۸۶۹۶۴

«بنام خدا»

نقش مدیران صنعت نفت در مهندسی ارزش

نویسنده مقاله: افسانه نصرت‌پناه
استاد راهنما: Dr. G.D.Londhe

خلاصه مقاله

برای بیرون کشیدن خود از یک کار مشکل، باید خود را از روش ثابت تفکر کنونی خارج سازیم تا بتوانیم خلاقیت‌ها را به وجود آوریم. خلاقیت عبارت است از ترکیب تجربه و دانش و خلق کردن یک روش جدید. برای به وجود آوردن خط مشی‌های رشد و توسعهٔ هوشیارانه، ضروری است مجموعهٔ گسترده‌یی از اطلاعات گردآوری شود. برای این هدف جمع‌آوری و ذخیره‌سازی تجربه و دانش براساس یک برنامه‌ریزی و سازماندهی اصولی و ایجاد یک شبکهٔ مطلوب الزامی می‌باشد. «مهندسی ارزش» روش رشد و توسعه‌یی ست براساس ارتباط بین عملیات و هزینه و تمایل به افزایش ارزش، این روش به تجزیه و تحلیل ارزش معروف گردیده است.

هدف این مقاله بعد از مقدمه، ابتدا تعریفی از مدیریت پروژه، مهندسی ارزش و نقش مدیریت در مهندسی ارزش و در قسمت دوم کاربرد مهندسی ارزش در صنعت نفت ایران و قسمت آخر نتیجه‌گیری و پیشنهاد برای مدیریت شرکت نفت در جهت پیشرفت این صنعت است.

significant and thereby acceptable at all levels within the organisation.

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4- CONCLUSION

The management of a company , a division, a department , a section , or a group must assume a prime responsibility for the VE program if the program is to have a chance of achieving success. Management from the very top to the very bottom level must:

1) Give initial and continuing impetus to a VE program,

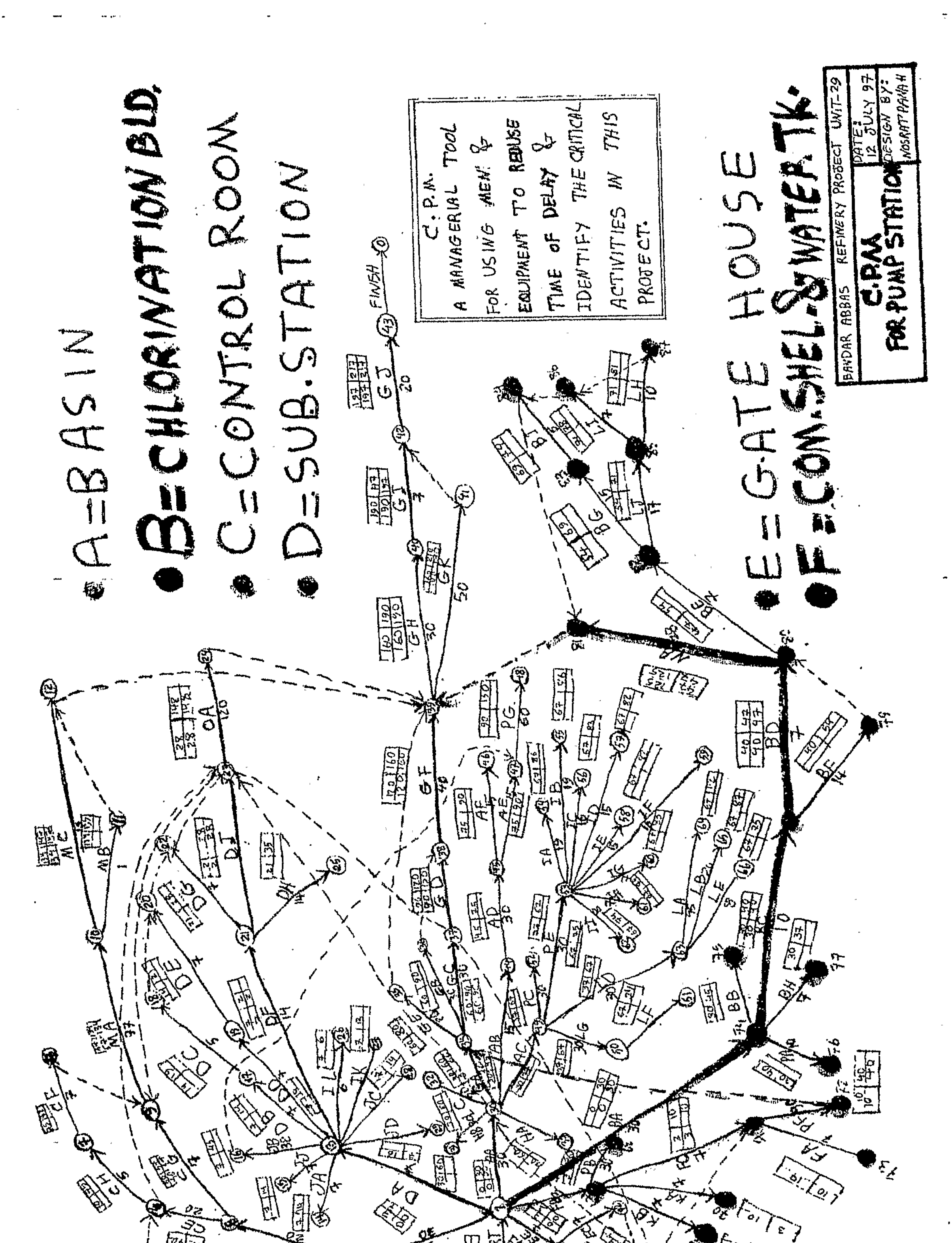
2) Establish overall value engineering goals,

3) Create an appropriate VE organization,

4) supply the necessary budget authorization to feed the effort,

5) provide a continuing audit system, and

6) provide for adequate merit recognition of individual and group performance execellence (2). This management participation is a primary prerequisite to achieving a total VE team effort and hence achieve reduced costs, increased profits, and enterprise growth. In Iranian oil company although VE is considered in all projects, but still there is not any recognized VE group in different section of oil company. This is a responsibility for top level management to recognize the capability of the personnel and form a VE group in organisation only then can value engineering remain


A=BASIN
B=CHLORINATION BLD.
C=CONTROL ROOM
D=SUB.STATION
E=GATE HOUSE
F=COM.SHEL.& WATER TK.
C.P.M.
A MANAGERIAL TOOL FOR USING MEN & EQUIPMENT TO REDUSE TIME OF DELAY & IDENTIFY THE CRITICAL ACTIVITIES IN THIS PROJECT.
FINISH
BANDAR ABBAS REFINERY PROJECT UNIT-29
DATE: 12 JULY 97
DESIGN BY: NOSRATPANAH
C.P.M. FOR PUMP STATION

these management incharges were able to meet the dead line. and by this value engineering decision, the project completed in a short time. there is a C.P.M. which worked out in same duration and net work are presented in the next page.

conduct the coating.

3-8- For early starting of refinery.there was need for sea water and **to reduce the time,** a temprory pump station was constructed and in this way early start up of refinery was without delay.

3-9- To decrease cost of materials used in this projects, for the first time, a large amount of materials was made in Iranian industries with standard qualifications. For example a lots of flanges and stop logs which it was decided to be purchased from abroad, all were made in Iran and also so many pressure vesseles were made in Iran.

3-10- To give speed for see water intake project, it was decieded to change of N.I.O.C middle managers incharge, in the sensitive time of start up of refinery, NIOC, needed more speed for activities and according C.P.M. (Critical Path Methode) which was determined, the maximum time for completing sea water intake was seven months and with same managers it was impossible to meet the dead-line , so NIOC high level managers changed the middle level managers, and in this way time consuming also decreased.

3-4- For 3nos. 56" C.S. pipe lines and 4 nos. 48" C.S. pipe lines **to decrease the cost** of internal cement lining, with two diffrent systems, contractors conducted the job with the equipment at site and could save the cost of transportation and probable damage of cement lining.

3-5- To save the time in outlet channel which in design was made with R.C.C. elements, through a earthen dam a considerable distance was dry and cost in situ was done and speed of work was excelent to save the time.

3-6- To decrease of cost , in basin of pump station, which considered that three R.C.C. diaphragm wall and one plastic diaphragm wall and anchorage system should be constructed by foreign contractor converted to Iranian contractor and in this way beside decrease of cost, know-how transfered from Germany to Iran.

3-7- To decrease the cost of poly urtain tar coating , for 80" pipes it was a system with a trained contractor in site to

3-2- To decrease the time and cost of "offshore sea lines" design of pulling system changed and each three 12M branch of pipes welded together and dipped in the respective position and flanges in each end bolted together. Value engineerring two time for offshore sea lines was considered. First for material, according so many meetings in NIOC and visit of polyethylen pipe factory in Ahwas and site of Nuculiar energy in Bushehr, lastly consultant of NIOC reject the polyethylen pipes for this purpose and main reason was weight of pipe which was not enuogh instead of wave current. Secondly carbon steel pipes were chosen, and with pulling system, NIOC needed long time to conduct these activities so after meetings with contractor and counsultant, the first design changed and instead of pulling the pipe at sea bed, all the pipes submerged from top of respective position to sea bed. In this way cost of pulling system decreased and time consuming was less than previous design.

