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Ministry of Economic Development

REGIONAL IMPACTS OF A NEW OIL OR GAS FIELD

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Regional Impacts of a new oil or gas field

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1 Introduction

This report presents three case studies that explore the impacts of the development of new oil and gas fields for a regional economy. These case studies are grounded in realistic production scenarios with the regional impacts based on real observed relationships in the Taranaki region.

The case studies provide a quantitative and qualitative analysis of activity at a regional level through the life of the fields developed – from exploration through to decommissioning. The fields are assumed to be in basins located in the South Island

1.1 Approach

The general approach uses estimates of production costs over the life of a field to identify regional expenditure and economic activity in terms of employment and GDP. The analysis only considers direct impacts and does not look at indirect and induced effects (multiplier analysis).

1.1.1 Scenarios and Initial Costings

Scenarios and initial costings were provided by the Ministry of Economic Development (MED). Case studies are presented for two oil fields and one gas field. All fields are offshore, with production exported directly without coming onshore. The basins in which the fields are discovered are not identifiable but are presumed to be in the South Island.

The key difference between the two oil fields is that one is 'near' offshore and the other is 'far' offshore. The effect of this is that the 'far' offshore development is more costly to develop and service.

These developments are consistent with the scenarios in that they can occur within the scenario parameters. However, base production costs have been reviewed and, where necessary, revised to more accurately reflect likely field developments.

All expenditure is in New Zealand dollars, which have been converted from US dollars at a cross rate of US$0.725. As well all dollar values are nominal and assume average inflation of 2.5 percent per annum.

1.1.2 Identifying Regional Expenditure

Having identified the production costs, the regional share of those costs are estimated. Participation of local companies in O&G activities depends upon the nature (level of specialisation) and scale (supplier capability and timeliness) of the task. It also depends on the degree to which the Energy and Petroleum (E&P) company, and its prime contractor are in a position to facilitate the involvement of local companies.

Regional share of expenditure is based on earlier work undertaken by BERL for Venture Taranaki and NZTE on the economic contribution of the oil and gas industry to New Zealand and Taranaki.[1] The analysis identified local participation in oil and gas expenditure in New Zealand across the project lifecycle and for different project types, which affect the level of local content. An estimate of New Zealand content of total expenditure for an offshore oil field is presented in Table 1.1.

Table 1.1. Regional Share of Total O&G Expenditure

	Offshore Oil (FPSO)
	% NZ content
Exploration	*28%*
Appraisal	36%
Development	30%
Production	63%
Decommissioning	33%

source: Wealth Beneath our Feet, 2010

A key assumption used in this analysis is that any activity captured locally requires participation from an existing O&G sector supplier. This is because an E&P company is very unlikely to utilise a company that a) it does not have an existing relationship with or b) does not have a successful 'track record' in the oil and gas industry. This excludes nearly all companies that are located outside Taranaki.

Work is currently in progress through Venture Taranaki to establish a hub and spoke model, where the expertise of the Taranaki O&G sector is transferred to other possible O&G areas as discoveries are made. This will ensure that local companies are capable of bidding for O&G projects through the different stages of the development.

1.1.3 Issues affecting regional participation in O&G activity

Local Ownership and Management

The majority of E&P companies in New Zealand are multi-nationals and as such, major decisions on construction and production are often made outside New Zealand. Similarly, the prime contractor on a project is also generally a large multi-national. This makes it difficult for local companies to capture a major share of activity.

[1] Venture Taranaki (2010). The Wealth Beneath our Feet. The Value of the Oil and Gas Industry to New Zealand and the Taranaki Region.

Local management of E&P companies all express a desire to maximise the local content of their development and production operations. This is driven by commercial interests, the convenience of shorter supply chains, and the benefits of fostering a local economy.

Location of Engineering Procurement Construction companies

Once an E&P company has finalised its design, it will contract the entire project with an Engineering Procurement Construction (EPC) provider. They have the discretion on who is contracted to provide the required components and services and often they will work with companies they already have an association with rather than looking for ‘local’ contractors. The scale and financial obligations of the construction process means that there are currently no New Zealand companies that can undertake this role. These companies are therefore largely based offshore, often close to a regional centre of O&G activity such as Houston, Aberdeen, or Perth. Being offshore, New Zealand companies have difficulty building up strong relations and credibility.

1.1.4 Identifying employment and GDP

Based on the regional share of expenditure, input output analysis is used to identify the regional employment and GDP. Based upon the previous assumption around the involvement of experienced O&G companies from Taranaki, employment and GDP to expenditure ratios from Taranaki are used to estimate regional employment and GDP. The regional impact therefore reflects the impact on the South Island (or regions in the South Island closest to the discovery) and Taranaki.

The employment to expenditure industry ratios have been revised to better reflect the stage of development of the field. For example, the ratio for O&G activity covers the exploration, development, and extraction stages, which tends to understate employment, particularly when only considering the exploration and development stages where extraction has not yet occurred.

1.1.5 Consultation

Expert advice and peer review was provided by Len Houwers (Arete Consulting). Financial costings were checked with Michael Adams, who provided the initial financial costings for the MED modelling.

2 Scenarios

Our analysis looks at the life cycle of three field developments in two separate basins – the first is an oil field in a near offshore basin; the second and third developments are a gas and an oil field in a far offshore basin.

2.1 Scenario Assumptions

Within the scenarios, assumptions were made on the production processes that are likely to occur over the life of the field. These are presented in Table 2.1 and guide the assessment of expenditure and activity over the life of the field.

