Independent Technical Specialists Report on the Petroleum Properties of SGEH Limited

July 2018

decisions with confidence

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1. Executive Summary

The Directors
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311-313 Hay Street, Subiaco,
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Level 17, 303 Kent Street
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9 July 2018

Dear Directors and Independent Expert,

Independent Technical Specialist's Report on the Petroleum Assets of SGEH Limited

Grant Thornton Corporate Finance ("Grant Thornton") has been appointed by the Directors of Sino Gas and Energy Holdings Limited ("SGEH") as the Independent Expert in relation to the proposed Lone Star takeover (the "Proposed Transaction").

To assist Grant Thornton in preparing its Independent Expert Report in relation to the Proposed Transaction, Grant Thornton has provided instructions to RISC Advisory Pty Ltd ("RISC") to prepare this document, an Independent Technical Specialist's Report in relation to the petroleum assets of SGEH.

The Technical Report documents our review of the petroleum reserves, resources and associated Overall Development Plan (ODP), development schedules, production data, production and cost forecasts. We prepared scenarios for valuation of the properties by Grant Thornton.

The Linxing and Sanjiaobei PSCs in the Ordos Basin, onshore China are SGEH's only petroleum resource properties. Deep gas resources provide the key value. Pilot production commenced late 2014 and built up to 25 MMscf/d in 2018. Over 100 wells have been drilled to appraise and develop the low permeability gas resources. The initial phase of the ODP for Linxing has been approved and the ODP for Sanjiaobei is expecting approval in 2018. Production will then be ramped-up to an estimated plateau gas rate of 450 MMscf/d from 2024.

SGEH also have contingent resources in a shallow CBM discovery in the north east of Linxing PSC. However, these resources are significantly smaller and their development is estimated to be uneconomic.

In April 2017, SGEH acquired an option to purchase an additional 7.5% contractor interest in Linxing PSC by paying 7.5% of past costs. SGEH does not hold these additional resources as the post ODP approval option has not yet been exercised.

Reserves, contingent and prospective resources

The estimated reserves, contingent resources and prospective resources to SGEH as at 31 March 2018 are shown in Table 1-1, Table 1-2 and Table 1-3 respectively. Reserves and resources have been evaluated in accordance with PRMS Guidelines.

Table 1-1: Deep Gas Reserves net to SGEH as at 30/06/2018

Reserves (Bcf)	1P	2P	3P
Linxing	114	168	227
Sanjiaobei	62	88	119
Total	176	256	346

Table 1-2: Deep Gas Contingent Resources net to SGEH as at 30/06/2018 (unrisked)

Contingent Resources (Bcf)	1C	2C	3C
Produced during PSC period	72	108	150
Produced Post PSC Expiry	192	319	463
Infill or re-completion	210	328	460
Total	**474**	**755**	**1073**

Table 1-3: Deep Gas Prospective Resources net to SGEH as at 30/06/2018 (unrisked)

Prospective Resources (Bcf)	Low	Best	High
Linxing	10	15	22
Sanjiaobei	247	360	483
Total	**256**	**376**	**505**

Notes to tables:

1. A combination of probabilistic and deterministic methods have been used.
2. Reserve totals and contingent resource totals have been aggregated arithmetically.
3. The reference point for reserves determination is the custody transfer point for the products. Reserves are stated as sales quantities net of fuel and flare.
4. All of the above reserves and contingent resources are considered unconventional (tight gas).
5. The contingent resources have not been risked to reflect the chance of development.
6. The prospective resources have not been risked to reflect the chance of discovery or development.
7. Contingent and prospective resources estimates include production after PSC expiry.

RISC has prepared sales gas and development cost forecasts associated with the 1P, 2P reserves and 2C contingent resources as shown in Figure 1-1.

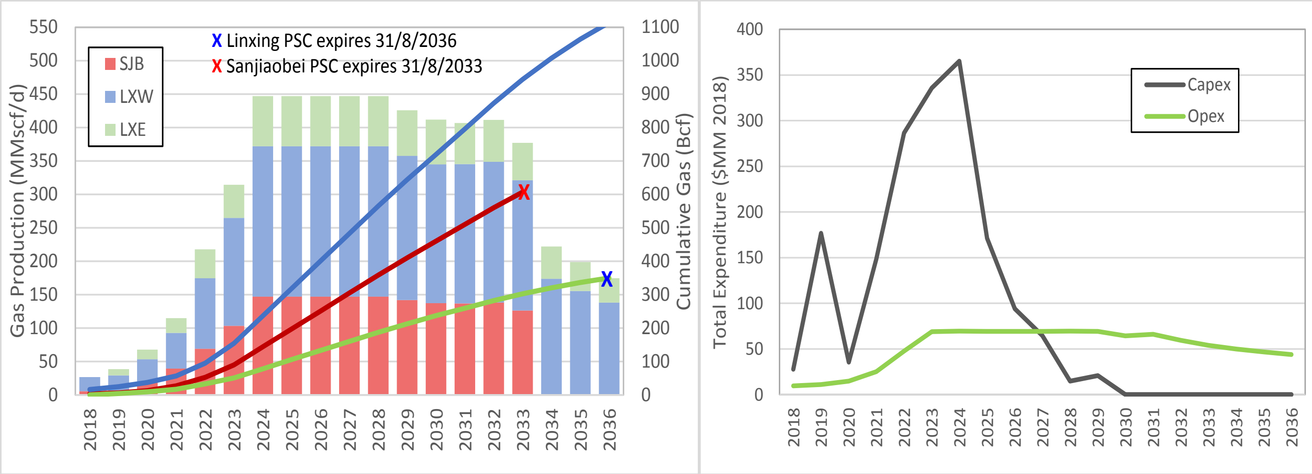

Figure 1-1: Gross 2P plus 2C gas sales and cost forecast

Reserves are limited to production prior to PSC expiry. Contingent resources include production post PSC expiry, although these resources are contingent upon PSC extension which carries uncertainty.

SGEH reserve estimates have reduced more than 50% since the previous assessment due to the 11th amendment to the Linxing PSC, new information regarding well performance, well completion intervals and the pace of development has become available:

- Development plans prepared based on available technical data and ODP submissions indicate that the completion interval of development wells will be less extensive than previously estimated, and new analogue data from Ordos basin gas fields is supporting a lower gas recovery per well. There is potential scope for future re-completion of wells or infill drilling to develop undeveloped gas but such plans are not firm and economics must be evaluated. Therefore this potential additional resource is classified as a contingent resource.
- The current ODP and development plans indicate the start of plateau production to be in 2023/2024, 3 years later than estimated in previous assessments. Gas rates prior to plateau are also reduced. This moves a larger proportion of production to post PSC expiry and contingent resources.

Table 1-4 shows SGEH contingent resources in the shallow CBM discovery in the north east of Linxing PSC. Development of these resource is estimated to be marginal economically so they are not included in valuation scenarios.

Table 1-4: Shallow CBM Contingent Resources net to SGEH as at 30/06/2018 (unrisked)

Shallow CBM (SGEH net)	1C	2C	3C
Contingent Resources (Bcf)	20	51	80

Resources associated with the option to acquire an additional 7.5% contractor share in Linxing PSC are shown in Table 1-5, and included in the valuation.

Table 1-5: Resources associated with additional 7% contractor share option in Linxing PSC as at 30/06/2018 (unrisked)

Net gas resources (Bcf)	Low (1P/1C)	Mid (2P/2C)	High (3P/3C)
Deep gas reserves (1P/2P/3P)	19	28	38
Deep gas contingent resources (1C/2C/3C)	51	81	115
Deep gas prospective resources	2	3	4
Shallow CBM contingent resources (1C/2C/3C)	2	6	9

2. Introduction

2.1. Terms of reference and basis of assessment

2.1.1. Terms of reference

This assignment has been conducted under the terms of our engagement with SGEH dated 8 June 2018 and under the direction of Independent Expert, Grant Thornton through RISC's engagement with Grant Thornton dated 7 June 2018. RISC's terms of reference are:

- A review of the technical assumptions underlying the future cash flows of the producing assets including resource and reserve estimation, production volumes, operating expenses, capital costs and other environmental and infrastructure considerations. RISC will advise Grant Thornton Corporate Finance on the reasonableness of these assumptions for valuation purpose and prepare various sensitivity/scenario cases;
- Assessment of prospective resources (exploration potential);
- Preparation of the Technical Report for inclusion in the Independent Expert's Report. The Technical Specialist's Report is to be addressed to Grant Thornton and the Board of Directors of SGEH.

2.1.2. Basis of assessment

The data and information used in the preparation of this report were provided by SGEH supplemented by public domain information. RISC has relied upon the information provided and has undertaken the evaluation on the basis of an update to previous Independent Reserve and Resource Assessments conducted by RISC for SGE.

Our assessment for the producing assets is based on production data up to 14 June 2018 and where necessary, has been truncated to 31 March 2018 for reserves reporting purposes.

RISC has reviewed the reserves/resources in accordance with the Society of Petroleum Engineers' internationally recognised Petroleum Resources Management System (PRMS)[1].

Unless otherwise stated, all resources presented in this report are gross (100%) quantities with an effective date of 31 March 2018. Unless otherwise stated, all costs are in US$ real terms with a reference date of 1 January 2018 (RT2018).

[1] SPE/WPC/AAPG/SPEE 2007 Petroleum Resources Management System

3. Geological overview and Data Summary

3.1. Regional Geology

The Linxing and Sanjiaobei PSCs lie on the eastern edge of the Ordos Basin. The basin is the second largest petroleum-bearing basin in China with a reported total discovered P50 oil initially in-place of 8 billion barrels and a discovered P50 GIIP of 50 Tcf.

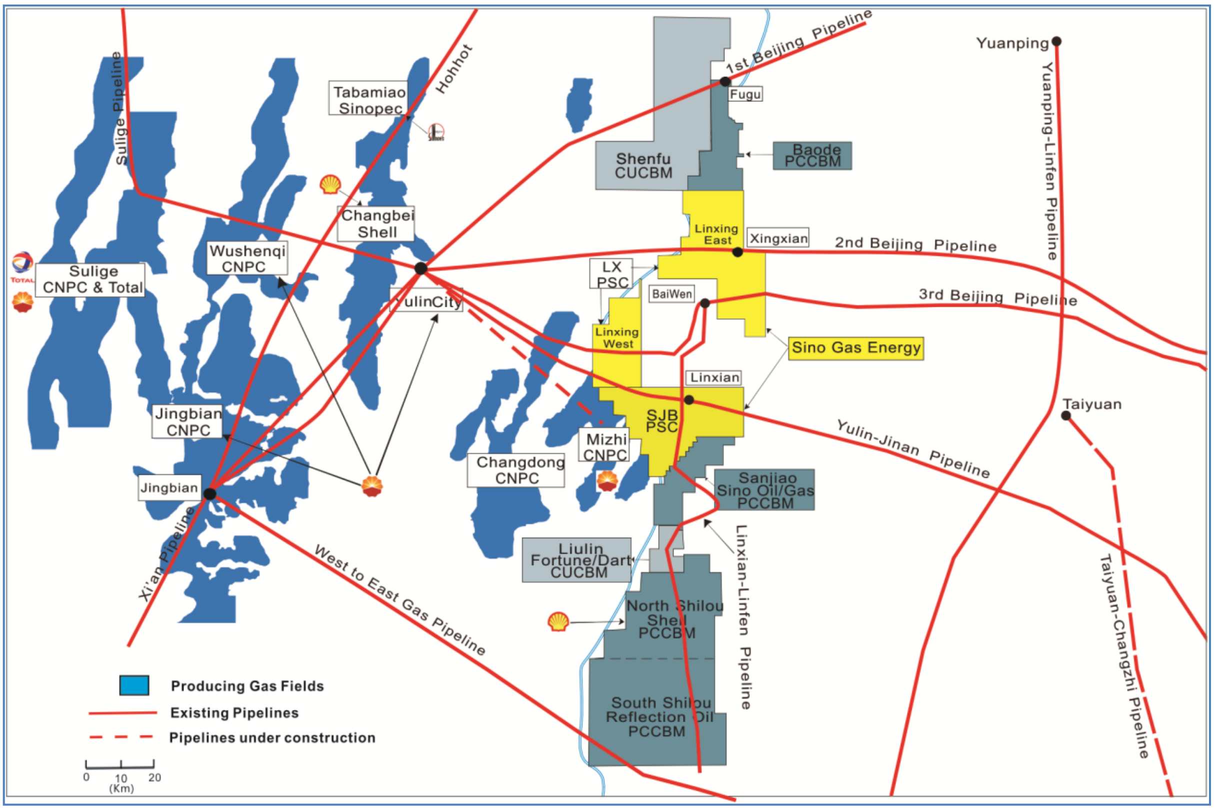

Figure 3-1: Ordos Basin Gas Fields and Pipelines (pre LXE relinquishment)

The Ordos Basin is a cratonic basin covering an area of 250,000 square km with up to 10,000 m of Palaeozoic and Mesozoic sediments. The Jingbian, Wushenqi, Changbei, Tabamiao, Sulige, Chandong and Mizhi gas fields to the west are producing and under further development. They are largely located in an area of a gentle monocline, which extends into the Linxing PSC. These fields are understood to be stratigraphically trapped, with gas present where reservoir quality sand bodies are present. As such the resource area is not limited to the traditional structural highs but extensive over the area.

