Petišovci Gas Field, Slovenia

Commerciality Report

Ascent Slovenia Ltd

6 September 2011

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1. Introduction

Petroleum Development Consultants (PDC) was awarded a contract by Ascent Slovenia Limited (Ascent) on behalf of the Petiśovci Joint Venture on 28 June 2011 to prepare a Commerciality Study of the Petišovci gas field, Slovenia.

Petišovci is a 200 km^2 project area that straddles the Hungary/Slovenia border and contains three former oil and gas fields. Geoenergo d.o.o. is the holder of the Petišovci Exploitation Concession and is a company jointly owned by Nafta Lendeva, the Slovenian State Oil Company and Petrol, the leading energy conglomerate in Slovenia. Ascent through its wholly owned subsidiary Ascent Slovenia Limited has a 75% interest in the Petišovci Project. Ascent's partner is Geoenergo with a 25% interest.

The Petišovci Miocene gas reservoirs were discovered in 1960 and gas was mapped in Sands A to E. Production started in 1961 and cumulative production has been 8.7 bscf. Production was primarily from the E-1 sand from the Pg-1 and Pg-5 wells. A volumetric assessment was made of these reservoirs by RPS Energy in October 2010.

The joint venture operated by Ascent drilled the Pg-11 well in May 2011 and this well tested 2,500 m^3/day of gas from a deeper K sand gas reservoir. A volumetric assessment of this reservoir has been made by Ascent. The Pg-10 well is currently being drilled to appraise both the A to F sands and the deeper K sand. Reservoir quality is expected to be better in the K sand reservoir. A K sand fracture stimulation programme is being prepared.

Existing production facilities were installed that provided the feedstock for a methanol plant. The methanol plant is no longer operating and the development plans for the Petišovci field involve export to the main Slovenian gas transportation system. There will need to be additional equipment in order to meet the gas transportation pipeline specifications and in particular to meet the carbon dioxide specification. Additional condensate handling facilities will also be required.

This commerciality report has reviewed four development scenarios:

Case 1 involves production from three wells completed in the K sand and using the existing production facilities at a peak rate of 9 Mmscfd starting 1 January 2012

Case 2 involves production from fifteen wells completed in the K sand using newly constructed facilities with a capacity of 40 Mmscfd starting 1 January 2014.

Case 3 involves production from fifteen wells and includes re-completion to E1 and D2 sands.

Case 4 assumes production from thirty wells originally completed in the K sand with re-completion of low rate K sand wells to E1 sand, D2 sand and E4 sand completions.

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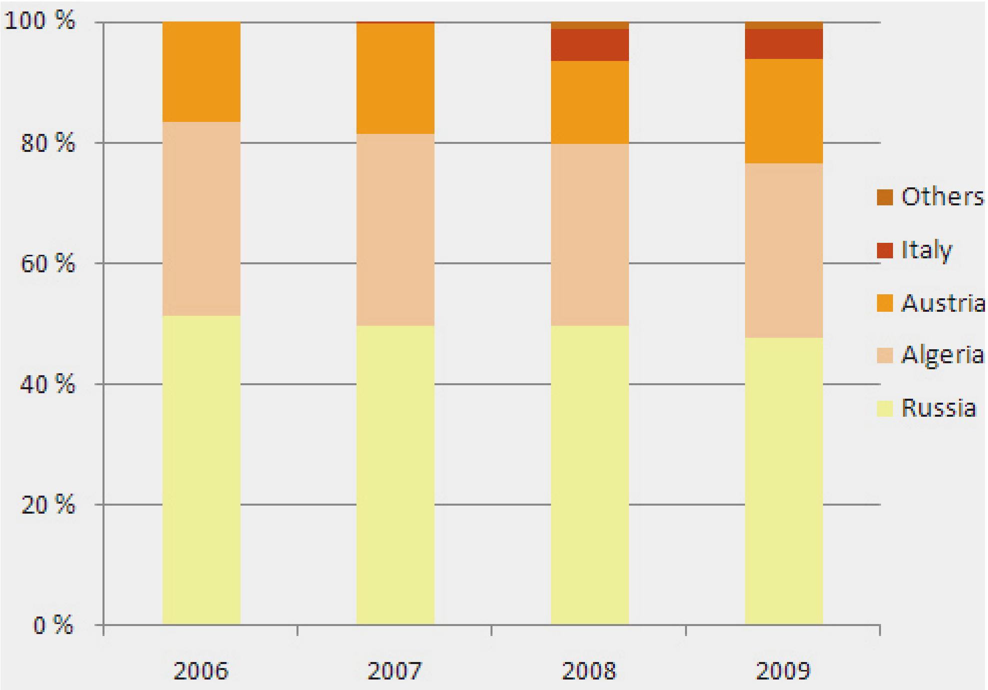
3. Gas Supply and Demand

3.1. Gas Supply

Slovenia is virtually entirely dependant on imported gas with negligible domestic production. In 2010 47% of gas was supplied from Russia, 33% from Algeria, 15% from Austria and 5% from Italy. Supply in earlier years can be seen in Figure 1 below for the period 2006-9.

