Electronic Copy

A Review of Regulatory Cycle Times in Certain Jurisdictions

Prepared for

Regulatory Issues Steering Committee of the Atlantic Energy Roundtable

August 2003

TABLE OF CONTENTS

Page No.

1. INTRODUCTION

The Regulatory Issues Steering Committee of the Atlantic Energy Roundtable commissioned Gaffney, Cline & Associates (GCA) to perform a review of the regulatory approval cycle times for certain offshore petroleum areas. These areas, the "Reference Jurisdictions", are the United States' Gulf of Mexico, the U.K. and Norwegian sectors of the North Sea and Australia.

There are many significant differences between these areas – in terms of infrastructure, proximity to market, environmental conditions, exploration maturity, etc. In order to attempt a meaningful comparison of the regulatory approval cycle times, GCA approached the issue from two directions – first, a statistical analysis of the time elapsed between licensing, drilling, discovery and first production (acknowledging that with differences in circumstances, nomenclature and reported information this will not be a straightforward "apples to apples" comparison). Second, the indicative timing was then assessed in the light of feedback from both the operating companies as well as the different regulatory bodies.

GCA compiled information about 60 fields in Australia, 69 in Norway, 301 in the U.K., and 1,112 in the U.S. Gulf of Mexico. This included timelines from discovery to first production and abandonment, when available. GCA also contacted 22 companies, representing a cross section of the industry that were operating in the Reference Jurisdictions, as well as the primary petroleum regulatory bodies, i.e. the Australian Department of Industry, Tourism and Resources, the Norwegian Petroleum Directorate, the Oil and Gas Directorate of the Department of Trade and Industry (U.K.), and the Minerals Management Service (U.S.).

2. CONCLUSIONS

- The timeframe for regulatory approvals has changed (and shortened) over time due to a variety of factors and circumstances.

- As markets mature and become more competitive the approach to regulating activity tends to evolve from highly prescriptive and directive systems towards principle and performance-based approaches.

- Regulatory structures and approaches, like the industries and general economic conditions in which they are present, are not static but evolving. Where regulatory reform is in progress, it is tending to be towards market liberalization

- While companies compete for investor capital by delivering profits and returns to shareholders, countries also compete for the industry's capital investments on the basis of the economic attractiveness of their petroleum resource bases.

- The economic attractiveness of a country or region is a function of geological prospectivity and risk, fiscal terms and costs (including those associated with time and regulatory uncertainty).

- It is increasingly clear that the way governments administer and regulate through the entire life cycle of activities in their petroleum sectors is an emerging frontier of competition.

- A direct comparison between the regulatory approval cycle time in different jurisdictions is complicated by both differences in definitions and reporting practices, as well as by different physical conditions in the Reference Jurisdictions (differences in cost, infrastructure, off-take markets, experience, environmental aspects, the scale and importance of the sector to the regional and national economy, etc.).

- The comparison is further complicated by fundamentally different approaches to both the approval process, as well as to the more basic issue of the role of the State in the petroleum sector.

    - While in Australia the license holders must deal with several authorities to obtain approvals for development plans, in the other jurisdictions there is a single point of entry (the Minerals Management Service in the U.S. Gulf of Mexico, the Oil and Gas Directorate of the Department of Trade and Industry in the U.K., and the Norwegian Petroleum Directorate in Norway).

    - The role of the State varies widely among the Reference Jurisdictions ranging from the minimalist State involvement in the U.S. to the historically high levels of State intervention in Norway's petroleum sector

- Notwithstanding a worldwide march towards exploration and production in deeper and more distant waters, a consistent trend in reduction of the time elapsed from discovery to first production, especially in the 1990s, is observed.

- In the 1990s, the U.S. Gulf of Mexico discoveries had the lowest average elapsed time between discovery and production (2.6 years), followed by Australia (3.8 years), the U.K. (4.3 years) and Norway (6.4 years).

- These belie the fact that the regulatory approval processes are not fundamentally different between the counties (although there are significant differences in how much is done contemporaneously as opposed to sequentially), with many of the differences being accounted for outside of the regulatory processes themselves.

- Often company internal approval and sanctions processes run in parallel with the regulatory approval processes.

- The interviews showed a trend in reducing the technical requirements for approval of petroleum developments, aiming at streamlining the approval processes. At the same time, they showed, in some areas, a trend to increase the environmental review requirements for petroleum operations though with limited to no effect on the total approval cycle because of parallel processing of environmental and development applications.

.

- The length of the regulatory approval process varies with the complexity and characteristics of the project (in months):

	Range	Median Duration
Australia	8-24	14
Norway	8-15	13
United Kingdom	5-12	<9
U.S. Gulf of Mexico	6-12	10

- By contrast, the comparable time-frame in Atlantic Canada has ranged between 13 and 21 months (Hibernia 13 months, Terra Nova 17 months, Sable 18 months and White Rose 21 months) and appears to be counter to compressing cycle times observed elsewhere. Key measures to close this gap would include an:

  - increased level of parallel processing of applications;
  - increased dialogue and interaction with companies prior to application;
  - increased orientation from rule-based towards outcome-based regulatory practices; and
  - the increased familiarity and comfort that comes with practice.

- In light of the fact that all of the Reference Jurisdictions are facing declining production, further cycle time compression and streamlining can be expected in order to compete for the industry's capital and encourage continued investment and activity.

3. EXECUTIVE SUMMARY

The international oil industry has changed considerably over the last 20 years. As described more fully in Appendix I, massive geo-political changes – the collapse of the Soviet Union in particular, but also the waves of petroleum-sector openings in Latin America, Asia, the Middle East and North Africa have dramatically increased the scale of the arena in which the international oil and gas companies explore and operate. At the same time, the industry has undergone a profound degree of consolidation as companies reacted to pressure from the capital markets to improve their financial performance and capital efficiency by consolidating into increasingly larger entities and slashing overheads to enhance profitability.

While companies compete for investor capital by delivering profits and returns to shareholders, countries compete for the industry's capital on the basis of their petroleum prospectivity (including consideration of risk and costs) and the share of any resulting profitability that they are willing to concede to the industry in exchange for its risk capital. While this is primarily done on the basis of the quantum and timing of the government's share of profitability (in terms of royalties and taxes), it is increasingly clear from the level of regulatory reform in the Reference Jurisdictions (as well as in other countries) that the way in which governments administer and regulate their petroleum sectors is an emerging frontier of competition – in particular because of the impact of a government's regulatory processes and procedures on both the cost and time of conducting exploration and production activities.

In order to compare the regulatory approval cycle times in the Reference Jurisdictions, GCA compiled information on about 60 fields in Australia, 69 in Norway, 301 in the U.K., and 1,112 in the U.S. Gulf of Mexico. This included timelines focusing on the period from discovery to first production. This data indicated a consistent trend in reduction of the time elapsed from discovery to first oil, especially in the 1990s. In that decade, the U.S. discoveries had the lowest average elapsed time between discovery and first production (2.6 years), followed by Australia (3.8 years), U.K. (4.3 years) and Norway (6.4 years).

Obviously these numbers measure simply the unequivocal timeframe between the dates of discovery to "first oil" or gas. For a number of reasons, discussed in more detail below, these "hard" data notwithstanding, the large sample size does not permit a clear conclusion as to how much of this time is a result, only, of the regulatory and State approval processes.

In order to complement the conclusions inferred from the statistical analysis, GCA conducted interviews with operating oil companies, as well as with the regulatory bodies of the Reference Jurisdictions. The interviews showed a trend in reducing the *technical* requirements for approval of petroleum developments aiming at streamlining the approval processes. At the same time, a trend towards greater environmental review and public consultation for petroleum operations was observed.

While the directional conclusions and trends can be reported with some confidence, the biggest single issue that undermines absolute conclusions and comparisons is the blurring of when, exactly, internal sanctions are received and when regulatory approval is sought. In many cases there are no meaningful "bright line" points in time at which they can be compared – for example, the development approval process timeline in Norway is not materially different than those in Australia, the U.K. or the U.S. Gulf of Mexico but gaining a position in the queue to file such a plan can take a considerable amount of time.

Fundamentally different approaches to both the approval process, as well as to the more basic issue of the role of the State in the petroleum sector, as discussed in the paragraphs below, frustrate and complicate a direct comparison between the Reference Jurisdictions. Moving along a spectrum from lower to higher levels of Government involvement and regulatory activism within these jurisdictions:

- The ***United States*** is characterized by extreme market orientation and a reduced role of the State in favor of allowing private sector market fundamentals to drive industrial and commercial activity. The stark separation of public and private sectors is evidenced in the regulators' lack of discretion in approvals and permitting. The award procedures tend to be rigid and rule- rather than principle-oriented with no scope for collaboration or negotiation between the regulators and the industry (due in part, no doubt, to government rules concerning *ex parte* communications). This approach is clearly evidenced in the cash bidding basis for the award of exploration licenses - no discretion (or subjectivity) is permitted to enter into licensing process. This prescriptive philosophy extends through all aspects of permits and licensing. Notwithstanding the rigidity of approach, the sheer volume of "throughput" through the system and the large numbers of participants in the sector have resulted in an effective and workable system with a straightforward permitting process and a highly predictable timeframe. In recent years there have been signs of increased flexibility on the part of the regulator to respond to industry initiatives and issues - the approval of FPSO (Floating Production Storage Offloading) - based developments as well as the provision for royalty relief in deepwater both evidence a desire of the regulator to remain on the competitive frontier for the industry's capital. Indeed with the current focus and high level of concern with respect to natural gas supply and deliverability, further changes designed to increase competitiveness and lower economic thresholds might be expected.

- Like the U.S., ***Australia*** has never had a tradition of direct State participation in the petroleum sector and adheres to a similar philosophy vis-à-vis the role of the public sector in industrial and commercial activity. While it is also oriented towards open and competitive bidding, it does so on the basis of the proposed work program and thereby introduces at least a degree of discretion into their decision-making. The government also engages in certain activities designed to promote activity in the sector - these include spending government monies to acquire data and information to lower the risk and costs to prospective entrants and investors.

- The ***United Kingdom*** has a partial history of state involvement in the industry (formerly via its equity interest in British Petroleum and British Gas, as well as British National Oil Corporation) and utilizes a much higher level of discretion than either Australia or the U.S. There is also a very high degree of formal and informal interaction between regulator and companies' throughout the approval process. Awards of licenses are based on the companies' work plans but are not evaluated on a purely quantitative basis. The government also is an active participation in the promotion of the sector via its sponsorship and involvement with initiatives such as LOGIC (Leading Oil and Gas Industry Competitiveness), LIFT (License Initiative for Trading), the fallow acreage initiative and others. Notwithstanding the dialogue-intensive philosophy which pervades all of the regulatory approval processes, the government basically appears to follow the general principle of allowing market forces to regulate the pace and nature of activity where it complies with established minimum standards.

- ***Norway*** has an even stronger and enduring tradition of state ownership in the sector – both through its shareholding in the national oil company, Statoil, as well as in other Norwegian companies and its former direct equity participation in Norway's oil and gas developments via the SDFI (State's Direct Financial Interest). The Norwegian Government has taken a much more proactive position in regulating and controlling activities within the sector than the other Reference Jurisdictions. It has many of the discretionary characteristics of the U.K. system with the added features of "forced marriages" (deciding which companies should be part of a consortium), as well as exercising an absolute level of control over licensing and permitting of developments, gas sales approvals, etc. The Government has indicated that its' direct policy is to try and fit the needs of industry with those of State in order to regulate employment and inflationary effects of activity, as well as other considerations such as inter-generational wealth transfer. Norway's highly discretionary regulatory philosophy may come under somewhat more pressure to relax with pressure from European Union competition rules (as has been the case for all-important gas sales/export authorities).

While direct comparisons of the costs of regulation are extremely problematic due to reporting or categorization differences, it would appear that the U.S. MMS (Mineral Management Service) and the Norwegian MPE (Ministry of Petroleum and Energy) and NPD (Norwegian Petroleum Directorate) represent the extremes (at least on a proportional basis), of US$750 million per year and 18 Billion Norwegian Kroner (US$2.4 billion), respectively.

Without question, the timeframes elapsed between licensing, discovery and first production have sharply reduced in the Reference Jurisdictions (see table below) - what is harder to determine is how much of this cycle compression is the result of regulatory streamlining versus the natural efficiencies and acceleration that are made possible by familiarity and practice (not only on the part of the regulators but also of the companies, their lenders, offtakers, etc.), the maturation of gas markets and the expansion of infrastructure and oilfield service and support industries.

Average Time from Discovery to Production (Years)							
Country	**pre 1960s**	**1960s**	**1970s**	**1980s**	**1990s**	**2000s**	**Average**
Australia		12.2	12.9	5.9	3.8		8.5
Norway		14.4	11.7	12.3	6.4		11.6
U.K.		17.0	14.4	9.2	4.3		10.5
U.S./GOM	4.1	8.9	6.4	5.8	2.6	0.9	5.9
Average	**4.1**	**10.0**	**8.8**	**6.9**	**3.2**	**0.9**	**7.1**

The table on average elapsed time by water depth (see below) is inconclusive – largely because the industry's advance into progressively deeper waters has been coincident with both expansion of infrastructure and regulatory maturation and evolution. Also, with the exception of the U.S. Gulf of Mexico, there are very limited deepwater developments in the Reference Jurisdictions. In the Gulf of Mexico, deeper and more distant developments appear to receive slightly more rather than less regulatory (in particular on the environmental aspects) scrutiny notwithstanding the increased distance from more fragile coastal eco-systems and technology advances allowing less permanent (TLPs, Compliant towers, FPSOs) structures, as well as fewer of them (better subsurface imaging, extended reach drilling and multiphase pipeline flow require less wells and less platforms) to efficiently produce a reservoir. Moreover, these are conducted in parallel and therefore do not effect the overall approval time-line.

Average Time from Discovery to Production (Years), by WWater Depth						
Country	**0-20m**	**21-100m**	**101-400m**	**401-1000m**	**> 1000m**	**Average**
Australia		11.0		24.0		8.5
Norway		11.3	13.7			11.6
U.K.	6.4	10.3	11.9	4.9		10.5
U.S./GOM	4.4	6.2	7.0	6.6	5.9	5.9
Average	**4.5**	**7.3**	**9.6**	**6.9**	**5.9**	**7.1**

Most of the more remote or hostile environments were pioneered by giant or super-giant "lead" fields (Prudhoe Bay in Alaska, Brent and Forties in the U.K. North Sea, Ekofisk in Norway and Kingfish in Australia's Bass Strait) and, while there is generally a positive relationship between project scale/profitability and the pace of internal company sanction, the relationship does not hold for regulatory approvals (largely because the stakes - in terms of environment, taxes and employment are considerably higher for such developments). Conversely, some more modest projects may only work in fast track environment where some uncertainties are acceptable risk to bear in exchange for acceleration of cash flow.

Some regulatory improvements are apparent, for example, in the U.K. the level of documentation required for approval has been dramatically reduced and the processes of consultation with the regulatory authorities greatly simplified. This has been achieved in large part through a highly collaborative process where the regulator and the companies have a high degree of interaction and communication and the actual mileposts of when an application is submitted and approved have become less meaningful. (i.e. the actual deliberation process has been ongoing so that when the application is submitted there is nothing in it that the regulator has not seen and, as a practical matter, already approved)

Delays may also be a function of the rules that apply to area relinquishment obligations and the rights to retain, without proceeding to either condemnation or development, of discoveries. Companies that have an unlimited time period in which to file for development approval will make the filing when the project meets all of their requirements and has migrated to the top of the priority list of projects that are competing for their capital. There are a large number of examples of marginal projects being retained by the companies (and therefore not available for re-licensing to companies that may have either more modest profitability requirements or higher risk tolerance) because they had no obligation to relinquish them - Venezuela's Crístobal Colón project and Peru's Camisea project were examples of this. The Hebron-Ben Nevis discoveries in Newfoundland may also be another example of this.

Despite the increasing attention given to environmental aspects and increasing amount of involvement from broad sectoral stakeholders there is evidence that cycle times are compressing in all areas. This had been achieved through a variety of means including:

- Increased level of parallel (as opposed to serial) processing of applications (often in the context of a consolidation of the various regulatory bodies to a single or limited interface with the companies;

- As noted above in the U.K., in particular, an increase in more frequent and informal communication such that most materials that are submitted for approval have already been previewed and commented on by the regulator;

- Increased reliance on use of common international standards such as the international classification societies (Lloyd's Register, Det Norske Veritas, American Bureau of Shipping, among others) and auditing compliance (as opposed to supervising it).

In looking to the Reference Jurisdictions as exemplars for Atlantic Canada, it is appropriate to consider differences in context. Currently the Reference Jurisdictions are in very different stages of maturity than Atlantic Canada. Further, the evolutionary cycle was different in each of those cases in terms of both the economic and political backgrounds prevailing at the outset and, significantly, in all four of the examples early exploration successes were substantial enough that they propelled both development and further exploration activity, and regulation was forced to catch up with the demands that this brought. Absent the momentum and threshold-lowering infrastructure generated by giant “lead” fields, the onus will remain on the regulatory authorities to proactively spur activity and encourage pursuit of finite windows of opportunity (such as the current deep concern over natural gas supply shortfalls in the U.S.).