Table 2.1. Scenario Production Assumptions

Field Stage	Key Scenario Assumptions
Exploration	Exploration takes three years, with discovery occurring during year three.
Appraisal	Appraisal takes two years at the end of which the Final Investment Decision (FID) is made.
Development	No oil or gas is brought onshore – Floating Production, storage and offloading units (FPSOs) and Floating Liquid Natural Gas Vessels (FLNGs) are purchased rather than leased. Oil – All wells are developed in the development phase - a two year development process. Gas – 15 wells in development phase and then a further 15 after 15 years of production - a three year development period. There is a two year development period for second phase of drilling.
Production	15 years for Oil Fields, 35 years for large gas field. There are no major re-works as the current trend is towards life of project production facilities. Therefore the only expenditure will be on OPEX. No onshore facilities are built as all production is exported
Decommissioning	Decommissioning takes two years and will cost 10 percent of development expenditure (excluding FPSO and FLNG costs).

Note that this is only a likely chain of activity, which is based on our understanding of how the field might develop. It is not a prescription of how the field development will actually occur. There are a number of factors involved and therefore a number of alternative outcomes that could eventuate.

It is also assumed that the fields will produce either all oil or all gas as opposed to being a combination of both with a primary output of one or the other.

Finally, the fields are being looked at in isolation. Over time, as more discoveries are made and activity is undertaken, infrastructure, capability and capacity improvements will result in different dynamics around what might occur at a local level. This assumption is defendable considering the oil and gas sector in Taranaki region, which has taken at least 50 years to get to its current stage.

2.2 Near Offshore Oil Field – P50

Under the P50 scenario, ten fields are developed – three gas and seven oil. The three gas fields are discovered between 2012 and 2021. These are developed with a technical field size ranging from 0.4 trillion cubic feet (tcf) to 1.4 tcf.

The seven oil fields are discovered between 2015 and 2046. These are developed with a technical field size ranging from 13.7 million barrels to 240 million barrels.

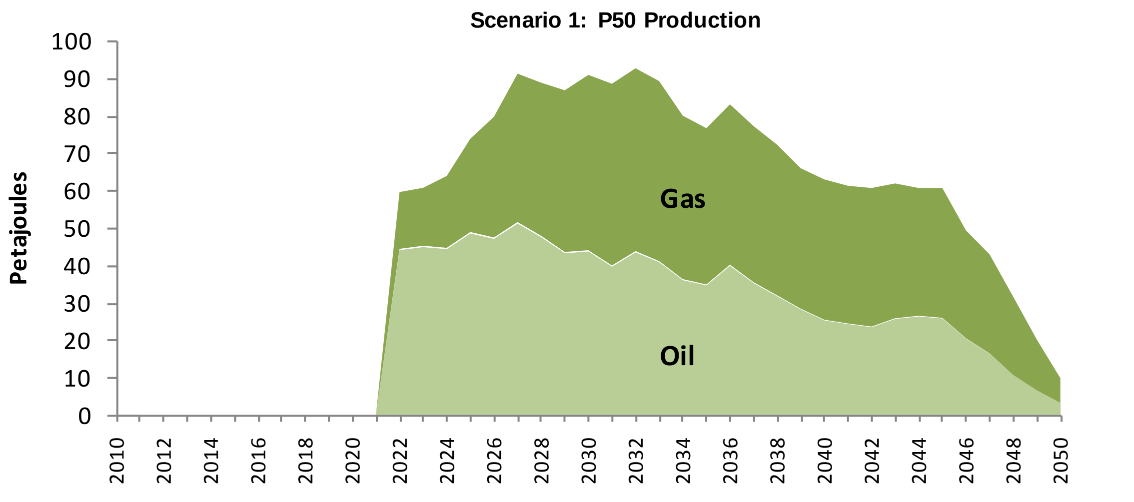
Near Offshore - P50

Discovery year	Field type	Tech field size (tcf / mmbbl)
2012	Gas	0.4
2015	Oil	120.1
2022	Gas	0.7
2021	Gas	1.4
2028	Oil	240.3
2030	Oil	13.7
2039	Oil	48.1
2043	Oil	60.1
2046	Oil	80.1
2046	Oil	40.0

source: NZ Petroleum & Minerals

The regional analysis looks at an oil field containing 120.1 million barrels, which is discovered in 2015 and only makes qualitative comments on the 1.4 tcf gas development from a 2021 discovery.

Figure 2.1. Near Offshore Field Scenario



source: NZ Petroleum & Minerals

The oil field being assessed is the first oil field developed in the basin and is the second largest of the seven (although it is only half the size of the largest field). It accounts for around 20 percent of total oil production in that basin to 2050.

2.3 Far Offshore Field – P10

Under the far offshore field scenario, eleven separate fields are developed of which eight are gas and three are oil.

Far Offshore - P10

Discovery year	Field type	Tech field size (tcf / mmbbl)
2015	Oil	124.7
2019	Gas	3.0
2019	Gas	12.1
2022	Gas	6.0
2023	Gas	2.0
2024	Gas	0.5
2025	Gas	2.4
2030	Gas	4.0
2030	Gas	1.7
2031	Oil	498.7
2049	Oil	83.1