Linxing and Sanjiaobei are geologically analogous to Sulige, Mizhi and other tight gas accumulations in the Ordos basin.

Stratigraphic Column

Era	System	Epoch	Formation	Para-formation	Code	Facies	Lithology	Wireline Logging
Palaeozoic	permian	Upper	SQF	Q1	P_3q_1	Flood Plain		
				Q2	P_3q_2			
				Q3	P_3q_3			
				Q4	P_3q_4			
				Q5	P_3q_5			
		Middle	Up Shihezi	He1	P_2sh_1	Lacustrine Deposit		
				He2	P_2sh_2			
				He3	P_2sh_3			
				He4	P_2sh_4			
		Lower	Lower Shihezi	He5	P_2x_5	Channel-Delta Deposit		
				He6	P_2x_6			
				He7	P_2x_7			
				He8	P_2x_8			
			Shanxi	Shan1	P_1s_1	Channel-Delta Deposit		
				Shan2	P_1s_2			
	Carboniferou	Upper	Taiyuan	Tai1	C_3t_1			
				Tai2	C_3t_2			
		Middle	Benxi		C_2b	Barrier Island Lagoon Deposit		
	Ordovician	Middle	Majiagou		O_1m			

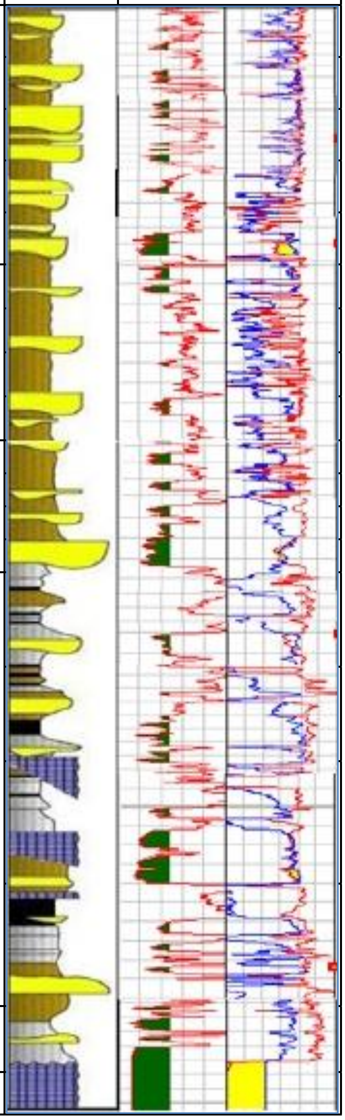

Figure 3-2: Stratigraphy of SGE Ordos Basin permits

The gas resources are contained in a number of stratigraphic, heterogeneous, interbedded sandstone layers between or overlying the coal seams extensively found in Carboniferous and Permian aged rocks at depths between 1,000 and 2,200 mbrt. Wells generally find gas in multiple formations over an 800 m vertical interval. At this depth the permeability of the coal may be too low to be productive and the gas is produced through the adjacent gas bearing sandstone intervals.

The Sulige and Mizhi gas fields produce from the same gas bearing formations as the SGEH fields. Sulige was discovered in 2000 and started production in 2006. Total proved reserves are over 50 Tcf with planned production of 1,300 MMscf/d. As of 2011 there were over 4,500 gas well producing 1,300 MMscf/d through 93 gathering stations and 5 processing plants. Multiple hydraulic fractures are used on deviated wells to complete 7 layers.

The Linxing and Sanjiaobei gas accumulations are updip extensions of the Mizhi gas reservoirs (formerly called Jia Xian). Mizhi was discovered in 1985. China National Petroleum Corporation (CNPC) started development of the Mizhi Gas Field in 2005 with first commercial gas production announced in 2007. Initial production through 61 gas wells and 13 gas gathering stations was 45 MMscf/d with facility capacity of 140 MMscf/d. Proved reserves were over 1.2 Tcf at end 2011. The Mizhi permit lies directly to the south west of Linxing.

3.2. Geological and Well Data

Figure 3-5 and Figure 3-3 shows the well and 2D-seismic and well coverage which is extensive across Linxing West, the northwest of Sanjiaobei and the southwest of Linxing East.

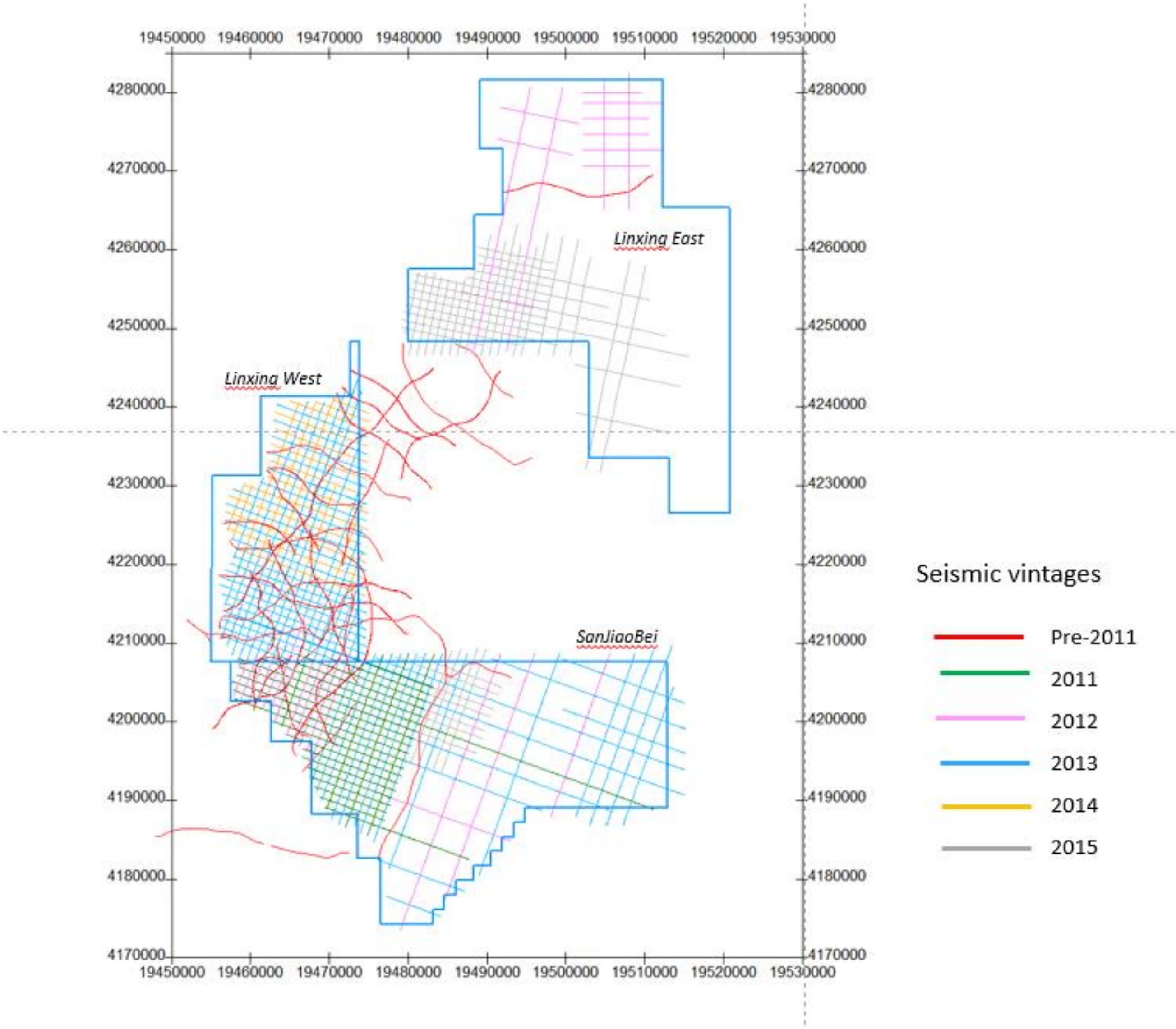

Figure 3-3: Seismic coverage

To date around 3,365 km of 2D seismic data have been acquired. Up until 2011, seismic acquisition over the Sanjiaobei and Linxing permits was constrained by the valleys resulting in sinuous lines. After 2011, seismic acquisition was no longer constrained by the topography and could be acquired in a regular fashion.

Seismic shows the coal seams and geology as continuous layers across the majority of the structure. However, it becomes quite complex in the east due to the impingement of the Lishi Thrust Belt (Figure 3-4). Note that this line is greatly compressed and the angle of the faults is shallow.

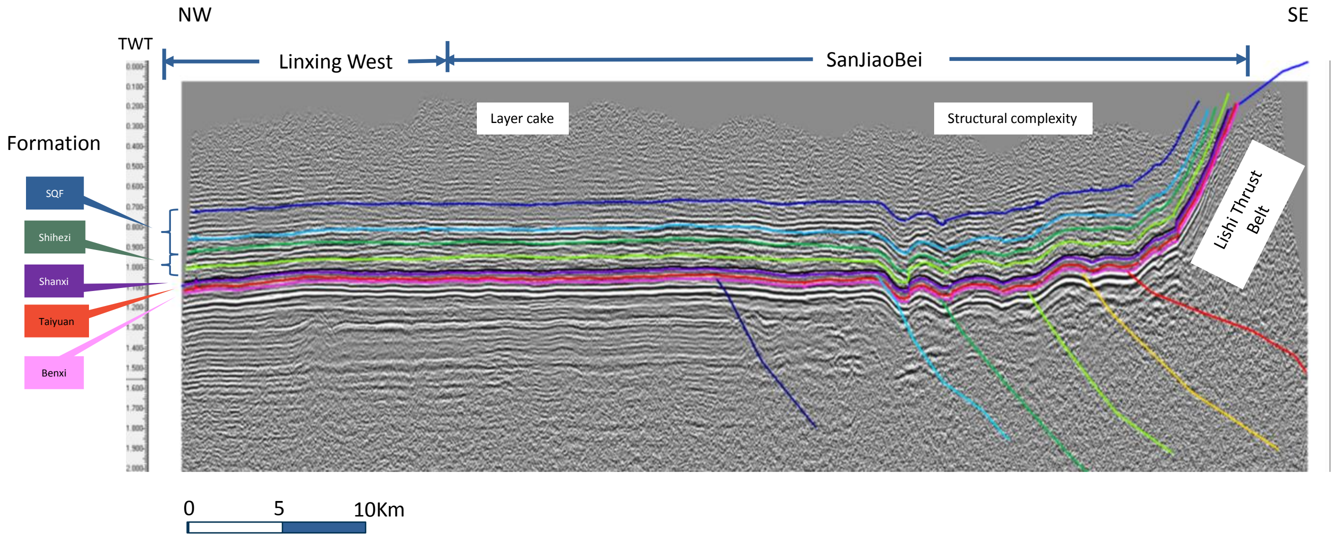

Figure 3-4: Line 219 showing thrusts

169 wells have been drilled to evaluate the deep gas across Sanjiaobei (SJB) and Linxing East (LXE) and West (LXW) areas, Table 3-1.

Table 3-1: Well count in Sanjiaobei and Linxing

	SJB	LXW	LXE	Total deep gas wells	LXE CBM
Total wells	59	97	13	169	15
Well tied-in	21	52	0	73	8
Wells planned for tie-in	11	23	10	44	0
Remaining lanned 2018 wells	7	7	12	26	3

73 wells have been tied-in for pilot production and 44 additional wells are planned for tie-in. An additional 26 wells are planned to be drilled in 2018.

To the east of the Lishi thrust belt the coals and sandstone formations are shallow and this area has been evaluated for potential CBM development. 15 CBM wells have been drilled with 8 pilot tested.

Figure 3-5 shows the available well coverage.