Charting the evolution of these other areas does not, of course, mean that it is appropriate simply to estimate at what point Atlantic Canada is in its life cycle, and endeavor to replicate others' steps and processes, nor does it suggest that the current practices and processes in those areas should be adopted on a wholesale basis.

The challenge will be understanding what has evolved elsewhere as a result of changes in circumstance, and what has evolved as a result of learning and adoption of “best practice” principles. This should lead to the identification and adoption of guiding principles that are culturally in-tune with Atlantic Canada's situation and provide the best balance of the competing needs of the different stakeholders in the sector.

4. DISCUSSION

4.1 General Principles of Petroleum Sector Regulation

4.1.1 Regulations in the Petroleum Sector

There are two principal forms of regulation prevalent in the world today:

- State-controlled, where virtually all functions are regulated to manage overriding political or social policy objectives and where Ministries and national oil, gas, and utility companies are the principal players; and
- Free market, where regulation is put in place to ensure competition and a level playing field, and where independent regulatory agencies are the norm. Such systems are more prevalent in the developed economies.

There are also two other factors that it is important to note:

- Regulation is not static, but evolving, everywhere;
- Where regulatory reform is in progress, it is tending to be towards market liberalization.

As a result of the dynamic nature of regulation, many of the systems in the world are having to cope with transition, and a snap-shot today makes them a hybrid of the principal forms above.

4.1.2 Evolution of Regulatory Structures

There is a pattern of "life-cycle" of regulation that can be observed as a number of attributes or factors have caused or influenced the evolution of regulatory structures and processes over time. The sequence follows the following path:

- The structure of certain industries (typically those where a limited number of options exist to transport or distribute, such as natural gas and electricity) create "natural" monopolies like pipelines or distribution systems;

- Regulation emerges to cause desired behavior (prevent abusive practices) in such natural monopolies;

- As the market matures and grows in size and complexity, the regulations also become more complex and onerous, or circumstances have changed whereby the original purpose of the regulations no longer exist;

- The mature market scenario typically results in inefficiency and limited market growth because there are no incentives for cost saving on the one hand and limited incentive to grow markets or create new responses to market demand on the other;

- Eventually, the cost burdens imposed by the regulations and lack of cost reduction/growth incentives wear the system down and a process of deregulation begins.

Experience in a number of countries (reflected in current regulatory trends) suggests that the long-term efficiency and economic growth is best achieved in a de- or lightly regulated environment *but* in order to get to the point where the broad national or regional interest is best served by minimal regulation, it may be necessary to *expand* the scope and authority of the regulatory bodies initially in order to mature the sector to that critical level of development. This paradox can be clearly observed in areas that are evolving away from a single player (usually state-owned) to a multi-player environment. Initially there is no need for regulation (i.e. the state company is "self-regulated" since there is limited advantage than can be gained by the monopoly company. As new players are introduced (or as the government dilutes its ownership in the state company), the new entrants require rules of conduct that are administered by an independent third party in order to protect their interests. As the sector evolves, matures and becomes more complex, the regulatory authorities expand their oversight until the increasing cost of compliance eventually discourages activity and leads to a de-regulation process, as outlined above. In fact, it is probably the combination of this plus the fact that the agencies become more experienced and discretionary in their activities and that natural forces of competition emerge to influence behaviors that swings the pendulum back towards lighter oversight.

4.1.3 Comparative (and Competitive) Regulation

Both governments and industry are continually looking elsewhere to try and improve and remain on the competitive frontier. The primary arena of competition between countries is in the fiscal terms applying to oil and gas activities. While there is little the resource owner (the State) can do to change the geological prospectivity and a lot of the cost and risk elements are largely out of the control of the resource owner - important steps can be taken to reduce the uncertainty and costs associated with both regulatory approval and to compress the critical time-gap in between capital outflow and a return on, and of, that capital. These steps might include measures to streamline regulatory approval cycles (parallel as opposed to serial processing), adoption of uniform international standards, area-wide permitting and towards greater consolidation of regulatory filings ("one stop shopping").

There are a number of problems in comparing different jurisdictions and attempting to isolate the effect of the regulatory deliberation and approval process from other factors. Primarily the issue is one of data and data point comparability. While certain discrete points in time (such as the date the license was granted, the date the discovery well was completed and the date of first oil/gas production) can be measured and compared from one country to the next, the information that indicates the timeframe between internal project sanction or submission of a development plan and regulatory approval are much more problematic. Not only is there a general lack of uniform reporting with respect to such milestones but the regulatory approval aspect is just one of many variables that effect decision-making process and speed, others include:

- Technical challenges – there is a big difference in bringing on-stream a cutting-edge technology development that is also dependent on the development of infrastructure and market (like the Snøhvit project in the Norwegian Sea) and one that is close to infrastructure and in a shallow water/benign environment (such as a shelf Gulf of Mexico or Southern North Sea development) ;

- Infrastructure – developments closer to existing infrastructure will enjoy lower costs, as well as benefit from the regulator's learning curve and increased familiarity on the part of other stakeholders;

- Costs - developments that are marginal will often be delayed pending the emergence of a technological breakthrough or a project re-think to lower the costs;

- Oil and natural gas price outlook – while petroleum exploration and production is very much a long-term business, year-to-year budget approvals are strongly influenced by near-term price expectations as well as cash-on-hand;

- Product markets - while crude oil is readily transportable to markets whether distant or local, natural gas is less fungible and therefore requires the existence of a market offtake (not an issue in the Gulf of Mexico, for example, but a key variable in areas with smaller and less liquid gas markets);

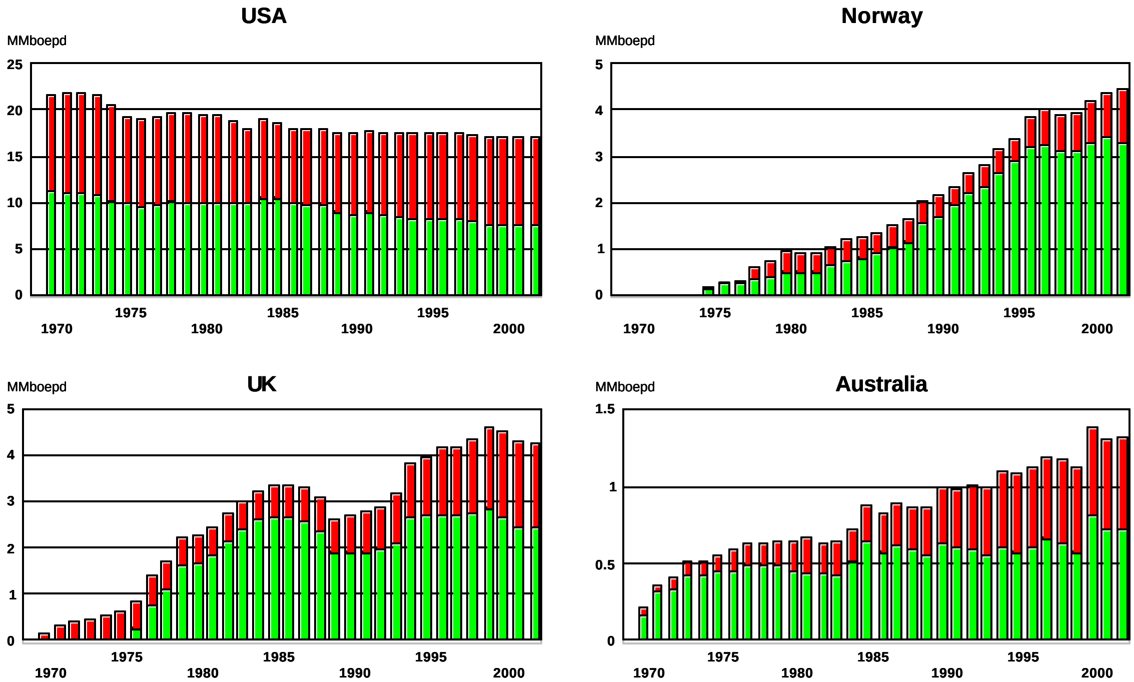
- Country risk - investment decisions are often delayed where there is perceived to be a possibility of legislative or regulatory change (whether positive or negative) or delay/uncertainty; and finally

- Competition from other projects within a company's portfolio – the larger the company the larger is their likely portfolio of potential investments that are competing for the company's investment capital.

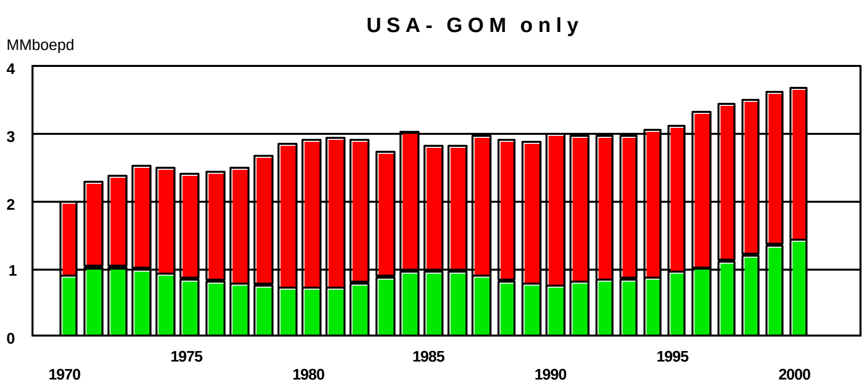
Regulatory approval processes and timeframes can also be dramatically affected by traumatic events. The offshore oil and gas industry has experienced a number of accidents which have contributed to closer regulatory oversight over certain operations – the Piper Alpha and Alexander Kielland tragedies in the U.K. and Norwegian sectors of the North Sea, respectively, each led to tighter regulatory oversight and review of offshore safety management and related processes. Likewise the Exxon Valdez disaster and the Brent Spar controversy have both had meaningful impacts on the level of regulatory and public scrutiny under which the industry operates.

Reference Jursidictions

Oil and Gas Production
1970-2002



Another factor which effects comparability is the scale and stage of maturity of the petroleum industry (and by extension, regulatory oversight) activities. As the 30-year oil and gas production history above graphically illustrates (oil in green, gas in red, gas converted on a 6:1 thermal equivalent basis), the U.S. overall is a far larger and far more mature petroleum producer than the other Reference Jurisdictions – each of which has largely emerged in the last 30 years. Looking at the Gulf of Mexico only (below), however, shows a much closer comparison to both the U.K. and Norway in terms of scale but still reflects the much earlier commencement of offshore operations in the Gulf.



The scale and maturity differences will also reflect the fact that the regulatory functions and processes in the U.S. will have had a lot more practice and throughput than those in the other Reference Jurisdictions. In the Gulf of Mexico, the government has completed 115 separate licensing rounds and issued over 18,000 licenses. Today, there are approximately 7,500 active leases and over 4,000 active platforms.

By contrast, both the U.K. and Norway have completed 17 licensing rounds (as well as a number of out-of-round awards). The U.K. has 260 fields under development or in production. In Norway as of the beginning of 2003, there were 40 fields in production, while Australia has approximately 50 offshore developments.

Just as scale and level of maturity might be expected to have some influence over the regulatory approval cycle times, so too would the petroleum trade balance and the overall importance of petroleum in the economy.

In terms of trade balance, it can be see in the following graphs that the U.S. is a massive importer of oil (as well as gas), while Norway exports the majority of both its oil and gas production. Two lessons might be drawn from this as well as from the table below which compares key current economic and petroleum statistics.

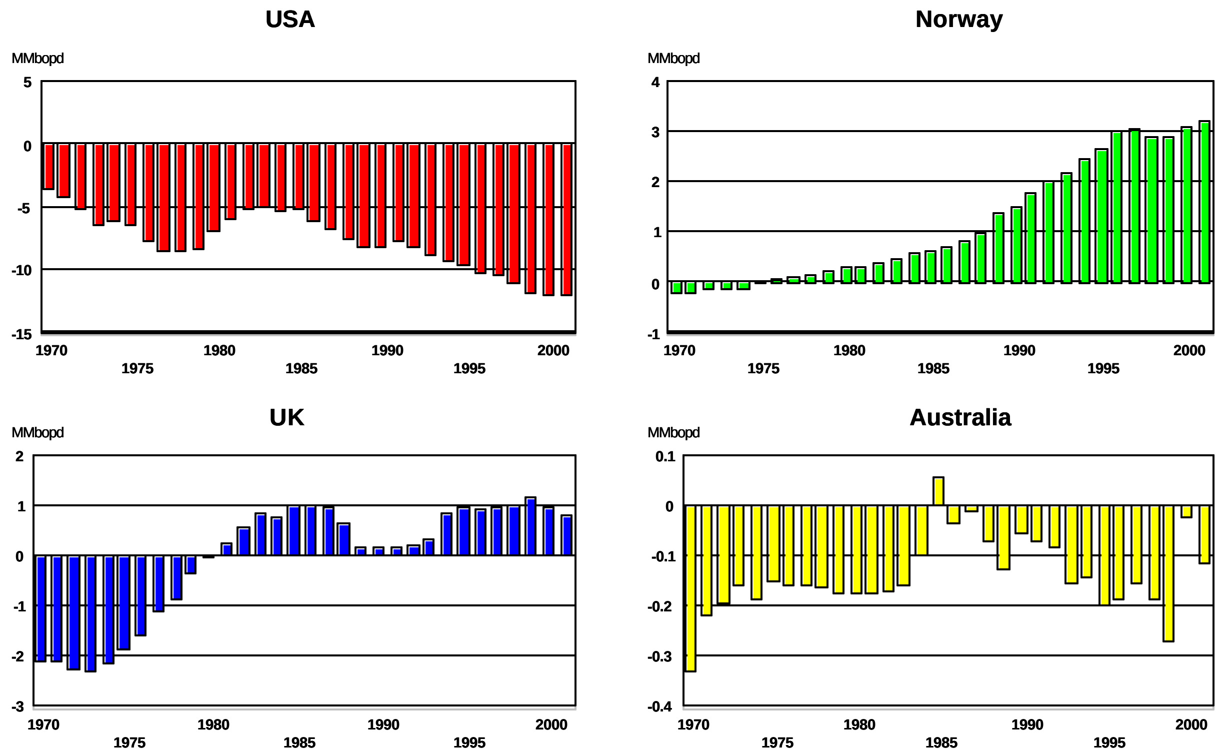
- First, the economy of a country with a relatively small work force like Norway is heavily influenced by (and exposed to) the level of activity and investment in the oil sector;

- Second, with a limited need for petroleum, Norway has the relative luxury of being able to postpone developments and activity to moderate its effect on the overall economy.

Reference Jursidictions

Oil Trade Balance

1970-2002



	Australia	Canada	Norway	U.K.	U.S.
GDP (US$ Billions)	528	923	143	1,520	10,082
Labor Force (Millions)	9.2	16.4	2.4	29.7	141.8
Unemployment Rate	6.3%	7.6%	3.9%	5.2%	5.0%
Fossil Fuel/Total Elec Generation (%)	90%	25%	0%	73%	71%
Oil Production (MBOPD)	730	2,880	3,330	2,463	7,698
Oil Consumption (MBOPD)	846	1,988	209	1,675	19,708
Oil Balance (MBOPD)	-116	892	3121	788	-12,010
Gas Production (Bcfd)	3.3	17.8	6.3	10	52.1
Gas Consumption (Bcfd)	2.3	7.8	0.4	9.1	64.6
Gas Balance (Bcfd)	1	10	5.9	0.9	-12.5

4.2 Australia

4.2.1 Offshore Exploration and Production Context

Ninety percent of Australia's oil and gas production comes from offshore, mostly from Commonwealth waters (more than three miles offshore) off the States of Western Australia and Victoria.

Western Australia

In the 1970s massive gas/condensate discoveries off the northwest coast of Western Australia were made. These included Scott Reef, North Rankin and Goodwyn by Woodside Petroleum, Petrel and Tern by Arco and Aquitaine and Gorgon by WAPET. These were not brought on-stream until 1984, partly as a result of infrastructure/cost challenges as well as then-existing government controls and prohibition against exports of oil and gas which discouraged exploration in the less populous western and northern parts of the country.

The North Rankin and Goodwyn discoveries provided the reserves base for the development of the Northwest Shelf Gas Project, the largest natural resource project ever undertaken in Australia. Gas produced offshore is delivered through 1,500+ kilometer pipelines to domestic and industrial gas users in the south and south-center of the Western Australia, as well as to an LNG liquefaction plant which came on-line in 1989. The LNG plant is currently producing 7.5 million metric tonnes per year with a fourth train (processing unit) at the plant due to be operational in mid-2004.

Offshore Victoria/Bass Strait

Australia's first significant offshore well was drilled in late-1964 and discovered the Barracouta gas field at a depth of 1,060 m. A second well on the structure, followed by discoveries at the Marlin field in 1966, confirmed that Gippsland was a major gas province.

In 1967, Kingfish-1 was drilled and encountered Australia's largest oil field (1.2 billion barrels recoverable). By any measure extraordinary exploration success was enjoyed - 15 or the first 16 wells drilled were successful, yielding three major gas fields (Barracouta, Marlin and Snapper - still the major gas producers) and the two largest oil fields in Australia (Kingfish and Halibut).

