7. PROJECT SUBSTANTIATION (ALTERNATIVES ANALYSIS)

7.1 PNG Government Directive

The Papua New Guinea Liquefied Natural Gas Project (PNG LNG Project) is consistent with the constitutional goals and directives of the country. The Fourth National Goal and Directive Principle of the Constitution of Papua New Guinea states:

> We declare our Fourth Goal to be for Papua New Guinea's natural resources and environment to be conserved and used for the collective benefit of us all, and be replenished for the benefit of future generations.

While the extraction of gas by the PNG LNG Project will consume a non-replenishable resource, the taxes, royalties and profits derived from the project will contribute to the capital wealth of the nation. In this respect, the wealth generated by the project will be a durable economic asset to future generations, even after the original source of wealth becomes depleted.

For the PNG LNG Project to meet the spirit of this directive, it depends on negotiated agreements between the co-venturers and other parties on their respective responsibilities and the sharing of benefits and, especially, on separate agreements (to which the co-venturers are not party) between governments and landowners for sharing project benefits – essentially, the political foundation for the project.

7.2 Economic Benefits to Papua New Guinea

The project will generate the following economic benefits (ACIL Tasman, 2008):

- Net present value to Papua New Guinea of between K10.8 billion and K14.4 billion over an approximately 30-year period from first gas (anticipated to be 2013) to approximately 2043.
- Construction direct employment peaking at 7,500 (20% national) and permanent direct operations employment of approximately 850 (> 90% national).[1]
- Net annual cash flow to the government and project-area landowners of between K2.4 billion and K6 billion over a 30-year period from first gas in 2013 to 2043 compared to an estimated K0.4 billion from 2013 (Balfe, pers. com., 2008) to the projected end of oil production in 2025. The total cash flow from the PNG LNG Project over the 30-year operational life would be K114 billion.
- A doubling of PNG's annual gross domestic product from K8.65 billion in 2006 to K18.2 billion.
- A fourfold rise in value of PNG's petroleum exports from K2.6 billion in 2006 to K11.4 billion.

[1] For a more recent employment estimate, see Section 1.2.6, Project Staffing. The employment numbers used in ACIL Tasman (2008) are based on the information available at the time the report was written.

- Capital investment of K36 billion and annual average recurrent operating expenditure of K680 million.

ACIL Tasman's (2008) analysis of the economic impacts of the PNG LNG Project concluded:

> The PNG LNG Project offers a means of unlocking value from the extensive gas resources of the Southern Highlands region. The project has the potential to transform the economy of Papua New Guinea…(and its benefits) would spread throughout the economy as the government applies the earnings from its substantial share of the project's revenues to its social and economic programs. These programs have the potential to improve the quality of life of Papua New Guineans by providing essential services and enhancing the country's productivity. Benefits would also flow through the economy as the wages and salaries of project staff are spent and as suppliers provide a range of goods and services to the project. Landowners stand to benefit from direct payments as well as improved social and economic infrastructure.

(See also Chapter 23, Project-wide Socio-economic and Cultural Impacts and Mitigation Measures.)

7.3 No-Project Option

In broad terms, the no-project option brings the inverse of the project's benefits (see Section 7.2, Economic Benefits to Papua New Guinea, and Chapter 23, Project-wide Socio-economic and Cultural Impacts and Mitigation Measures) and avoids the adverse impacts discussed in Part III of this EIS.

In addition, the no-project option carries an opportunity cost for PNG's oil and gas sector, and this opportunity cost has consequences for local communities and nationally. These are briefly discussed below.

7.3.1 Government and Landowners

The no-project option runs counter to the principles and policies of successive national and provincial governments, in particular:

- Falling short of the full attainment of the nation's economic and social development objectives.
- Ending the economic benefits of existing oil production operations earlier than could be the case. In the interim, the oil-only benefits would be lower than would be the case with the realisation of the PNG LNG Project.
- Similarly, shortening the period of active oil industry employment, training and contracting opportunities.

On the other hand, the land, water, air, amenity, social and cultural impacts associated with the project would not occur.

7.3.2 Local Aspirations Disappointed

Strong and consistent local support for the PNG LNG Project is evident in the household surveys conducted by the project (see Section 23.7, Host Community Support for Project). Not implementing the project will be a disappointment to the majority of the populace of the project impact area and will forego an opportunity for them to attain their aspirations for improved socio-economic circumstances (but see Section 7.3.4, Social Impacts Avoided, below).

7.3.3 Other Benefits Foregone

The loss of economic benefits would have flow-on effects on government services related to health, education and training, albeit from a low base. These benefits have fallen short of the expectations of local people in the project impact area since oil and gas production began, and these social services (together with benefits distribution) are the major issue between people at the grass roots and their representatives in the provincial and national governments. While nearly half the people inhabiting the project impact area think that the current petroleum developments have improved their lives, the remainder either disagrees (5%) or is unsure (50%). This does not diminish their support for the PNG LNG Project but highlights the fact that governance issues, the perceived inequitable distribution of benefits, and shortcomings in social service provision are among the local population's key issues (see Chapter 23, Project-wide Socio-economic and Cultural Impacts and Mitigation Measures).

7.3.4 Social Impacts Avoided

The main exception to the generally high local support for the PNG LNG Project has been a reservation among some people of Gulf Province about the fact that the project will make more likely a road linking their area to the highlands[2]. In 2005, this saw Highlanders' support for the road link at more than 90%, Gobe at 60%, but Kikori at less than 40%. The latter viewpoint in part reflects concerns about squatting and a deterioration in law and order. It persists to this day, even though the PNG LNG Project will not be turning pipeline ROWs into a public road link from the highlands to the gulf region.

7.3.5 Macro-economic Impacts Avoided

The no-project option will avoid the otherwise inevitable consequences that public revenues of the magnitude of those to be generated by the PNG LNG Project would have on other sectors of the PNG economy: upward pressure on the kina exchange rate; a draw of capital and labour from other sectors and, hence, a reduction in their export competitiveness; and inflation.

7.3.6 Environmental Impacts Avoided

Collateral biodiversity impacts (i.e., increased forest clearing and, to a greater extent, hunting) radiating out from the western road link associated with in-migration, poaching expeditions and settlement will not occur if the PNG LNG Project is not realised (see Chapter 28, Environmental Impact Summary Table). Rather, these collateral biodiversity impacts will remain mainly localised to the present-day footprint of the existing oil and gas operations.

[2] The completion of a road link was a specific requirement of the 2002 Gas Agreement for the earlier project to pipe natural gas to Australia (the PNG Gas Project).

More directly, the main environmental impact foregone will be that associated with the gas field development on Hides Ridge and the pipelines between Hides Ridge and Juha, where the (post-mitigation) residual direct and indirect biodiversity impacts of the PNG LNG Project are predicted to be as follows (see Section 18.7, Biodiversity):

- Of moderate severity, that is, an effect that is 'not severe (and is) unlikely to lead to major changes to population, community or ecosystem survival or health' (although the local populations or the areal extent of affected communities may be reduced).
- Over a limited area, that is, in the immediate surrounds of the limited number of impact sites and extending for a radius of from 200 m to 2 km around each site.

The biodiversity impacts avoided if there were no project at the LNG Facilities site at Caution Bay are relatively minor because the site has been largely cleared, because its main conservation asset (the Vaihua River Ecosystem Complex; see Section 12.3, Terrestrial Biological Environment) will be little affected by the project and because the site overall is unremarkable in the regional context.

On the other hand, to not build Papua New Guinea's largest industrial development on the outskirts of the capital city would avoid the inevitable changes (albeit much sought; see Chapter 23, Project-wide Socio-economic and Cultural Impacts and Mitigation Measures), but it would also forego the very considerable economic benefits that the project would bring (see Section 7.2, Economic Benefits to Papua New Guinea).

On the broader scale, the no-project option means that the PNG LNG Project's carbon dioxide emissions (see Chapter 26, Greenhouse Gases and Climate Change) would not occur, although it is likely that customers would be able to meet their gas requirements from a competitor project elsewhere in the world.

7.3.7 Strategic Consequences of the No-Project Option

For stand-alone resource projects, the no-project option is typically at least the inverse of the benefits and drawbacks of the project option. Moreover, as a feasible development proposition in its own right, a stand-alone resource project that does not proceed usually remains as a development option for the future.

However, the situation is more complex for the PNG LNG Project:

- First, the current project enjoys the synergies of contemporaneous oil production from established operations: the associated gas from the Kutubu, Gobe Moran, and Agogo oil fields; the use of the existing oil export pipeline ROW bench as a logistics route for a large portion of the onshore section of the LNG Project Gas Pipeline; and the availability of the Kutubu crude oil export pipeline and Kumul Marine Terminal for the export of the PNG LNG Project condensate produced at the Hides Gas Conditioning Plant. Moreover, the market for the gas creates the future opportunity to blow down the gas caps of the currently producing oil reservoirs. When production of associated gas begins, this will remove a current constraint on oil recovery[3] and will add to combined oil and gas recovery and the life of the fields.

To pursue an LNG project later, when the oil production operations have wound down, will see some of this advantage lost.

- Second, LNG projects take time to plan, finance and build. In global markets, they face many international competitors in the race to secure gas sales contracts.
- Third, the project sits as a link in a chain of sequential development, where each stage creates the foundation for future development. (The PNG LNG Project's synergy with existing operations, mentioned above, is a case in point.) No PNG LNG Project, combined with an end to oil production, will break the chain and reduce the future development prospects of Hides, Angore, Juha and other possible gas fields in the prospective but little explored country to the northeast of the existing oil production operations.

The implications of the no-project option for the PNG LNG Project fall therefore into two categories: the specific consequences in the near term (the benefits and the impacts foregone) and the strategic opportunity cost for the petroleum sector as a whole.

7.4 Gas Commercialisation Options

7.4.1 LNG

Petroleum liquids have long been readily saleable into the global marketplace (as is the case for PNG's current oil production). Natural gas; however, is commercially complex, requiring a number of (commonly related) criteria to be fulfilled, including:

- Customers for the gas.
- An adequate price for the gas to justify the costs of development.
- An affordable transport cost.
- Access to capital.

Moreover, global gas markets have been slow to mature: pipeline gas faces the limits to how far gas can be economically piped, and LNG contracts have traditionally relied on the long-term, take-or-pay contracts required to support the large capital costs of LNG processing and transport systems.

In recent years, however, rising demand and a growing number of suppliers have changed LNG into a commodity more readily tradeable on world markets. At the same time, a corresponding rise in world prices has made investment more attractive, but capital costs have also risen. Overall, however, LNG is a more attractive investment now than it has been, and a sufficient gas resource and favorable circumstances give PNG LNG enough advantage over its competitors to attract that investment.

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[3] The alternative exists to remove this constraint by the flaring of large quantities of gas. This is contrary to the state's resource conservation policy.

7.4.2 Other Gas Commercialisation Options

7.4.2.1 Pipeline to Australia

Two serious attempts have been made to commercialise natural gas from the PNG highlands by exporting it by pipeline to the Australian gas market.

Chevron Asiatic Limited embarked on feasibility studies for such a project in 1995 as the PNG Gas Project. The project went into abeyance in 2000 after failing to secure sufficient sales contracts to underwrite the capital cost of the project.

Esso Highlands Limited resumed feasibility studies in 2003, again as the PNG Gas Project. Once again, sales contracts turned out to be inadequate, compounded by rising input costs (notably for steel line pipe) and competition from new sources of natural gas (coal seam methane) in Queensland, Australia, the proposed termination point for the gas pipeline. The AGL Petronas Consortium had been responsible for the pipeline system from the PNG–Australian border to the customers in eastern Australia. When the consortium withdrew from the project, the PNG Gas Project lost access to its gas market and, in 2007, again went into abeyance.

7.4.2.2 Compressed Natural Gas

Natural gas compressed to up to 3,600 psi can be stored in pressure tanks and transported by tanker to export markets. Compressed natural gas has become an alternative to petrol and diesel fuel for buses and trucks in a number of countries. Compared to an LNG development, a compressed natural gas development would have a low capital cost and the advantage of being able to increase supply in small increments to meet gradually rising demand.