3-3- To decrease the cost of 3×80′ pipe for "offshore pipe lines", instead of purchasing coil of these pipes from abroad, after a search in Iran , the water supply company of Tabriz, handover these coil to the factory for making spiral pipe and reduces costs, increases profits; and brings about continuous growth of the enterprise (2).

3- APPLICATION IN N.I.O.C (National Iranian Oil Company)

In the construction of sea water intake project of Bandar Abbas refinery in south of Iran successful application of value engineering listed as follows:

3-1- To Decrease cost of project, The design of sea water intake has been changed from "Bona Pipe" to 3×80″ carbon steel pipe with polyurtain coating and 3×56″ carbon steel pipe with internal cement lining plus external poly ethylen coating for intake system and R.C.C. twin channel for discharge of water. For sea water intake system, Bona pipe was designed and contractor was choosen according tender, but for finance, the worse condition arised, and no bank in abroad helped the NIOC, so the high level management asked consultant to change the design pattern. In this way considerable saving was the result of change in design and on the other hand Iranian contractors had opportunity to show their capability of performing the job instead of foreign contractors.

increased profits which the value engineering program is to achieve.

3- Authorize and establish adequate staffing with competent value engineering personnel and an adequate training program and adequate facilities.

4- Develop effective program planning for the coming year through cooperation between the value engineering staff organization and the operating department management and / or division management of the company.

5- Provide and budget for adequate financing to support the value engineering activity plant.

6- Continuously audit the progress and status of the VE activity relative to the yearly plan.

7- Provide a merit recognition system where by outstanding value engineering performance can be formally recognized by the management team. Such a system provides adequate incentive to all decision-making people in the enterprise. Most employees want to please their superiors, but to do this they must first have a clear understanding of what their supervisor wants. Individuals in management must sincerely demonstrate by active participation in the VE effort that they want a strong VE program which produces results; i.e., it done by people who trust each other".

As an adjunct to professional leadership, value engineering can contribute greatly to progressive management. Unfortunately there are many weak value engineering programs in industry just as there are weak managements at the head of some large and apparently successful firms. It must be repeated that value engineering can not be practiced where there are restrictions to freedom to change. For the aggressive firm that intends to grow in the face of accelerationg competition, value engineering offters an avenue to profit that richly merits exploring.

2-3- The Role of Management in Value Engineering

There are a number of actions by management which effectively demonstrate its interest in and support for a vlalue engineering program. Some of the proposed primary management actions are:

1- Tie the upper management level into the value engineering program development through the establishment of a VE management advisory committee.

2- Establish (and make known) company objectives and overall goals in reduced costs, increased. Savings, and for this process (1).

2-2- Value Engineering

Value engineering is an organized effort to attain optimum value in a product , system, or service , by providing the necessary functions at the lowest cost.

The aggressive manager finds that the initiation of a value engineering program offers an unequalled opportunity to develop a spirit of progressive teamwork. The manager's best resources are the people who work for him. If he is successful in extracting the best effort from his people and can direct their energies into the most fruitful tasks , he will be a successful manager. People tend to build a protective insulation around themselves and their departments. In some cases they feel their specialized bit of knowledge is their security. In other cases, they have the ostrich attitude that what they do not know, or will not allow others to know, will protect them from change. Still others have a false pride which keeps them from asking. This is a real problem in business life and means real money to the management who can break down these attitudes. There is great truth to the anonymous quotation, "all the real work of an organization is problems to be seen in perspective, and needs to be assessed ahead of time. To some extent this understanding of project development is intuitive , though it clearly also depends upon specialist knowledge of the project's technology and industry. It can, however, also be acquired in large part from formal study of the development process of projects, since all projects, regardless of size or type, follow a broadly similar pattern of development. Project management is the application of the systems approach to the management of technologically complex tasks or projects whose objectives are explicitly stated in terms of time, cost , and performance parameters. All of these subsystems must be managed in an integrative manner for the effective and efficient accomplishment of organizationaly system objectives. Project management provides an interfunctional structure for a specific project and has a basic management orientation. It involves a project manager who, through funding control, obtains the required resources from the various functional departments. By the management functions of planning, organizing, directing, and controlling, the project manager coordinates the application of these resources to a given project with specific objectives, providing the primary focus a - Decreas of cost, result, increase of value.

$$\overset{\uparrow}{V}\ (\text{value}) = \frac{\vec{F}\ (\text{Functions})}{C\!\downarrow (\text{Cost})}$$

b- Increase of functions and decreas of cost, Result, increase of value.

$$\overset{\uparrow}{V} = \frac{F\!\uparrow}{C\!\downarrow}$$

c- Increas of functions, result, increase of value

$$\overset{\uparrow}{V} = \frac{F\!\uparrow}{C\!\rightarrow}$$

(3)

2- METHODOLOGY

2-1- PROJECT MANAGEMENT

Project management (PM) has evolved as a device to over- come, through "purposeful conflict", A "Cultural Lag" in the art of managing the development, Acquisition, and introduction into effective use of technically complex systems.

One of the most important qualities of a project manager is an understanding of the way projects develop. This allows the nature of project activities to be better understood, management in value engineering, secondly application of value engineering in National Iranian Oil Company (N.I.O.C) and the last part is conclusion and sugestion for oil company management to improve this industry.

Key Words:

Management, Value Engineering, Optimum Value, Lowest cost, Time Saving, National Iranian Oil Company (N.I.O.C)

1. INTRODUCTION

To scape from a difficult task, we should change our way of thinking, then creation appears. Creation is combination of knowledge and experience to reach a new methodology. To creat strategy for inteligent grow, it is necessary to collect various information, to reach this aim, it needs, Gathering and stroing of experience and knowledg according a correct organziation and suitable net work (3).

Value Engineering brings together all the specialized knowledge and skills within an organization , and makes them available at the design stage of a product or service(2).

In suitable condition of VE, chang in cost (C) and functions (F) can be formulated as shown below:

"In The Name of God"

THE ROLE OF OIL COMPANY MANAGEMENT IN VALUE ENGINEERING

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ABSTRACT

... Value engineering brings together all the specialized knowledge and skills within an organization...

Value engineering is an organized effort to attain optimum value in a product, system, or service , by providing the necessary functions at the lowest cost (2).

The aim of this paper after introduction, first is methodology which includes a descriptions of project management and value engineering and the role of

