SUBSURFACE INPUT TO ENVIRONMENTAL APPROVAL FOR THE SILVER SPRINGS/RENLIM GAS STORAGE PROJECT

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Version/Date: Rev 0 / 25 November 2010

Document Status

Version	Purpose of Document	Orig	Review	RPS Release Approval	Issue Date
Rev C	Draft for Internal Review.	LS	DM	DRG	14/11/10
Rev D	Draft for Client Review	LS	DM	DRG	21/11/10
Rev F	Draft for Client Review	LS	DM	DRG	24/11/10
Rev G	Draft for Client Review	LS	DM	DRG	25/11/10
Rev 0	Final for issue to client	LS	DM	DRG	30/11/10

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1.0 INTRODUCTION

1.1 Introduction Silver Spring-Renlim Fields

The Silver Springs-Renlim (SSR) gas fields of PL16 are located in the Surat Basin of Southeast Queensland (Figure 1-1). The location is approximately 100 kms south of Roma and 400 kms west of Brisbane.

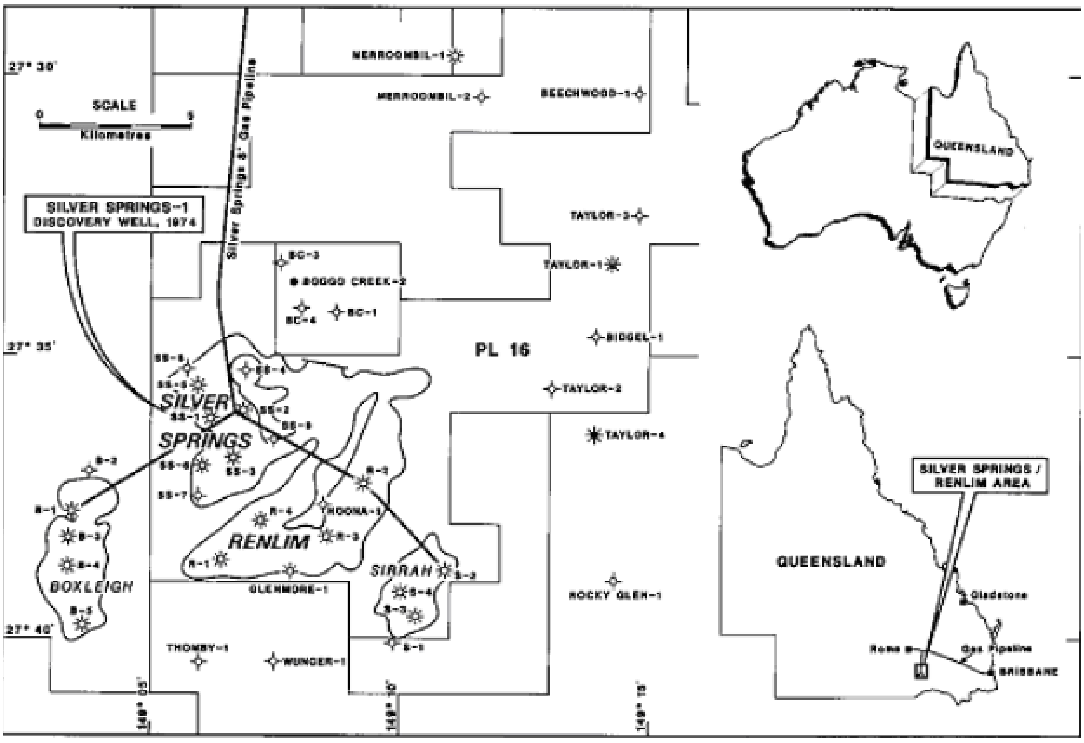

Figure 1-1 - Map of the Silver Springs and Renlim Gas Fields

The field was discovered in 1974, and has been on production since 1978, with most of the production taking place prior to 2001. Over 90.2 Bscf of gas along with 400 Mstb of condensate and over 3.3 MMstb of water have been produced.

1.2 Silver Springs-Renlim Underground Gas Storage Project

The SSR fields are depleted and will be developed as an Underground Gas Storage facility to fulfil a contractual obligation to store up 33 Bscf gas for future export once coastal LNG facilities are developed. The planned underground storage facility also includes use of the adjacent Renlim Field reservoir. The dominant philosophy for the storage program is to utilise wells that already exist on the Silver Springs and Renlim structures. This proposed project will only proceed after the present condition of the production wells is investigated thoroughly so that well integrity can be guaranteed over the duration of the project.

1.3 Scope of Work

The objective of this document is to review the sub-surface work that has been conducted for the Silver Springs Underground Gas Storage (UGS) project and make recommendations for future reservoir monitoring and management.

The study focused on the following topics:

- Determine the maximum gas injection volume and injection rate and highest sand face pressure during injection;
- Estimate the injectivity index of the well to demonstrate that the maximum expected well injection pressure is significantly less than formation fracture pressure;
- Review the integrity of existing and abandoned wells which will provide an insight to the corrosion level, future casing and cementing design;
- Review of adequacy of isolation of aquifers in the event of gas leakage into the well casing (to prevent leakage between aquifers and to surface);
- Review of future produced water disposal strategy; and
- Associated subsurface risks and recommendations.

2.0 PETROLEUM ENGINEERING / SUBSURFACE REVIEW

2.1 Storage / Withdrawal Volume

The project is driven by a contractual commitment to store 33 Bscf (33 PJ)[1] of gas with first gas to be injected by April 2011. Gas injection will commence at a rate of 3 MMscf/day and will continue for 36 consecutive months to meet the storage volume target. It is calculated that 10% of this i.e. 3 Bscf will be lost as a working gas volume.

Once the total gas storage volume in the Silver Springs and Renlim reservoirs reaches 33 Bscf the withdrawal phase will commence. Gas will be withdrawn at a rate similar to the injection phase. A complete injection-withdrawal cycle is expected to last six years.

2.2 Geology

The SSR gas field is an anticline feature of two joint accumulations. The productive horizon lies in the Triassic Age Showgrounds sandstone formation. The Showgrounds Sandstone is a coarse conglomeratic package deposited in a high energy fluvial environment, with single inter-bedded shale. The SSR field is an ideal candidate for UGS due to the high porosity (12%) and good permeability (10-6000mD) of the Showgrounds reservoir. The overlying Snake Creek Mudstone (cap rock) is of uniform thickness across the field (10-15m) and provides a proven reservoir seal.

2.3 Gas Initially In Place (GIIP)

Several studies have been conducted to determine the SSR GIIP. The most likely GIIP is approximately 115 Bscf with partial and torturous pressure support from a regional aquifer[2]. There is evidence that the reservoir pressure re-charged approximately 90 psi from 1998 to 2009. However, some studies suggest that GIIP could be as high as 203 Bscf based on a volumetric depletion analysis (P/Z Method)[3].

2.4 Reservoir Pressure

Historical static pressures for the SSR show that there is good communication between these two areas[3] (Silver Springs and Renlim). The Renlim area pressure is slightly higher than the pressure in Silver Springs, but follows the same depletion trend. The difference is no more than 50 psi between the two fields at any given time and is therefore insignificant. The initial reservoir pressure at 5,300 ft TVDss datum was found to be 2,790 psia and reservoir temperature is 82°C. The pressure gradient is 0.53 psi/ft, slightly over-pressured compared to a normal hydrostatic pressure gradient of 0.433 psi/ft. Figure 2-1 depicts the initial reservoir pressures.

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1 Silver Springs – Renlim Field Underground Gas Storage (UGS) Basic of Design Document for Subsurface Development (SSS-ENG-GL-002), 6 October 2010.

2 Silver Springs/Renlim OGIP and Material Balance Issues, Henry Irrgang, 16th April, 2009.

3 Silver Springs/Renlim Area, Explotation and Production Review, Surat Basin, Queensland, Prepared for Mosaic Oil N.L., Claudia Davies, 14th November 2000.