Figure 1 Gas Supply (2006-2009)



Source: Slovenia Energy Agency

Total imports in 2009 were just over 1 billion cubic metres (bcm) as shown in Table 1 below. Imports were dominated by one company (Geoplin) who supply the largest volume of gas.

Table 1 Gas Importers (million m3)

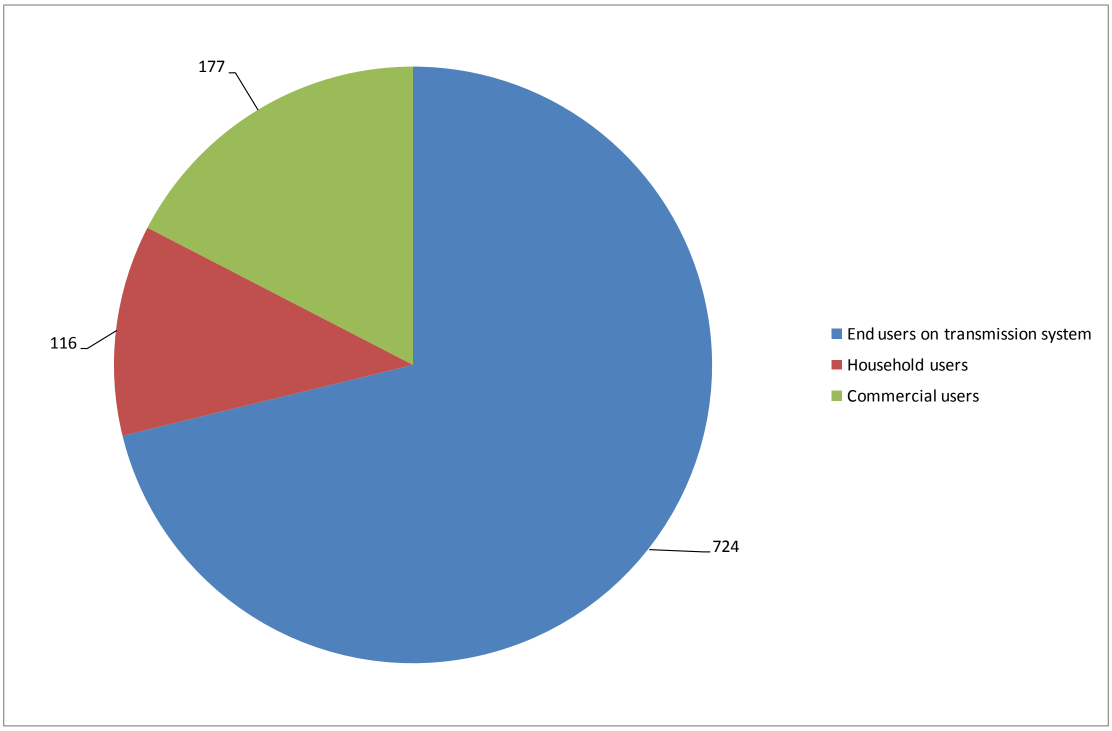
Supplier	2007	2008	2009
Geoplin	1,117	1,018	968
Petrol Plin	3	3	3
Adriaplin		54	57
Total	1,120	1,075	1,028

Source: Slovenia Energy Agency

3.2. Gas Demand

Most gas in Slovenia is supplied directly to customers off the gas transmission system as can be seen in Figure 2.

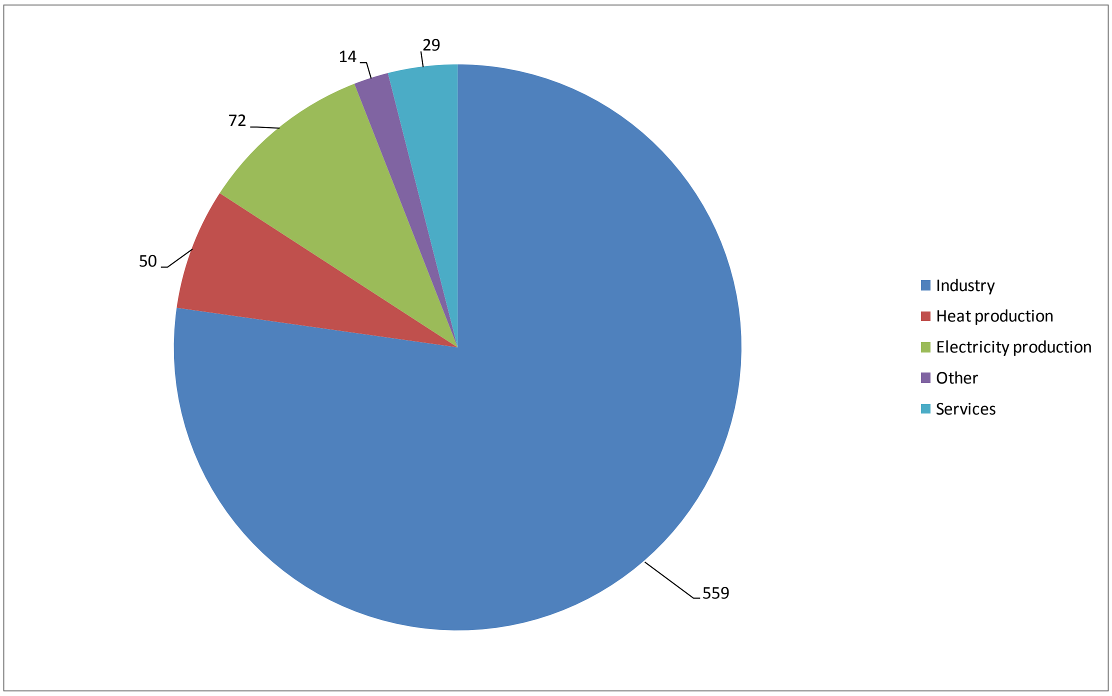
Figure 2 Gas Consumption by Sector - 2009 (million m3)



