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BROWSE BASIN GAS TECHNICAL REPORT
DEVELOPMENT OPTIONS STUDY

REPORT 3 of 3
ONSHORE LNG HUB DEVELOPMENT

Prepared for

THE NORTHERN DEVELOPMENT TASKFORCE

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TABLE OF CONTENTS

TABLES

FIGURE

APPENDICES

INTRODUCTION

The Browse Basin, offshore of north-west Western Australia, holds substantial resources of natural gas. At the date of this report, there is no hydrocarbon production from the Basin and there are no hydrocarbons based projects that are either under construction or approved for construction. However, two of the Basin tenement holders, Woodside Energy Limited (Woodside) and INPEX Browse Ltd (INPEX), are planning to use their known gas resources for "greenfield" Liquefied Natural Gas (LNG) projects[1].

The two projects are based on total gas resources of approximately 34 Trillion cubic feet (Tcf). While some of these resources were discovered over thirty years ago, the basin is "gas prone" and has been relatively lightly explored. The level of exploration activity has increased in recent years and it is likely that other companies currently active in the area will eventually propose LNG projects using Browse Basin gas.

From a technical perspective, the "logical" sites for a land based LNG plant to receive, process and export Browse Basin gas are on the Northern and Southern Kimberley coast or on one of the islands off the coast. The North Kimberley area is totally undeveloped, has no infrastructure and is an eco-tourist destination. The South Kimberley has some development (Broome and Derby), has minimal infrastructure and has several tourist destinations (Broome and Cape Leveque).

At the time of this report, both the Woodside and INPEX operated Joint Ventures have conceptualised their respective projects on a "stand alone" basis and have evaluated potential LNG processing sites on the basis of the individual requirements of those projects. Woodside has prepared a shortlist of several potential sites and INPEX has chosen the Maret Islands as its preferred site. Forecast total LNG production from the two projects is in the order of 20 to 25 MMtpa.

The Kimberley Northern Development Task Force (Taskforce) is an inter-departmental body formed by the Government of Western Australia. The Project Manager is Mr. Gary Simmons from the Department of Industry and Resources (DoIR). The Taskforce has been engaged to set the framework by which the State will protect and manage the important heritage, environment and tourism values of the Kimberley area while facilitating structured industrial development. The West Kimberley Subdivision of the Taskforce was established to manage across-government planning processes and stakeholder consultation in regard to selection and development of a suitable location or locations for the processing of Browse Basin gas reserves.

The Taskforce, through DoIR, has retained Gaffney, Cline & Associates ("GCA") to provide independent advice on technical issues associated with the selection and development of onshore and offshore locations, for the processing of the Browse Basin gas. This advice is to be in the form of a report titled "Browse Basin Development Options Study" (The Study).

The objective of the Study is to review specific technical and economic issues surrounding the processing of existing and yet to be discovered resources at a common LNG plant location or hub. The study has been undertaken in three parts as follows:-

[1] During the course of the study, Shell Development (Australia) announced that it plans to develop the Prelude field, in the Browse Basin using a floating LNG facility (FLNG) with no onshore processing facilities.

1. Review the existing site selection processes undertaken by Woodside and INPEX and provide commentary on the technical suitability of the sites considered to date in the context of a gas processing hub.

2. Consider and evaluate the key technical issues governing the offshore facilities required to develop Browse Basin Gas in the context of a gas processing hub.

3. Review the potential for an onshore infrastructure hub to support Browse Basin gas development and comment on the key technical, commercial and economic issues surrounding the integration of the LNG facilities and services at an onshore infrastructure hub.

Separate reports have been prepared for each of the three areas of review outlined above. This, the third report, covers the potential technical, economic and commercial issues and benefits for an onshore LNG Hub. The full scope of work for this third report is shown in **Appendix I**. A glossary is included as **Appendix III**.

CONCLUSIONS

The scope of work provided for this study by DoIR lists a number of specific points to be addressed. This has been done in the relevant sections in the body of the report. GCA's "high level" conclusions and recommendations are summarized as follows:-

1. It is technically feasible for LNG Hub participants to share ancillary services (required to support the Health, Safety of the personnel onsite as well and ensure compliance with Environmental regulations), support infrastructure (required to support operations, such as airstrips and construction areas), essential infrastructure (required to store and load LNG and its by-products) and core processing facilities (main gas receiving, treating and processing facilities).

2. Higher degrees of integration of onshore facilities typically imply more complex technical challenges. These in turn can be resolved through increased levels of cooperation, detailed operating agreements and provision of adequate dispute settlement mechanisms.

3. Significant cost savings, up to $US2 billion of Capital expenditure (Capex) on an initial installed cost of $US13.5 billion and up to $290 million of yearly Operating expenditure (Opex) saving, may be achievable through the integration of facilities within an onshore LNG Hub. This assessment is based on a notional two project LNG hub with each project having two 4.5 MMtpa LNG trains. Overall, cost savings increase with integration, although the major cost items, which are the core process facilities, offer the minimum savings from integration.

4. The establishment of one Hub operating company, providing access to the common facilities and services, is essential to integration success and the realization of cost saving.

5. The main barriers to uptake of an LNG Hub for the Woodside and INPEX operated Joint Ventures are likely to be the acceptance of a single party as operator for the whole facility, the difficulty to attain cooperation among competitors and the definition of an acceptable cost allocation mechanism for the common facilities and services. In addition, individual Browse Basin operators may perceive their participation in a hub as a factor that has potential to significantly delay their LNG production and reduce their control over LNG operations.

6. Potential future Browse Basin LNG proponents may perceive that the LNG Hub structure provides a "first mover's advantage" which can impair the economics of new projects.

7. Once the degree of integration of onshore hub facilities and services has been defined, the technical and commercial challenges can be mitigated through:-
   i. the definition of infrastructure investment roles for Government and Operators,
   ii. the consultation of Hub stakeholders to define cost allocation principles,
   iii. the thorough documentation of operating and conflict resolution procedures.

Such discussions could be facilitated by an independent third party and be supported by a study of international best practices.

8. The active engagement process between Government, current and potential Browse Basin Industry Players and other interested stakeholders could be articulated as follows:-
   i. provision of a timeline for completion of the engagement process, allowing Browse Basin tenement holders to assess potential impacts on development deadlines,
   ii. definition and sharing of the Government's vision for LNG developments in the Kimberley, in particular the roles of the different stakeholders involved and the expected extent of the gas processing facilities,
   iii. agreement on the expected degree of integration of onshore and offshore facilities and services,
   iv. selection of preferred LNG Hub onshore sites for further studies,
   v. assessment of potential appropriate commercial models,
   vi. identification of an LNG Hub common facilities operator. The operator could be an existing Browse Basin stakeholder with LNG experience or a specially created entity.

These steps will constitute the foundations of a "master plan" for current and future Browse Basin LNG developments.

It is noted that GCA's scope of work covered only the technical and economic aspects of the creation of an onshore hub. The conclusions are not intended to reflect the opinions expressed by the LNG Hub stakeholders, but considerations to be taken into account in a structured engagement process.

1. SUMMARY

1.1 Methodology

This, the third report, is largely based on the expertise of the GCA project team members involved. The team members include personnel with extensive first hand experience at PT Arun, Ras Laffan, Sakhalin and Angola LNG. One of the team members also has an ongoing role in the planning of Angola LNG's first LNG Hub.

The report is structured to review the technical, economic and commercial feasibility of five potential hub scenarios. These scenarios reflect the logical degrees of integration. As specified in DoIR's Scope of Services (**Appendix I**), the review of potential commercial models for an onshore infrastructure hub has been excluded from this study.

While the technical views of Browse Basin stakeholder have been incorporated into this and the two previous GCA reports, the views on integration expressed in this report have been developed independently by GCA. For the purposes of this study, condensate stripping and offloading has been expected to be done offshore. All cost estimation work has been done at a very high level, mostly by analogy.

1.2 Appropriateness and Feasibility of Sharing Onshore Facilities

Technically, all facilities and services (described in more detail in **Table 1**) can be shared in the context of an LNG Hub supporting several offshore developments.

It is common practice in existing LNG Hubs to have shared ancillary services and support infrastructure which achieves significant economies of scale. With proper systems and procedures in place, this approach can be adopted without reducing each Operator's autonomy or generating additional risks to LNG production reliability.

Sharing essential infrastructure presents some technical challenges, in particular related to compatibility of technologies and fair capacity allocation procedures in the event of equipment failure. These challenges can be overcome by actively engaging LNG Hub stakeholders and documenting mutually acceptable approaches. Essential infrastructure has successfully been shared in other LNG Hubs, generating significant economies of scale. However, Operators tend to be more reluctant to share this type of infrastructure, and perceive such an approach as a reducing their control over the LNG production process.

