By Courier

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Mr John Feil
Executive Director
National Competition Council
Level 12 Casselden Place
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Dear Mr Feil

Application for Revocation of Pipeline Coverage under the National Third Party Access Code for Natural Gas Pipeline Systems – Tubridgi Pipeline (PL16) and Griffin Pipeline (PL19)

We refer to our discussions on this matter and wish to submit an application for revocation of coverage by BHP Petroleum (Ashmore Operations) Pty Ltd ("BHPPAO") under the National Third Party Access Code for Natural Gas Pipeline Systems (the "Code"). Pursuant to sections 1.24 and 1.25 of the Code BHPPAO seeks revocation for the Tubridgi Pipeline (PL 16) and the Griffin Pipeline (PL 19). This submission deals with applications for revocation of two pipelines. The information contained in the submission is applicable to both applications.

The Tubridgi Pipeline System is listed in Schedule A of the Code as follows:

Pipeline Licence	**Location / Route**	**Operator**	**Length (km)**	**Pipeline Diameter (mm)**	**Regulator**
WA:PL16	Tubridgi to DBNGP Compressor Station No 2	BHP Petroleum (Ashmore Operations) Pty Ltd	87.5	168	A WA Independent Regulator
WA:PL19	Tubridgi to DBNGP Compressor Station No 2	BHP Petroleum (Ashmore Operations) Pty Ltd	87	273	A WA Independent Regulator

BHPPAO is required to submit a revised access arrangement for both pipelines by 19 January 2006. BHPPAO will seek an extension from the Economic Regulation Authority ("ERA") for submission of the revised access arrangement pending the outcome of this revocation application.

The Code provides that the Relevant Minister will make a decision on revocation of coverage based on the NCC's recommendation. We understand the Relevant Minister under the Gas Pipelines Access Act 1998 (WA) that will make the Revocation decision is the Hon Alan Carpenter, Minister for State Development; Energy.

Service Provided by PL16 and PL19

The Services that can be provided by PL16 and PL 19 are a:

- forward haul service;
- back haul service.

History of Tubridgi Pipeline System

The Tubridgi Pipeline and the Griffin Pipeline are located on the flood plain of the Ashburton River, 25km south of Onslow in Western Australia. Both pipelines are 87 km in length and run parallel from the Tubridgi gas processing facility to Compressor Station 2 ("CS2") on the Dampier to Bunbury Natural Gas Pipeline ("DBNGP").

The Tubridgi Pipeline was initially used by the Tubridgi Joint Venture ("TJV") to transport gas from the Tubridgi Gas field to Alinta Gas under a dedicated contract. Deliveries of Tubridgi Gas to Alinta Gas were limited to a maximum of 23TJ/d due to the high inert content of Tubridgi Gas. The TJV had an exemption from the DBNGP Operator that enabled TJV to deliver Tubridgi Gas into the DBNGP until the end of 2001; effectively a blending arrangement. BHPPAO understands that this blending arrangement had physical controls such that Tubridgi Gas could only enter the DBNGP when blending was possible.

The Griffin Pipeline was constructed pursuant to a contractual arrangement between the Griffin Joint Venture ("GJV") and the TJV. The arrangement included the sale and purchase of associated gas produced together with crude oil from the offshore Griffin Oil Field ("Griffin Gas") and its transmission to the DBNGP via a newly constructed offshore pipeline and gas plant. Griffin Gas is produced via a dis-connectable Floating Production and Storage Offloading facility ("FPSO"). The FPSO dis-connects when a cyclone approaches or when the facility requires dry docking for inspection or maintenance. Only a select few customers with a large portfolio of gas supply arrangements can purchase associated gas due to its non firm nature.

Griffin Gas is associated gas and the volume of gas produced is subject to oil production and disconnections of the FPSO. Griffin Gas (being high inert gas) requires processing to meet the DBNGP specification. In February 2001 the GJV entered into arrangements with various third parties which enabled the GJV to shut down and bypass most of the processing skids at the Griffin Gas Plant and turn the Griffin Gas Plant into a not normally manned custody transfer gas metering facility only. The affect of this is that Griffin Gas which passes down the Griffin Pipeline does not conform to the DBNGP specification having regard to maximum carbon dioxide, total Inerts, minimum and maximum HHV, and minimum and maximum Wobbe Index. Griffin Gas can enter the DBNGP via a blending agreement between the GJV and the DBNGP operator. The blending agreement enables the smaller volume of Griffin Gas to be blended into the larger volume of gas entering CS2 which is slightly within the DBNGP specification. As the gas entering CS2 approaches the maximum allowable DBNGP gas specification, that blending envelope is reduced. Accordingly Griffin Gas is subject to further interruption depending upon the availability of a blending envelope. The risk that some or all Griffin Gas may be denied entry into the DBNGP due to a reduced blending envelope, has been offset via the provision of injection facilities for the short term disposal of the gas into the Griffin Field.