In 2005, Oil Search, Itochu Corporation and EnerSea Transport LLC investigated the possibility of shipping compressed natural gas from Papua New Guinea to New Zealand to replace a declining local gas supply and to cover what was expected to be a New Zealand–wide shortage of natural gas beginning in 2009.

The investigations did not generate a development project and have not been revived. Depending on its scale and the volume of gas required, such a project in the future could add to rather than replace the PNG LNG Project.

7.4.2.3 Petrochemical Plant

There have in the past been investigations into the feasibility of constructing a petrochemical plant to produce dimethyl ether from methanol at Port Moresby, and a memorandum of understanding is understood to exist between Oil Search Limited and the State of Papua New Guinea to pursue the possibility of such a project. The plant feedstock was to be natural gas and therefore would be in addition to the PNG LNG Project. No development projects have eventuated, and there are no investigations current. Depending on its scale and the volume of gas required, such a project in the future could add to rather than replace the PNG LNG Project.

7.4.2.4 Liquefied Petroleum Gas

Liquefied petroleum gas (propane and butane, known collectively as LPG) is traded globally. Papua New Guinea is currently a net exporter of LPG from the InterOil refinery in Port Moresby.

The production of LPG from the PNG LNG Project at an export scale requires fractionation, storage and exporting facilities that are currently not economic. The propane and butane produced as a by-product of the liquefaction process will therefore be reincorporated into the feed gas to the LNG Plant within the limits of the LNG product specification.

Future recovery of LPG as a product for sale remains a possibility, and ACIL Tasman (2008) has assumed, for economic impact assessment purposes, that this could occur in 2023 at a nominal rate of 11,700 barrels of oil equivalent per day. Whether this takes place or not will depend on the requirements of the gross heating value specifications of the LNG sales contracts with customers and whether the capital investment associated with LPG production, storage and export can be economically justified. This option will be assessed during LNG marketing.

7.5 LNG Facilities Location Options

7.5.1 North Coast versus South Coast

An LNG facility on the north coast of Papua New Guinea (for example, near Wewak) would be closer to customers in Asia. However, constructing the LNG Project Gas Pipeline from Hides Gas Conditioning Plant to the north coast would involve the geotechnical hazards of the steep, seismically active mountains of the central cordillera of the PNG highlands and further challenges traversing the extensive swamps and large rivers of the Sepik River floodplain. Most of this almost wholly greenfield pipeline alignment would cross country with no roads, little population and correspondingly large, primary tropical forest areas of conservation value.

A south coast option, on the other hand, takes advantage of the existing Kutubu crude oil export pipeline ROW, which runs for some 180 km from the Kutubu Central Processing Facility to landfall in the Kikori River near Kopi. Here, the limestone-dominated terrain is inherently more stable with lower seismicity, and the environment and social setting are much better understood.

Esso did not, therefore, proceed with the north coast option, because the advantages of lower LNG shipping costs did not outweigh the environmental, constructability, operating experience and cost advantages of the area of established petroleum infrastructure.

7.5.2 South Coast Options

The location of an LNG facility needs to provide loading access and safe berthing to LNG carriers. This created two conflicting siting criteria:

- On the one hand, the shorter the LNG Project Gas Pipeline to the LNG Facilities site, the lower its cost.
- On the other hand, sediment deposited on the seafloor by the large rivers flowing into the Gulf of Papua has resulted in shallow water extending some way offshore between the Kikori River delta and points well east of the mouth of the Purari River[4]. In this area, LNG carriers would

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[4] This is why the Kumul Marine Terminal servicing crude oil exports from Kutubu had to be constructed some 40 km offshore from Cape Blackwood at the seaward extremity of the delta of the Kikori River.

need to berth so far from shore that the cryogenic loading lines would warm up during loading, and a substantial proportion of the LNG would be lost to vaporisation. Moreover, this is a zone of active sediment deposition and lacks the protection of the sediment-intolerant barrier reefs that occur beyond Yule Island to the east.

The comparison of options needed not only to balance these two conflicting criteria but also to consider the attributes of each particular site, notably land tenure and use, conservation status, and the requirement for a breakwater.

Figure 7.1 shows the four south coast LNG plant site options as they run up the coast from east (most distant) to west. Their attributes are discussed below.

7.5.2.1 Caution Bay (Base Case)

The base case, Caution Bay, is located on Caution Bay between the villages of Boera and Papa on the east coast of the Gulf of Papua. The principal features of the site are as follows:

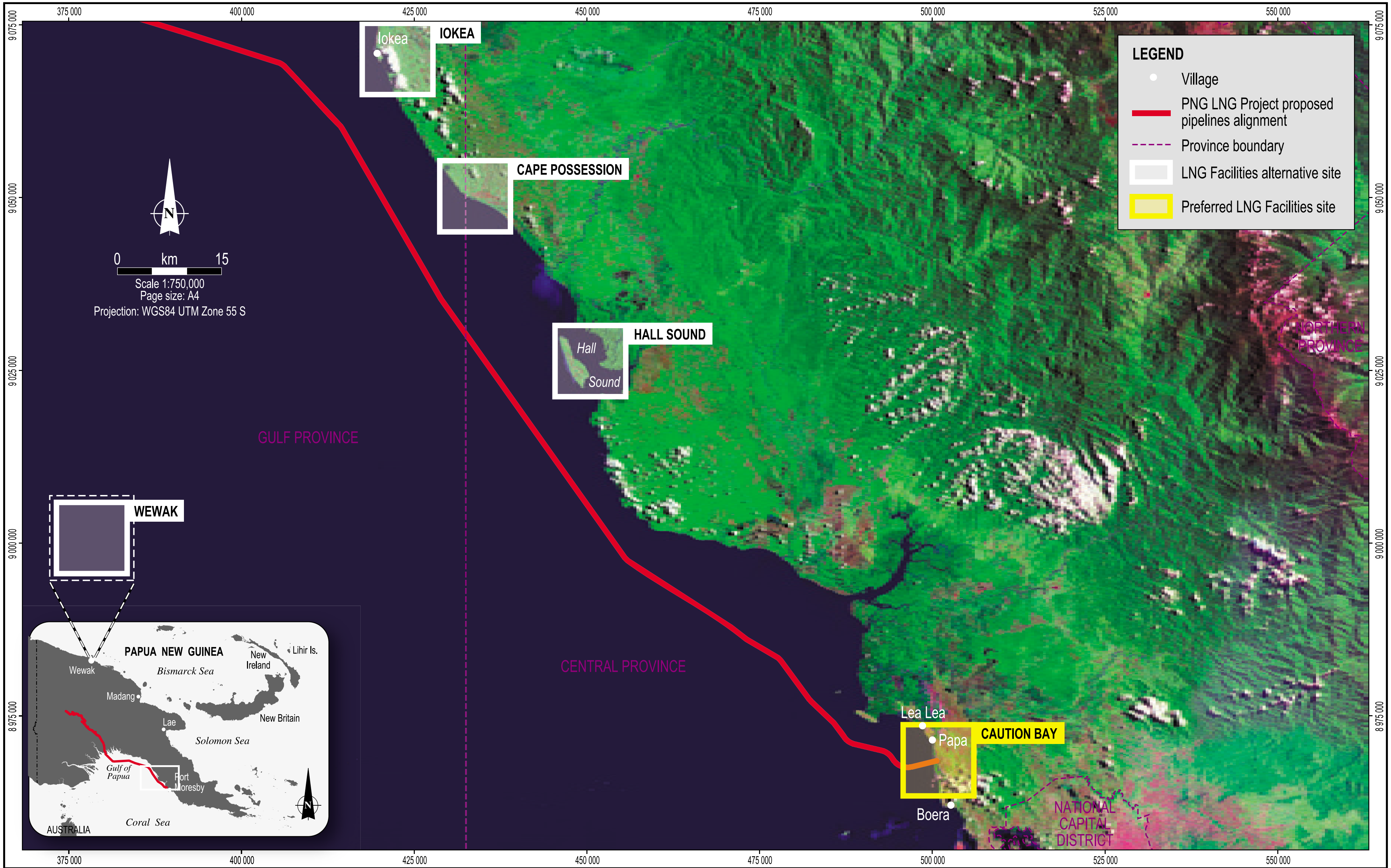
- State ownership in freehold title for most of the area required, which simplifies land access.
- Proximity to Port Moresby, which simplifies logistics.
- The land was cleared for a sisal plantation early in the twentieth century. Current vegetation cover is mainly pasture grasses and weeds, but there is no cultivation or grazing.
- The local inhabitants fish and harvest firewood in the mangroves fringing the coast and the mouth of the Vaihua River. This coastal strip is customary land.
- Offshore is the Papuan Barrier Reef, a coastal lagoon of coral reefs, bommies and inter-reefal sandy bottom and seagrass running over 500 km from Hall Sound to Milne Bay.
- The outer reefs of the lagoon protect the coast from high seas, and so a loading terminal at this location would not require a breakwater.
- Minor commercial fishing takes place offshore, but there is substantial subsistence fishing and associated small-boat traffic close to shore.
- A large plot area to accommodate functional, safety and amenity layout and spacing requirements of an LNG facility.

Caution Bay required the longest pipeline of all the options, but was in all other respects the best site.

7.5.2.2 Hall Sound

The Hall Sound plant site option is located on the eastern coast of the Gulf of Papua near Yule Island. It has the following features:

- Low coastal range.
- Area settled with large communities; Poukama, Delena and Rerena.
- Closed forest, woodland, garden and savanna complexes.



Note:
Pipelines approximate the proposed alignment based on engineering data provided up to 1 October 2008.

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Figure No: 7.1

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- Mangroves and a swamp.
- Offshore coral reefs.
- Occasional prawn trawling offshore by small boats.
- High local boat traffic offshore.
- Customary land ownership.

7.5.2.3 Cape Possession

The plant site option at Cape Possession has the following features:

- A steep coastal range, mostly grassland.
- Closed forest, savanna and woodlands.
- Well-tended subsistence gardens.
- Possible turtle nesting beaches.
- Commercial prawn fisheries offshore and nearshore subsistence fisheries.
- Villages of Kivori-Poe, Meauri, Rove and Mavaru near to site.
- Customary land ownership.
- Breakwater most likely needed.

7.5.2.4 Iokea

The Iokea plant site option lies on the eastern coast of the Gulf of Papua midway between the villages of Sarata and Iokea. Its features are:

- Extensive, steep and hilly terrain from the coast inland.
- Extensive subsistence gardens of local inhabitants.
- Closed forest, savanna and woodland. More continuous vegetation cover than at Hall Sound or Cape Possession.
- Possibility of turtle nesting beaches.
- Villages (Sarata and Iokea) near to site.
- Customary land ownership.
- Breakwater most likely needed.

7.5.2.5 Summary

The factors in the selection of Caution Bay over closer alternatives are summarised in Table 7.1.

Table 7.1 LNG Facilities site selection constraints

Site	Customary Land	Proximity to Workforce	Proximity to Infrastructure	Unexploded Ordnance	Settlement	Gardens	Perennial Rivers	Archaeology	Breakwater Needed	Major Bulk Earthworks	Biodiversity - Land	Biodiversity - Marine	Local Boat Traffic	Commercial Fishing	Subsistence/Artisanal Fishing	Coral Reefs	Prospectivity for Rare or Endangered Terrestrial Fauna
Caution Bay	***										6					1	
Hall Sound				P			P	3 P			7	*				1	
Cape Possession				P			P	P			7	*	P	4		P 2	
Iokea				P				P			8	*	P	4		P 2	5

Shaded quadrants indicate severity of constraint; caves likely at all sites but not at Caution Bay facilities footprint and improbable at the other sites; dugongs unlikely at all sites; no protected areas;

*turtle nesting beaches; **wildlife could benefit from protection within perimeter fence; ***shoreline fringe;
1 = barrier and fringing reef; 2 = fringing reef; 3 = long history of occupation; 4 = commercial trawlers offshore;
5 = wallabies and megapodes indicate low hunting pressure; 6 = site mainly cleared except for mangrove fringe; 7 = mosaic of gardens and disturbed forest;
8 = least disturbed vegetation; P = sparse or no information but probable constraint; na = no information available.