Sharing core processing facilities presents significant challenges. In particular the variation in raw gas composition between different stakeholders can be an issue. For example, carbon dioxide (CO_2) contents ranges from 4% to 12% for Woodside operated fields and 8% to 17% for INPEX operated fields. Another issue that complicates the sharing of core LNG processing facilities is the potential difference in LNG specifications required by the customers of each LNG operator, as LNG plants can be tailored to their expected customer base and their LNG heating value requirements. Finally, control by the individual operators over the process of LNG production is further reduced.

1.3 Potential Onshore Facilities Integration Implications

The decision to share certain onshore facilities needs to be supported by a long term vision for the LNG Hub. This will help define adequate sizing of the facilities, suitable cost allocation and appropriate operating procedures. These factors will determine the common foundations of the LNG Hub, and greatly influence its attractiveness to the Industry, in particular to tenement holders entering the hub at later stages. Integration principles will have to be perceived as fair and void of “first mover’s advantage” dispositions.

The successful integration of onshore facilities will require a more active engagement process between stakeholders than that required by independent “stand alone” developments. This typically requires significant Government involvement and extensive Industry consultation. The optimum outcome would be the establishment of one LNG Hub operating company that would provide all the facilities and services determined for the selected degree of integration.

1.4 Potential Cost Savings

Cost savings are referenced in absolute terms based on a notional investment of $US 13.5 Billion for each of two independent, separately located and operated LNG plants, each having two 4.5 MMtpa LNG trains. Assuming the two plants are brought together in a single location, cost savings may vary from approximately $US 85 million through to $US 2,120 million dependent on the degree of integration within the hub.

1.5 Possible Industry Concerns

The main barriers to uptake of an LNG Hub for the Woodside and INPEX operated Joint Ventures are likely to be the risk of delaying initial LNG production, the loss of full control over LNG operations and the requirement for cooperation among competitors.

The LNG operators’ ability to deliver LNG on a reliable basis is one of the most important features of marketing LNG, since the buyers have domestic and industrial users who depend on a steady supply of gas. With an independent LNG plant operated by one company, complete control over plant reliability and LNG delivery rests with the LNG operator. Introducing shared facilities operated by others removes some of the LNG plant operators’ ability to fully guarantee LNG supplies. This introduces additional risk from his perspective.

It will be necessary to convince the LNG proponents that the LNG Hub will be operated by a competent and experienced company which will provide reliable services. It will also be necessary to demonstrate to the LNG operators that the use of common facilities will generate significant cost savings for them.

The LNG operators will perceive a commercial risk proportional to the integration of facilities and services. It is likely that sharing key processing and gas liquefaction facilities will not be the Industry’s preferred approach, due to different technology preferences by individual operators, varying feed gas compositions; possible differences in LNG sales specifications and the potential commercial risk.

These barriers to uptake could however be mitigated by the benefits linked to economies of scale, joint procurement and coordinated construction, in particular in the current “tight” labour market.

2. DISCUSSION

2.1 Potential Integration Levels

2.1.1 Inventory of Typical Onshore Facilities and Services

Four categories of onshore facilities and services are typical to LNG developments:

- **Core Processing Facilities:** main gas receiving, treating and processing facilities.
- **Essential Infrastructure:** infrastructure required to store and load LNG and its by-products.
- **Support Infrastructure:** infrastructure required to support the operation of the core facilities and essential infrastructure. Depending on onshore development location, this infrastructure may already exist, for example a development in the close vicinity of Broome may not require its own airfield.
- **Ancillary Services:** services required to ensure the Health, Safety of the personnel onsite as well as the compliance with Environmental regulations (HSE).

The main components of these categories are summarized in **Table 1**. For the purposes of the study, this list is indicative and intended to highlight the major facilities and services components. Far more exhaustive breakdowns will be required as specific hub concepts are matured.

TABLE 1

TYPICAL ONSHORE FACILITIES AND SERVICES CLASSIFICATION

Ancillary Services	Support Infrastructure	Essential Infrastructure (4)	Core Processing Facilities
Security	Offices	LNG and other storage tanks	LNG train(s)
Catering	Accommodation	Warehouse / stores	Slug catcher
Fire fighting	Airfield **(2)**	Essential utilities **(1)**	
Emergency Response	Non essential utilities **(3)**	Laboratory	
Training	Port facilities	Power generation	
Medical			
Health, Safety and Environment			

Notes:-
1. Essential utilities are cooling water (if needed), and nitrogen etc.
2. Depending on the site chosen for the onshore LNG development, an airfield may be required.
3. Waste treatment facilities.
4. In addition, the creation of one common facility for the disposal of the CO_2 liberated from the LNG gas processing facility is technically feasible and could be considered at later stages of Hub design. If geosequestration is the selected disposal method, then sharing the facilities and pipelines for injecting CO_2 at a remote location could generate significant cost savings. This would also ensure consistency in CO_2 disposal methods and facilitate monitoring by the appropriate Australian authorities.

This inventory is designed to identify discreet blocks of facilities and services that can be shared across several LNG developments.

2.1.2 Notional Integration Scenarios

Theoretically, there is an infinite range of sharing or integration scenarios that could by contemplated by potential hub users.

At one end of the spectrum, sharing of core processing facilities represents the highest degree of integration. At the other end, sharing of ancillary services represents the minimal degree of sharing. No sharing of facilities or services is the "base" case against which integration options can be evaluated.

For the purposes of this study, GCA has selected five integration scenarios that are appropriate for consideration at this stage of Browse Basin LNG development. **Table 2** summarizes the five main scenarios which are appropriate to two or more "co-located" onshore LNG developments.

TABLE 2

ONSHORE FACILITIES AND SERVICES INTEGRATION SCENARIOS

Degrees of Integration	Ancillary Services	Support Infrastructure	Essential Infrastructure	Core Processing Facilities
Base Case	Not shared	Not shared	Not shared	Not shared
Case A	**Shared**	Not shared	Not shared	Not shared
Case B	**Shared**	**Shared**	Not shared	Not shared
Case C	**Shared**	**Shared**	**Shared**	Not shared
Case D	**Shared**	**Shared**	**Shared**	**Shared**

Note: It should be noted that some of the essential infrastructure (such as LNG storage) could not be practically shared unless the core processing facilities are also shared.

These scenarios are not exhaustive. For example, the LNG proponents could decide to share only the gas processing facilities, and not the other infrastructure or services. However it is logical to assume that, if there is a willingness to share "Core processing facilities" and / or "Essential infrastructure" technical and commercial agreement will have already been reached on the sharing of "Ancillary services" and / or "Support infrastructure.

The scenarios selected above are based on actual LNG Hubs where LNG stakeholders have found incentives to achieve various degrees of facilities sharing. Examples include Ras Laffan Industrial City in Qatar, Egyptian LNG in Egypt and Atlantic LNG in Trinidad. These examples are summarised in **Table 3**.

TABLE 3

ONSHORE FACILITIES INTEGRATION ANALOGIES

Analogies	Description
Ras Laffan Industrial City	- Site and common facilities (jetty, storage tanks etc) are typically owned by a single company designed for this purpose - Core processing facilities as well as certain other services and infrastructure are owned and operated typically by the gas fields/LNG plant operators
Egyptian LNG / Atlantic LNG	- Site and common facilities (jetty, storage tanks etc) are typically owned by a single company designed for this purpose - Trains are owned by individual LNG companies, which may involve several shareholders, typically the gas fields operators - Construction, staffing and operation of the trains and common facilities are typically managed by a single operating company designed for this purpose
Angola LNG	- All feed gas from three of four sources enters the plant inlet facilities via individual pipelines - After reaching the plant, all gas treatment is common through gas processing, liquefaction and storage

Note: Each individual analogy can typically relate to several of the cases described in this study, based on the degree of integration achieved.

The study of these analogies confirms the potential for different degrees of integration for onshore LNG facilities and services.

The potential technical issues related to each of these cases are studied in more detail in the following section.

2.2 Review of the Technical Feasibility of Different Levels of Integration

The scenarios reviewed are described in **Table 2**. They step through increasing levels of integration. The base case, which does not involve sharing any facilities or services, can be considered as "equivalent" to stand alone LNG development. The base case is therefore technically feasible and does not require further investigation.

The individual components of ancillary services, support infrastructure, essential infrastructure and core processing facilities are listed in **Table 1**.

2.2.1 Technical Issues - Case A

In this case, only the ancillary services are shared across the multiple LNG facilities co-located within an LNG Hub. Typical ancillary services cover the areas of security, catering, fire fighting, emergency response, medical, training as well as Health, Safety and Environment (HSE). In most respects, the provision of ancillary services constitutes an operating cost, with minimal relative capital cost.