Consequent upon the changes being made by the GJV to the Griffin Gas Plant, the TJV negotiated an arrangement to change the delivery point for the supply of Tubridgi Gas to Alinta. The TJV commenced supplying Tubridgi Gas down the Griffin Pipeline to Alinta. As the Tubridgi Pipeline was no longer being used, the TJV mothballed the pipeline. The Tubridgi Pipeline has not been used for gas transportation since that date.

In October 2004 the Tubridgi Gas Field ceased producing gas for on-sale although a very small quantity continued to 28 August 2005 for fuel for the site power generation and then that was also discontinued. The Tubridgi facility ceased all production from that date. Until October 2004 the TJV were supplying Tubridgi Gas to Western Power to fuel their power plant at Onslow, via a 2" spur line that connected to the Griffin Pipeline. The volume of gas supply to Western Power is approximately 0.3TJ/d. To allow the continuation of a gas supply to Western Power, the TJV negotiated with Alcoa (the purchaser of Griffin Gas at the entry of the Griffin Pipeline to DBNGP) to carve out a volume of gas from their long term contract to enable a gas supply to Western Power. That arrangement was agreed in October 2004 and Western Power has been supplied with Griffin Gas since that date.

Potential Users of the Tubridgi Pipeline and Griffin Pipeline

Associated Griffin Gas

BHPPAO will continue to transport Griffin Gas along the Griffin Pipeline for the term of the next scheduled access period pursuant to long term contractual arrangements between GJV and BHPPAO that were entered into before the Code was enacted. The GJV has priority to capacity in PL19 for ~ 50 TJ/d for Griffin Gas.

Associated Gas in the Exmouth Sub-basin

There are a number of oil fields in the Exmouth sub-basin which are in the process of being developed or are awaiting investment decisions. All of these fields contain associated gas. They include the Enfield oil field, the Stybarrow oil field, the Pyrenees oil field and the Vincent oil field. BHP Billiton Petroleum ("BHPBP") recently undertook a study to determine whether it would be economic to install gas collection and transportation infrastructure for transporting the associated gas to shore for storage or sale. The value drivers were the potential for increased oil recovery, possible gas sales together with there being available gas infrastructure for tying in other gas fields or oil fields containing associated gas. BHPBP arranged a facilitated work shop with each of the upstream joint venture partners to determine whether there was sufficient value for each company to pursue the project given that the project would require agreement and co-ordination from and between each joint venture. The conclusion of the group was that there was not sufficient value in exporting associated gas from these oil fields, at this time, and accordingly BHPBP terminated the project. The base case development plan for each oil project is for associated gas to be injected back into their respective reservoirs with no gas being exported to shore.

Macedon Gas

The Macedon Gas Field is situated in the Exmouth sub-basin and is held in joint venture by BHP Billiton Petroleum (Australia) Pty Ltd (71.43%) and Apache Northwest Pty Ltd (28.57%). The field contains dry gas which does not meet the current DBNGP specification. In the event that the ERA widens the DBNGP gas specification to the specification contained in its draft decision, Macedon Gas will still not meet the minimum Heating Value requirement and will just meet the minimum Wobbe Index requirement. The minimum Heating Value would need to be widened further to enable Macedon Gas to be commercialised. The most likely market for Macedon Gas is a firm supply into the South West market. At present BHPBP does not know if a firm market of sufficient size can be developed. As the Macedon Gas Field is marginal, cash flow and hence gas production needs to be maximised (in the order of 150TJ/d once production had been ramped up). The capacity of the Tubridgi Pipeline and the Griffin Pipeline, when combined, is 110TJ/d. Accordingly the Griffin Pipeline and the Tubridgi Pipeline do not have sufficient capacity to enable Macedon Gas to be transported to market. The Griffin Pipeline would need to be looped for its entire length to cater for Macedon Gas production[1]. The capital cost of the looping will be borne by the Macedon Project and included in that project's economics. Given the very large economies of scale in pipeline capacity increments, it would by definition in the case of Macedon be economic to duplicate the infrastructure.

Associated Thevenard Gas

BHPBP is not aware of any future intention of the Thevenard Joint Venture ("THJV") to export gas from the Thevenard Project.