After the initial phase of very high success rates, new discoveries were limited through the early 1970s with only the Cobia field being placed into production. In 1978, following the implementation of Import Parity Pricing for local oil that encouraged exploration, the Fortescue oil field (280 million barrels) was discovered, followed by the Seahorse and West Halibut discoveries.

Stimulated by the oil price rise in 1979 and a relinquishment of a significant portion of the original exploration permit by Esso/BHP in October that year, a number of modest discoveries were made the early 1980s with West Tuna, drilled in 1984, being the last of the large to giant oil discoveries by the Esso/BHPP joint venture. Since a campaign in 1995/6, which met with limited success, Esso/BHPP has largely conducted development and workover drilling to optimize existing field production. Other discoveries in the basin since that time have been of only modest proportions although the construction of the pipeline linking the main onshore processing plant to Sydney, along with the Interlink gas pipeline and joining the Victorian with the New South Wales gas pipeline system, has opened up gas markets and stimulated interest in developing existing gas discoveries and exploring for new gas.

4.2.2 Regulatory Oversight of Petroleum Sector

Australia's Government is a democratic federal-state style system which recognizes the British monarch as sovereign. A central Federal (Commonwealth) government oversees the individual governments of the country's six states and two territories.

Petroleum resources under the ground belong by the Crown, i.e. Governments own them on behalf of the community. Governments allow companies to explore and produce oil and gas under certain conditions and in return receive all the information collected about the resources and a share of the pre-tax profits.

Australia's established offshore petroleum resources are comprised of the states of Western Australia and Victoria and to a lesser extent the Northern Territory. Both Commonwealth and State Governments play a role in the oversight of the petroleum sector. States own areas within three nautical miles (5.6 km) from the coast, while the Commonwealth owns areas 3-200 nautical miles from the coast.

The Commonwealth Government is responsible for all international issues, as well as economic policy and the administration and collection of corporate and personal income taxes, in addition the Commonwealth owns all petroleum rights offshore outside of a three mile coastal band although the State administers these on a day-to-day basis.

The State Governments own and allocate petroleum rights and oversee all petroleum operations (including those offshore areas that are nominally under Commonwealth control) and activities including royalty collection.

The State and Commonwealth Government coordinate their activities and administration via the Joint Authority, composed of State and Commonwealth Ministers, who is responsible for critical issues such as bidding, awards, work programs, and production licenses. The Joint Authority appoints a Designated Authority who is responsible for the approval of day-to-day operations such as seismic surveys, drillings and Environmental Management Plan approval.

The general philosophy in Australia has been that the Government does not cause petroleum developments or activities to happen and does not participate in them in its own right but rather leaves that to normal market and commercial forces.

The Governments' general approach to its role in the sector is consistent with roles the Western Australia Government describes for itself:

- Establishing the macro-economic environment (broad economic policy);
- Providing a regulatory framework for exploration, development, project approval processes, safety, environmental assessment and revenue provision;
- Reducing commercial risk in petroleum exploration by generating and disseminating basic geo-scientific information; and
- Looking for ways to remove impediments to the industry's competitiveness.

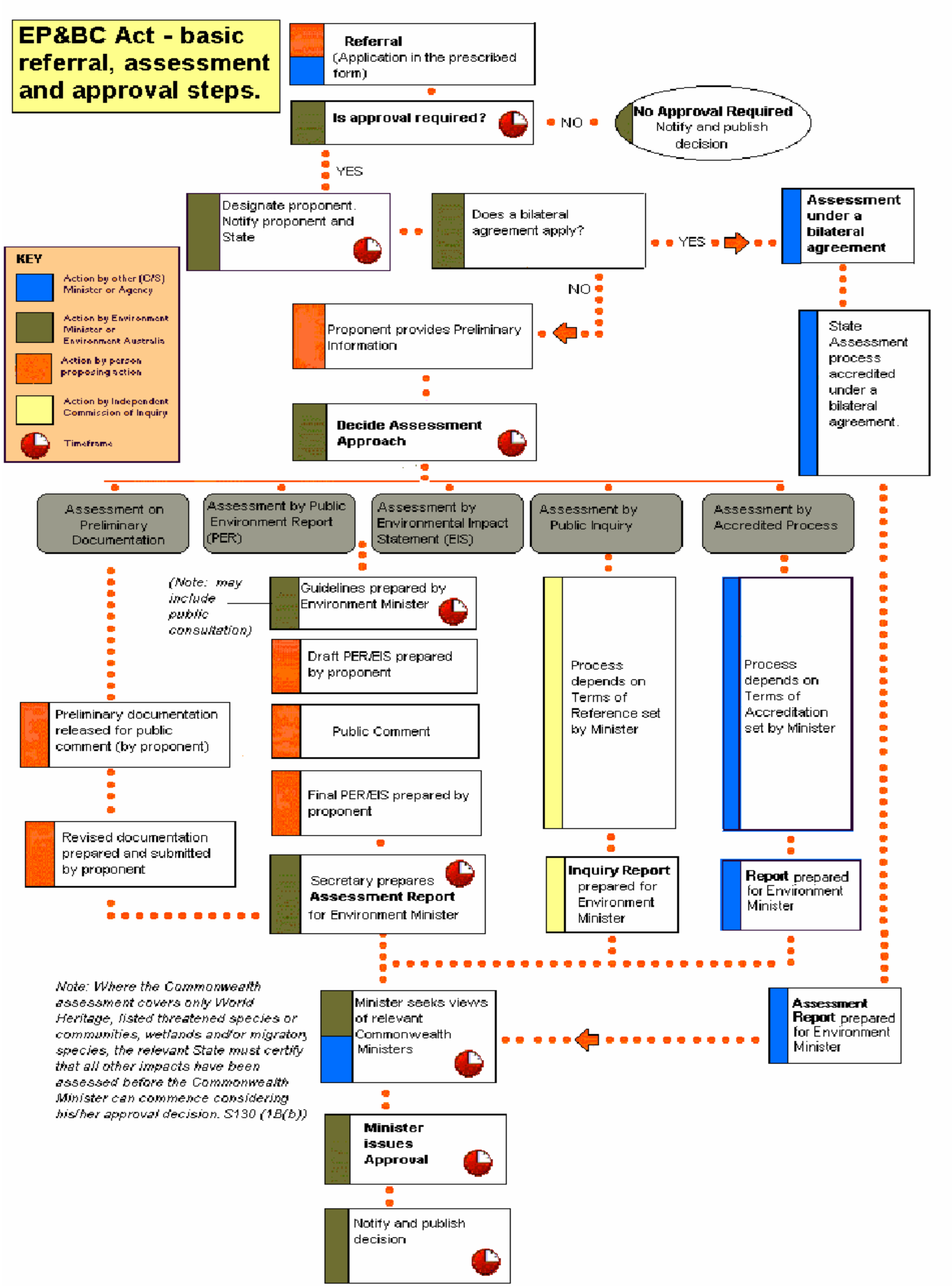
4.2.3 Permitting

Exploratory work can be undertaken by companies holding an Exploration Permit. Exploration areas are periodically released on a work program-oriented, competitive bid process. The State or Commonwealth Ministers nominate dates by which applications must be submitted (usually three months from announcement). Applications are usually done by individual companies, but if an application is done by a consortium, a heads of agreement for a Joint Operating Agreement (JOA) must also be submitted. The main considerations for the awards are the extent, timing and appropriateness of the proposed work program. Other criteria are financial and technical ability and, if bids are very close, consideration may be given to previous performance, Australian equity in the venture and the use of local goods, services and labor.

After a discovery, the permit holder can declare a "location" and has two years (extendable for two more years) to apply for a Production License. The permit holder has the statutory right to apply for production license if it deems the discovery is commercial. Production licenses have a term of 21 years, renewable for a further 21 years. For currently non-commercial discoveries which have potential to become commercial in up to 15 years, the permit holders can apply for a Retention Lease for that period.

Under the requirements of the *Petroleum (Submerged Lands) Act* of 1967, the Operator of a petroleum activity must not carry out any petroleum activity unless there is an accepted Environment Plan in force for that activity. This plan has an operational focus, with a requirement for description of systems and procedures to be used for reducing the risk to the environment. Environment Plans are to be submitted to the relevant Designated Authority, who has 28 days to accept or refuse the plan, or request the Operator to modify and resubmit a plan. An accepted Environment Plan will establish the legally binding environment management conditions that must be met by the Operator of an offshore petroleum activity.

Under the requirements of the *Environment Protection and Biodiversity Conservation Act* (EPBC Act) of 1999, if the license holder considers that the proposed development has, or has the potential to have, a significant impact on matters of national environmental significance, then it must submit a referral for the proposed development. The Commonwealth Ministry for Environment and Heritage has the responsibility to determine whether his approval under the EPBC Act is required (decision must be made within 20 business days), and the level of assessment needed. The level of assessment will depend on the nature of the expected impacts, and must be decided within 20 business days. The proposed development is then submitted to public consultation, after which Environment Australia will assess the report and submit it to the Minister of Environment for formal approval (see flow chart).



EP&BC Act - basic referral, assessment and approval steps.
Referral
(Application in the prescribed form)
Is approval required?
NO
No Approval Required
Notify and publish decision
YES
Designate proponent. Notify proponent and State
Does a bilateral agreement apply?
YES
Assessment under a bilateral agreement
NO
KEY
Action by other (C/S) Minister or Agency
Action by Environment Minister or Environment Australia
Action by person proposing action
Action by Independent Commission of Inquiry
Timeframe
Proponent provides Preliminary Information
State Assessment process accredited under a bilateral agreement.
Decide Assessment Approach
Assessment on Preliminary Documentation
Assessment by Public Environment Report (PER)
Assessment by Environmental Impact Statement (EIS)
Assessment by Public Inquiry
Assessment by Accredited Process
(Note: may include public consultation)
Guidelines prepared by Environment Minister
Draft PER/EIS prepared by proponent
Process depends on Terms of Reference set by Minister
Process depends on Terms of Accreditation set by Minister
Preliminary documentation released for public comment (by proponent)
Public Comment
Final PER/EIS prepared by proponent
Revised documentation prepared and submitted by proponent
Secretary prepares Assessment Report for Environment Minister
Inquiry Report prepared for Environment Minister
Report prepared for Environment Minister
Note: Where the Commonwealth assessment covers only World Heritage, listed threatened species or communities, wetlands and/or migratory species, the relevant State must certify that all other impacts have been assessed before the Commonwealth Minister can commence considering his/her approval decision. S130 (1B(b))
Minister seeks views of relevant Commonwealth Ministers
Assessment Report prepared for Environment Minister
Minister issues Approval
Notify and publish decision

The level of assessment set by the Commonwealth Environment Minister will depend on the nature of the expected impacts on matters of national environmental significance. The levels of assessment available to the Commonwealth Environment Minister include:

- Assessment on a case-by-case basis that may require completion of one or other of the following:
  - assessment on Preliminary Documentation;
  - assessment by Public Environment Report;
  - assessment by Environmental Impact Statement;
  - assessment by Inquiry;

- Assessment by an Accredited Assessment process under a Bilateral Agreement or Ministerial Declaration; and

- Assessment by an Accredited Approval process under a Bilateral Agreement or Ministerial Declaration.

The differences between these levels of assessment relate to the public review period and the detail of documentation required.

In parallel, proponents must also submit an application form to the Director of the Petroleum Division at the Department of Mineral and Petroleum Resources (MPR), the State regulator. This application must be accompanied by an Environmental Management Plan (EMP), containing background information on the proposal and its environmental issues and potential effects, as well as an Oil Spill Contingency Plan (OSCP) for exploration or production drilling. The MPR can not proceed with the assessment of the proposal until all necessary environmental information and supplementary information requested is received. The MPR will seek advice from other agencies where there are specific concerns (fisheries, conservation areas, etc.).

Based on the nature of the proposal, the MPR will either assess the proposal or refer to it to the State Environmental Protection Authority (EPA). In the latter case, a State Environmental Impact Assessment (EIA) will be required. The MPR has issued guidelines as to indicate what might trigger the more rigorous review. Generally, any activity that is in (a) a defined "protected area"; (b) within 3 nautical miles of shore; or (c) has potential for "significant impact"[1] is automatically referred to EPA. Regardless of the decision of the MPR, the EPA retains the right to call in any proposal for assessment, should it consider there is a potential for significant effects on the environment.

Circumstances where proposals are likely to trigger referral to the EPA for offshore activities are summarized in the table below (taken from the "Guide to Petroleum Exploration and Production in Western Australia", published by the Western Australia Department of Mineral and Petroleum Resources)

[1] MPR assesses this based on a number of criteria including: the character of the receiving environment and the use/value society has assigned to it; the magnitude, spatial extent and duration of anticipated change; the resilience of the environment to cope with change; the confidence of prediction of change; the existence of environmental standards against which a proposal can be assessed; and the degree of public interest in environmental issues likely to be associated with a proposal.

Type of Proposal	Protected areas[a]	State waters within 3 nm	States waters outside 3nm[b]	Potential for significant impact
Seismic exploration	Referred to EPA EPA assess	Referred to EPA MPR assess	Not referred to EPA MPR assess	Referred to EPA EPA assess
Exploration or appraisal drilling	Referred to EPA EPA assess	Referred to EPA EPA assess	Not referred to EPA MPR assess	Referred to EPA EPA assess
Production and development drilling	Referred to EPA EPA assess	Referred to EPA EPA assess	Not referred to EPA MPR or JA assess	Referred to EPA EPA assess

a. As defined in the New Horizons policy document.
b. Under the *P(SL)A* 1982, State jurisdiction may extend beyond 3 nautical miles to the outer extent of the Territorial Sea, e.g. in the North West Shelf region.

Once a proposal has been referred to EPA, the EPA has responsibility for determining the level of assessment, and determining the environmental acceptability of the proposal. The level of assessment will depend on the nature of the expected environmental effects and the level of public interest associated with the operation. The levels include non-assessment (a proposal considered to have environmentally insignificant effects), informal review, and formal assessment. An assessment level of "informal review with public advice" is applied to proposals for which the environmental effects associated with the proposal can be acceptably managed, or that the environmental effects are insufficiently significant to warrant formal assessment.

There are four levels of assessments (see following table):

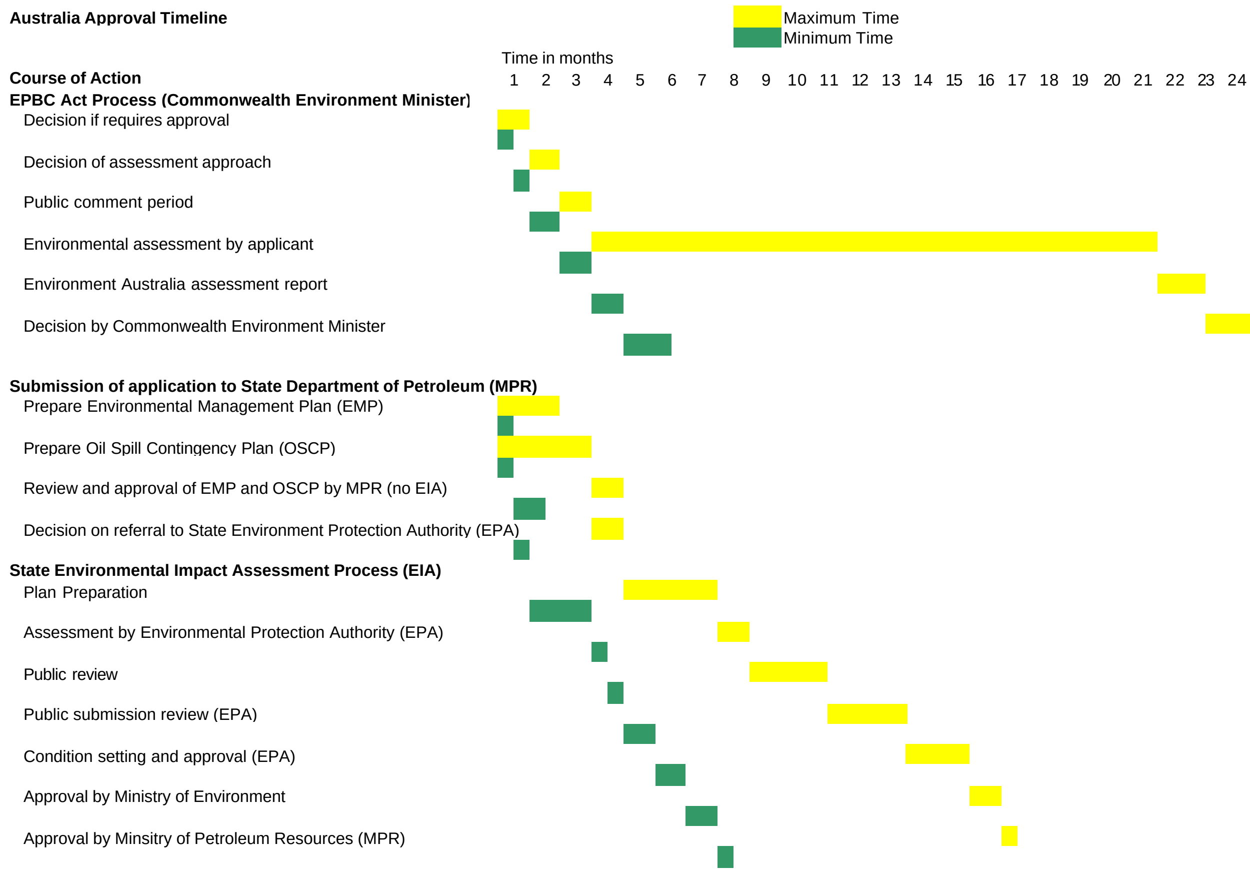
- Environmental Protection Statement (EPS);
- Proposals Unlikely to be Environmentally Acceptable (PUEA);
- Public Environmental Review (PER); and
- Environmental Review and Management Program (ERMP).