This scenario would typically involve a separate Company with the responsibility of providing these ancillary services to the LNG plants. In other LNG Hub locations (Ras Laffan Industrial City for example) a central service provider has been established by the national oil company. This central service provider typically runs all the non LNG company activities at the LNG Hub. This model has proven to be very effective and could be adopted for the operation of non LNG company activities in a Browse Basin LNG Hub.

At Ras Laffan Industrial City in Qatar, several common services are supplied to the LNG operating companies. These services cover the areas of security, safety, medical, training etc. The cost for these services is recovered from the LNG plant operators on the basis of actual costs plus a minimal uplift. These services are provided on a much larger scale than any individual company might justify on a "stand alone" basis, which generates significant economies of scale. One of the key success factors of such a configuration relates to the reliability of the third party supplying these services and its ability to develop trust with its customers. To this effect, at Ras Laffan Industrial City, the services supplier would provide the LNG plant operators with complete access to its financial statements through open audit.

The following paragraphs discuss in detail the services to be provided, any technical issues around the provision of the services, how they could be accessed, paid for, and integrated with the LNG plant(s) operation.

Security

LNG plants constitute major capital investment and a strategic asset providing energy to buyers, potentially domestic and overseas. Most LNG is sold on a long term contracted basis with penalties for failure to deliver cargoes. The failure to deliver contracted LNG cargoes also seriously affects the credibility of the plant as a reliable supplier, which can make the sale of subsequent LNG volumes more difficult. Ensuring adequate security is one of the measures required to safeguard the ongoing operation of the LNG facilities.

Security is normally achieved by surrounding the plant boundary by a high security fence with closed circuit television (CCTV) cameras to monitor fence security at all times. In addition, security personnel patrol the facility and manned security gates control the access of approved personnel to the facility.

In the context of an LNG Hub, where facilities of several operators are located within a common area, it would be impractical for separate LNG facilities to have their own security procedures and personnel due to the difficulty of coordinating such a combined effort. It is more effective and cost efficient to have one common security provider for the overall common boundary and internal facilities. This also ensures consistent security standards and procedures are applied to all entities within the LNG Hub facility.

Careful consultation with each LNG Company involved in the LNG Hub is required to establish a common security capability. This ensures that each company's internal security requirements are satisfied. Once a common security policy and necessary procedures have been agreed, it is also necessary to determine a suitable method to allocate the costs for these services. Allocating these costs on a "non profit" basis is generally considered a fair approach. In effect, all costs would be allocated to each LNG plant operator on some equitable basis. These costs are mainly the initial Capex required to establish the installation of the security equipment and the annual Opex to cover personnel costs related to the operation and administration of the security force.

An alternate to internal provision of the security capability is to contract the security of the LNG Hub to a well established security company. This option may be perceived less favourably by the LNG Companies, which could prefer to have full control on their internal security provider, instead of using a more independent external company. This would require detailed discussion with the LNG operating companies prior to initiating any contract with an external security company.

In summary, sharing security services, either provided internally or externally, is technically feasible and does not pose any major issue.

Catering

Staff catering facilities will be required by each LNG plant operator. It is a common practice in the LNG industry to contract catering out to a professional service provider. It is however necessary to provide the catering company with the facilities to prepare and serve the food. A mess hall / kitchen facility would typically be constructed as part of the overall LNG plant facilities. In the case of an LNG Hub, it will be economically effective to build one common catering facility to handle the staff from all Operators. However, this facility would need to be centrally located and within walking distance for all Hub personnel.

As in the context of sharing security services, it will be important to determine exactly who the catering entity will be and how the catering facilities will be built. The allocation of the capital cost required to build the mess hall / kitchen could be handled in different ways. For example the LNG companies could make a capital contribution to the building of the catering facility and the operating costs would only reflect the cost of staff, utilities, catering supplies etc. Future LNG companies locating at the LNG Hub would be required to pay a capital contribution, based on some formula and the original partners would receive a portion to compensate for the sunken costs they have already incurred. A second option would be to build the capital cost recovery into the cost of meals so the LNG Hub service company would be able to recover capital cost through this mechanism.

There are no identifiable technical issues associated with the development of shared catering facilities and services.

Fire Fighting

The first line of fire fighting is usually hosted in the LNG Operator's Operations Department and the resources used are typically plant and maintenance personnel. In the event of a major fire, the additional resources of a fire fighting service would be needed. Since the distance from a fire fighting facility to any LNG plant within the LNG Hub would be short, this service could certainly be shared.

It is important for the LNG plant Operators to be in agreement with the centralised facility concept since the safety of their plant depends on the effectiveness of this concept. Having the capability to fight major fires in LNG plants requires well trained fire fighters with adequate fire fighting equipment. Having independent fire fighting equipment and personnel in each LNG plant within an LNG Hub will involve higher costs without improving service quality. However, implementing this concept for each LNG plant operator will require considerable cooperative effort with the service provider. It is important to determine at a very early stage how this effort will be managed.

In setting up such a system it will be very important to establish common equipment requirements and engineering standards to avoid different LNG plants from having different specifications for fire fighting systems within their plant. It will also be important to understand and clarify where the responsibility to maintain and test the fire fighting systems will be allocated. All these types of decisions must be made with the initial LNG plant developers at the LNG Hub and must then be passed on to any LNG company wishing to locate at the LNG Hub. By carrying out this standardisation, the requirements for spare parts, for example, will be reduced and lead to economies of scale compared to each plant having their own specifications, equipment and fire fighting services.

As for the other ancillary services, it will be necessary to engage LNG Hub stakeholders to define the allocation of costs for the common facilities.

Emergency Response

LNG plant operators must have in place emergency response procedures to react to any major incident at their facility. The fire fighting capability is an essential part of the emergency response. The overall emergency response plans typically include the method the company would employ to react to all types of emergency situations. These could include plant fires, personnel injury, shipping emergencies, car accidents, loss of plant power, communications, medical emergencies etc. The emergency response plans would also include a process for information dissemination to the necessary government agencies etc.

In the case of a central LNG Hub with multiple LNG plant operations, it will be recommended to have a coordinated approach for emergency response. In the context of a major incident or of an incident requiring specific knowledge, more resources and adequate expertise are likely to be available than if emergency response is not coordinated.

A central emergency response centre could be set up as part of the responsibility of the company coordinating the provision of ancillary services. It is very important to include the LNG plant operators in the development of such systems to ensure that they are satisfied with the emergency response services and that the procedures meet all their internal requirements. Part of the responsibility of the central emergency response organisation will be to test the response effectiveness through regular emergency response drills. These drills would need to be conducted to test each individual LNG plant's ability to respond and also the coordination of response to an LNG Hub incident.

The main potential technical issue with developing a common emergency response service would be to ensure all plants have compatible communication systems to allow the free flow of information throughout the LNG Hub. In addition, the external emergency communication procedure needs to be defined and agreed by the LNG operators.

Training

Every LNG plant operator requires a training program to train personnel new to the LNG industry and to carry out regular training for all their staff to ensure that all the competencies for operating a successful LNG company are developed. Suitable training facilities, allowing the installation of specialist operations and maintenance training equipment for example, are also required.

In the context of an LNG Hub, it would be logical and cost effective to consider providing a centralised training facility and common training where appropriate. Common training facilities operated by a central training provider could support the competency development of all LNG Company staff. Some very general training modules could be common. Operator training, which is dependent on the type of process control system at the LNG plant, would likely be handled by each operator.

The provision of a common training facility would eliminate the need for individual training facilities at each LNG plant within the LNG Hub. If the common training facility is provided by a central company providing the ancillary services, the cost recovery for the facilities could be recovered from the individual operators or through annual charges based on facility usage.

The main potential technical issue with this type of common training facility could be the requirement for different training equipment to support all process control systems used by each plant. This type of issue reduces the incentive to share training services, as there would be limited economies of scale compared to having these process training models at each plant. Another potential issue would be the high level of coordination required to ensure that potential surges in training needs for each Operator (at plant start up for example) do not disrupt the training required by the other Operators.

Medical

It is normal for all LNG plants to have some type of medical facilities. These would normally be provided to cover the need for routine medical examinations for their staff and also to handle any type of medical emergency in the plant. Maintaining an adequate level of industrial hygiene is also important in any LNG facility and requires medical oversight. To achieve these objectives, investments in adequate medical facilities, equipment and personnel need to be made.

