methodology, are: risk register updates, risk-related contract decisions, project management plan updates, and project document updates.

5.5.6 Monitor and control risks

Monitor and control risks is a process of keeping identified risks on track, identifying new risks, optimizing risk responses and evaluating effectiveness of risk management process throughout the project. The purpose of this process is to determine if the project's assumptions are still effective; analysis of risks should be changed or retired; risk management techniques are being followed. This approach includes the following tools:

- Risk Reassessment;
- Risk Audits;
- Variance and Trend Analysis;
- Technical Performance Measurement;
- Reserve Analysis;
- Status Meetings.

It should be mentioned the few tools that Partex might find useful to implement in the risk management practice of current and future projects – Risk Audits and Variance and Trend Analysis.

Risk Audits

The purpose of risk audit tool is to monitor current risks and implementation of the risk response plan and also to test the effectiveness of the overall risk management process. This process can take place during the workshops with partners or as separate risk audit meetings.

Variance and Trend Analysis

Variance and trend analysis aims to compare planned results with the actual ones. When controlling risks, the project execution should be carefully monitored using project performance data. This can be accomplished using developed economic model as a tool to forecast unfavorable deviations from the budget and schedule plan and identify the potential impact of risks or opportunities.

The outcomes of the process of monitor and control risk might be updates of project management plan, updates of project documents such as update of risk register with results of risk reassessments, risk audits and risk reviews, project risks and risk responses.

Finally, the risk management information should be gathered and stored for the future projects and for lessons learned from project management activities.

5.6 Project performance measurement: Key Performance Indicators

The benefit of implementing Key Performance Indicators as a measurement of a project performance was already discussed in the Section 4.3. In this section a discussion of the distinctive KPI characteristics will be given.

5.6.1 Characteristics of KPIs

The ultimate goal of the KPI metric system is its effectiveness in the project performance measurement. Hence, a list below provides selected characteristics for successful KPIs developed by Wayne Eckerson:

- *Aligned***.** KPIs should be aligned with the corporate performance targets.
- *Owned***.** Each KPI should be "owned" by an individual or a project team who is responsible for its outcome.
- *Actionable***.** KPIs should present actionable data so project team can analyze the information and improve performance before the unfavorable consequences.
- *Few in number.* KPIs should concentrate employees on a few high-value tasks and not to spread their attention on too many indicators.
- *Easy to understand.* KPIs should be well defined and easy to understand.
- *Standardized.* KPIs should be based on standard definitions, rules, and calculations so they can be integrated throughout the company.
- *Relevant.* KPIs should address the work that is currently undertaken in a project and be periodically reviewed and updated.
- *Reinforced with incentives.* Investors can amplify the impact of KPIs by providing compensation to them (Wayne, 2006).

The core characteristics mentioned above can make key performance indicators effective and provide a common understanding of project targets.

5.6.2 Categories of KPIs

The selection of KPIs was based on documentation reviews, benchmarking with oil and gas majors, and interviews with Partex experts from reservoir, finance, HSE and management sectors.

Selected project KPIs were structured and grouped according to what they are planned to indicate. KPIs proposed for Partex practices were organized into four main categories (Table 8) common to oil and gas projects such as:

- Health, Safety and Environment (HSE);
- Operational Performance;
- Project Performance;
- Human Resources.

Each of high-level (corporate) KPIs contains sub-level KPIs. The corresponding weight can be applied in calculations of the index of overall project performance.

Table 8 – Proposed KPIs (high-level)

Category	KPI	Weight
Health, Safety and Environment (HSE)	Personal safety performance	10%
	Process safety performance	10%
	Transportation safety performance	10%
Operational Performance	Hydrocarbons production	10%
	Steam performance	10%
	Drilling performance	7.5%
	Operating costs	10%
	Capital employed	7.5%
Project Performance	Strategic performance	10%
	Financial performance	10%
Human Resources	Human resources availability and people development	10%

Below is a brief description of each category and the respective KPIs.

<u>Health, Safety and Environment</u>

HSE is an important indicator of any industry but particularly in the oil and gas sector which is one of the most hazardous ones. Nowadays it became very important for companies to track the number of dangerous occurrences, injuries and oil spills in order not to damage the reputation and to maintain the competitive advantage.

HSE category in Table 8 includes three high-level KPIs such as personal safety performance, process safety performance and transportation performance.

Personal safety performance monitors if employees are following the corporate rules and work safely.

Process safety performance monitors the reliability of operations and processes that deal with hazardous substances. According to International Association of Oil and Gas Producers (OGP) "in recent years, major incidents in oil and gas industry have highlighted the importance of having these robust processes and systems in place".

Transportation safety performance

As industry deals with driving operations of people and products, it can't avoid the inherent risks that transportation poses to the safety of processes. Therefore, through monitoring this group of KPIs transportation-related risks can be identified and mitigated in time.

<u>Operational Performance</u>

This group of KPIs is important for the overall success of the project as it measures the internal operational performance. We selected five high-level KPIs which are: hydrocarbons production, steam performance, drilling performance, operating costs, capital employed

Hydrocarbons production

This indicator measures the output rate of oil produced and should be carefully monitored to meet investors' expectations.

Steam performance

Due to the thermal development of Oman oil field, the steam performance should be monitored to ensure the reliability of oil extraction process.

Drilling performance

This KPI manages the drilling performance of the project in terms of new wells drilled versus wells planned, cost of the well and development of patterns.

Operating costs and Capital employed

Indicators measure if the project is executed according to the planned budget for OPEX and CAPEX.

<u>Project Performance</u>

This group of KPIs monitors well being of the project at the corporate level and gives investors a quick view of its profitability and if the project is executed according to the developed strategy. The following KPIs are being considered: strategic performance and financial performance.

Strategic performance

This KPI monitors of there is enough capability to complete the project on time and within budget on the basis of established targets.

Financial performance

Measurement of the net cash flow from investor's activities.

Human Resources

This set of KPIs monitor if project has enough manpower and to execute the project and if employees have all necessary capabilities.

HR availability and People development

KPI tracks the availability of human resources measuring employee turnover and recruitment rates. Employee training rate should monitor if staff has sufficient knowledge of operations and processes.

5.6.3 KPI targets and KPI measurement

The KPI targets serve as a boundary against which the measurements will be done. Targets should be realistic and tied to the project objectives. But it is important to mention that KPIs are not targets, they represent if the metric is above or below the established target.

Figure 22 shows an example of KPIs boundary bar. If the metric value meets the target value, it corresponds to a normal performance; 5-10% exceeding the target - outstanding performance; below 5% of the target might lead to an unfavorable expectation and below 10-15% to the failure of the KPI and need of an immediate attention.

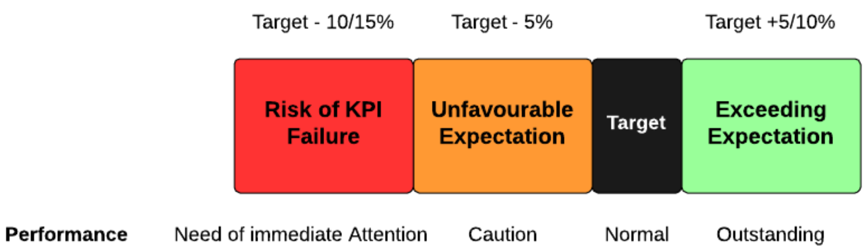

Figure 22 – KPIs Boundary Bar

For the current Omani project, four project's KPIs were selected to demonstrate the application of the measurement process (Table 9). The target range columns show the boundaries of metrics' targets and zones of success and failure. When project team would compare the actual project performance for a specific period, it would be easy to identify which zone corresponds to the metrics' results. For example, the actual performance of oil production is 99 MBOPD, which is below the predefined target (105 MBOPD).

For capital employed and operating costs the unfavorable situation will be if these costs increase, and as an opposite, if the project team will be able to keep the costs below the target limit. For fatalities, the target and the same tame favorable performance will be zero fatalities. Here, no values for unfavorable expectation can be identified as even one accident resulted in fatality means the failure in performance.