Their turn-around times range from one to four weeks in EPA, one to two weeks in MPR, four weeks in Ministry of Environment, and two to ten weeks for public submission review. The time required will depend on the location of the proposal and site-specific aspects of the proposed activity.

Levels of Assessment		Environmental Effect	Public Interest in Proposal
Not assessed	Not assessed by EPA	Insignificant	Minimal
Informal Assessment	Informal Review with Public Advice	Potential effects easily managed	Minimal
Formal EIA Process	Environmental Protection Statement	Significant effects but relatively easily managed	Local community or special interest groups
	Proposals Unlikely to be Environmentally Acceptable	Significant effects such that the proposal is unlikely to be approved	Major public interest
	Public Environmental Review	Significant effect not easily managed	Major public interest
	Environmental Review and Management Plan	Effects have strategic environmental implications	State-wide interest

Source: MPR Guide to Petroleum Exploration and Production in Western Australia

Upon acceptance of the environmental documentation by MPR, the proponent is notified that the proposal has been accepted and any ministerial conditions regulating the operation that have been set.



4.2 4 Other Observations on Australia's Regulatory Processes

The license holders in Australia have to deal with several authorities. At the Commonwealth level, when the EPBC process is triggered, the Commonwealth Environment Ministry is responsible for the environmental approvals, with the help of Environment Australia. At the State level, the license holders must deal with the State Department of Petroleum and the Environmental Protection Authority.

The regulatory process in Australia relies on legislation with considerable use of what they term "co-regulatory" approaches. The Commonwealth environment agencies have developed strong relations with the leading industry association to develop sustainable multiple-use solutions to the whole question of competing resource interests. The Australian Petroleum Production and Exploration Association (APPEA) is the national representative organization of the upstream oil and gas industry in Australia. It has over 50 member companies engaged in oil and gas exploration and production activities in Australia and over 80 associate member companies who provide services to the exploration and production parts of the industry.

The stated aim of the APPEA is to promote an efficient and effective policy, legislative and administrative framework for a competitive, safe, socially responsible and environmentally responsible petroleum exploration and production industry in Australia. PPEA regularly updates its Code of Environmental Practice, which provides the Australian petroleum industry with clear guidance on management practices and measures to protect the environment during onshore and offshore exploration, development and production.

It should also be noted that there is a widening perception of overlapping between the requirements of the Commonwealth and of the States, which may lead to a duplication of efforts, especially in the environmental impact assessments. This is currently under consideration by the Australian authorities, who wish to remove this duplicity and to change from prescription-based regulations into objective-based regulations.

4.3 Norway

4.3.1 Offshore Exploration and Production Context

The first license for a geological survey in Norway's offshore shelf was granted in 1962 however its first offshore licensing round did not take place until April 1965 shortly after reaching agreement with the U.K. and Denmark over common boundaries between the countries' territories. Twenty-two production licenses were granted in the first round and the first well (a dry hole) was drilled in mid-1966.

Norway has conducted a measured and phased opening of continental shelf, restricting the number of blocks awarded in each licensing, to maintain a moderate pace. The foreign companies dominated exploration in early stages, and the State oil company, Statoil, was created in 1972, aiming at building a Norwegian oil community, under the principle of 50% State participation in each production license.

The first discovery made was the Balder field in 1967 followed by the super-giant Ekofisk in 1969. Ekofisk's production startup in 1971 provided the launch pad for large scale infrastructure development in the Norwegian sector including the Norpipe oil pipeline (Ekofisk to U.K. in 1975) and the Norpipe dry gas pipeline (Ekofisk to Germany in 1977).

Frigg was discovered in 1971 and came on stream in 1978, while Statfjord (a field that straddled the U.K.-Norway border) was discovered in 1974 and came on stream in 1979. Norway's parliament, the Storting, approved the development of Troll and Sleipner East in 1986.

While these developments were taking place south of the 62nd parallel, the first production licenses north of the line in the Norwegian Sea were granted in 1980. The first discovery in this area was made in 1981 though the first development (Draugen) was not approved until 1988 and did not come on-stream until 1993.

Norway has conducted 17 licensing rounds since 1965 and numerous out-of-round allocations and "carve-outs". Norway has 195 current licenses in offshore waters. As of the beginning of 2003, 40 fields were in production and a further seven had been approved and were in various stages of development. There are a further 21 discoveries for which development decisions are expected to be taken over the next four years.

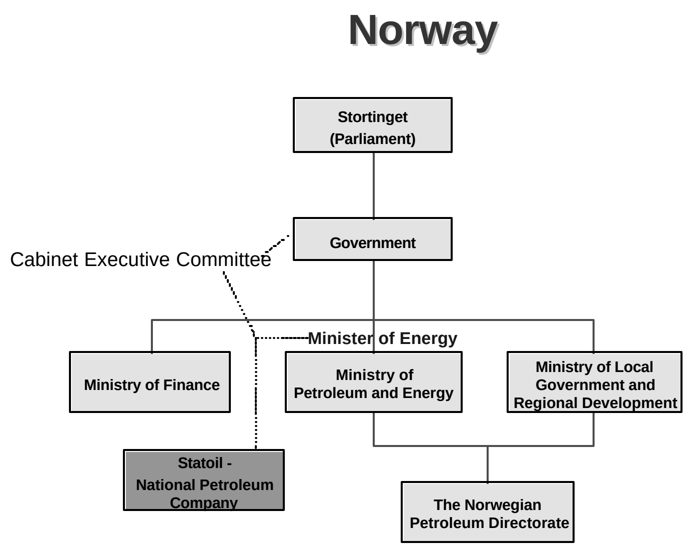
4.3.2 Regulatory Oversight of Petroleum Sector

Sovereignty over Norwegian Continental Shelf (NCS) was proclaimed in 1963, where the State owns natural resources and the Crown awards licenses for exploration and production. Oil and gas resources belong to the Norwegian community and must be managed for the maximum benefit of present and future generations.

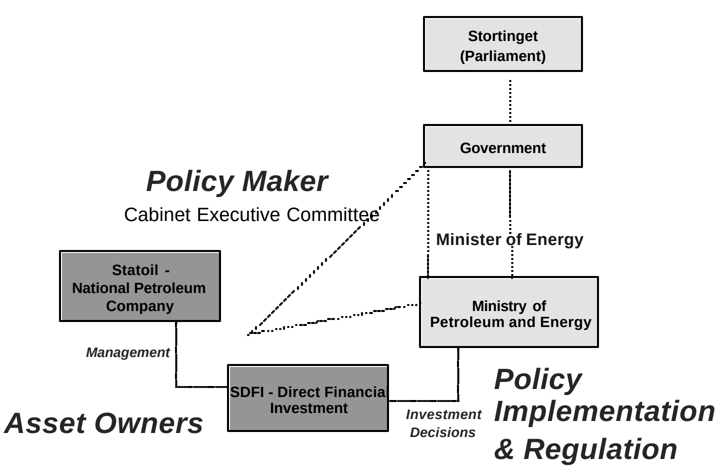
Norway is a generally an open-market economy, although with strong traditions of the state providing social benefits. While this is lessening to some degree, there is still strong state involvement in the economy.

Petroleum is an extremely important component in the Norwegian economy, representing 13% of GDP and about 33% of exports. It is a country of only some four million people and, along with Russia, is the world's second or third largest exporter of oil (behind only Saudi Arabia).

As such, the Storting has always closely controlled the exploration and exploitation of Norway's petroleum resources. This has ranged from limiting licensing to only those companies with whom it wishes to deal, to limiting the rate of exploration and development activity because of the impact it may have on the economy. The goals of Norwegian oil and gas policy are (i) national management and control, (ii) building a Norwegian oil community, and (iii) State participation (via Statoil and, prior to 2001, the State's Direct Financial Interest (SDFI). The Storting, government, Ministry of Petroleum and Energy (MPE) and Norwegian Petroleum Directorate (NPD) are responsible for administration of petroleum operations.



The MPE exercises political control (subject to final approval of certain matters by the Storting), and the NPD manages activities on a day to day basis. Although the NPD reports to both the MPE and the Local Government and Regional Development Ministry, all direction is set by the MPE. Over the years, Statoil has become less of a vehicle for involvement of the State and influencing operating decisions, and more of a private sector investor. However, the "state" relationship has not disappeared entirely, and national preferences can still be influenced to a degree by Statoil involvement in a project.



The MPE has close working relationships with the Ministry of Finance and also the Ministry for Local Government and Regional development. The second of these two Ministries is naturally concerned with the impact oil and gas developments have on local communities, both in creating jobs and changing the local environment. In Norway, this department is also responsible for the working environment, safety and emergency response plans within the petroleum sector. This function is kept deliberately outside of the MPE to ensure that there is no conflict of interest between monitoring of the safety and environmental impacts of the petroleum sector and maximizing the benefit of petroleum resources for the Nation.

The MPE is based in Oslo near the seat of government. It has a primarily monitoring and policy administration function, with no operational role and with most detailed technical analysis conducted on its behalf by the NPD based in Stavanger, the primary operating center for the E&P industry.

Historically much of the Government control over the sector was exercised by a centralized body for coordinating the export of natural gas (domestic consumption is approximately 6% of total production). This negotiating committee, known as the GFU, which was led by Statoil acting both in a commercial role and as regulator for the Norwegian authorities. While Statoil and government objectives were not always coincident, there was close liaison between the GFU and the gas team in the NPD over priorities. The allocation was based on the basis of the greatest estimated NPV to the country (with the exception of the super-giant Troll field which could alone meet Norway's contracted supply obligation though this would, of course, negatively impact any incentives for other companies to explore for or develop gas). With this exception, in practice this means the lowest cost supply for given future investment needs. Fields with large volumes of liquids production (associated gas, or rich gas-condensate fields) therefore do well in the priority system. In the face of European Union competition rules and the structural reforms within the sector cited below, the GFU and state-coordinated gas sales approach were disbanded in 2002. Individual producers are now free to seek their own markets although, importantly, within limits established and approved by the MPE.

The level of historical government oversight was not only a method of regulating the pace of development but also of attempting to manage prices (and therefore the benefits to be obtained by Norway as a whole) since a pure market force driver may have resulted in excess deliverability and falling prices.

The State's role in the sector has changed significantly in the last two years, not only with the dissolution of the GFU but also, in June 2001, Statoil was partially privatized and listed in New York and Oslo stock exchanges. The Norwegian government's stated intention was to concentrate on return on capital, dividends, with emphasis on long-term development of profitable operations and value creation for shareholders.

In connection with partial privatization of Statoil, a new company (Gassco AS) was created to manage the transport of natural gas, aiming at sharing neutrally the gas transport services and contribute to the efficient utilization of the Norwegian Continental Shelf resources

Also in 2001, the SDFI was restructured: 15% were sold to Statoil, while 6.5% were sold to other companies in 2002. A new company, Petoro AS, was created to manage SDFI on behalf of the State, with the long-term objective to create the largest possible economic value for the State's total economic assets.

In June 2003, the Storting approved a proposal to split off the part of the NPD that deals with safety and working environment into a separate supervisory body – the Petroleum Safety Authority (PSA). The new supervisory body will be in operation from 1 January 2004.

4.3.3 Permitting

Companies can apply for reconnaissance license (geological, petrophysical, geophysical, geochemical, geotechnical surveys, shallow drilling), which does not grant exclusive rights nor rights to exploration drilling. The areas are opened for exploration after assessment of environmental, economic and social impacts of operations on other industries and adjacent regions.

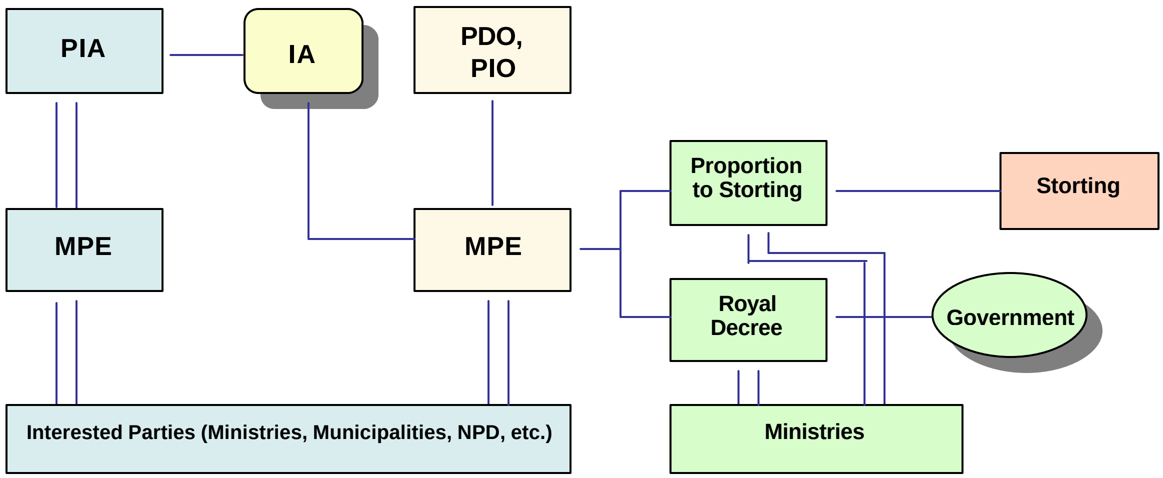
Production licenses awarded through licensing rounds, where companies normally apply individually. The awards are based on "objective, non-discriminatory and published criteria", but the MPE generally puts together a group of companies for each license and appoints the operator for the partnership. This is based on the MPE's perception of which is the most adequate work program proposed by the companies, as well as the technical and financial capabilities of each of the companies involved. From 1973 to 1991, the State participation was a minimum of 50% in each license.

The Licensees are responsible for preparing and submitting an Impact Assessment (IA) to the MPE. This should be started when a discovery is considered commercial, by preparation of a proposed Program for Impact Assessment (PIA). The PIA should describe the development and its anticipated impacts on the environment, and provide opportunity for the authorities and interested parties to submit comments on what should be included in the IA. The MPE circulates the PIA to concerned authorities and other interested parties for their comments. These comments should be submitted within 12 weeks or less, as decided by the MPE, depending on the size, complexity and extent of the possible impacts on the environment.

The IA, which is based on the approved PIA, is prepared by the Operator (the Assessment Phase) and its results are submitted to the MPE, who circulates the IA to all parties entitled to submit comments and establishes the deadlines for reply (in general 12 weeks). The whole process (submittal of PIA, plus preparation and submittal of IA) will take 24 weeks, plus the time needed for the Operator to prepare the IA. This can be further extended if the MPE decides there is a need for additional information.

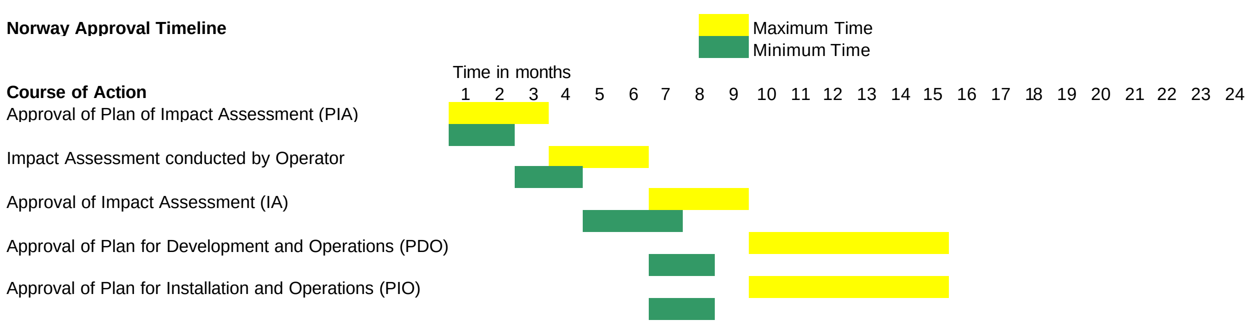
Together with the IA, the Operator will submit to the MPE a Plan for Development and Operations (PDO) and a Plan for Installation and Operations (PIO) for transportation facilities. The PDO contains an account of economic, resource, technical, safety related, commercial and environmental aspects; information as to how the facility may be decommissioned and disposed; information on facilities for transportation or utilization. The PIO must contain a plan for the construction, placing, operation and use of such facilities, including shipment, pipelines, liquefaction, generation and transmission of electrical power, and other facilities.

