The Allen Consulting Group

Proposed Petroleum Regulations 2011

Regulatory Impact Statement

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Report to Department of Primary Industries

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Victoria's petroleum exploration and production is concentrated in the Otway and Gippsland Basins. The Gippsland Basin has produced approximately two thirds of Australia's cumulative oil production and one third of its gas production (DPI 2009).

The majority of exploration and production in Victoria's Gippsland and Otway Basins occurs in Commonwealth waters, with a small amount of activity in Victorian coastal waters and some onshore gas production, storage and processing. There is also significant onshore petroleum exploration activity in Victoria. Victorian production accounts for the second biggest share of oil and gas production in Australia (after Western Australia) (Victorian Government 2008).

The focus of this RIS is on the sunsetting regulations — the *Petroleum Regulations 2000* (the Regulations). The Regulations support the *Petroleum Act 1998* (the Act), which requires that:

> (1) Before carrying out any petroleum operation, the holder of the authority under which the operation is to be carried out must give the Minister an operation plan—
>
> (a) that identifies the risks of injury or damage that the operation may pose to the environment, to any community, person, land user, land or property in the vicinity of the operation and to any petroleum, source of petroleum or reservoir that the operation might affect; and
>
> (b) that specifies what the holder of the authority will do to eliminate or minimise those risks; and
>
> (c) that specifies what the holder of the authority will do to rehabilitate the land that will be affected by the operation; and
>
> (d) that sets out any other matters required by the regulations.
>
> (*Petroleum Act, 1998*, s. 161)

These regulations came into effect on 4 July 2000, with a provision for them to sunset after ten years. The regulations were extended for 12 months to allow for changes to the *Petroleum Act 1998* to be made prior to the remaking of the regulations. As a result the *Petroleum Regulations 2000* are not due to sunset till 4 July 2011. The Petroleum Regulations apply only to onshore petroleum operations in Victoria. The Regulations set the instances in which plans should be developed, and some minimum requirements for plans (which vary by the type of activity undertaken).

Nature and extent of the problem

In the case where regulations are due to sunset, the role of the RIS is to determine whether there remains a case for government intervention (as represented by the sunsetting regulations). If the *Petroleum Regulations 2000* were allowed to lapse:

- petroleum firms would continue to be required to develop an operation plan, petroleum production development plan, and storage development plan prior to commencement of onshore petroleum operations, production or storage respectively; and
- these plans would require Ministerial approval, as facilitated by the responsible Department within government.

The critical difference between what occurs under the current regulations and what would occur in this 'base case' scenario (where the regulations lapsed without replacement) is that the process for the development of plans required in the Act (including content, structure, criteria for approval etc) would not be formally established.

The current Regulations provide guidance to industry on how to comply with the *Petroleum Act 1998* (for example section 161 of the Act which requires an operation plan be developed before 'petroleum operations' take place). In the absence of the Regulations, firms would continue to be required to develop a plan prior to undertaking petroleum operations, but they would do so without the guidance on the plans' content that is currently provided in the Regulations. This scenario has the potential to increase uncertainty around how to comply with the legislation, and, as a result, increase compliance costs to industry in terms of time and resources.

In consultations with industry, there was strong support for maintaining regulation around the development of plans to provide guidance on compliance with the *Petroleum Act 1998.* Three potential impacts on compliance costs were identified in these discussions:

- costs of compliance with requirements in the *Petroleum Act 1998* — firms report that, without regulations specifying how to comply with requirements in the Act, the development of plans would require more time and resources, in particular more time with the Department determining what the requirements are for plans and reviewing drafts of plans;
- greater risk of arbitrary or inconsistent decision making — without the Regulations specifying the structure and content of plans, and the process for approval, the responsible Department would still be required to develop a process to receive plans and have them approved by the Minister, however, these processes would not be set in regulations, and could therefore be subject to change without notice.; and
- costs of 'over compliance' — highly risk averse firms may take steps to ensure compliance over and above what is sufficient (for example, developing highly detailed operation plans, seeking additional discussions with the Department to ensure that their plan is correct or investing in additional external advice).

Additionally, there are likely costs to government of uncertainty and time delays in processing approvals in the absence of regulations.

Quantifying the extent of the problems discussed is difficult, because the proposed regulations are intended to extend and improve upon existing regulations. As a result, affected stakeholders — in both industry and government — have operated in a regulated environment, with guidance and structure around their obligations.

The government objective

At a high level, the overarching objective of the proposed Petroleum Regulations is to provide an efficient and effective framework to facilitate commercial exploration for, and development of, Victoria's petroleum resources. The Regulations also seek to eliminate or minimise risks to public health and safety and the environment and ensure appropriate management of resources. A sub objective of the regulations is to provide clarity and certainty to licence holders about the hard and fast requirements of the regulator.

Options to achieve the government objective

This RIS considers three options that are able to achieve the government's objective. These are:

- remake the current Petroleum Regulations to replace the lapsing *Petroleum Regulations 2000* — this option involves remaking the current Regulations in the same form, for a further 10 years, and would mean that there would be no change to current regulatory arrangements for government and business;
- introduce new regulations under the *Petroleum Act 1998*, which specify how petroleum firms can meet their obligations under the Act, and with a particular focus on the content and structure of operation plans (in their various forms); and
- develop Guidelines for industry in the place of the sunsetting regulations — the purpose of these Guidelines would be to provide guidance to firms on their obligations under the Act, and suggested practices on how to ensure that they are complaint. Under this option, firms would still be required to develop plans (as required in the Act), but it would not be mandatory for firms to follow the Guidelines in developing their plans.

The key differences between the lapsing regulations and the proposed new regulations:

- Move from a prescriptive to a more outcome based regulatory framework
- Reduction in the number of consents
- In addition, the fee structure used to recover the costs of government efforts in monitoring and enforcing the regulations will be altered. In 2007-08, the costs of the regulations to government amounted to around $219 000, of which only $181 000 was recovered. The changes to the schedule of fees are proposed to more accurately reflect the level of effort devoted to different aspects of enforcement. In 2010-11, the first year of the regulations, the costs of administering the regulations to government is expected to be $199,616, which will be fully recovered under the proposed scheme.

Impact analysis of options

The criteria used to assess the options in this RIS reflect key aspects of a cost-benefit framework, as well as the objectives of the proposed regulations (which ensures that the options are being tested in regards to how they address the problem), where the outcomes associated with each option are expected to differ from the base case. For example, one of the government's objectives is to minimise risks to the public and to the environment, however, given that the Act requires the submission and acceptance of an appropriate plan before any activity can commence, the risk to the public and the environment of the three options are no different than under the base case. As a result, the extent to which an option affects the risk to the public and the environment is not used as a criterion in the analysis.

The criteria are:

- clarity of regulations — this criterion addresses the extent to which firms know their obligations under the *Petroleum Act 1998;*
- certainty for firms — this criterion addresses the extent to which the options provide certainty for firms in relation to *how* they meet their obligations the *Petroleum Act 1998*;
- compliance costs for petroleum firms — this criterion reflects the cost impact on petroleum firms from the proposed options, including costs of gaining approval of plans prior to commencement of operations, as well as subsequent costs associated with applying for consents or approvals during operations (such as delay costs when consents are required and costs of lodging incident reports); and
- cost to government of compliance and enforcement — where the costs included in the assessment under this criterion include costs for approvals (such as approval of operation plans) as well as costs of administering inspections and consents.

The assessment of the options against the criteria is set out in Figure ES1.1. These scores reflect the performance of each option compared with the base case (no government action). The scores are set on a scale from –5 to +5, with a negative score indicating a poor performance compared with the base case, and a positive score indicating a strong performance compared with the base case (a score of 0 indicates that the option performs at the same level as the base case).

In this RIS, criteria 1 and 2 (regulatory certainty and clarity) have been assigned the highest weighting of 0.35 each, reflecting the analysis of the problem in Chapter 2, where this was identified as the critical problem that needed to be addressed (given the lapsing of current regulations). Compliance costs to petroleum firms is the second highest weighted criteria (0.20), reflecting the importance of changes in regulation to not impose a significant cost burden on those firms directly influenced by the options.

Table ES 1.1

ASSESSMENT OF REGULATORY OPTIONS AGAINST CRITERIA (COMPARED WITH THE BASE CASE)

	Weightings	Option 1	Option 2	Option 3
1. Clarity of regulations	35%	+3	+4	+1
2. Regulatory certainty for firms	35%	+1	+1.5	+0.5
3. Compliance costs for business (positive score = lower cost)	20%	-1	-1	-0.5
4. Costs to government (positive score = lower cost)	10%	0	0	0
Overall score (not weighted)		**+3**	**+4.5**	**+1**
Overall score (weighted)		**+1.2**	**+1.725**	**+0.425**

Note: these scores reflect the impact of the regulatory options compared with the base case. The base case is the state in which the current regulation lapses and government does not act in any way to address the problems associated with the lapsing of the regulation (do nothing approach).

This assessment shows that Option 2 (new regulations) has the highest assessment score, both with scores weighted and unweighted. All options assessed score higher than the base case, however Option 2 has the highest score based on its performance against all criteria.

Preferred option

The preferred option is Option 2 — new regulations. This conclusion is made on the basis that Option 2:

- Provides the greatest degree of regulatory certainty for firms to meet their obligations under the *Petroleum Act 1998* — the new regulations provide the strongest framework for structure and content of operation plans required under the Act.
- Stakeholders consider that the new regulations will assist in reducing compliance costs associated with the Act, as they will reduce the costs of developing operation plans, reduce holding costs through fewer 'consents' and provide better avenues for cost savings in subsequent operation plans.
- Provides government with the key data and information it needs to ensure that resources are being used efficiently and at lowest possible risk to the environment and the community.
- Provides government with the necessary powers to assess the operations compliance with the requirements of the Act and regulations. By setting out mandatory content for plans in the Regulations, government is required to maintain a certain level of quality of plans in line with the objectives of the Act.

The estimated average cost to firms in 2010-11 under this option is made up of:

- $80 000[1] in time spent preparing an operations plan, and managing the approvals process; and
- fees (which is dependent on the type of licence held and variations, suspensions, renewals etc that take place on that licence).

The proposed new fee structure based on the Department of Treasury and Finance, 2010 *Cost Recovery Guidelines* is summarised below:

PROPOSED FEE STRUCTURE UNDER NEW REGULATIONS

Fee incidence	Fee rate	Fee amount*
Application fee for Exploration Permit	700 fee units	$8,365.00
Application fee for Retention Lease	500 fee units	$5,975.00
Application fee for Production Licence	500 fee units	$5,975.00
Application fee for Special Access Authorisation	250 fee units	$2,987.50
Fee for renewal of Exploration Permit	250 fee units	$2,987.50
Annual fee for Exploration Permit	500 fee units	$5,975.00
Annual fee for Retention Lease	700 fee units	$8,365.00
Annual fee for Production Licence	700 fee units	$8,365.00
Transfer fee for Exploration Permit	250 fee units	$2,987.50
Transfer fee for Retention Lease	150 fee units	$1,792.50
Transfer fee for Production Licence	250 fee units	$2,987.50
Suspension or variation of condition on Exploration Permit/Retention Lease/Production Licence	150 fee units	$1,792.50
Document registration fee	5 fee units	$59.75
Inspection/copy of document in register	2 fee units/$4 per page	$23.90
Ministers certificate fee	5 fee units	$59.75

Note: The fee amount is based on the conversion of fee units being $11.95 for 2010-11.

A summary of the estimated costs to both industry and government stemming from the *Petroleum Act 1998* and the proposed regulations are as follows[2]:

[1] Industry estimate

[2] Assumes:

- 2 Licence applications
- 0.5 Exploration Licence renewals
- 0.5 Transfers
- 4 suspensions or variations
- 6 operation plans per annum
- $11.95 fee unit

	2010-11	10 years NPV
Cost to Government (1)	$199,166	$1,656,000
Cost to Industry (2), *comprised of*	$679,166	$5,648,000
Administrative costs	$480,000	$3,992,000
Fees paid (3)	$199,166	$1,656,000
Total Cost (1) + (2) – (3)	**$679,166**	**$5,648,000**

Chapter 1

Introduction

1.1 Policy context

Victoria's petroleum exploration and production is concentrated in the Otway and Gippsland Basins. The Gippsland Basin has produced approximately two thirds of Australia's cumulative oil production and one third of its gas production (DPI 2009).

The majority of exploration and production in Victoria's Gippsland and Otway Basins occurs in Commonwealth waters, with a small amount of activity in Victorian coastal waters and some onshore gas production, storage and processing. There is also significant onshore petroleum exploration activity in Victoria. Victorian production accounts for the second biggest share of oil and gas production in Australia (after Western Australia) (Victorian Government 2008).

The Department of Primary Industries (DPI) supports and promotes investment opportunities in the sector. This includes providing geoscience information to help reduce exploration risk. DPI also facilitates projects under development in the State, maintains a licensing and permitting system for exploration, resource development and operations, including for pipeline activities, and regulates the industry to ensure that environmental management standards are met (DPI 2009).

Major initiatives of the Earth Resources Division of DPI include:

- *Earth Resources Community Engagement Strategy 2008-2011*: The Earth Resources Division's Community Engagement Strategy was developed to ensure that the Division remains responsive to community expectations. The four-year strategy aims to embed community engagement into the core responsibilities of the Division and to encourage the earth resources industry to work better with their communities.

- *Moving Forward — Victorian Earth Resources Innovation Roadmap*: As part of the Victorian Government's Provincial Statement, entitled 'Moving Forward', the Innovation Roadmap project establishes a vision and development pathway for technology in the resources sector, a key and growing sector for provincial Victoria.

- *Rediscover Victoria*: The Rediscover Victoria initiative invests AUD$5 million over four years until June 2012 in a new geoscience program to encourage minerals and petroleum exploration in parts of the State where little exploration has occurred to date.

- *Victorian Geological Carbon Storage*: The Victorian Geological Carbon Storage (VicGCS) Initiative is a research project on the regional carbon dioxide storage capacity of the Gippsland Basin. This four-year, AUD$5.2 million project is being delivered by GeoScience Victoria, a branch of the Earth Resources Division of the Department of Primary Industries and will be completed by June 2012 (DPI 2009).