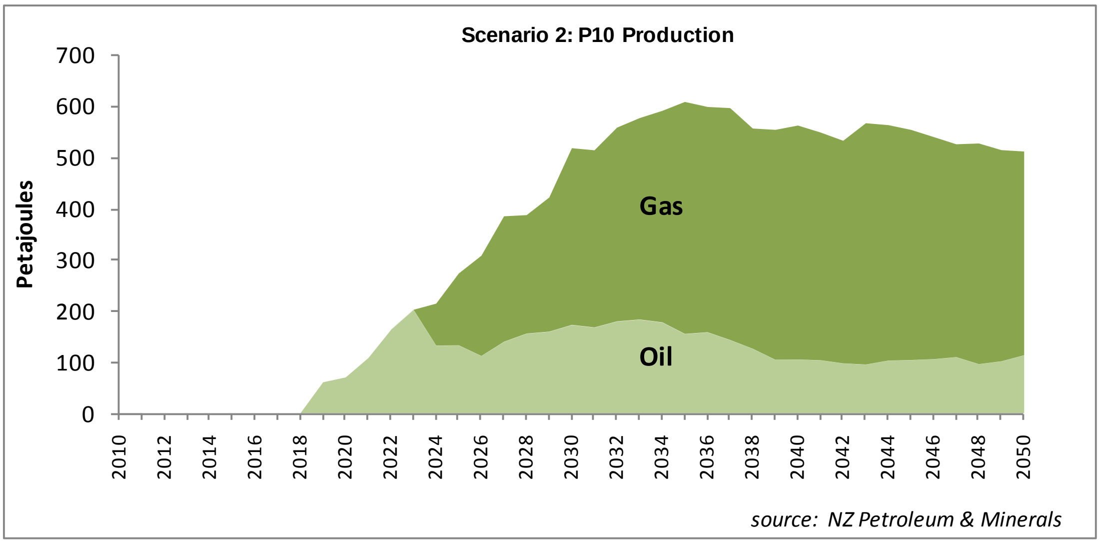
source: NZ Petroleum & Minerals

The eight gas fields are discovered between 2019 and 2030. These are developed with a technical field size ranging from 0.5 tcf to 12.1 tcf.

The three oil fields are discovered between 2015 and 2049. These are developed with a technical field size ranging from 83 million barrels to 499 million barrels.

The regional impact analysis looks at two field developments – an oil field and a gas field. The oil field of 125 million barrels is discovered in 2015 and a gas field of 12.1 tcf is discovered in 2019.

Figure 2.2. Far Offshore Field Scenario

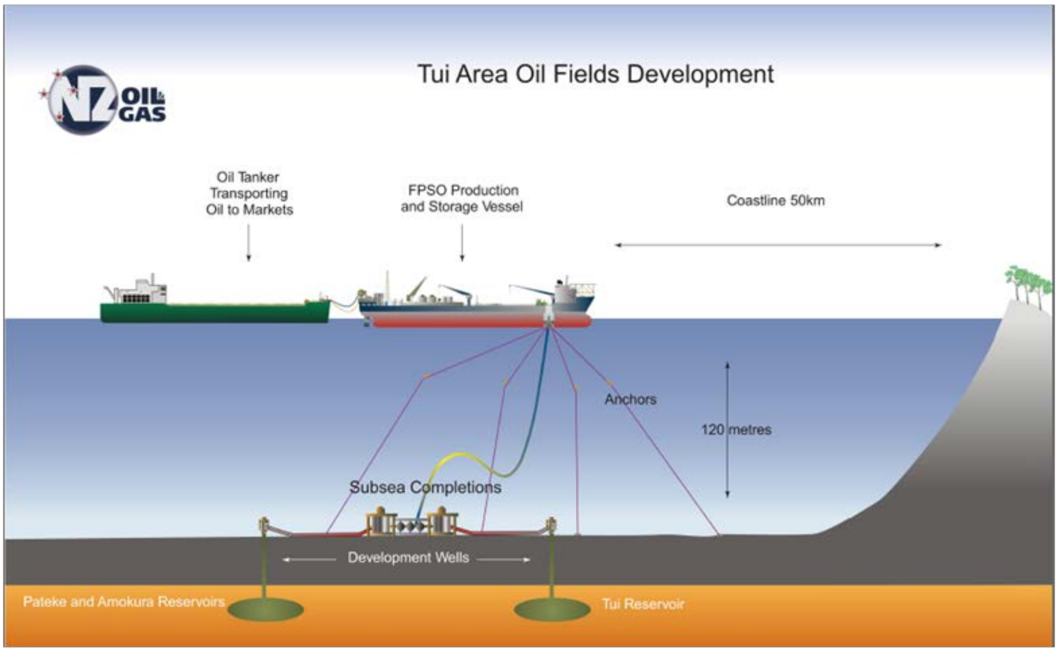


The oil field is the first oil field developed and is the second largest of the seven. It accounts for all production of oil in that basin to 2037 when the next field comes on stream.

The gas field is one of the first two fields developed and is the largest of the eight accounting for close to 40 percent of total gas production in that basin to 2050.

All production is processed and exported directly to market without coming onshore. Development is assumed to comprise subsea completions with wellhead risers directly to an FPSO in the case of oil or FLNG in the case of gas. Production is then transferred to either an oil tanker or an LNG vessel. The FPSO development finds an analogy in the Tui oil field development in Taranaki as shown in Figure 2.3.

Figure 2.3. Subsea Field Development – Tui Area Oil Field



Source: NZOG

3 Regional Case Studies

As noted in the previous chapter, regional impacts are identified for three fields:

- Near offshore oil
- Far offshore oil
- Far offshore gas.

3.1 Near Offshore Oil Field

The oilfield discovery is made in 2015 through a three well drilling exploration campaign following two years of survey and survey interpretation work to identify the prospect leads.

After a further 12 months interpreting the results of the well logging and integrating these with the seismic information the appraisal phase assumes a further two wells are required to de-risk the subsurface information in order to develop the necessary confidence to establish the field reserves. The two wells are drilled in 2016 in a single campaign during the summer offshore drilling window.

A further 12 months is assumed to analyse the new information and develop a business case for FID. The development assumes a total of eight production wells with the appraisal wells being used for water reinjection. Development drilling starts in 2017 and finishes in 2018 along with the subsea completions. During this period an oil tanker is converted to a FPSO in a shipyard in Asia and sailed directly to the field for hook-up and commissioning in 2019.

A Near Offshore Gas Field

The development of a 1.4 tcf near offshore development has been excluded from the analysis as an agreed parameter was that no production was brought onshore. Under this parameter, the near offshore gas field would not be viable and, therefore, not developed.

Conceptually, a 1.4 tcf near shore discovery is analogous to a larger version of a Pohokura discovery and development. A 1.4 tcf discovery is insufficient for an LNG type development but significant enough to improve New Zealand's gas reserve to production ratio and extending confidence to onshore gas development and downstream investment.