Revocation of Coverage

Coverage may be revoked if the Relevant Minister is not satisfied of one or more of the following matters set out in section 1.9 of the Code:

(a) that access (or increased access) to Services provided by means of the Pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the Services provided by means of the Pipeline;

(b) that it would be uneconomic for anyone to develop another Pipeline to provide the Services provided by means of the Pipeline;

(c) that access (or increased access) too the Services provided by means of the Pipeline can be provided without undue risk to human health or safety; and

(d) that access (or increased access) to the Services provided by means of the Pipeline would not be contrary to public interest.

The reasons for BHPPAO application for revocation are detailed below.

(a) Access (or increased access) to Services provided by means of the Pipeline would not promote competition in at least one market;

Pursuant to section 1.9(a) of the Code, coverage should only apply to pipelines if access (or increased access) to services provided by means of the pipeline would promote competition in at least one market.

[1] Note compression is not an option to lift capacity of the lines to 150 TJ/d due to maximum operating pressure constraints.

There are a number of reasons for access or increased access to the Pipelines not promoting competition in at least one market.

- We have set out above the possible sources of demand for access being the various oil and gas fields in the Exmouth Sub basin. Other than the Macedon Gas Field all the other oil fields will be injecting their associated gas into their respective reservoirs. No associated gas from known oil fields will be exported to shore for delivery into the Pipelines from these projects. There are no other known accumulations of gas in the area, other than Macedon Gas, which would be dedicated to domestic gas supply.

  Griffin Gas has access to the Griffin Pipeline under a long term contractual arrangement which will protect the GJV's access position for the period of the Griffin field life.

  The Macedon Gas field is the most significant sized gas field in the Exmouth Sub basin. BHPB, having the controlling interest in the Macedon Gas field, has been marketing Macedon Gas actively for a number of years. The commercialisation of Macedon will not be prevented due to lack of access to transportation capacity in Griffin Pipeline or the Tubridgi Pipeline but instead the inability to secure an economic gas market for Macedon Gas or Macedon Gas not meeting the specification for transportation in the DBNGP. Furthermore, as indicated above, the capacity of the Griffin Pipeline and the Tubridgi Pipeline will not be sufficient to transport the volume of Macedon Gas that will be required to be produced to make the Macedon Project economic. The Griffin Pipeline will need to be looped for its entire length for this purpose. The capex for the looping will be included in the project capex and be reflected in the Macedon economics. Accordingly it will be economic to duplicate the Griffin Pipeline in the event that Macedon is commercialised.

- BHPBP is not aware of a significant gas field in the Exmouth Sub-basin which has gas that meets either the current or proposed widened DBNGP specification. Accordingly gas entering the Pipelines will be off-specification gas that requires a blending envelope to enter the DBNGP. Furthermore any gas that enters the Griffin Pipeline and the Tubridgi Pipeline, other than Macedon Gas which will be separately provided for, will most likely be associated gas from off shore oil fields and be commingled with the existing associated Griffin Gas so that the entire gas stream, as with Griffin Gas, will not meet the existing (nor the proposed widened) DBNGP specification. Associated gas is low value gas due to its interruptible nature. The fact that it does not meet the DBNGP specification makes the gas of even less value as its supply is a function not only of oil production but the available blending envelope in the DBNGP. As mentioned already only a select few large gas customers with a diverse portfolio of gas supply contracts can accommodate associated gas in their portfolio and even then it is problematic for those customers. Accordingly the competition impact on downstream markets from produced associate gas via the Griffin Pipeline and the Tubridgi Pipeline is non existent as it is a non preferred gas supply for customers. Historically the volume of gas transported via these pipelines has been very small (currently 18-20TJ/d via the Griffin Pipeline) compared to the volume of gas that passes through CS2 (620TJ/d) which again dilutes its impact on competition in downstream markets. It is precisely this point that enables the associated non specification gas to enter the market given that any greater volumes would cause the blending envelope in the DBNGP to disappear. Accordingly there is a pre-determined limit, via a volume restriction, which prevents this gas, in the event that volumes do increase, from having any competitive impact on downstream markets.

- The Onslow power market is being supplied with Griffin Gas for its fuel needs under a long term contract. The gas volume required for Onslow is very small. In circumstances where the Griffin Venture is disconnected (for instance when a cyclone is approaching) there is sufficient line pack in the Griffin Pipeline and the Tubridgi Pipeline for the continuation of gas supply to the Onslow power station for a period of 10 days. The volume of gas is so small that the Onslow power market could not be regarded as a contestable market for a new entrant. The cost of providing the gas would not justify the benefit to be obtained. Pricing would generally be on a fuel replacement basis.

(b) *It would be uneconomic for anyone to develop another pipeline to provide the Services provided by means of the Pipelines;*

Pursuant to 1.9(b) of the Code, pipelines are to be covered if it is uneconomic to construct another pipeline which would provide the same service.