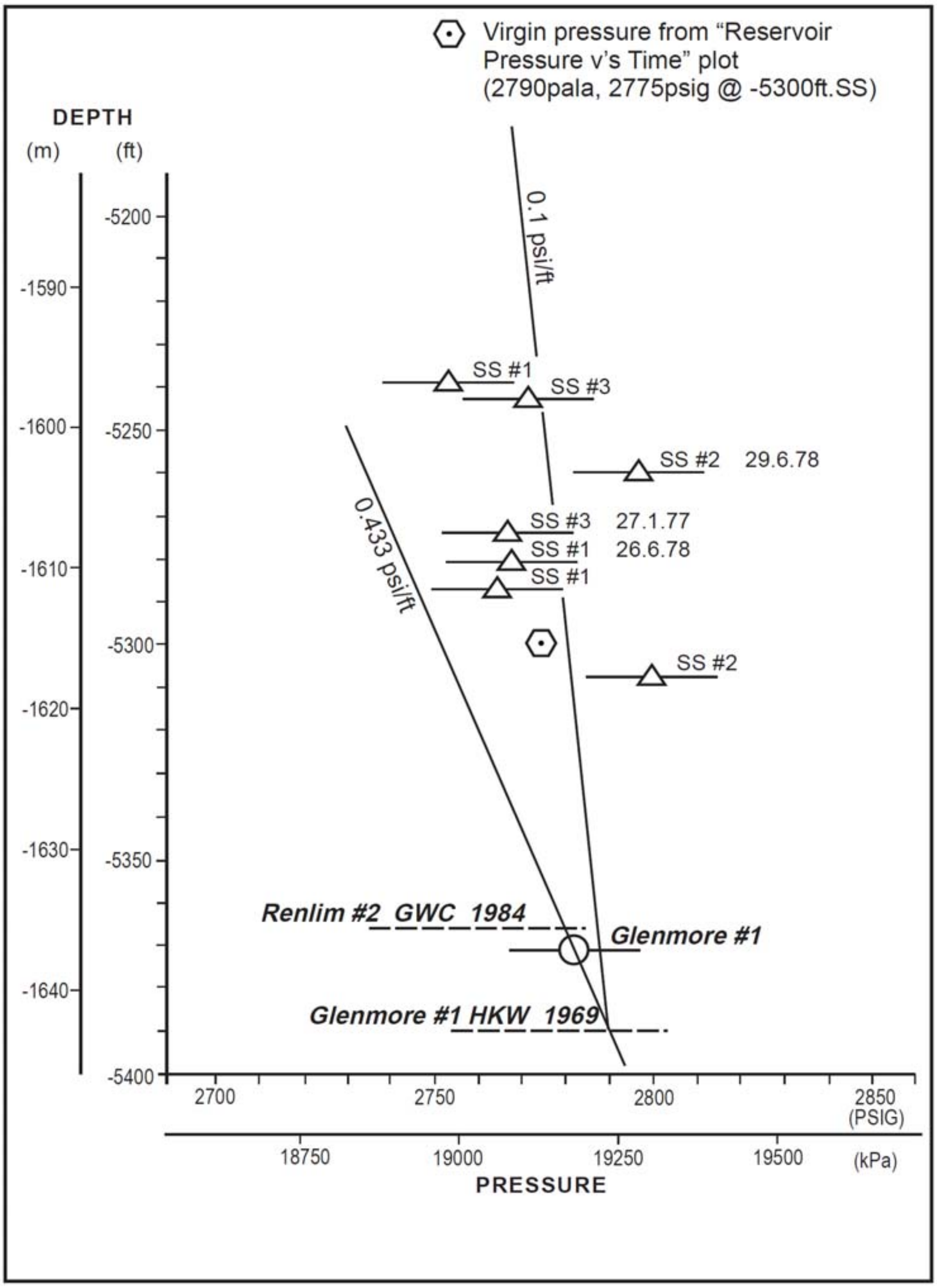

Figure 2-1 – SSR Pressure Gradient[4]

2.5 Maximum Gas Injection Volume

A dynamic SSR reservoir simulation for a complete injection-withdrawal cycle has been completed by AGL. Prior to the prediction runs, the reservoir pressures from start of production until the present date have been history matched (Figure 2-2). The injection and withdrawal volumes and rates are depicted in Figure 2-3 and the pressure profiles are in Figure 2-4.

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4 Silver Springs/Renlim Field-Australia, Bowen Basin, Queensland, Rowan Roberts, Bridge Oil Limited, Sydney, Australia

Based on the simulation work, the maximum gas volume that can be injected into the SSR field is approximately 70 Bscf without exceeding the sand face injection pressure of 2779 psia which is the original reservoir pressure. However, this is more than twice the obligated contractual volume and therefore, there is sufficient margin not to exceed the safe injection volume and injection pressure. The sand face injection pressure is the pressure at the perforations between the casing and the formation during the injection cycle.

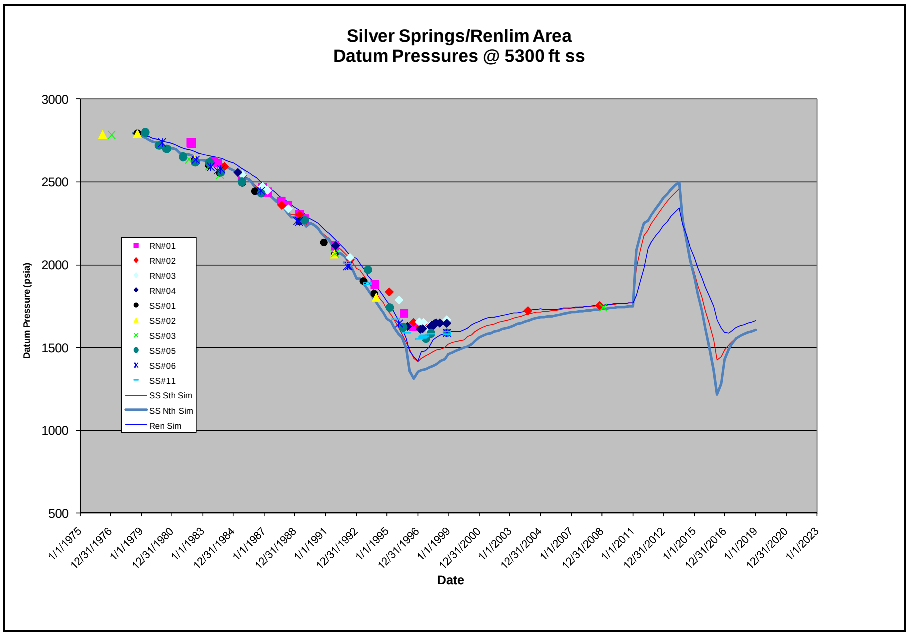

Figure 2-2 – SSR Reservoir Simulation Pressures (Complete)

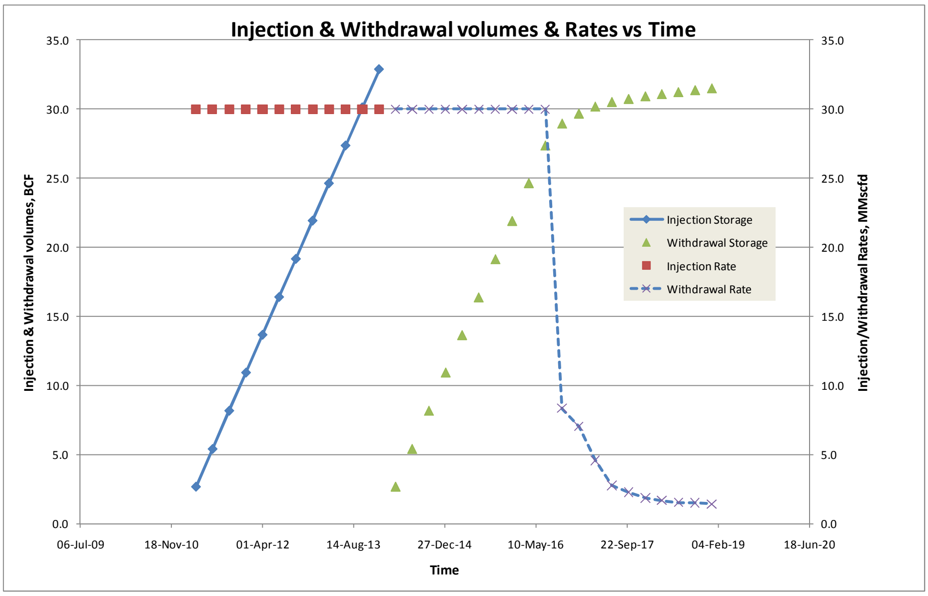

Figure 2-3 – SSR Reservoir Simulation Rates and Volumes (Injection-Withdrawal)