1.2 The Petroleum Regulations 2000

The focus of this Regulatory Impact Statement (RIS) is on the sunsetting regulations — the *Petroleum Regulations 2000* (the Regulations). These regulations came into effect on 4 July 2000, with a provision for them to sunset after ten years. They apply only to onshore petroleum operations in Victoria. The objectives of the *Petroleum Regulations 2000* are to

> ensure that the environment, health and safety hazards and risks involved in undertaking petroleum operations are eliminated or minimised so far as is practicable; and
>
> to prescribe various fees, administrative matters and other requirements authorised by the [Petroleum] Act [1998] (Petroleum Regulations 2000, s.1.).

The Regulations support the *Petroleum Act 1998* (the Act), which requires that:

> (1) Before carrying out any petroleum operation, the holder of the authority under which the operation is to be carried out must give the Minister an operation plan—
>
> > (a) that identifies the risks of injury or damage that the operation may pose to the environment, to any community, person, land user, land or property in the vicinity of the operation and to any petroleum, source of petroleum or reservoir that the operation might affect; and
> >
> > (b) that specifies what the holder of the authority will do to eliminate or minimise those risks; and
> >
> > (c) that specifies what the holder of the authority will do to rehabilitate the land that will be affected by the operation; and
> >
> > (d) that sets out any other matters required by the regulations.
>
> (*Petroleum Act, 1998*, s. 161)

The Regulations set the instances in which operations plans should be developed, and some minimum requirements for operation plans (which vary by the type of activity undertaken). For instance, the Regulations require an operation plan for drilling or workover operations[3] to include:

- details of the operation, including the location of wells and any equipment to be used;
- an environment and safety assessment which:
  - identifies the environment, health and safety hazards and risks associated with the operation
  - provides an assessment of the risks; and
  - identifies the measures to be used to eliminate the hazards and to minimise the risks so far as practicable. (Petroleum Regulations 2000, s.6.).

The regulations do not specify a format to an operation plan beyond these requirements. In practice, firms seeking to drill or undertake one of the other activities covered in the regulations (such as geophysical and geochemical operations), will seek the advice of DPI during the process of developing the operation plan, including seeking comments on iterations of the plan. This process typically would take around six months to complete (on average, though less time for firms more familiar with the requirements of the operation plan).

[3] A workover operation means a modification, maintenance or repair operation made to a well.

1.3 The role of the RIS

The proposed Regulations are subordinate legislation for the purposes of the *Subordinate Legislation Act 1994*, and as such, before they can be made, a RIS must be prepared.

The *Subordinate Legislation Act 1994* requires a RIS to consider the fundamental rationale for a regulatory proposal relative to the base case or absence of any regulatory framework. At the same time — and to provide readers with an easy to understand comparison — the RIS will also consider the impact of the proposed Regulations, relative to those currently in place.

The RIS is required to consider the problem to be addressed, the feasible options to address the problem, and to assess the economic and social costs and benefits associated with each feasible option. This ensures that due consideration is given to the regulatory proposal, regulation is only implemented where there is a justified need, only the most efficient forms of regulation are adopted, and there is an adequate level of public consultation in the development of regulatory measures.

Chapter 2

Nature and extent of the problem

2.4 Introduction

Best practice regulation aims to address market failures at minimum cost to consumers and industry. There are several reasons why an industry may need to be regulated. These include when there are public goods involved in an industry; when there are externalities or spillovers; when there are information failures or where there is a natural monopoly.

In order to make a case for government intervention, a RIS must first establish the problem that the proposed regulations are seeking to address. This is necessary in order to develop appropriate options — whether regulatory or non-regulatory — that can directly address the problem, and establish an objective framework, within which the relative performance of options can be compared.

The purpose of this chapter is to consider the nature and extent of the kind of issues or problems that may arise in the absence of the *Petroleum Regulations 2000*. This enables consideration of whether it is appropriate to allow the Regulations to lapse or whether they should be remade or replaced.

2.5 Assessing the need for government intervention where regulations are sunsetting

In the case where regulations are due to sunset, the role of the RIS is to determine whether there remains a case for government intervention (as represented by the sunsetting regulations) — that is, whether the problem for which the sunsetting regulations were established still applies. In this context, assessing the nature and extent of the problem should consider the need for regulations on a 'first principles' basis (rather than assessing whether current regulations should be amended).

In this RIS, the analysis of the problem focuses on a scenario where the regulations are not remade and current legislation and regulations are used (in their current form) to achieve the government objective. The following section provides a description of the regulatory setting in this instance (i.e. those legislation and regulations that would continue to influence the practice of the onshore petroleum industry in Victoria). Subsequent sections assess the potential 'problems' with this arrangement.

Potential regulatory approach without current regulations

The State of Victoria has responsibility for regulating petroleum operations in Victoria (those that are onshore and in Victorian coastal waters, up to three nautical miles from the coast). The Earth Resources Division of DPI administers Victorian onshore petroleum activities under the Petroleum Act 1998. Both Commonwealth and State legislation cover offshore operations. The principal Commonwealth legislation is the *Offshore Petroleum and Greenhouse Gas Storage Act 2006,* which applies beyond three nautical miles from the coast (DPI 2009).

In the absence of the *Petroleum Regulations 2000* the key legislation influencing practice in the Victorian petroleum industry would be:

- *Petroleum Act 1998*;
- *Occupational Health and Safety Act 2004*;
- *Environment Protection Act 1970*; and
- *Water Act 1989*.

Of these, the *Petroleum Act 1998* is the most important as it provides the legislation that the current Petroleum Regulations support.

Petroleum Act 1998

The *Petroleum Act 1998* regulates petroleum exploration and production in Victoria. The objectives of this Act are to encourage the exploration for petroleum in Victoria and to promote petroleum production for the benefit of all Victorians by providing:

> (a) an orderly, fair and competitive system for granting authorities enabling petroleum exploration and production;
>
> (b) clear and effective administrative frameworks for organising petroleum development activities;
>
> (c) fiscal regimes that offer petroleum explorers a fair return while benefiting all Victorians;
>
> (d) easy and effective access to information on Victoria's petroleum geology. (*Petroleum Act 1998, s.3*)

In encouraging petroleum exploration and production, this Act seeks to have regard to economic, social and environmental interests by ensuring:

> (a) the safe and efficient exploration for, and production of, petroleum;
>
> (b) that the impacts on individuals, public amenity and the environment as a result of petroleum activities will be minimised as far as is practicable;
>
> (c) that land affected by petroleum activities is rehabilitated;
>
> (d) that there will be just compensation for access to, and the use of, land; and
>
> (e) that petroleum explorers and producers will comply with all authority conditions that apply to them. (*Petroleum Act 1998, s.3*)

In terms of providing commercial certainty, the Act establishes a framework to enable a business to explore and produce petroleum by providing three different rights:

- an exploration permit – an exclusive right to explore in an area subject to conditions;
- a retention lease – where resources have been discovered, but cannot as yet be commercially developed; and

- a production licence – an exclusive right to explore for and produce petroleum in the licence area subject to conditions.

Some of the most important sections of the Act are listed in Table 2.1.

Table 2.1
REQUIREMENTS OF SECTIONS OF THE *PETROLEUM ACT 1998*

Sections	Requirements
Section 18	Requires an individual to apply for an exploration permit if they wish to undertake exploration activities.
Section 63(1)	Requires a petroleum production development plan that outlines how petroleum production will be undertaken in the licence area (section 63(2) allows the regulations to specify certain details in such a plan). Similarly, section 68(1) requires that the storage development plan outline how petroleum storage in a reservoir in the licence will be carried out.
Section 161(1)(a) to (c)	Imposes broadly defined information requirements on what must be included in an Operation Plan (section 161(1)(d) provides the option to set out additional requirements in the regulations).
Section 46	Requires an individual to apply for a production licence if they wish to undertake exploration and production activities.
Section 96	Sets out broad requirements concerning what details must be included in an application for an authority. Such information includes a detailed Work Program and how much the applicant intends to spend at each stage of the program, and any other details the Minister may require to assess the application. In addition to section 96, sections 20 and 51 of the *Petroleum Act* sets out detailed information required to be included in an application for an exploration permit and production licence respectively, including details about the financial resources of the applicant and technical qualifications of the applicant.
Section 179	Provides that authority holders must provide certain information to the government such as collecting information and samples required by the regulations, keeping records required by the regulations in the form required by the regulations, and providing the government with any information, samples or records when required to do so by the regulations.
Section 100(3)	Imposes conditions on an authority. For example, this section allows the Minister to impose conditions on an authority with respect to any operations that are carried out under the authority, or for the protection of the environment. It may also require the holder of an authority to provide specified information to the Minister.

Source: *Petroleum Act 1998*

As set out in the table above, the *Petroleum Act 1998* requires the development of plans (operation plan, petroleum production and development plan and storage development plan) prior to activities commencing:

- The Act requires that the petroleum production development plan ‘outlines how petroleum production will be undertaken in the licence area’ (*Petroleum Act 1998* s.63).
- The Act requires that the storage development plan ‘outlines how petroleum storage in a reservoir in the licence area will be carried out’ (*Petroleum Act 1998* s.68).

- The Act requires that an operation plan 'identifies risks of injury or damage that the operation may pose to the environment, any community, person, land user, land or property in the vicinity of the operation, and to any petroleum, source of petroleum or reservoir that the operation might affect' (*Petroleum Act 1998, s.161).* Where risks have been identified, the Act requires that the plan set out methods for eliminating or mitigating these risks, and methods for rehabilitation should an incident occur.

Beyond this guidance, the Act does not specify how the plans should be structured, their content, or the level of detail required for approval. As noted in the previous chapter, the Act requires that the Minister approve plans before the relevant petroleum activity can commence.

The petroleum industry can have significant impacts on the environment. Most of Australia's petroleum production comes from offshore wells. Exploring for oil and gas under the seabed, and the production activities that follow a successful exploration program, all involve some risks and potential impacts on the marine environment (World Petroleum Council n.d.).

The potential environmental impacts arising from petroleum activities are diverse and depend on the nature of the activity (including its scale, location and management). The environmental impacts of petroleum activities that are likely to be considered as part of an environmental management plan or assessment include:

- discharges to land or water — including 'drilling muds' and fluids, formation water, domestic water, and other discharges;
- emissions to air — such as gas flaring, venting and fugitive gas emissions;
- waste disposal and management;
- noise pollution;
- land and vegetation clearance, including disturbance to native flora and fauna and ecological processes — such as clearance for construction of production facilities and pipelines;
- social and economic impacts — environmental impacts can affect local tourist and recreational activity, visual amenity and wilderness values; and
- impact on sites with cultural or natural heritage value (PC 2009).

There is not a particular part of the *Petroleum Act 1998* that addresses environmental issues (other than the requirement for operation plans to include consideration of environmental risks, as specified in the *Petroleum Regulations 2000*). However, one of the stated objectives of the Act is to protect economic, social and environmental interests through the safe and efficient production of petroleum, minimising the impact of petroleum activities on the environment as much as a practicable and rehabilitating land affected by petroleum activities.

The Act requires an operation plan, covering environmental risks is required for onshore petroleum operations, and is to be provided to DPI. Without this requirement, it is possible that some firms may not comply appropriately with their environmental responsibilities.

Determining the potential cost of these environmental risks can be difficult because there are two key factors to consider, as illustrated in the risk matrix shown in Table 2.2. The key considerations in determining how to manage risks are the likelihood of an incident occurring and the consequence (or cost) of the incident, should it occur. As shown, an assessment of a high risk can be made even in the case where there is moderate probability of an incident occurring, if the consequences of the incident are deemed to be high.

Table 2.2
ASSESSING THE LEVEL OF RISK

Likelihood	High	Medium risk	High risk	High risk
	Moderate	Low risk	Medium risk	High risk
	Low	Low risk	Low risk	Medium risk
		Low	Moderate	High
			Consequence	

The environmental risks associated with petroleum operations can have significant consequences, even though the number of incidents that occur remains small. The important relationship to draw on in considering these risks is the extent to which the degree of regulation, or government action, has an influence on the incidence and severity of accidents that have occurred.

Environment Protection Act 1970

The *Environment Protection Act 1970* is the overarching law in Victoria covering environmental matters such as control of waste, noise, pollution of air, water and land and litter. Part V of the Act provides that a person must not pollute water. Part VII provides controls for the disposal of solid wastes and pollution of land. Over ten separate statutory environment protection policies are in place included a specific policy to regulate injections into groundwater. In 2001, 11 Principles of Environment Protection were added to the Act, which was consistent with the National Strategy on Ecologically Sustainable Development and the Intergovernmental Agreement on the Environment (IGAE). Further changes to the act were made by the *Environment Protection (Resource Efficiency) Act 2002*, which were designed to help all sectors of the Victorian community to find innovative ways of using resources more efficiently and to reduce the ecological impact. The *Environment Protection (Amendment) Act 2006* increased levies for prescribed industrial waste (PIW), which is generated by activities such as petroleum refining.

Other key environmental and heritage regulatory requirements for petroleum activities are based on the following Commonwealth, State and Territory Acts and regulations:

- In Commonwealth waters, petroleum activities must comply with the *Petroleum (Submerged Lands) (Management of Environment) Regulations 1999* (Cwlth) and the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* (Cwlth) (OPGGSA).

- Other relevant Commonwealth legislation includes the *Environment Protection and Biodiversity Conservation Act 1999* (Cwlth) (EPBC Act), the *Aboriginal and Torres Strait Islander Heritage Protection Act 1984* (Cwlth) and the *Historic Shipwrecks Act 1976* (Cwlth) (PC 2009).

Water Act 1989

The Water Act 1989 provides for the management of water resources in Victoria. It establishes ownership and authority to use water under a licensing regime. An authority holder will still require a secure entitlement to water under the *Water Act*. There are a range of entitlements that may be issued by the Minister for Water including bulk entitlements, environmental entitlements, water licences and water shares. Some entitlements to water are not formally issued but exist under the *Water Act 1989* for domestic and stock purposes by virtue of an individual's private ownership of, or access to, land. The Act also defines water that is set aside for the environment under the Environmental Water Reserve.

Some of the key purposes of the Act are:

- to re-state, with amendments, the law relating to water in Victoria;
- to promote the orderly, equitable and efficient use of water resources;
- to make sure that water resources are conserved and properly managed for sustainable use for the benefit of present and future Victorians;
- to eliminate inconsistencies in the treatment of surface and groundwater resources and waterways; and
- to continue in existence and to protect all public and private rights to water existing before the commencement of the relevant provisions of this Act.

2.6 Problems associated with allowing the regulations to lapse

If the Regulations were allowed to lapse:

- petroleum firms would continue to be required to develop an operation plan, petroleum production development plan, and storage development plan prior to commencement of onshore petroleum operations, production or storage respectively; and
- these plans would require Ministerial approval, as facilitated by the responsible department within government.