Table 9 – Example of an application of the project performance measurement

N	Category	KPI	Units	Target Range				Actual Performance
				Fail (-15%)	Caution(-5%)	Target	Success (+10%)	
1	HSE	Fatalities	Rate	1	-	**0**	0	**0**
2	Operations performance	Oil Production	MBOPD	95	100	**105**	115	**99**
3	Operations performance	Capital Employed	US M$	46	38	**40**	36	**35**
4	Operations performance	Operational costs	US M$	82	76	**72**	65	**81**

A list of proposed KPIs and sub-KPIs can be found in Appendix O.

To summarize, KPI is a useful tool to measure a project performance as these metric help to identify problem areas easier, provide time-based results for better-decision making and as a result improve project performance. KPI shows if the actual position is below or above a predefined target and designed to let investors know if the project is being executed according or not to the original plan.

6. Conclusions and recommendations for future projects

The main objective of the presented work was to generate a methodology and tools that can help to improve Partex Oil and Gas Group current management process of its ventures in oil and gas projects. In order to familiarize us with the current processes and techniques, an analysis of an ongoing venture where the Group participates as an investor was conducted. The solution that was chosen to address the main objective consists of two parts: firstly, utilization of an economic model to evaluate the impact of variations in assumptions on project performance (regarding model scenario) and perform sensitivity analysis to evaluate project risks; secondly, implementation of the framework of the Project Management Institute to standardize and enhance current project management processes.

The main concern of Partex is that since the Group is acting mainly as investor and not managing directly the operations of most of its assets, it relies on a data from the project operator and its methodology. This approach brings a lot of uncertainties and not always favorable expectations for Partex shareholders. The current situation can be improved using the following set of recommendations, which obtained a positive feedback from Partex senior management:

- Implement an internal project management analysis and review of data submitted by the operator.
- Use an economic model and risk management framework and obtain internal risk management results to be better prepared for negotiations with operator.
- Monitor the operator risk management process and ensure that all submitted data is complete and relevant.
- Internal review of risk management reports and analysis of project assumptions (strength and validity).
- Structure risks in Risk Breakdown Structure to ensure that all project risks are covered.
- Use risk benchmarking of oil and gas majors to ensure that list of risks provided by operator is comprehensive.
- Implement risk register to document, track, review, and manage risks throughout the project.
- Prioritize identified risks using qualitative analysis tools described in this report (Section 4.5.3).
- Quantify the impact of risks on project performance to ensure that identified risks are below the tolerable limits using quantitative analysis tools described in this report (Section 4.5.4).
- Evaluate risk factors of the project through simulating the occurrence of the unfavorable events using the economic model.
- Implement a risk response strategy to guarantee that there are enough alternatives to cope with the risk in case of its occurrence.
- Monitor and control risks throughout the project to ensure that risk management techniques are being followed.
- Measure the project performance using KPIs on a daily or weekly basis to monitor the project progress towards the target results.

The future work that should be done by Partex is as follows:

- Implement the abovementioned recommendations;
- Observe the results and make adjustments if necessary;
- Continue to study and explore project management risks and adaptation of frameworks to the oil and gas industry.

The current research work obtained a positive response from Partex senior management and some of the recommendations were already addressed to the operator of the project in the Sultanate of Oman during the workshop meeting of shareholders representatives in July, 2013.

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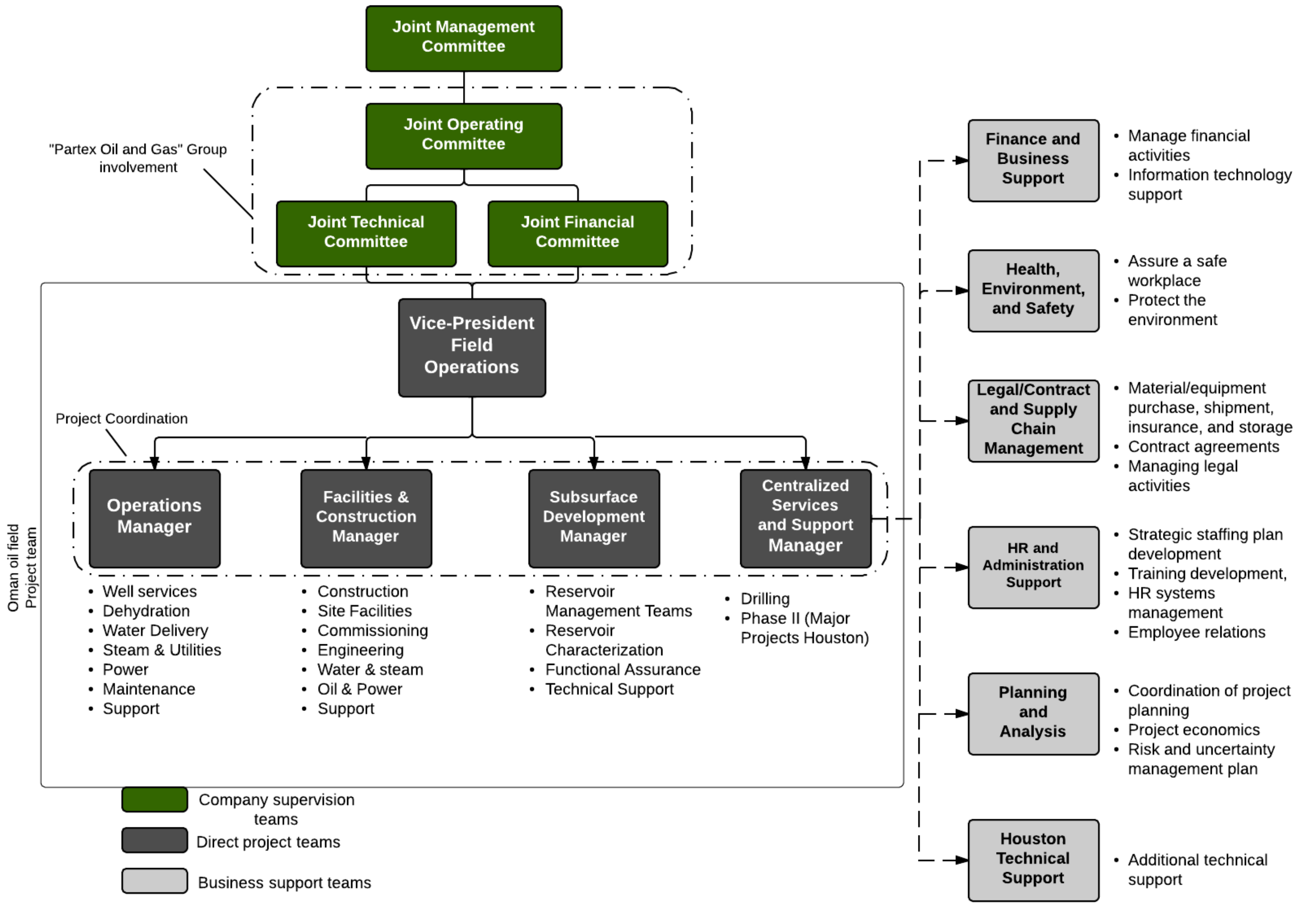
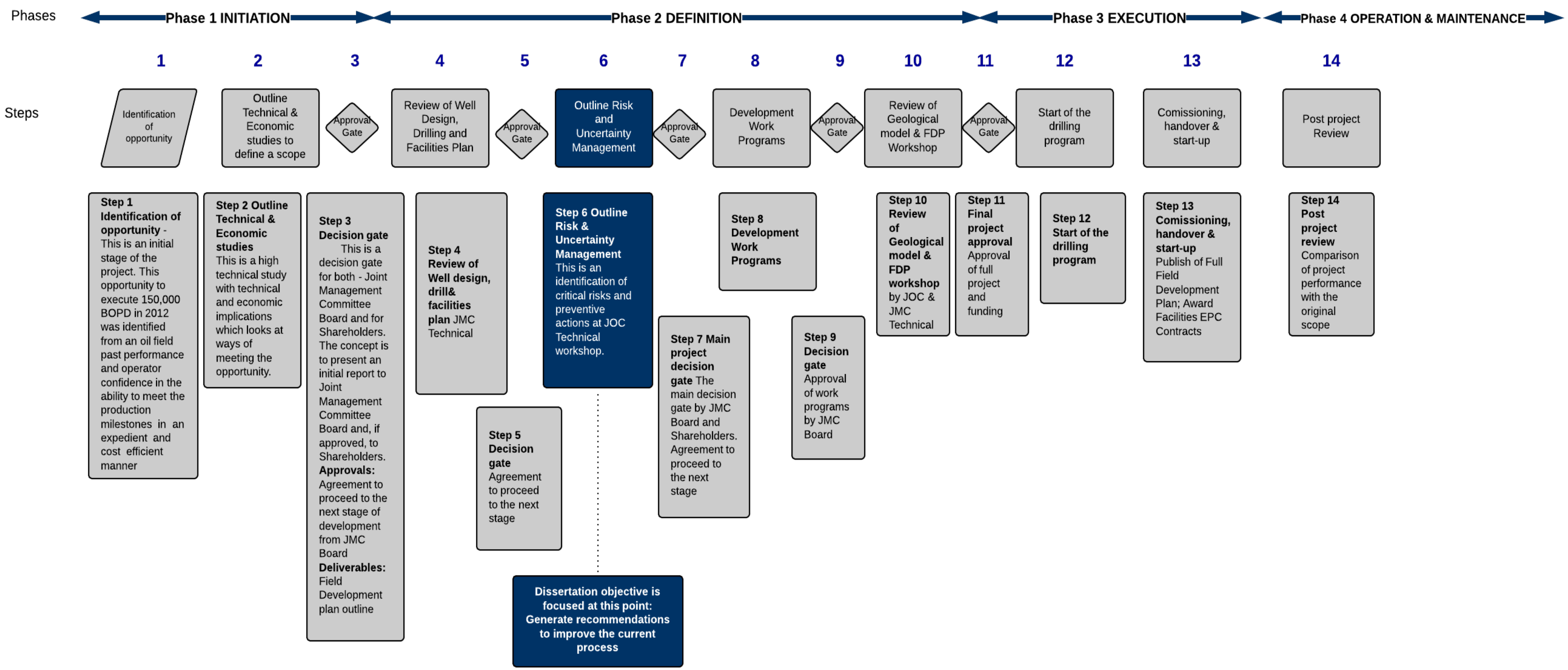
APPENDIX A: Organizational structure of case study project