A PAPER

ON

THE ROLE OF OIL COMPANY MANAGEMENT IN VALUE ENGINEERING

BY

AFSANEH NOSRATPANAH

B.E. (CIVIL), M.B.A

IN

THE FIRST SEMINAR OF VALUE ENGINEERING

IN OIL COMPANY

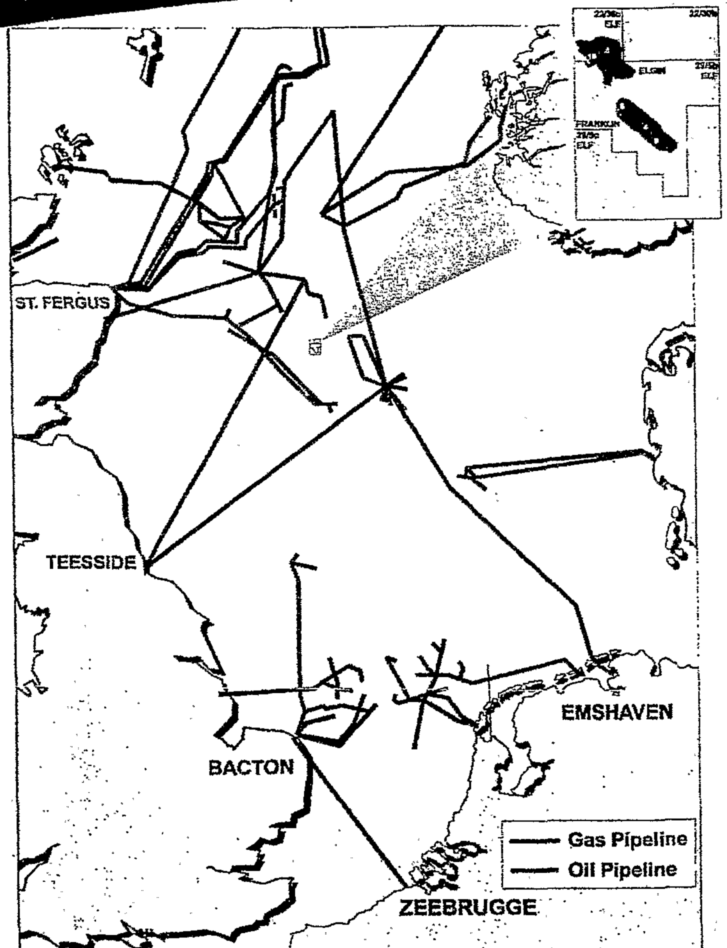
TEHRAN-6th MAY 2001

Major Decisions

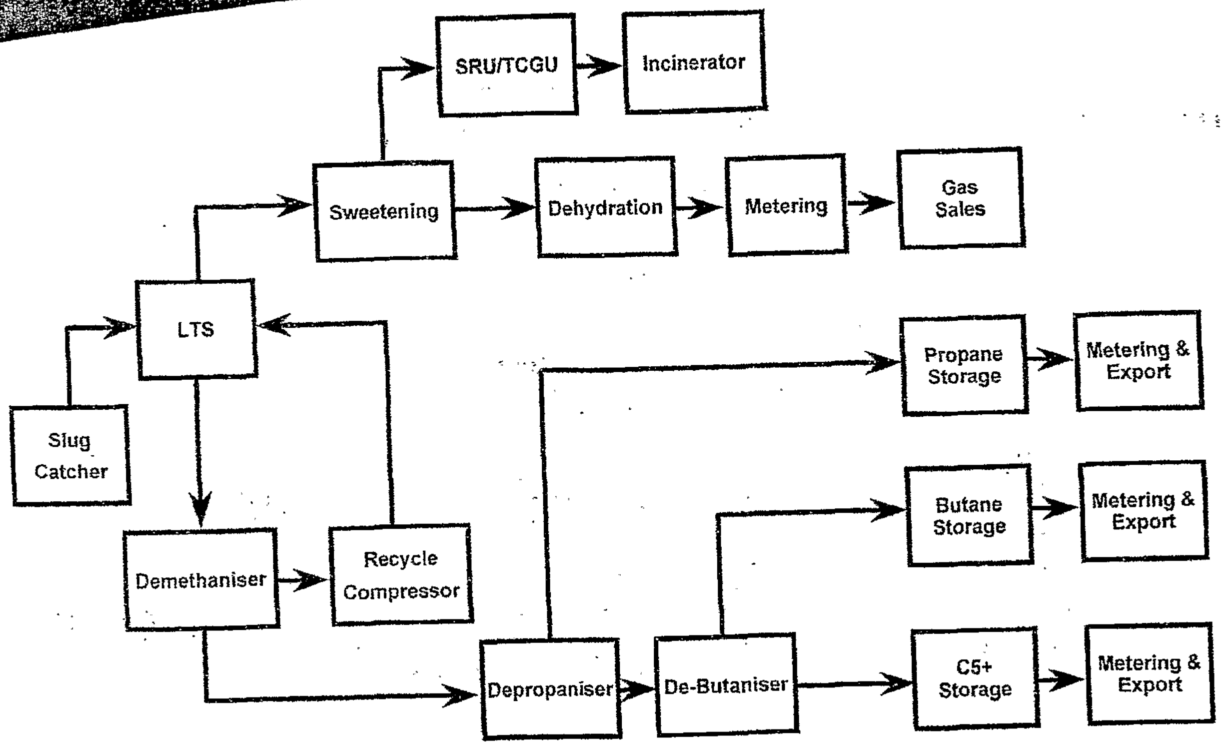
- Reservoir Recovery Mechanism
- How to integrate the two fields
- Configuration / location of central processing facility
  - Production Rates
  - Processing split, onshore vs offshore
  - new facilities vs use of existing infrastructure

- **Split of functions between central complex and satellites**

Existing North Sea Infrastructure



Basic Onshore Process (For Dense Phase Gas)

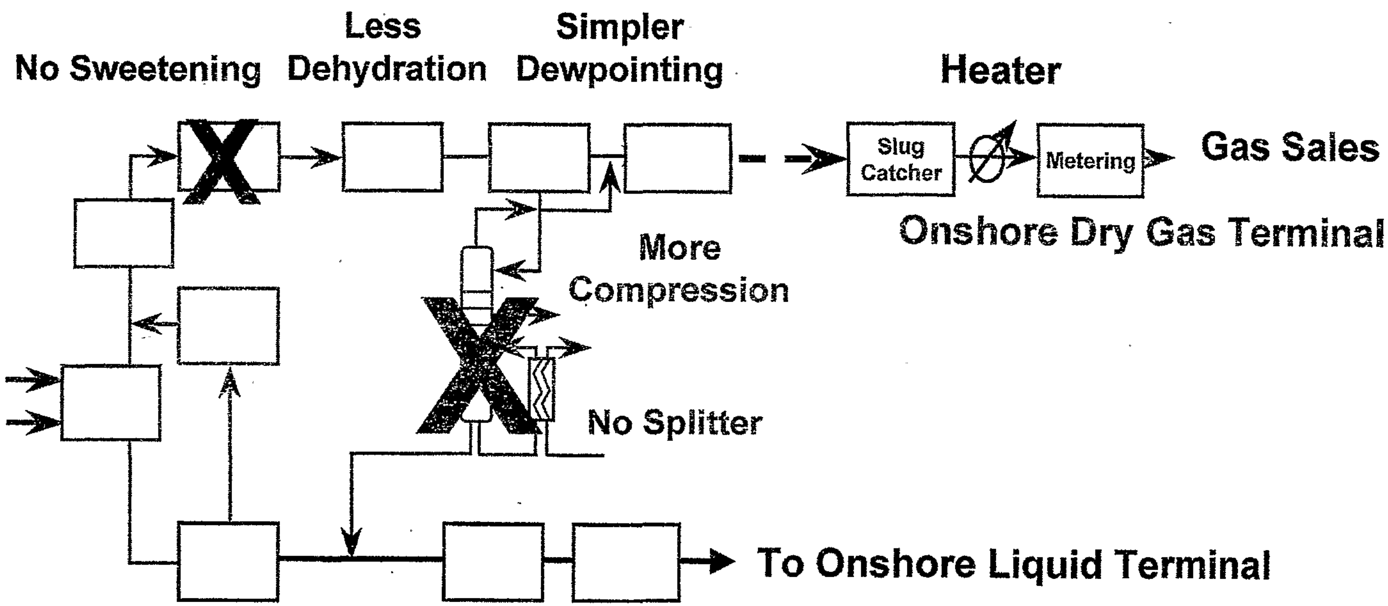


Typical Onshore Gas Plant

TOTALFINAELF

Joel Fort - Selection of the Process Scheme for an HP/HT Development - 15/04/01

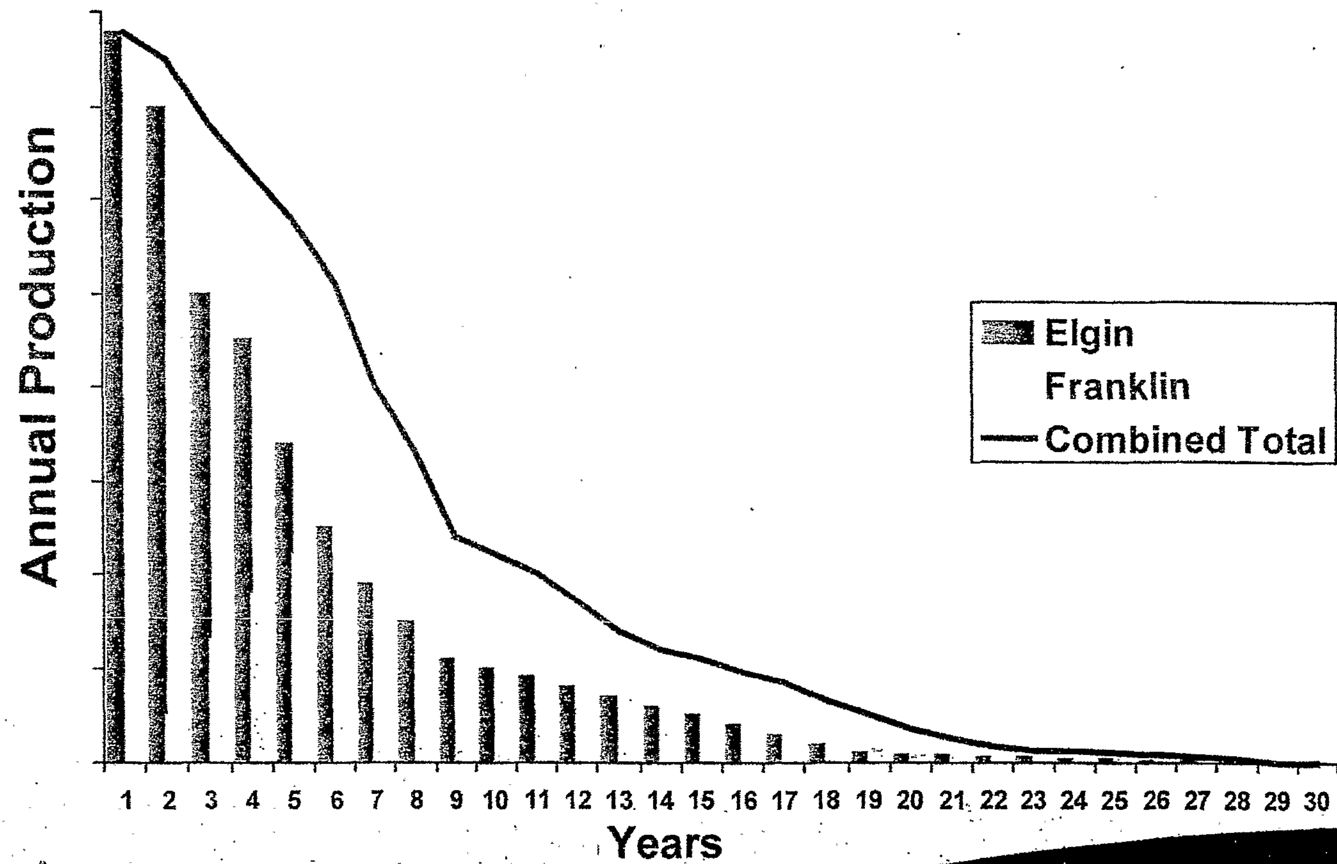
Basic Process : Dense Gas vs Commercial



Major Decisions

- Reservoir Recovery Mechanism
- How to integrate the two fields
- Configuration of central processing facility
  - Design Rates
  - Processing split, onshore vs offshore
  - new facilities vs use of existing infrastructure