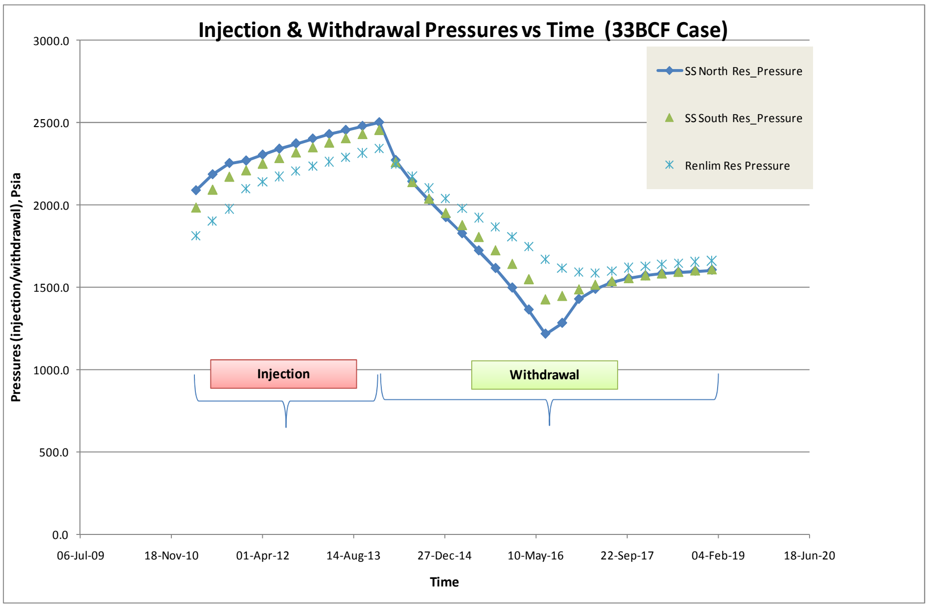

Figure 2-4 – SSR Reservoir Simulation Pressures (Injection-Withdrawal)

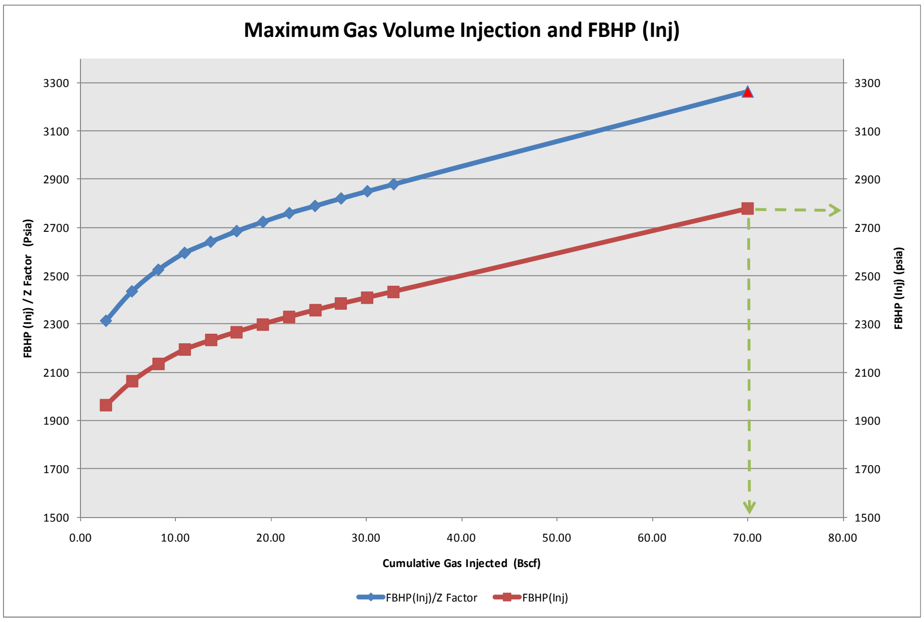

Figure 2-5 – SSR Maximum Gas Volume

During the withdrawal phase of the simulation study (Figure 2-6) an average of 320 stb/d of water was produced for the first 2.5 years. However, a significant amount of water is produced after recovering 28.9 Bscf of the injected gas which is 88% of the contract requirements. Assuming a water cut-off rate of between 2000 and 2500 stb/d (or WGR between 67 and 83 stb/MMscf), the total gas recovery would be approximately 29.6 Bscf or 90% of the contract requirements. RPS has independently modelled the gas producer (Section 2.6) to confirm that the wells are capable of producing such a high water gas ratio (WGR).

Based on the level of analysis conducted to date, RPS has concluded that approximately 10% of the gas will possibly be lost due to operational factors and gas dissolving in the water at higher pressure during a full cycle of injection and withdrawal. However, some "losses" may be seen as cushion gas, and will likely be recovered in the final blow down.

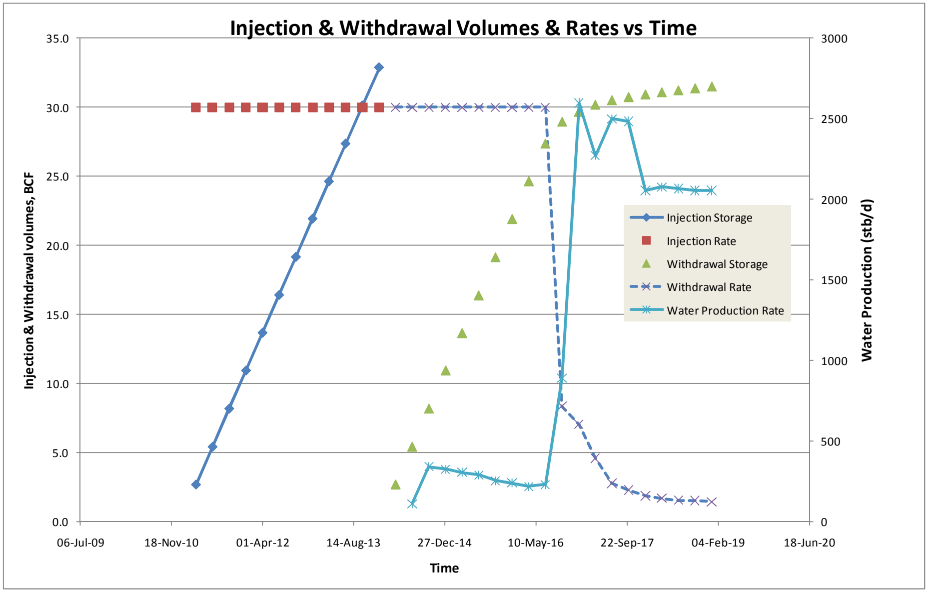

Figure 2-6 – SSR Injection and Withdrawal Volumes and Water Production

2.6 Gas Well Productivity and Injectivity

The knowledge of maximum sand face pressure and injection rates is crucial to ensure that the injection pressures do not formation failure or the seal / trap to leak. Prior to commencing the injection cycle, well injectivity testing must be conducted once the wells are re-completed as gas injectors. AGL has confirmed that the injectivity testing will be carried out at the start of the gas injection process.

RPS has modelled the gas well injectivity using the Prosper™ (Petroleum Experts) software. The gas injection well Inflow Performance Relationship (IPR) is generated by converting the IPR of the gas producer[5]. The inflow performance relationship is a mathematical tool used in production engineering to assess well performance by plotting the well production rate against the flowing bottom hole pressure (BHP).The reservoir parameters used to generate the gas producer's IPR is in Table 2-1 and the resulting IPR are presented in Figure 2-7.

5 Silver Springs/Renlim Gas Storage Gas Storage Review, Helix RDS, Ref: MONL0002, Revision No. 0, 22nd May 2009

RPS

Parameter	Value	Units
Reservoir Permeability, k	500	mD
Reservoir Thickness	63	ft
Drainage area	1447	acres
Dietz Shape Factor (Square reservoir)	30.9972	
Wellbore Radius (Assumed)	0.33	ft
Perforation Interval	30	ft
Skin	230	

Table 2-1 – Reservoir Parameters Used for Gas Producer IPR

The skin of 230 is very high. Skin is a dimensionless factor calculated to determine the production efficiency of a well by comparing actual conditions with theoretical or ideal conditions. A high skin indicates the well is damaged and may require stimulation to improve the production or injection efficiency.