In particular, it can add sufficient reserves and term security to support a greenfield petrochemical development such as a Motunui sized methanol plant or a world scale nitrogen fertiliser development. This would also support local industry and commercial and residential gas customers with an alternative low carbon fuel replacement.

There is also potentially scope, depending on the location of the find to create a South Island gas market and connect the North Island to improve supply security in regions where gas infrastructure is most developed.

The onshore investment and the ability to add value to the upstream products is likely to create significantly more regional and national value than larger structures where the product from the petroleum development is extracted offshore and exported without it ever reaching the New Zealand shore.

The field produces oil for 15 years. No oil comes onshore. After 15 years, the field is decommissioned, which takes two years.

All in all, from exploration through to decommissioning, activity on the field occurs from 2013 through to 2036, a period of 24 years. A total of 125 million barrels of oil are extracted and exported direct to market.

3.1.1 Expenditure

It is estimated that over the life of the field, from exploration through to decommissioning, a total of $3.17 billion is spent.

Expenditure can be broken down into the five stages of the field as shown in Table 3.1.

Table 3.1. Estimated Expenditure over the Life of Field

	($m)	near offshore oil
	Year of Discovery	**2015**
3 year process leading up to discovery	**Exploration**	
	Exploration wells drilled	*3*
	Cost per exploration well	*110.3*
	Well Capex	*331.0*
	Exploration Geology & Geophysics	*9.7*
	Exploration Seismic	*11.0*
	Total Pre-exploration	***351.7***
2-year process	**Appraisal**	
	Appraisal wells drilled	*2*
	Cost per appraisal well	*110.3*
	Well Capex	*220.7*
	Development Seismic	*16.6*
	Total Appraisal	***237.2***
2-year process Design, feed, FID undertaken in parallel	**Development**	
	Production wells	*8*
	Cost per production well	*110.3*
	Well Capex	*882.8*
	design/feed/FID	*118.6*
	Platform/FPSO	*689.7*
	Total Development	***1,691.0***
	Production	
	Years of production	*15*
	Annual opex	*48.3*
	Total Production	***724.1***
2-years	**Decommissioning**	**169.1**
	Total Expenditure	**3,173.2**

source: BERL, MED

Production occurs four years after the field is discovered. The greatest portion of expenditure is during field development, which costs $1.69 billion. Over $724 million is spent during the production phase.

A large proportion of the field development expenditure will not be spent in New Zealand. This includes almost all of the design expenditure, including FEED, and all of the EPC work associated with the FPSO.

With no production brought onshore, onshore investment is limited to production logistics. This includes support vessels, equipment storage, and a helicopter and a shore base for operations. Regional capability in maintenance and minor engineering supports the production phase.

3.1.2 Regional Impact

However, within each stage of the process, a certain proportion of the activity will be captured locally. With an offshore oil field, regional contribution will be will largely providing support services and provisions to the subsea completions/FPSO, including repairs and maintenance and operational support in terms of FPSO manning, chemical consumption, and marine support for work-overs and tanker offloading operations. These services also apply during the drilling programmes leading up to production. This activity occurs over the life of the project.

Figure 3.1 shows the employment and GDP captured within the region over the life of the field. There is high level of activity during the appraisal and production, with major peaks during the drilling phases. Activity then levels off over the production phase. During decommissioning there is a jump in FTE activity but a drop in GDP contributions.

Figure 3.1. Direct Regional Employment and GDP of a Near Offshore Oil Field

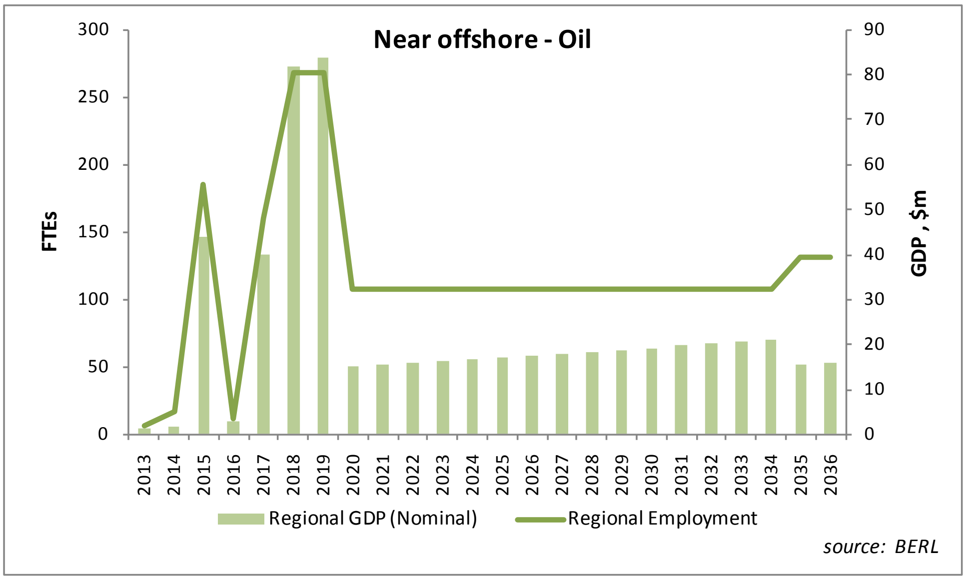


Table 3.2 shows the regional impacts over the life of the oil field. Total expenditure (including inflation) over the 25 year life of the project is around $4.06 billion. Of this, $1.6 billion is spent in the regional economy.

Table 3.2. Regional Impact of Near Offshore Oil Field (total)

near offshore oil (total)	exploration	appraisal	development	production	decomm issioning	Total
total expenditure ($m)	$378	$268	$1,986	$1,108	$317	$4,057
regional expenditure ($m)	$106	$97	$586	$702	$106	$1,597
regional employment (FTEs	208	173	535	1,616	263	2,795
regional GDP ($m)	$47	$43	$166	$270	$31	$557

source: BERL

Based upon employment to output ratios from the regional input output tables, which have been revised to reflect activity levels in similar projects, this level of expenditure is estimated to create employment for close to 2,800 FTEs over the life of the field. The output is expected to result in $557 million in regional GDP.