Liquid Production Profile



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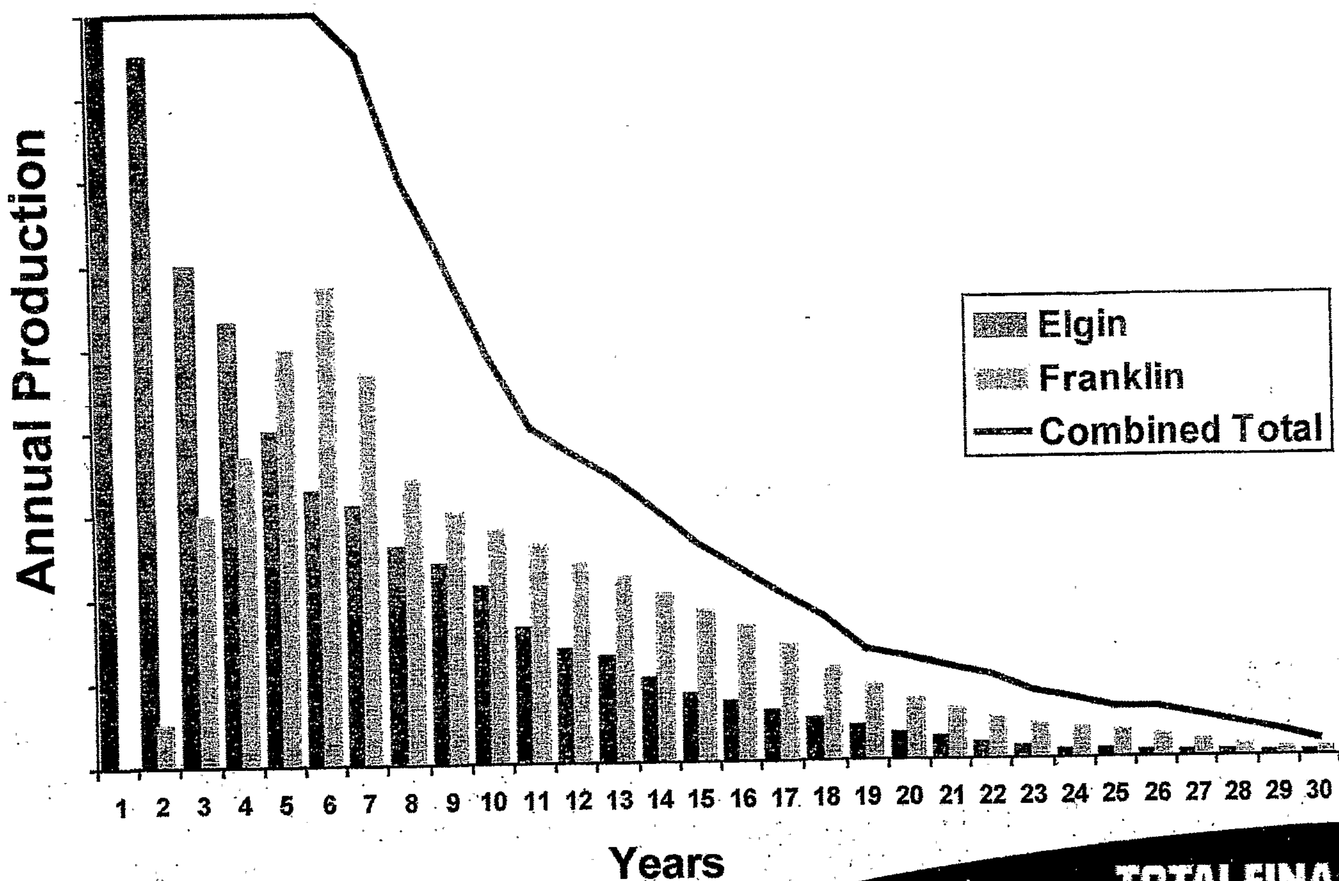
Gas Production Profile



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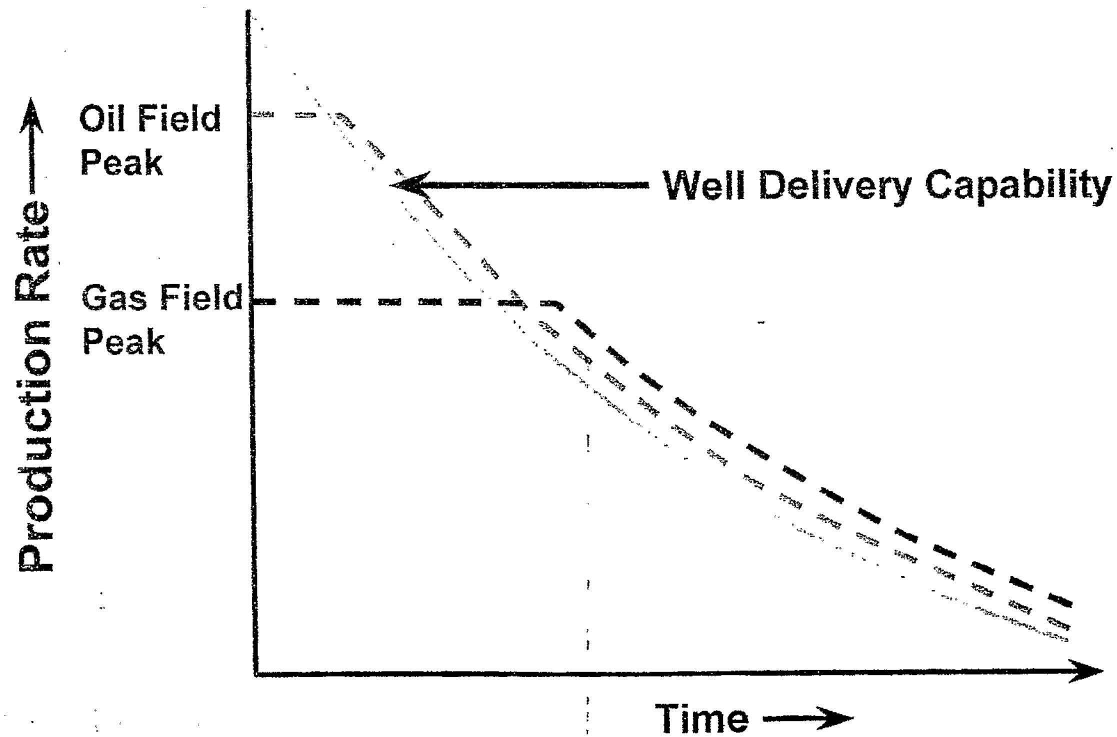
Production Rate Objectives



Major Decisions

- Reservoir Recovery Mechanism
- How to integrate the two fields

Decision Making Methodology

Applying a Six Step Process in the Spirit of the Value Engineering Methodology

- Information Gathering
- Creation of Alternatives
- Analysis of Alternatives
- Development of Alternatives
- Presentation of those Alternatives to the Elgin/Franklin Partnership
- Decision and Implementation

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Decision Making Approach

- Taking into account all aspects :
  - Technical Constraints/Opportunities
  - Economics
  - Strategic Interests/Market Conditions
- From Reservoir to Market Delivery Points
  - Offshore/Onshore Processing
  - Transportation
- Screening / Analysing All Alternatives
  - Conventional
  - Non-Conventional
- Without Pre-Conceived Ideas

Objectives

- Maximise economic value of the Asset
- Satisfy stringent safety criteria considering HP/HT exposures
- Minimise environmental impacts consistent with Best Practicable Environmental Option (BPEO)

These objectives are seen as complementary and when satisfied result in maximum total value from the Asset

How and why did Elf and its Partners reach this concept ?

Where did the (HP/HT) Energy Go ?