The shorter pipeline distances of the options to the west of Caution Bay were outweighed by the inherent disadvantages of the sites themselves:

- Earthworks to level the site.
- Distance from existing infrastructure and people.
- Customary land, settlement and active subsistence use.
- Conservation value.

As well, Iokea and Cape Possession would probably both require breakwaters. At Hall Sound, it would be difficult or impossible to avoid resettlement.

The Caution Bay option, albeit requiring the longest pipeline, entirely or largely avoids these drawbacks, and has been adopted as the base case accordingly.

7.6 Pipeline Route Options

The evolution of the pipeline routes and the options considered have been addressed in Section 6.1, Routing Process.

7.7 LNG Plant Infrastructure Options

7.7.1 LNG Jetty Length

LNG carriers require approximately 14 m of water depth at lowest astronomical tide (LAT). In Caution Bay, this water depth lies approximately 2 km offshore.

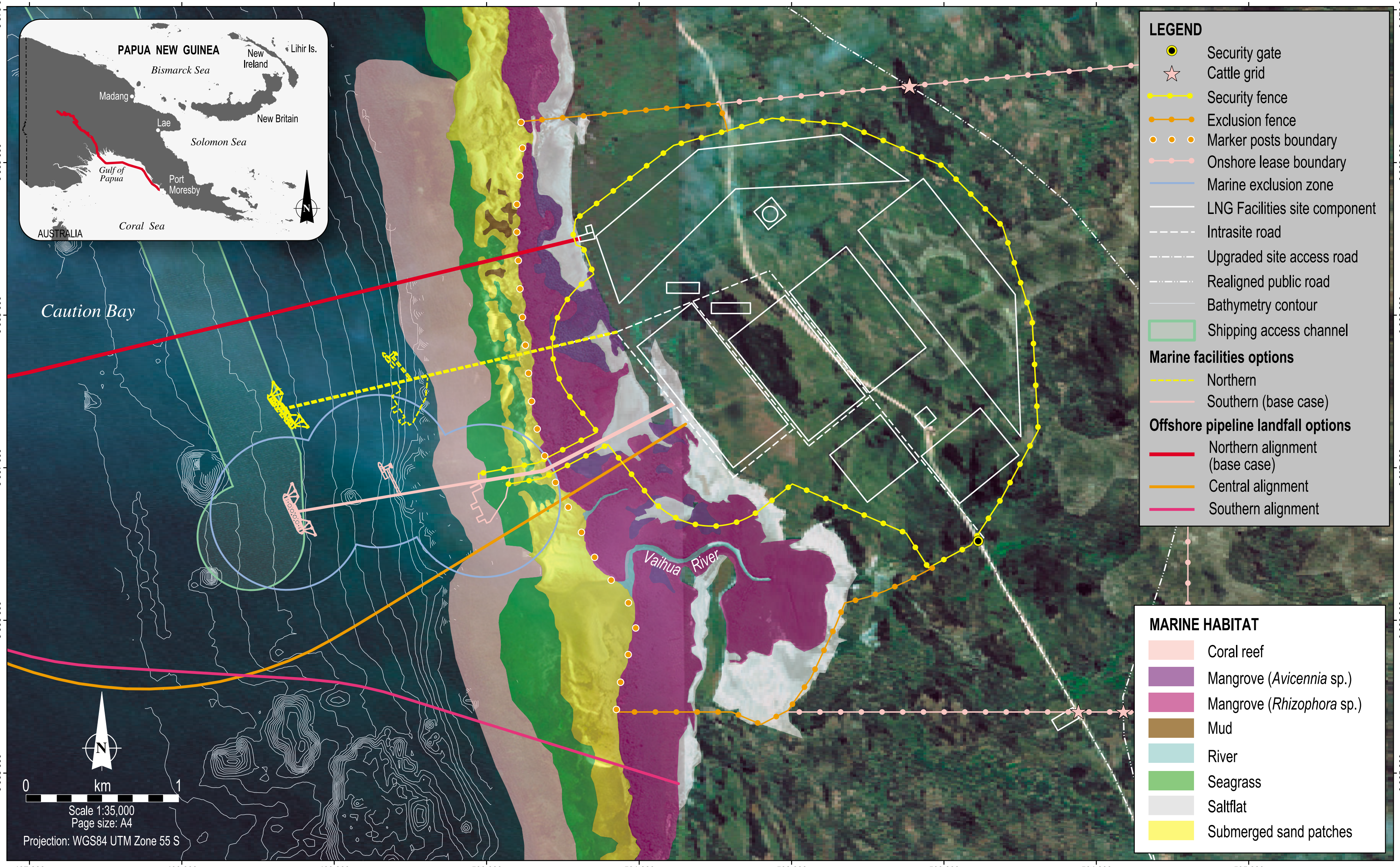
The choice of LNG Jetty length therefore reflects:

- The balance between the cost of a long structure to deep water versus the cost of dredging a channel to a less expensive, shorter structure.
- Environmental issues of dredging at the location.

The balance of these factors favours a long LNG Jetty; and a conventional, piled trestle extending seaward from the shared earthen causeway has been adopted as the base case. Offshore of the mangroves, the LNG Jetty will run approximately 2 km to the LNG export berth at a water depth of 14 m LAT.

7.7.2 Marine Facilities Location

Two options (northern and southern) were investigated for the location of the marine facilities to service the LNG Facilities (Figure 7.2). Either could be adopted without having to alter the location of the LNG Plant, which has been sited to provide an adequate noise and safety setback from the villages to the south (Boera) and north (Papa). Marine surveys have shown that no significant navigation obstacles are likely on the approaches to either option.



Note:
Layout is indicative only.
Final placement of all components is contingent on pending soil and geological data.
Pipelines approximate the proposed alignment based on engineering data provided up to 1 October 2008.

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PNG LNG Project

Pipeline landfall and marine facilities location options

Figure No: 7.2

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The choice of the southern option therefore reflects:

- Less mangrove clearance.
- Less construction interference between pipeline and jetty installation.
- Better ground conditions.

7.7.3 LNG Project Gas Pipeline Caution Bay Landfall

Three alignment options have been considered for the LNG Project Gas Pipeline landfall (shore crossing) at Caution Bay (see Figure 7.2): central, south and north.

The central alignment, 1 km south of the LNG Jetty head, runs east-northeast and crosses the coast 150 m south of the shared causeway. It shares (with the causeway) a single corridor across the littoral zone, but shoreline vegetation is more extensive at this point and so the central option has a higher biodiversity impact than the northern option. It also requires pipelay barge operations close to the causeway and Materials Offloading Facility.

The southern alignment runs east-southeast to a landfall south of the Vaihua River. It gives the LNG Jetty a wide berth but requires an extra 6 km of pipeline on land plus a river crossing. It runs close to cultural heritage sites (World War II crashed aircraft and ancestral village sites) and is the most expensive of the options.

The northern alignment (base case) is the shortest but crosses the LNG carrier shipping access channel. It has biodiversity and cultural heritage conservation advantages over the other options, allows good pipelay barge access and avoids crossing the Vaihua River. There is an ancestral village site of cultural heritage significance north of the alignment in this vicinity, but the pipeline can be laid without disturbing it.

7.7.4 Materials Offloading Facility

The Materials Offloading Facility will be used to receive deliveries of plant, consumables and components for the LNG Plant and associated infrastructure during construction.

7.7.4.1 Location

Four location options for the Materials Offloading Facility have been considered: two are in Caution Bay, the third is the existing Curtain Bros wharf at the northern end of Fairfax Harbour, and the fourth is Port Moresby.

The Caution Bay options comprise an earth-filled, sheet-piled causeway, wharf and laydown area.

The base case location in Caution Bay is approximately mid-way along the southern side of the LNG Jetty (see Figure 7.2). At this point, the 8-m water depth can accommodate the 9,000-t barges that will unload materials at the Materials Offloading Facility. This location has the advantages of proximity to the construction site and minimal construction-related traffic off site.

The second Caution Bay option is to locate the Materials Offloading Facility further south of the LNG Jetty near Boera village. This would require a heavy-haul road to the LNG Facilities site but has the advantage of facilitating future development of additional LNG trains without interference with operations at the LNG Plant. However, it carries the additional financial and environmental costs of building two marine facilities, rather than one.

The third materials offloading option makes use of the Curtain Brothers wharf in the outer harbour of Port Moresby (Fairfax Harbour). It has the advantages of an existing facility but requires offloaded materials to be transported some 15 km on existing roads.

The fourth option, Port Moresby, has the advantages of an existing facility with adequate draft. However, this option requires offloaded materials to be transported some 20 km on existing roads, and the first 4 km of the journey must traverse congested roads in Port Moresby.

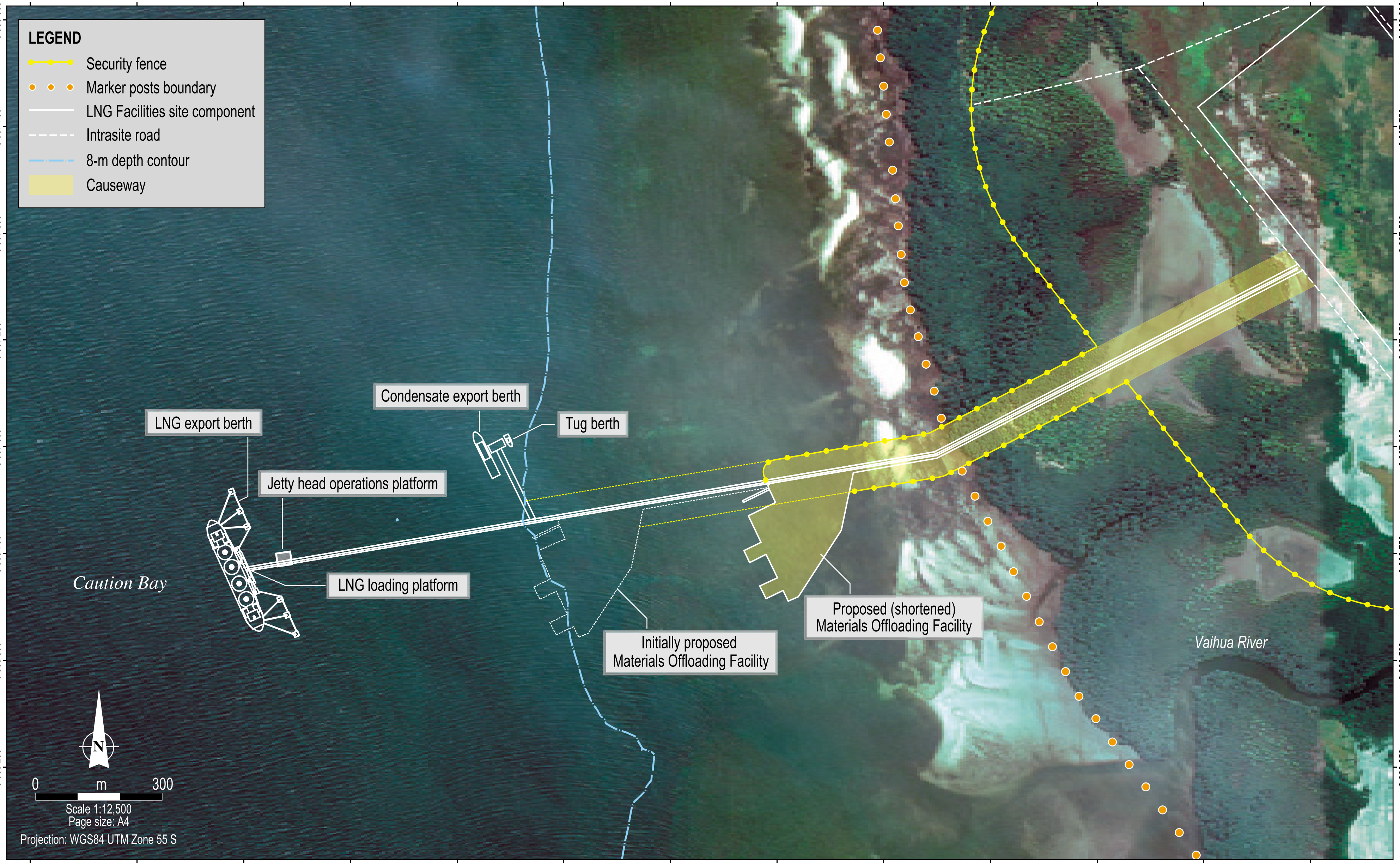
Overall, the advantages of proximity and minimising off-site traffic supported the decision to locate the Materials Offloading Facility adjacent to the LNG Jetty.