- The only significant gas resource offshore in the area that would be dedicated to the domestic gas market and therefore use the Griffin Pipeline and the Tubridgi Pipeline is the Macedon Gas Field. The Macedon Gas Field is marginal and as indicated above would need to produce in the order of 150TJ/d, once gas production is ramped up, to make the project economic. As a consequence, if a market is found for Macedon Gas and the DBNGP specification is sufficiently wide to enable entry into the DBNGP on a firm basis and accordingly the Macedon Project proceeds it will be economic to construct another pipeline as the Tubridgi Pipeline and the Griffin Pipeline have insufficient capacity for the Macedon Gas volume. The Capex for that pipeline will be included in the Macedon Project Capex and be reflected in the economics.
- Any subsequent gas fields that are discovered in the area that are of a similar size and specification would need to duplicate the Pipelines to achieve a similar economic return. Gas fields that are smaller than Macedon are by their nature uneconomic without existing offshore infrastructure being in place to facilitate their tie-in. We have already discussed above the situation concerning associated gas from existing oil fields in the area and the work done to establish that it is uneconomic to export gas to shore. Much larger gas fields chase LNG projects and markets and domestic gas commitments imposed by Government, if economic, would usually be larger in size than Macedon Gas volumes therefore requiring dedicated pipelines.

(c) *That access (or increased access) too the Services provided by means of the Pipeline can only be provided with increased risk to human health or safety;*

BHPBP is not aware of any increased risks to human health or safety that would arise as a consequence by providing access or increased access to the Pipelines.

(d). *Access (or increased access) to the Services provided by means of the Pipeline would be contrary to public policy.*

Pursuant to section 1.9(b) of the Code, coverage may be revoked if access (or increased access) to the Pipeline would be contrary to public policy.

BHPPAO has demonstrated above that there is no apparent demand for the Pipelines other than from Griffin Gas which is separately provided for by way of long term arrangements. Furthermore due to the composition of the existing gas and the fact that any gas that is likely to access the Pipelines in the future will be associated non specification gas there would be no impact upon competition in either the South West market or the Onslow market. Macedon Gas would be an exception to this category of users but a duplication of the Griffin Pipeline would be required to enable the Macedon Gas Field to be commercialised. Given the time and resources that are involved in submitting an access arrangement, BHPPAO believes that any potential benefits of access would be far out weighed by the associated cost and therefore the public interest would be best served by revoking coverage of the Griffin Pipeline and the Tubridgi Pipeline.

BHPPAO also maintains that submission of an access arrangement would impose unnecessary regulatory and compliance cost on the State, The Regulator and BHPPAO and will have no material effect on access given the information set out above.

BHP Petroleum's Submission Opposing Revocation - 10 June 1999

BHPBP made a submission to the NCC on 10 June 1999 (the "Submission") opposing the revocation application made by the TJV. The arguments made by BHPBP fell into the following categories:

1. Significant potential for PL16 and PL19 to be used by third parties – PL16 could be used quite separately from the service provided by PL19 i.e. used for gas commingling, back haul or reversible flows from DBNGP or GGT to utilize depleted Tubridgi Gas field storage.
2. PL16 could be used with a wider specification than PL19 to supply off specification gas into DBNGP or GGT.
3. The above uses would promote competition for upstream suppliers into the GGT and DBNGP and to serve nearby local needs for gas such as Western Power and other industrial users.
4. It is not economic to duplicate PL16 given that there was a concern that there was not sufficient capacity in PL16 to cater for the needs of both the Tubridgi Project and the Griffin Project particularly given that PL16 had a wider gas specification.
5. Third party access would enable actual or future gas supplies in the area (e.g. the Macedon Gas Field) to enter the market competitively.
6. It is relevant that third parties are currently seeking access i.e. PL19 was then carrying third party gas from CMS and that TJV had received an access request from Western Power.

It is certainly the case that circumstances have changed since the date of the Submission. Below is BHPBP's current view to each of the points set out in the Submission.

<u>Point 1</u>

It is now the case that:

- since February 2001 when the Griffin Gas Plant was shut down Griffin Gas entering PL19 does not meet the DBNGP specification and Griffin Gas can only enter the DBNGP via a blending envelope that currently exists;
- due to a lack of demand for gas transportation PL16 has been mothballed;

- the Tubridgi field is depleted and shut in;
- a number of joint ventures with oil projects in the Exmouth Sub basin have made decisions to inject associated gas into existing reservoirs rather than exporting the associated gas to shore.