APPENDIX B: Case study project management process



APPENDIX C: Case study risks evolution (2006-2010)

Risk name	Risk scale[9]				
	2006	2007	2008	2009	2010
Gas supply delayed/insufficient	VH	H	H	VH	-
		reduced	no movement	increased	-
Facilities Construction schedule delayed	VH	H	VH	VH	M
		reduced	increased	no movement	reduced
Insufficient/inadequate human resources	VH	H	VH	H	-
		reduced	increased	reduced	-
Reservoir does not respond as well as expected	H	H	H	H	M
		no movement	no movement	no movement	reduced
Water Supply for steam delayed/not available	H	M	M	M	-
		reduced	no movement	no movement	-
Selected water treating does not work	H	M	M	M	-
		reduced	no movement	no movement	-
Well construction schedule delayed	H	L	L	L	M
		reduced	no movement	no movement	reduced

[9] VH - very high; H – high; M – medium; L - low

Delays due to external approval	H	M	M	H	-
		reduced	no movement	increased	-
Unacceptable operating costs due to reservoir performance	-	-	-	-	M

The major project risk factors for the period 2006-2010 are:

1. Unacceptable operating costs due to reservoir performance

The original cost risk was high capital spending due to the fast pace of the project. Much of the capital spending has already occurred for the project, with the costs being higher than in the 2006 FDP. Project economics have been adversely affected by the market conditions of the first two years and by the fast pace of the project. The remainder of the capital expense is occurring during more favorable market conditions. In addition, stronger project management and control have been applied to the remainder of the capital expense projects. Cost control going forward will be focused on operating expense. The key cost is steam generation and fuel costs. Higher than expected steam costs due to reservoir quality, shale beds or aquifer support could drive costs higher. Mitigation will include diligent surveillance and heat management.

2. Facilities construction delays

More than half of the production capacity has already been built for the project. The impact and the risk have lessened because of the reservoir response and the existing facilities capacity. Delays in construction at this point will prolong a reduced capacity, but would simply defer production. Delays are being minimized by stronger project management and project controls.

3. Reservoir does not respond as well as expected

Reservoir response has the longest and most far-reaching impact on the project economics. Bottomhole pressure, well sanding and lower MG1 performance can be mitigated by additional spending on pressure reduction through casing vapor recovery, well cleanouts, and additional APO wells. Poorer reservoir quality in future development areas cannot be controlled. Proper delineation to identify these areas followed by an adjustment of the development plan will align the spending with the expected performance of these areas.

APPENDIX D: Case study risks evolution (2010-2013)

Risk name	Risk scale[10]		
	2011	2012	2013
Delay in 9E[11] repair	VH	M	-
	-	reduced	-
Greater than planned temperature associated with MVC	H	VH	M
	-	increased	reduced
Establish reliable supply of sodium chloride	H	M	-
	-	reduced	-
Insufficient human resources	H	VH	H
	-	increased	reduced
Inability to achieve target injection conformance	-	VH	VH
	-	-	no movement
Well construction schedule slippage	L	L	H
	-	no movement	increased
Operational up-time less than expectation (reference 5%)	M	M	VH
	-	no movement	increased
9E shutdown	-	-	VH
			new risk
Inability to achieve target bottomhole pressure	-	-	H
			new risk
Industrial Labor Dispute	-	-	VH
			new risk
Change in Oman Labor directives (recruitment, contract cost ...etc)			VH
	-	-	new risk

[10] VH - very high; H – high; M – medium; L - low
[11] 9E – name of the of the turbine used in operations

The main risks for a given period are as follows:

1. Inability to achieve target vertical injection conformance

This risk is posed by several factors:

- Inability to achieve conformance due to the surface;
- Subsurface splits and steam quality;
- Profile control equipment not working as designed.

2. 9E shutdown

The risk was caused by the following factors:

- Planned preventive maintenance and
- Planned corrective maintenance.

3. Operational up-time less than expectation

The operational up-time was affected by:

- Insufficient power;
- Mechanical and hydrolic problems;
- Insufficient processing facilities.

4. Well construction schedule slippage

The slippage happened due to:

- Shortage of qualified drilling personnel;
- Concurrent failure of major rig components;
- Tight rig/material market.

5. Inability to achieve target bottomhole pressure

The causes of this risk are:

- Well equipment limitation and surface facility temperature limitation;
- Higher pump setting depth due to wellbore configuration;
- Poor injection performance;
- Higher surface pressure;
- Strong/infinite acting aquifer.

6. Industrial Labor dispute and Changes in Oman Labor directives

The risks were caused by:

- Arab Spring movement;
- Demand of higher wages & more benefits; better working conditions; increased job security;
- Labor dispute;
- Nation-wide additional recruitment campaigns.