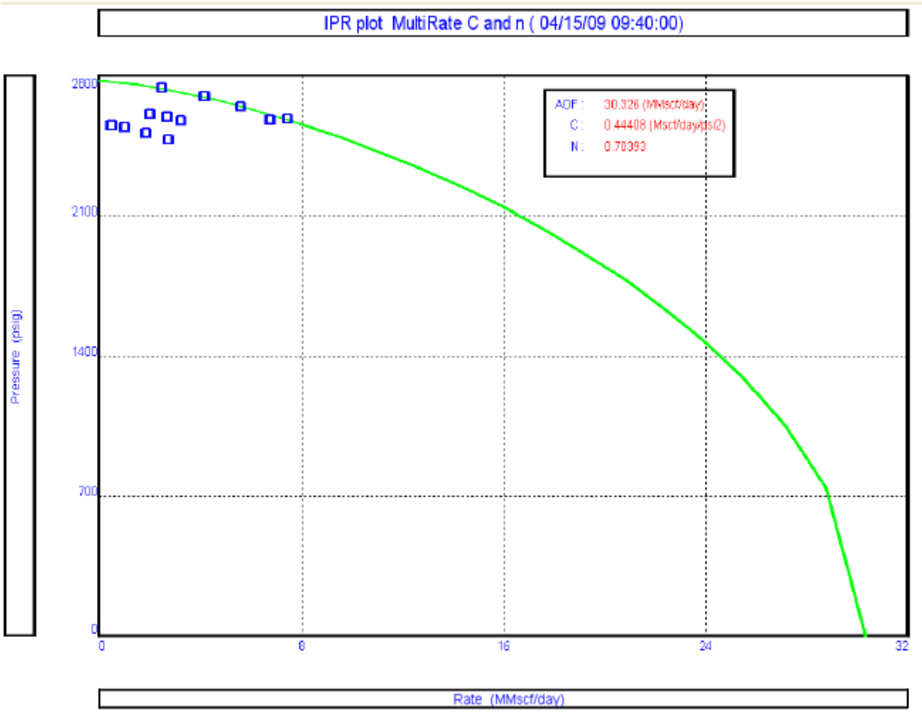

Figure 2-7 – IPR for Gas Producer (Skin=230)

Assuming well with skin of 2 , which assumes re-perforation will bypass skin, RPS had independently generated the IPR / VLP curves for 2.875, 3.5 and 4.5 inch tubing sizes to confirm that the gas producer is capable of producing at WGR between 60 and

90 stb/MMscf. Figure 2-8 and Table 2-2 show that only gas producer with tubing size of 4.5 inch is capable of producing more than 10 MMscf/d at these WGR's for reservoir pressure between 1700 – 2764 psig. For 2.875 inch tubing, the flow rate drops from 9 MMscf/d at reservoir pressure of 2764 psig to 3.0 MMscf/d at reservoir pressure of 1700 psig. This confirms AGL's simulation that once the WGR reaches between 60 and 90 stb/MMscf, the gas rate reduces drastically.

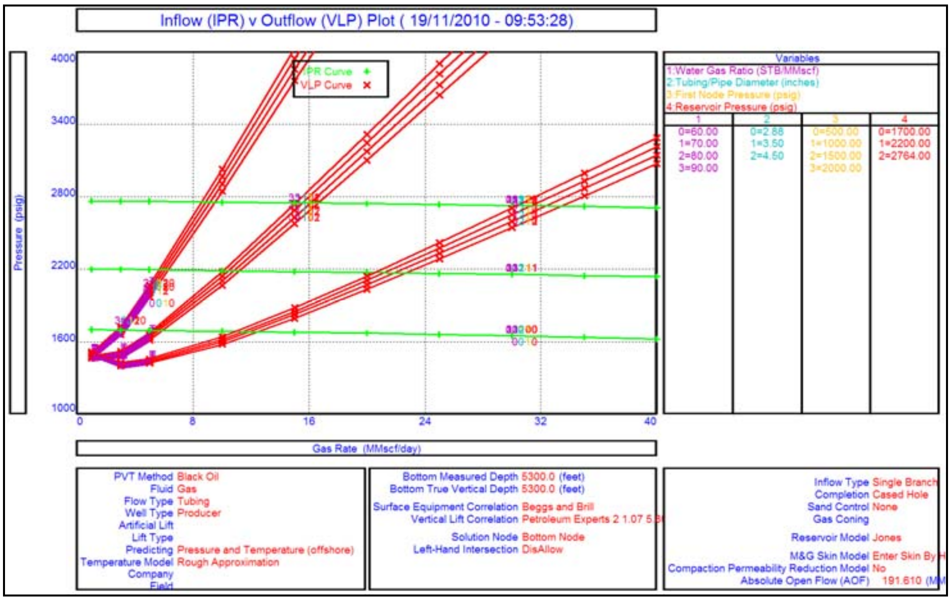

Figure 2-8 – Gas Producer IPR/VLP (Skin of 2)

Tubing Size (Inch)	2.875	3.50	4.50
WGR (stb/MMscf)	60 - 90	60 - 90	60 - 90
Reservoir Pressure (psig)	2764		
Gas Rates (MMscf/d)	8.5 - 9.5	15.0 - 16.5	30.5 – 33.5
Reservoir Pressure (psig)	2200		
Gas Rates (MMscf/d)	5.5 – 6.5	10.0 – 11.5	20.5 – 23.0
Reservoir Pressure (psig)	1700		
Gas Rates (MMscf/d)	2.5 – 3.5	5.0 – 6.0	11.0 – 12.5

Table 2-2 – Gas Rates at Various WGR and Tubing Sizes

The modelled IPR for gas injector assuming a skin factor of 2, 5, 10, 20 and 230 are depicted in Figure 2-9. The calculated skin of 230 is extremely high and is indicative of significant formation damage. Skin values generally range from -8 (stimulated well) to 0 (no damage) to 6 (minor damage) to +12 (significantly damaged well). A skin value greater than +12 is more likely an artefact of the mathematical calculations and does not indicate the extent of the damage other than the fact the well is likely to be badly damaged. RPS assumed the gas injection well will have a small skin for this study because AGL have indicated that they are going to re-perforate which if done successfully will bypass the damage.

The results from Prosper™ modelling are presented from Figure 2-10 to Figure 2-12 and Table 2-3. The maximum gas injection rate is approximately 46, 25 and 15 MMscf/d for 4.5, 3.5 and 2.875 inch tubing, respectively at flowing wellhead pressure (FWHP) injection pressure of 2,400 psig at the lowest reservoir pressure (1,800 psig). However, these rates reduce to 23, 12 and 7 MMscf/d at higher reservoir pressure (2,600 psig). The proposed field gas injection is 30 MMscf/d using three wells; each well will be injecting about 10 MMscf/d. The Prosper™ modelling work suggests that the proposed injection rates are achievable except 2.875 inch tubing at higher reservoir pressure of 2600 psig. From Table 2-4, the maximum pressure differential between shut-in bottom hole pressure (SIBHP) and injection bottom hole pressure (IBHP) (psi) at twice the design rate is 87 psi. Therefore, the expected sand-face injection pressure should be able to be maintained less than initial reservoir pressure during injection phase.