The only gas that is entering the Tubridgi hub is non specification gas and that is likely to be the situation into the future. Accordingly there is no reason to distinguish between the provision of different services based on gas specification.

BHPBP also made mention of the potential to use the depleted Tubridgi gas reservoir for gas storage. In fact the GJV has been interested in obtaining access to the TJV reservoir for the purposes of gas disposal, in the event that the blending envelope in the DBNGP was reduced or disappeared, in order to avoid a cut back in oil production. Our understanding of the Tubridgi reservoir has increased significantly since the Submission. BHPBP wishes to distinguish between "gas disposal" and "gas storage" as it relates to the Tubridgi reservoir. The reservoir can certainly be used for gas disposal i.e. injection without intention of recovering the gas at a latter date. However its suitability as a gas storage reservoir is much less certain. The Tubridgi reservoir is situated 86 km from the DBNGP. The reservoir is supported and pressurised by an aquifer and is highly stratified (comprising the Mardie, Birdrong, Flacourt and Mungaroo formations) with complicated geology and a significant amount of internal faulting. The net result of these features is that:

- there is no certainty that a party will get the same amount of gas out of the reservoir as it injects into the reservoir due to the uncertain behaviour of the aquifer depending upon which horizon you are withdrawing the gas from.
- the reservoir would require a very large amount of pad gas to be injected to enable the reservoir to operate as a storage reservoir;
- the cost of transporting gas 86km, injecting the gas into a reservoir and having the risk that you will not be able to extract the same injected volume and then transporting the gas back another 86km to the DBNGP would in our view make such an exercise uneconomic to undertake.

<u>Point 2</u>

The change in circumstances relating to this point is included under Point 1.

<u>Point 3</u>

BHPBP does not now consider this to be the case given the quality of the gas in PL 16 and 19, the distance of the Tubridgi reservoir from the DBNGP and the potential difficulties in extracting gas from the Tubridgi reservoir. BHPB has dealt with the only local gas load being the Western Power load at Onslow above and indicated the difficulties in that load being contestable.

<u>Point 4</u>

BHPBP's point in the Submission concerned PL16 and PL 19 with the then current flow of gas. As predicted in the Submission the TJV did in fact shut down and mothball PL16. The Submission, on this point, did not contemplate a much larger volume of gas from Macedon flowing down the pipeline requiring PL19 to be looped.

Point 5

BHPBP has provided an explanation of the actual and future gas reserves in the area and indicated the future plans for those reserves being injection into existing oil reservoirs and the commercialisation of Macedon in the manner suggested above. The strategy concerning these gas reserves has only been developed in the last few years.

Point 6

BHPBP is aware that Western Power approached TJV for a back haul service from the DBNGP when Western Power was looking for alternatives for gas supply to the Onslow power station following the shut-in of the Tubridgi reservoir. Western Power did not proceed with the application following the substitution of Griffin Gas into the Western Power contract. BHPBP is not aware of any other application for access being made for PL 16 or PL 19 throughout the period.

Draft Decision on the Proposed Revised Access Arrangement for the DBNGP

On 8 June 2005 the Economic Regulation Authority posted the revised access arrangement for the DNBGP (the "AA"). The regulator has sort to include a broader gas specification in the AA. Below is a comparison of the specification for Macedon Gas with the AA Broadened Gas Quality Specification.

	Macedon	AA Broadened Gas Quality Specification
Gas Component (Mole%)		
Nitrogen	5.34	n.a.
Carbon Dioxide	0.38	4.0
Methane	93.85	
Ethane	0.41	
Propane	0.01	
Octanes plus	0.01	
Heating Value	35.68MJ/m3	37.0 (min)
Wobbe Index	46.77 MJ/m3	46.5 (min) to 51.0 (max)
LPG Content	0.012 Tonnes/TJ	n.a.
Total Inert Gases Content	5.72%	7.0

The above indicates that while Macedon Gas fits comfortable within the Total Inerts requirement it will not meet the minium Heating Value requirement and accordingly Macedon Gas would require a blending agreement to enter the DBNGP. This will cause Macedon Gas to be classified as interruptible gas and valued as such.

Griffin Gas will not meet the wider specification and will always be subject to entry into the DBNGP via a blending agreement.

BHPBP is not aware of any other gas sources that would require the use of PL16 and PL19.

Contact Details for Third Parties

The contact details for the third parties that are referred to in this application are as follows:

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The company contact in relation to the Pipelines in question is:
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Enclosed is a cheque for the amount of $15,000, comprising the fee for two applications.

Please contact me if you have any queries.

Yours sincerely,

MRJ Macdermid

Mike Macdermid
Commercial Manager