The MPE will consult with the Ministry of Local Government and Regional Development for consideration of safety and working environment aspects, and with the NPD for consideration of resource related aspects. Based on these consultations, the MPE drafts a proposition to the Storting (for development projects with estimated investments in excess of NOK 10 billion or approximately US$1.3 billion), or a Royal Decree which is subject to a consultation process with the Ministries concerned. The MPE aims at a processing time of eight weeks for approval of PDOs and PIOs which do not require approval by the Storting. This is feasible if the Operator discusses with the authorities in advance on issues such as production strategy, development concept, health, environment and fisheries matters, and submits the IA two to three months in advance of the PDO and the PIO. This process is summarized in the flowchart below:



GLOSSARY:
PIA: Plan of Impact Assessment
IA: Impact Assessment
PDO: Plan for Development and Operations
PIO: Plan for Installation and Operations
MPE: Ministry of Petroleum and Energy
NPD: Norwegian Petroleum Directorate

The MPE may request a detailed account of the impact on environment, risks of pollution and impact on other affected activities. This usually takes four to six months to be completed.



In the case of a staged development, the PDO shall comprise the total development (to the extent possible), but approval may be granted to individual stages. The MPE must be notified of any significant deviation or alteration of PDO, and may require a new or amendment plan to be submitted for approval.

Upon application of the Licensee, and for fixed periods of time, the MPE stipulates the quantities that may be produced, injected or vented. This is based on the PDO, unless new information warrants otherwise. The "King in Council" may also stipulate, for "weighty social reasons", that production schedules will be raised or lowered.

The offshore operations are subject to strict environmental regime, where the companies pay a carbon dioxide tax, can flare gas under permission only, and are subject to zero discharge of hazardous substances into sea.

The MPE may also decide on the postponement of exploration drilling or field development, and may also require the Licensee to prepare, commence or continue production. This may happen if this is considered economically beneficial to the society, when necessary to develop an efficient transportation system, to ensure efficient utilization of facilities, for reservoir engineering reasons or for field unitization. In these cases, the Licensee has a two-year period to present a PDO, and 6 months to revise PDO if deemed necessary by MRE. If the Licensee does not present in due time or is not willing to prepare, commence or continue production, than MPE may revoke the license and reimburse exploration costs.

A Decommissioning Plan must be submitted to MPE if license expires or is surrendered, or if the use of a facility is terminated. This plan contains proposals for continued production or shutdown of production and disposal of facilities, and must be submitted at earliest five years and at latest two years before the expected termination of use of the facility.

Going forward, there are suggestions that the Norwegian government will make further enhancements, streamlining and reforms to its regulatory processes:

- The latest licensing initiative promises a more aggressive effort to stimulate activity in the more mature parts of the Norwegian shelf below the 62^{nd} parallel.

- The NPD will commence using its web site as the primary medium for communication concerning various HSE activities. These include:

    - Identical letters to the industry (relating to supervision);
    - Summaries of the NPD's investigations of undesirable incidents;
    - Summaries of the NPD's audit reports;
    - Orders;
    - Brief notices on consents; and
    - Notices on Acknowledgement of Compliance issues.

- New rules for offshore HSE approved in late-2001 culminated a long process to streamline and consolidate aspects of the regulatory oversight process. Simplifying the HSE regulations began as far back as 1985, when the rules comprised 25 separate documents. Over the subsequent 17 years, this total has been reduced to five. The revised offshore HSE regulations, valid from 1 January 2002, represent a pioneering collaboration between the NPD, the Board of Health and the Norwegian Pollution Control Authority. An NPD survey of 1995 asked the industry about its experience with the existing regulations, and a clear desire was expressed for less detailed control and more focus on areas. The companies also noted the rules as they stood contained too much repetition, and were too extensive. In part, this streamlining was achieved by transferring many of the guidelines in the regulations to industry standards.

4.4 United States of America – Gulf of Mexico

4.4.1 Offshore Exploration and Production Context

Offshore activity in the U.S. Gulf of Mexico (GOM) effectively started in 1947 when Kerr-McGee drilled a well from a fixed platform out of-sight of land. It thus pre-dated offshore activity in the North Sea and Australia by about 15 to 20 years. Activity grew steadily over the years, and by the late 1970s there were more than 800 platforms, and annual spending was some US$16 billion. The GOM was also the spawning ground for a number of technical innovations, including prototypes of ROVs and dynamically-positioning drillships.

Although early activity was concentrated in shallower water-depths, the GOM was also one of the leading areas in moving into deep water, and in 1992 Shell installed the "Bullwinkle" platform in 1,350 ft of water – at the time the world's tallest standing structure.

The GOM was beginning to be seen as a mature province when drilling moved into ultra-deep water in the early 1990s. Discoveries were soon made in water depths in excess of 3,000 ft, and developments followed. By 1997, 16 deepwater projects were on production, but this grew rapidly to 51 by the end of 2001, with a further 13 scheduled to come on stream in 2002. Some of the largest fields ever discovered in the GOM have been made in the deep water since 1995, and what is believed to be the largest ever (Crazy Horse) was discovered as recently as 1999. Currently nearly 60% of all GOM production comes from the deep water areas.

A feature that further differentiates the GOM from other areas of the world is the licensing system. Licenses are awarded by cash bonus bidding, and auctions are typically held twice a year – one for the western part and one for the central. The eastern GOM is theoretically available for license, but there is no activity there for environmental reasons. Not only are licenses offered more frequently than elsewhere, but blocks are significantly smaller. In total there have been 115 licensing rounds in the GOM, with over 18,000 leases issued. About 7,500 leases are currently active, and there are some 4,000 active platforms.

A typical GOM block is only 5,000 acres (approximately 20 sq kms), compared to 200-250 kms in the U.K. North Sea and 350 – 500 sq kms in the Norwegian sector. Taking together the license frequency and number of blocks on offer (together with the infrastructure and product – especially gas - offtake absorption capacity of the U.S.), the GOM with more than 100 companies operating (and many more participating) in the Gulf of Mexico has significantly more players than any of the other oil and gas province.

4.4.2 Regulatory Oversight of Petroleum Sector

The U.S. has a federal system wherein regulatory control is (can be) exerted at both state and federal levels and a substantial degree of authority overlap is built into the system (part of the "checks and balances" philosophy that is in the U.S. Constitution). Economically, the U.S. is a free market system in almost every area of the economy, and regulatory structures reflect this.

The Minerals Management Service (MMS), a bureau within the Department of Interior, regulates and manages the development of mineral resources in the Federal waters off the nation's shores. MMS also collects, audits and distributes all mineral revenues from these federal waters as well as from mineral resources on both Federal and Indian lands.

Established in 1982 by the Secretary of the Interior, MMS comprises four program areas: Offshore Minerals Management, Minerals Revenue Management, Administration and Budget, and Policy and Management Improvement. The MMS mission is to manage the mineral resources in Federal lands and waters in an environmentally sound and safe manner and to timely collect, verify, and distribute mineral revenues from federal and Indian lands.

The Federal government owns a vast amount of land, both on and offshore. These lands are managed for various purposes, including mineral production. Federal offshore lands begin approximately three nautical miles off coastal shorelines and extend 200 nautical miles out to sea. This area, known as the Outer Continental Shelf (OCS), covers about 1.76 billion acres in waters ranging in depth from a few feet to thousands of feet.

The Offshore Minerals Management Program provides oversight of industry's development of the mineral resources in these offshore areas - about 7,600 active leases on 40 million acres. This oversight helps ensure safe exploration and development, environmental protection and impact mitigation, and receipt of fair market value for mineral development. The deep water OCS accounts for over 60 percent of total Gulf of Mexico OCS oil production and about 24 percent of total Gulf of Mexico natural gas production.

The Minerals Revenue Management Program annually collects more than US$6 billion in mineral revenues from more than 84,260 onshore and offshore leases.

4.4.3 Permitting

The MMS publishes a five-year licensing program, indicating when and where blocks will be offered. The winner is selected based upon the highest cash bid for each block, but the MMS reserves the right to refuse a bid if it considers that the value offered for the block is not compatible with its value. The decision on the acceptance of the bids must be taken within six months, but usually occurs within one to two months.

Before initiating any exploration activity, the license holder must file an Exploration Plan (EP), containing a shallow hazard survey and an environmental assessment, plus information on all exploration activities planned by the operator for a specific lease(s), the timing of these activities, information concerning drilling vessels, the location of each well, and other relevant information.

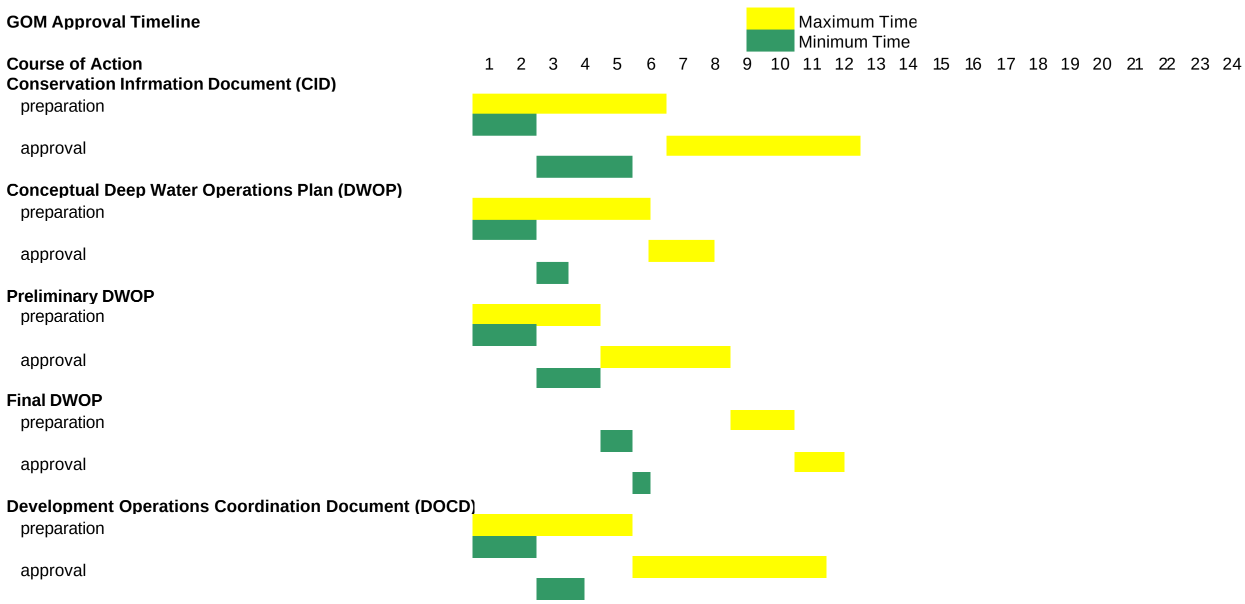
The MMS usually takes one to two months to approve the EP, except in Florida where more strict environmental requirements delay the process to six to nine months (if, indeed, it proceeds at all). In exceptional cases, there is a "walk through" approval process, which reduces the approval time to a few days only. Permits to drill are also issued within a few days.

The License owner must also submit a Conservation Information Document (CID) for approval. The CID contains technical information, such as geological, geophysical and reservoir data, as well as the plan to manage reservoir production.

For deep water operations (water depth greater than 1,000 ft, or 300 m), since 1995 the license holder must file a Deep Water Operations Plan (DWOP). This is divided in three documents: the Conceptual DWOP, the Preliminary DWOP and the Final DWOP.

In parallel to the DWOP submission, the license holders must also file a Development Operations Coordination Document (DOCD). This document contains supporting environmental information, archaeological report, biological report (monitoring and/or live-bottom survey), or other environmental data determined necessary. It must also describe a schedule of development activities, platforms, or other facilities, including environmental monitoring features and other relevant information. The DOCD and its supporting environmental information, as required, are sent to the affected State(s) having an approved Coastal Zone Management plan for consistency certification review and determination.

After DOCD approval, the operator submits for approval specific applications to MMS, such as those for pipelines and platforms, to conduct activities described in the DOCD.



4.5 United Kingdom

4.5.1 Offshore Exploration and Production Context

North Sea oil and natural gas were first discovered in the 1960s. The U.K. North Sea, however, did not emerge immediately as a key oil producing area until the late 1970s when major discoveries such as Forties and Brent Fields began coming online. The first licenses for offshore U.K. were granted in 1964 and the first well was drilled by Texaco/Chevron. BP discovered the first gas field at West Sole in 1965, and production started in 1967. First oil was found in U.K. waters by Amoco at Arbroath Field. Hamilton's Argyll and Shell/Esso's Brent, both primarily oil fields, started production in 1975. In 1994 a record number of fields (33) received development authority approval, including Foinaven, the first oilfield to be developed in the Atlantic, to the west of Shetlands. A record number of offshore fields (186) were in production at the end of 1997, and production commenced at 22 new offshore fields. Two hundred and four offshore fields were in production at the beginning of 1999. All the largest and most easily developed oil fields have been discovered and are now past their production peak. North Sea offshore crude oil production peaked in 1999, and has declined in both 2001 and 2002. As of 2003, the U.K. has conducted 17 licensing rounds and has approved 293 fields for development.

4.5.2 Regulatory Oversight of Petroleum Sector

Although the U.K. is an open market economy, until the mid 1970s most utilities were delivered by state monopolies which had resulted from consolidations and nationalizations in the 1940s and 1950s. Following the election of the Thatcher government in 1979, there was a complete political about-face, and most state-run entities were restructured and have been privatized. Restructuring of these industries continues, as does the regulatory structure put in place to manage them.

In the U.K., the petroleum licensing regime is overseen by the Oil and Gas Directorate of the Department of Trade and Industry (DTI). Its overall aim is to maximize the economic benefit to the U.K., taking in account the environmental impact and the need to ensure energy supplies at competitive prices.

The objectives of this policy are (i) to ensure the recovery of all economic hydrocarbon reserves, (ii) to ensure adequate and competitive provision of pipelines and facilities, and (iii) to take proper account of environmental impacts and the interests of other users of the sea.

To ensure the recovery of all economic hydrocarbon reserves, the DTI seeks agreement with the licensee on a development option that is the most likely to secure full recovery of economic reserves. Economic reserves are defined as those for which the market value is larger than the cost of extraction (using a 10% discount rate).

To ensure adequate and competitive provision of pipelines and facilities, the DTI will encourage interested parties to cooperate in constructing and sizing lines according to future potential. Therefore, pipelines may be oversized to create capacity for future tie-in developments, as the DTI will seek to avoid unnecessary proliferation of pipelines. However, this may create some conflicts which require regulatory action form the DTI to ensure that those building and operating pipelines and other infrastructure compete on a level playing field and that third party access to infrastructure is streamlined, easy and fair. (Indeed, this issue of control of infrastructure access and tariffing is one of the major issues in the U.K. North Sea today).

Taking proper account of environmental impacts and the interests of other users of the sea puts a high priority to the prevention of pollution. Flaring must be authorized to avoid unnecessary wastage, especially since the U.K. has gone beyond Kyoto Protocol commitments, targeting 20% reduction in CO_2 from 1990 levels by year 2010. Environmental Impact Assessments must be carried out for most developments, the Fishery Department and fishery organizations which operate in the area of development must also be consulted.