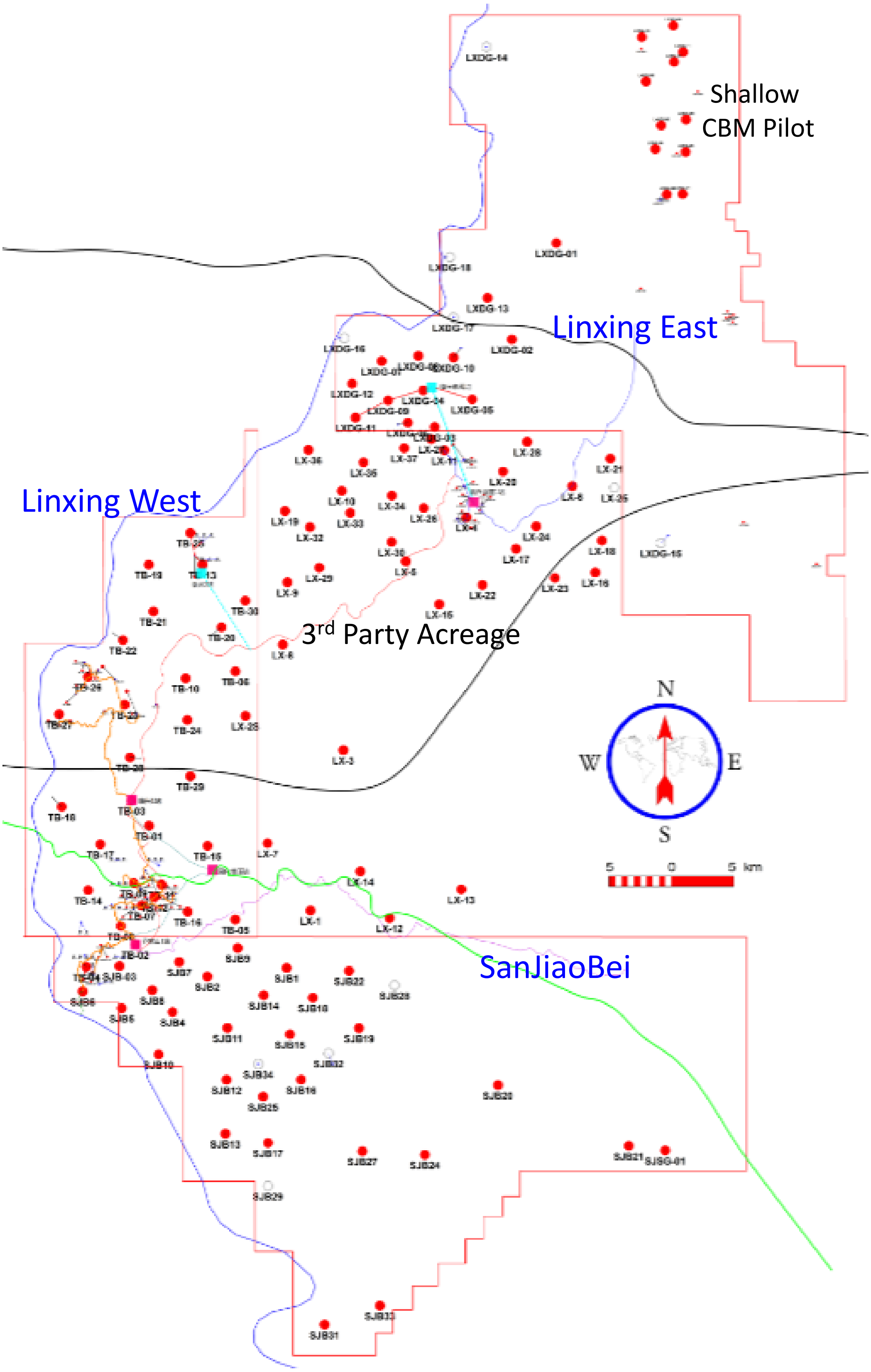

Figure 3-5: Well database for Linxing and Sanjiaobei permits

The 3rd party acreage between Linxing East and Linxing West was previously part of the Linxing PSC. However it was requested to be relinquished back to the authority CUCBM, as part of an extension to the exploration period. The wells shown on Figure 3-5 were subsequently drilled by CUCBM and the northern wells put onto production.

3.3. Well Test Results

Data from 146 well tests across various reservoir intervals in 101 wells in Sanjiaobei and Linxing were available for this review. The table below summarises the formations tested, flowrates, bottom hole and tubing head pressures (BHP and THP).

The well test flowrates vary from zero to 141,000 m^3/d (5.0 MMscf/d), including horizontal wells. Figure 3-6 shows the distribution of well test rates (pre-frac tests are excluded where superseded by post frac tests).

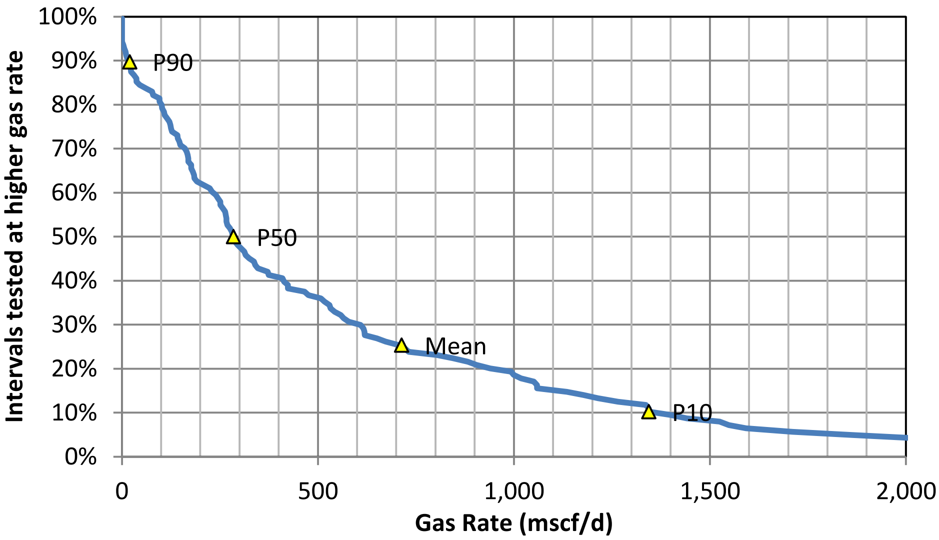

Figure 3-6: Distribution of Interval Well Test Rates

- 6% of tested intervals failed to flow, died or flowed water;
- 50% of tests flowed at more than 8,000 m3/d (285 Mscf/d);
- 18% of tests flowed at more than 28,300 m^3/d (1,000 Mscf/d).

Hydraulic fracturing has been conducted on 77% of well test intervals although:

- A well test with one of the highest gas rate was not fractured; 53,000 m^3/d (1.9 MMscf/d) from the SQF formation in TB-07-LX;
- The pre-frac rate in TB-11 increased 8 fold after hydraulic fracturing. A large proportion of reservoir intervals will not flow without hydraulic fracturing;

Water production has occurred in only 2 of over 100 well tests. Therefore, water is generally not an issue and water influx and production are not expected in these low permeability sands.

Four horizontal wells have been drilled and tested TB-1H, 2H, 3H and 4H in Linxing West. Three tested at high rates between 1.7 and 5.0 MMscf/d with the forth producing 0.28 MMscf/d. However, vertical or deviated wells are the primary development method in order to connect the heterogeneous multiple gas bearing sands over an 800m vertical interval.

Permeability and skin factors have been determined from pressure build-up analysis on 24% of the well tests. The average and range in permeability determined for each formation is shown below:

Table 3-2: Average Well Test Rate and Permeability

Formation	Average test rate		Well Test Permeability (mD)		
	m3/d	mscf/d	min	mean	max
SQF	21,096	745	0.445	6.74	42.10
Shihezi	10,979	388	0.012	0.11	0.49
Shanxi	13,759	486	0.002	0.04	0.10
Taiyuan	8,111	286	0.022	0.17	0.57
Total	14,431	510	0.002	1.60	42.10

- There is a good correlation between well test permeability and well test flow rate per meter of pay;
- The average SQF permeability is skewed by one value of 42 mD. However, the average rates of all SQF well tests (including those without permeability estimates) supports the 6.74 mD average;
- The SQF is the most productive formation having successfully flowed in all tests with an average rate of 710 Mscf/d. However, productivity is variable, and the interval required hydraulic fracturing in TB-08-LX to achieve sustainable flow.

The minimum economic well flow rate to support development is estimated at 110 Mscf/d at semi-steady state conditions, which equates to a transient flow rate after 2 weeks flow of 220 to 270 Mscf/d at 200 psia THP. The average well test flowrate of an individual interval is often greater than this and development wells will be completed on multiple intervals.

The well tests intervals have generally included sections of porosity greater than 8.5%. Therefore there is uncertainty if lower porosity intervals will flow and how much they contribute to production. RISC uses a 5%, 7% and 9% porosity cut off to estimate the high, mid and low percentage of the GIIP that is productive. A 4% porosity cut-off is used to estimate GIIP, which is the normal cut-off used by Operator’s in these Ordos Basin formations.

RISC has used the mean permeability in Table 3-2 and the net pay with 7% porosity cut-off to model the P50 performance of an average well completed in the different formations.

3.4. Reservoir Pressure and Gas Properties

Well test data is the most accurate source of information and has been used to determine reservoir pressure and temperature data. Reservoir pressure estimates from fracture fall-off tests are also considered. Wireline pressure measurements have not been attempted as the reservoir permeability is generally too low to give successful measurements. The pressure data are from a limited number of well tests and therefore carry a higher degree of uncertainty than usual.

The deeper formations (Shanxi, Taiyuan) are normally pressured but the shallowest formation (SQF) is under pressured in Linxing West and Sanjiaobei with the Shihezi formation at intermediate pressure. In Linxing West the SQF formation is less under-pressured.

From well test data the reservoir temperature is estimated to be 53°C at 840 mtvdss with a gradient of 0.0147°C/m.

Table 3-3 shows the average depth, estimate pressure, temperature and gas expansion factor of formations.

Table 3-3: Reservoir Pressure, Temperature and Gas Expansion Factors

Reservoir	SanJiaoBei and Linxing West						Linxing East Deep Gas					
	Average Depth		Pressure		Temp	Eg	Average Depth		Pressure		Temp	Eg
	mtvdss	mbrt	Mpa.a	psia	C	v/v	mtvdss	mbrt	Mpa.a	psia	C	v/v
SQF1	314	1324	4.16	604	45	40	157	1167	10.33	1498	43	113
SQF2	371	1381	4.72	685	46	46	218	1228	10.92	1584	44	120
SQF3	429	1439	5.29	767	47	52	276	1286	11.50	1667	45	126
SQF4	475	1485	5.74	833	48	57	326	1336	11.98	1738	45	132
SQF5	512	1522	6.10	885	48	61	371	1381	12.43	1803	46	137
U+LShihezi	651	1661	13.15	1907	50	142	529	1539	11.96	1734	48	129
He8	810	1820	14.71	2134	53	157	692	1702	13.56	1966	51	146
Shanxi 1+2	898	1908	18.84	2732	54	199	773	1783	17.62	2555	52	189
Taiyuan	953	1963	19.38	2811	55	203	981	1991	19.66	2851	55	206

The gas comprises 96 mole% methane with less than 1 mole% carbon dioxide, less than 3 mole% nitrogen and no H_2S.

3.5. Permit History

The 35 year Sanjiaobei PSC was implemented 31/08/1998 and will expire 31/08/2033. The initial 5 year exploration phase has been extended a number of times, although these do not alter the PSC expiry date and leaves less time for the production phase. Sanjiaobei PSC is currently in the extended exploration phase which expires in 31/08/2018. The first ODP was submitted in 4Q-2017 and approval is expected in 2018, or an exploration extension sought. The PSCs are operated by the operating company SGE which is owned 49% by SGEH.

SGE is in discussion with the Sanjiaobei authority (PCCBM) regarding negotiations to conclude a supplemental agreement for Sanjiaobei. Such discussions are common in China to support ODP approval.

The 30 year Linxing PSC was also implemented 31/08/1998 and was due to expire 31/08/2028. In 2018, an 8 year extension was granted extending the PSC to 31/08/2036. However, conditions of the extension were:

- The contractor interest was reduced from 70% to 49% for the deep natural gas. Now both the Linxing and Sanjiaobei PSCs have 49% contractor share and 51% Authority share for deep natural gas. The contractor share remains at 70% for shallow CBM;
- The exploration phase of Linxing East was extended to 31/08/2019 with a relinquishment of 1,000 km^2 of Linxing East exploration area. RISC understands that this relinquishment was partly due to the agreed exploration programme not been completed.

Stage-1 of the Linxing deep gas ODP was approved in May 2018 after submission in October 2017. This covers an initial development of 20% of the discovered area. The Authority (CUCBM) has supported a staged approval process to facilitate a continued ramp-up in production. SGE and SGEH estimate the full development of Linxing and Sanjiaobei to have gross plateau production of between 350 and 550 MMscf/d; 350 MMscf/d from discovered resources and 550 MMscf/d including successful exploration of field extensions.