In the case of an LNG Hub, it would be cost effective to consider common medical services, which could provide more comprehensive medical facilities than individual plant medical facilities. It would be important however for the facility to cover the needs of all LNG operators and any special requirements they might have. One central company could provide these services, similarly to the other ancillary services.

There are no anticipated technical issues with this type of common medical facility and medical services. It would be necessary to determine how the costs associated with the medical facility would be recovered.

Health, Safety and Environment

Each LNG Company would normally have a comprehensive HSE program with the appropriate staff to oversee and implement the program. In the case of an LNG Hub it would be appropriate for the individual operators to have their own HSE programs with their own staff to implement and monitor them.

However, there could be one central HSE organization in charge of ensuring overall compliance for the entire LNG Hub. For example, the central HSE group could establish monitoring stations in the LNG Hub and the surrounding vicinity to ensure air and water emissions meet the mandated Australian standards.

There are no anticipated technical issues associated with the establishment of a common LNG Hub HSE group. It may be in the interest of the government of Western Australia (WA) to mandate an independent service provider to constitute this HSE oversight group. However, this may be perceived as an additional cost by the LNG Hub Operators.

2.2.2 Technical Issues - Case B

Case B progresses one integration step further than the previous case in that it envisages sharing support infrastructure in addition to ancillary services.

This case would involve much larger capital and operating expenses than in Case A. The operation and financing of these facilities would need extensive consultation with the potential LNG Hub plant operators. Cost allocation for both Capex and Opex will require the establishment of several legal agreements with the LNG plant operators and the central facility company involved in establishing the facilities. Typical approaches for cost allocation in this type of configuration are described in more detail in Case C.

The following will address the practicality, potential technical issues and possible cost recovery scenarios of establishing common support facilities.

Offices

It is possible to consider one common office building for all LNG plant operators at the LNG Hub. This could save the individual companies Capex since there would be economies of scale in a larger office building.

There are however some significant difficulties that would be encountered in this type of central office complex.

LNG operators have highly sensitive LNG sales and marketing data and computer systems which are often proprietary to their company. A common office building would have to accommodate a complete secure separation between the areas occupied by different companies, to ensure information confidentiality.

Determining the size of the office building would also be a challenge since it requires accurate knowledge of the manpower of the organizations to be housed. In addition, LNG plants are likely to be built at different times, which means that some Operators may need to invest in the central office building before they are ready to occupy the premises.

There will also need to be provisions made for future expansion of the office building to handle future LNG companies establishing themselves at the LNG Hub. This requirement will impact the selection and sizing of office utilities and will require an estimate of the possible future additions.

Individual LNG operators will most likely want to have their operations and maintenance personnel located in their plant, to ensure a close connection between staff and plant operations. Therefore the personnel located in the central office would most probably be administrative staff and management.

Since individual companies normally have distinct office space requirements, often depending on the level of the personnel occupying the office, it would be appropriate to offer the office building in a shell form. Individual companies would then be able to outfit their office space as needed. The same is true for the individual communication and computer systems.

Providing common office space should not present any major technical issues, however the location of the building should be determined as part of an overall LNG Hub Master Plan. It will be necessary to locate the office at a safe distance form the operating plants.

Accommodation

LNG Hub accommodation requirements are conditioned by the manpower levels of each LNG plant. Assuming an initial plant size of 9 MMtpa, in a remote location, it is reasonable to estimate manpower requirement of approximately 450 employees. With multiple plants, manpower requirements would exceed 900 employees. Housing and recreational facilities will need to be designed to accommodate this work force.

Completely different types of accommodation and recreational infrastructure would be required for a “bachelor camp” or for the housing of the work force and their families.

If the decision is taken to have the work force on a rotational basis, only bachelor accommodation and recreational facilities will be required. However, the LNG company will need to double the number of staff to ensure 24/7 coverage. This has a large financial impact, as the most significant component of a typical LNG operating budget is manpower.

In the case of a remote LNG Hub, where employees are accompanied by their families, an extensive community and large facilities would be required to provide an acceptable living environment. This would typically result in much higher capital expenditure for accommodation. However, higher Capex could be more than offset by reduced transport and manpower requirements leading to lower Opex.

The decision by each company to work on a rotation basis or to have the employees' families in accommodation close to the LNG Hub must be taken at an early stage and should be consistent for all existing and future LNG plant operators. It is noted that recent practice for remote Australian resource development projects is to use "fly in – fly out" construction and operations workforces.

Accommodation could be shared by the employees of the LNG companies operating within the LNG Hub. The company overseeing the LNG Hub could be responsible for developing these common accommodation and recreational facilities. Capex could be provided by the LNG companies, accommodation Opex could be recovered through regular daily accommodation charges. It would also be logical to combine the catering services described in Case A with the accommodation and recreational facility to optimise costs.

There are no technical issues linked to sharing accommodation facilities in an LNG Hub.

Non Essential Utilities

Non essential utilities would certainly be ideal candidates for sharing. Typical "non essential" utilities are water for drinking, irrigation of surroundings, and sewage treatment. Supply of all these from a central facility in the LNG Hub removes the need for the LNG plant operators to install and operate facilities for water supply, treatment and delivery. The water from the waste treatment plant can normally be used for the purpose of irrigation of the vegetation surrounding the plants.

Financing the construction and paying for the facility running costs of the common non essential utilities would require the cooperation of the LNG plant operators with the entity established to develop the service and operate the facilities.

The central provision of common "non essential utilities" does not present any specific technical issues.

Port Facilities

The installation of port facilities represents a very large capital expenditure. However, the cost of the port facilities will depend on the marine conditions at the LNG Hub location.

In the State of Qatar, port facilities were installed at Ras Laffan Industrial City at a cost of US$1 Billion (1995). The port was constructed in such a manner that two LNG berths were installed with provision for several additional berths. Such an approach and front end investment requires a clear vision for the future of the LNG Hub so that the long term port usage can be estimated and planned for. In Qatar, the port was made available to the LNG companies. However, it was the responsibility of the LNG companies to outfit the berths to make them suitable for berthing and loading of LNG tankers. In addition, construction berths to allow off loading of construction material and product specific berths (sulphur, propane, butane and condensate) were included in the port design. In the Qatar situation, the port Capex (apart from the costs of outfitting the berths) was the responsibility of the Government of Qatar. These costs were recovered through port usage fees for the LNG companies and berthing fees paid by the ships berthing in the port.

One benefit of having a common port facility is that all shipping, tugs and pilotage requirements are coordinated through one party. In addition, having multiple LNG berths in one port increases the potential LNG plant reliability since problems with one berth will still allow LNG loading through the second berth.

The development of a port for the common use of multiple LNG companies would require careful consultation with the companies to ensure adequate berth availability.

Some sites may be better suited than others to accommodate large common port facilities. However, there are no intrinsic technical issues linked to sharing port facilities. The concept of one port for usage by multiple LNG producers is proven, with operations in Qatar and other LNG plants around the world.

Airfield

Depending on the location of the LNG Hub, it may well be necessary to install a dedicated airport. An airport could be developed to serve multiple LNG plant operators using the hub. The airport would need to be administered and operated to meet minimum safety and availability requirements. This could be outsourced to a company not related to the LNG operation. Indeed, most LNG companies prefer not to have to assume the responsibility for an activity that falls well outside their core competencies.

The cost of constructing and operating an airport, and the provision of air services, would be the subject of negotiations between the airport company and the LNG plant operators who would use the airport for personnel and cargo transfer.

No technical issues are foreseen in the construction and operation of an airport, assuming appropriate land can be located within the proximity of the LNG Hub.

2.2.3 Technical Issues - Case C

Case C is Case B with the addition of Essential Infrastructure. This takes the integration concept to a higher level than that described in Cases A and B. The prospect of sharing essential infrastructure might be of concern to an LNG plant operator. Indeed, the operator needs to fulfil LNG cargoes from a system where a critical part of the LNG manufacturing and shipping process is not fully within his control.

The Ras Laffan Industrial City in Qatar has several shared facilities, which include LNG tanks. The LNG densities produced from both Qatargas and Ras Gas trains in Ras Laffan Industrial City are similar, therefore minimizing the risks associated with the common storage of different LNG streams. In addition, the incoming gas streams, coming to each of the LNG train operators, are produced from similar reservoirs and have very similar compositions.

The model for recovering the costs of these facilities is based on both a capital cost component and an operating cost component. The recovery of the capital cost component of an LNG tank, for example, involves the LNG plant operator paying the capital portion of the facility which he needs access to. For example, if one LNG plant operator requires access to 30% of the common LNG tank facility, he is then required to pay 30% of the overall capital cost. In addition, the LNG plant operator needs to commit to a certain quantity of through put. The recovery of the operating cost component is then determined based on the costs of operating and maintaining the portion of the facility being used by the specific LNG plant operator. This approach can be applied for recovering the costs of all major facilities shared by multiple users.