4.5.3 Permitting

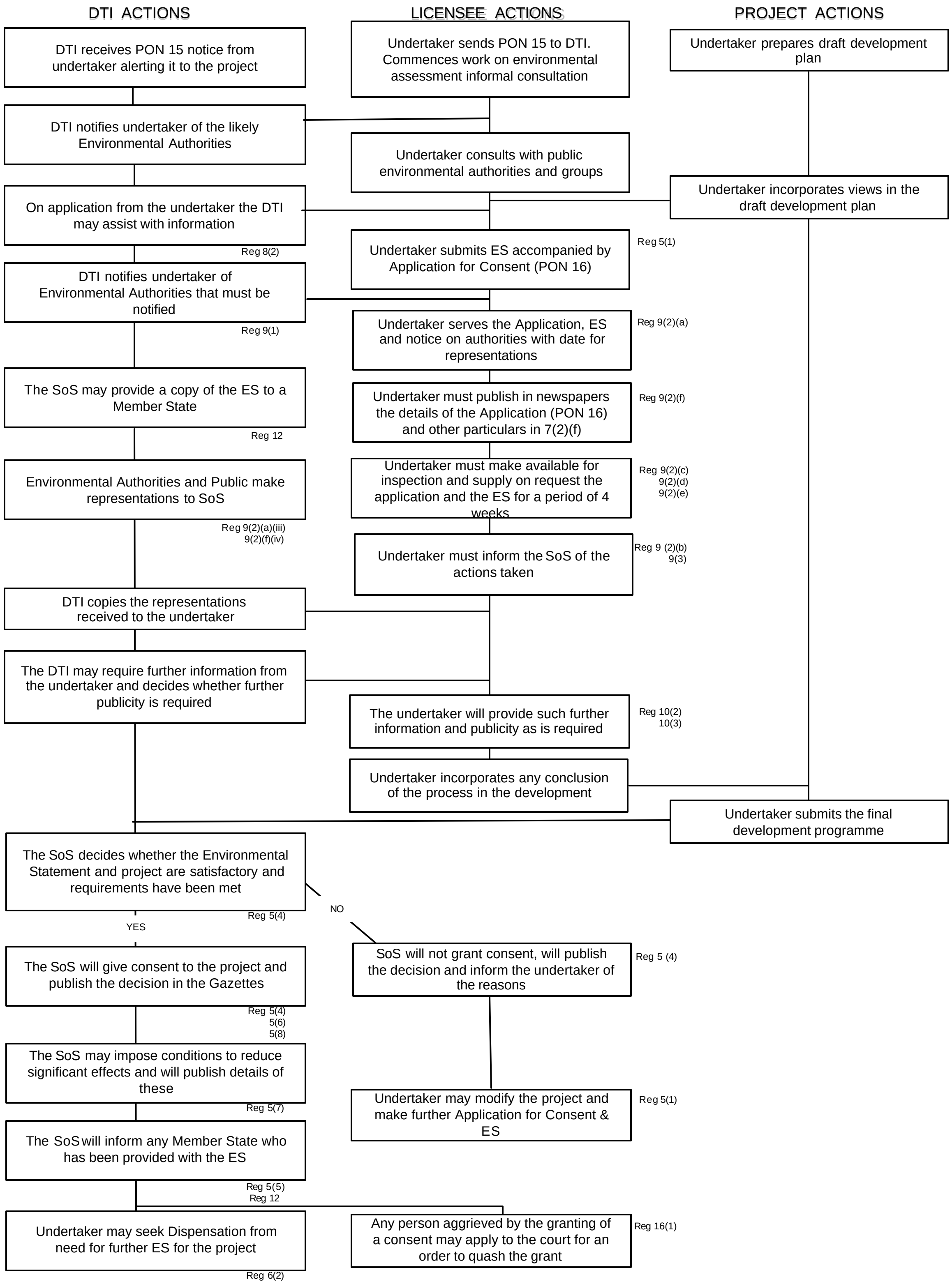
The DTI will ensure that practices harmful to future oil and gas recovery, or which conflict with the interests of other potential users of the licensed area, are avoided at all stages of planning and development. To determine good practices, Licensees proposals will be compared to the practice adopted in similar, successful developments. This is an important characteristic of the U.K. regulatory regime, as the DTI is involved since the very early stages of preparation of the Field Development Programs (FDP).

The FDP is the support document for development and production authorizations. It must be discussed with DTI, aiming at identifying and resolving aspects related to DTI's objectives and elements on which there are divergences. The FDP should provide a summary of the information and requirements that led to the proposed development, together with a more detailed account of the development's principles, objectives and management.

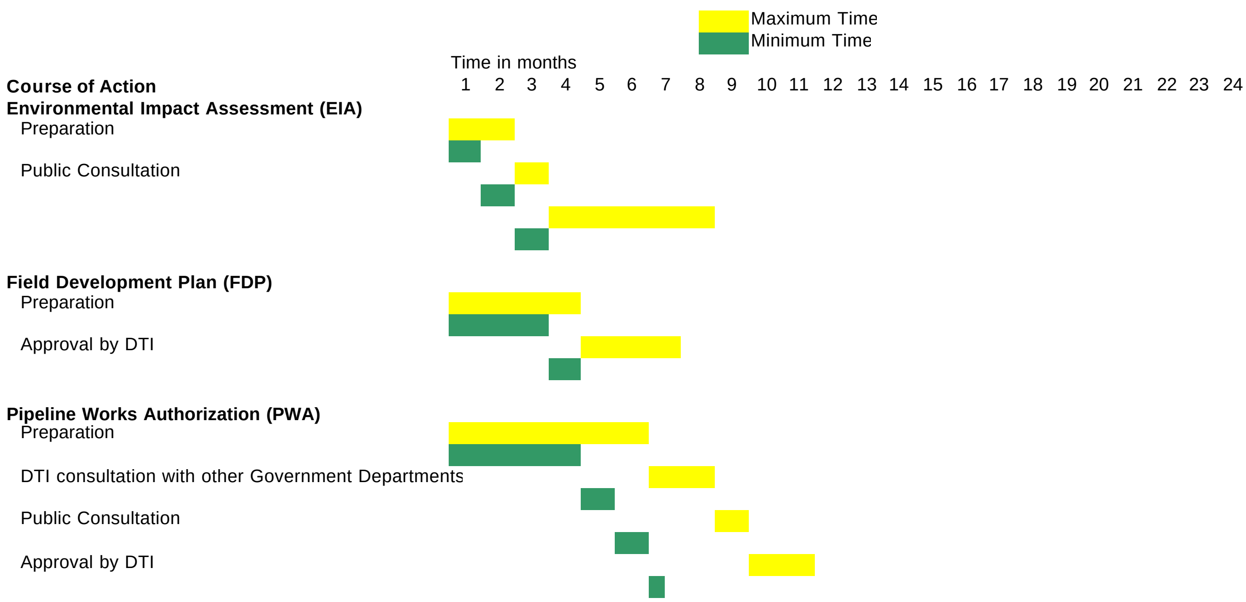
To meet the DTI's policy objectives, the discussion process which leads to the submission of the FDP is started at the beginning of the appraisal activities. The aim of the process is to identify the aspects of the FDP that relate to the DTI's objectives and to identify where the views of the Licensee and of the DTI may diverge. The Operator, representing all licensees (which are jointly and severally liable), will discuss the FDP with a multi-disciplinary team assigned by the DTI. The DTI team will be headed by a manager empowered to take technical decision on behalf of the DTI and to coordinate, where necessary, DTI's response on policy issues. The DTI will formally notify of any aspects where a conflict of views is identified, so these issues can be resolved in the early stages of field development planning. When an agreement has been reached on some issues (intermediate decisions), the DTI may issue "Letters of Assurance". Although this should not be taken as an indication that the final Field Development Program will be approved, it gives comfort to the licensees that there are no major issues pending.

When the above-described interactive process has been fully implemented and there are no major unresolved issues, the DTI aims at approving Field Development Program in one month. This is a very short time frame, made possible only by the interactive process initiated since the appraisal of the discoveries.

Approval of the FDP also requires completion of an Environmental Impact Assessment (EIA). This requires formal consultation with relevant environmental authorities (the names of which will be notified to the Licensee by the Secretary of State) and must also be advertised and made available to the public. If there are no objections from the interested parties, the approval cycle time does not exceed three months. If there are objections, approval will take as long as needed to overcome these objections. This can be the most time-consuming aspect of obtaining FDP approval, but can be done in parallel with the FDP discussion with the DTI, it does not usually represent a delay in obtaining approval. The flowchart for the Offshore Petroleum Production and Pipelines Assessment of Environmental Effects) Regulations 1999 can be found on the next page.


DTI ACTIONS
LICENSEE ACTIONS
PROJECT ACTIONS
DTI receives PON 15 notice from undertaker alerting it to the project
Undertaker sends PON 15 to DTI. Commences work on environmental assessment informal consultation
Undertaker prepares draft development plan
DTI notifies undertaker of the likely Environmental Authorities
Undertaker consults with public environmental authorities and groups
Undertaker incorporates views in the draft development plan
On application from the undertaker the DTI may assist with information
Reg 8(2)
Undertaker submits ES accompanied by Application for Consent (PON 16)
Reg 5(1)
DTI notifies undertaker of Environmental Authorities that must be notified
Reg 9(1)
Undertaker serves the Application, ES and notice on authorities with date for representations
Reg 9(2)(a)
The SoS may provide a copy of the ES to a Member State
Reg 12
Undertaker must publish in newspapers the details of the Application (PON 16) and other particulars in 7(2)(f)
Reg 9(2)(f)
Environmental Authorities and Public make representations to SoS
Reg 9(2)(a)(iii) 9(2)(f)(iv)
Undertaker must make available for inspection and supply on request the application and the ES for a period of 4 weeks
Reg 9(2)(c) 9(2)(d) 9(2)(e)
Undertaker must inform the SoS of the actions taken
Reg 9 (2)(b) 9(3)
DTI copies the representations received to the undertaker
The DTI may require further information from the undertaker and decides whether further publicity is required
The undertaker will provide such further information and publicity as is required
Reg 10(2) 10(3)
Undertaker incorporates any conclusion of the process in the development
Undertaker submits the final development programme
The SoS decides whether the Environmental Statement and project are satisfactory and requirements have been met
Reg 5(4)
YES
NO
SoS will not grant consent, will publish the decision and inform the undertaker of the reasons
Reg 5 (4)
The SoS will give consent to the project and publish the decision in the Gazettes
Reg 5(4) 5(6) 5(8)
The SoS may impose conditions to reduce significant effects and will publish details of these
Reg 5(7)
Undertaker may modify the project and make further Application for Consent & ES
Reg 5(1)
The SoS will inform any Member State who has been provided with the ES
Reg 5(5) Reg 12
Undertaker may seek Dispensation from need for further ES for the project
Reg 6(2)
Any person aggrieved by the granting of a consent may apply to the court for an order to quash the grant
Reg 16(1)

Where the proposed development contemplates pipeline facilities extending outside of the license boundary, licensees must also apply for a Pipeline Works Authorization (PWA). On receipt of an application, DTI will decide whether the application is to be considered further or rejected. The application will then be forwarded to consultees for comment. (These are generally other Government Departments and users of the sea). When any queries have been answered, the DTI will normally notify the applicant that he is to proceed to Public Notice. This requires the applicant to publish and make available for inspection details/maps of his project in such publications and at such addresses as may be directed by the Secretary of State for a period of 28 days. Once objections have been resolved or if no comments have been received, the Pipeline Works Authorization may be issued. The PWA contains terms which must be adhered to and gives detail in tabulated form of the pipeline(s). DTI will inform all consultees of the issue of the PWA and arrange publication of a notice to this effect.



Companies interviewed indicated that the process is very smooth due to the constant interaction with the DTI, who has done considerable effort to cut down cycle times and to reduce the requirements for information in the FDPs. The DTI goal is not to review the technical aspects of the FDP, but rather identifying and resolving potential areas where DTI's and Licensee's goals may diverge. This was a result of the work undertaken by the *Oil and Gas Industry Task Force* in the late 1990's.

4.5.4 Other Observations on the U.K.'s Regulatory Processes

Several structural and philosophical changes have taken place in the regulation of the U.K. petroleum sector. Initially the State had a heavier involvement in the sector (ownership position in BP, BNOC as majority oil off-taker and British Gas as monopoly gas buyer), it was also treated separately within Government – having its own Secretary of State. The push towards market-based reform in the U.K. in the early-mid 1980s resulted in both a withdrawal of the State from direct participation in the sector, as well as the Government treating the oil and gas sector no differently than other industrial activities.

As in Australia, "co-regulatory" aspects have had a significant impact on the way industry is regulated, the U.K. Offshore Operators Association (UKOOA) is the representative organization for the U.K. offshore oil and gas industry. Its members are companies licensed by the Government to explore for and produce oil and gas in U.K. waters. UKOOA states its mission as "To provide leadership to maintain the development of a forward-looking, profitable, thriving and responsible offshore oil and gas industry and to enhance its reputation and develop relationships with government, public and other stakeholders". In conjunction with UKOOA, the DTI has also taken a more active role in promoting and spurring industry activity through initiatives such as CRINE[2], PILOT[3], LIFT[4], and others.

4.6 Comparison of the White Rose and Sable Developments with Hypothetical Developments in the Reference Jurisdictions

4.6.1 The White Rose and Sable Developments

The White Rose Field was discovered in 1984, in the Jeanne d'Arc Basin. The oil pool covers approximately 40 km^2 and contains an estimated 200-250 million barrels of recoverable oil. First oil is expected in late 2005 or early 2006.

The White Rose Project was subject to review under the Canadian Environmental Assessment Act (CEAA), which was initiated when the proponent submitted the project description in March 2000. In October 2000, the proponent submitted to the CNOPB a Comprehensive Study Report, which was reviewed by the Canadian Environmental Assessment Agency and by the Federal Minister of Environment, and made available for public comment and review. In June 2001, the Federal Minister of the Environment determined that the project did not require further environmental assessment.

In a parallel process, the White Rose Development Application was filed with the CNOPB in January 2001. The CNOPB did its internal review and provided the completed application to the appointed Commissioner and to public review. This began in July 2001 and was concluded in September 2001. The CNOPB examined all aspects of the Development Application, including reservoir and drilling aspects, production systems, Canada-Newfoundland benefits, and safety and environmental impacts. The application was approved by the CNOPB in December 2001.

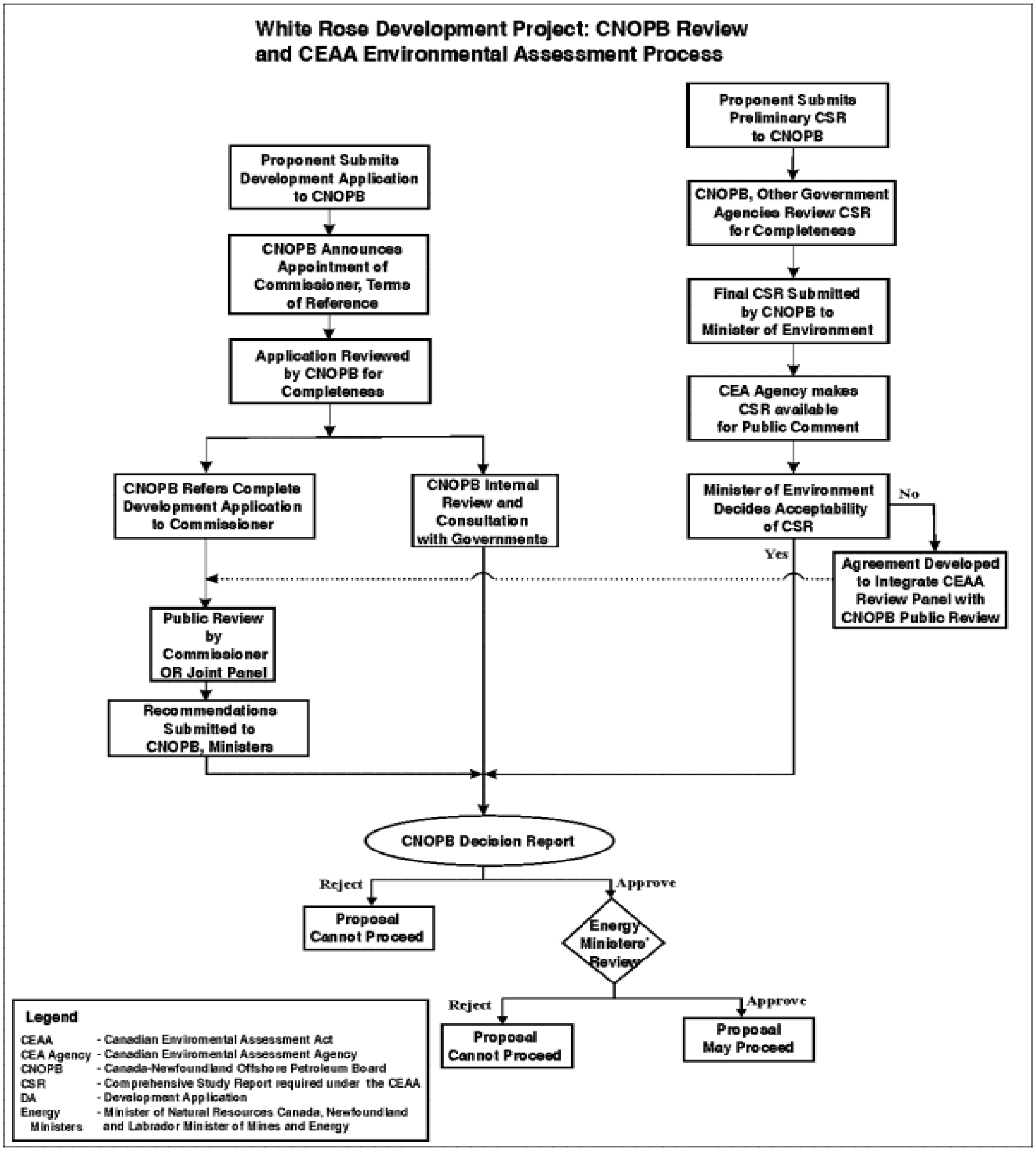
The flowchart for the CNOPB review and CEAA environmental Assessment Process is found below (taken from Sheppard, 2003).

The total duration of the process, from submittal of the project description until project approval was 21 months. . This is comparable to the maximum timeframes encountered in the Reference Jurisdictions.

[2] CRINE (Cost Reduction in the New Era) was a 1993 initiative comprised of representation from all sectors of the UK offshore industry including the DTI, UKOOA, operators, contractors, suppliers etc. CRINE's activities have since been assumed by LOGIC (Leading Oil and Gas Industry Competitiveness) a similarly composed body with an overall objective of promoting best practice in the supply chain.

[3] PILOT is a joint Government-industry body that also targets improving/maintaining competitiveness in the UKCS.