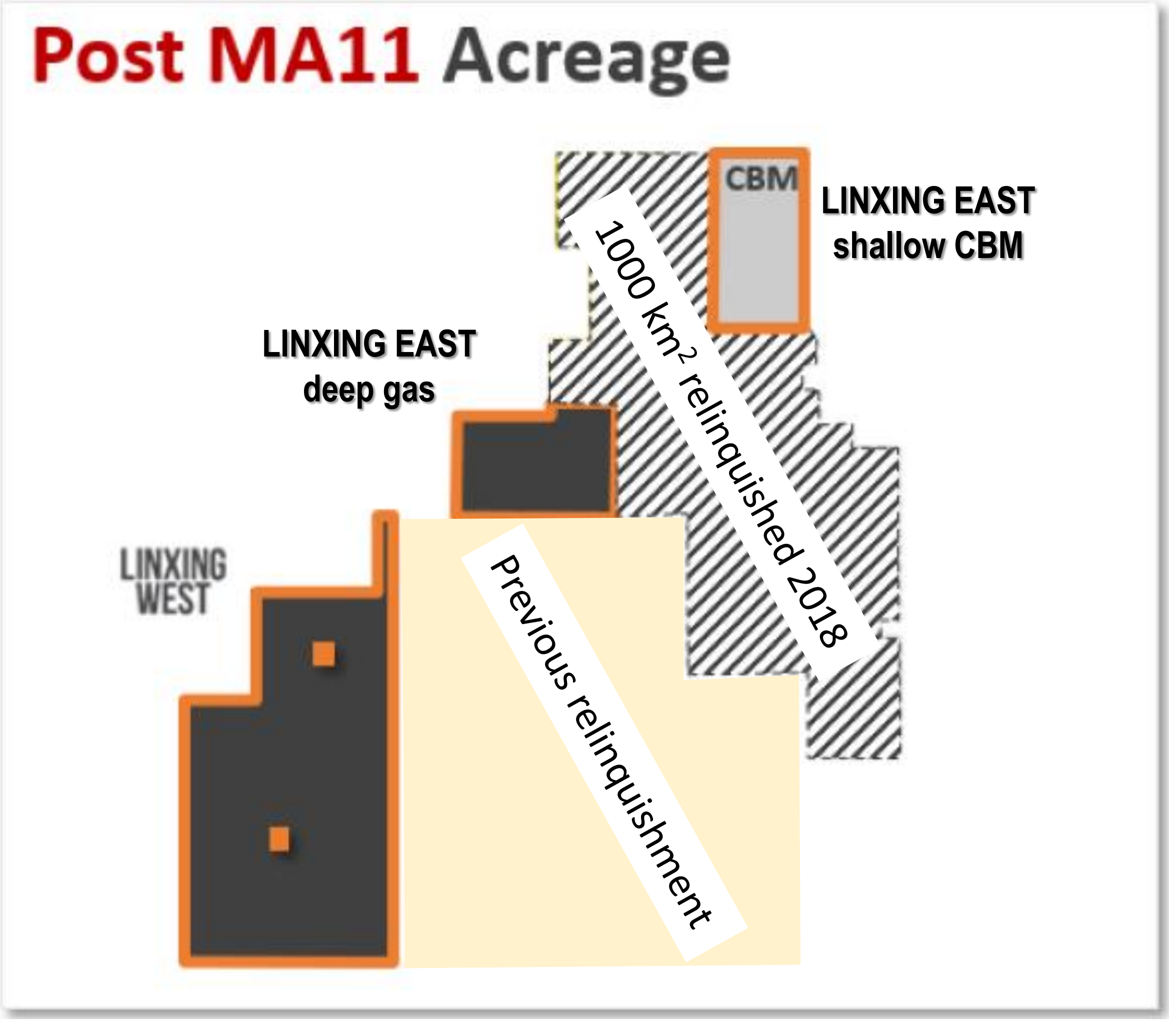

Figure 3-7: Changes to Linxing Acreage

The area of Linxing West remains at 573 km^2 but Linxing East is reduced from 1,304 to 304 km^2 as shown in Figure 3-7. Linxing East now consists of 149 km^2 of deep gas acreage near Linxing West and 155 km^2 of shallower CBM acreage in the northeast.

In an earlier extension to the Linxing exploration period the central area had to be released dividing Linxing into Linxing East and Linxing East. This released acreage has been drilled and put on production by the Authority CUCBM.

Gas was discovered in the Linxing PSC by well TB-01 drilled in 2006 which flowed gas at a rate of 0.15 to 0.18 MMscf/d. 97 deep gas wells have been drilled in Linxing West including 4 horizontal wells. In Linxing East 13 deep gas wells and 15 shallow CBM wells have been drilled. In the adjacent Sanjiaobei permit, 59 wells have been drilled by SGE. A discovered area has been defined around the successful exploration and appraisal wells.

Shallow CBM pilot production started in March 2013. However, production rates have been low and the gas flared despite multi-year gas sales agreement with CUCBM to provide up to 35 MMscf/d. Development of this shallow CBM is estimated to be marginally economic so it is not included in this evaluation.

Pilot testing and gas sales from the deep gas started in November 2014.

4. Linxing and Sanjiaobei Deep Gas Project

4.1. Introduction

The Linxing and Sanjiaobei PSC are operated by the contractors joint operating company SGE (Sino Gas and Energy) which is owned 49% by SGEH and 51% by CNEML (China New Energy and Minerals Ltd.).

Pilot gas production started in November 2014 with up to 10 wells on production.

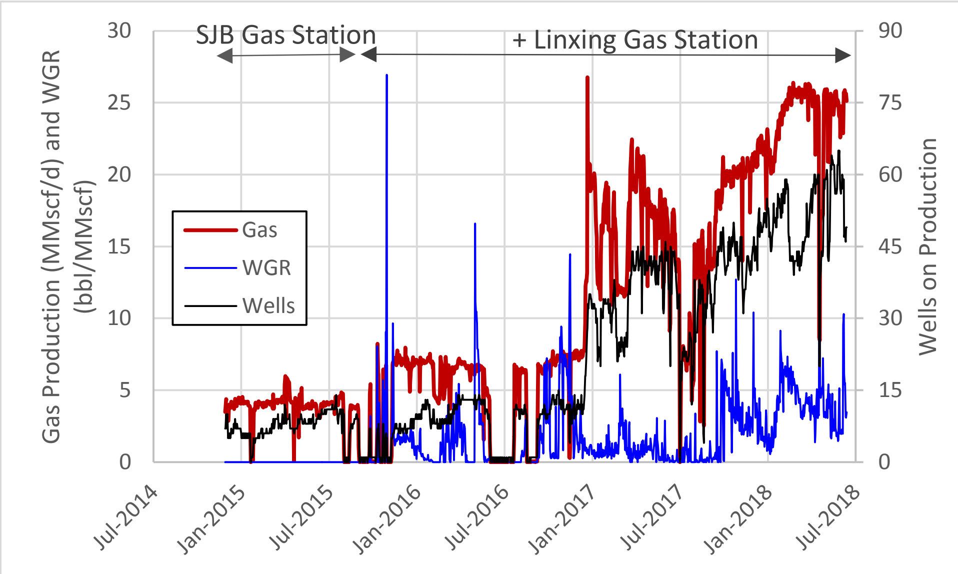

Figure 4-1: Linxing plus Sanjiaobei pilot production

Linxing West and Sanjiaobei wells initially produced to the Sanjiaobei Gas Station which had an initial capacity of 4 MMscf/d subsequently increasing to 8 MMscf/d with additional compression. Production was suspended in 3Q 2015 until payment for gas sales was resolved. A second gas station at Linxing started late 2015 with an initial capacity of 7 MMscf/d and subsequently increased to 17 MMscf/d. Gas production has built up to 25 MMscf/d in 2018 with 75 wells hook-up and up to 60 wells on production at one time. Water production at up to 5 bbl/MMscf has largely been water of condensation. Cumulative production to 14 June 2018 was 13.4 Bcf.

4.2. GIIP and Resource Evaluation

RISC has conducted independent reserve and resource assessment for SGEH and SGE in 2011 and year end 2012, 2013, 2014, 2015 and 2016. YE2017 were based on YE2016 estimates adjusted for 2017 production as there was little additional subsurface data acquired in 2017. The assessments were based on PRMS guidelines.

GIIP has been estimated from RISC's petrophysical evaluation of all wells. The gross reservoir thickness, NTG, porosity and gas saturation were determine for each formation in each well. Data varied from well to well but no regional trends were identified. Average properties and their uncertainty were estimated and combined probabilistically to determine the range of GIIP.

The PSC areas were divided into areas classified as reserves, contingent resources and prospective resources based on proximity to wells with identified gas pay and successful well test. Figure 4-2 shows the estimated discovered and prospective areas. The area within 2 well spacing of successful wells is classified as reserves and the remaining discovered area contingent resources.

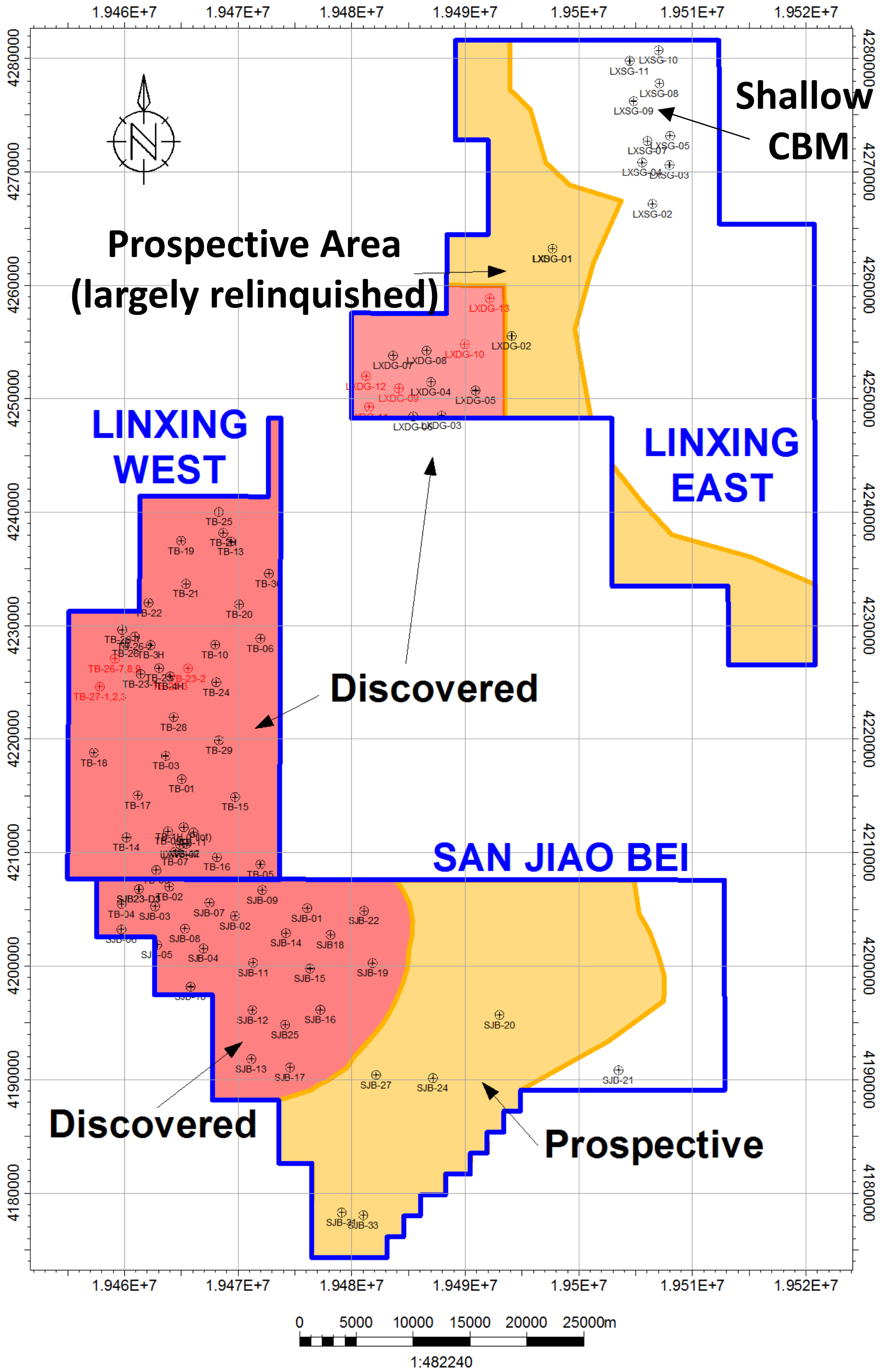

Figure 4-2: Discovered and Prospective Areas

Since RISC's evaluation 1,000 km^2 of Linxing East has been relinquished as part of the PSC extension. This removes most of the Linxing East prospective area, leaving 19 km^2 around the Linxing discovered area.

The estimated areas and GIIP range are shown in Table 4-1.

Table 4-1: Resource Areas and GIIP range

Region	Resource Classification	Area (km^2)	GIIP (Bcf)		
			P90	P50	P10
Sanjiaobei	Reserves	268	2195	2669	3251
	Contingent Resource	102	836	1016	1238
	Prospective	595	3468	4219	5111
Linxing West	Reserves	337	2770	3362	4068
	Contingent Resource	236	1940	2354	2849
	Prospective	0	0	0	0
Linxing East	Reserves	88.5	862	1021	1205
	Contingent Resource	41.5	404	479	565
	Prospective[#1]	19	125	158	197
Total	Reserves	693.5	5827	7052	8524
	Contingent Resource	379.5	3180	3849	4652
	Prospective	614	3593	4377	5308
#1: GIIP estimated adjusted based on remaining Linxing East exploration area relinquishment					

The prospective area requires additional wells and well tests to confirm mobile gas. The contingent resource areas required additional wells and well tests to confirm reservoir quality and commercial gas flowrates.

These gas fields consist of multiple thin intervals of generally low permeability, low porosity sands. Gas saturation is low and a key uncertainty. The GIIP estimates are sensitive to the petrophysical cut-offs used to define net pay. RISC has used the following cut-offs to define net pay: >4% effective porosity, <30% shale, <80% water saturation. The 4% porosity cut-off is typically used in the Ordos basin.