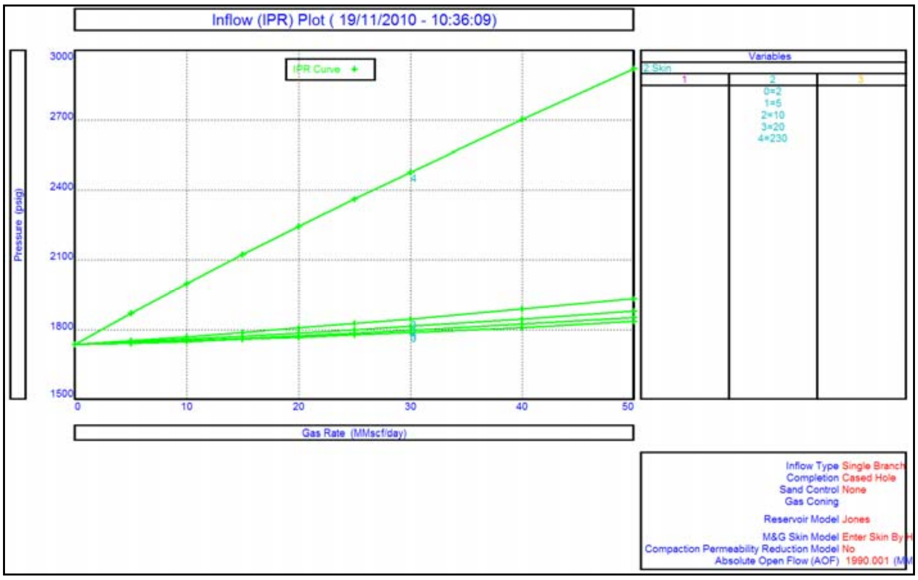

Figure 2-9 – IPR for Gas Injector at Various Skin

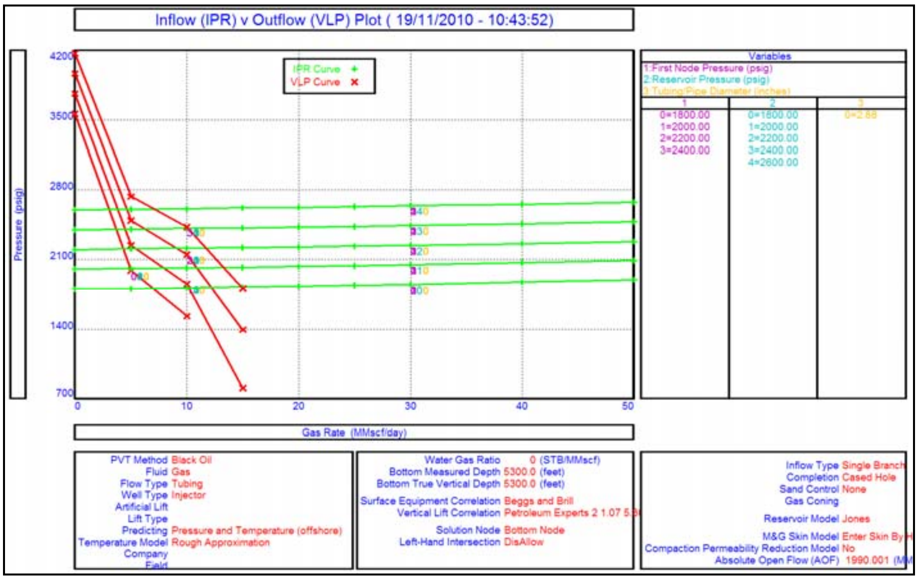

Figure 2-10 – IPR/VLP for Gas Injector (Tubing Size = 2.875 Inch)

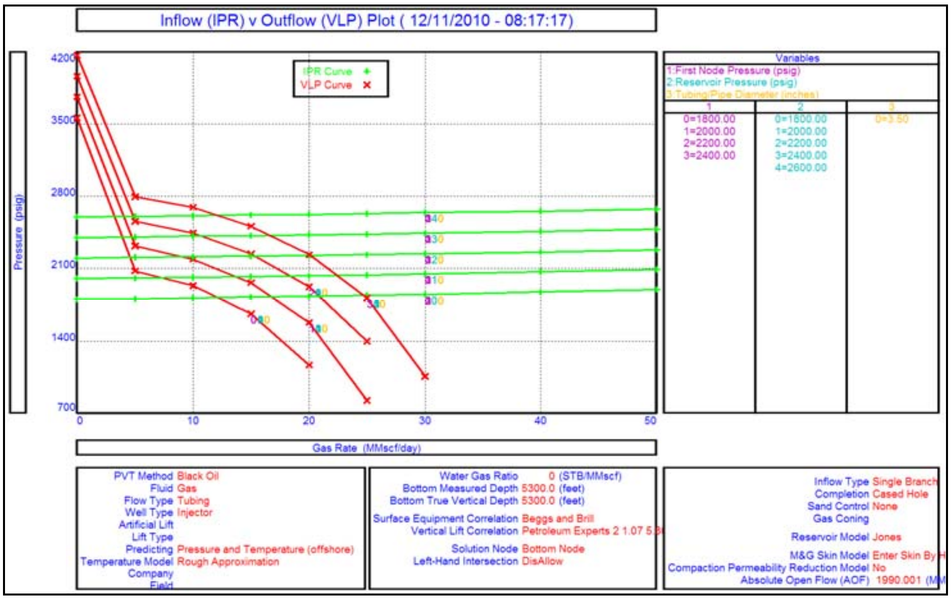

Figure 2-11 – IPR/VLP for Gas Injector (Tubing Size = 3.5 Inch)

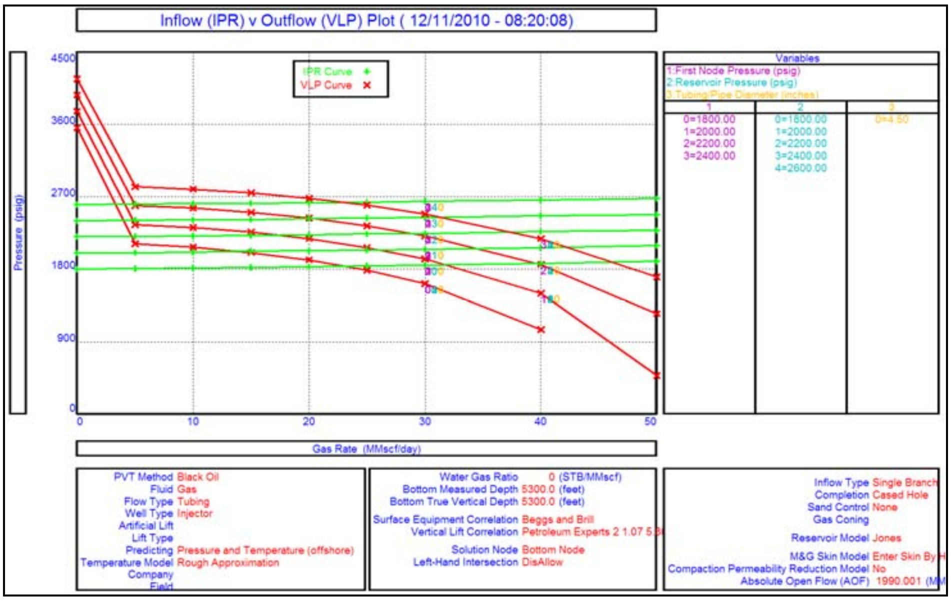

Figure 2-12 – IPR/VLP for Gas Injector (Tubing Size = 4.5 Inch)

Tubing Size (Inch)	**2.875**		**3.50**		**4.50**	
Skin	**2.0**					
FWHP-Injection (psig)	1,800	2,400	1,800	2,400	1,800	2,400
Reservoir Pressure (psig)	**1,800**					
Maximum Gas Injection Rate (MMscf/d)	7	15	12	25	23	46
BHP-Injection (psig)	1,810	1,821	1,817	1,839	1,836	1,887
Reservoir Pressure (psig)	**2,600**					
Maximum Gas Injection Rate (MMscf/d)	3	7	3	12	3	23
BHP-Injection (psig)	2,603	2,607	2,603	2,613	2,603	2,628

Table 2-3 – Prosper™ Maximum Gas Injection Rates

Tubing Size (Inch)	2.875	3.50	4.50
Maximum Gas Injection Rate (MMscf/d)	15	25	46
Maximum Pressure Differential Between SIBHP and IBHP (psi)	21	39	87

Table 2-4 – Maximum Pressure Differential between Shut-in BHP and Injection BHP

2.7 Basis of Design for Subsurface Development

AGL has prepared the subsurface design considerations and methodology for SSR underground gas storage project[6]. The current status and future well planning for are presented in Figure 2-13. A total of four injector / withdrawal wells are planned; three converted existing wells and one new well, which will be designated as SS#12, will be drilled. SS#12 will be drilled under IA-120150. There are two primary injectors and two back up wells. The five nominated monitoring wells are distributed across the field. Some wells used for reservoir monitoring and will be utilised to observe pressure development and movement of the gas-water contact. AGL will use other wells to monitor gas leakage into Walloon Coal and Showgrounds Aquifer and degree of gas-water saturation during the injection and withdrawal phases.

6 Silver Springs-Renlim Field Underground Gas Storage (UGS) Basic of Design Document for Subsurface Development, Document # SSS-END-GL-002, Kris Johnstone, 6th October 2010.