It is important to note that economies of scale will be realized on Opex for common facilities, as one common work force will be operating the facility instead of multiple work forces operating individual facilities, such as LNG storage tanks for example. Spare parts and maintenance procedures are also optimized in this configuration, as opposed to being duplicated by multiple operators.

Having common LNG, condensate and sulphur storage tank facilities can also provide significant operating flexibility for LNG plant operators. The unused storage capacity can then be periodically re-allocated to any operator with high LNG production at that point in time.

The LNG plant operators' access to the facilities and the establishment of usage priorities will be of paramount importance. Indeed, the LNG plant operators have LNG delivery obligations, which have large financial penalties for failure to deliver contracted volumes.

The operation and maintenance of these shared facilities may also be of concern to the plant operators, as these will be out of their direct control.

The following will describe the equipment defined as "essential infrastructure", the operational and business issue that may exist with sharing this equipment and the potential financial implications. Any technical issues will also be noted.

LNG and Other Storage Tanks

LNG storage requirements are typically based on LNG production rates, forecasted LNG sales, shipping schedules and harbour access. LNG operators would normally design the LNG storage to hold approximately seven days of production. In the event of ship delay, this is usually considered sufficient storage to avoid complete shut down of the LNG plant, which would have to occur once the storage tanks are full. LNG plants are not easily shut down or started up once shut down, so the optimum operating practise is to ensure the LNG storage have enough spare capacity to avoid "tank tops" situations.

The use of common LNG storage facilities presents a significant technical issue and potential safety risk. Two different LNG streams from different plants with differing LNG densities can generate two distinct LNG layers in the common LNG tank. LNG liquid normally "weathers" in the tanks, which means that vapour is released from the liquid due to heat increase in the tank. The vapour is typically recovered and returned to the plant LNG fuel system. In the case of two layers of LNG in the same tank, the heavier layer sinks and the lighter layer rises. Both layers give off vapour; however the lower layer vapour cannot be released into the tank vapour system because of the hydrostatic head of the top layer. The top layer density increases as the LNG gives off vapour and at some point the two layers approach the same density. This causes LNG "roll over", as the two layers mix rapidly and the lower layer gives off large amounts of vapour. If the tank relief system cannot handle the excessive gas volume, there is a risk for tank explosion. In the context of a Browse Basin LNG Hub, the use of common LNG tanks is unlikely to be an issue if the LNG densities from the different LNG operators are similar.

Sharing LNG storage facilities between multiple LNG operators is also expected to be difficult, due to the different timing of the LNG projects. In such a configuration, the first LNG operator or the common facility operator may have to pre-invest in LNG tankage for the second LNG operator, in order to realise economies of scale. LNG tanks represent significant capital expenditures, which are in excess of US$ 50 million per tank. Although the timing and cost of LNG storage tankage is not a technical issue, it does constitute a potential commercial risk.

In the case of shared LNG tanks, clear procedures will need to be developed for allocation of LNG from the different plants. Sampling and measurement of the LNG delivered to the plants from the different operators will also need to be precisely monitored.

Warehouse / Stores

Sharing a common warehouse facility should be technically feasible, as long as each company can have a secure area allocated to them for their storage requirement.

It is necessary to consider two different types of spares for potential storage sharing:

- Spares which are not equipment specific and could be considered "consumables", (gaskets, lube oil, filters, bolts etc).
- Capital spare parts for specific equipment.

Consumables and their allocated storage facilities can be shared without generating any major technical difficulty. Unless the separate LNG plants have identical equipment and utilise the same LNG liquefaction technology, sharing capital spare parts for major LNG plant equipment is not feasible and would be uneconomical.

Essential Utilities

The supply of essential utilities does not present any significant technical issues. All LNG plants require supplies of nitrogen to purge gas lines in the event of maintenance. In addition, should sea water cooling be used in the LNG processing facilities, it would be possible to utilise one common facility.

Laboratory

Laboratory facilities in LNG plants are mainly used for verifying the quality of the LNG loaded on the tankers, which is essential to define the value of the cargo. Indeed, LNG is sold on the basis of British thermal units (Btu) delivered. The total Btu's delivered to an LNG tanker is determined by multiplying the heating value of a sample of the LNG being loaded (Btu/standard cubic meter) by the volume of LNG delivered on board the vessel.

Using one common laboratory for several LNG plants would not be problematic technically. The other tests carried out by the laboratory, like determining water quality for example, do not pose any technical issue for integration either.

Power Generation

Electrical power requirements for LNG plants can be considerable. Individual LNG plants usually prefer to be self sufficient and install the necessary power generation plant. This is based on the objective to be a reliable LNG supplier and the thought that dependence on an external source for the supply of electrical power constitutes a risk. Indeed, in such a context, the LNG company is not in complete control of the overall LNG manufacturing process. In addition, local power stations can rarely supply the large electricity requirements of an LNG plant.

It would be logical to combine the power requirements for multiple LNG plants in one power generation facility within the LNG Hub, leading to economies of scale. In addition, one large power generation plant could provide more security of electricity supply, as it could accommodate the requirement for sparing electrical generation equipment to cover breakdowns of essential equipment. The LNG plant operators would need to ensure that the operation and maintenance of the power plant is handled by a competent entity, reliably providing steady power supply and higher levels during peak times.

The method of distributing power to each LNG plant in the event of a reduction of electricity production is an issue that would require thorough consultation with the participating LNG companies. In the event of the central power plant having to shed load, there would need to be a clear procedure for power shedding that was equitable to all LNG plants.

Similarly to the other issues developed in this section of the report, distribution and recovery of Capex and Opex will need to be agreed with the potential LNG plant operators.

The only major potential technical problem would be the compatibility of the centralised power plant to supply the necessary power at the levels and frequency required by the LNG plants. The limitations to power supply should also be well understood by the different plant operators.

2.2.4 Technical Issues - Case D

Case D represents maximum integration of facilities.

Both the Angola LNG facility and the Atlantic LNG facility in Trinidad represent operations where a degree of integration beyond Case C has been achieved.

In the case of Atlantic LNG, each of the four operating trains has different sources of feed gas. However, the trains are not exclusively dedicated to one source, with some trains taking a mix of feeds. The ownership of the individual trains in some cases bears no relation to the ownership of the gas. LNG storage is not in dedicated facilities. Atlantic LNG is the operator of the site on behalf of the individual LNG train owners. The earnings from the operations, referred to as a quasi – tolling basis, are calculated by Atlantic LNG via a complex allocation procedure.

For Atlantic LNG, this modus operandi grew from the initial investment decisions where LNG facilities were conceptually new and it was important to develop economies of scale. In the early days of LNG projects, the Atlantic LNG project succeeded at least partially as a result of an enlightened government policy on tax incentives, which was also probably fundamental in the development of a single integrated hub facility.

Angola LNG is entirely different, and its character as a single integrated plant for a number of gas suppliers stems from its use of associated gas from offshore operations. Supplies of associated gas from individual fields are limited, and the feeds from a number of fields must be combined to allow an initial single train to be developed. Now that the principle has been established it is likely that future LNG expansion in the area will also be through the existing plant.

LNG Train(s)

LNG trains are normally composed of two main components, a gas treating and dehydration section and an LNG liquefaction section. The gas treating and dehydration section of the train removes components of the gas that cannot be allowed into the liquefaction section (CO_2, hydrogen sulphide, mercury and water). The design of the gas treating section of an LNG train is based on the composition of the incoming gas stream. This section can be designed to accommodate small variations in gas composition, but cannot tolerate compositions greater than design once established. This makes the mixing of various gas compositions a significant technical problem, which could result in equipment failure, reduction in effective plant capacity or producing LNG that would be off specification and unsalable. LNG plants typically do not have the ability to re-run LNG to bring it back to specification.

Where mixed feeds are proposed, a more robust process is selected to accommodate the likely feed composition variations. The Phillips Cascade Process or various of its derivatives use individual refrigeration loops (compared to the Mixed Refrigerant Cycles using complex mixtures whose refrigerant properties are adjusted to match the condensing characteristics of the feeds). This may lead to a less efficient process, but one which is inherently more capable of dealing with composition variations away from the design point.

It can be acceptable for one operator to build a dedicated train to process gas from a second operator. In this case, there would only be one LNG plant, but each train dedicated to processing specific types of gas from different fields. This is a common practice, implemented in Indonesia at both the Arun and Bontang gas plants, and as identified above in a different format, for Angola LNG and Atlantic LNG.

GTL Plant

Similarly to LNG trains, multiple companies sharing common GTL facilities would be problematic from both commercial and technical aspects.