7.7.4.2 Design

The initial design concept for the Materials Offloading Facility involved duplicating the earthen causeway component of the LNG Jetty to a distance 2 km from the shore (and approximately 1 km beyond the mangroves) to the 8-m depth contour (Figure 7.3). Such a large, solid structure would impede longshore currents and potentially change the sediment regime by forcing the flow around the end of the causeway. Areas of weaker currents would develop shorewards of the causeway, and the wave action would be reduced to the north or south of the causeway according to season and predominant wind direction.

Figure 7.4 shows a typical profile of tidal and wind-driven currents without and with the 2 km-long combined LNG Jetty/Materials Offloading Facility earthen causeway. The shadow effect and potential consequences are evident: if weaker currents were to deposit sediment near the Vaihua River mouth as sandy cays, then the probability increases that they will in due course block the entrance to the river.

Appendix 22, Hydrodynamic Modelling, examined the effects of the combined LNG Jetty/Materials Offloading Facility earthen causeway on sediment transport and coastal processes. Monitoring points were set up to record sea levels and currents during simulations of before and after causeway construction for ambient and storm-driven currents. The results at the monitoring points are summarised in Table 7.2.



Note:
Layout is indicative only.
Final placement of all components is contingent upon pending soil and geological data.

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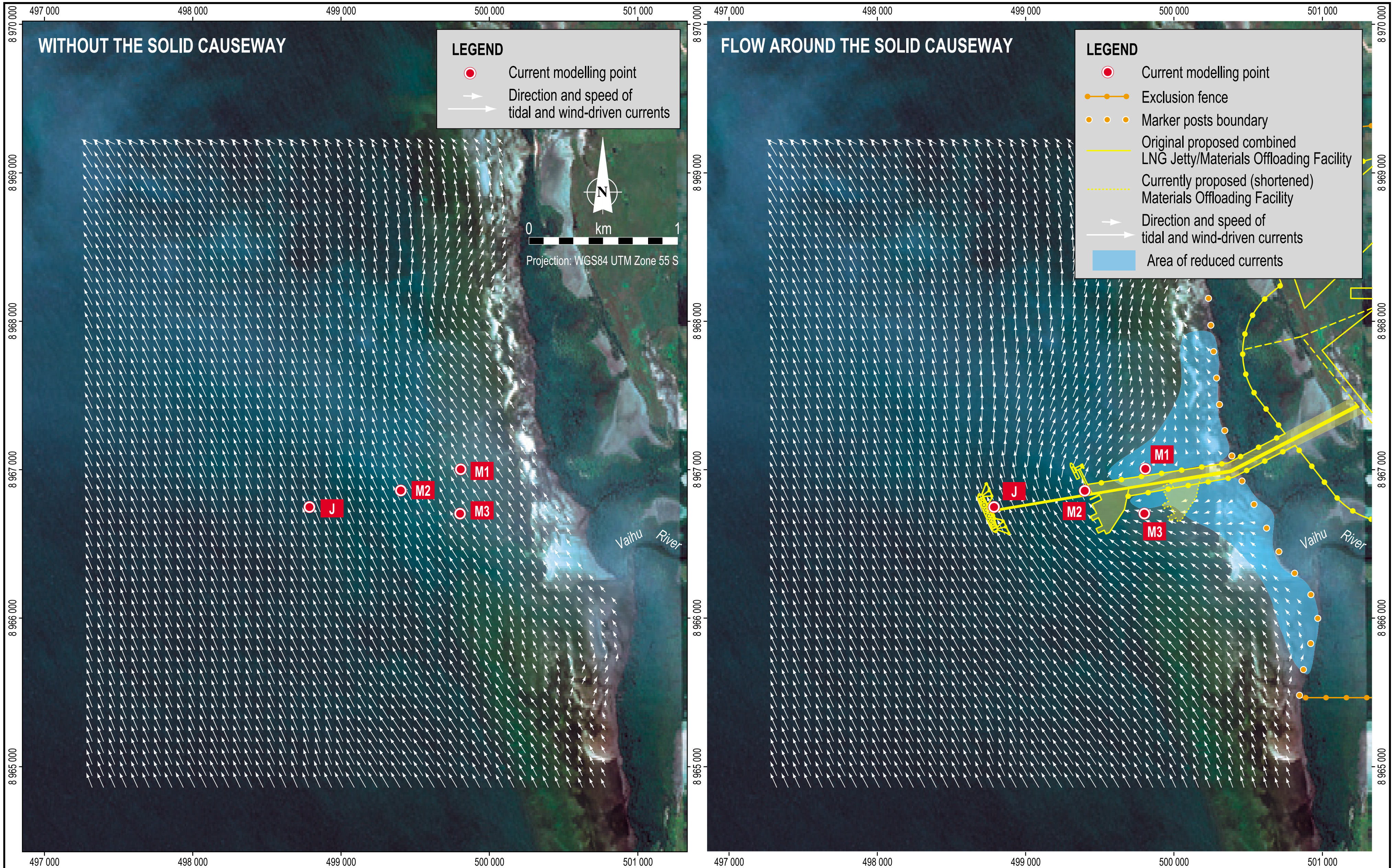
Initially proposed and shortened Materials Offloading Facility layout

Figure No: 7.3



Source:
Current data from GEMS, 2008.
Note:
Modelling based on initially proposed Materials Offloading Facility location. Layout is indicative only.
Final placement of all components is contingent upon pending soil and geological data.

PNG LNG

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Tidal and wind-driven currents with and without a causeway in Caution Bay

Figure No: **7.4**

Table 7.2 Modelled hydrodynamic effects of the 2-km-long combined LNG Jetty/Materials Offloading Facility causeway

Parameter	Percentage or Absolute Change to Ambient Conditions After the 2-km Solid Causeway is Built	Percentage or Absolute Change to Storm Conditions After the 2-km Solid Causeway is Built
Sea level	0%	0%
Current speed at M1 (100 m north of the causeway)	-78%	-33%
Current direction at M1 (100 m north of the causeway)	83 degrees	80 degrees
Current speed at M2 (100 m west of the causeway)	+6%	+15%
Current direction at M2 (100 m west of the causeway)	6 degrees	5 degrees
Current speed at M3 (100 m south of the causeway)	-62%	-78%
Current direction at M3 (100 m south of the causeway)	68 degrees	60 degrees
Current speed at J (Location of end of LNG Jetty)	+2%	+4%
Current direction at J (Location of end of LNG Jetty)	0 degrees	0 degrees

The implications of Table 7.2 are as follows:

- During ambient conditions:
  - There is a substantial slowing of the alongshore flow north and south of the causeway, which may result in a build up of sedimentation.
  - The alongshore flow at the end of the LNG Jetty is virtually unchanged (2% increase) and will not have any significant effect on ship movements.
  - The wave climate near the mouth of the Vaihua River will change in the wave shadow of the causeway.
  - The wave climate at the end of the LNG Jetty will not change.
  - There is no change in sea levels.
- During extreme conditions:
  - Storms are most likely to occur from the northwest and so will drive currents alongshore onto the northern side of the solid causeway. Meanwhile, the southern side will be in the lee.
  - Currents (and waves) on the northern side of the causeway are therefore less reduced than the currents (and waves) on the southern side.
  - Currents at the end of the causeway need to increase by approximately 15% to move the water mass travelling along the coast around the causeway.

– The alignment of the causeway changes the direction of the currents in a similar manner as it does for normal ambient flows.

– The alongshore flow at the end of the LNG Jetty is virtually unchanged (4% increase).

– The wave shadow of the causeway will reduce wave heights near the mouth of the Vaihua River.

– The wave climate at the end of the LNG Jetty will not change.

– There is no change in sea levels.

The model predicted that the causeway, as initially proposed, would cause sedimentation and closure of the Vaihua River mouth within three to five years. This would, in turn, reduce tidal flow, cause mangrove dieback and interrupt continuity of habitat and fish movements in and out of the river.

These results required an examination of the extent to which the combined LNG Jetty/Materials Offloading Facility earthen causeway needed to be shortened to maintain the sediment regime of the Vaihua River mouth. A series of simulations (see Appendix 22, Hydrodynamic Modelling) indicated that a reduction in causeway length of around 500 m or approximately 50% of its length from the seaward edge of the mangroves (see Figure 7.3), would allow wave action from the northwest to reach the area around the river mouth and thereby minimise sedimentation of the Vaihua River estuary (Table 7.3).

Table 7.3 Summary of results for the three causeway options

Parameter	Original Causeway (1,000 m)*	750 m Causeway*	500 m Causeway*
Sea level	0%	0%	0%
Current speed at M1 (100 m north of the causeway)	-78%	-55%	-8%
Current direction at M1 (100 m north of the causeway)	83 degrees	63 degrees	10 degrees
Current speed at M2 (100 m west of the causeway)	+6%	+3%	0%
Current direction at M2 (100 m west of the causeway)	6 degrees	5 degrees	3 degrees
Current speed at M3 (100 m south of the causeway)	-62%	-45%	-5%
Current direction at M3 (100 m south of the causeway)	68 degrees	50 degrees	8 degrees
Current speed at J (Location of end of LNG Jetty)	+2%	+4%	+4%
Current Direction at J (Location of end of LNG Jetty)	0 degrees	0 degrees	0 degrees

*Percentage or absolute change to ambient conditions relative to the no-causeway case.

The original causeway concept substantially slowed alongshore currents north (-78%) and south (-62%) of the causeway. Table 7.3 shows that shortening the causeway by 250 m improves this situation only slightly (to a -55% slowing), but shortening by 500 m brings current speeds close to the no-causeway situation (-8%).

The decision has therefore been taken to change the design and shorten the causeway by 500 m for the specific purpose of maintaining the hydrodynamic regime of the estuary of the Vaihua River.

The shorter structure also improves the flushing and dilution of desalination brine, compared to the original causeway, which created two zones of elevated salinity to the north and south of the structure. Previously, under the originally proposed causeway length, modelling of brine discharge indicated the development of pockets of elevated salinity to the north and south of the causeway in the area of lowered currents (Figure 7.5). With the reduced length of the causeway, pockets of elevated salinity do not occur (see 'Discharge of Brine (from Desalination) and Wastewater' in Section 21.3.3.1, Operations and Appendix 22, Hydrodynamic Modelling).

The environmental disadvantage of the shorter causeway is the requirement to dredge in the order of 150,000 to 200,000 m^3, in order to meet the 8 m-LAT navigation depth limit for vessels making deliveries to the Materials Offloading Facility. This impact would take the form of turbidity plumes at the dredge site and of plumes and localised benthic smothering in the spoil dump zone in deep water offshore. It would, however, be a single and finite episode of environmental impact at the start of construction, and hence preferable to the long-term impact on the Vaihua River of the original, long-causeway alternative (see discussion in Section 21.3, Sea Water Quality).