Most well tests have included an interval of good porosity (>8.5%). The contribution of flow from the lower porosity (4 to 8.5%) sand is uncertain. Wells have been completed across a limited interval of the total pay using cemented and perforated liners. The degree of communication between the completed interval and other uncompleted pay intervals is uncertain and estimated to be limited.

It is unlikely that the total GIIP will contribute to production due to low productivity and lack of connectivity with the intervals completed in wells. RISC has applied a range of porosity cut-offs to estimate the amount of productive or developable GIIP. We estimated the high, mid and low case developable GIIP by applying 5, 7 and 9% porosity cut-offs respectively. Table 4-2 shows the estimate GIIP density in Bcf per square kilometre for the total GIIP and developable GIIP in Linxing West discovered area.

Table 4-2: Total and Developable GIIP density: LXW discovered area (RISC)

GIIP Density (Bcf/km^2)	P90	P50	P10
Total GIIP density	8.2	10.0	12.1
Developable GIIP density	5.4	8.2	11.7

The estimated GIIP densities in Sanjiaobei discovered area is the same as LXW. The GIIP density is 13 to 18% higher in LXE discovered area due to higher pressure in the shallow formations. The GIIP density in the prospective areas is lower due to uncertainty and lower estimated gas saturation and some potential water bearing intervals.

RISC generated P90, P50 and P10 type curves from single well simulation models using 130 acre (0.53 km^2) well spacing with the estimated developable GIIP density and corresponding net pay. Larger well spacing is estimated for the shallowest, higher productivity SQF formation. Therefore 1 in 3 wells is assumed to include an SQF completion. Average well type curves for the deeper reservoirs and including 1/3 SQF completion are shown in Figure 4-3.

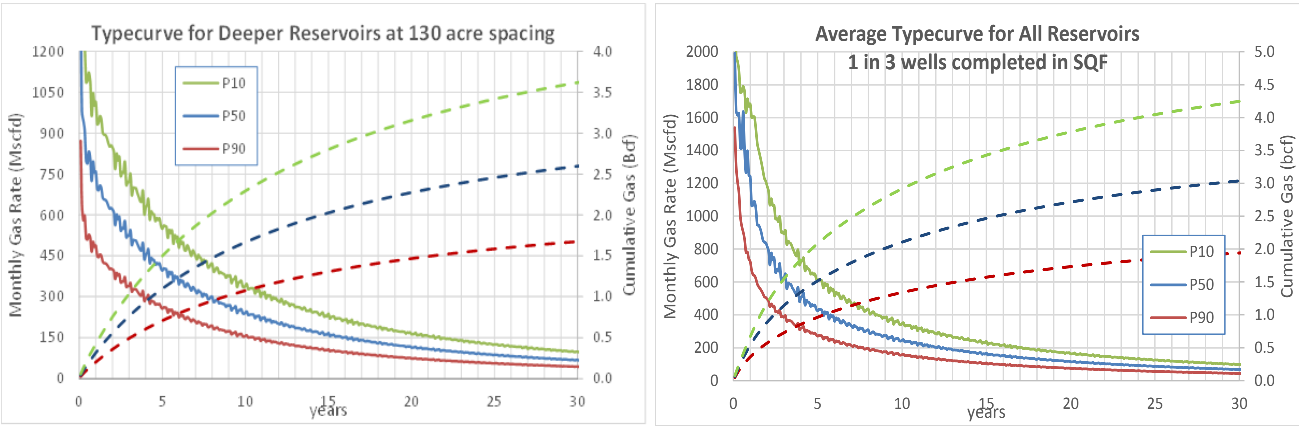

Figure 4-3: RISC Single well type curve for discovered area

It is assumed that:

- Wells will be completed across multiple intervals using multi-stage hydraulic fractures;
- Production from formations at various depths and pressure would be managed with a combination of multiple completion strings and commingled production.

SGEH have used a local Beijing consultant with experience in analogue Ordos Basin fields to help develop the Field Development Plan. They have applied similar porosity and shale volume cut-offs to estimate net pay but applied a resistivity cut-off instead of a gas saturation cut-off. The estimated GIIP density is 55 to 78% of the developable GIIP density estimated in Table 4-1.

The local consultant estimates similar development areas, vertical well spacing and development well numbers. However, they have generated more conservative type curves shown in Figure 4-4.

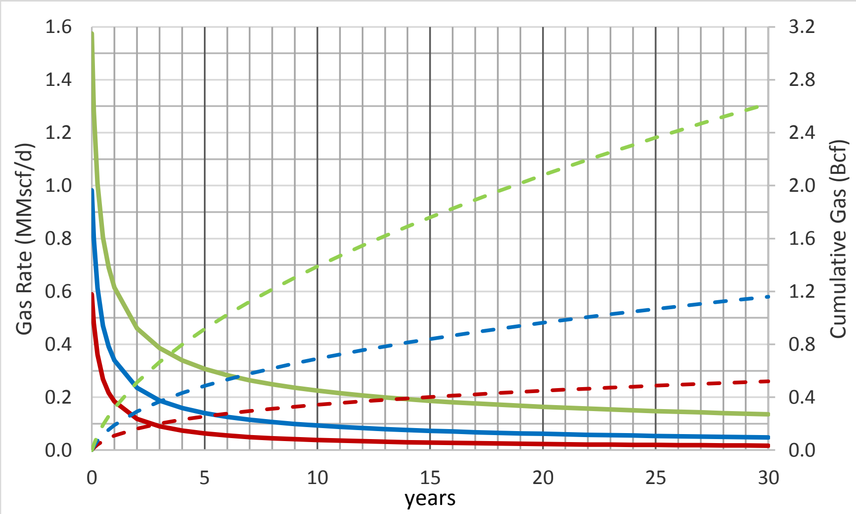

Figure 4-4: Conservative 1P, 2P, 3P type curves (local consultant)

The local consultant's type curves are from a review of SGE pilot well production and experience from analogue Ordos Basin fields Sulige and Mizhi. They show:

- P50 recovery of 1.2 Bcf over 30 years compared with 3.0 Bcf in RISC's type curve;
- Rapid (super-harmonic) decline in P50 well productivity from 1.0 MMscf/d to 0.4 MMscf/d after 1 year.

Analogue data from Sulige field indicates a lower rate of decline and recovery of 1 to 1.5 Bcf over 30 years. Anecdotal information from Mizhi suggests an average of 0.8 Bcf recovery per well.

Figure 4-5 plots the cumulative production of each pilot well against the number of days the well has produced. Horizontal well TB-1H is the best well having produced 1.36 Bcf to date.

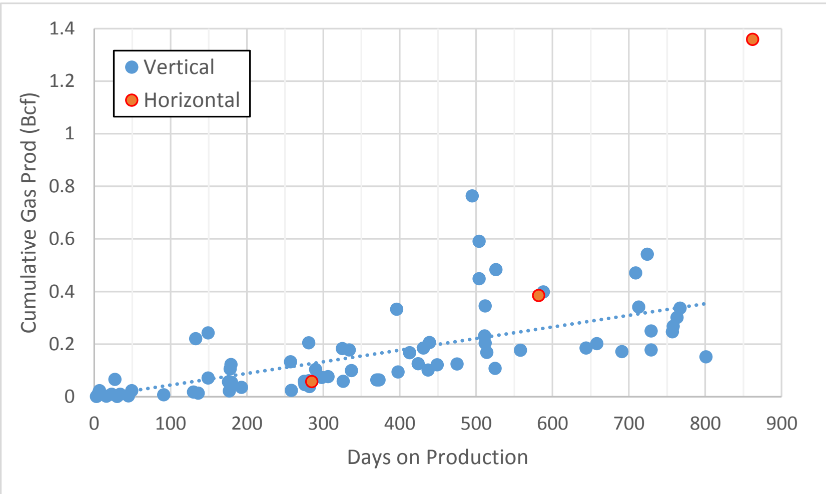

Figure 4-5: SGE pilot wells: cumulative gas vs days on production

On average pilot wells have produced 0.16 Bcf in the first year of production and a similar amount in the second year. This is less than RISC type curves and between the 2P and 3P local contractor type curves.

The earlier SGE exploration wells were completed across 1 or 2 intervals so were connected to only a limited proportion of the total pay and GIIP. RISC's analysis of select exploration and appraisal well production indicates:

- An average connected GIIP and ultimate recovery of 1.1 and 0.8 Bcf per completion interval. RISC estimates 3 to 6 completion intervals are required per well;
- Limited vertical connectivity between the completed interval and uncompleted pay in the well. Multiple completion intervals and multi-stage fracs will be required to maximize recovery.

SGE pilot wells have been completed across more intervals bringing the average number of completion intervals to 5 across 3 sub-formations. One vertical pilot well has been completed across 18 intervals and 8 sub-formations with 11 hydraulically fractured intervals and 7 perforated.

The differences in GIIP density and development well type curves estimated by RISC and a local consultant highlights the uncertainty in the performance of these and tight gas reservoir in general. RISC estimates that RISC's type curves represent an upside case and the local contractor type curves are in line with pilot production, current completion philosophy and local analogue data.

SGE's current well completion strategy and the planned development indicates that the completion intervals will be less extensive than RISC previously estimated. It is likely that wells will be re-completed and re-fractured possibly adding additional intervals at a later stage. Alternatively, infill wells could be used to develop pay not completed in the initial well and maximise field recovery. However, extensive re-completion and infill drilling are not in the development plan and the economics of such incremental activity has not been demonstrated. Therefore any associated resources are classified as contingent resources.

RISC has adjusted its type curves in line with pilot well results to date, analogous field data and the ODP assumptions (reduced completion intervals). The resulting Sanjiaobei and Linxing West type curves are show in Figure 4-6.

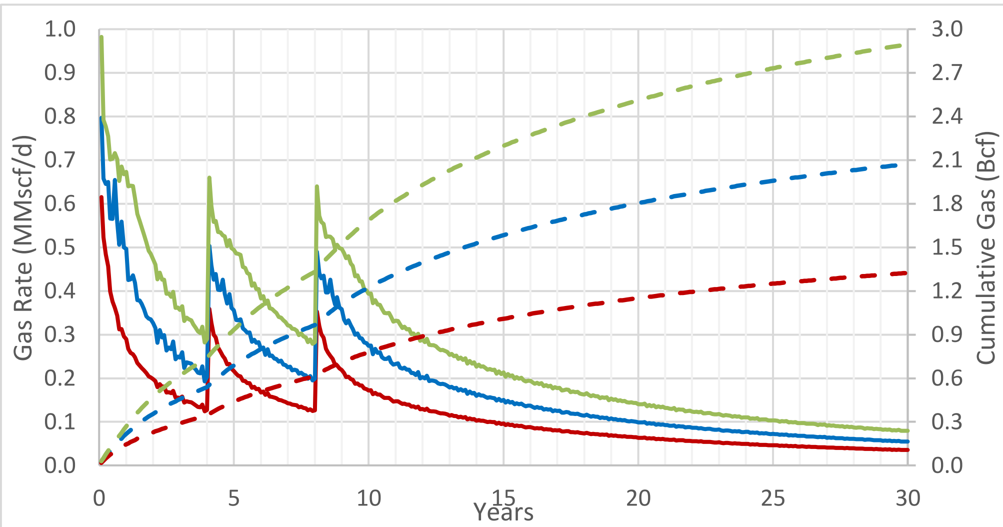

Figure 4-6: Adjusted Vertical Well type curves

RISC estimate that development wells are initially completed on 40% of the total pay and GIIP estimated by RISC. A workover after 4 years is estimated to connect an additional 15% of the pay/GIIP and a second workover after 8 years is estimated to connect an additional 15% of the pay/GIIP. The remaining 30% is a potential target for infill drilling or further recompletions. The type curve for LXE included higher pressure in the shallower intervals but is similar to Figure 4-6. The short term performance in RISC adjusted type curves are similar to that the seen in pilots wells; slightly better allowing for further optimisation of the completion philosophy.

Table 4-3: Adjusted Vertical Well type curve; short and long term gas recovery

Type curve	1st Year Recovery (Bcf)	2 Year Recovery (Bcf)	30 Year Recovery (Bcf)
1P	0.14	0.22	1.32
2P	0.22	0.35	2.07
3P	0.27	0.46	2.89

In the P50 type curve, the initial 40% completion recovers 1.2 Bcf over 30 years, the re-completions increase the 30 year recovery to 1.66 and 2.07 Bcf respectively.

4.3. Evaluation Scenarios

In consultation with the Independent Expert (Grant Thornton) RISC has developed production and cost forecasts for five scenarios for economic evaluation by Grant Thornton.

Table 4-4: Evaluation Scenarios

Scenario		Development Area km^2	Number of productive wells	Well Type curve
1	1P	693.5	1001	P90
2	2P	693.5	1001	P50
3	2P+2C	1073	1549	P50
4	2P+2C accelerated	1073	1549	P50
5	2P+2C delayed	1073	1549	P50

2P reserves are often used for the base valuation. However, contingent resources have a high probability of maturing to reserves as the development wells appraisal the contingent area and confirm commercially productive reservoir. RISC estimates a 90% probability for contingent resources maturing in time to reserves. Therefore, the base valuation is estimated to be between the 2P and the 2P+2C scenarios.