A possible scenario that would be acceptable to gas suppliers, would be for one GTL plant to be operated by one company but processing gas supplies from others. Similar technical issues would exist as a result of varying gas composition from multiple gas fields.

Slug Catcher

Slug catchers are normally sized based on the anticipated liquid quantity in the incoming gas. Forecasting future gas volumes and liquid content would be required to design a slug catcher that could be expanded and shared by multiple users.

Existing LNG plants expand their LNG production capacity and often have to enlarge their slug catcher to accommodate increased gas and liquid volume. Sharing a slug catcher across several users is technically feasible but likely to require pre-investment of capital.

Condensate Treating Facility

The condensate can either be stripped from the produced gas offshore or at the onshore LNG plant. In the onshore scenario, the slug catcher would separate condensate from the incoming gas stream and from the water. The condensate then needs to be stabilised in order to meet shipping specifications. This is necessary since during the voyage the gas will tend to evaporate from the condensate and the receiving customer will have lost some of the cargo due to evaporation. This would have an economic impact since one volume was loaded but a lesser volume was received by the purchaser. The normal standard used in limiting this evaporation is the use of a Reid Vapour Test (RVP). To achieve the necessary RVP level, it is necessary to treat the condensate to reduce the volume of any entrained gas. This is normally achieved by heating the condensate and removing the necessary volume of gas.

It would certainly be possible to have a condensate treating facility that is shared by multiple users. However, sharing such a facility does not generate significant cost savings as, although there would be some economies of scale, there would typically need to be additional pipelines from the individual plants to the central condensate facility which could offset the benefit achieved.

2.3 Review of the Economic Incentives of Different Levels of Integration

2.3.1 Indicative Cost of Main Onshore Facilities

The estimates of savings for the various major categories are based on a notional total investment cost of US$ 13.5 billion for two independent, physically segregated plants. These represent typical investment costs for two plants each of two trains of 4.5 MMtpa LNG capacities (9 MMtpa per plant). This is assumed as an initial development size to evaluate the cost savings, recognising that each operator may have a somewhat different approach.

TABLE 4

FACILITIES AND SERVICES
POTENTIAL CAPEX SAVINGS FOR INTEGRATED FACILITIES

Categories	Savings on Two Integrated Plants Compared with Two Separate Plants	
	US$ Million	Percentage of Total Costs
Ancillary services	85	1%
Support infrastructure	475	4%
Essential infrastructure	1160	8%
Core processing facilities	400	3%
TOTAL	**2,120**	**16%**

Based on the preliminary stage of this study, accuracy should be taken as +40% / -30%. All costs are based on mid 2008 estimated prices.

2.3.2 Sizing of Facilities in Each Integration Case

Each category of saving as shown in **Table 4**, is made up of savings from a combination of sources which are described below, for the major areas of savings.

Ancillary Services

There are no substantial Capital items contained within the ancillary services, with most of the potential cost savings arising from reductions in Opex (**Table 5**).

Shared Infrastructure

There are significant cost savings to be realised in the Support Infrastructure by integration of the two plants into a single hub development. The optimisation of space usage for the site will reduce the cost of site infrastructure, roads and fencing. There will be no necessity for duplication of airstrips, for example, or the facilities for marine offloading and hence direct savings will be achieved equivalent to the cost associated with the provision of these items in full for one plant.

A hub facility will permit accommodation for the participating personnel to be grouped into a single entity, rather than two autonomous locations with subsequent reduction in cost through more efficient use of resources.

With a single hub development, several of the non critical buildings could be grouped together, further saving through optimisation of resources.

Essential Utilities

The main item in the essential utilities category is power generation. Two large base load LNG plants will require very large power generation facilities of approximately 125 Megawatts (MW) installed each, which if combined into a single integrated plant, could be implemented as base load combined cycle gas turbine (CCGT) power plants with a different sparing provisions. This leads to substantial cost reduction opportunities, which could possibly be enlarged even further by incorporating power supply into the regional infrastructure.

Similar arguments apply to Cooling Water (if used), Nitrogen, Air and other utilities which could all be supplied “across the fence” from larger units built with economies of scale.

Essential plant utilities such as the flare and blowdown systems, drainage and liquid waste disposal systems can all successfully be served by a single resource rather than two separate resources, providing economy of scale. There is a side issue associated with this, in that logically such integration arrangements are best suited to a single operatorship for all of the plant facilities and require accurate forecasting of gas volumes to be processed at the onshore Hub.

The LNG loading and other liquid product loading can be integrated through a single jetty. Even if full integration is not carried out (effectively through mixing of products or mixing of feed), the major costs impact of two jetties for separate developments can possibly be reduced to a single jetty serving both. This must be tempered with cautionary note since detailed studies of shipping and site will need to be carried out to confirm this assumption.

If it is assumed that the LNG and other liquid products can be stored in an integrated facility with mixing of the products, and that LNG roll over risks can be mitigated, then substantial saving is possible from optimisation of the number of LNG tanks. Typically two separate facilities may require four LNG tanks, whilst an integrated facility of the same capacity may be served by three tanks.

Thus this category of integration offers the scope for maximum cost saving, recognising that much detailed analysis needs still to be complete to fully confirm the assumptions made herein on integration.

Core Facilities

This reference is to the main process facilities, which in this example refers to four equal trains of 4.5 MMtpa LNG production capacity. There is little economy of scale possible since each train is likely to be designed and built close to the limit of LNG technology. Savings are possible in procurement charges, design and engineering and construction management if each train is of the same design. This may yield only a small saving and assumes that such similarity of design would be achieved by mixing the feedstock to the plant or otherwise setting a common design. This is a fundamental principle which must be agreed by the owners.

Greater saving would however ensue to the Opex charge in this case if a single operator were nominated.

2.3.3 Considerations on Opex saving

The overall Opex is simply and approximately estimated at an average cost approaching US$ 500 million per annum per plant for two independent plants. Two independent plants in distinct separate locations would require entirely independent operating teams for every facet of the operation, from maintenance, ship loading, plant supervision, control room, security etc.

Table 5 gives an indicative breakdown of these costs for a 9 MMtpa plant.

TABLE 5

ASSESSMENT OF OPEX AND OPEX SAVING FOR AN INTEGRATED HUB FACILITY

Categories	Average Annual Cost for Two Independent Plants US$ Millions	Savings on two integrated plants compared with two separate plants	
		US$ Million	Percentage of total costs
Operations and maintenance	600	210	35%
Transport, logistics and freight	200	60	30%
Consumables	50	0	0%
Support Services	25	5	20%
General and Administrative	25	5	20%
Insurance	100	10	10%
TOTAL	**1,000**	**290**	**29%**

This indicative breakdown shows potential for a 29% reduction in Opex resulting from integration of the two plants into a single operator hub.

2.4 Possible Industry Concerns

2.4.1 Commercial Incentives and Challenges to Integration

One of the major challenges from a commercial perspective will be the method of charging for the use of common facilities and services.

With common services, the Capex component will normally be small and the majority of the costs will be Opex. For the LNG proponents the costs will need to be attractive enough to be competitive with what it would cost them to provide the same facilities on an independent basis.

On the large shared facilities where the Capex costs will dominate and the Opex costs will be much lower, the challenge will be to develop a method of investment and cost recovery. The common facilities could be installed and financed by the LNG Hub operating company with these cost being recovered through tolling charges. Some companies may prefer the tolling charge method since this will be an Opex cost for them and may be more attractive than contributing to Capex costs. Allocation of charges will be a challenge, whether Capex or Opex, for the original LNG operators. A clear cost recovery method will also need to be defined for any subsequent LNG operator moving into the LNG Hub. To ensure the acceptance of the LNG Hub facilities sharing concept, it will be necessary to make the participation by LNG proponents commercially attractive.

There will be several technical and procedural challenges to the integration of LNG operating companies into the common facilities provided by the LNG Hub. Major LNG operators have very strict engineering standards and operating procedures specifically designed for their company. It will be a key step to have multiple operators agree to the specifications and procedures to be employed in any common facilities. It will be essential to have compatibility between the LNG Hub operator and the LNG plant operators with regard to engineering and equipment specifications. The LNG operators will also be concerned with the competency and reliability of the Hub operators, since the reliability of the LNG deliveries will depend on these factors. It will also be important for the LNG Hub operator to demonstrate that adequate spare parts and appropriate maintenance procedures are in place to ensure high equipment reliability.

Sharing common facilities will also require extensive legal negotiations to ensure all parties are satisfied with the services they will receive and the types of risk they may be exposed to. This legal process can be lengthy and incur significant costs.