Source: Energy Agency

Details of the gas supplied directly through the transmission system can be seen in Figure 3. Around 78% of this gas is supplied to industry such as steelworks. A much smaller amount (10%) is provided for electricity generation with a further 7% being supplied for district heating.

Figure 3 Transmission System Customer Consumption – 2009 (million m3)



Source: Energy Agency

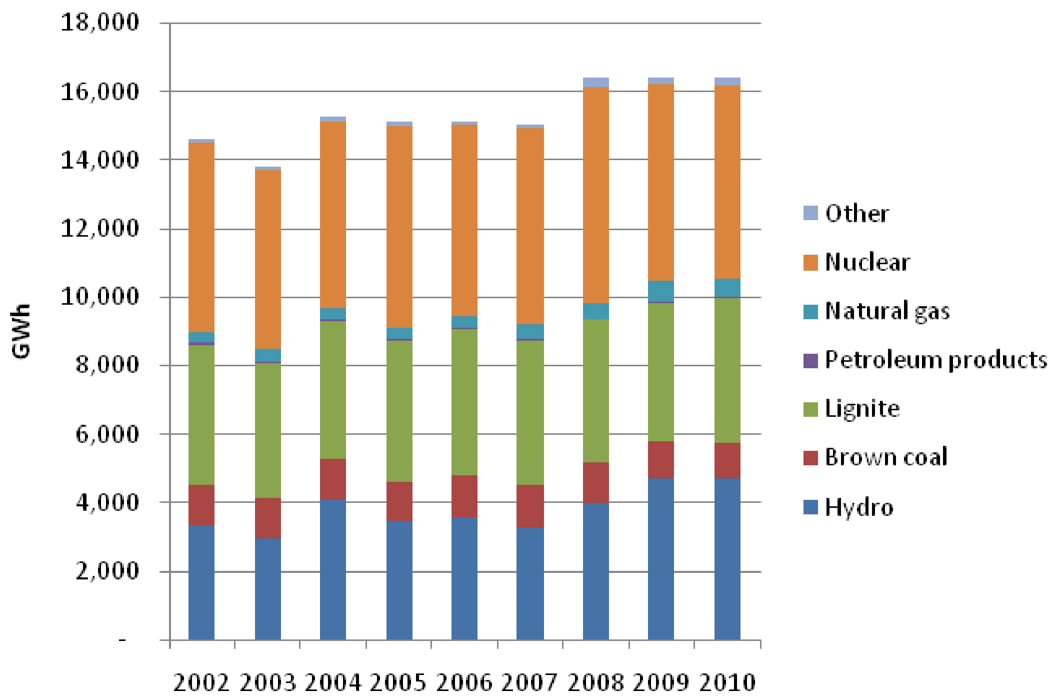
3.2.1. Power Generation

The most important fuel for power generation is nuclear power which supplied 34% of all electricity produced in Slovenia in 2010. The next most significant is hydroelectric (29%) followed by lignite (26%). Gas only supplied 3% of the electricity generated in 2010. Details of the power fuel source 2002-2010 can be seen in Figure 4 below.