Table 3.3 shows the same regional activity on an annual basis. On average, over the 24 years that the field operates, $169 million will be spent annually. Of this, $67 million will be spent regionally, creating 116 jobs and generating $23 million in GDP each year.

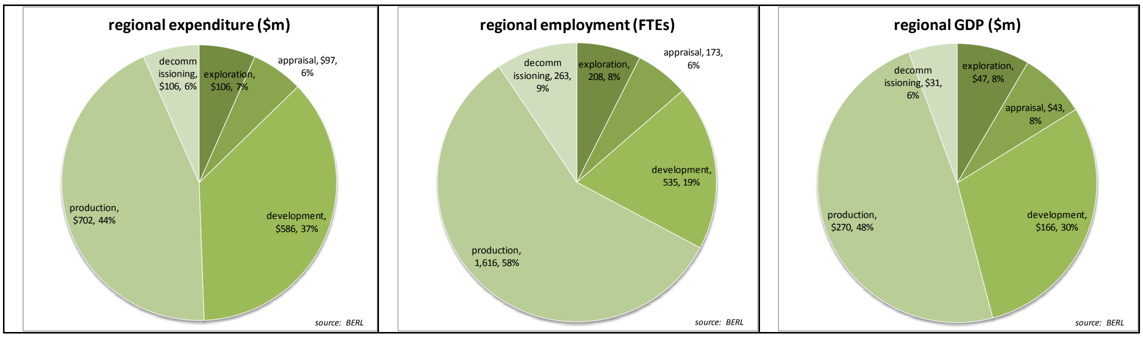
Table 3.3. Regional Impact of Near Offshore Oil Field (annual)

near offshore oil (annual)	exploration	appraisal	development	production	decomm issioning	Total
total expenditure ($m)	$126	$134	$993	$74	$159	$169
regional expenditure ($m)	$35	$49	$293	$47	$53	$67
regional employment (FTEs)	69	86	268	108	132	116
regional GDP ($m)	$16	$21	$83	$18	$16	$23

source: BERL

As reflected in Figure 3.2, the majority of the impacts occur during the production phase, particularly as this is the longest facet of activity. The highest period of activity, where there are also large regional benefits is in the development phase.

Figure 3.2. Regional Expenditure, Employment and GDP by Stage of Development



3.2 Far Offshore – Oil Field

There is little difference between the near and far offshore scenarios for oil as the field sizes are almost the same (124 million barrels vs. 120 million barrels), the discovery year is the same, and the development concept identical. Thus, the near offshore assumptions can also be used for this field.

3.2.1 Expenditure

It is estimated that over its life, the far offshore oil field will incur expenditure of $4.99 billion. Expenditure can be broken down into the five stages of the field life as shown in Table 3.4.

Table 3.4. Estimated Expenditure over the Life of Field

	($m)	far offshore oil
	Year of Discovery	2015
3 year process leading up to discovery	**Exploration**	
	Exploration wells drilled	*2*
	Cost per exploration well	*165.5*
	Well Capex	*331.0*
	Exploration Geology & Geophysics	*13.8*
	Exploration Seismic	*24.8*
	Total Pre-exploration	***369.7***
2-year process	**Appraisal**	
	Appraisal wells drilled	*3*
	Cost per appraisal well	*165.5*
	Well Capex	*496.6*
	Development Seismic	*24.8*
	Total Appraisal	***521.4***
2-year process Design, feed, FID undertaken in parallel	**Development**	
	Production wells	*8*
	Cost per production well	*165.5*
	Well Capex	*1,324.1*
	design/feed/FID	*149.0*
	Platform/FPSO	*827.6*
	Total Development	***2,300.7***
	Production	
	Years of production	*15*
	Annual opex	*104.8*
	Total Production	***1,572.4***
2-years	**Decommissioning**	**230.1**
	Total Expenditure	**4,994.2**

source: BERL, MED

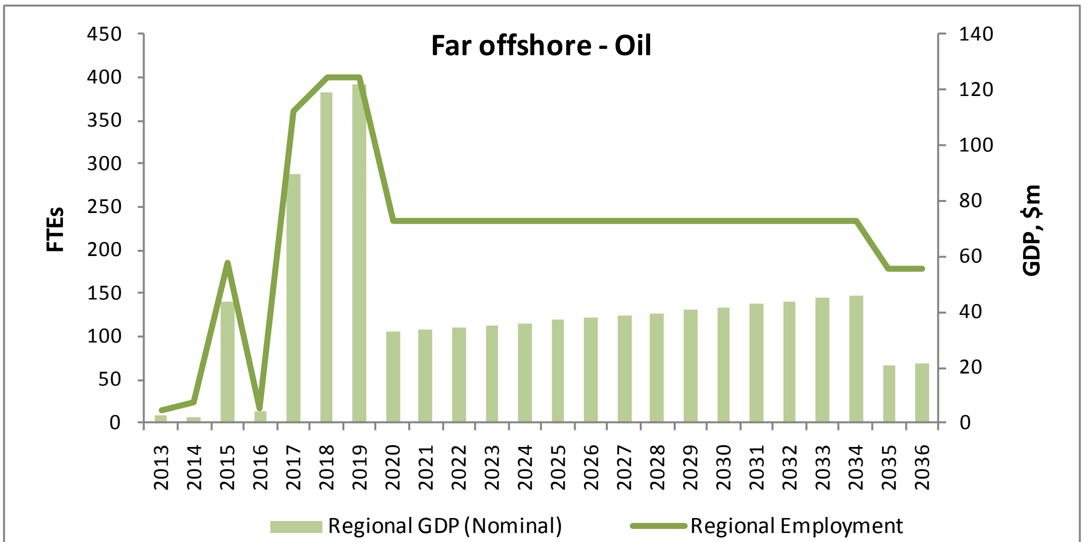
The greatest portion of expenditure is field development, costing $2.3 billion, with $891 million spent during the exploration and appraisal stages. Production is expected to be over 15 years, with an annual operating expenditure of $105 million. Decommissioning is expected to cost around $230 million and take two years.