APPENDIX E: Economic model input data

2006-2035					Real values				
Date		Daily Production*	Yearly Production	Price	Operating Costs	Facilities CAPEX	Drilling CAPEX	Total CAPEX	Training Fund
Year	Days	MBOPD	MMBO	$/BOE	M$	M$	M$	M$	M$
2005	122	2.5	0.31	53.77	11.748	124.325	0	124.325	0.5
2006	365	9.5	3.47	43.53	54.614	298.614	106.211	404.825	0.5
2007	365	24	8.76	35.70	99.709	519.659	111.210	630.869	0.5
2008	365	48.7	17.78	35.70	118.049	236.032	130.810	366.842	0.5
2009	365	78.1	28.51	35.70	176.159	106.692	123.748	230.44	0.5
2010	365	111.7	40.77	35.70	248.159	145.340	123.279	268.619	0.5
2011	365	140.0	51.10	35.70	333.308	149.563	122.987	272.55	0.5
2012	365	150	54.75	35.70	406.394	72.056	107.180	179.236	0.5
2013	365	150	54.75	35.70	419.534	28.662	98.843	127.505	0.5
2014	365	150	54.75	35.70	420.370	27.029	96.878	123.907	0.5
2015	365	150	54.75	35.70	427.239	24.801	81.212	106.013	0.5
2016	365	150	54.75	35.70	432.967	24.631	78.127	102.758	0.5
2017	365	150	54.75	35.70	436.667	24.063	76.655	100.718	0.5
2018	365	150	54.75	35.70	440.764	26.361	75.132	101.493	0.5
2019	365	150	54.75	35.70	440.190	27.014	73.640	100.654	0.5
2020	365	150	54.75	35.70	435.680	28.019	72.177	100.196	0.5
2021	365	150	54.75	35.70	428.037	23.865	50.010	73.875	0.5
2022	365	120.4	43.95	35.70	363.641	17.958	12.187	30.145	0.5
2023	365	103.3	37.70	35.70	309.140	17.309	12.187	29.496	0.5
2024	365	86.2	31.46	35.70	262.269	15.363	12.187	27.55	0.5
2025	365	73.2	26.72	35.70	222.315	14.859	12.187	27.046	0.5
2026	365	61.5	22.45	35.70	184.645	2.210	0	2.210	0.5
2027	365	46.8	17.08	35.70	141.405	1.000	0	1.000	0.5
2028	365	38.9	14.20	35.70	107.603	1.000	0	1.000	0.5
2029	365	27.1	9.89	35.70	79.678	1.000	0	1.000	0.5
2030	365	20.8	7.59	35.70	62.014	1.000	0	1.000	0.5
2031	365	14.9	5.44	35.70	47.712	0.750	0	0.750	0.5
2032	365	9.9	3.61	35.70	34.725	0.750	0	0.750	0.5
2033	365	6	2.19	35.70	25.543	0.750	0	0.750	0.5
2034	365	2.9	1.06	35.70	16.622	0.750	0	0.750	0.5
2035	365	1.7	0.62	35.70	10.218	0	0	0.000	0
Total			922.149		7,197	1961.425	1576.847	3,538.272	15.000

*Values according to FDP 2006

APPENDIX F: Economic model calculations

2006-2035

Year	Daily Production MBOPD	Yearly Production MMBO	Cumulative Production MMBO	Brent Price $/BOE	Oman official price $/BOE	Oman Blend differential $/BOE	Quality Bank Differential $/BOE	Field Realized Price $/BOE	Inflation index	Total Capex M$	Total Opex M$	Abandonment M$	Total costs M$	Training Fund M$	Gross Revenue M$
2005	2.5	0.305	0.305	54.52	53.77	0.75	0	53.77	1.00	124.325	11.748	0	**136.073**	**0.5**	**16.400**
2006	9.5	3.47	3.7725	65.14	61.67	3.47	0	61.67	1.00	404.825	54.614	0	**459.439**	**0.5**	**213.841**
2007	24	8.76	12.5325	72.39	66.30	6.09	0	66.30	1.00	630.869	99.709	0	**730.578**	**0.5**	**580.788**
2008	48.7	17.78	30.308	97.26	101.06	-3.80	10.93	90.13	1.00	366.842	118.049	0	**484.891**	**0.5**	**1602.106**
2009	78.1	28.51	58.8145	61.67	56.70	4.97	1.35	55.35	1.00	230.440	176.159	0	**406.599**	**0.5**	**1577.835**
2010	111.7	40.77	99.585	79.50	76.64	2.86	4.17	72.47	1.00	268.619	248.159	0	**516.778**	**0.5**	**2954.638**
2011	140	51.10	150.685	111.26	102.95	8.31	7.24	95.71	1.00	272.550	333.308	0	**605.858**	**0.5**	**4890.781**
2012	150	54.75	205.435	111.63	109.57	2.06	5.31	104.26	1.00	179.236	406.394	0	**585.630**	**0.5**	**5708.235**
2013	150	54.75	260.185	80.00	77.94	2.06	5.31	72.63	1.00	127.505	419.534	0	**547.039**	**0.5**	**3976.493**
2014	150	54.75	314.935	80.00	77.94	2.06	5.31	72.63	1.00	123.907	420.37	0	**544.277**	**0.5**	**3976.493**
2015	150	54.75	369.685	80.00	77.94	2.06	5.31	72.63	1.00	106.013	427.239	0	**533.252**	**0.5**	**3976.493**
2016	150	54.75	424.435	80.00	77.94	2.06	5.31	72.63	1.00	102.758	432.967	0	**535.725**	**0.5**	**3976.493**
2017	150	54.75	479.185	80.00	77.94	2.06	5.31	72.63	1.00	100.718	436.667	0	**537.385**	**0.5**	**3976.493**
2018	150	54.75	533.935	80.00	77.94	2.06	5.31	72.63	1.00	101.493	440.764	0	**542.257**	**0.5**	**3976.493**
2019	150	54.75	588.685	80.00	77.94	2.06	5.31	72.63	1.00	100.654	440.19	0	**540.844**	**0.5**	**3976.493**
2020	150	54.75	643.435	80.00	77.94	2.06	5.31	72.63	1.00	100.196	435.68	0	**535.876**	**0.5**	**3976.493**
2021	150	54.75	698.185	80.00	77.94	2.06	5.31	72.63	1.00	73.875	428.037	0	**501.912**	**0.5**	**3976.493**
2022	120.4	43.95	742.131	80.00	77.94	2.06	5.31	72.63	1.00	30.145	363.641	0	**393.786**	**0.5**	**3191.798**
2023	103.3	37.70	779.8355	80.00	77.94	2.06	5.31	72.63	1.00	29.496	309.14	0	**338.636**	**0.5**	**2738.478**
2024	86.2	31.46	811.2985	80.00	77.94	2.06	5.31	72.63	1.00	27.550	262.269	0	**289.819**	**0.5**	**2285.158**
2025	73.2	26.72	838.0165	80.00	77.94	2.06	5.31	72.63	1.00	27.046	222.315	0	**249.361**	**0.5**	**1940.528**
2026	61.5	22.45	860.464	80.00	77.94	2.06	5.31	72.63	1.00	2.210	184.645	0	**186.855**	**0.5**	**1630.362**
2027	46.8	17.08	877.546	80.00	77.94	2.06	5.31	72.63	1.00	1.000	141.405	0	**142.405**	**0.5**	**1240.666**
2028	38.9	14.20	891.7445	80.00	77.94	2.06	5.31	72.63	1.00	1.000	107.603	0	**108.603**	**0.5**	**1031.237**
2029	27.1	9.89	901.636	80.00	77.94	2.06	5.31	72.63	1.00	1.000	79.678	0	**80.678**	**0.5**	**718.420**
2030	20.8	7.59	909.228	80.00	77.94	2.06	5.31	72.63	1.00	1.000	62.014	0	**63.014**	**0.5**	**551.407**
2031	14.9	5.44	914.6665	80.00	77.94	2.06	5.31	72.63	1.00	0.750	47.712	0	**48.462**	**0.5**	**394.998**
2032	9.9	3.61	918.28	80.00	77.94	2.06	5.31	72.63	1.00	0.750	34.725	0	**35.475**	**0.5**	**262.449**
2033	6	2.19	920.47	80.00	77.94	2.06	5.31	72.63	1.00	0.750	25.543	0	**26.293**	**0.5**	**159.060**
2034	2.9	1.06	921.5285	80.00	77.94	2.06	5.31	72.63	1.00	0.750	16.622	0	**17.372**	**0.5**	**76.879**
2035	1.7	0.62	922.149	80.00	77.94	2.06	5.31	72.63	1.00	0.000	10.218	0	**10.218**	**0.0**	**45.067**
Total		**922.149**								**3538.272**	**7197.118**	**0**	**10735.39**	**15**	**69599.56**