The critical difference between what occurs under the current regulations and what would occur in this 'base case' scenario (where the regulations lapsed without replacement) is that the process for the development of plans required the Act (including content, structure, criteria for approval etc) would not be established within regulations. In this situation, the responsible department may develop documentation to assist firms in developing plans, though these would be subject to change (and the department would not be obliged to follow this information if they saw reason to change their approach for a particular application). Such changes would not be subject to the same level of scrutiny or public consultation as would be the case if the process was set in regulations.

The department may choose, following the lapsing of regulations, to continue follow those processes that they are familiar with, (that is, those under the current regulations). Where this familiarity is high, the underpinning of regulations to provide the appropriate structure for the process may be less important. In the case of plans developed under the current regulations, however, there are relatively few plans developed each year,[4] and firms may have periods of several years between developing plans. Where these conditions prevail, the regulations have a greater importance in setting practice by both the department and firms (given likely staff turnover within the department, and the low frequency of plan development).

The focus of this analysis of the problem is, therefore, on the impact on firms and government from a scenario whereby the current regulations lapse without being replaced. The problems associated with this scenario can be characterised as the problem of regulatory uncertainty for firms, and costs (and inefficiencies) for government agencies that administer the Act:

- For firms, the lapsing of the Regulations increases uncertainty around both their obligations under that Act, and the decision making by government agencies (where there is no process set in regulations to determine the content and approvals process for plans). Costs of this uncertainty include time costs in the plan development stage and costs of potential changes to government processes and decisions (for which there is greater scope without the current regulations in place).
- For government agencies responsible for compliance and enforcement (such as administering the approval of plans), the absence of the Regulations will mean that agencies must support Ministerial approval of plans without established criteria for consideration or approval.

In addition, there is the associated potential problem where these uncertainties, or potential inconsistencies in approved plans, may impact on the effectiveness of the Act to address environmental externalities associated with petroleum operations. These risks are considered to be an second order issue given the continued need to achieve approval of plans from the Minister (i.e. the risks would eventuate only in a situation where the quality of plans developed diminished considerably, which is unlikely to be the case when Ministerial approval is still required for all plans, under the Act).

2.7 Problems associated with greater regulatory uncertainty

Currently, the Regulations provide guidance to industry on how to comply with the *Petroleum Act 1998* (for example section 161 of the Act which requires an operation plan be developed before ‘petroleum operations’ take place). In the absence of the Regulations, firms would continue to be required to develop a plan prior to undertaking petroleum operations, but they would do so without the guidance on the plans’ content that is currently provided in the Regulations. This scenario has the potential to increase uncertainty around how to comply with the legislation, and, as a result, increase compliance costs to industry in terms of time and resources.

4 The Department estimates that it has received around twelve plans a year in the last five to ten years.

In consultations with industry, there was strong support for maintaining regulation around the development of plans to provide guidance on compliance with the *Petroleum Act 1998*. Three potential impacts on compliance costs were identified in these discussions, as set out below.

Costs of compliance with requirements in the Petroleum Act 1998

1. Nature of the problem

As noted above, the requirement for the plans is set in the *Petroleum Act 1998* with specifications for compliance set out in the Regulations. In the absence of regulations, firms report that their costs of developing a compliant plan are likely to increase. These expected higher costs were projected as a result of reduced clarity around the structure and content of a plan, and in particular specific guidance on what is needed for a plan to be approved by DPI.

In terms of the impact of allowing the Regulations to lapse, firms report that, without regulations specifying how to comply with requirements in the Act, the development of plans would require more time and resources, in particular more time with DPI determining what the requirements are for plans and reviewing drafts of plans. As one stakeholder commented: 'removal of regulations would create uncertainty — we would immediately need to schedule meetings with the regulator to work out what they want'. As development of these types of plans is not a regular occurrence for firms (as noted with the frequency data above) firms are less likely to develop critical mass within their staff to achieve efficiency in plan development over time.

2. Quantification of problem

Quantifying the extent of the problem (higher costs associated with plan development) requires an analysis of:

- current costs associated with plan development, with the Regulation in place; and
- the potential change in the level of these costs in the case where the regulations lapse (which is one element of the cost of the problem being measured in this RIS).

In consultations for this RIS, industry stakeholders estimated that an operation plan currently requires (on average) 400 working hours to complete, at a rate of $200 per hour (a total average cost of $80 000). They further estimate that 30 hours of this time is currently required for discussions with DPI in negotiating the approval of the plan (around 7.5 per cent of the total cost of the plan). Firms interviewed indicated that many components of the plan are key elements of good business practice, and that responsible operators would most likely develop an operation plan even in the absence of regulation (though the extent to which the plan would mirror what is required in regulations is unclear, it may be that for some firms they would develop a shorter or less detailed plan if not required in legislation). Therefore, the cost of requiring an *approved* operation plan is, primarily, this cost of approval processes with DPI.

Firms were not able to put a dollar estimate on the expected additional cost of developing plans in the absence of the Regulations, though all agreed that the estimated 30 hours of negotiation and approval would increase substantially (particularly as for many of the firms interviewed, the drafting of a plan is not a regular occurrence). Follow-up discussions with a sample of firms tested the reasonableness of estimating a 50 per cent increase in plan development costs associated with the removal of the regulations, which was considered to be reasonable by these firms contacted.

Greater risk of arbitrary or inconsistent decision making (sovereign risk)

1. Nature of the problem

The second key problem associated with lapsing regulations is the risk of arbitrary or inconsistent decision making in the absence of the Regulations. Without the Regulations specifying the structure and content of plans, and the process for approval, the responsible department would still be required to develop a process to receive plans and have them approved by the Minister. These processes would not be set in regulations, and would therefore be subject to change without notice. Further, under this scenario there would be scope for the department to take require additional information for approvals and/or change their decisions during the approval process.

In considering these aspects, it is important to note that the *presence* of these risks for firms can have an impact, even if in practice DPI develops a consistent framework for approvals that minimises changes and variation in decisions. For firms, the potential for changes in decisions places a higher level of uncertainty in the plan approval phase, which means that firms may be more likely to devote greater resources to developing the plan, and/or allow a longer time period for approval, both of which increase compliance costs for firms. Further, firms who develop plans more regularly will have limited capacity to apply learnings from previously developed plans, and there is no certainty for them that the next plan will be assessed under the same process (i.e. such as using the same criteria, etc). This scenario diminishes the capacity of firms to reduce costs for subsequent plans.

A related concern is administrative uncertainty, which is similar but affects the enforcement side of the problem. Without the Regulations setting out the specific requirements for operations and other plans required by the Act, certainty around the decision making criteria of the administrators of the regulations (the department) would reduce. That is, without the regulations setting out the statutory criteria for the assessment of plans, there would be greater administrative discretion. While a degree of flexibility and administrative discretion within regulation is important to ensure the regulation is responsive and relevant, certainty around the hard and fast requirements of the administrator affords industry greater certainty of the consistency and equity of decisions taken by the department.

2. Quantification of problem

These costs associated with regulatory uncertainty are essentially a loss of efficiency for firms. As noted in the literature, the efficiency of regulatory structures diminishes when market participants are uncertain about processes, responsibilities and obligations:

> A primary aim of regulation is to create an environment in which investment can take place … regulatory systems where a high degree of discretion is vested with the regulatory agency may actually work against this aim – investors fear arbitrary decisions that could expropriate value and consequently they either do not invest or require a higher rate of return than would otherwise be the case to compensate for this risk. (Alexander 2008, p.1)

Further, these uncertainties have the potential to influence future investment decisions, in particular in capital intensive sectors, such as minerals, extractives and petroleum. Analysis for the minerals sector by the Australian Bureau of Agricultural and Resource Economics (ABARE) examined the issues of regulatory uncertainty acting as impediments to investment decisions (Penney et. al., 2007). This report found that 'as well as prices and geological prospectivity, the decision to invest in mineral exploration is strongly influenced by the regulatory and institutional framework of an economy'. The report noted that transparency of regulation and process provides companies with important information in order to make decisions about investment in minerals exploration. Transparency reduces uncertainty and increases commercial confidence. The ability to access relevant information can make investors more willing to undertake exploration. To that end, an absence of transparency and regulatory certainty was cited as 'potentially one of the largest single deterrents to investment …' (Penney et. al., 2007, p.57).

Given the capital intensity of the onshore petroleum sector, delays in commencing operations can lead to large delay cost (also known as 'holding costs'). This may occur where plans takes longer than expected to be approved, or where there are changes in regulatory decisions which mean operations must stop for a period of time. There is a risk of this occurring if allowing these regulations to lapse means that the process of preparing and obtaining approval for the plans takes longer than it does currently. Under these circumstances, industry may commit equipment and labour to an activity that takes longer to be approved than they anticipate. As a result, these committed resources are idle until the plan is approved. The associated costs can be substantial for industry, particularly when they occur in a period where a quick approval cannot be provided (for example over a weekend or public holiday). In consultations with industry, estimates of time delays of between \$50 000 and \$100 000 per day were provided (these are standby costs associated with paying for equipment and labour which is not being utilised).

Cost of 'over-compliance'

1. Nature of the problem

Without the Regulations, an authority holder may 'over invest' in the development of their plans, or exceed safety and environmental requirements due to a lack of understanding of the nature of compliance with relevant legislation — effectively imposing costs to firms through over compliance.

Firms may act in this way if they have a high risk aversion to being found to be non-compliant with the Act, and therefore take additional steps to ensure compliance over and above what is likely to be required (for example, developing highly detailed operation plans, seeking additional discussions with DPI to ensure that their plan is correct or investing in additional external advice). These potential costs are difficult to quantify, and in practice would be difficult to distinguish from normal business practice. It is important to note, however, that these costs are the result of a lack of clarity in legal obligations for firms. In any setting some firms may wish to take extra precautions or invest heavily in ensuring compliance with the law. The key point in this case is that the potential of firms acting in this way is increased when there is ambiguity in how obligations are communicated to industry.

2. Quantification of problem

Quantifying this problem is difficult, because the proposed regulations are intended to extend and improve upon existing regulations. As a result, the firms that have been consulted for this RIS have always operated in a regulated environment, with guidance and structure around their obligations, and did not provide an estimate of the likely additional costs to them of over compliance.

Increased costs to government for compliance and monitoring

1. Nature of the problem

Without the Regulations it is likely to be more difficult, and more costly, for the Victorian Government to monitor and assess compliance with relevant legislation and performance against certain objectives. In terms of the monitoring and assessment of compliance with the Act, the role of the Minister is quite extensive. In particular, the Act states that an obligation of holders of authorities is to provide the Minister with the following:

- the Minister must be told if petroleum is discovered;
- if petroleum is discovered the Minster will require details such as chemical composition and quantity of the petroleum;
- the authority holder must collect samples and keep records as outlined in the regulations; and
- the Minister may require any further information on the petroleum operation to be provided by the person in question.

The current regulations provide more specific guidance for monitoring and assessment through the following sections:

- the provision of an operation plan;
- well evaluation logs;
- review of operation plans; and
- reporting of rate of recovery and composition of petroleum.

The *Petroleum Act* and subsequent regulations have required there to be a close working relationship between the government and holders of authorities. In practice, without regulations DPI would be required to invest in its own internal guidelines and directions to set standards for plans that they assess. The Department is also likely to have to provide additional staff for consultations with firms, which are expected to increase in the absence of regulations (as noted above). In essence, the additional costs to DPI arise from the removal of the regulations as a source of information and guidance, with this void most likely to be filled by DPI (in terms of staff time and other information materials).

2. Quantification of problem

DPI has processes in place to ensure that all plans approved meet the requirements set out in the Act and Regulations. If those hard and fast requirements are not well understood by industry (i.e., considered to be guidance rather than requirements) it is reasonable to assume the quality of plans would diminish and more iterations would be required for plans to meet the departments standards. This would result in increased workloads for government in liaising with firms and assessing plans. This would be expected to increase the costs to government of administering the Act and Regulations beyond the 2007/08 costs of $219 000.

2.8 Fees

Principles for applying fees

The Productivity Commission notes in its report, *Cost Recovery by Government Agencies*, that '[w]ell designed cost recovery arrangements can promote economic efficiency and equity by ensuring those who use regulated products … bear the costs, and by instilling cost consciousness among agencies and users of government products' (Productivity Commission 2001, p.155). Recovering such costs may also help to avoid some of the economic distortions inherent in general taxation, and may help to make the costs of regulation more transparent to the whole community. Ensuring the price of a regulated product incorporates the administrative costs of the regulation is appropriate and equitable in cases where the licence holder captures the main benefits of regulation.

In addition, the Department of Treasury and Finance *Guidelines for Setting Fees and User Charges Imposed by Departments and General Government Agencies 2006-07* require that all user-pay type fees and charges should be set to recover the full cost of the product or service provided from users, unless there are explicit policy or public good reasons for not doing so.

Full or partial cost recovery?

There are basically two alternatives available to governments for setting the level of fees or charges. These are full-cost recovery (or the user pays principle) and partial cost recovery of fees. Of course, a government can choose to charge no fees at all.

Commonly accepted justifications for departing from the full cost recovery principle are that:

- other parties may benefit from provision of a good/service other than the person to whom the good/service is directly provided (i.e., the 'public good' rationale); or

- there are equity reasons for ensuring that a wide range of persons have access to the service at a price that is regarded as affordable.

It could be argued that the Victorian community may benefit from achieving the objective of the proposed regulations — in this case, establishing a standard of operations within the onshore petroleum sector — then fees could be subsidised or not imposed. However, providing less than full cost recovery for the proposed fees would be an indirect and 'blunt' policy tool to achieve this objective. For example, it is unlikely that a fee reduction of several hundred dollars or even the decision not to charge a fee at all would have an impact on decisions by firms to conduct petroleum operations in Victoria. Moreover, given the nature of the industry participants, equity arguments do not appear relevant. Equity reasons usually refer to assisting the disadvantaged parties or those unable to afford an essential service.

The Productivity Commission regards full cost recovery as generally appropriate. However, where activities generate benefits to unrelated third parties departure from full cost recovery is appropriate. As some benefits flow from activities undertaken by the department in administering this legislation fees should be set to fully recover an appropriate proportion of costs incurred by DPI in relation to assessing plans, as specified under the Act and Regulations.