Pressure

- Used to deliver high production rates from each well (minimises wells)

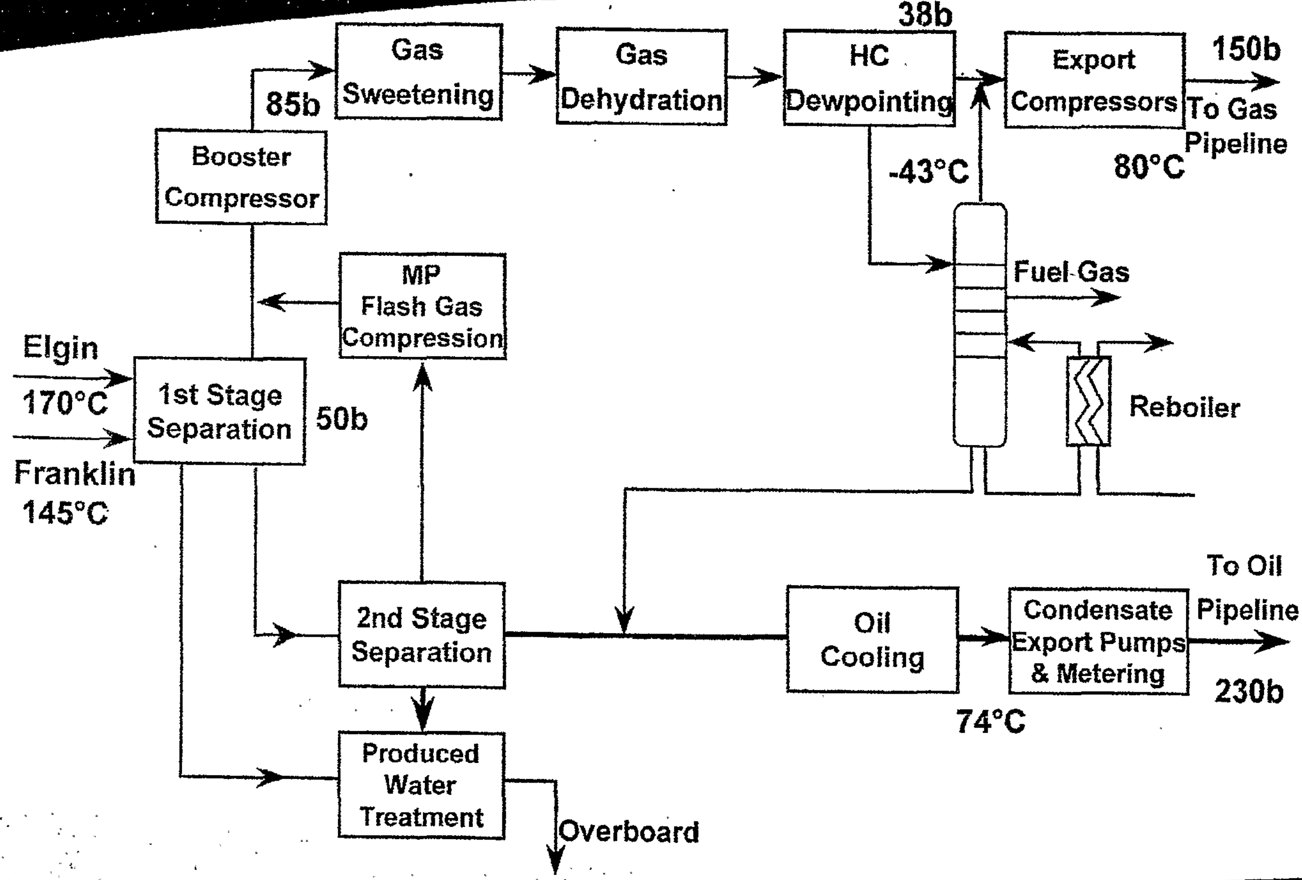
Temperature

- Allows hydrate-free and wax-free flow to the PUQ (with demanding insulation requirements)
- Improves Oil / Gas / Water separation
- Substantial dissipation of heat required for gas processing
- Some heat input may be required later in field life

Some Statistics

- Total Installed Compression 130 MW
- Total Installed Power Generation 50 MW
- Total Installed Heat Exchange 250 MW
- OperatingTopsides Weight 33,000 tonnes

Basic PUQ Process



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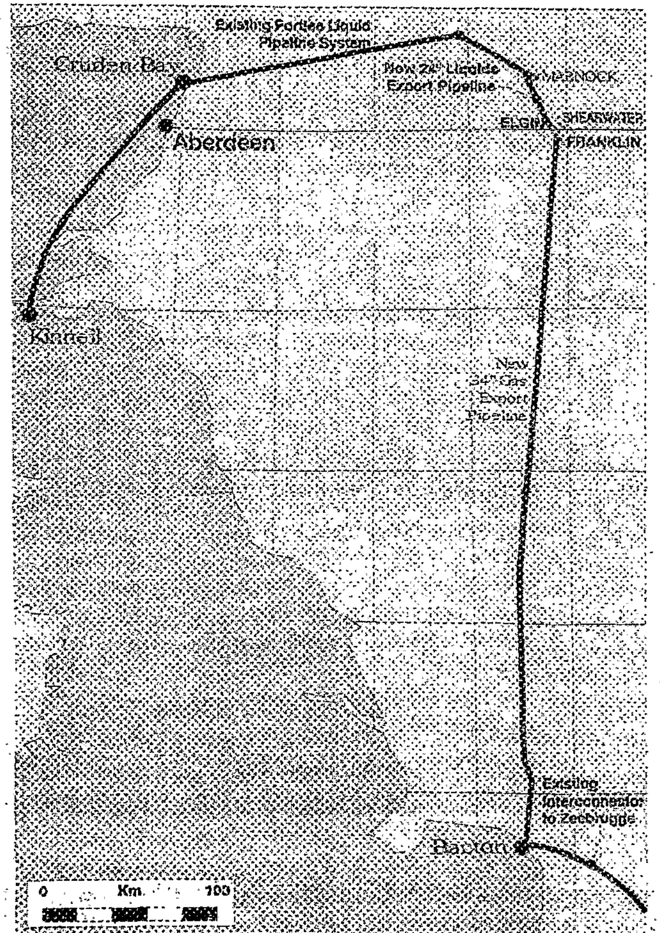
Export Pipeline Routes



Joël Fort - Selection of the Process Scheme for an HP/HT Development 15/04/01

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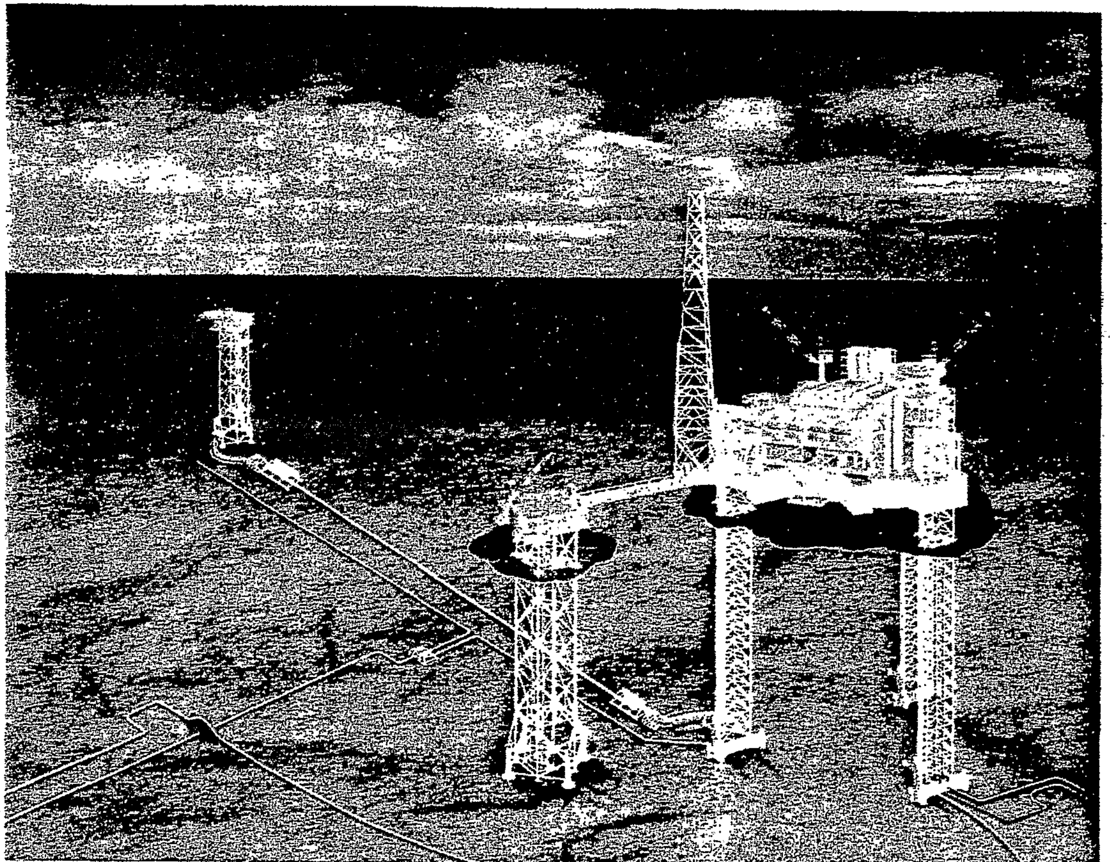
Elgin/Franklin Offshore Field Architecture



Selected Sales Gas Specifications

Max H_2S	ppmV	<3.3
Max CO_2	Mol%	<2
Max Hydrocarbon Dew Point	Below °C at pressure	-2°C @ <75 barg
Gross Calorific Value	MJ/Sm^3	38 to 42.3
Wobbe Index	MJ/Sm^3	48.3 to 51.2

Reservoir Fluid Composition Molar %

COMPONENT	Elgin Field	Franklin Field
N2	0.5	0.3
CO2	**2.5**	**3.7**
C1	66	74
C2	8	8
C3	5	3
IC4/NC4	3	2
IC5/NC5	2	1
C6+	13	8

Each field also contains about 40ppm H_2S

Introducing the Elgin/Franklin Fields and the Development

- Located in Central Graben of UK North Sea
- Deep HP / HT Fields : 5500m, 1100 Bar, 200°C
- Largest HP/HT Development in the World (775MMBOE)
- Reservoir fluids yield high LGR (circa. 10 BBL/MCM)
- Large Investment : £1.65Billion (inclusive of Export Systems Share)
- Started 31/03/01
- Expect Plateau above 220,000 BBL/day for 5 years
- Production Life 22 Years

Selection of the Process Scheme for the Elgin/Franklin Fields

- Introduction to the Fields
- Describe the PUQ (Process/Utilities/Quarters) Process . . . in the context of the field facilities
- Explain the rationale for the development concept

> How and why did we arrive at this field development architecture ?