Year	Cost oil							Profit Oil				Contractor Revenue	Contractor CASH Flow	Discount factor	Contractor CASH Flow Discounted
	Multiplier %	Gross revenue * multip M$	Opening M$	Cost year M$	Recovered Cost oil M$	Unrecovered M$	Excess M$	Gross Revenue-Recovered cost oil M$	Multiplier %	Contractor Profit oil M$	Government Profit oil M$	M$	M$		M$
2005	60%	9.840	0	136.073	9.840	126.233	0.000	6.560	12%	0.787	5.773	10.63	-125.95	1.00	-125.946
2006	60%	128.304	126.233	459.439	128.304	457.368	0.000	85.536	12%	10.264	75.272	138.57	-321.37	0.91	-292.155
2007	60%	348.473	457.368	730.578	348.473	839.473	0.000	232.315	12%	27.878	204.437	376.35	-354.73	0.83	-293.163
2008	60%	961.263	839.473	484.891	961.263	363.100	0.000	640.842	12%	76.901	563.941	1,038.16	552.77	0.75	415.307
2009	60%	946.701	363.100	406.599	769.699	0.000	177.001	808.135	12%	96.976	711.159	866.68	459.58	0.68	313.897
2010	60%	1772.783	0.000	516.778	516.778	0.000	1,256.005	2,437.860	12%	292.543	2,145.317	809.32	292.04	0.62	181.336
2011	60%	2934.469	0.000	605.858	605.858	0.000	2,328.611	4,284.923	12%	514.191	3,770.732	1,120.05	513.69	0.56	289.965
2012	60%	3424.941	0.000	585.630	585.630	0	2,839.311	5,122.605	12%	614.713	4,507.892	1,200.34	614.21	0.51	315.188
2013	60%	2385.896	0.000	547.039	547.039	0	1,838.857	3,429.454	12%	411.534	3,017.919	958.57	411.03	0.47	191.751
2014	60%	2385.896	0.000	544.277	544.277	0	1,841.619	3,432.216	12%	411.866	3,020.350	956.14	411.37	0.42	174.459
2015	60%	2385.896	0.000	533.252	533.252	0	1,852.644	3,443.241	12%	413.189	3,030.052	946.44	412.69	0.39	159.109
2016	60%	2385.896	0.000	535.725	535.725	0	1,850.171	3,440.768	12%	412.892	3,027.875	948.62	412.39	0.35	144.541
2017	60%	2385.896	0.000	537.385	537.385	0	1,848.511	3,439.108	12%	412.693	3,026.415	950.08	412.19	0.32	131.337
2018	60%	2385.896	0.000	542.257	542.257	0	1,843.639	3,434.236	12%	412.108	3,022.127	954.37	411.61	0.29	119.228
2019	60%	2385.896	0.000	540.844	540.844	0	1,845.052	3,435.649	12%	412.278	3,023.371	953.12	411.78	0.26	108.434
2020	60%	2385.896	0.000	535.876	535.876	0	1,850.020	3,440.617	12%	412.874	3,027.743	948.75	412.37	0.24	98.719
2021	60%	2385.896	0.000	501.912	501.912	0	1,883.984	3,474.581	12%	416.950	3,057.631	918.86	416.45	0.22	90.632
2022	60%	1915.079	0.000	393.786	393.786	0	1,521.293	2,798.012	12%	335.761	2,462.251	729.55	335.26	0.20	66.330
2023	60%	1643.087	0.000	338.636	338.636	0	1,304.451	2,399.842	12%	287.981	2,111.861	626.62	287.48	0.18	51.706
2024	60%	1371.095	0.000	289.819	289.819	0	1,081.276	1,995.339	12%	239.441	1,755.898	529.26	238.94	0.16	39.069
2025	60%	1164.317	0.000	249.361	249.361	0	914.956	1,691.167	12%	202.940	1,488.227	452.30	202.44	0.15	30.091
2026	60%	978.217	0.000	186.855	186.855	0	791.362	1,443.507	12%	173.221	1,270.286	360.08	172.72	0.14	23.340
2027	60%	744.399	0.000	142.405	142.405	0	601.994	1,098.261	12%	131.791	966.469	274.20	131.29	0.12	16.129
2028	60%	618.742	0.000	108.603	108.603	0	510.139	922.634	12%	110.716	811.918	219.32	110.22	0.11	12.309
2029	60%	431.052	0.000	80.678	80.678	0	350.374	637.742	12%	76.529	561.213	157.21	76.03	0.10	7.719
2030	60%	330.844	0.000	63.014	63.014	0	267.830	488.393	12%	58.607	429.786	121.62	58.11	0.09	5.363
2031	60%	236.999	0.000	48.462	48.462	0	188.537	346.536	12%	41.584	304.952	90.05	41.08	0.08	3.447
2032	60%	157.469	0.000	35.475	35.475	0	121.994	226.974	12%	27.237	199.737	62.71	26.74	0.08	2.039
2033	60%	95.436	0.000	26.293	26.293	0	69.143	132.767	12%	15.932	116.835	42.23	15.43	0.07	1.070
2034	60%	46.127	0.000	17.372	17.372	0	28.755	59.507	12%	7.141	52.366	24.51	6.64	0.06	0.419
2035	60%	27.040	0.000	10.218	10.218	0	16.822	34.849	12%	4.182	30.667	14.40	4.18	0.06	0.240
Total					**10735.390**			**58,864.171**		**7,063.701**	**51,800.471**	**17,799.09**	**7,048.70**		**2281.910**
					15%					10%					

APPENDIX G: Economic model output

2006-2035

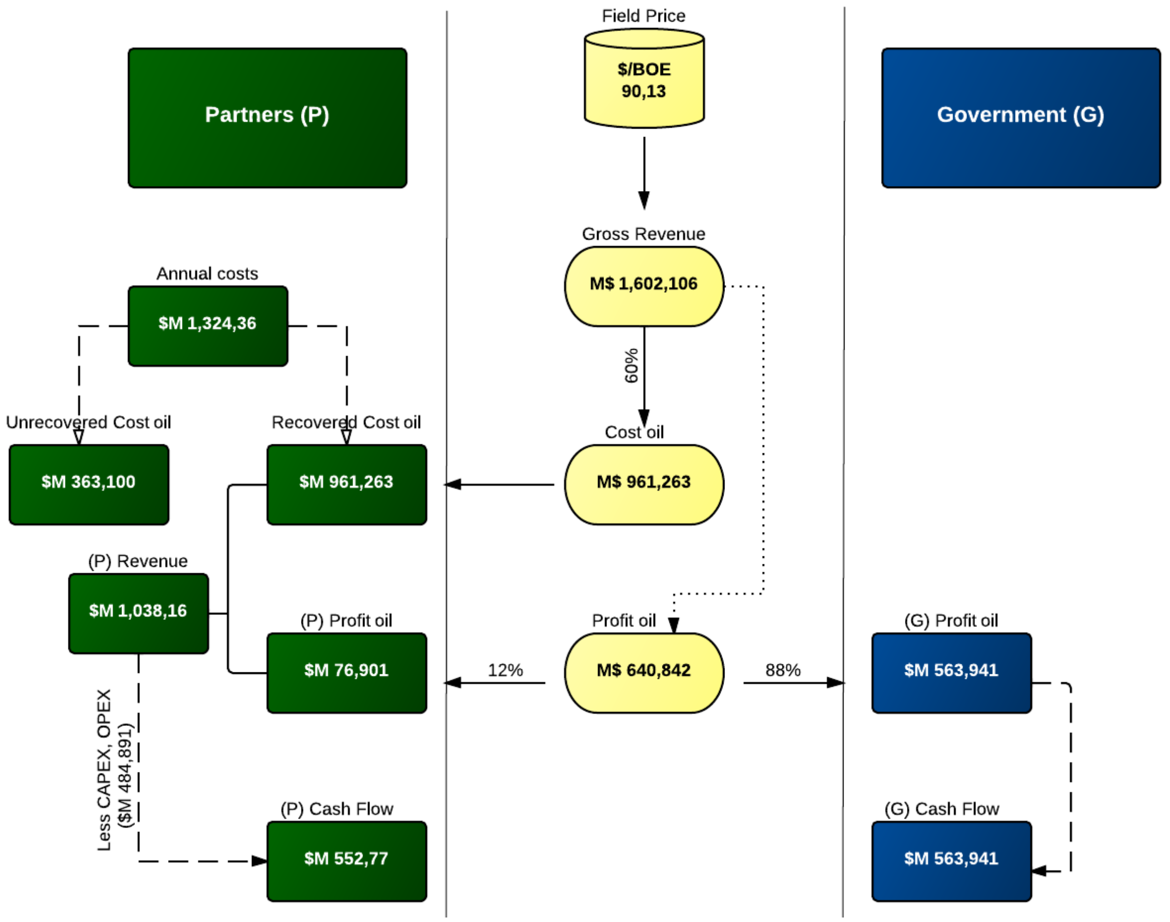
100% Equity Net Position
Real terms: No Inflation