Petroleum Regulations 2010 – Schedule of Fees

It is worth noting that paragraph 2.04 of the *Subordinate Legislation Act 1994* Guidelines states that, '[w]here the authorising Act dictates the form of subordinate legislation is required, for example where the authorising legislation provides for fees to be prescribed by statutory rule, there is no discretion to set those fees by any other method'.

The fees were calculated on a full cost recovery basis. That is, all the costs associated with administering the *Petroleum Act 1998* and *Petroleum Regulations 2010* that could reasonably be recouped, from those who 'use' the legislation, are wholly allocated across the fees within the Regulations.

The Department of Treasury and Finance's Cost Recovery Guidelines require that all user-pay type fees and charges should be set to recover the full cost of the product or service provided from users, unless there are explicit policy or public good reasons for not doing so.

Methodology

A top-down methodology was employed to establish the appropriate fee rate for the administration of both the Act and Regulations. The reason for this approach was the relative infrequency of the different aspects of the Act and Regulations, which made it difficult to obtain a precise estimate of the number of hours or days required by DPI to administer each of the facets of the legislation. For example, DPI may only undertake to transfer an exploration permit once every two years (or even less frequently) which makes it difficult to determine an 'average' for the amount of time that is required to administer this part of the legislation.

DPI has determined, due to the difficulty in undertaking a bottom-up costing, that the costing should be established by looking at the cost to the Earth Resources Division associated with administering all earth resources legislation and the proportion of time and effort expended on the Act (and subordinate legislation) as a proportion of that total to form the basis of the costs associated with the Act.

To establish the appropriate fee rate it was necessary to establish the rate of full cost recovery for each of the services provided by DPI in administering the Act and Regulations. DPI has endeavoured to take into consideration both the public and private benefits accrued from the legislative framework. DPI provides a wide range of both regulatory and industry facilitation services to the onshore petroleum industry, and also provides policy advice related to the industry and its regulatory regime. Industry faclitiation however, discretionary and it is therefore not appropriate that these costs should be recovered from industry.

Regulatory services provided by the department can be divided into three broad categories — licensing and related administration, operational regulation and approvals, and support services. The vast majority of the benefits associated with these activities are accrued by industry and the majority of these costs should be recovered from industry.

Exploration licensing has both public and private benefits. The private benefit goes to the finder of a resource, which establishes an asset and a strong expectation of gaining ownership of the resource for future development. The public benefit is from the discovery of a State owned resource, which until found has no value. This adds to the State's asset base and potential future royalty flows.

Development licensing is primarily the legal mechanism for the transfer of rights to discovered resources from the State to the licensee (generally the finder or preceding holder of exploration rights). The private benefit (to the licensee) is security of tenure over the resource and ability to generate profits from resource development. The direct public benefit arises from royalties following development that are paid to the State upon production/storage. However, indirect public benefits also flow to communities as a result of earth resource developments, for example through employment and regional development.

The appropriate level of expenditure by the Earth Resources Division attributable to licence holders varies between licence types as there are variations in the balance of public and private benefits flowing from these activities. It was determined that the appropriate level of expenditure attributable to the licence holder across all licensing activity should be set at 70 percent.

The need for operational regulation, approvals and support services arises from the negative externalities or potential externalities associated with earth resources exploration and production. It is appropriate that a larger proportion of the expenditure by the Earth Resources Division associated with these activities should be internalised by industry in their operating cost, however some of these activities do provide the community with benefits (eg: community engagement plans) and as such an appropriate level of expenditure attributable to licence holders should be set at 90 percent.

DPI provides a wide range of industry development support of the onshore petroleum industry, from GeoScience Victoria's basic and interpretive data products, assistance with approvals in other legislation, development of approval conditions etc. Generally expenditure on these activities should not be attributed because they are discretionary and designed to attract private exploration investment in Victoria's earth resources. However, these units also play a minor role in earth resources regulation;

- GeoScience Victoria allocates 2.0 FTE to monitoring compliance with exploration reporting and data submission, management of acreage releases and some administrative functions.
- Resource Investment Facilitation has a limited role in petroleum acreage releases and on occasion development of approval conditions (an allocation of 0.5 FTE across all earth resources regulation

To attribute expenditure, DPI has used a semi-qualitative approach based on budget analysis and consultation with departmental staff to apportion the perceived time and effort expended by the Earth Resources Division on each of the Acts administered by the Division. Also taken into consideration were estimates of proportion of costs which are not recoverable because they are incurred on input to government/DPI processes, such as legislation & policy development, ministerial support and correspondence and DPI governance and reporting. For most work units the estimated proportion is 15 percent, based on semi-quantitative assessment. The 15 percent estimate is an average across units' staff and will tend to be higher for management positions and lower for operational positions.

The result for the Act (including subordinate legislation) is shown in Table 2.3.

Table 2.3
GOVERNMENT EXPENDITURE ATTRIBUTABLE TO LICENCE HOLDERS 2007-08

Expenditure area	Estimate ($)
Operations	68 000
Tenements	42 000
Minerals and Petroleum Regulations branch management and support	53 000
Information Development Branch	24 000
Geoscience Victoria	20 000
Business Development and Technology (section)	5 000
Minerals and Petroleum Division management and support	7 000
Total government cost	**219 000**

Source: DPI

Based on the makeup of the licensing system in 2007-08 under the current fee structure the fee revenue was in the order of $181 279. This indicates an under recovery of attributable expenditure of approximately $38 000 per annum in 2007-08 dollars.

In 2010-11, the first year of the regulations, the cost to government of administering the regulations is expected to be $199,616.

Current fee structure

The current fee structure in the Regulations is relatively flat, consisting of annual fees and application fees. The result is that all licence holders pay the same fee regardless of the number of transfers of licences, suspension or variation of conditions that may be initiated by the licence holder.

Table 2.4
CURRENT FEE STRUCTURE

Fee incidence	Fee rate
Annual fee for Exploration Permit	$0.55 per square kilometre
Annual fee for Retention Lease	550 fee units
Annual fee for Production Licence	1100 fee units
Late fee for renewal of Exploration Permit	10 fee units

Under the current licensing breakdown — seven Exploration Permits with a total area of 7483 square kilometres, thirteen Production Licences and three Retention Licences — DPI would expect to receive 16 302 fee units (around $195 000) for 2009-10. A review of the current authorities show that the average age of Exploration Permits is ten years (average size 1069 square kilometres), and the average age of Production licences is eleven years. Over the life of a petroleum operation an authority holder would, based on the averages above, expect to pay 12 602 fee units (around $150 000).

Proposed fee structure

The Department of Treasury and Finance's Cost Recovery Guidelines (May 2010) sets out that cost recovery involves setting and collecting charges to cover the costs incurred in undertaking activities. This is based on the user-pays principle, where those who benefit from the service should pay for it.

The present fee structure fails to expose the quantum of time and effort expended by DPI in administering different sections of the legislation. The proposed fee structure will reduce the annual fee, and introduces new fees for the most time consuming *ad hoc* activities initiated by licence holders. This new structure will also introduce a licence application fee into the Regulations. The annual fee for an exploration permit under the proposed scheme will move from a per square kilometre rate to a flat rate. This reflects the fact that the size of a tenement is not correlated with the cost to DPI of administering that tenement. Therefore, for ease of administration, the new fee structure moves to a flat annual fee

Once again, it is not possible to undertake a bottom-up calculation of the fees, for the same reasons already given above. Given the total attributable expenditure in 2007-08 established in Table 2.3, the fees recovered through the Regulations for that year should have been in the order of 18 734 fee units (around $224 000).

A well-designed fee structure should provide a relatively stable cost recovery base, smoothing year to year fluctuations. As many of the activities under the Act and Regulations are *ad hoc* and infrequent it is important that a portion of the fees should be recovered as a flat annual fee, to ensure a stable fee recovery base. The annual fee incorporates the costs of administering the Act and Regulations outside of those activities identified for direct cost recovery. Operations plans have been incorporated into the annual fee simply because the amount of time and effort can vary so significantly from plan to plan.

PROPOSED FEE STRUCTURE UNDER NEW REGULATIONS (OPTION 2 – *PETROLEUM REGULATIONS 2010*)

Fee incidence	Fee rate	Fee amount*
Application fee for Exploration Permit	700 fee units	$8,365.00
Application fee for Retention Lease	500 fee units	$5,975.00
Application fee for Production Licence	500 fee units	$5,975.00
Application fee for Special Access Authorisation	250 fee units	$2,987.50
Fee for renewal of Exploration Permit	250 fee units	$2,987.50
Annual fee for Exploration Permit	500 fee units	$5,975.00
Annual fee for Retention Lease	700 fee units	$8,365.00
Annual fee for Production Licence	700 fee units	$8,365.00
Transfer fee for Exploration Permit	250 fee units	$2,987.50
Transfer fee for Retention Lease	150 fee units	$1,792.50
Transfer fee for Production Licence	250 fee units	$2,987.50
Suspension or variation of condition on Exploration Permit/Retention Lease/Production Licence	150 fee units	$1,792.50
Document registration fee	5 fee units	$59.75
Inspection/copy of document in register	2 fee units/$4 per page	$23.90
Ministers certificate fee	5 fee units	$59.75

Note: The fee amount is based on the conversion of fee units being $11.95 for 2010-11.

When the proposed fee structure is calculated across the current licensing breakdown (seven Exploration Permits, thirteen Production Licences and three Retention Licences), DPI expects to receive 16 733 fee units (around $200 000) for 2009-10. Using internal estimates of the frequency of the *ad hoc* activities included in the new fee structure,[5] the additional revenues outside the annual fees for 2009-10 would be expected to be in the order of 2235 fee units (around $27 000). This gives a total fee revenue of 18 968 fee units or (around $227 000) for 2009-10. Authority holders under the proposed structure would pay 13 900 fee units (around $166 000) over the life of an operation.[6]

[5] Assumes:
- 2 Licence applications
- 0.5 Exploration Licence renewals

Chapter 3

Options to achieve the desired objectives

3.9 The Government's objectives

At a high level, the overarching objective of the proposed Petroleum Regulations is to provide an efficient and effective framework to facilitate commercial exploration for, and development of, Victoria's petroleum resources. The regulations also seek to eliminate or minimise risks to public health and safety and the environment and ensure appropriate management of resources. A sub objective of the regulations is to provide clarity and certainty to licence holders about the hard and fast requirements of the regulator.

3.10 Options to achieve the desired objectives

There are three options for government to address the problem set out in the previous chapter, and to achieve the government objective (along with the base case 'do nothing' option). Details of these options are set out below. In the impact analysis, each of these options will be assessed against the base case option.

Option 1: Remaking current Petroleum Regulations to replace the lapsing Petroleum Regulations 2000

This option involves remaking the current Regulations in the same form, for a further 10 years. This would essentially mean that there would be no change to current regulatory arrangements for government and business. These remade regulations would continue to support the *Petroleum Act 1998*.

The primary purpose of the remaking of regulations under this option is to establish what should be included in plans for onshore petroleum operations. The remade regulations would work in the same manner as the current regulations by establishing that plans must:

- detail of the operation, including any equipment or facilities to be used;
- include an environment and safety assessment which identifies the environment, health and safety hazards and risks associated with the operation, and provides an assessment of the risks; and identifies the measures to be used to eliminate the hazards and to minimise the risks so far as is practicable;
- include a description of the management systems required by regulation;
- outline how petroleum production will be undertaken in a licence area; and
- outline how petroleum storage in a reservoir in a licence area would be carried out.

Under these remade regulations, current processes for approvals of plans will be maintained, with firms required to work with DPI to gain approval of their plan by the Minister.

- 0.5 Transfers
- 4 suspensions or vartions

[6] Based on the assumption that they hold an EL for 10 years and a PL for 11 years.

Option 2: New regulations under the Petroleum Act

Option 2 involves introducing new regulations under the Act, which specify how petroleum firms can meet their obligations under the Act. These new regulations would have a particular focus on the content and structure of operation plans (in their various forms, while maintaining the same objective as the current regulations. The purpose of proposing these new regulations is to strengthen the provision of guidance to firms in developing operation plans, compared with the current regulations (as represented by Option 1), as summarised in Table 3.5.

Table 3.5

SUMMARY OF OPERATION PLAN CONTENT REQUIREMENTS, BY ACTIVITY

Petroleum Activity	Operation Plan Content must include
Geophysical or Geochemical Operations	Environment Management Plan Reporting & data submission
Well Operations	Environment Management Plan Well Operation Plan Reporting & data submission
Production Operations	Environment Management Plan Well Operation Plan Reporting & data submission
Storage Operations	Environment Management Plan Well Operation Plan Reporting & data submission
Decommissioning/rehabilitation	Environment Management Plan Well Operation Plan Reporting & data submission

Source: DPI

In addition, the new regulations would seek to provide greater flexibility to firms in developing operations plans. The new regulations would specify when firms need to prepare an operations plan, and the type of information required within each plan, however, a key aspect of this approach is that plans should be relevant to the activity being conducted, and in keeping with the scale of activity. Therefore, while the components of each plan are clearly specified, the regulations will allow for the detail included in each plan to be proportionate to the scale of activity being proposed.

The new regulations will introduce a fee structure consistent with the Department of Treasury and Finance Cost Recovery Guidelines, as discussed in section 2.8.

A key goal of new regulations proposed in this option is to improve the efficiency of the process of operation plan development, both in relation to providing firms with certainty around their obligations, and flexibility to account for variation in the scale of operations. For instance, as specified in Table 3.1, each operation plan would be required to include an environmental management plan. This is a key difference between Option 1 (remaking the current regulations) and Option 2 (new regulations) Under Option 1, there would be a requirement that operation plans identify and set in place measures for environmental risks. However, under Option 2, the environmental management plan would have more clearly defined structure and content, as described in Box 3.1.

Box 3.1

ENVIRONMENT MANAGEMENT PLANS UNDER PROPOSED MODERNISED REGULATIONS

Description of the environment

An environment management plan must—

(a) describe the environment, including any relevant values and sensitivities;

(b) describe any relevant cultural, historical, aesthetic, social, recreational, ecological, biological, landscape and economic aspects of the environment that may be affected by the petroleum operation.

Description of environmental effects and risks

An environment management plan must include an assessment of the environmental effects and risks of the petroleum operation that—

(a) identifies and evaluates the environmental effects and risks that may arise directly or indirectly from the normal activities of the petroleum operation (including construction where applicable); and

(b) assesses the risks of potential effects on the environment resulting from reasonably possible activities in relation to the petroleum operation, or incidents or events (whether planned or unplanned) that are not normal activities, incidents or events in relation to the operation.