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THE FIRST CONFERENCE ON VALUE ENGINEERING IN PETROLEUM INDUSTRIES

07 May 2001

Selection of the Process Scheme for an HP/HT Development using Value Engineering

The Elgin / Franklin Fields in the UK North Sea

J. Fort and G. Menou

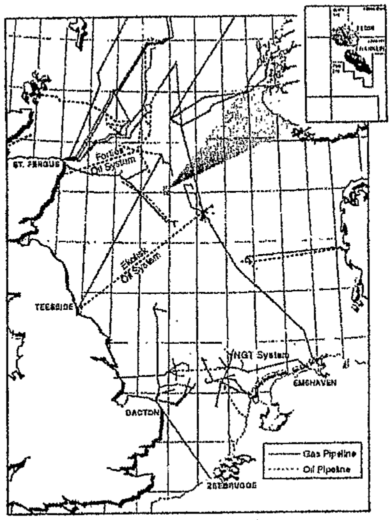

Fig.9 - North Sea Pipeline Infrastructure

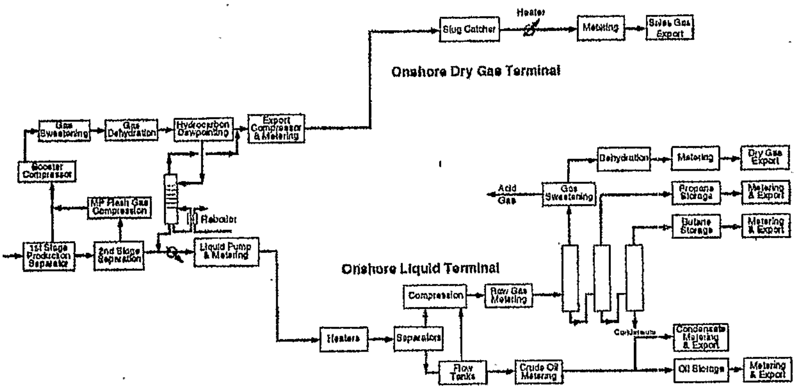

Fig.10 - Offshore Gas Processing to Commercial Specification

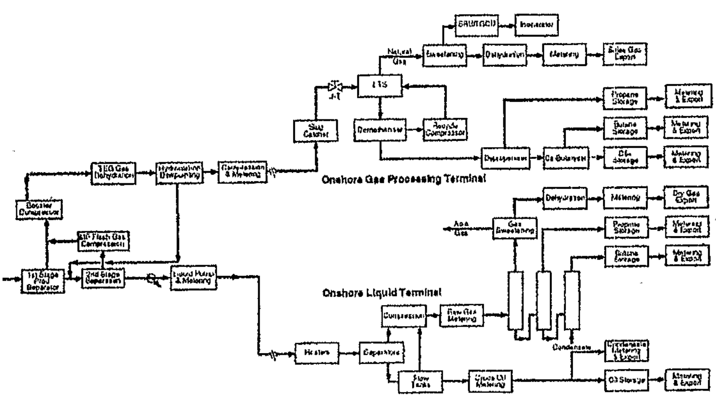

Fig.11 - Offshore.Gas Processing to Dense Gas Specification

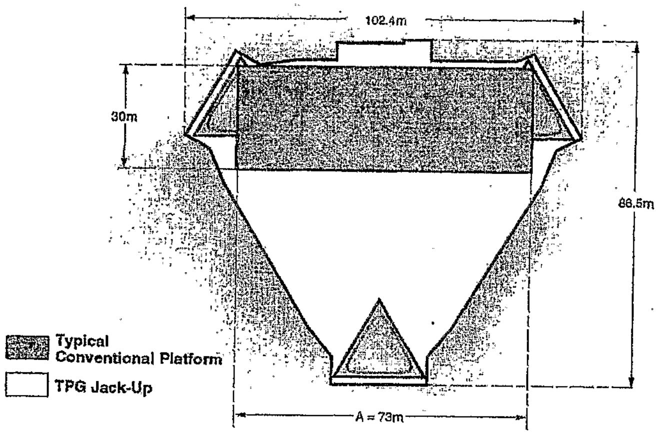

Fig.6 - TPG Jack-up vs Conventional PUQ

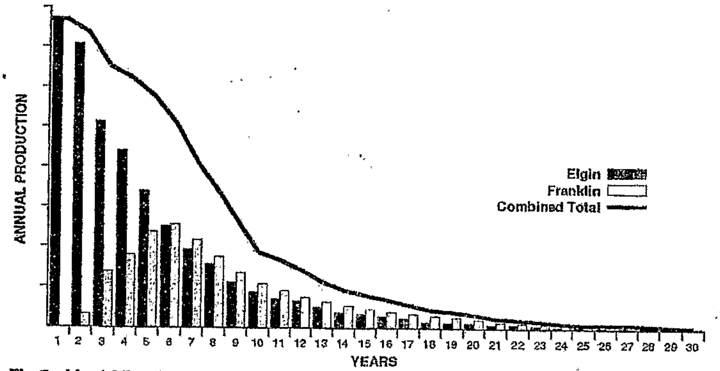

Fig.7 - Liquid Production Profile

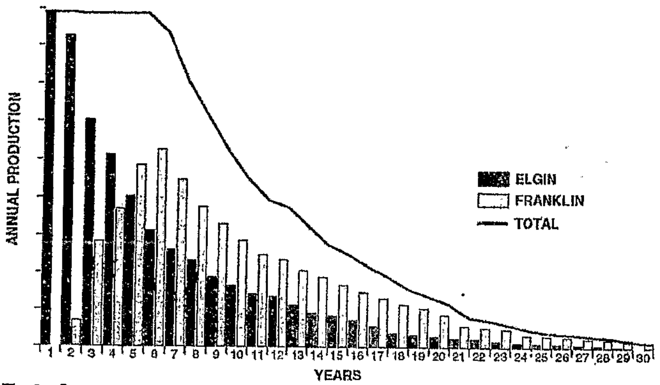

Fig.8 - Gas Production Profile

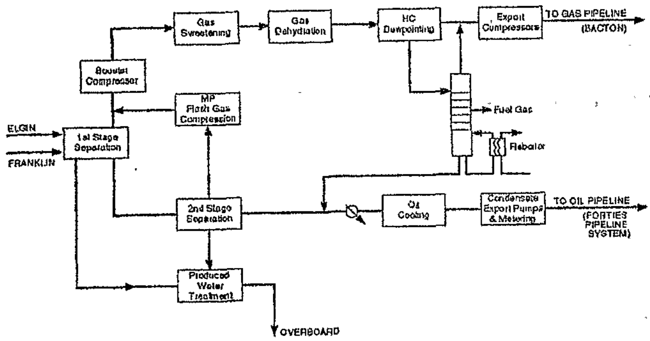

Fig.3 - Basic PUQ Process

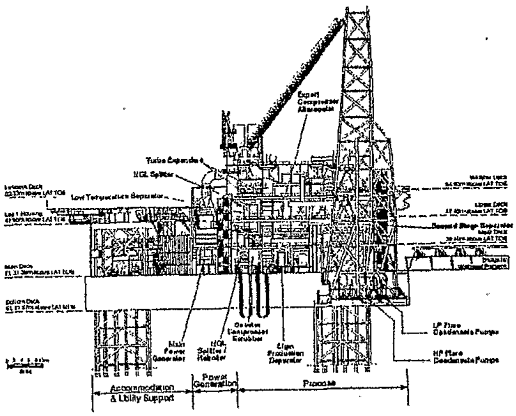

Fig.4 - Elgin PUQ Topsides - South Elevation

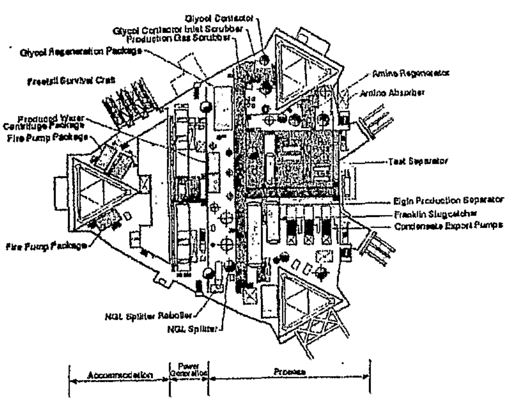

Fig.5 - Elgin PUQ Equipment - Main Deck

TABLE 1
RESERVOIR FLUID COMPOSITION, MOLAR %

Component	Elgin Panels			Franklin Field
	W & C	E	Lower A	
N2	0.50	0.49	0.73	0.26
CO2	2.72	2.39	4.70	3.60
C1	68.09	64.50	77.46	74.12
C2	7.83	8.84	7.55	7.94
C3	3.94	4.73	2.79	3.29
IC5	0.90	0.98	0.82	0.68
NC4	1.72	2.03	1.01	1.24
IC5	1.04	1.03	0.66	0.55
NC5	0.94	1.07	0.38	0.61
C6	1.98	2.26	0.61	0.87
C7	2.14	2.38	0.62	1.15
C8	1.67	2.00	0.50	1.07
C9	1.20	1.24	0.34	0.95
C10	0.98	1.00	0.30	0.67
C11	2.59	2.80	0.99	1.65
C12	1.50	2.04	0.47	1.13
C13	0.28	0.20	0.07	0.22