The LNG Hub can be structured to be attractive to the LNG companies. This can be achieved through several potential policy and communication measures, such as:

- Pre-investing in LNG Hub infrastructure, such as port facilities for example, which reduce the LNG operator's investment requirements.
- Providing economic incentives through tax treatment.
- Demonstrating the cost savings that can be achieved by sharing specific facilities and services.
- Demonstrating the operating flexibility that can be gained by sharing facilities, such as LNG and condensate storage tanks for example.

In the State of Qatar, the Ras Laffan Industrial City is an example of a planned industrial complex which houses multiple LNG projects with many common facilities. This industrial area was conceived and developed by the national oil company of Qatar, Qatar Petroleum. At an early stage, the Ras Laffan Industrial area was selected to be developed for gas based industries. Economic incentives, in the form of tax breaks, were provided to the LNG companies, attracting them in this area. In addition, the existence of a planned industrial area with some initial infrastructure, including comprehensive port facilities, a road network and a common services company operating and administering the complete industrial complex, played a significant role in gaining the industry player's buy-in. It was also demonstrated and clearly communicated to the potential LNG companies that economies of scale existed in many areas and that the individual operators would benefit from the facilities sharing concept.

2.4.2 Possible Engagement Process between Government and Industry

The following outlines a possible approach for the Government to define its visions for Browse Basin LNG.

An initial step would be for the Government to select and further develop the LNG Hub concept outlining the possible degrees of integration, possible Hub location etc. This step would be followed by the development of a detailed implementation strategy for the selected integration cases including organizational concepts, possible options for commercial structures and capital financing plan options.

The following sequence could be considered to engage the Industry:

i. provision of a timeline for completion of the engagement process, allowing Browse Basin tenement holders to assess potential impacts on development deadlines,

ii. definition and sharing of the Government's vision for LNG developments in the Kimberley, in particular the roles of the different stakeholders involved and the expected extent of the gas processing facilities,

iii. agreement on the expected degree of integration of onshore and offshore facilities and services,

iv. selection of preferred LNG Hub onshore sites for further studies,

v. assessment of potential appropriate commercial models,

vi. identification of LNG Hub common facilities operator. This could be a Browse Basin stakeholder with proven LNG operating experience.

Successful engagement will require the Northern Development Task Force and other Government representatives as appropriate to meet individually and collectively with potential Browse Basin LNG producers and with potential Hub operators to discuss the Hub concept, the Hub location, the proposed degree of integration, the appropriate cost structure and possible commercial principles.

APPENDIX I

RFT DOIR2271107 – SCOPE OF SERVICES – Extract

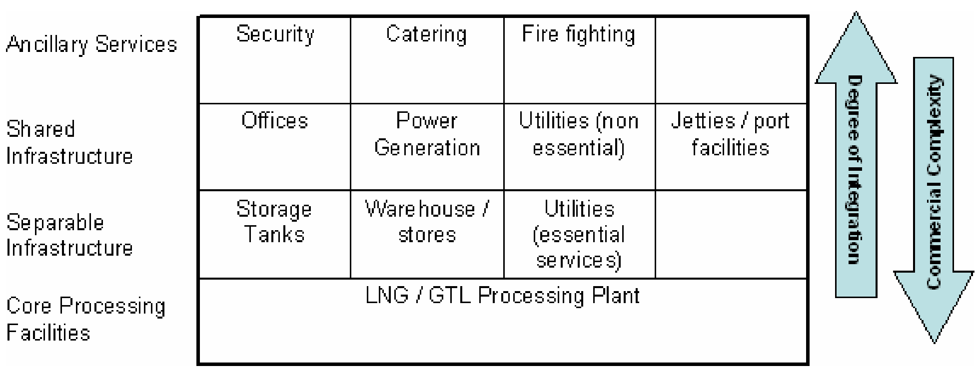
RFT DOIR2271107 – SCOPE OF SERVICES – Extract

Onshore Infrastructure Hub Development

The objective of this study is to review potential for a development based on an onshore infrastructure hub, and provide commentary on the feasibility issues from a Technical, Commercial, and Economic perspective.

A number of potential models are available for the establishment of joint infrastructure for the multi-proponent use.

- Review the appropriateness and feasibility of sharing facilities, this should include a review of the various elements of the infrastructure; and
- Provide commentary on the potential implications of varying degrees of integration of the onshore facilities.



Provide commentary on attractiveness of the hub to industry, including an estimate of the potential cost savings attributable to a joint development as opposed to multiple standalone developments.

This should include:

- Identification of potential infrastructure cost savings through use of a multi-user facility; and
- Consideration of potential cost savings attributable to likely economies of scale associated with co-location.

Provide commentary on the likely barriers to uptake of the industrial site from industry, including both current proponents, and identification of potential issues for future (prospective) companies in terms of both access to the site and future expansion.

NOTE: The scope of this study excludes a review of potential commercial models for the onshore infrastructure hub. The critical issue to be resolved in the short term is the development of an engagement process between: Government, Industry, and other interested stakeholders to identify the most suitable model.

APPENDIX II

COMMENTARY ON DOMESTIC GAS POTENTIAL

COMMENTARY ON DOMESTIC GAS POTENTIAL

Summary

For the Woodside and INPEX LNG projects as currently envisaged, the total gas reserved under the Western Australia gas reservation policy is estimated to be about 3,840 PJ. Over the 20 year life of the projects, this equates to an average domestic gas rate of 192 PJ/year.

Technically this volume of gas is sufficient to support one or more of the following:-

- Domestic gas sales via connection to the the Dampier to Bunbury Natural Gas Pipeline (DBNGP).
- Domestic gas sales to a large scale local user in the Northern Kimberley region not co-located with the LNG Hub (eg;- Minerals processing facility).
- Feedstock to GTL, Ammonia or Methanol plants co-located with the LNG Hub (i.e., the gas processing hub).

Sites that could accommodate the above options are tabulated below. Also shown is the estimated cost of a pipeline to connect each of the sites to the DBNGP (**Table I**):-

TABLE I

SUMMARY OF DOMESTIC GAS CONSIDERATIONS

	GTL, Ammonia, Methanol	Domestic Gas	DomGas to Dampier (US$MM)
Maret Islands	N	Y	2,095
Bigge Island	Y	Y	1,918
Wilson Point	Y	Y	1,799
Koolan Island	N	Y	1,633
North Head	Y	Y	1,281
Fishermans Bend	Y	Y	1,105

As can be seen from the above table, if piping of domestic gas to Dampier is a consideration in site selection, then it will have a significant influence.

Discussion

This section addresses the potential to utilize gas domestically from each of the potential hub sites under consideration.

In October 2006 the Western Australian Government announced a gas reservation policy that requires LNG project proponents to reserve gas equal to 15% of LNG production, from export projects, for domestic use. This reservation is a condition of access to Western Australian land for the process facilities. This reservation requirement was introduced to provide continued certainty that Western Australian consumers will have ongoing access to supplies of natural gas. The method by which proponents meet their obligation will be negotiated on a case by case basis and will include the option of meeting the obligation from a different source.

Table II shows the average gas production rate over a 20 year period to utilize reserved gas equal to 15% of the LNG produced, over 20 years for each of the proposed LNG projects.

TABLE II

15% GAS RESERVATION

	Woodside Project	INPEX Project	Total
Reserved gas, PJ	2,460	1,380	3,840
Average gas rate over 20 yrs, PJ/yr	123	69	192

There are three main options available for an LNG proponent to sell gas to the domestic market from its reserved volume:

1. Produce gas from a different source. This could be from a field where the LNG proponent has an interest or could be by the proponent buying gas from another field and onselling it to the domestic market.
2. Provide gas to a large gas user such as a methanol plant or gas-to-liquids plant situated in WA.
3. Provide gas to the existing WA domestic gas distribution system by connecting to the Dampier to Bunbury Gas Pipeline (DBNGP).

1 - Produce gas from different source

The governments stated policy is to allow producers maximum flexibility including consideration of providing gas from a different source. This option is not effected by the location of a gas processing hub and is not addressed in this study.

2 - Provide gas to large gas consumer located in the Kimberley or Pilbara

It would appear that if gas was sold to a large gas consumer in the Kimberley or Pilbara region, such as a methanol plant, this would satisfy the government's gas reservation policy but it is not clear that it would bring additional benefits to the state over and above those flowing from an LNG development and would not provide certainty that Western Australia gas consumers would have continued access to natural gas.

For most of the potential hub sites under review this option would alleviate the need to install a long trunk line to connect to the DBNG and the existing WA gas distribution system.

It is expected that any large gas user in the Kimberley or Pilbara region would be producing a product that can be shipped to export markets, such as methanol, diesel, beneficiated iron ore or fertilizers. Another alternative would be the production of minerals.