3.2.2 Regional Impact

With an offshore oil field, regional contribution will be will largely providing support services and provisions to the subsea structures/FPSO including repairs and maintenance and operational support in terms of FPSO manning, chemical consumption, and marine support for work-overs and tanker offloading operations. These services also apply during the drilling programmes leading up to production. This activity occurs over the life of the project.

Figure 3.3 shows annual employment and GDP generated in the region over the life of the oil field. There are peaks in the pre-production phase, particularly around the drilling of wells. Activity is then steady over the production phase, dropping during the decommissioning of the field.

Figure 3.3. Direct Regional Employment and GDP of a Far Offshore Oil Field



source: BERL

Table 3.5 shows the regional impacts over the life of the oil field. Total expenditure over the 24 year life of the project is estimated to be $6.53 billion. Of this, $2.79 billion is spent in the regional economy.

This is estimated to create employment for 5,269 FTEs over the life of the field. The output is expected to result in an additional $1.01 billion to regional GDP.

Table 3.5. Regional Impact of Far Offshore Oil Field (total)

far offshore oil (total)	exploration	appraisal	development	production	decomm issioning	Total
total expenditure ($m)	$396	$589	$2,701	$2,406	$432	$6,525
regional expenditure ($m)	$111	$214	$798	$1,524	$144	$2,791
regional employment (FTEs	223	379	800	3,508	358	5,269
regional GDP ($m)	$49	$94	$241	$586	$43	$1,013

source: BERL

Table 3.6 shows the same impact on an annual basis. On average, over the 24 years that the field operates, around $272 million will be spent annually. Of this $116 million will be spent locally, creating 220 jobs and adding $42 million to regional GDP each year.

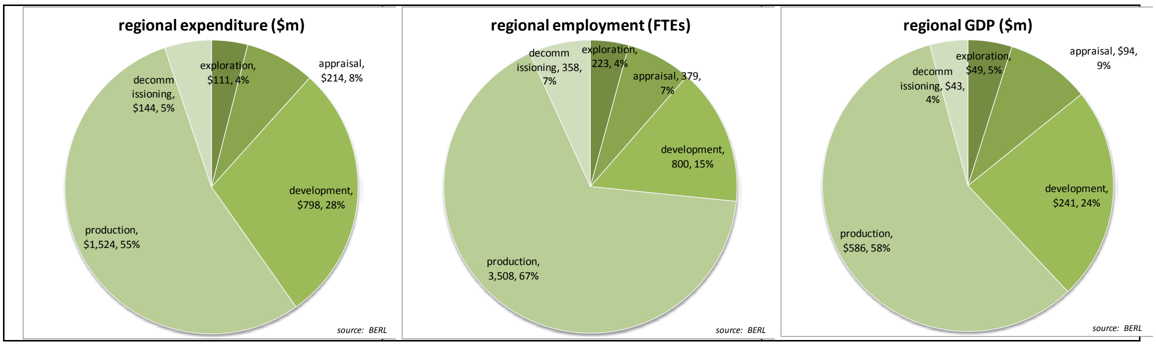
Table 3.6. Regional Impact of Far Offshore Oil Field (annual)

far offshore oil (annual)	exploration	appraisal	development	production	decomm issioning	Total
total expenditure ($m)	$132	$295	$1,351	$160	$216	$272
regional expenditure ($m)	$37	$107	$399	$102	$72	$116
regional employment (FTEs)	74	190	400	234	179	220
regional GDP ($m)	$16	$47	$120	$39	$21	$42

source: BERL

As shown in Figure 3.4, a much higher proportion of employment and GDP (than in the near offshore oil field) is captured during the production phase. This is because the production phase is more costly due to distance from shore, and regional capture of expenditure during the production phase is relatively high.

Figure 3.4. Regional Expenditure, Employment and GDP by Stage of Development



3.3 Far Offshore - Gas Field

The far offshore gas field is discovered in 2019, following two years of extensive exploration drilling from seven wells and preceded by a further two years of survey and seismic interpretation work. After discovery, a further two years is spent on interpretation and appraisal drilling comprising a further three wells to delineate the prospect and declare reserves.

Developing the field takes three years from the final investment decision. The field starts with fifteen production wells, with five wells drilled each year during the development phase. Although it is likely that the gas field will have associated condensate and LPG content the regional analysis doesn't require these to be identified in order to calculate the regional benefits. Although it adds some complexity to the FLNG design and operation to have two other petroleum products produced from the field, the regional resources are able to support these within the context of a mainly LNG facility.

A total of 30 production wells are assumed to be necessary to access all of the reserves. A simplifying assumption is that the field produces gas for 15 years before a further drilling phase to add 15 new wells occurs. The field than continues producing for a further 18 years.

All gas is exported directly to market via a FLNG, with no gas coming onshore. The field is then decommissioned over a two-year period.

All in all, from exploration through to decommissioning, activity on the field occurs from 2017 through to 2064, a period of 45 years.

3.3.1 Expenditure

Total expenditure on the far offshore gas field is estimated to by $18.5 billion, with $8.3 billion of that amount required for the purchase/ lease of a FLNG. Expenditure can be broken down into the five stages of the field as shown in Table 3.7.