7.7.5 Tug Permanent Moorage

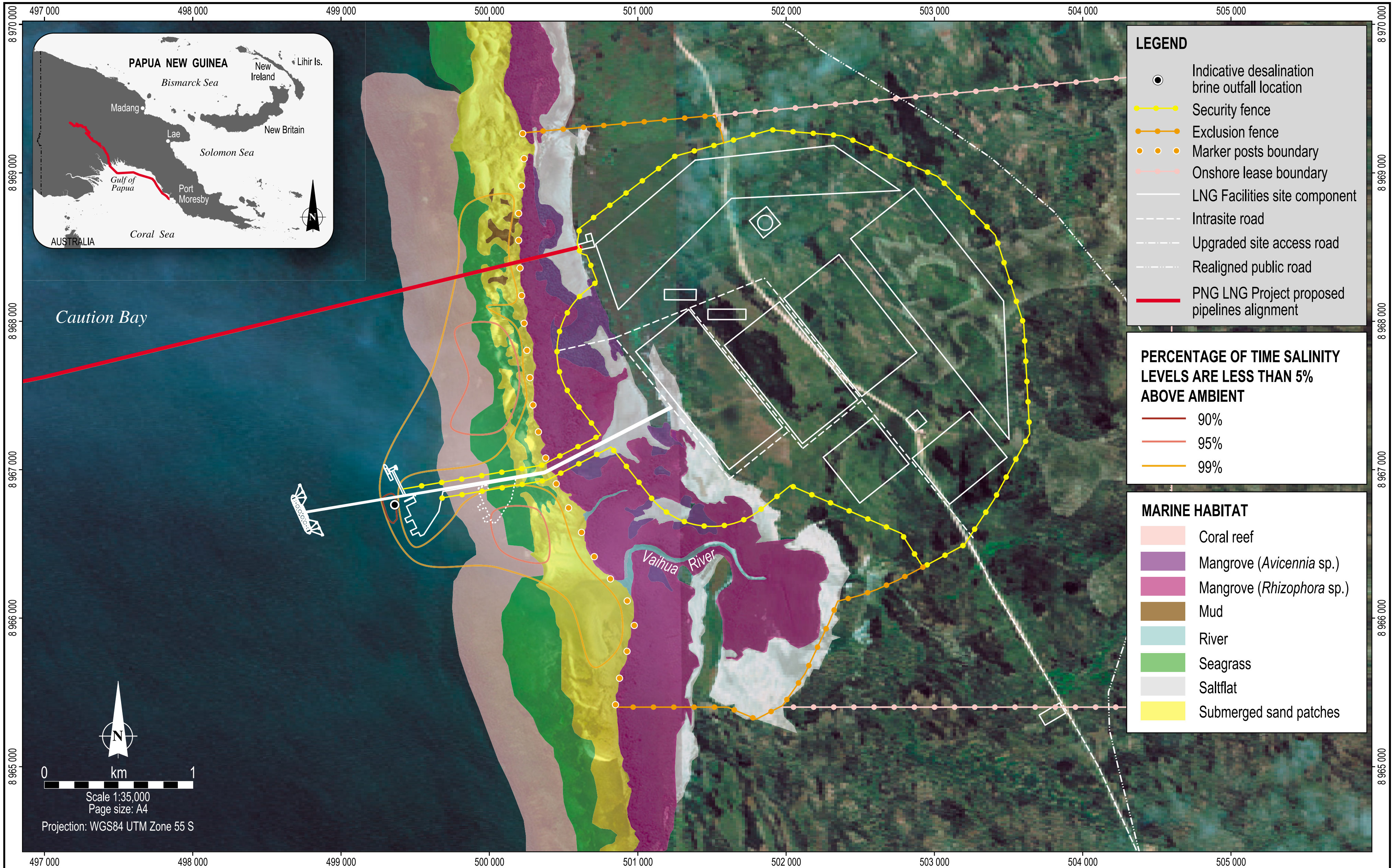
Tugs are required to control the LNG carriers and condensate tankers during berthing and departure, and two options for berthing the tugs themselves have been assessed.

The base case is to berth the tugs at the LNG Jetty. This places them at all times at the location where they will be required to work and avoids the cost, scheduling issues and general inconvenience of tugs having to travel to the LNG Jetty every time an LNG carrier or condensate tanker arrives or departs. Tugs and their permanent moorage would be the responsibility of the operator in this instance.

The fall back position is to have a third party develop and operate tug permanent moorage at Motukea Island. This location offers the advantage of proximity to general boat traffic in Port Moresby Harbour and hence the easy deployment of project tugs for other customers in the periods between LNG carrier and condensate tanker loading.

7.8 LNG Plant Component Options

Options for the components and configuration of the LNG Plant with implications for safety, health or the environment are discussed below.



Source: Salinity data digitised from GEMS figure, 2008. Indicative only.
Note: Layout is indicative only.
Final placement of all components is contingent on pending soil and geological data.
Pipelines approximate the proposed alignment based on engineering data provided up to 1 October 2008.

PNG LNG

Date: 21.11.2008
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File Name: 1284_09_F07.05_GIS_HB

Esso Highlands Limited

PNG LNG Project

Brine output mixing zones and marine habitats for the initially proposed Materials Offloading Facility location

Figure No: 7.5

PGGP-EN-SRENV-000001-001
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7.8.1 Power Generation

The options evaluated for power generation for the LNG Plant were either three 35-MW or four 22-MW gas turbine generators, with the latter selected for the following reasons:

- Reliability—the trip of one smaller unit would minimise or eliminate the need for load shedding, whereas the trip of a larger unit would require load shedding to meet the load acceptance criteria.
- Operability—it will be possible to shut down one of the smaller units under light load conditions without affecting the reliability of the plant.

From an air quality standpoint, the smaller units will be operating more at higher power levels, with correspondingly lower NO_x emissions.

7.8.2 LNG Tanks

7.8.2.1 Features

Single-containment LNG tanks comprise an inner tank rated to the low-temperature ductility specification of LNG and an outer vessel to protect the insulation and constrain the vapour purge gas pressure. It is not designed to contain LNG escaping from the inner tank but is surrounded for this purpose by a berm.

In double-containment LNG tanks, the outer tank is also capable of containing and subsequently controlling the discharge of LNG. (These systems are also bermed.)

Table 7.4 summarises the features and trade-offs of the two systems.

Table 7.4 Single- and double-containment LNG tanks

Aspect	Single Containment	Double Containment
Cost ratio	100	130
Schedule	36 months	40 months
Property size		Smaller footprint and smaller separation from jetty, process areas, pipelines
Maintenance and safety	Easier access to the primary tank through the carbon-steel outer shell	Minimises chance of escalation Provides better blast protection
Regulations	Both accepted by IFC EHC *Guidelines for LNG Facilities* No regulation that prevents the use of single containment tanks	Both accepted by IFC EHC *Guidelines for LNG Facilities* No regulation that prevents the use of single containment tanks
Number operational world-wide	320	110

Both types are in widespread use, with an increasing uptake of double-containment designs in recent years. Nonetheless, single-containment tanks have a good safety record in their own right and can readily meet the IFC (2007a) Environmental, Health and Safety Guidelines for LNG Facilities for 'adequate secondary containment (e.g., …single wall tank with an external containment basin…) in the event of a sudden release', backed up by 'grading drainage, or impoundment for vaporisation, process, or transfer areas able to contain the largest total quantity of LNG or other flammable liquid that could be released from a single transfer line in 10 minutes…'.

7.8.2.2 Risk Assessment

Double-containment clearly has an inherently lower likelihood of system failure. The question then is whether this in-principle advantage is significant in practice.

A comparative risk assessment has been conducted on the two tank designs, based on the likelihood and consequences of the following failure scenarios:

- Small liquid leak from the primary container (potential for localised fire).
- Spill from the primary container (potential for explosion).
- Loss from vapour from over-pressurised outer tank (potential for vapour-cloud ignition).

The findings of the risk assessment were that the accident scenarios for single- and double-containment systems alike had the potential consequence of fatality or serious injury, time and monetary costs and media publicity, but with the lowest category of probability (defined as a 0.1% likelihood during the design life of the project).

On this basis, the single-containment option has been selected as fit-for-purpose, with cost, build time and inspection advantages.

7.8.3 Refrigeration Circuit Compressors

The refrigeration circuits require compressors, which are driven by gas turbines, for which two options have been evaluated.

Frame turbines are essentially industrial units applicable to a range of uses. They have historically been the standard compressor type for most LNG plants and have the advantage of a long record of reliable operation.

Aero-derivative turbines are aircraft engines modified for industrial application and are more fuel-efficient. In commercial terms, the capacity limits of the PNG LNG Gas Pipeline mean any less gas consumed at the LNG Plant translates directly to higher gas sales. In environmental terms, aero-derivatives have correspondingly lower (by between 10% and 15%) CO_2 emissions (see detailed discussion in Section 26.3.3, Emissions from LNG Facilities). Moreover, aero-derivative turbines provide enhanced operational flexibility and availability. The aero-derivative turbines have been successfully adopted in LNG service, and their widespread use in the oil and gas industry confirms their suitability as refrigerant compressor and power generation prime movers for the PNG LNG Project.

On this basis, Esso has selected the aero-derivative turbines option. IFC (2007a) LNG Facilities guidelines do not discuss these competing technologies, but the choice of aero-derivative turbines meets the guideline requirement to maximise '…energy efficiency and design facilities to minimize energy use…with the overall objective of reduc(e)ing air emissions and evaluat(e)ing cost-effective options for reducing emissions that are technically feasible'.

7.8.4 Low NOx

Low-NOx equipment will be installed in major gas and liquid prime movers (such as gas turbines) at facilities for gas production and the LNG Plant. The IFC LNG facilities guidelines (2007a) do not discuss this option specifically, but the choice of low NOx burners meets the general guideline requirement to 'reduce air emissions and evaluate cost-effective options for reducing emissions that are technically feasible'.

7.8.5 Acid Gas Treatment

Amine will be used to strip carbon dioxide and hydrogen sulfide from the LNG Plant feed gas, and two types of amine solvent (diglycolamine and methyl diethanolamine) have been evaluated. Both operate in a similar manner (see 'Acid Gas Removal System' in Section 4.2.2.1, Feed Gas Processing). However, the methyl diethanolamine that was evaluated (which is a proprietary formulation of BASF) has lower reboiler duty (and hence energy consumption), lower make-up requirement, and no reclaimer waste stream disposal requirement. Subject to satisfactory licensing arrangements, methyl diethanolamine has been chosen for its environmental and cost advantages.

7.8.6 Mercury Removal

Mercury removal systems (described under Section 4.2.2.1, Feed Gas Processing) remove elemental mercury from the feed gas to control the risk of mercury corrosion of aluminium. Specifications for the outlet gas from these systems are generally about 10 nanograms per normal cubic meter (10 ng/Nm^3) of gas. The nominal mercury concentration in the feed gas to the LNG plant is 4 µg/Nm^3 (4,000 ng/Nm^3).

There are currently two basic processes for mercury removal in LNG plants: a non-regenerative, sulfur-impregnated, activated-carbon process and a non-regenerative, metal-oxide or metal-sulfide process. Both trap elemental mercury in the gas phase and fix the volatile mercury as mercury sulfide. There are also two options for the location of the mercury removal system: downstream of the dehydration unit or upstream of the acid gas removal unit.

The metal-sulfide option works best when there is sufficient hydrogen sulfide in the feed gas to sulfidise the adsorber. However, levels of hydrogen sulfide in the project's feed gas are low; thus, on-line sulfidation would be required for the metal-sulfide option. Therefore, the base case is the activated-carbon process, and the system will be located downstream of the dehydration system so that residual moisture in the feed gas does not lower the adsorption rate of the activated carbon. Costs are similar, and both removal options provide for the cost of packaging, transport of the spent adsorbent offsite and mercury recovery. For the preferred option, the adsorbent will be sent off site, as operationally necessary, for mercury recovery and recycling and incineration of the stripped carbon. However, mercury levels in the feed gas are so low that the adsorbent may not need to be replaced during the life of the project.

7.8.7 Cooling Medium

Cooling is required to maintain safe operating temperatures for a number of items of equipment in the LNG Plant, and four options for cooling media have been considered:

- Air cooling.

- Direct seawater cooling (single pass).
- Indirect seawater to closed freshwater cooling system.
- Freshwater/seawater cooling tower.

Air cooling emerged as the clear preference, with no major operability or environmental drawbacks and by far the lowest total installed cost. The water cooling options were between 60% and 400% more expensive due to the high cost of titanium shell and tube exchangers, of the metal alloys in the seawater pumps, and of the seawater intake and outfall basins. Operating costs for electrical power for fans were either lower than or comparable to the water cooling options.