Environmental performance objectives and standards

An environment management plan must—

(a) define environmental performance objectives, and set environmental performance standards, against which performance by the holder of the authority in protecting the environment from the petroleum operation is to be measured; and

(b) include measurement methods for determining whether the objectives and standards have been met.

Implementation strategy for the environment management plan

An environment management plan must contain an implementation strategy that—

(a) includes measures to ensure that the environmental performance objectives and standards in the environment management plan are met; and

(b) identifies the specific systems, practices and procedures to be used to ensure that—

- (i) any potential adverse environmental effects of, and any risks to the environment arising from, the petroleum operation are eliminated or minimised so far as is reasonably practicable; and
- (ii) the environmental performance objectives and standards in the environment management plan are met; and

(c) establishes a clear chain of command, setting out the roles and responsibilities of personnel in relation to the implementation, management and review of the environment management plan; and

(d) includes measures to ensure that each employee or contractor working in connection with the petroleum operation—

- (i) is aware of the employee's or contractor's responsibilities in relation to the environment; and
- (ii) has the appropriate skills and training to be able to fulfil those responsibilities; and

(e) provides for the monitoring, audit and review of the environmental performance and implementation strategy of the holder of the authority; and

(f) provides for the maintenance of a quantitative record of emissions and discharges into the air, or onto the land surface environment, or below the land surface environment that is accurate and that can be monitored and audited against the environmental performance standards; and

(g) includes arrangements for recording, monitoring and reporting information about the petroleum operation (including information required to be recorded under the Act, the regulations and any other environmental legislation applying to the activity) sufficient to enable the Minister to determine whether there is compliance with the environment management plan; and

(h) provides for appropriate consultation, ongoing for the life of the operation, about the holder of the authority's environmental performance with—

(i) relevant agencies of the Commonwealth and the State; and

(ii) other relevant interested people and organisations; and

(iii) provides for the maintenance of an up-to-date emergency response manual that includes detailed response arrangements for—

(A) dealing with any threat to the environment in the vicinity of the petroleum operation; and

(B) ensuring that the threat does not harm the environment.

Other information in the environment management plan

The environment management plan must contain the following—

(a) a statement of the corporate environmental policy of the holder of the authority; and

(b) a report on any consultations between the holder of the authority and relevant agencies, interested people and organisations in the course of developing the environment management plan; and

(c) a list of all environmental legislation of the Commonwealth or the State that may apply to the petroleum operation.

Source: DPI

In addition, four of the five types of operation plans must include a Well Operations Plan, as described in Box 3.2.

Box 3.2

WELL OPERATIONS PLAN REQUIREMENTS UNDER PROPOSED MODERNISED REGULATIONS

Well operation management plan

(1) The well operation management plan included in an operation plan by the holder of an authority—

(a) must be appropriate for the nature and scale of the well activity; and

(b) must include details of the design of the well, including details of how the well will protect the petroleum resource; and

(c) must include details of—

(i) the proposed petroleum operation, including proposed drilling; and

(ii) the process by which the well is to be brought to the stage where a connection can be made with a petroleum reservoir so that fluids can be produced from, or injected into, the reservoir; and

(iii) how modifications, maintenance and repairs to the well and ancillary equipment are to be managed; and

(iv) how suspension and abandonment of the well are to be managed; and

(v) the equipment and facilities to be used in connection with the well and its ancillary equipment; and

(d) identify the risks associated with the well activity and state how the holder of the authority proposes to eliminate or minimise those risks.

(2) The well operation management plan must include the following material, unless the Minister has given the holder of the authority permission, in writing, not to include material specified in the permission—

(a) information about the conduct of the well activity;

(b) an explanation of—

(i) the philosophy of, and criteria for, the design, construction, operational activity and management of the well and ancillary equipment; and

(ii) the possible petroleum production activities of the well, showing that the well activity, and all associated operational work, will be carried out appropriately;
(c) details of—
(i) the logs to be run; and
(ii) the proposals for testing of the well and ancillary equipment; and
(iii) proposed sampling and testing for petroleum;
(d) performance objectives against which the performance of the well activity is to be measured;
(e) measurement criteria that define the performance objectives;
(f) an explanation of how the holder of the authority will deal with—
(i) a well integrity hazard; or
(ii) a significant increase in an existing risk in relation to the well, including the possibility of continuing an activity for the purpose of dealing with the well integrity hazard or the risk;
(iii) the protection of aquifers.

Source: DPI

Option 3: Guidelines

Option 3 to be assessed in this RIS is to develop Guidelines for industry in the place of the sunsetting regulations. The purpose of these Guidelines would be to provide guidance to firms on their obligations under the Act, and suggested practices on how to ensure that they are complaint. Under this option, firms would still be required to develop plans (as required in the Act), but it would not be mandatory for firms to follow the Guidelines in developing their plans. The purpose of the Guidelines would be to provide firms with information and guidance, should they consider that they need such assistance in developing their plan. The Guidelines would be used by firms and DPI in the approvals process, though would not place a limit on what DPI would consider in recommending to the Minister whether a plan should be approved (i.e in practice, DPI could request the firm provide additional information in plans, even if not specified in the Guideline). In this way, a Guideline does not provide firms which as much certainty around decision making by government as regulations would.

Guidelines are often used for regulation of resources industries. For example, in order to help companies comply with the legislation and regulation, the Petroleum and Geothermal Group in South Australia provides guidelines on petroleum exploration and production, including but not limited to the following areas:

- onshore exploration and production;
- pipeline licensing and approvals;
- well location surveys, naming conventions, abandonment and evaluation programs;
- annual report requirements; and
- environmental management.

It is proposed that under this option the Guidelines would provide guidance to firms on:

- content and structure of plans; and

- when a plan should be provided, in order to meet their obligations under the Act.

3.11 Approach in other Australian jurisdictions

All other Australian jurisdictions have formal, regulatory arrangements in place for industry in this area. Given the nature of the activity that is regulated, it is unsurprising that the regulatory arrangements are very similar. For example, all jurisdictions require information contained in work plans, operation plans, and system of issuing licences for an appropriate fee. Where these arrangements differ is with respect to the level of detail stated in or required by the formal regulations, and administrative arrangements pertaining to whether the regulation is enforced by a single government body, or whether the approvals require input from a number of departments or agencies.

As to whether the arrangements proposed for Victoria are more onerous than in the other jurisdictions, this is difficult to judge from comparing the regulations directly, given that the arrangements across jurisdictions are very similar in nature. Informal feedback from industry stakeholders suggests that South Australia has the best regulatory arrangements (from an industry perspective), and the regulations proposed for Victoria are very similar to South Australia's. This is an area where feedback from stakeholders is particularly invited for this consultation RIS.

Chapter 4

Cost and benefits

4.12 Introduction

The primary purpose of the RIS process is to present evidence on the most appropriate means of resolving the problem/s in question, and achieving the stated objective of government intervention. In order to provide this evidence, a comprehensive assessment of the costs and benefits of each of the viable options must be undertaken.

Cost benefit analysis in a RIS requires:

- consideration of the government's objectives;
- identification of viable options that will achieve the objectives; and
- assessment of the costs and benefits of each of the viable options.

The final aspect of cost benefit analysis is the selection and application of appropriate decision criteria to determine whether a regulatory option is attractive (i.e. its benefits outweigh its costs).

4.13 The base case

In identifying the costs and benefits likely to arise from the proposed Regulations, the base case first needs to be defined for comparison purposes (i.e. the scenario against which all other options are compared with).

In the case of sunsetting regulations, as in this RIS, the base case is set as the scenario where the current regulations are allowed to lapse and no government action is undertaken to replace or adjust for the lapsing regulations (essentially a 'do nothing' scenario). This base case best represents the situation that would apply without government intervention. As noted in the previous chapter, existing regulations, policies and legislation would still apply, but they would not be amended to account for the lapsing regulations.

The following cost-benefit analysis of options uses as a base case the scenario where the *Petroleum Regulations 2000* are allowed to lapse, the *Petroleum Act 1998* would remain, as would other relevant legislation (as described in the discussion of the problem in Chapter 2 of this RIS). The costs and benefits assessed in this RIS, therefore, are those in addition to those that are the result of the *Petroleum Act 1998*.

4.14 Criteria to assess options

Multi–criteria analysis is a tool for assessing options within a RIS. It is most suitable where costs and benefits for comparison in the RIS cannot all be represented quantitatively — this is most comment when costs can be quantified but benefits cannot. The value of this approach is that it allows a transparent comparison of the most important impacts of the options being assessed, ensuring that there is not a bias towards quantifiable impacts.

Multi-criteria analysis is the approach taken for the impact analysis in this RIS because it provides the best means of comparing a range of qualitative and quantitative impacts. As it is not possible to quantify many of the impacts associated with the options in this RIS, a set of decision criteria is also outlined, which allows for comparison of the options, relative to the base case.

The criteria used to assess the options in this RIS are set out below. They reflect key aspects of a cost-benefit framework, as well as the objectives of the proposed regulations (which ensures that the options are being tested in regards to how they address the problem, as set out in Chapter 2 of this RIS), where the outcomes associated with each option are expected to differ from the base case. For example, one of the government's objectives is to minimise risks to the public and to the environment, however, given that the Act requires the submission and acceptance of an appropriate plan before any activity can commence, the risk to the public and the environment of the three options are no different than under the base case. As a result, the extent to which an option affects the risk to the public and the environment is not used as a criterion in the analysis.

Criterion 1 — Clarity of regulations

An important function of the current regulations is to establish a process for compliance with obligations in the *Petroleum Act 1998*. For instance, while the Act requires that operations plans must be approved by the Minister, the regulations set out the specifics of what an operations plan is, and what needs to be included in a plan in order to be approved.

The analysis of the problem in Chapter 2 of this RIS found that, without this clarity, there is potential for higher compliance costs, and higher risks of non-compliance with requirements in the Act. It is an important objective of any government action, in response to the identified problems, to improve clarity of obligations, compared with the base case.

Criterion 2 — Certainty for firms

The assessment of options under this criterion considers the extent to which each option provides certainty for petroleum firms in relation to how they meet their obligations the *Petroleum Act 1998*. The inclusion of this criterion reflects the identified need for certainty around the timing of approvals discussed in Chapter 2 of this RIS.

A positive score under this criterion indicates that the option provides greater regulatory certainty under the *Petroleum Act 1998* for petroleum firms, than the base case.

Criterion 3 — Compliance costs for petroleum firms

This criterion reflects the cost impact on petroleum firms from the proposed options — primarily costs of compliance. Assessment against this criterion considers all those costs to firms associated with complying with the measures under each option (but not those costs associated with compliance with the Act itself). Costs include costs of gaining approval of plans prior to commencement of operations, as well as subsequent costs associated with applying for consents or approvals during operations (such as delay costs when consents are required and costs of lodging incident reports).

For the multi-criteria analysis this criterion is scored on the basis of lower costs being preferable, therefore a higher score reflects *lower* compliance costs for petroleum firms compared with the base case.

Criterion 4 — Cost to government of compliance and enforcement

The fourth criterion in this assessment is cost to government of compliance and enforcement. The costs included in the assessment under this criterion include costs for approvals (such as approval of operation plans) as well as costs of administering inspections and consents.

For the multi-criteria analysis this criterion is scored on the basis of lower costs being preferable, therefore a higher score reflects *lower* costs to government compared with the base case.

4.15 Assessment of options against criteria

The rationale for each score is provided in the following sections, with supporting evidence underpinning each assessment.

Clarity of obligations

The discussion of the problem in Chapter 2 of this RIS emphasised the importance of the current regulations in establishing a process for firms to comply with obligations established in the *Petroleum Act 1998*. Greater clarity for firms results in lower costs associated with developing plans, both for firms and government, and an environment whereby firms are more willing to invest (that is, a lower risk environment, due to higher certainty over regulatory settings and decision making).

In assessing the options against this criterion, the following conclusions can be drawn from available evidence:

- Each option assessed provides a higher degree of certainty than the base case, because each provides additional information and guidance on the development and approval of plans than the base case (where only the Act would apply). Greater information and guidance in the development of plan was a key factor raised by firms in consultations, which they considered lowered risks and costs for them in operating under the Act.

- Options 1 and 2 both involve establishing requirements for plans in regulations, supporting the obligations under the Petroleum Act. The new regulations proposed under Option 2 provide a structure for the inclusion of particular elements within each plan and, crucially, set clearly a structure and content for the inclusion of environmental management plans as a means of addressing environmental risks (as opposed to the remade regulations under Option 1 which simply require that environmental risks be identified and strategies developed to mitigate these risks).

Certainty of decision making under the Petroleum Act 1998

In a cost-benefit context, regulatory certainty is essentially an efficiency issue — higher certainty lowers risks for firms, which allows them to minimise their costs of operation and make investment decisions based on commercial considerations rather than being driven by regulatory settings. These factors translate to compliance costs — considered primarily in the next criteria — but more broadly relate to the environment within which firms are able to operate in.

In assessing the options against this criterion, the following conclusions can be drawn from available evidence:

- Of the three options being assessed, Option 3 (Guidelines) is assessed as providing the smallest marginal benefit compared with the base case. The Guidelines will provide additional information for firms, but as they are not established in regulations, they cannot fully represent all potential requirements for the approvals process (that is, the Department would retain the capacity to add additional requirements or seek new or different types of information). Therefore, the presence of these risks results in a lower degree of regulatory certainty under Option 3, compared with Options 1 and 2.
- Option 2 reduces the number of consents that must be applied for from 7 to 2, substantially reducing the number of instances where special consent would need to be sought and thus reducing delay costs to industry while they wait for approvals. Option 2, therefore, provides a stronger set of guidance to firms, and best supports those firms who are likely to need to submit multiple plans under the 10 year period of the regulations (as the process is well established in the regulations, there is less scope for Departmental requirements to change over this period).

Compliance costs for petroleum firms

Under this criterion the assessment is based on the capacity of each option to *minimise* compliance costs for petroleum firms — a higher score indicates *lower* costs compared with the base case.

The assessment of compliance costs under this criterion needs to take into account those compliance costs that are incurred by firms due to obligations established under the Act. Most importantly, the obligation for plans is established under the Act, and therefore would apply under each option being assessed. The requirement that plans be submitted to the Minister, and that 'the holder of the authority must not carry out the petroleum operation unless the Minister has accepted the plan for the operation in writing' indicates that an approval process of some kind would be required in the base case, though the rigour or time requirements for this approval process may differ from that which is in place under the current regulations.