[4] LIFT (License Initiative For Trading), an initiative to increase liquidity of acreage and encourage activity on licensed but inactive or "fallow" areas.



The Development Plan application for the Sable Offshore Energy Project was submitted to the Canada Nova Scotia Offshore Petroleum Board (CNSOPB) on June 14, 1996. The CNSOPB provided its Decision Report for the Project on December 4, 1997 and production began on December 31, 1999. This project has an offshore and an onshore component. The onshore component included the construction of a pipeline, whose application was filed in October 1996, four months after submission of the Development Plan. There was a considerable amount of informal and formal communication between the proponent and the regulator.

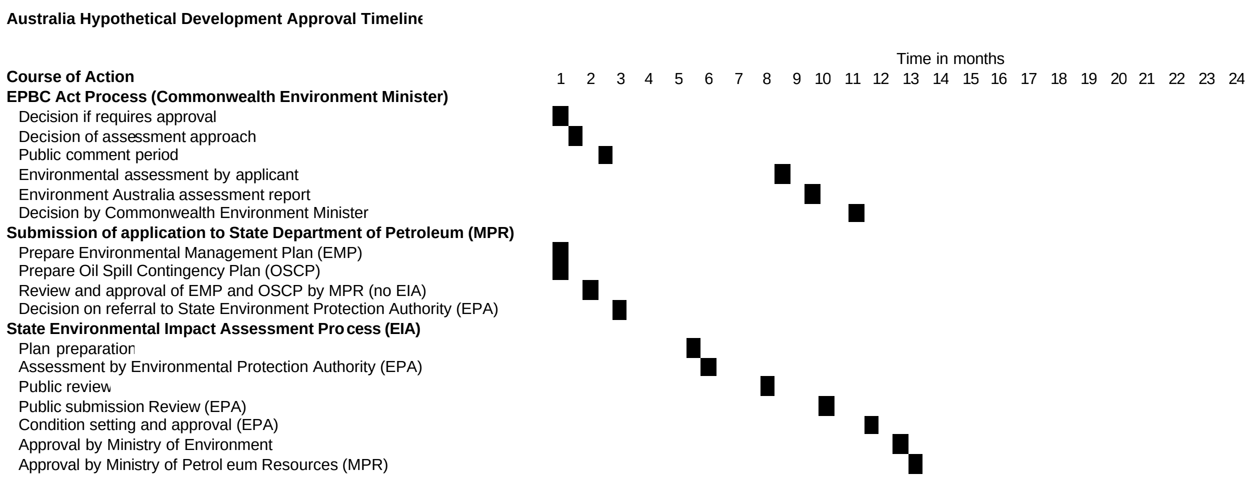
4.6.2 Hypothetical Developments in the Reference Jurisdictions

The hypothetical developments in the Reference Jurisdictions were based on the average approval timeframe identified in the surveys. The focus has been on the approval timeframes between the submission of the development plan and the approval by the relevant authorities. Though a relationship between the drilling of the final appraisal well and the first oil was sought the data were inconclusive since the time intervals between appraisal wells and developments in the fields surveyed were so variable and appeared more contingent on internal appraisal decisions rather than regulatory approvals. Further, the information gathered suggests there are no significant variations in the approval process timeframes between the reference jurisdictions for seismic acquisition and well drilling.

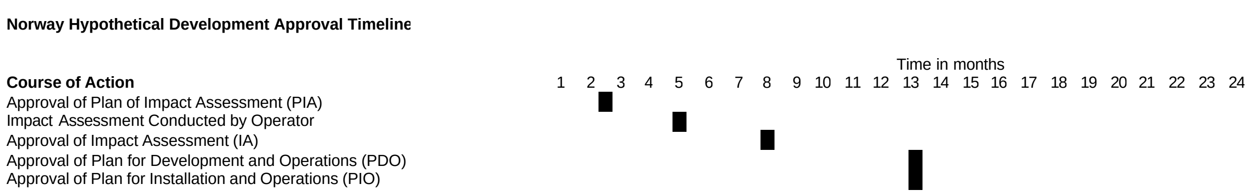
The results can be seen in the following figures. The U.K. development had the shortest approval time (less than nine months), followed by the U.S. Gulf of Mexico (ten months), Norway (13 months) and Australia (14 months). However, these numbers must be taken in perspective as the Norwegian example, unlike the other examples, does not include the time needed to prepare the proposal.

The time frames can be compressed if companies are able to take advantage of some features such as parallel processing of applications, early dialogue and communication with the regulators and reduced technical reporting:

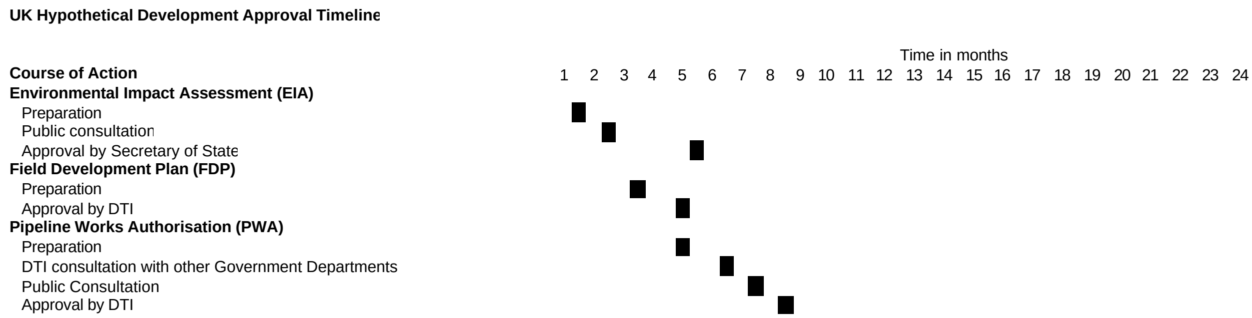
Australia



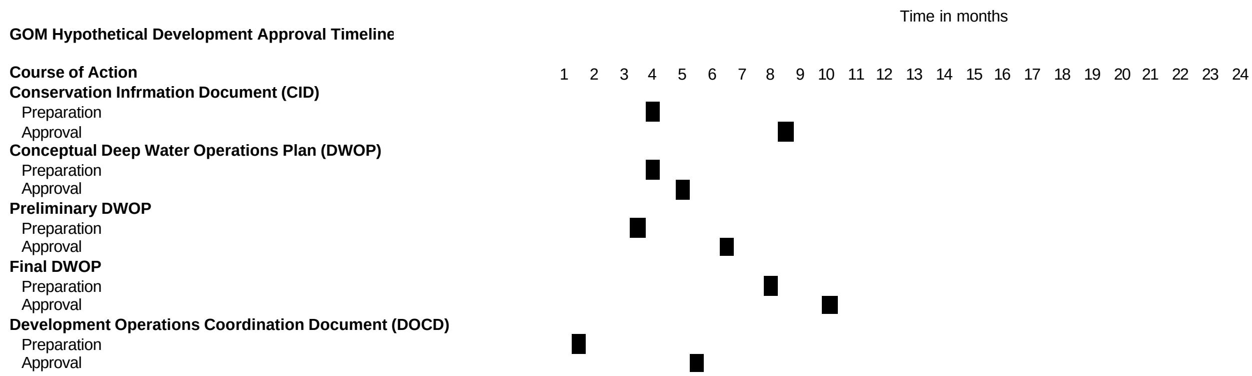
Norway



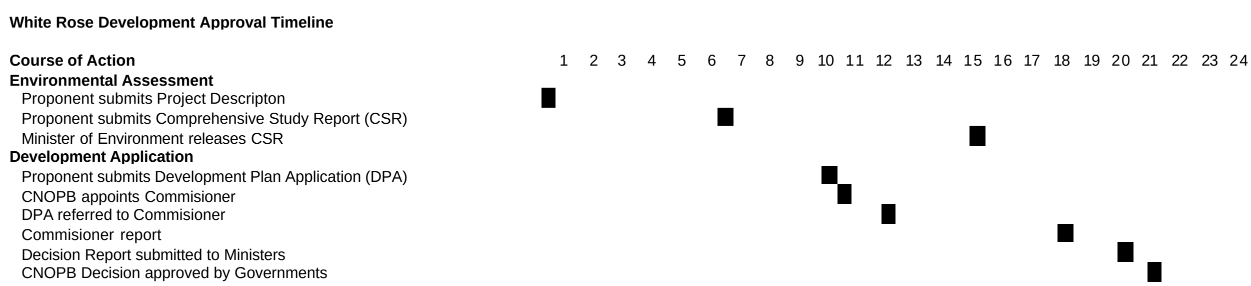
United Kingdom



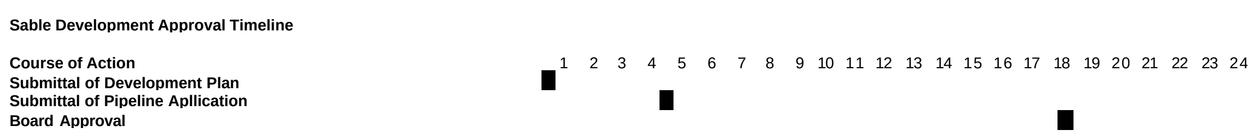
United States



Canada – White Rose



Canada – Sable



The hypothetical development timeframes in the reference jurisdictions are significantly shorter than the timeframes observed in the White Rose and Sable projects. This is possible when the license holders are able to take advantage of parallel processing and submit the different documents concurrently.

4.6.3 Streamlining Practices in the Reference Jurisdictions

1. ***Parallel Processing***: In some jurisdictions, it is possible to concurrently submit different documents for approvals. In Australia, the EPBC approval process can run in parallel with the PSLA process. In the Gulf of Mexico, the CID, DWOP and DOCD can be processed in parallel by the MMS. In the U.K., the EIA, FDP and PWA can also be processed in parallel. This allows a significant reduction in the approval times in contrast to the White Rose project, where the approvals seem to be sequential.

2. ***Early discussion with the regulators***: This an important characteristic of the U.K. and Norwegian processes, where there are regular meetings between the operator and the regulatory agency, aiming at identifying potential conflicts from the early stages of development planning. This process provides sufficient time for the correction of early detected problems, so that when the development plans are submitted the regulators, the regulators already know what to expect and the operators can be confident in a relatively smooth final approval process. It is also worth noting that the early dialogue can have a significant impact on capital costs since design or concept changes that are addressed later in the process are often drastically more costly than those addressed early.

3. ***Reduced technical reporting***: The U.K. and Norway have adopted a trend to reduce the technical information requirements of the development plans, while focusing attention on the optimization of the use of the resources. This reduces the paperwork needed, without compromising the efficient use of the countries' mineral resources.

In the U.K., the discussion process which leads to the submission of the Field Development Plan (FDP) is started at the beginning of the appraisal activities. The aim of the process is to identify the aspects of the FDP that relate to the DTI's objectives and to identify where the views of the Licensee and of the DTI may diverge. The Operator will discuss the FDP with a multi-disciplinary team assigned by the DTI and headed by a manager empowered to take technical decisions on behalf of the DTI and to coordinate, where necessary, DTI's response on policy issues. The DTI will formally notify of any aspects where a conflict of views is identified, so these issues can be resolved in the early stages of field development planning. When an agreement has been reached on some issues (intermediate decisions), the DTI may issue "Letters of Assurance". Although this should not be taken as an indication that the final Field Development Program will be approved, it gives comfort to the licensees that there are no major issues pending. When this interactive process has been fully implemented and there are no major unresolved issues, the DTI aims at approving Field Development Program in one month. This is a very short time frame, made possible only by the interactive process initiated at or shortly after the appraisal of the discoveries.

In Norway, the approval processes are different according to the estimated investments. For projects with estimated investments in excess of NOK ten billion (or approximately US$1.3 billion), the Ministry of Petroleum and Energy (MPE) drafts a proposition to the Storting (Parliament), who is responsible for the approval of the development plan. For projects with estimated costs below ten billion NOK, the MPE prepares a Royal Decree. The MPE aims at a processing time of eight weeks for approval of plans which do not require approval by the Storting. This is feasible if the Operator discusses with the authorities in advance on issues such as production strategy, development concept, health, environment and fisheries matters, and submits an Impact Assessment two to three months in advance of the development plan.

Even in the U.S. where informal communications and discretion on the part of the regulatory authorities is not a part of the regulatory approach because of the over-arching principles with respect to regulatory transparency, the regulator recognizes the importance of this dialogue to sound and cost-effective activities (though in a predictably non-discriminatory broadcast manner. In the Gulf of Mexico, the MME issues "Notices to Lessees and Operators" (NTLs), which are documents that provide interim guidance on new regulatory requirements. The MMS website (http://www.gomr.mms.gov/homepg/regulate/regs/ntlltl.html) defines NTLs as formal documents that provide clarification, description, or interpretation of a regulation or standard; provide guidelines on the implementation of a special lease stipulation or regional requirement; provide a better understanding of the scope and meaning of a regulation by explaining MMS interpretation of a requirement; or transmit administrative information such as current telephone listings and a change in MMS personnel or office address. Letters to Lessees and Operators (LTLs) and Information to Lessees and Operators (ITLs) are also formal documents that provide additional information and clarification, or interpretation of a regulation, standard, or regional requirement, or provide a better understanding of the scope and meaning of a regulation by explaining MMS interpretation of a requirement. These documents are published frequently and provide an important mean of communication with the license holders. The MMS published 17 NTLs in 2003, the latest one being on August 15, covering procedures on the design, fabrication and installation, and on a mandatory assessment of existing platforms in the Gulf of Mexico that has been in service for more than five years. This NTL provides a timetable and guidance on how to conduct these platform assessments. The issues recently covered by NTLs are as diverse as flaring and venting approval guidelines, hurricane evacuation procedures, implementation of seismic survey mitigation measures, etc.

4.7 Some comments on the Brazilian Regulatory Framework

Although not one of the Reference Jurisdictions the experience in Brazil over the last five years may provide some useful insights into the issues around compressing the regulatory approval cycle times. In 1997, the Brazilian Government removed the exclusive rights of the national oil company, Petrobras, in the upstream petroleum sector initiating a transition of the sector from a single state-owned and essentially self-regulated monopoly towards a multi-player competitive environment.

The Brazilian Federal Government owns the hydrocarbon resources, which can be explored and produced under concessions granted by the National Petroleum Agency (*Agência Nacional do Petróleo* or ANP) via competitive licensing rounds. The ANP is also responsible for evaluating and approving development plans, as wells as issuing authorizations for the installation of pipelines.

After a discovery is made, appraised and declared commercial, the concessionaires have 180 days to submit a development plan, covering all aspects of the field production systems. The ANP has 60 days (although this has been extended to 180 days for the Brazil Round 5 concession agreements) to approve it or request modifications. Once approved, a development plan can still be amended if there are significant changes in technical or economical conditions.

However, each individual activity, such as seismic acquisition, drilling a well, installing a platform or pipeline requires one or more environmental licenses, which are issued by the Brazilian Environmental Institute (IBAMA) when the project is offshore. As IBAMA was not sufficiently staffed to handle the dramatic growth in environmental permit applications after the opening of the petroleum sector in 1997, there were some significant delays in obtaining environmental permits, which eventually slowed the petroleum activities in Brazil.

In addition, besides dealing with the ANP and IBAMA, the concessionaires must obtain authorizations from the Navy to bring into the country any vessels used in petroleum activities, and from the Customs to import any equipment.

The delays caused by the IBAMA permitting were the subject of much concern and criticism from the industry – especially after drilling activities commenced and delays led directly to unproductive but costly stand-by time for high day-rate ultra-deepwater drilling rigs that were brought in to explore Brazil's offshore. The issue was partly addressed by ANP and IBAMA entering into a formal cooperation agreement – this allowed ANP to extend some of its capacity and expertise to help IBAMA process the applications and also allowed the regulatory authorities to exercise a higher degree of coordination and cooperation.

As a result of this cooperation, ANP and IBAMA jointly published an informational CD before the Brazil Round 4 bidding conference in 2002. This CD contains basic information on the environmental sensitivity of the Brazilian coastal and offshore zones to drilling activities and identifies for prospective licensees those areas that might be expected to attract a higher and more extended level of environmental and permitting scrutiny For Brazil Round 5 (2003), this was further extended to include seismic activities, based on a document published by the Brazilian Ministry of Environment in 2002, called "Evaluation and Priority Actions for the Conservation of the Biodiversity of the Coastal and Offshore Zones". These CDs contain "base maps" and the requirements of the Terms of Reference published by IBAMA, and aim at streamlining the environmental licensing process by providing information to support the early planning of environmental studies to be performed by the concessionaires. This early planning should enable the concessionaires to prepare the environmental studies in sufficient time to allow them to comply with their work and investment obligations under their Exploration and Production Concession Agreements.

APPENDIX I

Global Petroleum Industry Context

APPENDIX I

Global Petroleum Industry Context

The last 20 years has seen some remarkable shifts in the character of the international oil and gas business.