Table 3.7. Estimated Expenditure over the Life of Field

	($m)	far offshore gas
	Year of Discovery	**2019**
3 year process leading up to discovery	**Exploration**	
	Exploration wells drilled	*7*
	Cost per exploration well	*165.5*
	Well Capex	*1,158.6*
	Exploration Geology & Geophysics	*13.8*
	Exploration Seismic	*24.8*
	Total Pre-exploration	***1,197.2***
2-year process	**Appraisal**	
	Appraisal wells drilled	*3*
	Cost per appraisal well	*165.5*
	Well Capex	*496.6*
	Development Seismic	*24.8*
	Total Appraisal	***521.4***
3-year process Design, feed, FID undertaken in parallel	**Development**	
	Production wells	*30*
	Cost per production well	*165.5*
	Well Capex	*4,965.5*
	design/feed/FID	*165.5*
	FLNG	*8,275.9*
	Total Development	***13,406.9***
	Production	
	Years of production	*35*
	Annual opex	*82.8*
	Total Production	***2,896.6***
2-years	**Decommissioning**	**496.6**
	Total Expenditure	**18,518.6**

source: BERL, MED

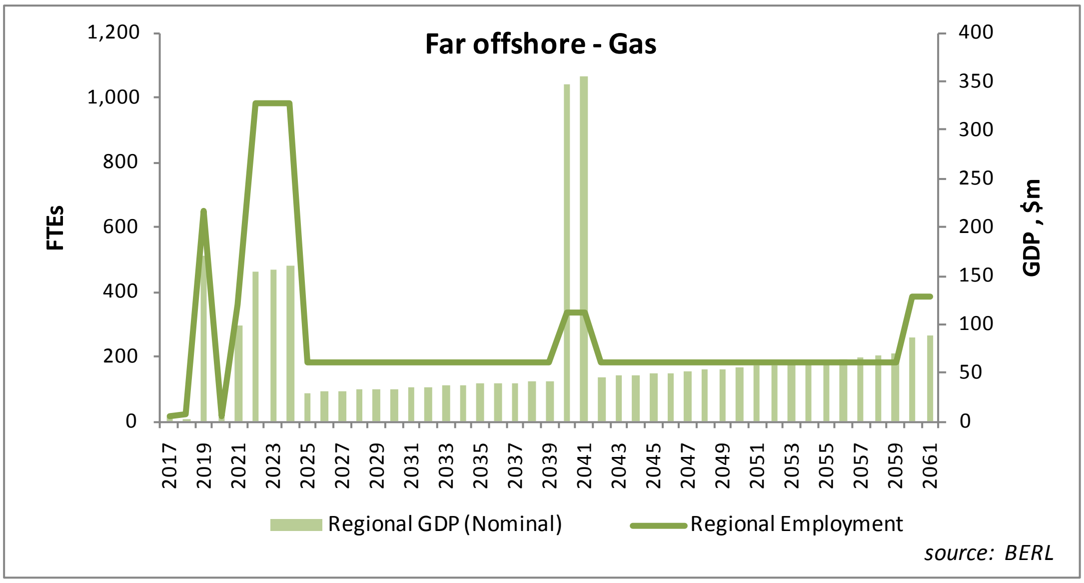
Production doesn't occur until six years after the field is discovered, over which time appraisal and development occurs. The greatest portion of expenditure is field development, costing $13.4 billion, although that includes $8.3 billion for the purchasing of a FLNG. All of that expenditure goes directly offshore.

Over the 35 years of production, operating expenditure is expected to be around $83 million annually. Decommissioning is expected to cost close to $500 million.

3.3.2 *Regional Impact*

Within each stage of the process, a certain proportion of the activity is captured locally. With an offshore gas field, regional contribution is largely providing support services and provisions to the FLNG. This activity occurs over the life of the project. As well, there is a certain level of activity around providing maintenance and repair services. This occurs during the development, production and decommissioning phase. Figure 3.5 represents the employment and GDP generated regionally as a result of the gas field.

Figure 3.5. Direct Regional Employment and GDP of a Far Offshore Gas Field



There are peaks in local activity during the appraisal and development phase, and then again when the second tranche of drilling occurs in 2040/41. Finally there is a peak during decommissioning. Otherwise there is a steady level of employment and GDP over the production phase of the field.

Table 3.8 shows the regional impacts over the life of the oil field. Total expenditure over the 45 year life of the project is calculated to be around $19.2 billion. Of this, $8.1 billion is spent in the regional economy. This expenditure is estimated to create employment for11,540 FTEs over the life of the field. The expenditure is expected to contribute $3.19 billion to regional GDP.

Table 3.8. Regional Impact of Far Offshore Gas Field (total)

far offshore gas (total)	exploration	appraisal	development	production	decomm issioning	Total
total expenditure ($m)	$1,421	$650	$3,258	$12,153	$1,771	$19,254
regional expenditure ($m)	$398	$237	$962	$5,870	$590	$8,056
regional employment (FTEs	687	379	2,940	6,760	773	11,540
regional GDP ($m)	$176	$104	$472	$2,258	$176	$3,186

source: BERL

Table 3.3 shows the regional impact on an annual basis for each stage and in total. On average, over the 45 years that the field operates, $428 million is spent annually. Of this $179 million is spent regionally, creating 256 jobs and generating $71 million in regional GDP on average each year.

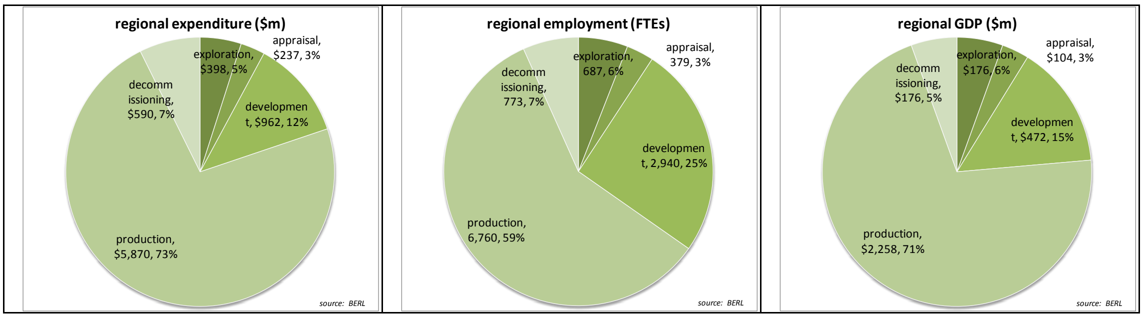
Table 3.9. Regional Impact of Far Offshore Gas Field (annual)

far offshore gas (annual)	exploration	appraisal	development	production	decomm issioning	Total
total expenditure ($m)	$474	$325	$1,086	$347	$886	$428
regional expenditure ($m)	$133	$118	$321	$168	$295	$179
regional employment (FTEs)	229	190	980	193	387	256
regional GDP ($m)	$59	$52	$157	$65	$88	$71

source: BERL

Due to the long production life of the field, the greatest benefits are during the production phase (see Figure 3.6). However, the development phase accounts for around 25 percent of the employment with 980 FTEs employed each year of development.