The electricity transmission company is required to prepare long-term forecasts of electricity supply and demand and the most recent report covers the period 2009-18 and was approved by the government in April 2009. This shows installed generation capacity increasing from 3,000 MW to over 5,000 MW in 2015. This increase is provided through additional lignite, hydro and gas power stations being brought into service. Additional gas fired powered plants being considered in the plan includes:

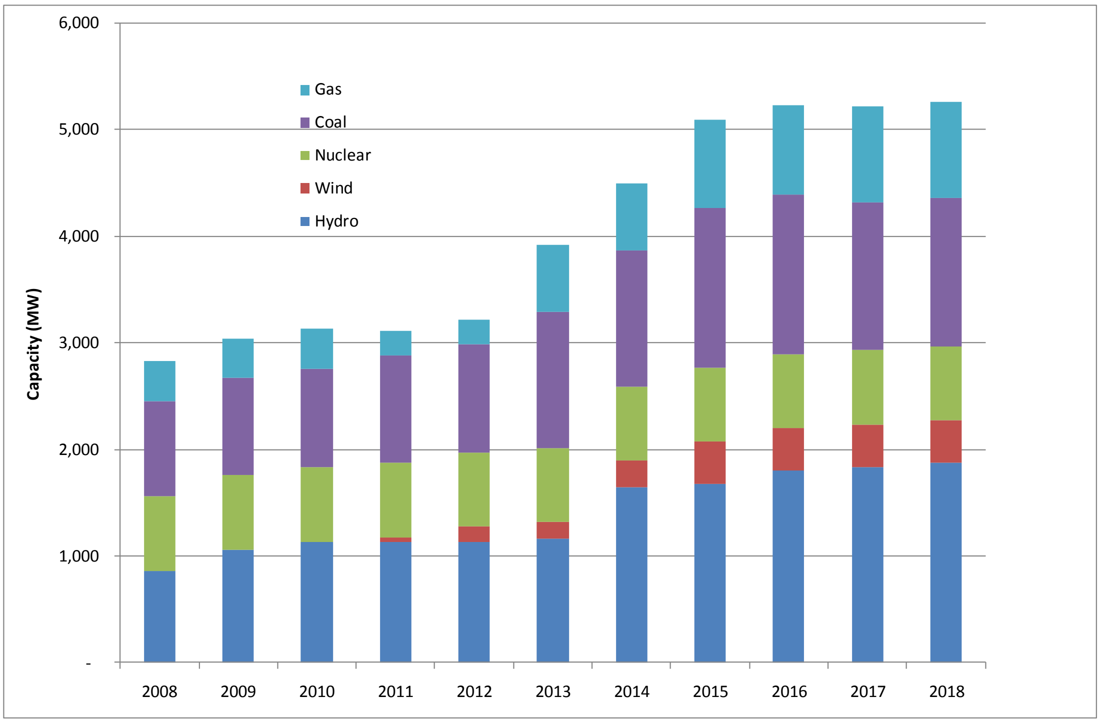
- 144 MW Unit IV, Ljubljana CHP from 2013
- 234 MW CCGT Koper from 2013
- 540 MW Unit VI, Šoštanj from 2015
- 25 MW CHP, Vevče
- 200 MW Krško, 2015
- 72 MW Unit V, Ljubljana CHP from 2017

Figure 4 Power Generation Fuel Source (2002-2010)



Source: Statistical Office, Slovenia

Figure 5 Slovenia Power Capacity by Fuel (2008-2018)

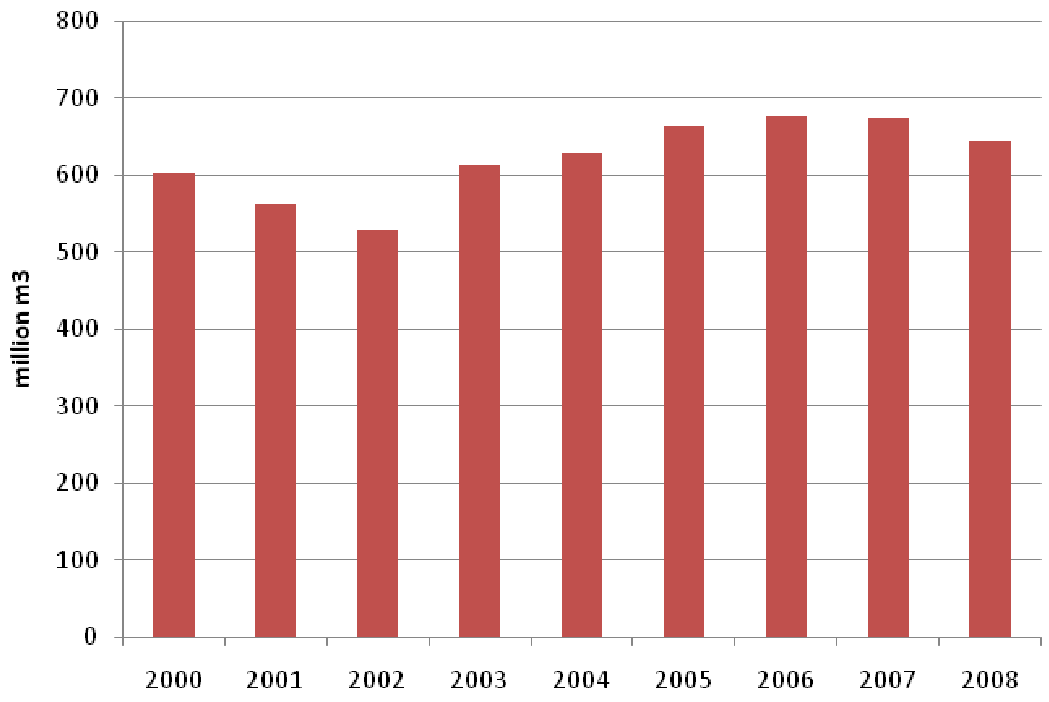


Source: ELES Development Strategy 2008-2018

3.2.2. Industrial

Industrial gas consumption in 2009 according to the Energy Agency was 559 million m^3. Consumption has been dropping since 2006. Information on consumption can be seen in Figure 6.