Continued production post PSC expiry has a lower probability of commercial development due to uncertainty if and under what terms PSC might be extended.

The 1P scenario represents a downside, where well performance is disappointing and contingent resources fail to be commercially productive.

Production forecasts have been generated for each scenario with the following assumptions:

- 130 acre (0.526 km^2) well spacing across 80% of the area. 20% of area assumed inaccessible due to surface constraints and not developed;
- 5% of wells fail to produce due to mechanical or geological failure (excluded from productive well numbers but included in costs);
- 10% well and facility downtime;
- 4% of produced gas used for infield fuel (compression, field operations);
- Plateau rate adjusted to give 5 year plateau.

Based on ODP information, the ramp-up in gas production has been adjusted with plateau rates from 2023. This ramp-up has been used in scenario 1, 2 and 3. However, RISC estimates and uses higher plateau production rates from 2024.

The pace of development and ramp-up in gas production rate carries uncertainty. An accelerated production ramp-up with plateau from 2022 is used in scenario 4. A delayed production ramp-up with plateau from 2025 is used in scenario 5.

RISC generated a full field forecast based on the type curves in Figure 4-6 and the estimate number of vertical or deviated wells that can be drilled in the reserve and contingent resource areas using 130 acre well spacing.

Figure 4-7 shows the forecast gas production from 2P + 2C resources.

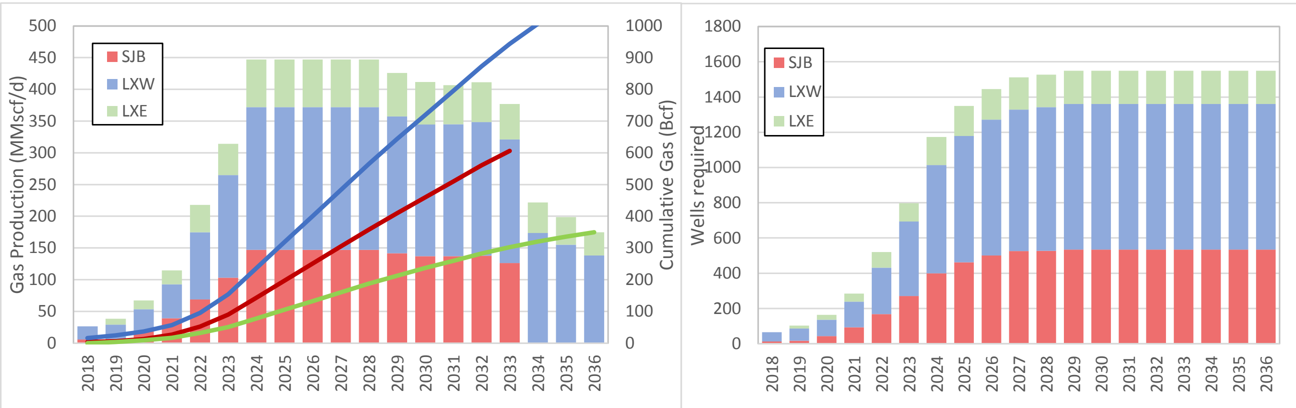

Figure 4-7: Gas production and well forecast; 2P + 2C

Table 4-5: Gross 2P+2C forecast parameters

PSC	Area (km^2)	Total productive wells	Plateau rate (MMscf/d)	Production prior to PSC expiry (Bcf)	
				Gas Produced	Gas Sales
SJB	370	534	147	590	566
LXW	573	827	225	1089	1045
LXE	130	188	75	345	331
Total	1073	1549	447	2024	1943

The reserve areas are a fraction of the discovered gas (reserves + contingent resources) area, with a corresponding reduced number of well locations.

Figure 4-8 shows the full field production forecast for the 2P reserves only.

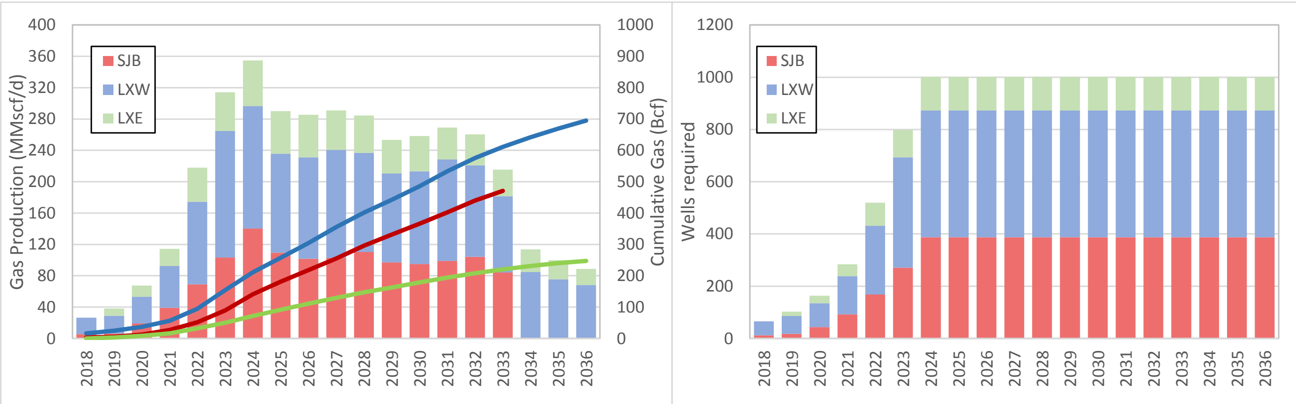

Figure 4-8: Gas production and well forecast; 2P

The 2P forecasts assume the same drilling sequence and ramp-up in gas production as the 2P+2C forecasts. However, all reserve locations are drilled by 2023 and plateau rates cannot be reached or maintained. The effect of the estimated well recompletions after 4 and 8 years is apparent in the production forecast.

The 1P forecasts use the same total number of wells as the 2P forecast with the P90 type curve. Drilling is accelerated to achieve the ramp-up in gas demand but the plateau rates lowered - Figure 4-9.

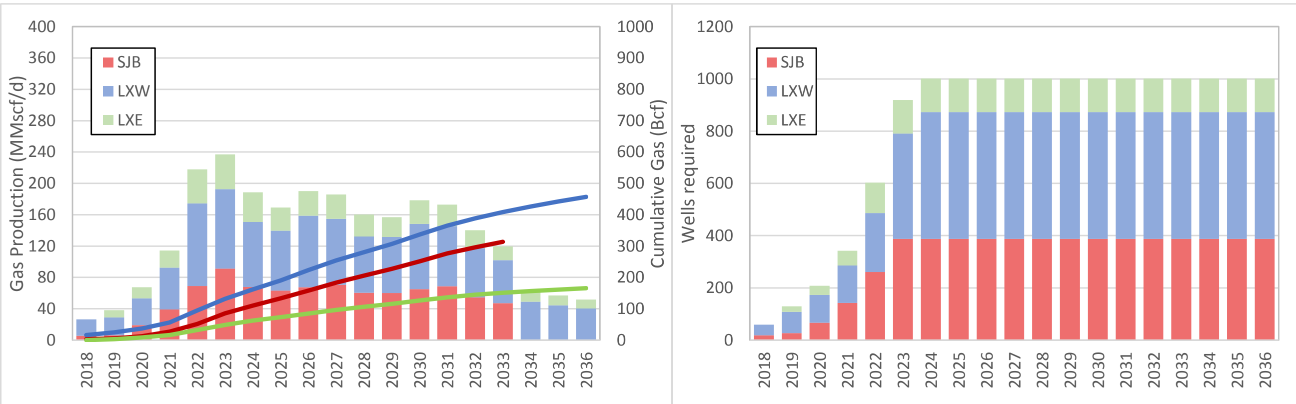

Figure 4-9: Gas production and well forecast; 1P

The 1P plateau rates is selected to give a 5 year plateau when developing the 1P + 1C resources. However, all reserve locations are drilled by 2024 so plateau rates cannot be maintained. Table 4-6 shows the 1P and 2P forecast parameters.

Table 4-6: Gross 1P and 2P forecast parameters

PSC	Area (km^2)	Productive wells	1P Production during PSC (Bcf)		2P Production during PSC (Bcf)	
			Gas Produced	Gas Sales	Gas Produced	Gas Sales
SJB	268	387	307	294	459	441
LXW	337	486	444	426	678	651

LXE	88.5	128	164	157	245	235
Total	693.5	1001	914	878	1383	1327

The base scenarios assume that the PSCs are not extended and following expiry are taken over by the Chinese Authorities. Production is estimated to remain economic for many years after PSC expiry. Extension to the PSC's is uncertain and likely to be with reduced PSC terms.

4.4. Existing Facilities

Table 4-7 shows the number of deep gas wells drilled, tied-in and planned to be tied-in as of May 2018.

Table 4-7: Deep gas wells available

Area	Wells drilled	Wells Tied-in	Wells to be tied-in
SJB	57	21	9
LXE	13	0	10
LXW	96	57	22
Total	166	78	41

- 166 deep gas wells have been drilled across the three areas. 78 are tied in for production and an additional 41 are planned for tie-in. These wells and tie-ins are sunk costs and excluded from future well requirements.
- In addition to the deep gas wells there are 13 shallow CBM wells in the northeast of Linxing East and one unsuccessful well in Sanjiaobei.

Two gas stations are currently operating and exporting gas into regional pipelines; Sanjiaobei gas station with a capacity of 8 MMscf/d and Linxing-1 gas station with a capacity of 17 MMscf/d. The gas stations dry and compress the gas to pipeline requirements. Wells are typically operated at a minimum WHP of about 200 psia.

4.5. Future Development

A second Linxing gas station in LXE with a capacity of 17 MMscf/d in under construction and planned to be commissioned in 2018. A third Linxing gas station is planned to be constructed and commissioned in 2019. RISC estimated that 17 MMscf/d gas stations will be developed across the PSCs as required to accommodate the forecast production with a 10% additional capacity for downtime.

4.6. Reserves

Gross field reserves equal the gas production prior to PSC expiry less an estimated 4% of gas used as fuel in the field. SGEH net reserves are based on their entitlement to cost and profit gas under the terms of the PSC through their 49% ownership of SGE, and assumes both SOE partners take their full entitlement. Net reserves are slightly sensitive to the Capital and Opex spend as this is recovered as cost gas. Economic modelling of the PSCs has been used to estimate the net resources shown in Table 4-8.

SGEH deep gas resources are based on their 49% ownership of SGE who hold 100% of the contractor interest in Sanjiaobei PSC and 92.5% of contractor interest in Linxing PSC. SGEH's option to the remaining 7.5% contractor interest in Linxing PSC has not yet been exercised so these potential resources are not included.

Table 4-8: 1P, 2P and 3P deep gas reserves as at 30/06/2018

Reserves (Bcf)	Linxing PSC			Sanjiaobei PSC			Total		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Gross Reserves	581	883	1195	293	440	593	874	1323	1788
Contractor share	252	371	502	126	180	242	378	551	744
SGEH share	114	168	227	62	88	119	176	256	346

The estimated gross reserves in Table 4-8 are significantly lower than those estimated by RISC at YE2017. The reconciliation of the current and previous resources is provided in report section 4.10.

Table 4-8 shows developed plus undeveloped reserves. Table 4-9 shows the estimated developed reserves from the wells that have been hooked-up (Table 3-1) with production prior to PSC expiry through the current facilities with 25 MMscf/d capacity.

Table 4-9: 1P, 2P and 3P developed deep gas reserves as at 30/06/2018

Reserves (Bcf)	Linxing PSC			Sanjiaobei PSC			Total		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Gross Reserves	44	72	102	18	28	36	62	100	138
Contractor share	19	30	43	8	11	15	27	41	58
SGEH share	9	14	19	4	6	7	12	19	27

4.7. Capital and Operating Costs

Development costs (excluding sunk costs up to 1 January 2018) for the deep gas development scenarios are summarised in Table 4-10.

Table 4-10: Development costs

Costs, US$ million 2018 RT	1P	2P	2P + 2C
Wells	627	627	1038
Gathering lines	204	205	327
Plant and Trunklines	245	300	377
Total Capex	1076	1132	1741

The majority of the development Capex is related to drilling, completion and fraccing of the development wells. The development wells drive not only the well costs but also the associated gathering costs. Gathering costs include flowlines connecting well pads to local gas processing stations. Trunk lines connect the gas station to each other and export pipelines.

SGE propose to drill multiple wells (nine) from each drilling pad. This reduces the cost of wellhead facilities, flowlines and site preparation, but is offset by higher well costs due to the requirements for deviated drilling.

SGEH has provided drilling, hydraulic fracturing and hook-up costs for the wells SGE drilled in 2017. RISC support these costs as reasonable. The estimated cost for drilling & completion, hydraulic fracturing, and hook-up are 0.45, 0.29 and 0.22 million USD per well. RISC has added US$0.10 million per well for pre-spud engineering. Costs have reduced with experience over the past 3 years and a further 15% reduction in drilling and hydraulic fracturing costs estimated over the next 2 years.