There are two types of costs that may be incurred under the options, compared with the base case:

- the marginal costs associated with the *process of approval* of plans under each option, compared with that which would apply in the base case; and
- the costs associated with reduced flexibility in plan content, detail and format.
- the delay costs associated with obtaining consents.

Cost of plan approval

In considering the potential costs of each option it is useful to first consider the cost of the current regulations. The current regulations, while in case not representing the base case option because of the sun-setting clause, do provide actual examples of how firms and government operate under regulations specifying how to meeting obligations under the Act.

In stakeholder consultations for this RIS, industry stakeholders estimated that under the *current regulations* the cost of developing those plans required in the Act currently requires (on average) 400 working hours to complete, at a rate of $200 per hour (a total average cost of $80 000). Estimates of the cost of developing Petroleum Production Development plans (PPDP) and Reservoir Management plans (RMP) have not been included in this analysis as DPI's records indicate that no new PPDPs or RMPs have been prepared in the past 5 to 10 years. It is possible that there were no PPDPs or RMPs prepared under the *Petroleum Regulations 2000,* and DPI invites comments from industry on the time and cost involved in updating PPDPs and RMPs.

Firms further reported that up to 30 hours of this time is currently required for discussions with DPI and negotiating the approval of the plan (representing around 7.5 per cent of the total cost of the plan, or an average of $6000). The firms that were interviewed reported that many components of the plan are key elements of good business practice, and that responsible operators would most likely develop plans even in the absence of regulation (though the extent to which the plan would mirror what is required in regulations is unclear, it may be that for some firms they would develop a shorter or less detailed plan if not required in legislation). Therefore, they considered the key variable in costs under different regulatory setting is this approval component of the total cost of plan development.

The second key issue to consider is the way in which current costs would change if the regulations lapsed, and how would each of the options compared against the base case, in relation to the costs of plan development. In consultations, firms reported that without any regulations in place (and in the absence of other measures), the costs of plan development would be higher than under the current regulations (i.e. costs would be higher in the base case). Industry stakeholders reported that without regulations specifying how to comply with requirements in the Act, the development of plans would require *more* time and resources, in particular more time with DPI to determine what the requirements are for plans and reviewing drafts of the plans. As one stakeholder commented: 'removal of regulations would create uncertainty — we would immediately need to schedule meetings with the regulator to work out what they want'. Firms were not able to estimate the expected additional cost of developing plans in this instance, though all agreed that the estimated 30 hours of negotiation and approval with increased substantially (particularly as for many of the firms interviewed, the drafting of a plan is not a regular occurrence).

On this basis, the cost of approval processes should be lower for each option compared with the base case. Option 2 is expected to have the lowest approval costs of the three options being considered because the changes to the structure of the operations plans is expected to reduce the time required for firms to work with DPI — there are clearer directions on what each element of the plan should include which firms expect will reduce the number of iterations required in the approval process.

Costs associated with reduced flexibility in plans

As noted earlier in this RIS, the plans required by the Act are widely considered to be documents that form part of good business practice for petroleum firms. While it is likely that firms would develop plans voluntarily in the absence of government mandate, the requirements under regulations set a standard for context and structure which is likely to be different to that which firms themselves would choose individually (for instance, the plan required in regulations may have a stronger focus on factors external to firm operations, such as environmental factors). Further, the scope and degree of detail required by regulation may be greater than that which a firm would invest in by choice. Finally, the cases in which a firm may choose to develop a plan may differ.

None of the options assessed in this RIS (including the base case) removes the requirement for plans to be developed. Where the options differ is in the level of detail in instruction for plans, and the degree of flexibility in plan content. For some firms, flexibility is not necessarily a benefit because it increases regulatory uncertainty and reduces the clarity of their obligations. Other firms may have a preference for plans with less detail and/or a narrower scope than is the case currently (which may be proportionate to the risks involved in the operation being conducted).

This discussion highlights the potential costs for firms where their ability to determine the content, scope and structure of the plans is diminished. In terms of the options assessed in this RIS, Option 2 (modernised regulation) provides for plans to be at a level of detail that is proportional to the activity being undertaken, which reduces the costs for operators who may prefer to use a less detailed plan for small operations.

Costs associated with consents

The Act requires that the Minister's consent must be obtained before petroleum operations are carried out on-shore. Work cannot commence until this consent is granted, which may result in delays or increased holding costs to firms. In consultations with industry, estimates of time delays of between \$50 000 and \$100 000 per day were provided (these are standby costs associated with paying for equipment and labour which is not being utilised).

Overall assessment

Overall, the assessment of compliance costs finds that there are no additional compliance costs imposed by the options, compared with the base case. The options work to reduce compliance costs where they reduce the time required for approvals (a requirement established in the Act). The assessment in Table 4.2 reflects a higher score for Option 2, given that it include provisions for flexibility in a plans scope and content, based on the scale of operations between planned.

Costs to government for compliance and enforcement

The final criterion being assessed is cost to government for compliance and enforcement. Data provided by DPI as shown earlier in Table 2.3 indicated the *total* cost of administering the Act and regulations. DPI further advise that the cost of the regulations themselves is represented by the 'Operations' cost estimate (\$68 000).

In assessing the options for this RIS, further detail was sought from DPI as to how government costs would change compared with the current regulations, and compared with the base case. DPI has indicated that there will be only minor changes in operations costs under Option 2 (modernised regulations) and Option 3 (Guidelines), as the Act would still require approval of plans. The assessment scores for this criteria therefore reflect a marginal increase in Departmental costs compared with the base case.

Minimising risks to the environment and public safety

Petroleum operations pose risks to the environment and public safety. These risks include the risk of contamination of water sources or soil, the risk to flora and fauna where local habitats are impacted. Public safety risks include risks from explosions or spillages where they occur near homes or public places (such as parks, rivers or lakes).

Reflecting these risks, the *Petroleum Act 1998* seeks to have regard to economic, social and environmental interests by ensuring:

> (a) the safe and efficient exploration for, and production of, petroleum; and
>
> (b) that the impacts on individuals, public amenity and the environment as a result of petroleum activities will be minimised as far as is practicable; and
>
> (c) that land affected by petroleum activities is rehabilitated. (s.3).

The Act does this by setting standards of operations (maintained through approvals and licensing of operators). Currently, plans are a key tool in setting standards of practice of onshore petroleum firms, the content and approval process for which is established in the *Petroleum Regulations 2000*.

As discussed in Chapter 2, in the absence of the *Petroleum Regulations 2000* there are risks of non-compliance with the Act, and/or risks of a lowering of standards of operation in the industry. In considering options, and their impact on environmental and public safety risks, the effectiveness of the options should be compared with the base case, where these risks would be addressed through the Act alone.

In order to assess the effectiveness of each option against this criteria, it is important to understand the mechanisms by which these types of risks are minimised. The Act determines that an operation plan must be provided:

> (a) that identifies the risks of injury or damage that the operation may pose to the environment, to any community, person, land user, land or property in the vicinity of the operation and to any petroleum, source of petroleum or reservoir that the operation might affect; and
>
> (b) that specifies what the holder of the authority will do to eliminate or minimise those risks; and
>
> (c) that specifies what the holder of the authority will do to rehabilitate the land that will be affected by the operation. (s.161)

The *Petroleum Regulations 2000* currently specify that plans submitted for approval must include an environmental and safety assessment which 'identifies the environment, health and safety hazards and risks associated with the operation', and 'identifies the measures to be used to eliminate the hazards and to minimise the risks so far as it practicable' (r.6). During the process of approval of plans under the current regulations, the Department makes a determination as it whether the plan meets these requirements (in terms of identifying risks and having in place measures which reduce the chance of incidents occurring).

Given that operation plans are a critical tool in reducing risks to the environment and public safety, the key consideration in this assessment is, for each option:

- what will be the *quality* of operation plans developed (focusing specifically on how the plans address environmental and public safety risks); and
- what is the potential level of compliance with the requirement to submit an operation plan (i.e compliance with the Act).

In the base case scenario for this RIS, petroleum firms would continue to be required to submit an operation plan (as specified in the Act), though the parameters around how a plan would address environmental and public safety risks would be broader (or less transparent) than is the case currently with the regulations in place.

In consultations with stakeholders on the potential impact of changes to the operation plan process and structure, most firms noted that an operation plan is a core document for their operations, and would most likely be developed even without a legislated requirement to do so. That said, firms were concerned about a relaxation of requirements around the plans that may impact on the quality of plans developed (with suspicions about competitors who may seek to 'cut costs' but submitting less detailed plans than are currently required). Given that the requirement to submit a plan remains in the Act, the key area of risk appears to be through variation in the *quality* of plans submitted, rather than the risk that firms will choose not to develop a plan at all. Therefore, in considering options, and how they perform in minimising risks to the environment and public safety, the key consideration is the potential impact on the quality of operation plans.

As noted in Chapter 2 of this RIS (the analysis of the problem), under the base case there remains a requirement that an operation plan be developed prior to onshore petroleum operations commencing, *and* the Minister must approve this plan. This suggests that, under all options *and* the base case, operations plans will still be required to consider environmental risks, and have their risk management approach approved by the Minister. Given these factors, there is no evidence to suggest that there would be a discernable difference in risk to the environment between the base case and options considered.

4.16 Scoring of options against criteria

The above analysis of options can be brought together within a multi-criteria framework. The assessment of the options against the criteria is set out in Table 4.6. These scores reflect the performance of each option compared with the base case (no government action). The scores are set on a scale from –5 to +5, with a negative score indicating a poor performance compared with the base case, and a positive score indicating a strong performance compared with the base case (a score of 0 indicates that the option performs at the same level as the base case).

In constructing a multi-criteria analysis, it is necessary to weight the criteria used according to their relative importance. Rarely are all criteria of equal importance in this type of analysis. It is therefore importance that the relatively importance of the criteria is reflected in the assessment results.

In this RIS, criteria 1 and 2 (regulatory certainty and clarity) have been assigned the highest weighting of 0.35 each, reflecting the analysis of the problem in Chapter 2, where this was identified as the critical problem that needed to be addressed (given the lapsing of current regulations). Compliance costs to petroleum firms is the second highest weighted criteria (0.20), reflecting the importance of changes in regulation to not impose a significant cost burden on those firms directly influenced by the options.

This assessment shows that Option 2 (new regulations) has the highest assessment score, both with scores weighted and unweighted. All options assessed score higher than the base case, however Option 2 has the highest score based on its performance against all criteria.

Table 4.6

ASSESSMENT OF REGULATORY OPTIONS AGAINST CRITERIA (COMPARED WITH THE BASE CASE)

	Weightings	Option 1	Option 2	Option 3
1. Clarity of regulations	35%	+3	+4	+1
2. Regulatory certainty for firms	35%	+1	+1.5	+0.5
3. Compliance costs for business (positive score = lower cost)	20%	-1	-1	-0.5
4. Costs to government (positive score = lower cost)	10%	0	0	0
Overall score (not weighted)		**+3**	**+4.5**	**+1**
Overall score (weighted)		**+1.2**	**+1.725**	**+0.425**

Note: these scores reflect the impact of the regulatory options compared with the base case. The base case is the state in which the current regulation lapses and government does not act in any way to address the problems associated with the lapsing of the regulation (do nothing approach).

Chapter 5

Impacts on small business and competition

5.17 Small business impacts

It is a requirement for a RIS to include a specific impact of the proposal on small business. The purpose of this is to ensure that government regulation does not unduly impact on business productivity and growth in Victoria, with particular emphasis being given to how proposed measures will affect small businesses. In effect, the concern is that:

> Uniform application of regulatory requirements…gives a competitive advantage to larger firms, which have lower per–unit compliance cost due to economies of scale. This increases the size of firm that can survive, and drives smaller, marginal firms out of business. In addition, the increased costs to small firms resulting from economies of scale will raise barriers to entry and eliminate the potential competition on which we rely so heavily to keep prices in line. (Bradford 2004, p.29)

Table 5.7

FACTORS TO BE CONSIDERED WHEN REGULATING SMALL BUSINESS

Factor	Answer
The variation in the compliance burden between a typical small business and a large business	Not significant variation in compliance burden found.
Where possible, estimates should be provide of typical compliance costs for small, medium and large entities, with details of how these estimates are derived	Estimates reflect the average compliance costs for business, with the effected business cohort not including a wide variation in business size.
The relative impact of penalties and non-compliance	

The onshore petroleum sector in Victoria is a small sector made up of large firms, who operate both in Victoria and across other State and Territories (and internationally in some cases). The nature of the sector, with high capital costs of entry and large operating costs, preclude any significant participation by small business (as is the case in this sector across Australia). In consultations with firms, only a small number identified as having worked under the current regulations, reflecting the itinerant nature of onshore petroleum exploration and extraction. Given these factors, it is unlikely that the options considered will have any discernable impact on small business.

5.18 Competition assessment

Any new legislation in Victoria must not restrict competition unless it can be demonstrated that:

- the benefits of the restriction, as a whole, outweigh the costs; and

- the objectives of the legislation can only be achieved by restricting competition.

A legislative amendment is considered to have an impact on competition if any of the following questions in the table below can be answered in the affirmative.

Table 5.8
CRITERIA FOR DETERMINING ADVERSE COMPETITION IMPACTS

Question	Answer	Significance
Is the proposed measure likely to affect the market structure of the affected sector(s) – i.e. will it reduce the number of participants in the market, or increase the size of incumbent firms?	The proposed measure should not have an affect on the market structure of the petroleum sector	Low
Would it be more difficult for new firms or individuals to enter the industry after the imposition of the proposed measure?	No given requirements for entry to sector are established under the Primary legislation	Low
Would the costs/benefits associated with the proposed measure affect some firms or individuals substantially more than others (e.g. small firms, part–time participants in occupations, etc)?	No	Low
Would the proposed measure restrict the ability of businesses to choose the price, quality, range or location of their products?	No	Low
Would the proposed measure lead to higher ongoing costs for new entrants that existing firms do not have to meet?	No - all firms are currently subject to requirements under the Petroleum Act 1998	Low
Is the ability or incentive to innovate or develop new products or services likely to be affected by the proposed measure?	No	Low

Source: Government of Victoria 2007, pp. 5–22.