Figure 6 Industrial Gas Consumption 2000-8

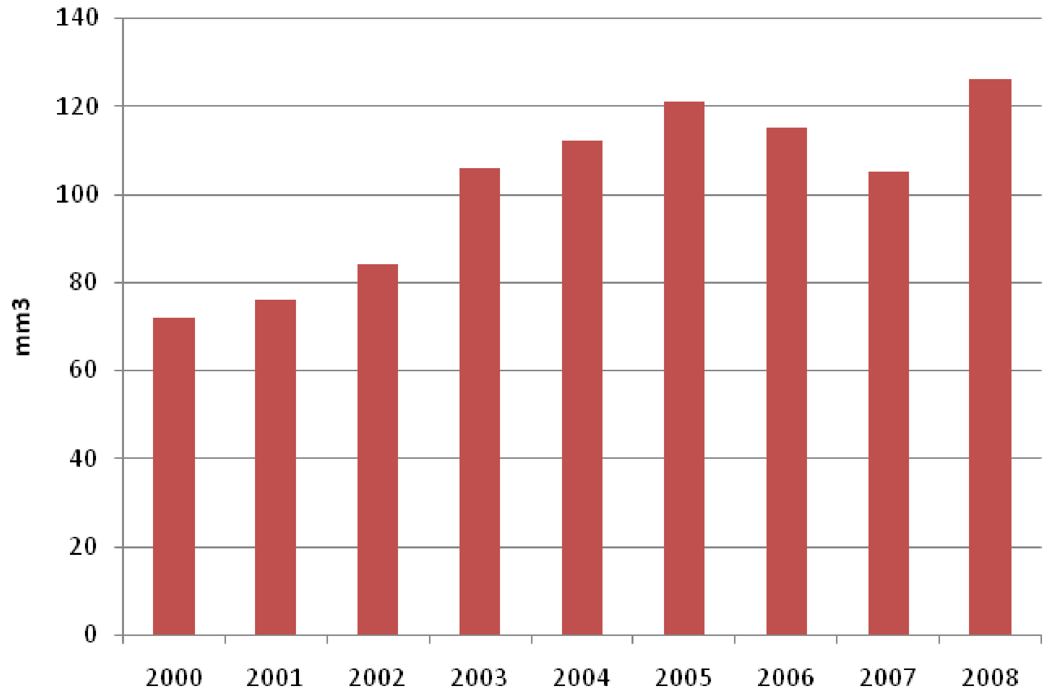


Source: Statistical Office, Slovenia

3.2.3. Residential

Residential gas consumption in 2009 according to the Energy Agency was 116 million m^3. It has been growing steadily since 2000 as can be seen in Figure 7.

Figure 7 Residential Gas Consumption 2000-8



Source: Statistical Office, Slovenia

4. Gas Transportation

4.1. System

The gas transmission system consists of 805 kilometres of high pressure pipe as shown in Figure 8. There are two import points (Ceršak and Šempeter) from Austria and Italy respectively. There is an export point to Croatia at Rogatec. There are two compressor stations – Kidričevo and Ajdovščina. Slovenia has no gas storage and it is therefore dependent on line pack and supplier flexibility to meet variations in demand. The Ceršak to Rogatec system operates at 50 bar pressure.

In 2009 1,011 million m^3 of gas was transported and delivered to customers in Slovenia. In addition 1,046 million m^3 of gas was transported through Slovenia from Austria to Croatia.