From an environmental standpoint, air cooling is noisier than water cooling and requires more space, both of which can be accommodated by the land available (see the assessment of noise impact in Section 20.8, Noise). On the other hand, air cooling avoids the marine impacts, albeit localised, of discharges of warm, saline blowdown (from the cooling tower option), hot return water (from the direct and indirect seawater systems) and anti-corrosion additives and biocides.

7.9 Reservoir Carbon Dioxide

A total of 6.53 Mt (0.124 trillion cubic feet) of carbon dioxide, a greenhouse gas, will be removed from the raw gas stream during the project's nominal 30-year operational life. The base case involves venting to the atmosphere at the LNG Plant through the acid gas incinerator. This represents between 7% and 8% of the project's overall carbon dioxide equivalent (CO_2-e) emissions.

The alternative is geosequestration. This involves capturing the carbon dioxide and injecting it into an underground reservoir. Near the LNG Plant, however, there are no identifiable suitable geological structures.

The option of capturing carbon dioxide from the raw gas stream and injecting it into the production reservoirs at Juha and Hides (after Juha start-up in year 10) was also examined.

However, reservoir simulation and production modelling studies showed that recycling of reinjected carbon dioxide would lead to high carbon-dioxide levels in the produced gas:

- At Juha, an assumed limit of 20% carbon dioxide in the inlet gas stream to the Juha Production Facility would reduce otherwise recoverable gas reserves. This loss of gas, combined with the capital and operating costs of carbon-dioxide removal, recovery and injection equipment, renders the option infeasible.
- Similarly at Hides, recycling of reinjected carbon dioxide would raise concentrations above the 12% limit for feed gas to the Hides Gas Conditioning Plant, with similar consequences for gas recovery and feasibility.

The option to inject captured reservoir carbon dioxide into a depleted oil field reservoir, such as Gobe, was also examined. This has the advantage of not interfering with natural-gas recovery in the gas reservoirs. However, it requires a carbon-dioxide removal plant on the gas pipeline with corresponding high capital and operating costs.

None of the options investigated was considered viable. Reasons included lack of suitable reservoirs for injection (near the LNG Facilities site), potential losses of gas reserves, limited carbon-dioxide removal (at Juha), and prohibitive operational and capital costs. Also, the generation of power to inject carbon dioxide would result in an additional 2 Mt of carbon dioxide being emitted, nearly one-third of the amount of carbon dioxide that would be sequestered[5]. The decision was therefore made to vent the carbon dioxide at the acid gas incinerator.

7.10 Construction Options

7.10.1 Hides Gas Field Development

Within the area of the PNG LNG Project, the karst in the Hides Ridge area constitutes a noteworthy biodiversity area, featuring little-disturbed montane forest and sinkhole habitat. Hides, the neighbouring Karius Range and the extinct volcano of Mt Sisa are the high-altitude outliers of a much larger expanse of montane forest to the northwest, but they are, in and of themselves, notable for their largely or entirely undisturbed condition and suite of endemic plants and animals (see Section 10.3, Terrestrial Biological Environment). Nonetheless, the conservation status of Hides warranted the investigation of unconventional, low-impact construction methods. These are locating wellpads in adjacent valleys, so as to avoid the need for a construction ROW and access track along the ridge (Section 7.10.1.1, Hides Wellpad Location Options), and using similar helicopter-supported methods as were adopted to build the existing gathering system at Hides gas field (Section 7.10.1.2, Hides Wells and Gathering System – Installation Options).[6]

7.10.1.1 Hides Wellpad Location Options

In addition to the currently planned well arrangement on Hides Ridge (the base case described in Section 2.2.3, Fields, Wells and Gathering Systems), two options for completely avoiding development of wells and gathering systems on Hides Ridge have been investigated:

- **Valley Case 1:** To the northeast in the Tagari River valley within the footprint of existing roads, villages and gardens of the adjacent Tagari River valley.
- **Valley Case 2:** To the southwest in the undisturbed intermontane valley between Hides Ridge and the Karius Range.

The feasibility of the two valley options depends on the ability to establish production wells.

Drilling Issues

The PNG oil and gas industry has several decades of experience in the PNG highlands and has encountered a number of recurring drilling issues.

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[5] Natural gas consumed by the compressor turbine used to remove the gas would reduce the amount of LNG available for export, which would, in turn, be replaced by gas from other sources.

[6] Well siting at the other gas fields (Angore, Juha and South East Hedinia) does not present such clear-cut alternatives as at Hides. That is, wellpads sited according to engineering and cost criteria will incur the least clearing, so the environmental performance will be more a consequence of construction management and rehabilitation.

A number of units within the stratigraphic sequence of the Papuan Fold Belt (see Figure 2.2) present specific and predictable drilling difficulties, in particular high overpressures, strength degradation and tectonically highly stressed rock. These factors set up the competing requirements of wellbore stability, pore pressure control and avoiding lost drill fluid returns, the effect of which, inter alia, is to place limits on the inclination of a wellbore.

Design Basis

Both valley cases require inclined drill holes offset from the bottomhole targets in the producing formation. Wellbore instability is a common feature of the formations of the PNG highlands and becomes a significantly higher risk at high well inclinations. This progressively and rapidly increases drilling costs, with a correspondingly increasing risk of losing the well altogether. Therefore, the design basis used for the Hides wells is to limit the maximum well-inclination angle to 65 degrees from vertical.

A high level of availability during a well's productive life eliminates the need for backup wells to cover downtime. If a well requires intervention, it must be able to be repaired and brought back on line quickly. Well inclinations below 65 degrees enable straightforward wireline operations and simplify the well maintenance and repair process.

Wells in the Hides gas field require high drilling-fluid densities for two reasons:

- To control the pressure in the overpressured Bawia Formation above the gas-bearing Toro Sandstone.
- To stabilise the wellbore while drilling open hole in highly tectonically stressed rock.

Two factors place technical limits on the density of the drilling fluid that can be used at Hides:

- The maximum amount of solids that can physically be suspended in the drilling fluid.
- The strength of the formations, which, if exceeded, would fracture the wellbore and see a total loss of drilling fluid. These limits have been empirically established by previous drilling experience at Hides.

In the Hides area, the drilling-fluid density limit is approximately 19 ppg (pounds per gallon), or a specific gravity of nearly 2.3.

Calculations and Conclusions

The inclination and drilling fluid weights for each of the eight new production wells at Hides have been calculated for each case:

- **Base Case:** The maximum well inclination is 58 degrees, with four of the wells at Hides being vertical (lowest drilling and operational risk and cost). Maximum drilling-fluid densities are below 19 ppg.
- **Valley Case 1:** Wellpads distant from the bottomhole targets require well inclinations between 77 and 82 degrees. Corresponding drilling-fluid densities are well above the 19-ppg wellbore fracture limit, with the minimum required drilling-fluid density calculated to be 22 ppg. None of these wells is able to meet the design basis criteria (and would far exceed extended-reach wells actually drilled to date for the equivalent mud density and reach).

- **Valley Case 2:** Two wells would be vertical and would meet inclination and drilling-fluid density criteria. Two of the six deviated wells would fall within the well-inclination criterion (one at 44 degrees and the other at 66 degrees) and would narrowly meet the drilling-fluid density criterion. The other four wells fail on either one or both design criteria.

The Hides Ridge base case wells take advantage of three existing and useable wellpads; an additional four wellpads will be needed for the eight new wells.

Valley Case 2 would need to become a hybrid of ridge and valley wells to achieve the required production rates. However, in so doing, it would lose its environmental objective while incurring additional impacts in an otherwise little disturbed area. It would require six new wellpads instead of the four new wellpads in the base case, with four of the new wells being drilled from Hides Ridge. The existing wells would also have to be accessed. This option would require access tracks to be built both along the valley and on Hides Ridge, the latter in the northwest portion of the field. This would mean that the ROW access track along Hides Ridge would be no shorter than for the base case.

In addition, it would not be technically feasible to drill wells targeting the backlimb (eastern side) of the reservoir under Valley Case 2. These backlimb wells are not currently in the base case, but they are a future option.

Drilling from other than Hides Ridge is therefore not a feasible alternative, and it is the intention of the project to adopt the base case, i.e., to drill the wells required to meet gas supply requirements from conventional locations on the top of the ridge.

7.10.1.2 Hides Wells and Gathering System: Installation Options

During the first phase of petroleum development in Papua New Guinea, seismic lines and pads, exploration wells, and gas production wellpads, wells and flowlines were installed in the Hides area, the gas production for electricity generation beginning in 1991. The small scale of the Porgera Gas to Electricity Project enabled these works to be carried out by low-impact manual methods with helicopter support. Today, the limited impact of this development is evidenced by its light and localised footprint.

The PNG LNG Project is a much larger-scale endeavour (Table 7.5). The question is the extent to which it can be built by the same methods as those used during the initial development of Hides gas field to supply the Porgera Gas to Electricity Project.

Table 7.5 Comparison of existing and PNG LNG Project Hides gas field wells and gathering systems

Gas Field Infrastructure	Porgera Gas to Electricity Project (Existing)	PNG LNG Project (Initial and Further Developments)
Production wells	2 wells	10 wells, 2 of which are workovers of existing production wells
Gathering lines – length	10 km of flowlines from wells to the Hides Gas to Electricity Plant	10 km of flowline from wells either to Wellpad E or directly to the 17 km spineline to the Hides Gas Conditioning Plant plus a 24 km MEG line
Gathering lines – nominal bore	DN 100 (4”) flowlines	DN 550 (22”) spineline, DN 300 (12”) and DN 250 (10”) flowlines, DN 50 (2”) MEG line

The proposed case for the PNG LNG Project is a gathering system (flowlines and a spineline) that will convey raw gas and liquids from wellheads on Hides Ridge to the Hides Gas Conditioning Plant. The design is based on a buried DN 300 (12”) flowline from Hides Wellpad G to Hides Wellpad E, a DN 550 (22”) spineline from Wellpad E to the Hides Gas Conditioning Plant (which will receive gas from wellpads A to E via DN 250 (10”) flowlines), and a DN 50 (2”) MEG line, with a DN 100 (4”) above-ground water pipeline.

The route for both the pipeline ROW and the access track from Hides Wellpad A will generally follow Hides Ridge, threading a path between sinkholes on either side. The access track will support pipeline installation and provide ground access for drilling the wells. In very steep terrain, the access track will separate from the ROW. The ROW and access track will become a private access track to service the wells, support pipeline inspections, and carry out maintenance and monitoring during operations, as well as to provide access for future drilling campaigns.

Options

Only the localised footprint of the existing gas wells and wellpads and the aboveground, small-diameter flowlines breaks the generally undisturbed condition of the forest habitat on Hides Ridge. This infrastructure could be built using manual methods with helicopter support because of the small diameter of the line pipe (DN 100, or 4”) used to construct the flowlines. This raises the question of whether similar reduced-impact methods could be adapted to the PNG LNG Project’s much larger production capacity and a spineline involving larger-diameter line pipe (DN 550, or 22”) with a heavier wall thickness.

A road already exists as far as the Hides 4 well on Wellpad A. The following alternatives have been compared for the construction of facilities beyond the Hides 4 well:

- Helicopter construction of wellpads with wells drilled entirely with heli-support.
- Helicopter-supported spineline construction.
- Conventional spineline construction with no permanent access track, a revegetated ROW and support of future operations by helicopter.
- Base Case: Conventional spineline construction, decoupling of the ROW and access track and use of the latter as a narrowed (7- to 10-m-wide) private access track (see Section 7.10.1.3, ROW Formation Earthworks on Hides Ridge).
- Helicopter-supported drilling and multiple small-diameter flowlines to replace the large-diameter spineline.

Weather Constraints for Helicopter-based Options

The use of helicopter-based construction techniques has been a common practice in Papua New Guinea for remote exploration wells, including the Hides discovery and exploration wells, two of which were subsequently (and as a separate exercise) completed as producing wells.