Well	Current Status	UGS Well Status
Silver Springs #8	Partially Abandoned – Water Well	Abandoned
Silver Springs #7	Partially Abandoned – Water Well	Abandoned
Silver Springs #6	Shut-In. (Perforated in Waloon Coal)	Monitoring
Silver Springs #5	Shut-in.	Abandoned
Silver Springs #1	Shut-in	Monitoring
Silver Springs #11	Shut-In	Withdrawal (back-up)
Silver Springs #12	***Not yet drilled***	**Injector (PRIMARY)**
Silver Springs #2	Shut-In	Abandoned
Silver Springs #3	Shut-In	Injector (back-up)
Silver Springs #9	Partially Abandoned – Water Well	Abandoned
Silver Springs #10	Partially Abandoned – Water Well	Abandoned
Silver Springs #4	Abandoned	Abandoned
Renlim #5A	Producer (Intermittent)	Injector (back-up)
Renlim #4	Shut-In	Injector (PRIMARY)
Renlim #1	Shut-In	Monitoring
Renlim #3	Shut-In	Monitoring
Renlim #2	Shut-In	Monitoring

Figure 2-13 – Status of Current Wells and Future Well Planning

2.7.1 Well Integrity Considerations

Throughout the life of the field, the gas composition will be mainly methane (CH_4: 80%; C_2H_6: 6%; C_3H_8: 6%) with no CO_2 or H_2S. Therefore the injection and production gas is considered non- corrosive. However, corrosion due to water is still a possibility. Therefore, a measure of corrosion rate for tubing and casing is crucial.

AGL has planned to analyse the tubing removed from SS#1 which is the oldest well in the field with more than 20 years production. Evaluation of this well will provide a good benchmark to estimate the level of corrosion expected on other wells in the field. The condition of the production casing on five wells in the field will be evaluated. Any completion tubing will be removed from the well prior to running evaluation logs. The following parameters will be logged via electric line to help determine the forward program:

- Wall thickness checks of the production casing using equipment such as the Schlumberger USIT™ UltraSonic Imager tool (USIT). The USIT emits ultrasonic pulses and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection.

- Confirmation of top of cement and condition of existing cement using equipment such as the Schlumberger CBL/VDL, a sonic device which generates a representation of the integrity of the cement job, especially whether the cement is adhering solidly to the outside of the casing.

RPS opines that the proposed testing is adequate to ascertain that the well integrity is not compromised.

The original well design criteria included partial cementation of the production casing, with top of cement placed above the Hutton sandstone, the main aquifer in the area. Because of the good porosity and permeability it is also a potential hydrocarbon reservoir. The previous surface casing string (9-5/8 inch casing) is set shallow at +/- 220m from ground level, thereby leaving up to 1300m of production casing un-cemented. It is imperative that adequate isolation of Hutton and Springbok aquifers is achieved to avoid gas loss in the event of gas leakage.

The proposed designs for monitoring and injection / withdrawal wells are presented from Figure 2-14 to Figure 2-16. The old wells will be cemented up to 400 meters above the reservoir and the new well will be cemented to surface.