Sub–clause 1(3) of the *Competition Principles Agreement* provides guidelines for assessing the net public benefit. It sets out the circumstances in which the weighing up process is called for, and also some of the factors that need to be taken into account in making the decision:

> Without limiting the matters that may be taken into account, where this Agreement calls:
>
> (a) for the benefits of a particular policy or course of action to be balanced against the costs of the policy or course of action; or
>
> (b) for the merits or appropriateness of a particular policy or course of action to be determined; or
>
> (c) for an assessment of the most effective means of achieving a policy objective;
>
> the following matters shall, where relevant, be taken into account:

(a) government legislation and policies relating to ecologically sustainable development;

(b) social welfare and equity considerations, including community service obligations;

(c) government legislation and policies relating to matters such as occupational health and safety, industrial relations and access and equity;

(d) economic and regional development, including employment and investment growth;

(e) the interests of consumers generally or of a class of consumers;

(f) the competitiveness of Australian businesses; and

(g) the efficient allocation of resources.

Chapter 6

The preferred option

6.19 Summary of preferred option

Based on the analysis in Chapter 5 of this RIS, the preferred option is Option 2 — new regulations. In summary, the proposed regulations:

- Provide an objective based framework for meeting the requirements of the Act, specifically setting out the information to be included in plans (which are required by the Act);
- Set out a framework for reporting pecuniary interest;
- Set out the reporting processes required by the Act; and
- Set fees to recover the cost of administering the Act and Regulations

This conclusion is made on the basis that Option 2:

- Provides the greatest degree of regulatory certainty for firms to meet their obligations under the *Petroleum Act 1998* — the new regulations provide the strongest framework for structure and content of operation plans required under the Act.
- Stakeholders consider that the new regulations will assist in reducing compliance costs associated with the Act, as they will reduce the costs of developing operation plans, reduce holding costs through fewer 'consents' and provide better avenues for cost savings in subsequent operation plans.
- Provides government with the key data and information it needs to ensure that resources are being used efficiently and at lowest possible risk to the environment and the community.
- Provides government with the necessary powers to assess the operations compliance with the requirements of the Act and regulations. By setting out mandatory content for plans in the Regulations, government is required to maintain a certain level of quality of plans in line with the objectives of the Act.

6.20 Change in the administrative burden

The Guidelines note that measurement of changes to the administrative burden of a new regulatory proposal — through the application of the Regulatory Change Model — is not required if changes are immaterial (that is, if they generate less than $250 000 in new costs or savings per annum).

The calculations in this RIS demonstrate that the additional administrative costs to business directly attributable to the regulations fall below this threshold. As such, a Standard Cost Model report is not required.

6.21 Implementation and enforcement

The proposed regulations are due to commence in 2011. As the proposed regulations do not impose any new requirements or make any changes to the licensing regime, there will be no need for transitional arrangements.

In line with existing practices, DPI will continue to liaise with current and prospective authority holder to assist them in preparing plans that meet the standards set by the regulations.

DPI has had extensive experience in administering regulations of a similar style, the *Geothermal Energy Resources Regulations 2006* and the *Greenhouse Gas Geological Sequestration Regulations 2009*, and does not expect any significant implementation issues to arise.

6.22 Evaluation strategy

An important feature of best practice regulation is for it to be reviewed regularly to ensure that it represents the most appropriate means of meeting the regulatory objectives.

DPI reviews and assesses the effectiveness and efficiency of all the regulations it administers on an ongoing basis. These reviews consider baseline and key performance indicators derived from internal reporting, enforcement data and industry consultation. In addition, DPI consults regularly with stakeholders affected by the administration of the relevant legislation, and DPI's standard business practices offer an opportunity for open dialogue on matters such as the appropriateness of legislation.

Aside from the ongoing informal evaluation of the regulations, a formal evaluation will be required prior to their expiration in 2021.

Appendix A

Environment risks associated with petroleum operations

The following are some examples of accidents which have occurred, their costs and relationship with regulatory settings.

Longford gas plant explosion

On 25 September 1998 there was an explosion at the Esso gas plant at Longford, which processes gas flowing from the Bass Straight. The explosions were caused due to a rupture in a heat exchanger, which released hydrocarbon vapours and liquid. Two people were killed by the explosion, with a further eight injured. A Royal Commission was formed to investigate the causes of the accident. The Commission found that personnel at the plant were not properly trained to deal with the situation they faced, which led to errors being made. Esso was subsequently convicted of 11 counts of breaching the *Occupational Health and Safety Act*. The estimated damage from the explosion is $1.3bn. The accident had a wide impact in Victoria, with residential and industrial gas supply being severely restricted for 14 days.

West Atlas oil leak

On 21 August 2009, the West Atlas oil drilling rig in the Montara Field in the Timor Sea developed a leak; the leak could not be plugged until 3 November. The operator of the well, PTTEP, found the most likely cause of the leak was a missing cap on one of the wells. It has estimated its own cost as a result of the oil spill at $177 million, though this estimate was made before fire broke out on the oil rig. In addition, PTTEP is paying for the environmental clean-up costs incurred by the Australian Maritime Safety Authority, estimated at $5.3 million (PTTEP FAQ).

Aside from the immediate costs related to the oil spill there are other longer term costs as well. For example, the spill has had an effect on marine life, including fish, which affects local fishermen. It will take several years before the full environmental impact is known. Submissions to the Montara Commission of Inquiry have indicated a variety of regulatory breaches, leading to the oil spill (Prestipino 2010). The important link to regulatory settings in this instance is the requirement for the operator to report incidents was not immediate.

Sidoarjo mud flow

The Sidoarjo mud flow is a mudflow in the Sidoarjo region of Indonesia, which was most likely caused by oil drilling. It started in May 2006 and continues to this day. The mud flow emits 100,000 m3 per day, covering a total area of 7 m2 and displacing 25,000 residents. The mud flow erupted after two casing points were missed in the drilling process, resulting in 1742m of unprotected drill hole (Tingay et al 2008). The mudflow has had profound effects on residents in the area, who have had to be evacuated, as well as environmental effects. It is expected that the land surrounding the mudflow will subside significantly in coming years, and that the mudflow may continue for another 30 years. Damage estimates for the first year alone are US$4.9 billion, excluding infrastructure damages such as damage to toll roads and rail lines. Thirteen deaths can be directly attributed to the mudflow. (Schiller 2008)

Lake Peigneur disaster

In 1980 Texaco was exploring for oil at Lake Peigneur in the United States, when it made a calculating error and drilled through to a salt mine. As a result, the lake drained into the resulting hole, taking with it the drilling platform and several barges. When the lake refilled it had turned from a shallow fresh-water lake to a deep salt-water lake.

Appendix B

Stakeholder consultations

Details for the stakeholders consulted for this RIS are shown in Table B.1. We note that while fifteen organisations were contacted and invited to provide input into this RIS, only a small number actually participated, which reflects the small number of firms that are affected by the proposed regulations.

Table B.1

LIST OF CONSULTATIONS

Company	Contact	Date
Lakes Oil	Tim O'Brien	14 January 2010
AGR Field Operations	Penny Drew, Phil Harrick	19 January 2010
TRUenergy	Rod Harris	20 January 2010
Nexus Energy	Michelle Zaunbrecher	21 January 2010
Origin Energy	Tim Jessen	22 January 2010

Appendix C

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Appendix D

The proposed Regulations

STATUTORY RULES

S.R. No. 00/2011

Petroleum Act 1998

PETROLEUM REGULATIONS 2011

The Governor in Council makes the following Regulations:

Dated:

Responsible Minister

PETER BATCHELOR
Minister for Energy and Resources

Clerk of the Executive Council

PART 1 – PRELIMINARY

1 Objectives
The objectives of these Regulations are—

(a) to provide for the elimination and minimisation, so far as is practicable, of the environmental and public health and safety hazards and risks involved in undertaking petroleum operations; and

(b) to prescribe requirements for operation plans; and

(c) to prescribe various administrative matters, fees and other requirements authorised by the Act.

2 Authorising provision
These Regulations are made under section 252 of the **Petroleum Act 1998.**

3 Commencement
These Regulations come into operation on (*tba*).

4 Revocation

The Petroleum Regulations 2010[i] are **revoked**.

5 Definitions

In these Regulations—

ancillary equipment, in relation to a well, includes—

(a) equipment located downhole; and

(b) a blow-out preventer; and

(c) a well-head;

environmental legislation means an Act of the State or the Commonwealth or any instrument made or issued under or for the purpose of those Acts that relates to the protection of the environment.

facility means a structure that—

(a) is used or constructed for the purpose of recovering petroleum; or

(b) carries, contains or includes equipment for the drilling, modification, maintenance or repair of a well or ancillary equipment;

practicable, in relation to eliminating or minimising hazards and risks, means practicable having regard to—

(a) the severity of the hazard or risk; and

(b) the state of knowledge about the hazard or risk; and

(c) the availability and suitability of ways to eliminate or minimise that hazard or risk; and

(d) the cost of eliminating or minimising that hazard or risk;

risk means the likelihood of a specific, undesired event occurring within a specific period or in specified circumstances;

Note: A risk may be understood as a frequency (the number of specified events occurring within a period) or a probability (the likelihood of a specific event following another event).

the Act means the **Petroleum Act 1998**;

well activity, in relation to a well, means an activity carried out during the life of the well;

well integrity, for a well, means that the potential producing zone in the well bore—

(a) is under control, in accordance with an accepted well operation management plan; and

(b) is able to contain reservoir fluid; and

(c) is not the subject of any unforeseen risk;

well integrity hazard means an event—

(a) that—

(i) may compromise the well integrity of a well; and

(ii) would, if it occurred, have consequences of a significant threat to the safety of individuals; or

(b) that may involve a risk of significant damage to the environment or the well reservoir.

PART 2—OPERATION PLAN

Division 1—General

6 Operation plan

(1) For the purposes of section 161(1)(d) of the Act, an operation plan—

(a) must set out—

(i) a description of the petroleum operation and the equipment and facilities to be used in the operation; and

(ii) an environment management plan in accordance with Division 2; and

(iii) if the operation involves petroleum exploration, a statement of the activities referred to in section 7 of the Act that are proposed to be carried out; and

(iv) if a well is to be made, a well operation management plan in accordance with Division 3; and

(b) must provide for—

(i) a review by the holder of the authority of the risks identified in the plan whenever there is a significant change in the risks that the petroleum operation may pose; and

(ii) a review of the plan by the holder of the authority at least once every 5 years; and

(iii)the submission to the Minister of a report by the holder of the authority on the findings of each such review.

(2) If an operation plan has been submitted by the holder of an authority, the Minister may, by notice in writing, require the holder to provide any additional information that the Minister considers to be relevant to acceptance of the plan.

7 Operation plan applying to a facility—design etc of facility

(1) If a facility is proposed for a petroleum operation, the operation plan must include details of—

a) the proposed design, construction, installation and maintenance of the facility; and

b) if the facility is to be modified, details of the proposed modifications; and

c) the proposals for the decommissioning of the facility.

(2) The details provided under sub-regulation (1)(a) and (b) must be sufficient to show whether the facility is adequate for the proposed petroleum operation.

Division 2—Environment management plan

8 Description of the environment

An environment management plan must—

(a) describe the environment, including any relevant values and sensitivities;

(b) describe any relevant cultural, historical, aesthetic, social, recreational, ecological, biological, landscape and economic aspects of the environment that may be affected by the petroleum operation.

9 Description of environmental effects and risks

An environment management plan must include an assessment of the environmental effects and risks of the petroleum operation that—

(a) identifies and evaluates the environmental effects and risks that may arise directly or indirectly from the normal activities of the petroleum operation (including construction where applicable); and

(b) assesses the risks of potential effects on the environment resulting from reasonably possible activities in relation to the petroleum operation, or incidents or events (whether planned or unplanned) that are not normal activities, incidents or events in relation to the operation.

10 Environmental performance objectives and standards

An environment management plan must—

(a) define environmental performance objectives, and set environmental performance standards, against which performance by the holder of the authority in protecting the environment from the petroleum operation is to be measured; and

(b) include measurement methods for determining whether the objectives and standards have been met.

11 Implementation strategy for the environment management plan

An environment management plan must contain an implementation strategy that—

A. includes measures to ensure that the environmental performance objectives and standards in the environment management plan are met; and

B. identifies the specific systems, practices and procedures to be used to ensure that—

(i) any potential adverse environmental effects of, and any risks to the environment arising from, the petroleum operation are eliminated or minimised so far as is reasonably practicable; and

(ii) the environmental performance objectives and standards in the environment management plan are met; and

C. establishes a clear chain of command, setting out the roles and responsibilities of personnel in relation to the implementation, management and review of the environment management plan; and

D. includes measures to ensure that each employee or contractor working in connection with the petroleum operation—

(i) is aware of the employee's or contractor's responsibilities in relation to the environment; and

(ii) has the appropriate skills and training to be able to fulfil those responsibilities; and

E. provides for the monitoring, audit and review of the environmental performance and implementation strategy of the holder of the authority; and

F. provides for the maintenance of a quantitative record of emissions and discharges into the air, or onto the land surface environment, or below the land surface environment that is accurate and that can be monitored and audited against the environmental performance standards; and

G. includes arrangements for recording, monitoring and reporting information about the petroleum operation (including information required to be recorded under the Act, the regulations and any other environmental legislation applying to the activity) sufficient to enable the Minister to determine whether there is compliance with the environment management plan; and

H. provides for appropriate consultation, ongoing for the life of the operation, about the holder of the authority's environmental performance with—

(i) relevant agencies of the Commonwealth and the State; and

(ii) other relevant interested people and organisations; and

(iii) provides for the maintenance of an up-to-date emergency response manual that includes detailed response arrangements for—

(A) dealing with any threat to the environment in the vicinity of the petroleum operation; and

(B) ensuring that the threat does not harm the environment.

12 Other information in the environment management plan
The environment management plan must contain the following—

(a) a statement of the corporate environmental policy of the holder of the authority; and

(b) a report on any consultations between the holder of the authority and relevant agencies, interested people and organisations in the course of developing the environment management plan; and

(c) a list of all environmental legislation of the Commonwealth or the State that may apply to the petroleum operation.

Division 3—Well operation management plan

13 Well operation management plan

(1) The well operation management plan included in an operation plan by the holder of an authority must—

(a) be appropriate for the nature and scale of the well activity; and

(b) include details of the design of the well and ancillary equipment, including details of how the well will protect the petroleum resource; and

(c) include details of—

I. the proposed petroleum operation, including proposed drilling; and

(ii) the process by which the well is to be brought to the stage where a connection can be made with a petroleum reservoir so that fluids can be produced from, or injected into, the reservoir; and

(iii) how modifications, maintenance and repairs to the well and ancillary equipment are to be managed; and

(iv) how suspension and abandonment of the well are to be managed; and

(v) the equipment and facilities to be used in connection with the well and its ancillary equipment; and

(d) identify the risks associated with the well activity and state how the holder of the authority proposes to eliminate or minimise those risks.