However, for a large, 15-month drilling program at Hides Ridge, consistent access becomes hostage to frequent poor flying weather, and considerable and costly schedule delays would be incurred.

The limitations to helicopter utilisation arise mainly because clouds tend to sit on the ridges in this area; the valleys are usually flyable most of the year, with morning fog clearing as the sun rises. Clouds between 1,850 and 2,600 m, mainly on the north side, usually cover Hides Ridge. In June, July, August and September (the rainy season), the ridge tops are usually in the clouds all day. In the non-rainy season, helicopter flights would usually be possible from 0630 or 0700 hours to 1000 or 1100 hours. By late morning, wind from the southeast pushes warm air up the ridges, and clouds form that obscure the ridge. There will be limited occasions at any time of the year when flying is possible all day.

Realistic planning for a typical year assumes no flying on the ridges in the four months of the rainy season, with flying possible for three to four hours per day for the remaining eight months of the year.[7]

Heli-supported Drilling

Helicopter-supported drilling would substantially increase the cost of each of the currently planned 10 wells (eight new wells and two workovers). A variation on this alternative would be to interconnect the wellpads with in-field access tracks to facilitate movement between them but without constructing a permanent access track from Wellpad A. This would still require all equipment and vehicles to be brought in by helicopter in the face of the weather availability problems described above. Either way, heli-supported drilling would serve little purpose because heli-supported pipelaying is infeasible, and a construction ROW for the spineline and for the flowline between wellpads G and E is still required.

Heli-supported Pipeline Construction

Large helicopters can carry 4.3-t, DN 550 (22”) line pipe sections, but the high altitudes of the Hides Ridge affect the performance of aircraft. More than 2,000 helicopter flights will be needed, with a corresponding safety risk and an enormous maintenance effort required to keep the machines in service (approximately seven hours of maintenance are required for each flying hour for a twin-rotor Chinook helicopter). All construction equipment, machinery, supplies and workers will also need to be heli-lifted if this pipeline construction approach were to be utilised. The requirement to trench the pipe into the ground and the weight and size (diameter and wall thickness) of the line pipe, however, mandate the use of heavy ground machinery for its actual installation.

Conventional Pipeline Construction (No Permanent Access Track)

In accommodating terrain, the number and size of co-located pipelines on Hides Ridge (DN 550 (22”) spineline, DN 50 (2”) MEG line and DN 100 (4”) water line) would normally call for a 30 m-wide working easement. However, the terrain in the Hides area makes this impractical. An 18 m-wide ROW is considered to be a reasonable nominal easement width for this type of construction, although the rate of pipelaying will be slowed. The cleared ROW would also be used as an access track for equipment, personnel and loads of pipe and to prepare wellpads. The pipelines

[7] Information on flying conditions courtesy of E. Zeitler, pilot, Columbia Helicopters, Moro, Southern Highlands Province, PNG. Telephone conversation, 26 October 2005.

will be installed before all of the wellpads are installed and all of the wells are drilled, so the access track will need to stay in service throughout the subsequent drilling campaigns.

Without a permanently maintained private access track to support operations activities, part of the ROW could be allowed to regenerate once drilling activities were completed. Regrowth above the pipelines would need to be controlled to prevent the growth of trees that could damage the pipe. Required vegetation management could be accomplished on foot.

If the construction access track were not subsequently maintained as a permanent private access track, then all future operations at the wellheads would need to be undertaken by helicopter, with its attendant weather issues for safety and operability. To overcome the latter and ensure gas availability would require an additional well, with its own incremental environmental impacts.

Conventional Pipeline Construction (Private Access Track)

If the spineline were constructed conventionally with a reduced-width ROW being cleared, then the access track could be maintained as a private single-track, access track during operations. This would support the subsequent drilling campaigns, pipeline pigging and inspection and would offer operations access to the wellheads more reliably and safely than by helicopter and in all weather conditions. Access to the track would be controlled west of Hides Wellpad A, and its usage would be managed so it did not become an avenue for indirect impacts associated with facilitated or increased public access, especially access by vehicles.[8]

Multiple Small Flowlines

The Porgera Gas to Electricity Project has been using gas from the Hides 1 and Hides 2 wells to fuel the Porgera Power Plant since 1991. These wells feed small-diameter flowlines installed manually with helicopter support. The flowlines run above ground and straight down the fall line of Hides Ridge to the existing Hides Gas to Electricity Plant. This raises the question of why a similar method could not be used by the PNG LNG Project.

The principal constraint arises from the vast difference between the gas flows required by the Porgera Power Plant and those required by the PNG LNG Project. By way of comparison, the power plant currently requires 18 kSm^3/h; the Hides Gas Conditioning Plant is designed for a normal outlet rate of 1,133 kSm^3/h.

Under the base case, therefore, the spineline needs to deliver almost 100 times the amount of gas currently being produced by the existing Hides wells.

There are difficulties in scaling up the use of multiple aboveground flowlines of a diameter similar to that of the existing Hides flowlines to deliver the gas flow rate required by the PNG LNG Project.

[8] As previously noted, the authority over what activities occur on customary land resides with its landowners. The operator will seek to strike an agreement with Hides Ridge landowners regarding access controls and the limitation of certain activities on their land.

Modeling indicates that the nominal number of DN-100 (4”) flowlines is a range of between 70 and 90.

The aboveground flowlines from each wellhead would be supported on pipe racks along a shared ROW to a manifold at Hides Wellpad A.

Construction would require the ROW to be cleared by hand and the pipeline racks to be installed by hand with support from helicopters. Pipe of such small diameter can usually be bent to conform to the natural land surface, so bulk earthworks would not generally be needed.

A number of construction locations would need to be established at which pipe sections could be stockpiled by helicopter, welding stations established, the flowlines continuously welded and the pipestrings pulled out along the racks. All construction equipment, machinery and supplies would also need to be heli-lifted. The total weight of the multiple smaller-diameter pipes would be approximately the same as that of the single large-diameter spineline, and a large number of helicopter flights would be required to ferry the pipe up to the ridge. Unlike a buried spineline, aboveground flowlines require insulation to prevent hydrate blockages expected at the low ambient temperatures characteristic of the Hides Ridge climate. This would probably require considerably higher injection rates for mono-ethylene glycol, which in turn would require larger pumps, tanks and MEG lines.

The practicalities of helicopter transport and manhandling on the ground require the smaller-diameter pipe to be in short lengths. The 12 m pipe lengths necessitated by this scenario would require considerably more linear metres of welding.

Aboveground multiple flowlines would require a wider ROW to accommodate their pipe racks. The number of individual flowlines using the ROW would increase at each well, and the rack arrays would become progressively wider, to the point where the ROW would be up to 28 m wide approaching Wellpad A. This ROW would need to be kept cleared of vegetation regrowth for the life of the project. Aboveground pipelines are also more accessible to the public and are therefore less secure (note, though, that no tampering has been experienced with the existing above-ground lines to date).

The conventional pipelay crew for the DN 550 (22”) base case would number about 150 to 200. The multiple, above-ground flowline option requires additional labour for clearing, setting pipe support, manhandling pipe lengths and welding; and this could lead to a workforce of up to 400. A daily helicopter commute for the workers would be impractical in the poor flying weather on Hides Ridge, so there would need to be camps of approximately 200 people each at intervals along the ridge to service the multiple pipelay crews.

The environmental objective of this option is to avoid the bulk earthworks that ground access for vehicles would require. Consequently, future operations at the wellheads would also need to be supported by helicopter. This would include shutdowns, routine maintenance, interventions, well workovers, inspections and pigging. Poor weather will frequently make the field facilities inaccessible, which creates some chance that a well stays off-line long enough to affect gas supply. A back-up production well would be the normal safeguard against this risk, but an additional well would have incremental environmental impacts associated with it.

In summary, the base case is preferred on grounds of safety, schedule, environment and cost.

Conclusion

Table 7.6 summarises the attributes of the various methods for constructing the field facilities at Hides. These options fall broadly into two categories:

- Drilling and pipelaying with ground access support and the workforce housed generally off Hides Ridge.
- Drilling and pipelaying using helicopters, with the workforce housed on Hides Ridge.

The functionally optimum size and wall thickness of buried pipe to be installed from the wellheads to the Hides Gas Conditioning Plant mandate traditional ground-access-based pipelaying methods and machinery for reasons of safety, cost and schedule. The nominal 18-m-wide ROW bench is a necessary constraint imposed by the difficult terrain in the area and is much narrower than typical pipeline construction ROW widths in more accommodating country. However, the lateral effects of the earthworks needed to establish even this narrow bench will extend tens of metres beyond the ROW, in the form of cut and fill batters and sidecast scree slopes.

The ROW above the buried pipelines will need to be maintained as an access track to support successive drilling campaigns on Hides for up to 10 years and thereafter as a single-track, private operations access track, with a good chance of forest canopy re-closure.

Under the no-access-track case, lack of ground access to sections of the pipelines during operations may still (see also ‘Multiple Small Flowlines’ in Section 7.10.1.2, Hides Wells and Gathering System: Installation Options) make it necessary to have a back-up well, with the additional earthworks and associated, albeit localised, environmental impacts that this would entail.

The multiple, small-diameter pipeline option does achieve the environmental benefits of reduced earthworks. However, the safety, construction cost and schedule delay costs and risks associated with this option are not trivial. They are compounded by the requirement for a much larger workforce, which brings its own environmental management challenges (for example, sewage treatment and discharge, water use, waste generation and disposal, and poaching).

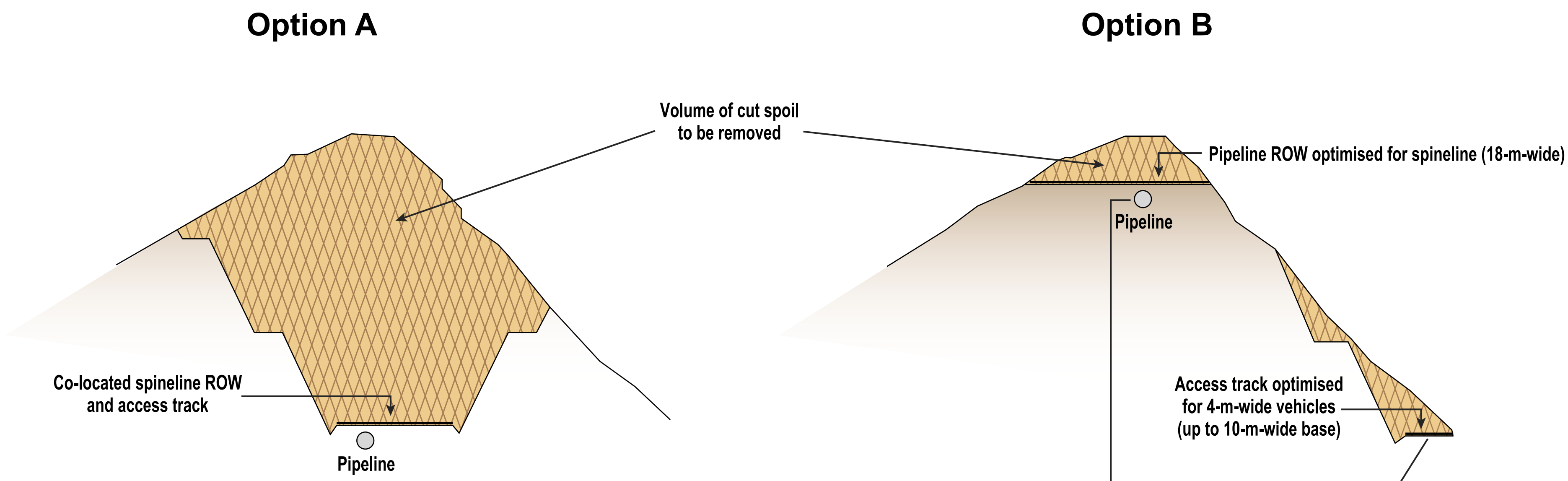
It is therefore the intent of the project to construct the field infrastructure on Hides Ridge using conventional means but with the ROW reduced to a width of 18 m with a separate access track in steeper terrain.