Gas processing will be conducted by a number of gas station spread across the field. RISC and SGEH estimate a cost of US$8.5 million per 17 MMscf/d gas station. The gas station will dry and compress the gas from 200 psia to 1450 psia for export. The costs of in-field trunk lines between gas stations are also added.

The region offers a number of sales opportunities into the provincial pipeline grid or to a customer via one of the national gas pipelines that either run through or nearby the PSC.

The Capex estimate for each of the cases is considered to have an accuracy of +50%, - 25%.

Opex has been estimated based on scaling from the number of development wells and the facilities configuration and phasing. RISC's Opex estimates carry uncertainty. However, the impact of changes in Opex on the NPV is small.

Total Capex, Opex, production from 1/1/2018 to PSC expiry and resulting unit costs for the cases are shown in Table 4-11.

Table 4-11: Total and unit development costs

Gross costs		1P	2P	2P + 2C
Productive wells		1001	1001	1549
Production	Bcf	915	1384	2025
Total Capex	$ million (2018 RT)	1076	1132	1741
Total Opex	$ million (2018 RT)	1256	1316	1913
Unit Capex	$/mscf	1.2	0.8	0.9
Unit Opex	$/mscf	1.4	1.0	0.9
Unit Cost	$/mscf	2.5	1.8	1.8

The 2P case has the same number of wells as the 1P but larger production and facility capacity requirements. Therefore, the 2P Capex is slightly greater than 1P. The 2P Opex is greater due to higher production rates. However the unit costs are reduced by the greater production. The 2P+2C case has additional wells and production increasing the Capex and Opex. However the unit costs are similar to the 2P case. The cost of the two workovers per well after 4 and 8 years has increased previous Opex estimates.

4.8. Contingent Resources

Table 4-12 shows SGEH net contingent resources. These resources are more distant from well control and further appraisal is required to confirm their commerciality.

Table 4-12: Deep Gas Contingent Resources at 30/06/2018 (unrisked)

Contingent Resources (Bcf)	Gross			SGEH net		
	1C	2C	3C	1C	2C	3C
Produced during PSC period	412	615	857	72	108	150
Produced post PSC expiry	897	1487	2158	192	319	463
Infill or re-completion	977	1527	2143	210	328	460
Total	**2286**	**3629**	**5158**	**474**	**755**	**1073**

The contingent resource production forecast uses the same gas recovery per well and type curves as the reserve area; namely assuming that 70% of the estimated productive GIIP is developed. The remaining 30% of estimated productive GIIP may be a target for infill drilling or further well recompletions. However it is unclear if this opportunity will be commercial or pursued so these potential resources are contingent resources.

Production after the PSC expiry both from reserve areas and contingent resource areas is classified as a contingent resource for SGEH; contingent upon PSC extensions being awarded. Contingent resources associated with infill or re-completion are also estimated to largely be produced post PSC expiry.

RISC estimate a 90% probability that the 2C resources will mature to reserves and be developed. For SGEH and other contractors' contingent resources produced during the PSC period should be assigned this commercial probability.

SGEH contingent resources estimated to be produced after PSC expiry carry the additional risk of obtaining a PSC extension with the current terms. PSC extensions are not assured and RISC estimate that potential extensions are likely to include a reduction of PSC terms. Therefore, the commercial probability of these contingent resources is reduced.

Contingent resources produced after PSC expiry should not be included in the evaluation scenarios or heavily discounted due to uncertainties regarding PSC extension.

SGEH have additional contingent resources associated with the shallow CBM discovery in the north east of Linxing PSC. Development of these resources are estimated to be uneconomic due to low gas well production rates. Therefore, the resources are contingent upon demonstrating improved performance and economics.

RISC evaluated these resources year end 2016 and estimate the valuation to remain valid. However, the resources have reduced due to part of the area being relinquished; the area has reduced 42% from 265 to 155 km^2.

Table 4-13 shows the shallow CBM contingent resources after adjustment for the reduced area.

Table 4-13: Shallow CBM Contingent Resources at 30/06/2018 (unrisked)

Contingent Resources (Bcf)	Gross			SGEH net		
	1C	2C	3C	1C	2C	3C
Shallow CBM	64	160	252	20	51	80

The shallow CBM resources are not included in the valuation as their development is uneconomic.

4.9. Exploration Prospective Resources

The PSCs have prospective resources in undrilled or untested areas of the PSCs. Exploration wells are required to demonstrate mobile and commercial gas. However, nearly all of the exploration area in Linxing have been relinquished. If exploration is successful prospective resources are likely to be developed after contingent resources with very limited production before PSC expiry. Therefore, the potential value of prospective resources is estimated to be small and not included in the valuation scenarios.

Prospective resources were estimated by RISC YE2016. Linxing prospective resources have been adjusted for the reduced PSC area and contractor interest, Table 4-14.

Table 4-14: Prospective Resources as at 30/06/2018 (unrisked)

Prospective Resources (Bcf)	Area (km^2)	Gross			SGEH net		
		Low	Best	High	Low	Best	High
Sanjiaobei	394	1221	1926	2719	247	360	483
Linxing	19	45	76	110	10	15	22
Total	**413**	**1266**	**2002**	**2829**	**256**	**376**	**505**

RISC estimates a 60% geological change of success exploring for the prospective resources. In addition we estimate a 90% chance of commercialising the resources, giving a 54% overall chance of commercial development.

If successful most of the prospective resources are likely to be produced after PSC expiry. Therefore, SGEH and other contractors share of the resources carries the additional risk of obtaining PSC extensions with the current terms.

4.10. Resource Reconciliation

Table 4-15 shows the changes to SGEH deep gas resource estimates since year end 2017 due to:

- Gas production and sales;
- Changes to Linxing PSC;
- Technical revisions.

Table 4-15: Deep Gas Resource Reconciliation

Resource	PSC	Resource YE2017 Bcf	Production Bcf	PSC changes Bcf	Revisions Bcf	Resource 30/6/2018 Bcf	Change	See footnote
Reserves								
1P	Linxing	258	-2.9	-19	-122	114	-56%	#1, #2
	Sanjiaobei	126	-1.5		-63	62	-51%	#2
	Total	**384**	**-4.4**	**-19**	**-185**	**176**	**-54%**	
2P	Linxing	389	-2.9	-27	-191	168	-57%	#1, #2
	Sanjiaobei	188	-1.5		-98	88	-53%	#2
	Total	**577**	**-4.4**	**-27**	**-289**	**256**	**-56%**	
3P	Linxing	525	-2.9	-35	-259	227	-57%	#1, #2
	Sanjiaobei	251	-1.5		-131	119	-53%	#2
	Total	**776**	**-4.4**	**-35**	**-390**	**346**	**-55%**	
Contingent Resources								
1C	Linxing	414		-124	17	307	-26%	#3, #4
	Sanjiaobei	114			54	168	47%	#3
	Total	**528**		**-124**	**71**	**475**	**-10%**	
2C	Linxing	639		-192	40	488	-24%	#3, #4
	Sanjiaobei	174			93	267	54%	#3
	Total	**813**		**-192**	**133**	**755**	**-7%**	
3C	Linxing	891		-267	70	694	-22%	#3, #4
	Sanjiaobei	240			140	380	58%	#3
	Total	**1131**		**-267**	**210**	**1073**	**-5%**	
Prospective Resources								
Low	Linxing	283		-273		10	-97%	#5
	Sanjiaobei	247				247	0%	
	Total	**530**		**-273**		**256**	**-52%**	
Best	Linxing	461		-446		15	-97%	#5
	Sanjiaobei	360				360	0%	
	Total	**821**		**-446**		**376**	**-54%**	
High	Linxing	663		-641		22	-97%	#5
	Sanjiaobei	482				483	0%	
	Total	**1145**		**-641**		**505**	**-56%**	

Notes:

#1 Reserves in Linxing are reduced by the contractor interest in Linxing PSC reducing from 70% to 49% but increased by an 8 year PSC extension.

#2 Reserves are reduced by lower recovery per well, delayed production ramp-up and lower plateau production rates. This results in less production before PSC expiry. The volumes have been transferred to contingent resources.

#3 Contingent resources are increased by the transfer of reserves to contingent resources

#4 Contingent and prospective resources in Linxing are reduced by the contractor interest in Linxing PSC reducing from 70% to 49%.

#5 Linxing prospective resources have reduced due to relinquishment of 375 km^2 of the 394 km^2 deep gas exploration area plus contractor interest reduced from 70 to 49%.

4.10.1. Reserves reconciliation

Changes to Linxing PSC have had a small effect on reserves as the reduced contractor interest (70 to 49%) is offset by the 8 year PSC extension. The reduced interest is offset by 8 years additional production.

Reserves in both Linxing and Sanjiaobei have been reduced by technical revisions to the estimated gas recovery:

- Lower estimated recovery per well: This is in light of additional pilot production data, information from analogue fields and ODP information regarding a reduction in the estimated completion intervals per well. The initial completion is estimated to develop 40% of the pay and productive GIIP. Subsequent re-completion and hydraulic fracturing is estimated to develop an additional 30% of the pay and productive GIIP. The remaining 30% of the pay and productive GIIP could be developed with infill drilling or further re-completions. However, the economics and plans to pursue this remaining 30% are uncertain. Therefore these volumes have been moved from reserves to contingent resources.
- Slower estimated ramp-up in gas production and the lower plateau gas rates based on ODP plans: This results in less gas production prior to PSC expiry. Production from wells in the reserves area post PSC expiry is classified as a contingent resource; contingent upon PSC extensions with the same PSC terms.
- Plateau production was estimated from 2021 in the year end 2017 reserve estimates. ODP submissions and development plan have now matured and indicate plateau production from 2023/2024. Sanjiaobei and Linxing PSCs expire on 31/8/2033 and 31/8/2036 respectively, so this 3 year deferment is significant.
- Slower gas recovery per well: The initial well rate and early well production is reduced by the initial completion interval being limited to an estimated 40% of the pay and productive GIIP. Subsequent recompletion, adding another 30% of pay, generates additional production later in the wells life. However, overall this results in less production before PSC expiry and more production post PSC expiry. Production post PSC expiry is classified as a contingent resource.
- The slower planned ramp-up in production, reduced and slower gas recovery per well has moved more than 50% of reserves to contingent resources.

4.10.2. Contingent Resource reconciliation

Contingent resources have increased due to the movement of reserves to contingent resources. In Sanjiaobei the reduction in reserves is largely matched by an increase in contingent resources. In Linxing the movement of reserves to contingent resources is offset by a reduction in contractor interest in the Linxing PSC.

- The reduced contractor interest in Linxing PSC (70 to 49%) directly reduces Linxing contingent resource estimates by 30%. Contingent resources estimates are not limited to production prior to PSC expiry so the Linxing PSC extension does not affect them.

The contingent resources can be divided into the following groups with different probability of commercialisation:

- Estimated gas production from contingent resources area prior to PSC expiry. RISC estimate these resources to have a 90% probability of being developed.
- Estimated gas production from reserve and contingent resource areas after PSC expiry. Extension to PSCs are uncertain and the recent extension to Linxing resulted in reduced contractor interest. Therefore, the probability of SGEH as the PSC contractor commercialising these contingent resources is limited.
- Potential gas production from infill wells or further re-completion. Potential production is estimated to be largely after PSC expiry. Therefore, the discounted value and probability of commercialization is limited.

SGEH also have contingent resources in the shallow CBM area in the north east of Linxing East. However pilot production has not demonstrated economic development, therefore no value is assigned to these contingent resources.

4.10.3. Prospective Resource reconciliation

Prospective resources have been reduced in Linxing by the relinquishment of most of the exploration acreage and reduced contractor interest in the PSC. If exploration is successful, production of prospective resources is estimated to be largely after PSC expiry. Therefore, the discounted value and probability of commercialisation is limited.

4.11. Development Risks

Commercial gas production has been demonstrated by pilot production and most well test producing gas at rates above economic rates. SGE has also demonstrated its ability to manage field operations including multiple drilling rig, hydraulic fracturing and infrastructure construction operations. However, the ramp-up in gas production to plateau levels is taking longer than initially expected and the following milestones are yet to be managed:

- Approval of Sanjiaobei ODP and any associated supplementary agreements;
- Approval of additional stages of Linxing ODP and any associated supplementary agreements;
- Management and relinquishment of exploration areas;
- Building up gas production to plateau rate;
- Achieving plateau gas rates that maximize contractor return prior to PSC expiry;
- Negotiating potential PSC extension to enhance contractor return.

Economic production of tight gas fields typically extends over 30 to 40 years. However, these PSC are not planned to reach peak production until 2023, leaving only 10 to 13 years before PSC expiry. Negotiation of an 8 year extension to Linxing PSC resulted in the contractor interest reducing from 70 to 49%. This indicates that further PSC extensions if possible may be with reduced terms. Therefore, the value of economic production post PSC expiry for the contractor is uncertain and likely to be limited.