TABLE 2
SALES GAS SPECIFICATION

PARAMETER	UNITS	LIMIT
Max gas delivery pressure	barg	69
Min gas delivery pressure	barg	45
Max gas temperature at delivery	°C	20
Min gas temperature at delivery	°C	2
Water dew point	Below °C at pressure	-10°C @ <75 barg
Max hydrocarbon dew point	Below °C at pressure	-2°C @ <75 barg
Max hydrogen sulphide (H_2S)	ppmV	<3.3
Max total sulphur content	ppmV	<15
Max carbon dioxide CO_2	Mol%	<2
Maximum oxygen	ppmV	<10
Maximum CH_3OH	ppmV	<3.7
Gross calorific value	MJ/Sm^3	38 to 42.3
Wobbe Index	MJ/Sm^3	48.3 to 51.2

TABLE 3
SYSTEM UNAVAILABILITY/AVAILABILITY

	COMMERCIAL	DENSE PHASE
Offshore installations	1.42%	1.01%
Gas Export Line	0.23%	0.23%
Liquid Export Line	0.34%	0.34%
Gas Terminal	0.08%	0.44%
Total Unavailability	2.07%	2.00%
OVERALL AVAILABILITY	97.93%	98.00%

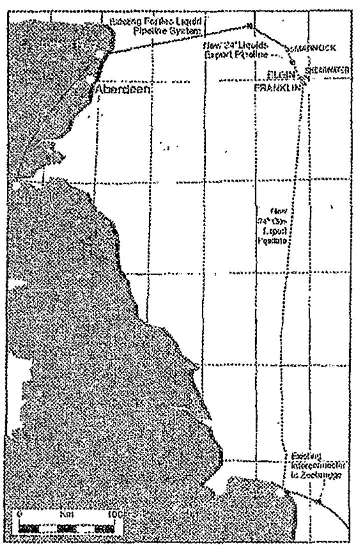

Fig.1 - Export Pipelines Routes

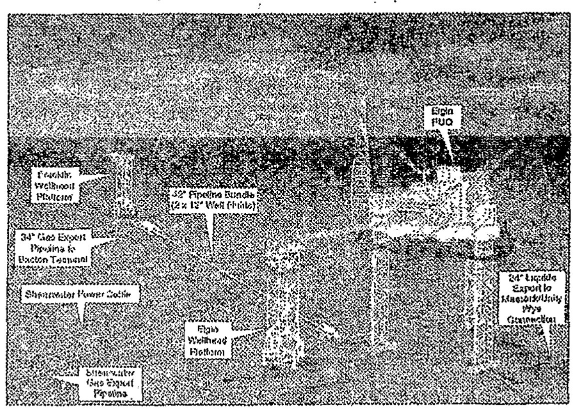

Fig. 2 - Offshore Field Architecture

process confirmed the technical studies that indicated the most efficient and cost effective solution would be derived from full offshore processing to a commercial gas specification.

The concentration of substantial gas processing offshore gave rise initially to some concerns regarding plant availability. However, with a suitable sparing philosophy, detailed studies indicated comparable overall system availability between the commercial gas alternative and the dense phase alternative. As summarised in *Table 3*, total availability of about 98% is expected.

Safety studies and risk analyses significantly influenced the offshore field architecture. The separation of drilling and of the HP/HT wells from the processing and accommodation facilities results in significant risk reduction. The location of the wells on a separate platform also allows the drilling programme to be initiated earlier. Early drilling allows high production rates to be achieved as soon as the process facilities are completed and avoids significant exposure to risks associated with simultaneous drilling and production operations. It also alleviates drilling difficulties associated with drilling into pressure depleted zones with the high mud weight necessary to contain fluids at high pore pressures.

Conclusions

The integrated development of the Elgin and Franklin fields results in reduced infrastructure costs, increased operational flexibility and optimised gas and liquid offtake rates. Additional cost savings have been achieved through integration of the export systems with a nearby development. Processing alternatives have been optimised by concentrating processing functions on a large common offshore processing facility. Costs of this facility have been minimised through the use of a new build jack-up production platform. Gas transportation system costs were minimised and gas marketing flexibility maximised by routing the gas pipeline directly to the Bacton area where either the NTS or Interconnector system can be accessed. Separation of drilling centres from the main offshore process facilities increases safety and allows well construction to be initiated early with all wells being available at the beginning of production to both maximise liquid offtake rates, maintain gas plateau rates and minimise, if not eliminate, risks associated with simultaneous drilling and production activities.

The overall approach has resulted in a development scenario which is unconventional (commercial gas processing offshore and pooling of the gas and liquids export systems with another development) which has been assessed at bringing 15% additional value in terms of NPV 9%. The contribution of the Value Engineering methodology represents a significant part of this amount.

Nomenclature

$MMsm^3$	=	million standard cubic metres $1sm^3$ = 35.315 scf
BCM	=	billion cubic metres
MCM	=	1000 cubic metres
1 BOE	=	150.6 standard cubic metres gas

1 cubic metre = 6.29 bbl

was developed for the Franklin subsea flowline system and minimised the cooling required on the Franklin satellite. Nevertheless, significant cooling is required, as described, to satisfy processing requirement and much of the temperature energy available from the reservoir had to be dissipated.

Joint development of the Elgin and Franklin fields is advantageous, not only to achieve economies of scale with regard to infrastructure costs, but also to increase operational flexibility in producing the fields. In relation to offtake profiles, gas condensate fields are normally exposed to competing objectives. On the one hand European gas markets prefer extended, and thus relatively low, plateau production rates and these generally attract better prices. On the other hand, the liquids represent about two thirds of the total product value and a relatively high initial offtake rate would maximise investment returns. The integrated development of Elgin and Franklin fields allows both objectives to be met by phasing production between the fields at optimised offtake profiles. The marketing of the combined gas production from the two fields allows the aggressive production of the rich Elgin fluids while deferring the relatively leaner Franklin production to extend the gas plateau. The resultant profiles are illustrated in *Figures 7 and 8* and demonstrate how early liquid production can be maximised for economic advantage while optimised gas plateaus are maintained.

A key decision involved the selection and location of the gas processing functions and this is where the Value Engineering approach was the most powerful and offered more potential for unconventional scenarios. A full range of processing options, varying from the transport of raw gas to shore to full offshore gas processing was considered. As the UK oil and gas province is fairly mature, a number of gas processing facilities already exist as illustrated by the infrastructure shown in *Figure 9*. Existing terminals in the south, near Bacton, typically handle relatively lean gas from the southern basin gas fields. To the north the terminals can also handle dense phase gas from richer accumulations, often from gas condensate fields. Consequently, the potential availability of this existing infrastructure, both offshore and at onshore terminals, was an important input to this decision.

The transportation of raw gas to shore for treatment, without separation of produced liquids, was quickly eliminated on technical considerations alone. This left the main processing decision as primarily gas treatment to a dense phase offshore –v- offshore processing to a commercial gas specification. A number of variants within these two main processes were considered, particularly onshore gas sweetening associated with offshore hydrocarbon dew point control.

An objective Value Engineering approach concluded that on a balance of economics and technical evaluation, offshore processing to commercial quality is the most efficient if total onshore and offshore processing requirements are considered. This is illustrated by *Figures 10 and 11* which compares total processing functions for a dense phase offshore gas export specification with a commercial sales gas quality offshore specification. Also, with dense phase transport, the high gas pipeline operating pressures increase total compression demands. Dehydration is required at both offshore and onshore processing sites for a dense phase export. These theoretical disadvantages for dense phase gas processing are to some extent offset by reduced operating costs onshore compared to offshore. However, with processing at two sites, operations staff is required at two different sites.

The selection of the offshore gas processing spec is also closely linked to the selection of the onshore gas terminal location. Commercial input to the processing configuration and the gas export pipeline destination was obtained by soliciting processing and/or transportation bids from terminal operators at the major UK terminals at St Fergus, Teesside and Bacton, and from the UK NTS operator, Transco. These bids were integrated with the estimated costs for building the processing facilities under consideration. The results of the bidding

Concept Selection Methodology

The development concept and field architecture for the Elgin and Franklin fields was selected in the frame of a Value Engineering approach after comprehensive evaluations, driven primarily by the objectives of:

- economic development maximising the inherent value of the asset
- safety and low personnel risk recognising particularly the exposures of HP/HT drilling and wells
- environmental priorities which respect the need to minimise impacts

Inputs into the evaluation included technical (safety, costs, environmental impacts), commercial and strategic considerations.