7.10.1.3 ROW Formation Earthworks on Hides Ridge

The conventional practice of co-locating the pipeline trench and construction access track requires a ROW 18 m wide. This will generally reduce earthworks volumes in most types of terrain and, for much of Hides Ridge, could be achieved by routing along ridge tops. However, there are places where steep slopes on the long axis of ridges would require large cuts to meet the grade requirements of the access track (Figure 7.6). The alternative was therefore investigated of separating the pipeline ROW from the access track in separate benches. The stylised sections in Figure 7.6 show that the volume of earthworks reduces considerably if the access track and pipeline ROW can be separated in this way, and this approach has therefore been adopted. The plate embedded in Figure 7.6 shows an example of a separated ROW and access track.

Table 7.6 Hides gathering system (Hides Wellpads A to E only) construction methods summary

	Ground Construction Access	Helicopter Construction Access	
Design basis	Base case: DN 550 spineline, construction access track	DN 550 spineline	Multiple DN 100 flowlines
Engineering, constructability	Constructible by standard methods	Manhandling – heavy work for light tools and for all practical purposes impossible	Manhandling
Cost (construction)	Lowest cost	Significant helicopter cost, severe weather downtime	Significant helicopter cost, severe weather downtime
Cost (operations)	Lowest cost	Operations cost penalty (helicopters) Back-up well required	
Workforce	Smaller pipelaying workforce accommodated off Hides Ridge at the Hides Gas Conditioning Plant	Large pipelaying workforce; housed on Hides Ridge at several wellpad locations to avoid heli-commute and weather downtime	Large pipelaying workforce; housed on Hides Ridge to avoid heli-commute and weather downtime
Schedule	Standard	Weather risk for heli-lifting machinery and pipe	
Well availability	Standard	Weather risk for well workovers, emergency repairs	
Safety risk – construction	Standard	Flying risk; limited options in an emergency Construction methods dangerous (manhandling)	
Safety risk – operations	Standard	Flying risk; limited options in an emergency	
Earthworks	Major	Minor	Negligible
Area affected	More than 90 ha	Not estimated	Not estimated
Nominal ROW width	18 m and periodic 7 to 10 m for separate access track	18 m	28 m plus



Option A

Initial routing option co-located pipeline and access track in 18-m-wide ROW:

- Major earthworks required to achieve 16% grade limit for access road
- Large volumes of excess spoil generated and sidecast

Option B

Base case is 18-m-wide pipeline ROW and access track, with separate 7- to 10-m-wide access track routed in separate alignment in steep areas (approx 10 km):

- Pipeline ROW routed along ridge top requires smaller cut
- Access track can route across side slope contours to achieve 16% road grade limit, resulting in smaller earthwork cuts
- Overall, less earthworks and excess spoil generated

Example of separated ROW and access track

PNG LNG	Job No: 1284	Esso Highlands Limited	Reducing the landform and associated impacts of the Hides Ridge ROW and access track	Figure No: 7.6
	File Name: 1284_09_F07.06_KB	PNG LNG Project		

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7.10.2 Spoil Management

The establishment of roadways and pipeline ROWs in steep terrain yields a surplus of cut material over fill material (called spoil) that requires management. The normal and long-standing practice in Papua New Guinea is set down in the Department of Works Road Design Manual, which provides for spoil to be sidecast. This method creates vegetation damage down the slopes, and fugitive sediment falls or is transported by rainfall runoff into nearby streams and rivers. These processes have an analogue in the natural landslides that are a common feature of the PNG highlands.

7.10.2.1 Mitigation Options

In more accommodating environments, it would be normal practice to dispose of spoil in stable emplacements and to implement measures to reduce erosion, downstream sedimentation and turbidity. Therefore, the bulk earthworks necessitated by the PNG LNG Project raise the question as to the feasibility, affordability and utility of such mitigation measures.

Table 7.7 sets out the factors for the standard base case and three levels of mitigation related to spoil management, with approximate additional costs of applying these mitigation measures.

The mitigation options fall broadly into two categories:

- Spoil sidecasting (options 1, 2 and 4).
- No spoil sidecasting (Option 3).

Table 7.7 Spoil management options

Factor	Option 1 (Base Case: Sidecasting without Mitigation)	Option 2 (Spaced Sidecasting)	Option 3 (No Sidecasting; Removal to Dump)	Option 4 (Sidecasting with Active Revegetation)
Slope stability	Unstable until vegetation naturally re-establishes.	Unstable where dumping occurs until vegetation naturally re-establishes.	Limited downslope stability issues.	Unstable until revegetation occurs.
Engineering feasibility	Feasible; standard practice for roadworks in Papua New Guinea.	Difficult; requires haulage procedures for new fleets of large earthmoving plant and trucks on narrow benches. Turnaround and passing areas in steep unstable sections increase cut volumes.		Feasible; similar to standard practice for roadworks in Papua New Guinea but with progressive active revegetation.
Construction schedule	Lowest construction schedule risk.	Several more months for roadway and pipeline construction.		Limited impacts to construction schedule.
Biodiversity impacts	Direct loss of vegetation and fauna habitat in path of sidecast material. Natural regeneration of grasses instead of trees increases fire risk and may permanently alter habitat.	Similar impacts as for Option 1 with less frequent but thicker deposits of sidecast material. Revegetation rate may be reduced in the short term.	Limited downslope impacts. However, would require additional area to be cleared for dump site, and possibly for passing bays.	Direct loss of vegetation and fauna habitat in path of sidecast material. Impacts would be mitigated where slopes are actively revegetated.

Table 7.7 Spoil management options (cont'd)

Factor	Option 1 (Base Case: Sidecasting without Mitigation)	Option 2 (Spaced Sidecasting)	Option 3 (No Sidecasting; Removal to Dump)	Option 4 (Sidecasting with Active Revegetation)
Time to achieve revegetation on slopes	Six months; may be longer on unstable sections and significantly longer on hard limestone substrate.	Longer than for Option 1 as slopes would be more unstable and would take longer for vegetation to establish.	Limited in any areas of disturbance. Dump area would be unavailable for revegetation for six months.	Involves active revegetation on steep slopes and monitoring and maintenance until vegetation is established.
Riverine impacts	Will temporarily increase riverine turbidity and possibly bed aggradation where sidecast spoil enters river system. However, impacts will reduce as vegetation re-establishes, with the affected watercourses recovering in 2 to 3 years.	Would increase riverine turbidity and possibly bed aggradation where sidecast spoil enters river system. However, impacts would reduce as vegetation re-establishes, with the affected watercourses recovering in 2 to 3 years.	Limited impacts to riverine system.	Would increase riverine turbidity and possibly bed aggradation where sidecast spoil enters river system. However, impacts would reduce as vegetation re-establishes, with the affected watercourses recovering in 2 to 3 years.
Personal safety	Lowest risk to personal safety as minimum additional work required.	Inherent risks in manoeuvring loaded trucks along narrow benches and reversing into designated sidecast areas in generally wet weather.	Increased safety risks, as additional work would be required to transport materials to dump sites.	Depends on method of revegetation (hand planting on steep slopes may be hazardous).
Visual amenity	Immediate, widespread visual impacts where bare earth is visible. Changes in vegetation (grasses instead of trees) may cause long-term localised visual impacts.	Immediate, localised visual impacts where bare earth is visible. Changes in vegetation (grasses instead of trees) may cause long-term localised visual impacts.	Limited downslope visual impacts; however, spoil dump would be large and may visually alter the landscape.	Temporary widespread visual impacts where bare earth is visible until vegetation re-establishes. Limited long-term impacts.

7.10.2.2 Discussion

Option 1, the base case, reflects the present-day standard practice in Papua New Guinea and conforms to government road building requirements and directives. Sidecasting of spoil is believed to have been adopted for all roads and pipelines built in Papua New Guinea to date, except where cut material could be economically and practically salvaged as fill or for land reclamation. Cost increases over the base case for options 2 and 3 have not been estimated but might be in the range of $50 million to $150 million, with Option 4 in the order of $2 million.

The rationale of Option 2 is to break up the continuity of downslope vegetation impacts by concentrating spoil disposal in sacrificial areas spaced according to the:

- Amount of material to be disposed.
- Suitability of site.
- Ability to transport spoil from the source to the sidecasting locations.

Option 3 seeks to restrict sidecast spoil to natural erosion from active construction areas, with the bulk of cut material being trucked to a dedicated stable deposition area.

Option 4 adds active revegetation to Option 1, the rationale being to accelerate the recovery of a stabilising and more visually attractive plant cover and to prevent the establishment of fire-prone grassland that is such a common impediment to forest regrowth in the PNG highlands.

From a feasibility standpoint, these options again divide between those that require rehandling, trucking and placement of spoil (options 2 and 3) and those that do not (options 1 and 4). The following constraints apply to the double-handling options:

- The trucking operation to move spoil from workfaces to other locations would require a larger fleet of heavy earthmoving equipment and trucks that would not otherwise be needed. Incremental fuel consumption associated with the more numerous trucks and earthmoving equipment would be significant.
- Safety is the priority of the PNG LNG Project, and traffic safety is a matter of management. However, the introduction of large numbers of heavy earthmoving equipment and trucks in a steep, narrow, wet and remote environment will add a very challenging and significant safety risk. To ameliorate truck haul safety hazards, more passing bays may be necessary, resulting in additional vegetation clearing
- The overall project schedule would require more active workfaces, which in turn would require a larger workforce and more camps; these would give rise to incremental environmental impacts (e.g., water use, sewage treatment and disposal, and waste generation and disposal).

An examination of the section between the Hides E and Hides A wells reveals the practical difficulties of the two spoil-trucking options. For example, a nominal 1.2 million m^3 of cut-to-spoil material over 17 km would require the ROW to be widened to accommodate the heavy earthmoving equipment and trucks required to remove the spoil. This, in turn, would generate large quantities of additional spoil: twice the volume or more on the sections of 45-degree slopes, where the ROW width would need to be increased to enable truck traffic to safely circulate.

It is not straightforward to trade off the feasibility disadvantages and the potential environmental benefits of the trucking options. What is clear is that, at most locations, the cost and schedule penalties of trucking will be substantial. At the same time, however, the additional earthworks that double handling of spoil requires will make the environmental benefits of trucking less than might be first thought. This holds particularly true when temporarily conspicuous short-term impacts of spoil sidecasting are viewed in their time context: generally rapid and unaided vegetation regrowth is evident on the earthworks associated with the Kutubu Petroleum Development Project (where all cuts were established by spoil sidecasting; see Section 18.2.3.1, Observed Regeneration Potential). A corresponding rapid decline in sediment catchment yield is the basis for the predictions of Section 18.6, Aquatic Ecology, of minimal impacts on rivers from spoil sidecasting. These predictions are based on monitoring for the Kutubu Petroleum Development Project (see 'Increased Suspended Sediment Loading' in Section 18.4.4.1, Construction).

Active revegetation is possible only on the ROW benches, because it is unsafe to work on sidecast material at the angle of repose. The bench itself could be actively revegetated, although, as discussed in Section 18.2.3, Regeneration Potential Context, in areas where favourable substrate conditions exist, this will occur in a matter of a few years without intervention. The type of unassisted vegetation regrowth will not necessarily be the same as before disturbance. Nonetheless, it will mimic regrowth after one of the various forms of natural disturbance, namely the landslides that are common in the steep, unstable country where the largest sidecasts are required.

In general terms, therefore, options 2 to 4 incur costs and safety risks for little improvement over what will occur naturally over a matter of a few years.

As on Hides Ridge, where decoupling of the ROW and access track has delivered considerable reductions in the volume of spoil to be sidecast, pipeline and access track optimisation during FEED and detailed design has committed to mitigate impacts from sidecasting in other steep terrain areas by:

- Examining the separation of the pipeline ROWs and roadways or access tracks to reduce sidecasting where practicable.
- Using fine particle size organic matting or a lattice framework or similar in karst areas to trap organic matter across sidecast where safe and practicable.
- Implementing sediment control measures downstream of sidecast material where safe and practicable.