Competition for Capital – Fewer companies are exploring - Over the last decade the international oil industry has been going through an intense period of consolidation. A look at the largest U.S. based oil and gas companies in 1998 compared to 2003 (see following tables) reveals a startling 50% contraction over that period and the contraction inside of the independent oils companies and service sector has arguably been even more severe. Companies like BP now include assets formerly held by Amoco, Arco and Union Texas while the current Devon Energy comprises more than a dozen former companies including Pennzoil, Seagull, Santa Fe Energy, Mitchell Energy and Anderson Exploration.

Top Publicly Traded Petroleum Companies
January 1998 Market Capitalization (Billion Dollars)

Royal Dutch Shell	188.7	YPF	12.1	LASMO	4.1
Exxon	152.0	Norsk Hydro	11.7	Anadarko	3.6
BP	75.0	Enron	10.6	Vastar	3.5
Mobil	56.9	Marathon	9.7	Gulf Canada	3.4
Chevron	50.3	Occidental	9.7	Renaissance	3.4
ENI	45.6	Unocal	9.6	Enron O&G	3.3
Amoco	42.3	Petrofina	8.6	Apache	3.2
Elf	32.1	Burlington	7.9	AEC	3.1
BHP	30.1	PetroCanada	7.0	Can. Oxy	3.1
Texaco	28.7	Coastal	6.6	Norcen	3.1
TOTAL	27.0	UPR	6.2	Can Natural	3.0
ARCO	25.8	PanCanadian	5.8	Kerr-McGee	3.0
BG	18.8	Suncor	5.4	Pioneer	2.9
Conoco (Oct. 98)	15.5	Amerada Hess	5.1	Oryx	2.7
Phillips	12.8	Talisman	4.8	Noble	2.0
Repsol	12.8	Enterprise	4.7	UTP	1.8

Total = $989.1 Billion Dollars

Top Publicly Traded Petroleum Companies
January 2003 Market Capitalization (Billion Dollars)

ExxonMobil	230.0	Norsk Hydro	10.7	Anadarko	11.4
BP	146.6				
		Enron	0		
Royal Dutch Shell	171.6	Marathon	6.5		
TotalFinalElf	91.4	Occidental	11.0	Enron O&G (EOG)	5.0
		Unocal	7.2	Apache	9.5
Chevron Texaco	68.8				
ENI	60.8	Burlington	8.9	Nexen	2.7
Conoco Phillips	32.6	PetroCanada	8.7		
				Can. Natural	4.1
BHP	19.6	Encana	15.0	Kerr-McGee	4.2
		Suncor	7.5	Pioneer	2.8
BG	13.5	Amerada Hess	4.0		
		Talisman	5.1	Noble	2.0
Repsol YPF	17.2				

Total = $973.4 Billion Dollars

The phenomenon has not been limited to the North American market but experienced at comparable levels in all other markets with a range of privately owned companies including the U.K., Western Europe, Australia and Argentina. This has dramatically reduced the number of companies that are potential explorers in areas such as Atlantic Canada.

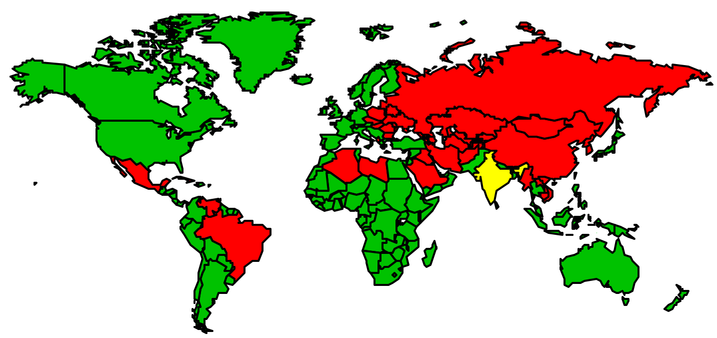
Areas, like Atlantic Canada, which are relatively lightly explored and do not have extensive infrastructure are particularly strongly effected by the trend. The companies that are most capable of bearing high risk and high cost ventures tend to be the larger companies who can spread the exploration risk and exposure over a much wider range of opportunities (allowing a portfolio effect to absorb some of the risk). These companies also have capital structures that are able to sustain extensive and costly exploration programs (the health of smaller companies being much more exposed to exploration outcomes and/or extended periods between exploration expenditure and first cash flow).

The major players have gotten much bigger – ExxonMobil for example is now a US$300 billion company that produces more than 1.6 billion barrels equivalent per year. A company like that will have a large “materiality threshold”- i.e. the minimum size of opportunity that will appeal to them– and accordingly they have focused their exploration expenditures on very large scale targets such as deepwater Gulf of Mexico, West Africa offshore, the Middle East and North Africa. These larger companies, who are integrated with extensive multinational operations, are also increasingly sensitive to pressure from the environmental lobbies and NGOs with respect to exploration and production activities in high profile environments (rain forests, national parks, fisheries, etc.).

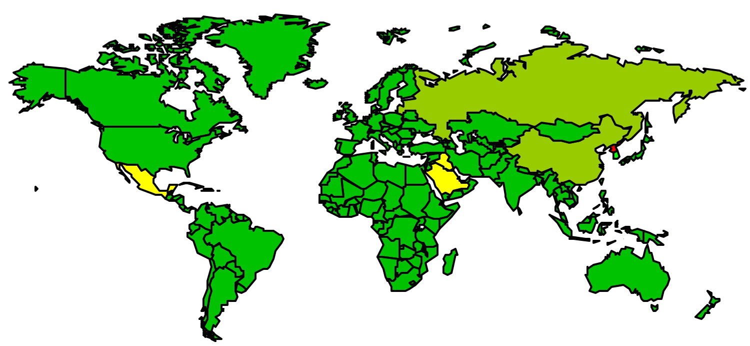
The consolidation trend has been largely forced by pressure from the capital markets for the companies to deliver shareholder returns competitive with other investment opportunities. In a period dominated by flat/low oil price outlooks this has focused the industry on the cost side of the equation and to seek economies of scale – essentially by consolidating assets and reducing the cost that burdens each barrel of production. Between 1982 and 1999 there was a clear underperformance of the industry relative to the overall equity markets – the integrated companies value had risen only 50% of the value of the market as a whole (as measured by the Dow Jones Industrial Average) while the independent producers achieved only 22% of the returns of the market. Following a focus on costs after the oil price crash of 1986, and subsequent consolidation (in addition to the bursting of the stock market "bubble") the majors have performed in line with the market over the past ten years, though the independents (both producers and refiners) have increased in value by only two-thirds of the market as a whole. In the case of the independents, this has resulted in pressure from the capital markets for these smaller companies to eschew or limit operations such as high risk exploration.

Competition for Capital – more countries competing - At the same time as the industry has been consolidating, there has been a dramatic increase in the number of countries that are seeking investment from the international oil companies in exploration. These new competitors including, for example, Brazil, Venezuela, Russia, Kazakhstan, Azerbaijan, Algeria and Libya and a number of countries in the West Africa deep water plays (not to mention prospective openings in Kuwait, Iraq, Iran and Saudi Arabia) are also widely perceived as having geologic prospectivity, a scale of opportunity sufficient for the largest companies <u>and,</u> in a number of cases, low operating cost environments.

The 1980s



The 2000s



Open to Foreign Investment in the Energy Sector

Transition Toward Total Opening of the Energy Sector to Foreign Investment

Some Foreign Investment in the Energy Sector

Closed to Foreign Investment in the Energy Sector

Not only are more areas competing for the industry's capital but advances in technology such as deepwater drilling and production technology have expanded the physical arena for exploration and production while others such as 3D seismic have dramatically lowered exploration risk or cost (directional and extended reach drilling, multi-phase flow, LNG).

Competition for the industry's capital is coming not just from the new entrants but also from the existing players (the U.S., U.K., Norway, etc.). These have competed aggressively by improving their fiscal terms to compete more effectively.

The U.K. provides a good example of a country that has proactively sought to maintain the balance of government rent collection and attractiveness to the industry in the face of changing oil prices and changing perceptions of prospectivity by repeated adjustments (both up and down) to the weight of its petroleum fiscal system.

While the U.K. has been the most active in terms of fiscal changes it has also been experienced in a number of other environments including Norway, the U.S., Colombia, Argentina etc. The most significant trend that can be observed in petroleum fiscal systems is one towards "progressive" fiscal instruments or those that are based upon profitability. These are increasingly replacing more traditional take instruments like, in particular royalties because of their responsiveness to changes in the critical economic variables – costs and oil prices.

The degree to which countries are able to attract industry activity and investment, and consequently capture economic rents, is a function of many factors. Collectively these might be termed "prospectivity". Prospectivity in this sense is more than just geologic or technical attractiveness (the chance of finding hydrocarbons) but includes the other principle variables in exploration decision-making – cost and risk.

Costs principally takes into account the costs of exploring, finding, developing, producing and transporting the hydrocarbons to a point of sale, as well as the funding costs of those activities. However, costs also include however, the royalties, taxes and imposts that may be imposed by the Government. In addition to the total quantum of the Government Take is the critical issue of <u>when</u> it is taken – for example, a fiscal system that collects a 50% Government Take (i.e. share of total revenues less total costs) but collects that take before the investor has recovered his investment is much more onerous than one which collects the same amount of take but does so after the investor has recovered his costs.

In addition to the quantitative aspects of costs potential investors also look to more qualitative aspects in assessing the attractiveness of a particular investment environment (often referred to as the "hassle factor"). These will include political and legislative stability, transparency of process and Government oversight, environmental and other legal liabilities, rules regarding local content, labor and procurement, the ease of importing people and equipment and the ease of exporting any profits. While many of these may not be easily quantifiable in terms of a cost that can be included in an economic analysis they will influence the prospective investors views on what minimum level of return is required to invest in the country (that is, an environment where the investor is very comfortable will typically attract a lower cost of capital for a positive investment decision).

It follows that a country with high technical attractiveness and low costs (for example, in an extreme case, Saudi Arabia) will be able to claim a relatively higher share of economic rent than one (for example Paraguay) where there is a perception of limited technical attractiveness. Countries endeavor to maintain themselves in a competitive balance vis-à-vis their peers by adjusting fiscal terms or the amount/type of acreage that is being offered. A country that has experienced poor exploration results and/or has a perception of higher costs that has fallen off the "competitive frontier" (as evidenced by an exodus of explorers and/or a reduction in exploration activity – especially if this is taking place during a period of reasonably robust oil prices) has two choices on the way to proceed. It may either choose to wait for some other event (oil price increase, new infrastructure, new discovery etc.) to restore it to the competitive frontier, or act with whatever tools are available to it to encourage the desired level of activity.

APPENDIX II

Terms of Reference

Request for Proposals

APPENDIX II

Terms of Reference

Request for Proposals

Regulatory Regime Cycle Time: Phase 1 of a Benchmarking Study for the Newfoundland & Labrador and Nova Scotia Offshore Areas

The Canada-Newfoundland Offshore Petroleum Board is inviting your company to submit a proposal to conduct Phase 1 of a benchmarking study.

Purpose

The purpose of the benchmarking study is to compile a contextual comparison of the regulatory regime cycle times for the Newfoundland/Labrador and Nova Scotia Offshore Areas with counterparts in other offshore areas of the world. The study will compare: regulatory cycle times for exploration, development and production approvals for similar projects; practices by regulatory agencies, regulatory complexity; and regulatory cost. The Comparison Reference jurisdictions are Norway, United Kingdom, Gulf of Mexico and Australia.

Requirements

For Phase 1, the contractor will:

(a) Conduct an analysis/assessment and description of the offshore regulatory regimes of the Comparison Reference jurisdictions and the comparison will include the elements listed in the "purpose" section above, together with other relevant comparison elements.

(b) Describe each jurisdiction's initial regulatory philosophy and measures taken to streamline the process over time. This description will also compare "practice" with the legal and regulatory framework, and assess problem areas.

(c) Assess other factors within the jurisdictions that affect comparability such as, regulatory evolution, basin maturity, project size, water depth, etc.

(d) For cycle time comparison purposes, provide examples from the jurisdictions (i.e. standalone exploration, greenfield developments, development facilities expansion, and deep water applications).

(e) For each jurisdiction, provide an assessment of the regulatory approval time for the exploration, development and production of a "hypothetical" deep-water development

(f) Assemble and present the information and conclusions from the study in a readable and readily accessible format.

Contract

The amount paid (including expenses) under the contract will not exceed US$ 50,000.

Phase 1 Study Completion Date

The contractor will complete the study and submit the study report on or before July 11, 2003.

Essential Contractor Attributes

The successful contractor will have a strong track record in conducting international studies of the Phase 1 type and will have demonstrated experience with, and a strong working knowledge of, the Comparison Reference jurisdictions.

Submission Information
RFP submissions should be forwarded to:

Canada-Newfoundland Offshore Petroleum Board
Fifth Floor, TD Place
140 Water Street
St. John's, NL
Canada
A1C 6H6
ATTN: Martin Sheppard
FAX: (709) 778-1473
Email: msheppard@cnopb.nf.ca

Deadline

The closing date for this RFP is May 28, 2003.

Distributed (2003 05 16):
Gaffney, Cline & Associates- Houston, TX, USA
Wood Mackenzie-Edinburgh, Scotland
Jacques Whitford Environment Ltd. & Cox Hanson O'Reilly Matheson, St. John's, NL, Canada
The Landar Consulting Corporation, Fredericton, NB, Canada
Accent Engineering Consultants Inc., Halifax, NS, Canada
PEV International R&D Inc., Halifax, NS, Canada

APPENDIX III

Entities Contacted

APPENDIX III

Entities Contacted

The table below lists the companies GCA considered as offering a broad look at the issue and appropriate to interview to obtain information on internal and external charging policies. The companies in **bold** type are those from which GCA received feedback.

Company Name	Classification	HQ Location
Amerada Hess	Independent, Producer & Refiner	U.S.
British Gas	Ex-NOC, E&P and midstream focus	U.K.
BHP	Independent	Australia
BP	Super Major/Major	U.K.
Centrica	Independent Gas Marketer	U.K.
ChevronTexaco	Super Major/Major	U.S.
ConocoPhillips	Super Major/Major	U.S.
Devon	Independent	U.S.
DNO	Independent	Norway
El Paso	Mid size, pipeline and power focus	U.S.
EnCana	Independent	Canada
ExxonMobil	Super Major/Major	U.S.
Kerr- McGee	Independent	U.S.
Marathon	Independent	U.S.
Newfield	Independent	U.S.
Nexen	Independent	Canada
Petrobras	Integrated NOC	Brazil
Santos	Independent	Australia
Shell	Super Major/Major	Netherlands/U.K.
Statoil	Integrated NOC	Norway
Total	Super Major/Major	France
Unocal	Independent	U.S.

APPENDIX IV

Sample Interview Form

APPENDIX IV

Sample Interview Form

1) How many concessions does your company operate in the following jurisdictions?

- Gulf of Mexico
- U.K.
- Norway
- Offshore Australia
- Offshore Canada

2) In which stage are these concessions?

- exploration
- appraisal
- development
- production
- abandonment

3) Are there any specific environmental/location issues, such as sensitive areas, transition zone, shallow or deep waters?

4) Are there any specific operational problems, such as remote areas, HP/HT zones, strong currents, etc.?

5) Is the project routine or employing new technology? If it is employing new technology, pleased provide a brief description.

6) What were the timeframes needed for approval (by petroleum regulators, environmental authorities, customs, etc.) and reporting? Please specify the authority from which you received or requested approvals, in case of multiple authorities.

6.1) Entering agreements:

- decision about new licensing round (time elapsed since deadline for block nominations, if any)
- bids (time elapsed since tender protocol was published)

- awards (time elapsed since bids were submitted)
- enter agreements (time elapsed since awards were announced)

6.2) Exploratory activities (please separate time needed to fill application from time elapsed between submittal and approval of request):

- exploratory seismic acquisition
- other exploratory data acquisition (grav-mag, geochemistry, etc.)
- exploratory drilling
- mandatory discovery reporting (please indicate maximum time allowed to report discovery since end of drilling)

6.3) Appraisal activities (please separate time needed to fill application from time elapsed between submittal and approval of request)

- approval of appraisal program
- appraisal seismic
- appraisal drilling
- declaration of commerciality (please indicate maximum time allowed for declaration of commerciality since end of appraisal)

6.4) Development activities (please separate time needed to fill application from time elapsed between submittal and approval of request)

- development plans
- development drilling
- development seismic

6.5) Production activities (please separate time needed to fill application from time elapsed between submittal and approval of request)

- production plans
- changes/updates in development/production plans
- installation of production facilities (gathering stations, fluid separators, etc.) (please specify separately the times needed to receive approval for importation, construction, installation, operation, etc.)
- secondary/tertiary recovery programs
- drilling of injectors

6.6) Abandonment activities (please separate time needed to fill application from time elapsed between submittal and approval of request)

- abandonment plans
- termination of agreement

6.7) Other administrative issues

- operator change (please separate time needed to prepare request from time elapsed between request and authorization for operator change)
- assignment of agreement (please separate time needed to prepare request from time elapsed between request and assignment)

7) How easy/difficult is it to obtain the required approvals? What are the costs associated?

8) Could you describe the timeline of a recent development operated by your company, highlighting the more efficient and the more cumbersome approvals and indicate where you think the process could be improved?