Indicators	
NPV (2005-2035)	2,282
IRR (%)	44%
Max Exposure (M$)	802.04
Payback (years)	4.5
Government Take (%)	88.02%
Capex per bbl	$3.84
Opex per bbl	$7.80

Assumptions	
Discount rate	10%
Base year	2005
Values discounted	2005
Brent price	80 from 2013 onwards
2006-2012 historical prices	

Year	Daily Production MBOPD	Yearly Production MMBO	Contractor Net Revenue $M	Cost oil $M	Profit oil $M	OPEX $M	CAPEX $M	Training Fund $M	Abandonment $M	Net cash flow $M
2005	2.5	0.31	11	10	1	12	124	1	0	-126
2006	9.5	3.47	139	128	10	55	405	1	0	-321
2007	24.0	8.76	376	348	28	100	631	1	0	-355
2008	48.7	17.78	1,038	961	77	118	367	1	0	553
2009	78.1	28.51	867	770	97	176	230	1	0	460
2010	111.7	40.77	809	517	293	248	269	1	0	292
2011	140.0	51.1	1,120	606	514	333	273	1	0	514
2012	150.0	54.75	1,200	586	615	406	179	1	0	614
2013	150.0	54.75	959	547	412	420	128	1	0	411
2014	150.0	54.75	956	544	412	420	124	1	0	411
2015	150.0	54.75	946	533	413	427	106	1	0	413
2016	150.0	54.75	949	536	413	433	103	1	0	412
2017	150.0	54.75	950	537	413	437	101	1	0	412
2018	150.0	54.75	954	542	412	441	101	1	0	412
2019	150.0	54.75	953	541	412	440	101	1	0	412
2020	150.0	54.75	949	536	413	436	100	1	0	412
2021	150.0	54.75	919	502	417	428	74	1	0	416
2022	120.4	43.95	730	394	336	364	30	1	0	335
2023	103.3	37.70	627	339	288	309	29	1	0	287
2024	86.2	31.46	529	290	239	262	28	1	0	239
2025	73.2	26.72	452	249	203	222	27	1	0	202
2026	61.5	22.45	360	187	173	185	2	1	0	173
2027	46.8	17.08	274	142	132	141	1	1	0	131
2028	38.9	14.20	219	109	111	108	1	1	0	110
2029	27.1	9.89	157	81	77	80	1	1	0	76
2030	20.8	7.59	122	63	59	62	1	1	0	58
2031	14.9	5.44	90	48	42	48	1	1	0	41
2032	9.9	3.61	63	35	27	35	1	1	0	27
2033	6.0	2.19	42	26	16	26	1	1	0	15
2034	2.9	1.06	25	17	7	17	1	1	0	7
2035	1.7	0.62	14	10	4	10	0	0	0	4
Total		**922**	**17,799**	**10,735**	**7,064**	**7,197**	**3,538**	**15**	**0**	**7,049**

APPENDIX H: Example of case study fiscal regime calculations



The figure above shows example of the calculation mechanism. Assume, that the field price is 90,13 $/BOE, which, according to the fiscal assumptions, constitutes to 60% of the annual gross revenue as a cost oil.

The annual project costs (cost of the year + unrecovered costs of previous years) are higher than the cost oil of the year, which means that the Partners will recover only the amount of the cost oil of the year and remaining will be recovered in the following years.

The profit oil constitutes to another 40% of the annual gross revenue and calculates using the terms described in the Section 5.1 and it splits between the Government and the Partners. In our example, Partners share of the Profit oil is 12%, whereas the Government share of the Profit oil is 88%.

APPENDIX I: Economic model assumptions

When developing a model for the Oman oil field case study, the following assumptions were made:

Oil price assumptions

In order to exclude the impact of market conditions on oil price variations, the following assumptions were considered:

- The economic model used for calculations is the historical oil price (from 2005 to 2012); for onward years (2013-2035) it is assumed that the price would be steady and the same for all three case scenarios (Figure 23):

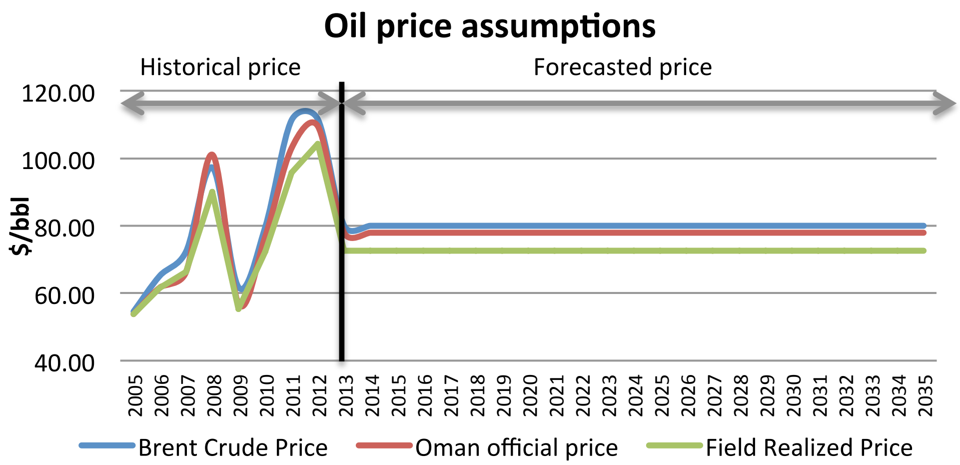


Figure 23 – Case study, oil price assumptions

- Oman oil field realized price was calculated as:

  Field realized price = Brent price – Oman Blend differential – Quality Bank differential

- Brent crude is one of the leading benchmarks of sweet light crude oil and the price was assumed as 80 US$ per barrel ($/bbl).
- Oman Blend is a medium sort crude oil and it is assumed that the Oman Blend differential to Brent price is 2.06 $, therefore:

  Oman realized price = Brent oil price – Oman Blend differential

Under the Oman Blend Revenue Distribution Agreement, and based on a "poor" oil quality relative to the Oman Blend, once the S.A.O.C

- Oman case study field production crosses the 15 MBOPD threshold, it will begin making quality bank payments which in the model is assumed 5.31 US$ per barrel.

Table 10 – Case study oil price assumptions (forecasted)

Brent official price	Oman realized price	Field realized price
$/bbl	**$/bbl**	**$/bbl**
80	77.94	72.63

Fiscal assumptions

Under the terms of the PSA, all capital and operating expenditures required to implement the proposed development plan are to be borne by all investor partners and subsequently recovered through sales of "cost recovery oil". "Cost recovery oil" is linked to the realized market price for Oman crude during a calendar year by the following relationship:

If Field Realized Price <= $25/bbl; Cost Recovery Oil = 70% Net Production;

If Field Realized Price > $25/bbl; Cost Recovery Oil = 60% Net Production.

The remaining "profit oil", together the "remaining cost recovery oil" after expenditures are recouped, is then split between the Government of the Sultanate of Oman and the Joint Operating partners according to the terms outlined in the Table 11.

Table 11 – Terms of profit oil calculations

Field Realized Price (US$)	Government Share of Profit Oil (%)	Partners Share of Profit Oil (%)
FRP <=$20	80%	20%
$20 <FRP <=$40	100% - $(15+(5*(\frac{40-FRP}{20})))\%$	$(15+(5*(\frac{40-FRP}{20})))\%$
$40 <FRP <=$50	100% - $(12+(3*\frac{50-FRP}{10})))\%$	$(12+(3*\frac{50-FRP}{10})))\%$
FRP >$50	88%	12%

Appendix H provides an example of calculations based on cost oil and profit oil mechanism.

Other assumptions:

- Discount rate for calculations of discounted cash flow is assumed as 10% and the base year is 2005;
- Calculations of all three case scenarios were made in real terms, thus no inflation was applied;
- Calculations of contractors' revenue and cash flow are assuming 100% equity;
- No royalty or taxes were applied;
- All oil that has been produced is sold;
- Model is not taking into consideration leap years for calculations of oil yearly production;
- Costs for abandonment are not being considered in the "Case Scenario 1" and "Case Scenario 2" due to the absence of such information from operator. Abandonment costs are considered in the "Case Scenario 3".