Figure 3.6. Regional Expenditure, Employment and GDP by Stage of Development



4 Summary

The analysis considers the regional impacts of three field discoveries off the South Island that lead to field development and production. Two of the three fields analysed are oil and the third is gas. A summary of regional impacts is presented in Table 4.1.

Table 4.1. Summary of Regional Impacts

Total Impacts	Near Oil	Far Oil	Far Gas
total expenditure ($m)	$4,057	$6,525	$19,254
regional expenditure ($m)	$1,597	$2,791	$8,056
regional employment (FTEs)	2,795	5,269	11,540
regional GDP ($m)	$557	$1,013	$3,186

Annual Impacts	Near Oil	Far Oil	Far Gas
length of impact	24yrs	24yrs	45yrs
total expenditure ($m)	$169	$272	$428
regional expenditure ($m)	$67	$116	$179
regional employment (FTEs)	116	220	256
regional GDP ($m)	$23	$42	$71

source: BERL

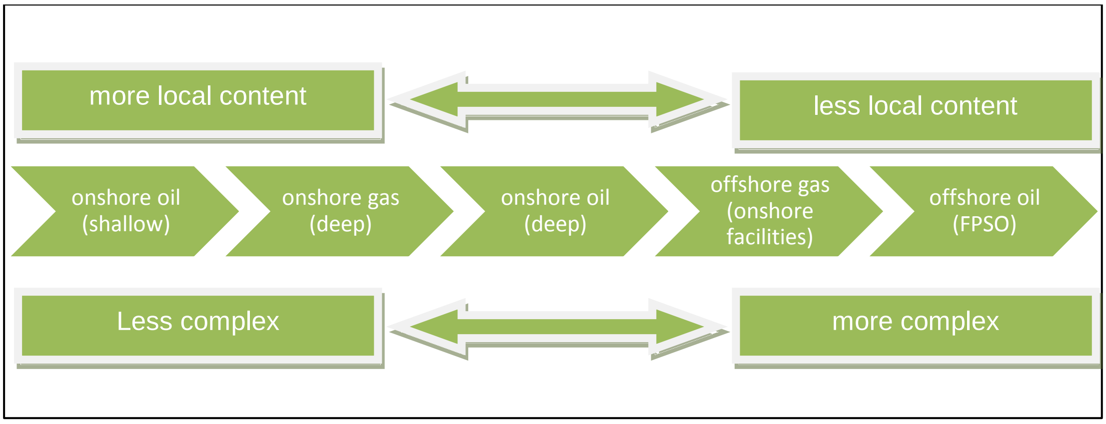
While the impacts appear significant, all production is exported directly from offshore facilities. The main regional impacts are from providing services and provisions to the field, along with some maintenance and repair during production.

Participation of local companies in O&G activities depends upon the nature (level of specialisation) and scale (supplier capability and timeliness) of the task. It also depends on the degree to which the E&P company and its prime contractor are in a position to facilitate the involvement of local companies. All locally based E&P companies expressed their desire to encourage local participation as much as possible.

A key assumption used in this analysis is that local participation in direct O&G activity will only occur with companies that are already involved in O&G activity. This is either by existing companies setting up branches in the region, or joint ventures with local companies.

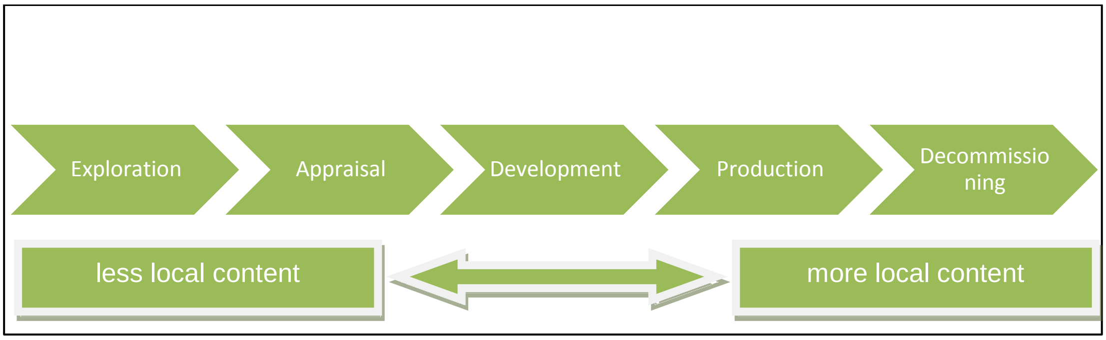
As a general rules of thumb: the closer the field is to shore, and the later the stage of development, the higher the local content.

Figure 4.1. Local Content and Field Type



The further offshore the development the more complex it becomes. Local contributions are likely to be in the less complex developments.

Figure 4.2. Local Content and Stage of Development



It could be argued that, considering the type of field developments assessed, the regional impacts identified are conservative. For example, were gas to come onshore, there would be much more investment and employment in onshore processing facilities as well as infrastructure (pipes) to bring the gas onshore. Further, an increased domestic supply of gas would provide opportunities for downstream processing or distribution, which would generate significantly higher investment, employment and GDP for the region.