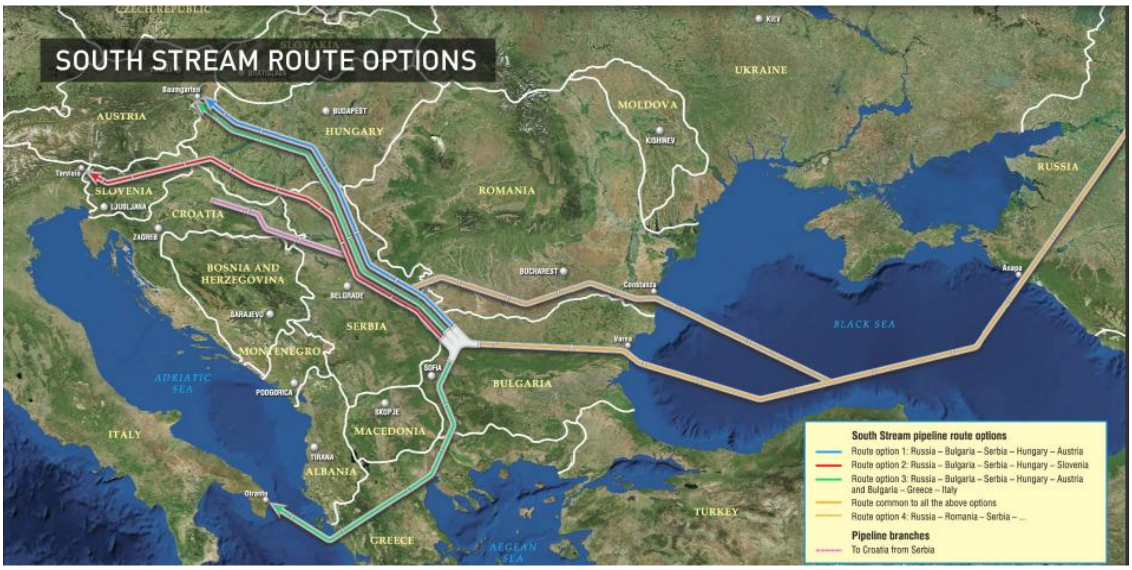
Gazprom is currently considering developing what it calls the South Stream project. This would involve switching gas currently being transported to Europe via Ukraine to a new southern route. The project is currently planned to start production at the end of 2015. An investment decision is planned by the end of 2012. There are a number of options being considered. Option 2 (see Figure 9) would involve a pipeline to Slovenia.

Figure 8 Slovenia Gas Transportation System

Key: Import/export station Offtake point Compressor station

Source: Geoplin

Figure 9 South Stream Pipeline

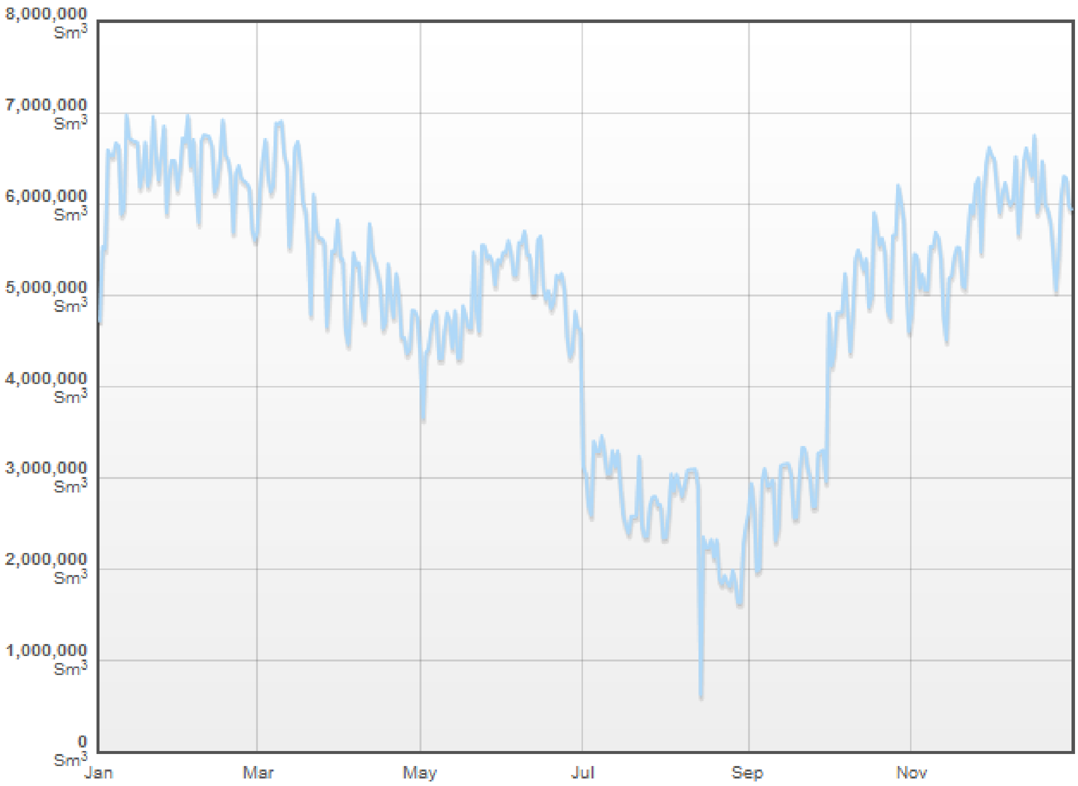


Source: Gazprom

4.2. Capacity

The capacity of the Ceršak import station bringing gas from Austria (originally from Russia) is 7,080,000 m^3/day. Throughput data for 2010 shown in Figure 10 indicates that in winter months the system is at capacity. The graph also shows that there are large variations between summer and winter demand.