The pace of development and hence contractor value will depend upon the contractor and Authorities commitment to progress development, staff resourcing and funding capability, all of which carry uncertainty.

5. Declarations

5.1. Qualifications

RISC is an independent oil and gas advisory firm. The RISC staff engaged in this assignment include qualified petroleum reserves and resources evaluators as specified in ASX listing rules, engineers, geoscientists and commercial analysts, each with many years of relevant experience and most have in excess of 20 years.

RISC was founded in 1994 to provide independent advice to companies associated with the oil and gas industry. Today the company has approximately 40 highly experienced professional staff at offices in Perth and Brisbane, Jakarta and London. Our services cover the entire range of the oil and gas business lifecycle and include:

- Oil and gas asset valuations, expert advice to banks for debt or equity finance;
- Exploration/Portfolio management;
- Field development studies and operations planning;
- Reserves assessment and certification, peer reviews;
- Gas market advice;
- Independent Expert/Expert Witness;
- Strategy and corporate planning.

The preparation of this report has been supervised by **Mr Peter Stephenson**, RISC Partner. Mr Stephenson has over 34 years' experience in the upstream hydrocarbon industry with BP, Shell and RISC. He has extensive experience with mature and greenfield oil, gas, gas-condensate and CSG developments in the North Sea, Africa, Middle East, China, Asia and Australasia. Mr Stephenson has global experience in project gate reviews, data room and investment evaluation. Mr Stephenson specialises in reservoir evaluation, field development planning, integrated project reviews, multidisciplinary team coordination and leadership preparation of Independent Technical Specialist reports. Mr Stephenson is Member of the Society of Petroleum Engineers (SPE), the Society of Petroleum Evaluation Engineers (SPEE), the Institution of Chemical Engineers, and holds a M.Eng Petroleum Engineering, Heriot Watt University, 1984 and a B.Sc Chemical Engineering (IIi Hons), University of Nottingham, 1982. Mr Stephenson and is a qualified petroleum reserves and resources evaluator (QPPRE) as defined by ASX listing rules.

A summary of the experience of other staff contributing to this report follows:

Stephen Newman, Principal Advisor, has over 30 years of experience as a Geoscientist in the oil industry including 17 years with BP and Woodside and 9 years as a consultant including 6 years with RISC. He has led and contributed to assignments for due diligence, independent reserve and resource assessments, expert witness, geoscience studies, portfolio and strategy analysis. Mr Newman has a BSc in Exploration Sciences from University of Nottingham 1980, an MSc in Petroleum Geology from Imperial Collage 1985, is a member Petroleum Exploration Society of Australia (PESA) and South East Asia Petroleum Exploration Society (SEAPEX).

Joe Collins, Principal Consultant, has 14 years' experience in Process and Facilities engineering. During his time at RISC he has participated in over 100 assignments including due diligence work, asset evaluations, reserves certifications and project reviews with clients located all over the world. He has in-depth skills in the areas of; upstream facility capital and operational cost estimating, conceptual facilities design, well design and cost estimation and project performance evaluation and forecasting. Joe has particular experience in reviewing and evaluating LNG projects and unconventional developments in Australia. Prior to joining RISC Mr Collins worked for Wesfarmers for six years at their Petrochemical facilities in Kwinana, Western Australia where he filled a number of engineering and management roles. Joe started his career in the exploration industry gaining experience in electric wireline logging throughout Australasia with Halliburton. Mr Collins is a chartered professional engineer with Engineers Australia and a member of SPE. Mr Collins holds a Bachelor of Oil & Gas Engineering (Petroleum and Process Engineering), UWA, 2004 and a Diploma of Project Management.

5.2. VALMIN Code and ASIC Regulatory Guides

This Report has been prepared by RISC. This Report has been prepared in accordance with the Code for the Technical Assessment and Valuation of Mineral and Petroleum Assets and Securities for Independent Expert Reports 2015 Edition ("The VALMIN Code") as well as the Australian Securities and Investment Commission (ASIC) Regulatory Guides 111 and 112.

5.3. Petroleum Resources Management System

In the preparation of this Report, RISC has applied the guidelines and definitions of the Petroleum Resources Management System approved by the Board of the Society of Petroleum Engineers in 2007 (PRMS).

5.4. Report to be presented in its entirety

RISC has been advised by SGEH that this report will be presented in its entirety without summarisation.

5.5. Independence

This report does not give and must not be interpreted as giving, an opinion, recommendation or advice on a financial product within the meaning of section 766B of the Corporations Act 2001 or section 12BAB of the Australian Securities and Investments Commission Act 2001.

RISC is not operating under an Australian financial services licence in providing this report.

In accordance with regulation 7.6.01(1)(u) of the Corporations Regulation 2001. RISC makes the following disclosures:

- RISC is independent with respect to SGEH and confirms that there is no conflict of interest with any party involved in the assignment;
- Under the terms of engagement between RISC and SGEH for the provision of this report RISC will receive a time-based fee, with no part of the fee contingent on the conclusions reached, or the content or future use of this report. Except for these fees, RISC has not received and will not receive any pecuniary or other benefit whether direct or indirect for or in connection with the preparation of this report;
- Neither RISC nor any of its personnel involved in the preparation of this report have any material interest in SGEH or in any of the properties described herein;
- RISC has provided the following professional services to SGEH in the past two years.

Table 5-1: Projects completed

Project Name	Assignment Manager	Project completion date
Linxing & Sanjiaobei Independent Reserves and resource update YE2016	Peter Stephenson	01/03/2017
Linxing & Sanjiaobei Pilot production analysis	Peter Stephenson	05/12/2017
Linxing & Sanjiaobei Independent Reserves letter YE2017	Peter Stephenson	02/03/2018
Linxing PSC extension; sensitivity runs	Peter Stephenson	03/05/2018

- RISC has not provided advice to SGEH specifically in relation to the Proposed Transaction.

5.6. Limitations

The assessment of petroleum assets is subject to uncertainty because it involves judgments on many variables that cannot be precisely assessed, including reserves, future oil and gas production rates, the costs associated with producing these volumes, access to product markets, product prices and the potential impact of fiscal/regulatory changes.

The statements and opinions attributable to RISC are given in good faith and in the belief that such statements are neither false nor misleading. In carrying out its tasks, RISC has considered and relied upon information obtained from SGEH as well as information in the public domain.

The information provided to RISC has included both hard copy and electronic information supplemented with discussions between RISC and senior SGEH staff.

Whilst every effort has been made to verify data and resolve apparent inconsistencies, we believe our review and conclusions are sound, but neither RISC nor its servants accept any liability, except any liability which cannot be excluded by law, for its accuracy, nor do we warrant that our enquiries have revealed all of the matters, which an extensive examination may disclose. We believe our review and conclusions are sound but no warranty of accuracy or reliability is given to our conclusions.

Our review was carried out only for the purpose referred to above and may not have relevance in other contexts.

This report was substantially completed by 30 June 2018. We are not aware of any changes since that date that would have a material impact on the values and opinions contained within this report.

5.7. Consent

RISC has consented to this report, in the form and context in which it appears, being included in the Prospectus. Neither the whole nor any part of this report nor any reference to it may be included in or attached to any other document, circular, resolution, letter or statement without the prior consent of RISC.

This Report is authorised for release by Mr. Peter Stephenson, RISC Partner dated 9 July 2018.

Peter M Stephenson

Peter Stephenson
RISC Partner

6. List of terms

6.1. Abbreviations

The following table lists abbreviations commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
1P	Equivalent to Proved reserves or Proved in-place quantities, depending on the context.
1Q	1st Quarter
2P	The sum of Proved and Probable reserves or in-place quantities, depending on the context.
2Q	2nd Quarter
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional
3P	The sum of Proved, Probable and Possible reserves or in-place quantities, depending on the context.
3Q	3rd Quarter
4Q	4th Quarter
AFE	Authority for expenditure
bbl	US barrel
bbl/d	US barrels per day
Bcf	Billion (10^9) cubic feet
Bcm	Billion (10^9) cubic meters
BFPD	Barrels of fluid per day
BOPD	Barrels of oil per day
BTU	British thermal units
BOEPD	US barrels of oil equivalent per day
BWPD	Barrels of water per day
°C	Degrees Celsius
Capex	Capital expenditure
CAPM	Capital asset pricing model
CGR	Condensate gas ratio
CO_2	Carbon dioxide
cP	Centipoise
CPI	Consumer price index
DEG	Degrees
DHI	Direct hydrocarbon indicator
DST	Drill stem test
E&P	Exploration and production
EMV	Expected monetary value
EOR	Enhanced oil recovery
ESMA	European Securities and Markets Authority
ESP	Electric submersible pump

Term	Definition
EUR	Estimated ultimate recovery
F	Degrees Fahrenheit
FDP	Field development plan
FEED	Front end engineering and design
FID	Final investment decision
FM	Formation
FPSO	Floating production, storage and offtake unit
FWL	Free water level
FVF	Formation volume factor
GIIP	Gas initially in place
GJ	Gigajoules (10^9 J)
GOC	Gas-oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GSA	Gas sales agreement
GTL	Gas to liquid(s)
GWC	Gas water contact
H_2S	Hydrogen sulphide
HHV	Higher heating value
ID	Internal diameter
IRR	Internal rate of return
JV(P)	Joint venture (parties)
Kh	Horizontal permeability
km^2	Square kilometres
Krw	Relative permeability to water
Kv	Vertical permeability
kPa	Kilopascals (thousand Pascal)
Mstb/d	Thousand stock tank barrels per day
LIBOR	London inter-bank offered rate
LNG	Liquefied natural gas
LTBR	Long-term bond rate
m	Metres
MDT	Modular dynamic (formation) tester
mD	Millidarcies
MJ	Megajoules (10^6 J)
MMbbl	Million US barrels
MMscf(/d)	Million standard cubic feet (per day)
MMstb	Million US stock tank barrels
MOD	Money of the day (nominal dollars)
MOU	Memorandum of understanding
Mscf	Thousand standard cubic feet
Mstb	Thousand US stock tank barrels

Term	Definition
MPa	Megapascal (10^6 Pa)
mss	Metres subsea
MSV	Mean success volume
mTVDss	Metres true vertical depth subsea
MW	Megawatt
NPV	Net present value
NTG	Net to gross
ODT	Oil down to
ODP	Overall Development Plan (Chinese equivalent to a Field Development Plan)
OGIP	Original gas in place
OOIP	Original oil in place
Opex	Operating expenditure
OWC	Oil-water contact
P & A	Plug and Abandon (abandonment of wells)
PBU	Pressure build-up
PJ	Petajoules (10^{15} J)
POS	Probability of success
PRMS	Petroleum Resources Management System
PSC	Production sharing contract
PSDM	Pre-stack depth migration
PSTM	Pre-stack time migration
psia	Pounds per square inch pressure absolute
p.u.	Porosity unit
PVT	Pressure, volume and temperature
QA/QC	Quality assurance/ control
rb/stb	Reservoir barrels per stock tank barrel (at standard conditions)
RFT	Repeat formation tester
RT	Rotary table or real terms, depending on context
SC	Service contract
scf	Standard cubic feet (measured at 60 degrees F and 14.7 psia)
Sg	Gas saturation
SGE	Sino Gas and Energy Operating Company owned 49% by SGEH, 51% by CNEML
SGEH	Sino Gas and Energy Holdings
Sgr	Residual gas saturation
SOE	State Owner Enterprise (China)
SRD	Seismic reference datum lake level
SPE	Society of Petroleum Engineers
s.u.	Fluid saturation unit
stb	Stock tank barrels
STOIIP	Stock tank oil initially In place
Sw	Water saturation
TCM	Technical committee meeting

Term	Definition
Tcf	Trillion (10^{12}) cubic feet
TJ	Terajoules (10^{12} J)
TLP	Tension leg platform
TRSSV	Tubing retrievable subsurface safety valve
TVD	True vertical depth
US$	United States dollar
US$ million	Million United States dollars
WACC	Weighted average cost of capital
WHFP	Well head flowing pressure
WPC	World Petroleum Council
WTI	West Texas Intermediate

6.2. Definitions

The following table lists some definitions for terms commonly used in the oil and gas industry and which may be used in this report.

Term	Definition
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingent Resources are a class of discovered recoverable resources as defined in the SPE-PRMS.
Discount Rate	The interest rate used to discount future cash flows into a dollars of a reference date
EG	Gas expansion factor. Gas volume at standard (surface) conditions/gas volume at reservoir conditions (pressure and temperature)
Expectation	The mean of a probability distribution.
P90, P50, P10	90%, 50% & 10% probabilities respectively that the stated quantities will be equalled or exceeded. The P90, P50 and P10 quantities correspond to the Proved (1P), Proved + Probable (2P) and Proved + Probable + Possible (3P) confidence levels respectively if probabilistic techniques are used.
Possible Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.
Probable Reserves	As defined in the SPE-PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations as defined in the SPE-PRMS.

Term	Definition
Proved Reserves	As defined in the PRMS, an incremental category of estimated recoverable volumes associated with a defined degree of uncertainty Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. Often referred to as 1P, also as "Proven".
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.
Working interest	A company's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.