Approximate gas usage for large (world scale) gas projects is shown in the following **Table III**:

TABLE III

GAS USAGE RATES FOR LARGE GAS CONSUMERS (PJ/YR)

Plant type	Gas usage rate
GTL plant	140
Methanol plant	55
Ammonium plant	21
Minerals processing facilities **(1)**	40

Note:
1. Similar to Gove

A comparison of **Tables II and III** show that if the gas reservation for the INPEX project was 15% then it could potentially supply large minerals processing facilities.

Either project could supply a world scale methanol plant or several world scale ammonia plants. It appears that a GTL plant is the only large gas user likely to utilize 15% of the gas reserved for domestic consumption from both projects over a reasonable time period.

It is not necessary for a large domestic gas user to be located at the same location as gas liquefaction facilities, for example Burrup Fertilizers ammonia plant is located on the Burrup Peninsula rather than on Varanus Island where the gas is processed. However, the cost of supplying gas will be less, if the user is located close to the gas source, that is at a hub.

3 - Connection to the DBNGP

If gas reserved for domestic sales is produced to the DBNGP it can then be made available to any existing gas user in WA and is likely to be the best option for providing continued access for Western Australian consumers to natural gas.

In considering this option GCA has considered that facilities are sized to deliver the reserved gas over a period of 20 years, when the volume of reserved gas is equal to 15% of the LNG exported. This is at a rate of 192 PJ/yr as shown in **Table II**. This compares with WA's current gas demand of approximately 330 PJ/yr. It should be noted that because it is expected that the gas throughput will build with time the reserved gas will not be produced in 20 years.

For smaller rates a gas line from the Kimberley area could connect to the Burrup to Pt. Hedland pipeline at Pt Hedland. However the capacity of this line is limited to about 65 PJ/yr so for 192 PJ/yr a new line to the Burrup Peninsula is required.

Pipeline costs were estimated for a gas transmission line from five potential hub sites to the Burrup Peninsula. The cost of transporting gas from each of the hub sites to the Burrup Peninsula was then estimated. These hub sites cover the range of suitable sites and allow the transportation cost from any of the suitable sites to be estimated. The sites considered ranged from Maret Islands in the North to Fishermans Bend in the South.

Pipeline Costs

Pipeline lengths and the estimated approximate cost of pipelines from the potential hub sites under consideration are shown in the following table. The costs include costs for offshore sections where necessary and also compression stations.

TABLE IV

DOMGAS PIPELINES SUMMARY

Potential sites	Length (kms)	Cost (US$MM)
Maret Islands	1,313	2,095
Bigge Island	1,279	1,918
Wilson Point	1,200	1,799
Koolan Island	1051	1,633
North Head	860	1,281
Fishermans Bend	730	1,105

Transportation costs

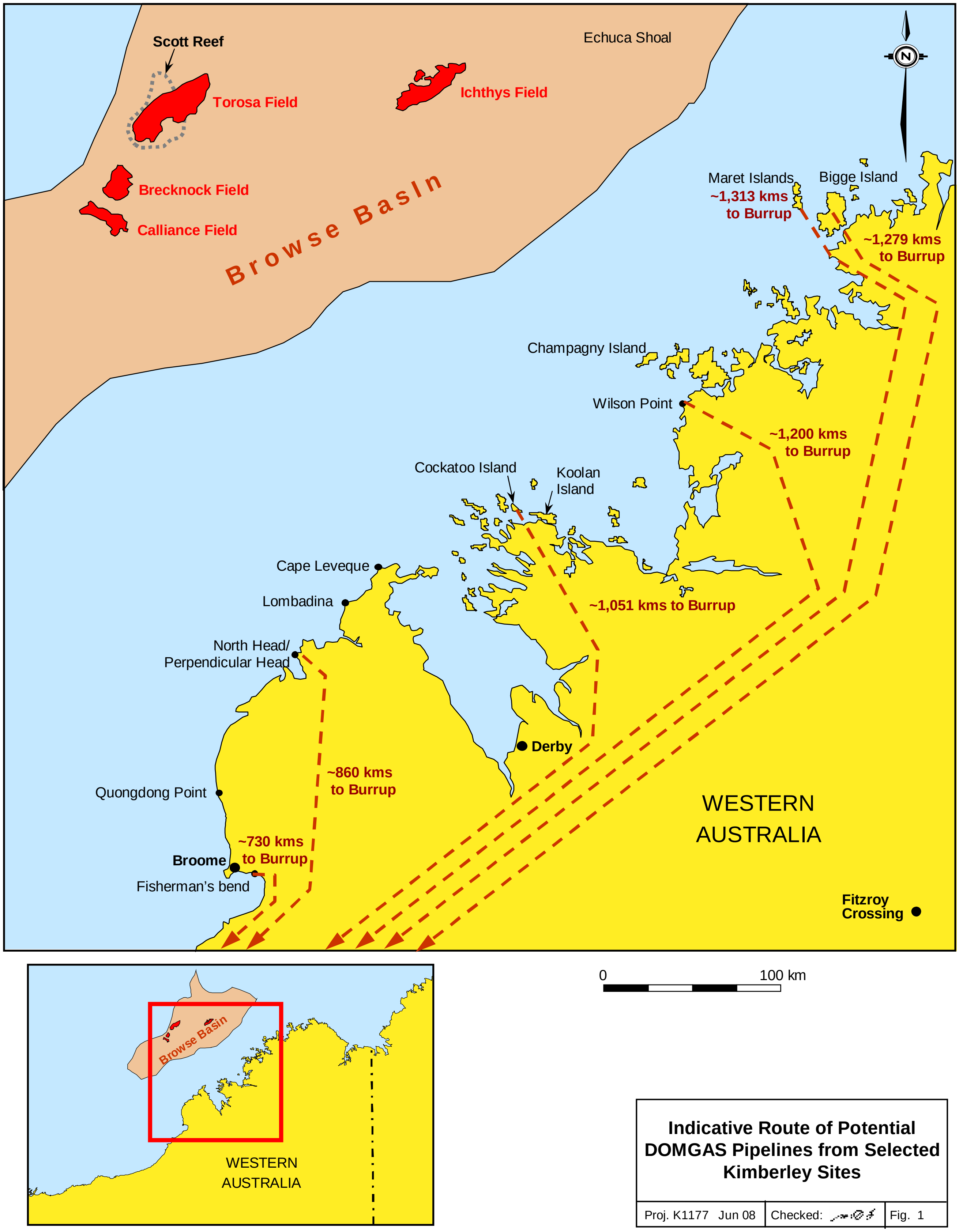
The cost of transporting gas to the domestic market from the hub sites to the DBNGP at the Burrup Peninsula was estimated by providing for a 10% nominal after tax return on the pipeline over a 20 year period. The estimated transportation charge was based on the initial pipeline throughput being about 100 TJ/d and building at 9% p.a. transportation costs are shown in the following table.

TABLE V

DOMESTIC GAS TRANSPORTATION COSTS ($/GJ)

Potential sites	Costs ($/GJ)
Maret Islands	3.00 – 4.00
Wilson Point	2.50 – 3.50
Koolan Island	2.30 – 3.30
North Head	1.70 – 2.70
Fisherman's Bend	1.50 – 2.50

The costs shown in **Table V** above, compare with zero transportation cost for gas from a LNG Hub on the Burrup Peninsula.



Indicative Route of Potential DOMGAS Pipelines from Selected Kimberley Sites

Proj. K1177 Jun 08 | Checked: | Fig. 1

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APPENDIX III

GLOSSARY

GLOSSARY

Btu	British thermal units
Capex	Capital expenditure
CCGT	Combined cycle gas turbine
CCTV	Closed circuit television
CO_2	Carbon dioxide
DBNGP	Dampier to Bunbury Gas Pipeline
DoIR	Department of Industry and Resources
DomGas	Domestic Gas
GCA	Gaffney, Cline & Associates
GJ	Gigajoule (PJ = 10^9 J)
GTL	Gas to liquids
HSE	Health, Safety and Environment
JV	Joint Venture
km(s)	Kilometre(s)
LNG	Liquefied Natural Gas
MMtpa	Million tons per annum
MW	Megawatts
Opex	Operating expenditure
p.a.	Per annum
PJ	Petajoule (PJ = 10^{15} J)
PJ/yr	Petajoule per year
RVP	Reid Vapour Test
$/GJ	Dollars per gigajoule
Tcf	Trillion cubic feet
TJ	Terajoule (PJ = 10^{12} J)
TJ/d	Terajoules per day
US$MM	Million US dollars
WA	Western Australia