The primary technical considerations were:

- reservoir recovery mechanism (depletion –v- gas recycling)
- integration of production from the two fields and the phasing between them
- configuration of the processing facility and its location
- the split of functions between the central complex and remote or satellite facilities
- type of drilling rigs and drilling sequences

Commercial considerations influenced design rates, the split of processing between offshore and onshore, terminal sites and transportation routes. It also influenced the construction of new facilities in comparison with the use of existing infrastructure.

Strategic objectives exerted some influence on consideration of the potential to integrate the Elgin/Franklin development with that of another contemporaneous development nearby and on the provision of incremental capacity in the system, particularly the transportation elements, for future third party use. All of these considerations overlapped to some extent.

The Value Engineering methodology steps were then applied to the various scenarios combining the above considerations:

- information gathering
- creation of alternatives
- analysis of alternatives
- development of alternatives
- presentation of these alternatives to the Elgin/Franklin partnership
- decision and implementation

Development of Alternatives and Selection

Blowdown of the Elgin/Franklin fields yields a recovery factor in excess of 50% of gas and 50% of liquids. Gas recycling was not found to improve liquid recovery sufficiently to offset the deferred gas production and would have substantially and uneconomically increased costs.

Particular attention was made to take maximum practical advantage of the high pressure and temperature energy contained within the reservoir fluids. The high reservoir pressure was used primarily to deliver high flow rates through a minimum number of wells, thus minimising the costs, time and energy associated with drilling operations. Concerning temperature, the high arrival temperatures at the PUQ ensure hydrate and/or wax formation is avoided and aids in initial gas/oil/water separation. High temperature insulation material of 30 mg/l. Produced water is taken from the 3 phase separators and is filtered prior to introduction to the centrifuge section. After being centrifugally de-oiled, dissolved aromatics are removed in a stripping column using low pressure fuel gas. Space is provided to add additional equipment to handle up to 3600 m^3/day if required later in the field's life.

Utilities

The complex process as described above and the high production rates naturally create substantial utility demands. Total power demand is on the order of 25 MW, not including the 115 MW of direct driven gas compressors. Installed power generation is 50 MW in a 2 x 100% arrangement.

The primary power demands are:

- main oil export pumps
- seawater lift pump
- flash gas compressor
- amine circulation pumps

Total heat exchange duty is 245 MW. Direct seawater cooling duty is 170 MW and installed capacity is 250 MW, primarily for the following gas processing duties:

- produced gas downstream of 1st stage separation
- fuel gas
- booster compressor discharge
- sweet gas discharge
- NGL splitter liquids
- export compressor discharge

Accommodation on the PUQ for 69 personnel is provided primarily for production operations. Any significant maintenance will be undertaken on a campaign basis using dedicated support vessels. Drilling and well servicing requirements are provided by dedicated rigs.

The process, utility and accommodation requirements result in a very large installation with a topside installation weight of about 30,000 tonnes. With the advantage of the relatively modest 90 metres water depth, a purpose built jack-up production platform *figures 4 and 5*, is used to support the facilities. After being towed to location in July 2000, the hull was jacked-up and locked in position. The legs are pile-founded into the seabed. Each leg is supported by six 72" piles driven to a penetration of about 55 metres.

The hull itself contains two decks which house much of the utilities equipment and accommodation facilities. Process equipment, power generation equipment and some supplementary office/control facilities is stacked on the main, top deck of the hull section. The jack-up platform provides a relatively large area compared to more conventional North Sea platforms which have heavy lift barge installed topsides. It can carry substantial weight. Its primary dimensions are about 75m x 100 m, giving a plan area of 5500 m^2 (1.5 acres). Topside operational weight is 33,000 tonnes. *Figure 6* illustrates its dimensions in comparison with a conventional jacket structured platform for a comparable duty. A major advantage of this concept is the capability to complete, connect and commission virtually all systems onshore. Offshore installation time and cost is thus minimised.

Table 2 summarises the commercial gas sales specification. A complex offshore gas processing system is required to achieve this gas quality with the Elgin/Franklin fluid compositions. The process needs to:

- remove H_2S
- partially remove CO_2 to a controlled level
- dehydrate the gas, and
- provide hydrocarbon dew point control

The relatively high proportions of ethane and propane in the produced fluids combined with the restrictive CO_2 limits of the sales gas specification and the variations in fluid composition over field life necessitate fairly precise control over the split of NGL components. Ethane and propane in particular must be precisely distributed between the gas and oil streams.

Gas from the inlet separators is initially compressed to 83 bar, the operating pressure for the gas processing train. The gas is then sweetened to remove H2S and a controlled amount of CO2 in an activated MDEA (proprietary TotalFinaElf) amine process.

Sweet gas from the amine absorber is cooled to reduce its water content then dehydrated with glycol (TEG) in a column fitted with both structured packing and trays sections.

To achieve the required hydrocarbon dew point, the gas is cooled first with seawater coolers to 14°C, then by exchange of heat with the cold low temperature separator effluent and NGL splitter streams, and finally by expansion through a turbo expander to a pressure of 38 bar (from 75 bar). A final separation temperature of –43°C is achieved. Liquid from the low temperature separator downstream of the turbo expander is further split in an NGL splitter column to ensure the oil pipeline TVP specifications are met and, simultaneously, that the gas specifications can be met. Gas from the top of the NGL splitter is re-combined with the main gas stream for export through the discharge compressors. Fuel gas is taken from a sidedraw on the NGL splitter to aid in achieving the optimal balance of NGL components. The stabilised NGL liquids are spiked back to the oil stream.

Gas compression requirements are substantial. First stage separation is initially at 50 bar. With the gas process stream operating at about 80 bar, boosting compression is required downstream of the first stage separators and discharge compression is required to achieve the gas pipeline inlet pressure of 145 bar. As the reservoir pressure declines, first stage separation pressure will be progressively reduced to maximise production. The booster compressors will be reconfigured as required to increase Δp as the production rates fall. The booster compressors consist of two 23 MW units in a 2 x 100% duty arrangement and the discharge compressor consists of three 23 MW units in a 3 x 50% duty arrangement. Total installed gas compression, including the flash gas compressor and the turbo-expander compressors, is 130 MW.

Oil Process

The combined oil stream from the 1st stage separators is degassed and stabilised in a 2nd stage (also 3-phase) separator. As incoming fluid temperatures decline later in the field life the oil may need to be heated prior to 2nd stage separation. Oil from the 2nd stage separator is then cooled, mixed with the NGL splitter liquids, metered and finally pumped to the oil export pipeline at a pressure up to 230 bar.

Produced water volumes are expected to be relatively low, 1200m^3/day max, at least initially. A centrifuge process is used to treat the separated water to an overboard discharge quality although at a normal depth gradient. The reservoirs are, however, under abnormally high pressures of about 1100 bar.

The combined reserves, gas condensates, are large – about 775 MM BOE. Sales gas reserves are about 50 BCM and liquid reserves (including oil and NGL products) are about 440 MM bbl.

Reservoir fluid compositions are indicated in *Table 1*. Both fields are rich in liquids, but are sour. The Elgin field is richest, containing about 11 bbl/MCM. Franklin contains about 6.6 bbl/MCM.

The substantial size of the Elgin/Franklin reserves combined with the properties of the reservoir fluids dictated that a strategic perspective be undertaken in considering development alternatives. Consequently, a Value Engineering approach considering production, processing, transportation to end users and marketing strategies was taken. This overarching perspective has led to a field development architecture that fully processes the produced fluids offshore with gas being exported at commercial sales quality.

First production from Elgin occurred 31/03/01 and production will increase over the coming months, with Franklin expected to be on stream mid August 2001.

Description

The location of Elgin/Franklin fields and their pipeline export systems are shown in *Figure 1*. The offshore field architecture is illustrated in *Figure 2*. Wellhead platforms in each field are connected to a common production, utilities and quarters (PUQ) platform. Well flowlines are manifolded on their respective platforms. The commingled production from each is piped to the PUQ for treatment. Both wellhead platforms are classified as not normally manned. The Elgin wellhead platform is connected to the PUQ with a 90-metre long bridge. The Franklin wellhead platform is connected to it through a subsea system consisting of a 42" pipeline bundle (containing 2-12" lines), two control umbilicals and a power cable.

Sales quality gas from the Elgin/Franklin PUQ platform is commingled with gas coming from a neighbouring field, of a similar quality, and shipped through a 34" gas pipeline to a new receiving facility in an existing gas terminal at Bacton. The Bacton terminal primarily provides flow control and metering but also warms the gas as required from the ambient seawater temperature at which it arrives. At Bacton the gas can be introduced either into the UK National Transportation System (NTS) or to the Interconnector pipeline which links the UK and Continental Europe gas markets.

Pipeline quality oil (rich in NGLs) from the PUQ, also commingled with the same other field's production, is piped through a new 24" oil pipeline to the vicinity of the Marnock field where it enters the existing Forties oil pipeline system. The oil is transported to the Forties System Terminal at Kinneil where it is separated into crude oil, butane, propane, ethane and gas products.

The basic offshore process is indicated in *Figure 3*. The production steam from the adjacent Elgin wellhead platform and the remote Franklin wellhead platform are received on the PUQ in first stage, 3-phase gas/oil/water, separators arriving initially at about 170°C. Franklin fluids, initially are cooled prior to entering the subsea flowlines and arrive at a maximum temperature of 45°C.