APPENDIX J: Summary of Case Scenarios (input and output variables)

Input variables

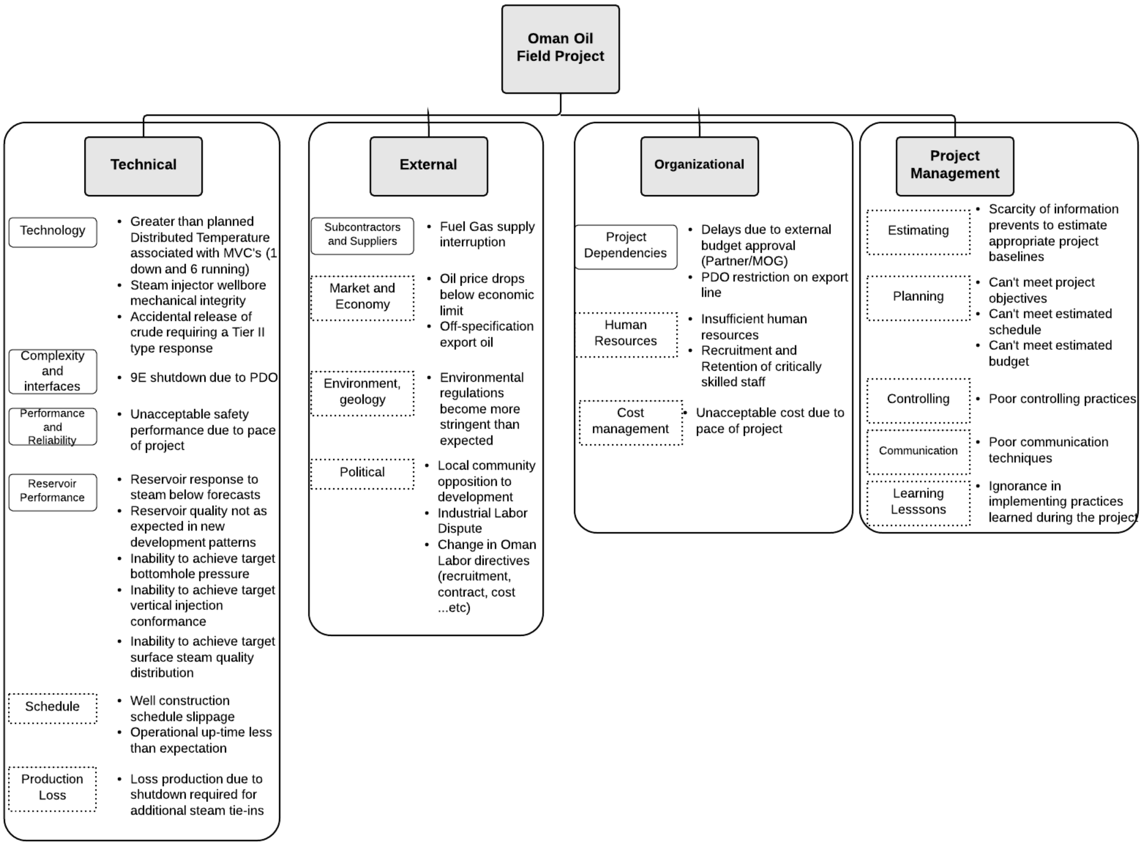
Case Scenario	Year of reaching the peak production (150 MBOPD)	Length of maintain the peak production	Cumulative Oil Production (2006-2035)	Total Expenditures
	MBOPD	**Years**	**MMBO**	**$M**
Case Scenario 1[12]	2012	10	922	10,735
Case Scenario 2	2013	6	889	16,713
Case Scenario 3	2014	2	850	18,242

Output variables

Case Scenario	NPV	IRR	Gross Revenue	Partners' Cash Flow
	$M	**%**	**$M**	**$M**
Case Scenario 1	2,282	44	69,600	7,050
Case Scenario 2	1,405	22	66,943	6,013
Case Scenario 3	1,164	20	63,790	5,451

[12] Target values according to the original project plan

APPENDIX K: Application of RBS tool to the Oman oil field project



APPENDIX L: Benchmarking of risk factors (oil and gas majors)

EXXONMOBIL	BP	SHELL	CHEVRON
COMMON RISKS			
Market price changes			
Changes in oil, gas and petrochemical prices and changes in margins on refined product	Fluctuating prices of crude oil and gas	Fluctuating prices of crude oil, natural gas, oil products and chemicals	Changing in commodity prices
Socio-political risk			
Security concerns such as civil unrest, acts of sabotage or terrorism, and other local security concerns.	Political developments and consequent changes to the operating environment, regulatory environment and law	Risk of litigation and disputes worldwide. Risk of Social Instability	Political instability
Health, safety and environment risks			
Safety, business controls, and environmental risk management.	Process safety, personal safety and environmental risks	Health, safety, security and environment risks.	-------------
Risk of Competition			
------------	BP's group strategy depends upon continuous innovation and efficiency in a highly competitive market.	Ability to achieve strategic objectives depends on how company reacts to competitive forces.	-------------
Risk of Climate Change			
-------------	Climate change and carbon pricing	Climate change concerns	-------------
Risk of Failure in Project Delivery			
-------------	Risk of failure to deliver major projects successfully	Delivery of large and complex projects	-------------
Risk in R&D			
Risk in success of research and development	-------------	Risk of failure in development and deployment of new technologies	-------------
Joint ventures and other contractual arrangements risk			

For projects in which we company not the operator, it depends on the management effectiveness of one or more partners whom it does not control.	BP may not have full operational control and may have exposure to counterparty credit risk and disruptions to our operations and strategic objectives due to the nature of some of its business relationships.	Joint ventures risk	--------------
Information Technology Risks			
--------------	Risk of breach in digital security	Shell relies heavily on information technology systems in its operations.	--------------
OTHER RISKS			
Risk of poor project management	Risk of failure in successful recruitment, development and utilization of staff	Risk of erosion of the business reputation	Risks of operations disruption by natural forces or human factors
Risk of failure in operational efficiency.	Risk of failure in ability to operate within established financial framework	Global macroeconomic environment as well as financial and commodity market conditions.	Risk of failure in success of developing resources
--------------	Risk in failure to accurately report the data	--------------	--------------
--------------	Risk in failure to meet product quality standards	--------------	--------------
--------------	Drilling and production – these activities require high levels of investment and are subject to natural hazards and other uncertainties.	-------------	--------------

APPENDIX M: Identified risk factors (2014)

In order to estimate a list of risk factors for the following year, we used several techniques such as analysis of project historical data, benchmarking of major international oil and gas companies - ExxonMobil, BP, Shell and Chevron (according to Forbes "The World's 25 Biggest Oil Companies"), and series of interviews with experts of "Partex Services Portugal".

We estimated that the major technical risks from Appendix D will remain the same and some additional risks may arise.

We would like to bring the operator attention to the variety of risk categories that are typical for the projects in oil and gas sector and can't be ignored or underestimated. Along with technical risks, we would recommend to take into consideration risks from other categories – external, organizational and project management – that in our opinion can complement the operator list risks in new field development plan of 2013 and to prepare the adequate response plan. We believe, that the potential impact of any of the risks, mentioned below, can affect project performance, shareholders' revenue, cash flows as well as the value of the project.

The recommended complementary risks for Oman project are:

- Market price changes;
- Health, safety and environment;
- Risk of failure in project delivery;
- Contractual arrangements risk;
- Risk of poor project management;
- Risk of failure in successful recruitment, development and utilization of staff;
- Risk of failure in ability to execute and operate within established financial framework;
- Risks of operation disruption by natural forces or human factors.

Market price changes

The financial performance of oil and gas project depends on a fluctuating price of oil in the market and can strongly affect profitability of company's operations. However, this risk can't be mitigate or be avoided as, according to BP, "Oil, gas and product prices and margins can be very volatile, and are subject to international supply and demand. Political developments (including conflict situations) and the outcome of meetings of OPEC can particularly affect world supply and oil prices".