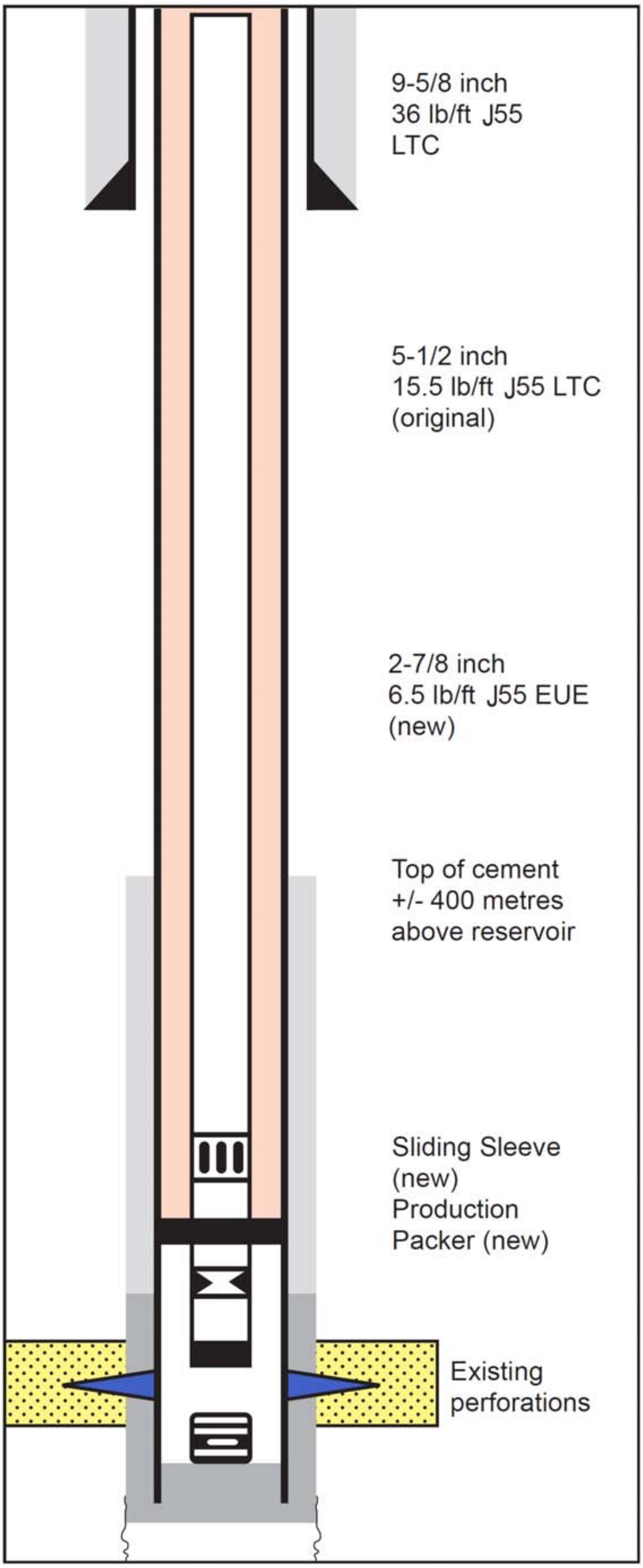

Figure 2-14 – Proposed Monitoring Well Design

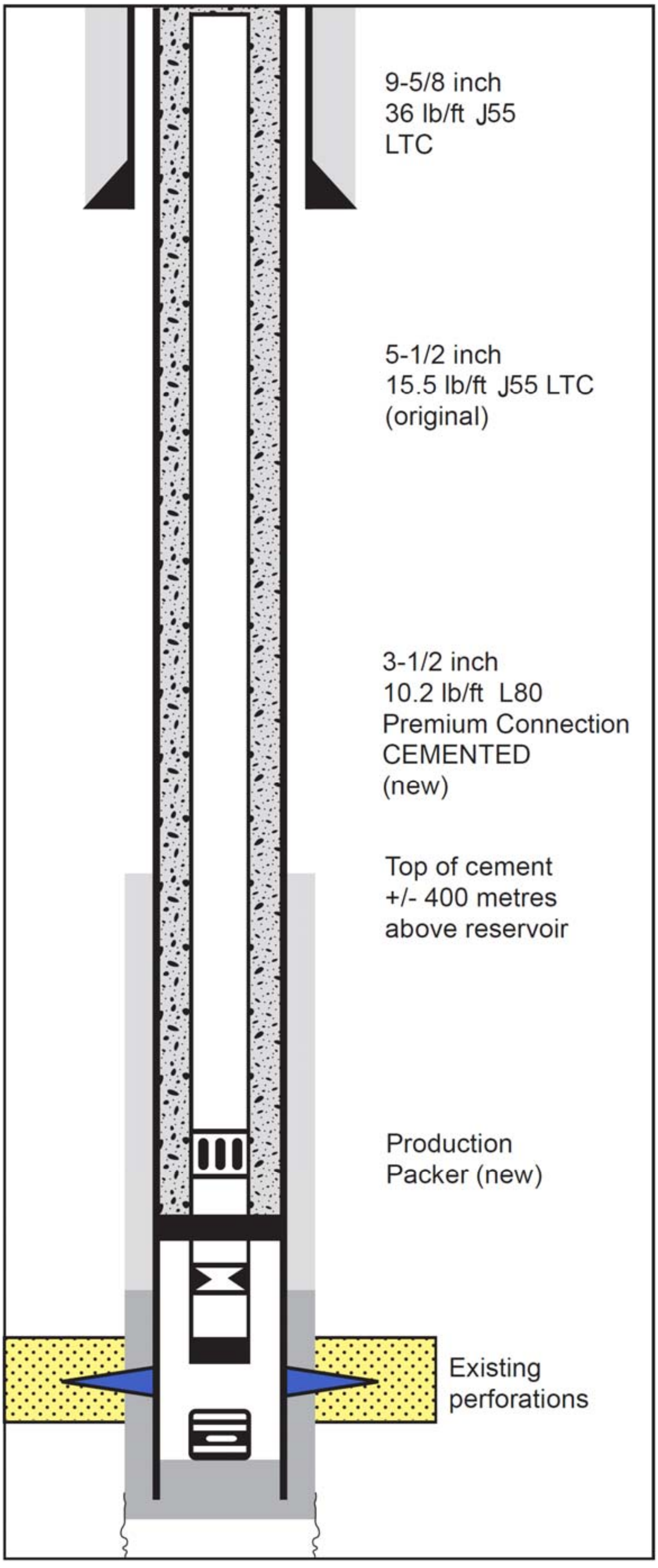

Figure 2-15 – Proposed Design for Injection / Withdrawal Wells

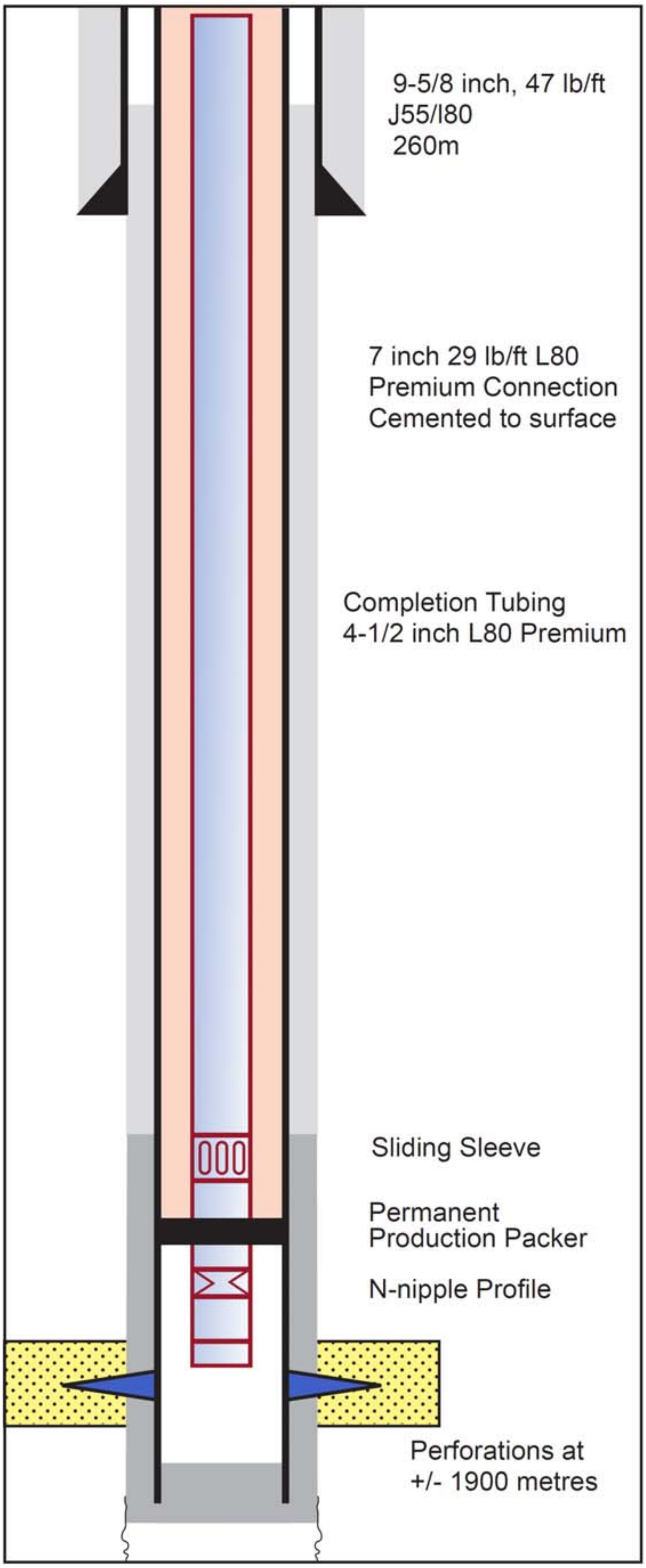

Figure 2-16 – Proposed Design for Newest Injection / Withdrawal Well (Option 1)

2.7.2 Well Design Criteria

2.7.2.1 Design Criteria for Injection Wells

The maximum static pressure of the reservoir should not be exceeded during the injection phase. The original virgin reservoir pressure is 2790 psia and the estimated maximum flow rates of wells in injection mode are:

- For 4.5 inch in completion: 20 MMscf/day
- For 3.5 inch in completion: 10 MMscf/day

The re-calculated internal yield of production casing will be based on the actual measured wall thickness. The re-calculated internal yield must not be less than 3000 psig to be compatible with the design criteria of the compression facility. The operating time for the injection phase is estimated to be 36 months.

The largest difference between 'injection' and conventional production is that the injection phase induces wellhead pressures higher than any previously experienced during the production phase. In addition, it is expected that the temperature of the injected gas may be higher than that of the produced gas, depending on the amount of discharge cooling in the compression facilities and the length of the flow line.

2.7.2.2 Design Criteria for Withdrawal Wells

The estimated maximum rates of wells in withdrawal mode are:

- For 4.5 inch completion: 30 MMscf/day
- For 3.5 inch completion:15 MMscf/day

Actual flow rates will vary over the withdrawal period based on pressure drop across reservoir and water production. The gas is anticipated to enter the surface facilities / pipeline at +/- 1080 psig

The re-calculated internal yield of production casing based will be based on the actual measured wall thickness. The re-calculated internal yield must not be less than 2000 psig to ensure that there is sufficient safety factor in the casing in the even that the cement job is less than satisfactory.

The operating mode for gas withdrawal is very similar to that of conventional production albeit with a shorter phase life. At some point during the withdrawal phase formation water will be produced and production rates will be adjusted according to field strategy. The operating time for withdrawal is estimated to be 36 months.

It should be noted that this proposed design (utilising existing well architecture) assumes a limited life of one gas storage cycle (approximately 7 years). This is in contrast to the surface facilities which have been designed for a 20 year lifespan.

2.7.2.3 Independent Tubular and Wellhead Design Review

It is recommended that the tubing, casing and wellhead design calculations are reviewed by an independent third party. These design checks should take into account the data obtained from the inspection of the tubing and casing in selected existing wells as well as the predicted wellhead temperatures and pressures to be experience during the production and injection cycles.

2.7.3 Water Disposal

Since there are new environmental directives regarding evaporation ponds, AGL is considering water disposal into the aquifer. The produced water needs to be treated (so that it is equal to or of better quality than that contained in the aquifer) prior to re-injection into the down-dip wells in the Showground reservoir. Periodic water sampling will be required to determine potential hydrocarbon contamination of the aquifer.

2.8 Subsurface Risks

There are some subsurface risks associated with the project. These have been addressed in AGL's Basis of Design document but have also been reproduced below:

- Current production casing may not suitable for well conversions. The present condition of the casing is unknown. If the casing condition does not match the minimum design criteria, then the well will be abandoned. A contingency plan exists to cement the production string and/or drill new wells for monitoring, injection and withdrawal.

- Based on offset drilling experience in the nearby Taylor Field which is also a depleted reservoir,, drilling fluid losses were encountered after entering the reservoir. A similar problem situation could arise when drilling the new injection well. Lost Circulation Material (LCM) will be available onsite during drilling operations as a contingency for lost circulation. LCM is a collective term for material added to drilling fluids when drilling fluids are being lost to the formations while drilling a well. The LCM eliminates or minimizes the loss of drilling fluids to the formation. Reducing the fluids lost while drilling leads to a reduction in the damage to the formation caused by drilling operations and allows the well to be drilled safely. Commonly used lost circulation materials include cedar bark, shredded cane stalks, mineral fibre, calcium carbonate and pieces of plastic or cellophane sheeting; or granular material such as ground and sized limestone or marble, wood, nut hulls, Formica, corncobs and cotton hulls.