(2) The well operation management plan must include the following material, unless the Minister has given the holder of the authority permission, in writing, not to include material specified in the permission—

(a) information about the conduct of the well activity;

(b) an explanation of—

(i) the philosophy of, and criteria for, the design, construction, operational activity and management of the well and ancillary equipment; and

(ii) the possible petroleum production activities of the well, showing that the well activity, and all associated operational work, will be carried out appropriately;

(c) details of—

(i) the logs to be run; and

(ii) the proposals for testing of the well and ancillary equipment; and

(iii) proposed sampling and testing for petroleum;

(d) performance objectives against which the performance of the well activity is to be measured;

(e) measurement criteria that define the performance objectives;

(f) an explanation of how the holder of the authority will deal with—

(i) a well integrity hazard; or

(ii) a significant increase in an existing risk in relation to the well, including the possibility of continuing an activity for the purpose of dealing with the well integrity hazard or the risk;

(iii) the protection of aquifers.

14 Consent to conduct production or drill stem tests

(1) The holder of an authority must not conduct a production or drill stem test in an exploration or development well that has not been opened to production except with, and in accordance with, the written consent of the Minister.

Penalty 20 penalty units.

(2) An application for consent must provide details of the testing program and the equipment to be used.

15 Consent to suspend or abandon a well

(1) The holder of an authority must ensure that a well is not suspended except with, and in accordance with, the written consent of the Minister.

Penalty 20 penalty units.

(2) The holder of an authority must ensure that a well with a measurable interval of petroleum is not abandoned except with, and in accordance with, the written consent of the Minister.

Penalty: 20 penalty units.

(3) An application for consent to suspend or abandon a well must include—

(a) the name and number of the well; and

(b) the reasons for the proposed suspension or abandonment; and

(c) details of the proposed suspension or abandonment program, including the method by which the well will be made safe.

PART 3—DEVELOPMENT PLANS

16 Petroleum production development plan

(1) For the purposes of section 63(2) of the Act, a petroleum production development plan must include—

(a) a description of each stage of the petroleum operation, including equipment or facilities to be used; and

(b) a description of the relevant existing geological and reservoir data and interpretations of that data; and

(c) details of proposed further data acquisition and studies to enhance geological and reservoir understanding; and

(d) a reservoir management plan that—

(i) describes how the reservoir will be produced; and

(ii) provides the reasons for adopting the proposed approach; and

(iii) estimates the future performance of the reservoir; and

(iv) specifies the proposed rate of recovery of petroleum.

(2) The holder of the authority must ensure that the petroleum development plan is reviewed within 12 months after initial petroleum production (unless the Minister agrees to a longer period of time) and then at intervals not exceeding one year.

17 Storage development plan

(1) For the purposes of section 68(2) of the Act, a storage development plan must include—

(a) a description of each stage of the petroleum operation, including equipment or facilities to be used; and

(b) a description of the relevant existing geological and reservoir data and interpretations of that data; and

(c) details of proposed further data acquisition and studies to enhance geological and reservoir understanding; and

(d) a reservoir management plan that—

(i) estimates the remaining recoverable reserves; and

(ii) evaluates the suitability of the reservoir and seal for storage purposes; and

(iii) specifies the proposed storage operating volume; and

(iv) specifies the proposed rates of injection and recovery of petroleum; and

(v) details the methods to monitor and verify containment of injected gas and the petroleum-water contact; and

(vi) provides information about any proposals to conduct storage operations at nearby petroleum fields.

(2) The holder of the authority must ensure that the storage development plan is reviewed within 12 months after initial petroleum production (unless the Minister agrees to a longer period of time) and then at intervals not exceeding one year.

18 Additional information

If a petroleum production development plan or a storage development plan has been submitted by the holder of an authority for the purposes of section 64 or 69 of the Act, the Minister may, by notice in writing, require the holder to provide any additional information that the Minister considers to be relevant to approval of the plan.

PART 4—REPORTING

19 Annual report

(1) For the purposes of section 179(c) of the Act, the holder of an authority must give the Minister a report, in respect of each financial year, of—

(a) the petroleum operation activities (if any);

(b) conclusions derived from petroleum exploration activities;

(c) reports and studies relating to those activities—

undertaken under the authority during that year.

(2) A report under subregulation (1) must include—

(a) details of the expenditure by the holder of the authority on each activity undertaken during the year;

(b) the date the report was completed;

(c) the name of the person who prepared the report.

(3) The holder of an authority must give the report under subregulation (1) to the Minister—

(a) within 28 days after the end of the financial year to which it relates; or

(b) if the authority ceased to have effect during a financial year, within 28 days after the authority ceased to have effect.

(4) The Minister may, on a request from the holder of an authority, extend the period for the submission of a report.

(5) If the Minister extends the period of time in accordance with subregulation (4), the holder of an authority must give the report to the Minister within the extended period of time.

(6) For the purposes of this regulation, a holder of an authority includes a person who was the holder of an authority in the financial year to which the report relates.

20 Reports of surveys, drilling and other activities

(1) For the purposes of section 179(c) of the Act, the holder of an authority must give to the Minister, in an electronic form which accords with industry standards

(a) a report (including interpreted data) of—

i. surveys taken;
ii. drilling activities, together with logs and maps showing the locations of the drill holes;
iii. seismic activities;

iv. samples of any material tested, together with test results;
v. any petroleum reservoir, identified, if possible, in an industry standard manner;
vi. each geophysical, geochemical or seismic survey carried out by the holder; and

(b) copies of field, positional and processed or re-processed data (including interpreted data).

(2) A report under subregulation (1) must be dated and include the name of the person who prepared the report.

(3) The holder must give each report to which subregulation (1) applies to the Minister as soon as possible after the activities to which it relates have been completed.

21 Report by holder of production licence

For the purposes of section 179(c) of the Act, the holder of a production licence must in each month give to the Minister a report of petroleum production under the licence, including details of hydrocarbons, water and other substances produced from, or injected into, a well.

22 Incident reporting

(1) For the purposes of this regulation, a ***reportable incident*** means an incident arising out of a petroleum operation that—

(a) causes, or could have caused, substantial damage to the environment, the integrity of the petroleum operation or the immediate area of the operation (whether above or below ground); or

(b) is indicative of a possible future incident of that kind; or

(c) occurs in circumstances where the operation has not been carried out in accordance with the operation plan.

(2) The holder of an authority must give notice of a reportable incident to the Minister as soon as is practicable—

(a) after the reportable incident occurs; or

(b) if the operator is not initially aware of the reportable incident, after the operator becomes aware that it occurred.

Penalty: 20 penalty units.

(3) The notice under subregulation (2) must—

(a) be given orally or in writing;

(b) include the date, time and place of the reportable incident;

(c) describe the steps taken to minimise the impact of the reportable incident.

(4) As soon as is practicable after the holder of an authority has given notice to the Minister under subregulation (2), the holder must give the Minister a written report that includes—

(a) the date, time and place of the reportable incident; and

(b) a description of the reportable incident; and

(c) any known or suspected causes of the reportable incident; and

(d) a description of the steps taken to minimise the impact of the reportable incident; and

(e) a description of the steps taken or proposed to prevent a recurrence of the reportable incident.

Penalty: 20 penalty units.

PART 6—ROYALTIES AND RENT

23 Time of payment of royalties

(1) For the purposes of section 154(2) of the Act, a royalty for a production licence must be paid—

(a) for each period of 6 months ending on 30 June and 31 December in each year; and

(b) within 10 days of the expiry of the period for which they are payable.

(2) Unless otherwise specified in a production licence, the royalty payment for the period must be accompanied by a copy of records of the quantity of petroleum extracted or recovered in that period from any well within the licence area as measured by an approved measuring device.

(3) For the purposes of section 179(b) of the Act, the holder of a production licence must retain a copy of records of petroleum extracted or recovered for inspection purposes for 5 years.

Penalty: 20 penalty units.

(5) Subregulations (2) and (3) do not apply in relation to a well in any period in which the quantity of petroleum extracted or

recovered from that well in that period was determined by the Minister in accordance with section 153(3) of the Act.

24 Rent for occupancy of Crown Land

(1) In this regulation***, valuer-general*** means the valuer-general referred to in section 3(1) of the **Valuation of Land Act 1960**.

(2) For the purposes of section 160(3) of the Act, the amount of rent payable is the current market value for occupying the land, having regard to the use of the land permitted by the authority, as determined by a valuer nominated by the valuer-general.

(3) The holder of the authority is liable for the costs incurred in obtaining the determination.

(4) The rent must be reviewed by a valuer nominated by the valuer-general at intervals not exceeding 3 years but not less than one year.

(5) Rent must be paid for each period of 6 months ending on 30 June and 31 December in each year and must be paid within 10 days of the commencement of the period for which the rent is payable.

PART 7—PECUNIARY INTEREST STATEMENTS

25 Definitions

In this Part—

domestic partner of a person means a person with whom the person is in a domestic relationship within the meaning of section 35(1) of the **Relationships Act 2008**;

family, in relation to an officer, means—

(a) a spouse or a domestic partner of the officer; or

(b) a relative of the officer who is under the age of 18 years and who normally resides with the officer;

interest register means the register of interests of officers established under regulation 27;

officer means a person who is employed in the administration of the Act;

reportable interest, in relation to an officer, means a pecuniary interest of the officer, or of a member of the officer's family, which might appear to raise a conflict with the officer's responsibilities as an officer but does not include any remuneration or allowance received by an officer under the Act or the **Public Administration Act 2004.**

26 Duty of disclosure of pecuniary interest

(1) For the purposes of section 243 of the Act, an officer must give a pecuniary interest statement of any change in a reportable interest, and any new reportable interest, to the Minister within 30 days after becoming aware of the change or interest.

(2) An officer must not perform or exercise any function or power under the Act in relation to a matter to which a reportable interest relates unless the Minister authorises her or him to do so.

Penalty: 20 penalty units.

27 Disclosure of interest register

The Minister must cause an interest register to be established and maintained containing the information included in pecuniary interest statements submitted to the Minister under regulation 26.

28 Keeping and inspection of register

The interest register must be kept at a place nominated by the Minister and must be open to inspection by any person who has the consent of the Minister.

PART 8—ADMINISTRATIVE MATTERS AND FEES

29 Period before a disputed claim can go to the Tribunal or Supreme Court

Unless otherwise agreed by the owner or occupier of land and the holder of an authority for that land, the period of time for the purposes of section 134(2) of the Act is—

(a) if the claim for compensation relates to petroleum exploration— 14 days after the claim is first made;

(b) if the claim for compensation relates to petroleum production—30 days after the claim is first made.

30 Application fees

(1) For an application for an exploration permit, a fee of 700 fee units is required to be paid.

(2) For an application for a retention licence, a fee of 500 fee units is required to be paid.

(3) For an application for a production licence, a fee of 500 fee units is required to be paid.

(4) For an application for a special access authorisation, a fee of 250 fee units is required to be paid.

31 Fee for renewal of exploration permit

For the purposes of section 30(1)(b) of the Act, the fee for the renewal of an exploration permit is 250 fee units.

32 Annual fees for exploration permit, retention lease or production licence

(1) The following annual fees are payable—

(a) for an exploration permit, 500 fee units;

(b) for a retention lease, 700 fee units;

(c) for a production licence, 700 fee units.

(2) The annual fee payable in respect of the first year after the grant of an authority must be paid no later than 7 days after the authority is granted.

(3) The annual fee payable in respect of the second or subsequent year after the grant of an authority must be paid before the first anniversary of the grant of the authority.

33 Fees for transfer of an exploration permit, retention lease or production licence

The following fees are payable—

(a) for transfer, or partial transfer, of an exploration permit, 250 fee units;

(b) for transfer of a retention lease, 150 fee units;

(c) for transfer, or partial transfer, of a production licence, 250 fee units.

34 Fees for a suspension or variation of conditions or an exploration permit, retention lease or production licence

The following fees are payable—

(a) for suspension or variation of conditions of an exploration permit, 150 fee units;

(b) for suspension or variation of conditions a retention lease, 150 fee units;

(c) for suspension or variation of conditions a production licence, 150 fee units.

35 Fees for registration of documents

The fee for registration of a document under section 232 of the Act is 5 fee units.

36 Fees for inspection of, or copy of document in, petroleum register

For the purposes of section 236 of the Act, the following fees are payable—

(a) for inspection of the petroleum register, 2 fee units;

(b) for each page of a copy of a document or entry in the petroleum register, $4.

37 Fee for Minister's certificate

For the purposes of section 273(2) of the Act, the fee payable for a certificate is 5 fee units.

ENDNOTES

[i] Reg 4: S.R. No. 65/2000 as amended by S.R. Nos. 91/2000, 88/2004 and 6/2005.

Fee Units

These Regulations provide for fees by reference to fee units within the meaning of the **Monetary Units Act 2004**.

The amount of the fee is to be calculated, in accordance with section 7 of that Act, by multiplying the number of fee units applicable by the value of a fee unit.

The value of a fee unit for the financial year commencing 1 July 2010 is $11.95. The amount of the calculated fee may be rounded to the nearest 10 cents.

The value of a fee unit for future financial years is to be fixed by the Treasurer under section 6 of the **Monetary Units Act 2004**. The value of a fee unit for a financial year must be published in the Government Gazette and a Victorian newspaper before 1 June in the preceding financial year.

Penalty Units

These Regulations provide for penalties by reference to penalty units within the meaning of section 110 of the **Sentencing Act 1991**. The amount of the penalty is to be calculated, in accordance with section 7 of the **Monetary Units Act 2004**, by multiplying the number of penalty units applicable by the value of a penalty unit.

The value of a penalty unit for the financial year commencing 1 July 2010 is $119.45.

The amount of the calculated penalty may be rounded to the nearest dollar.

The value of a penalty unit for future financial years is to be fixed by the Treasurer under section 6 of the **Monetary Units Act 2004**. The value of a penalty unit for a financial year must be published in the Government Gazette and a Victorian newspaper before 1 June in the preceding financial year.

NOTE:

These endnotes will be amended if the Public Finance and Accountability Bill 2009 is enacted and in force before these Regulations are made (unless the proposed repeal of the ***Monetary Units Acts 2004*** *is omitted from the Bill).*