The negative change in oil price can affect the validity of the project assumptions that were used for making strategic decisions and a result is no longer appropriate. The oil price, lower than expected, can have a direct impact on project's profit and Parties cash flow with a consequent effect on value of the project. "The global financial and economic situation may also have a negative impact on third parties. In particular, ongoing instability in or a collapse of the Eurozone could trigger a new wave of financial crises and push the world back into recession, leading to lower demand and lower oil and gas prices" (Annual report 2012, BP).

Also the negative impact on a financial performance of the project can be caused by variations in prices for chemicals and materials that supply project's operations.

Health, safety and environment risks

The nature of the project exposes it to the risks concerned with personal and process safety and health. The occurrence of these risks can lead to the increased costs as well as to damaging the reputation of the Parties involved. That's why we believe this risk should be included in Operator risk factors.

Risk of failure in project delivery;

Successful implementation of the project plan heavily depends on availability of qualified human resources and failure to deliver major project milestones can negatively affect Parties' financial performance. According to BP, "successful project delivery requires, among other things, adequate engineering and other capabilities and therefore successful recruitment and development of staff".

Contractual arrangements risk

The Oman project is conducting through contracting and sub-contracting agreements. This can explain the complexity of decision-making process and the fact that operator in execution of the work is relying on third parties. Contractors and sub-contractors are "primarily responsible for the adequacy of the human or technical competencies and capabilities which they bring to bear on the project and, in the event these are found to be lacking, Operator may not be able to meet his financial or other project targets, potentially threatening the viability of the project".

Risk of poor project management

The oil and gas projects require a high degree of project management involvement in order to maximize project's efficiency. The particular factors that can influence the successful performance of the projects are: correct estimation of project assumptions, budget and schedule, and effective management of project's costs.

Risk of failure in successful recruitment, development and utilization of staff;

We noticed that the problem of insufficient human resources Operator is facing each year, trying to mitigate this risk by hiring fresh graduates, training interns and bringing expatriates home. However, we can propose to Operator to review internal HR policies, compensation benefits and working conditions, as "inability to develop human capacity and capability, both across the organization and in specific operating locations, could jeopardize performance delivery" (Annual report 2012, BP).

Risk of failure in ability to operate within established financial framework;

The financial framework for Oman project is being established annually in a Work Program and Budget report. The inability to operate and execute the project in a pre-defined budget can increase the operating and capital costs as well as negatively impact the shareholders' revenue.

Risks of operation disruption by natural forces or human factors

Oman is located in he southwest Asia and has a very hot climate with a lack of rainfalls. The sand storms and hurricanes occurred several times during the Oman oil field project execution. Thus, this is exposing a project operations and facilities to a risk to be negatively affected by natural causes in future again. The human factors can include war, political instability, terrorist attacks or other factors that can harm the project implementation.

APPENDIX N: Qualitative analysis of identified risks (2014)

N	Risk	Impact on an objective	Consequences on an objective	Probability of occurrence	Risk - Natural Language Expression	Risk - Numeric score
1.	Inability to achieve target vertical injection conformance	High /.40	15-20% CAPEX increase	0.90	**High**	**0.36**
2.	9E (turbine) shutdown	Medium /.20	5-10% volume decrease	0.90	**High**	**0.18**
3.	Operational up-time less than expectation	High /.40	10-15% volume decrease	0.70	**High**	**0.28**
4.	Well construction schedule slippage	Medium /.20	5-10% time increase	0.30	**Low**	**0.06**
5.	Inability to achieve target bottomhole pressure	High /.40	>15% volume decrease	0.70	**Very High**	**0.56**
6.	Industrial labor dispute	High /.40	15-20% OPEX increase	0.30	**Medium**	**0.12**
7.	Change in Oman Labor directives (recruitment, contract costs, etc.)	High /.40	20-40% OPEX increase	0.50	**High**	**0.20**
8.	Risk of poor Steam Quality	Medium /.20	5-15% CAPEX increase	0.70	**Medium**	**0.14**
9.	Risk of poor Infill Drilling performance	Medium /.20	5-10% volume decrease	0.30	**Medium**	**0.06**
10.	Oil price changes	Very High /.80	>20% oil price decrease	0.50	**High**	**0.40**
11.	Health, safety and environment risks	High /.40	15-20% OPEX and CAPEX increase	0.30	**Medium**	**0.12**
12.	Contractual arrangements risk	High /.40	15-20% OPEX increase	0.30	**Medium**	**0.12**
13.1	Risk of poor project management (Production rate)	Very High /.80	>15% volume decrease	0.70	**Very High**	**0.56**
13.2.	Risk of poor project management (Cost)		>20% OPEX and CAPEX			

			increase			
14.	Risk of failure in successful recruitment, development and utilization of staff	Medium /.20	5-15% OPEX increase	0.70	**Medium**	**0.14**
15.	Risk of failure in ability to execute and operate within established financial framework	High /.40	>20% OPEX and CAPEX increase	0.90	**High**	**0.36**

APPENDIX O: Proposed KPIs and sub-KPIs

KPI	sub-KPI	Description	Unit	Weight
Health, Safety and Environment				
Personal safety performance	**Fatal Accident Rate (FAR)***	Number of company fatalities per 100,000,000 (100 million) hours worked	Rate	10%
	Recordable Injury Frequency (RIF)*	Recordable injury frequency measures the number of reported work-related incidents that result in a fatality or injury (apart from minor first aid cases) per 1,000,000 (1 million) working hours	Rate	
	Days away from work case frequency (DAFWCF)*	Days away from work case frequency measures the number of incidents per 1,000,000 (1 million) hours worked, that resulted in an injury where a person is unable to work for a day (shift) or more	Rate	
	Near miss incidents	Near miss incidents per million working hours	Rate	
Process safety performance	**Tier 1 Process Safety Event**	Losses of primary containment, from a process, of greatest consequence – causing harm to a member of the workforce or costly damage to equipment, or exceeding defined quantities (ex. oil spills; fire or explosion resulting in greater than or equal to $25,000 of direct cost to the Company).	Numerical value	10%
	Tier 2 Process Safety Event	Losses of primary containment, from a process, of lesser consequence (ex. oil spills; a fire or explosion resulting in greater than or equal to $2,500 of direct cost to the Company).	Numerical value	
	Tier 3 Process Safety Event	Losses of primary containment above Tier 2 Thresholds	Numerical value	
	Tier 3 Process Safety Event	Number of deferred start-ups and unplanned shutdowns	Numerical value	
	Greenhouse Gas Emissions (GHG)	Million tones of CO2 equivalent for hydrocarbons produced	Million tones of CO2	
Transportation safety performance	**Total Vehicle Accident Rate (TVAR)**	Total number of all motor vehicle accidents per one million kilometers driven.	Rate	10%

Operational Performance				
Hydrocarbons Production	**Oil Production Rate**	Crude oil produced per year	MBOPD	
	Oil Production Capacity	Available capacity to produce crude oil	MBOPD	10%
Steam Performance	**Steam Capacity**	Year-end installed steam generation capacity	MBSPD	
	Steam Injection Rate	Average annual rate	MBSPD	10%
Drilling Performance	**New Wells**	Wells drilled vs. target	Numerical value	
	Patterns Development	Actual number of steam injectors and producers vs. target	Numerical value	
	Well cost	Current well cost vs. cost of the prior year	Rate	7.5%
Operating Costs	**OPEX**	Actual vs. Budget	$ Million	
	Unit operating cost	Operating cost per barrel (target OPEX per year/target oil production per year)	$/bbl	10%
Capital Employed	**CAPEX**	Actual vs. Budget	$ Million	7.5%
Project Performance				
Strategic Performance	**Project Delivery**	Capability to complete the project on time and within budget on the basis of targets set in the annual Work Program and Budget.	%	10%
	Milestones missed	% of corporate milestones that didn't met the target set in the annual Work Program and Budget	%	10%
Financial performance	**Operating Cash Flow**	Net cash flow provided by operating activities	$ Million	10%
Human Resources				
HR availability and People Development	**Employee Turnover rate**	% of fired employees /total number of employees	%	
	Recruitment rate	% of Recruited vs Planned	%	10%
	Omanization	% of Oman national recruits	%	
	Employee Training rate	Hours of Training per Employee	Rate	