- Loss of integrity (leaking gas) is a possibility. Sustained casing pressure (annulus) is an indication of "loss of barrier" and annulus communication with the reservoir or higher pressured formation. Integrity checks with logs and Ultrasonic will be conducted to assess the condition of this cement column prior to running a new completion. This information will be used to assess the possibility and probability of any future leakage. Figure 2-17 shows the number of potential leak paths along a well.

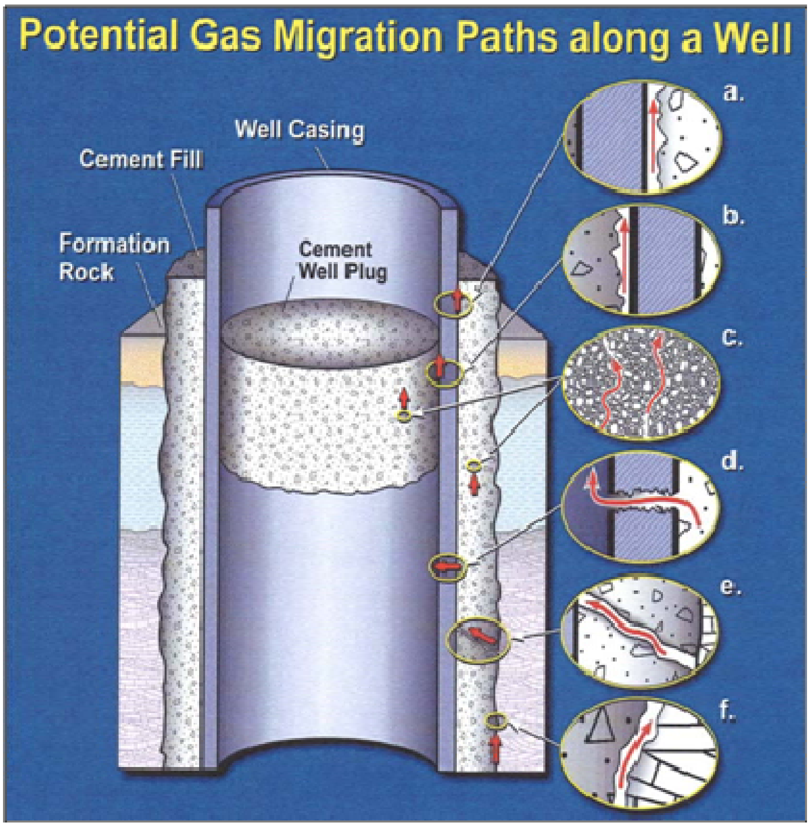

Figure 2-17 – Potential Migration Paths along a Well

- High skin factor - High skin factors were reported to effect original Silver Springs and Renlim production rates. Whilst the exact cause is unknown it is suspected that mud type, cementing technique and perforation technology may have contributed at the time. The Silver Springs and Renlim wells were drilled over the period from 1974-1991. For all existing wells to be re-entered, the workover program should be carried out with a partially filled well or by snubbing to avoid further damage by fluid losses. In cases where injection or withdrawal efficiency is declining, consideration should be given to re-perforating the intervals.

- Communication with aquifer is a possibility especially through the existing wells that are planned as monitoring wells due to previous completion practices. It is imperative that adequate isolation of Hutton and Springbok aquifers by cementing the surface / intermediate / production casings to avoid gas loss in the event of gas leakage.

- Well collision risk - the planned new well (SS#12) will be drilled within 50m of the existing SS#2 wellhead location. Any subsequent new wells are also likely to be drilled within 100m proximity of abandoned wells. To avoid future collision with existing well bores, it will be important to carefully monitor the trajectory of the well. Current directional drilling technology will adequately manage this risk. The bottom-hole location of any injection well should also be known for future reference.

- Wellhead damage – catastrophic damage to the wellhead could result in uncontrolled release of stored gas. To reduce the possibility of this occurrence a visible crash barrier will be constructed around the wellhead.

- Weather risk - the Surat basin is subject to excessive rainfall from October to March. Heavy downfalls can bring drilling and workover operations to halt due to poor road conditions and loss of access. The priority remains to undertake workover and drilling activity at the earliest opportunity so that weather related delays do not affect the critical path of the project. Locations will be pre-prepared and a spare capacity of gravel will be available at Silver Springs for emergency use to repair access should it be required.

3.0 CONCLUSIONS

RPS was contracted to review the sub-surface work that has been conducted for the Silver Springs Underground Gas Storage (UGS) project and provide recommendations for future reservoir monitoring and management. The conclusions of this review are as follows:

- Based on the simulation study, the maximum gas volume that can be injected into the SSR field is approximately 70 Bscf without exceeding the original reservoir pressure of 2779 psia in any portion of the reservoir. Since this is more than twice the obligated contractual volume there is sufficient margin to ensure the required volumes of gas are injected and stored without exceeding the design criteria.

- The maximum pressure differential between shut-in bottom hole pressure (SIBHP) and injection bottom hole pressure (IBHP) (psi) at twice the design rate is 87 psi. Therefore, the expected sand-face injection pressure should be able to be maintained less than initial reservoir pressure during injection phase.

- Throughout the life of the field, the gas composition will mainly be methane with no CO_2 or H_2S reported. Corrosion due to these hydrocarbon gases is negligible. However, corrosion due to water is still a possibility. AGL plans to analyse the tubing removed from SS#1 which is the oldest well in the field with more than 20 years production. RPS opines that the proposed testing is adequate to ascertain that the well integrity is not compromised.

- RPS recommended that the tubing, casing and wellhead design calculations are reviewed by an independent third party. These design checks should take into account the data obtained from the inspection of the tubing and casing in selected existing wells as well as the predicted wellhead temperatures and pressures to be experience during the production and injection cycles.

- Subject to reservoir / well integrity testing the Silver Springs-Renlim Field is considered to be appropriate for gas storage as proposed by AGL:

- Injection pressures are not anticipated to disrupt well integrity

- Water production from wells is anticipated to be 320 stb/day (50 kL/day) during plateau and 2220 stb/day (350 kL/day) during the decline phase.

- Lost circulation material that may be used in the well will not contain any hazardous chemicals and given well integrity will remain within the well bore and be recovered in drilling rig tanks during the drilling operations.

4.0 RECOMMENDATIONS

It is recommended that further data analysis and study work be performed in order to address the following issues:

- A review of previous history of pressure or gas bleeds off from the annulus to the surface might provide some insight to the cement bonding against the formation and source of leaking path.

- A review of completion design, cost and well productivity (i.e. skin) and well bore stability should to be investigated further prior to drilling any new well.

- New well location / placement needs be studied to avoid well collision / crossing.

- Tubing, casing and wellhead design calculations should be reviewed by an independent third part. These design checks should take into account the data obtained from the inspection of the tubing and casing in selected existing wells as well as the predicted wellhead temperatures and pressures to be experience during the production and injection cycles.

RPS

APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS

B	billion
B_g	gas formation volume factor
Bscf	billions of standard cubic feet
CO_2	Carbon dioxide
condensate	liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas
cP	centipoise
EUE	External Upset End
°F	Degrees Fahrenheit
FBHP	flowing bottom hole pressure
FTHP	flowing tubing head pressure
ft	feet
GIP	Gas in Place
GIIP	Gas Initially in Place
GOR	gas/oil ratio
GWC	gas water contact
H_2S	Hydrogen sulphide
IBHP	Injection Bottom Hole Pressure
IPR	Inflow Performance Relationship
LTC	Long Thread and Coupling
M	thousand
MM	million
MMscf/d	millions of standard cubic feet per day
petroleum	deposits of oil and/or gas
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge

PVT	pressure volume temperature
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	standard cubic feet per day
SIBHP	Shut In Bottom Hole Pressure
Skin	A dimensionless factor calculated to determine the production efficiency of a well
stb	stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	stock tank barrels per day
TVDSS	true vertical depth (sub-sea)
VLP	Vertical Flow Performance
WGR	Water Gas Ratio