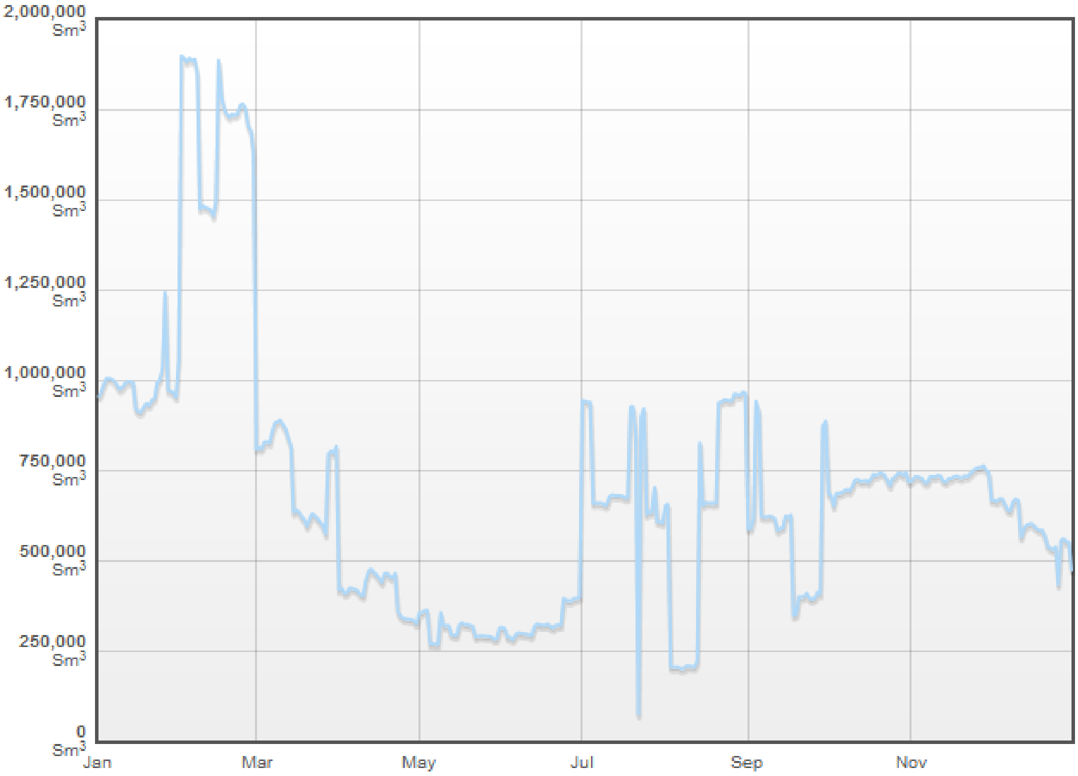
Figure 10 Ceršak Import Volumes (2010)



Source: Geoplin

The capacity of the Šempeter import station bringing gas from Italy (mostly originally from Algeria) is 2,640,000 m^3/day. Throughput data for 2010 shown in Figure 11 shows that the system was only used to any large extent in the winter months of 2010.

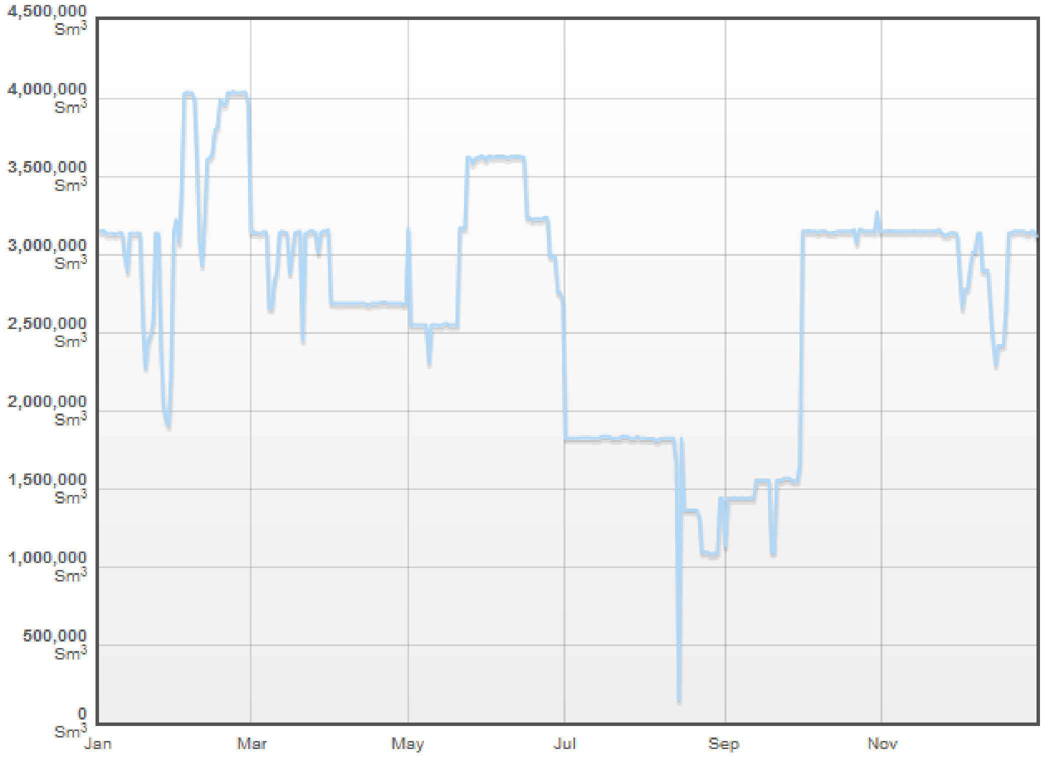
Figure 11 Šempeter Import Volumes (2010)



Source: Geoplin

The capacity of the Rogetec export station to Croatia is 5,040,000 m^3/day. There is a significant difference between summer and winter demand in Croatia as indicated in Figure 12.

Figure 12 Rogatec Export Volumes (2010)



Source: Geoplin

4.3. Connection

Connection of the Petišovci field can be made at Lendava. The requirements for gas quality are provided in the Official Gazette of 7 October 2005. The main requirements are:

- Methane content to be a minimum of 89.7% mol
- Ethane content to be a maximum of 6.3% mol
- C3+ content to be a maximum of 2.1% mol
- Carbon dioxide content to be a maximum of 1.575% mol
- Calorific value to be between 33,560 – 36,630 kj/m^3 at 15^0 C
- Water dew point less than -7^0 C at pressure of 39 bar
- Hydrocarbon dew point less than -5^0 C at pressure of 39 bar
- Maximum gas temperature to be 42^0 C

The existing connection runs from the Lendava pressure reduction plant to the methanol plant. It is around 0.8 km long and has a diameter of 8 5/8” and operated at 27 bar. There is some concern regarding the integrity of this line as it was not subject to cathodic protection. A connection from the existing production facilities to the methanol plant is 1.9km and has a diameter of 6" and an operating pressure of 30 bar.

The initial phase of production would use the existing production facility. The connection to the gas transportation from the production facility would use the existing 6" line. This then would be extended to a new 6" pipeline that would follow the route of the existing 8 5/8" pipeline. It is suggested that the new pipeline makes use of the sleeved connection under the railway line.

The main production phase would require a new pipeline from the new production facilities to the gas transportation tie-in point.

5. Gas Pricing

5.1. End User Pricing

5.1.1. Power Generation

There are no special prices for power generation and prices apply as per industrial customers (see below).

5.1.2. Industrial

Industrial prices are shown below (including VAT and taxes) depending on the level of consumption.

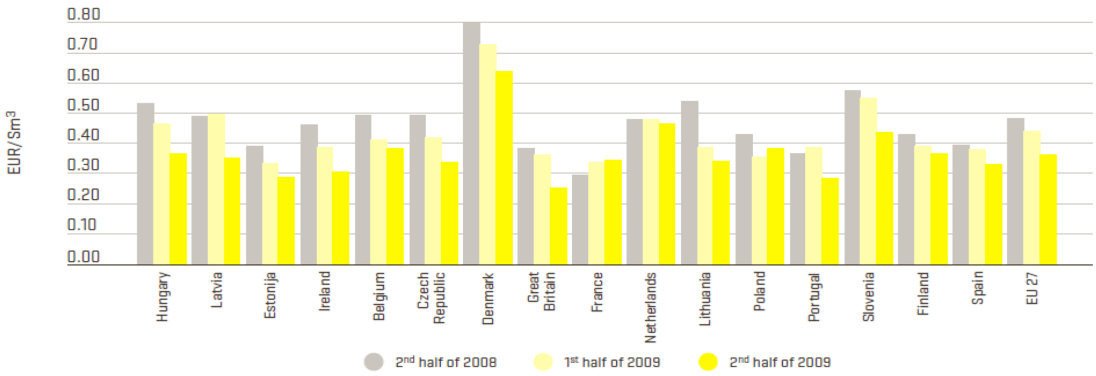
Table 2 Industrial Gas Prices (2009)

Group	Consumption (m^3)		Price (€/m^3)
	From	To	
I_1	0	26,435	0.70
I_2	26,435	264,349	0.67
I_3	264,349	2,643,489	0.52

Source: Energy Agency

Industrial prices are high in Slovenia. Average EU prices for the I_3 group were €0.43/m^3 as compared to €0.52/m^3 shown above. The comparison with other EU prices is shown below.

Figure 13 EU Industrial Prices – I3



Source: Energy Agency

5.1.3. Residential

Residential prices are shown below in Table 3 (including VAT and taxes) depending on the level of consumption

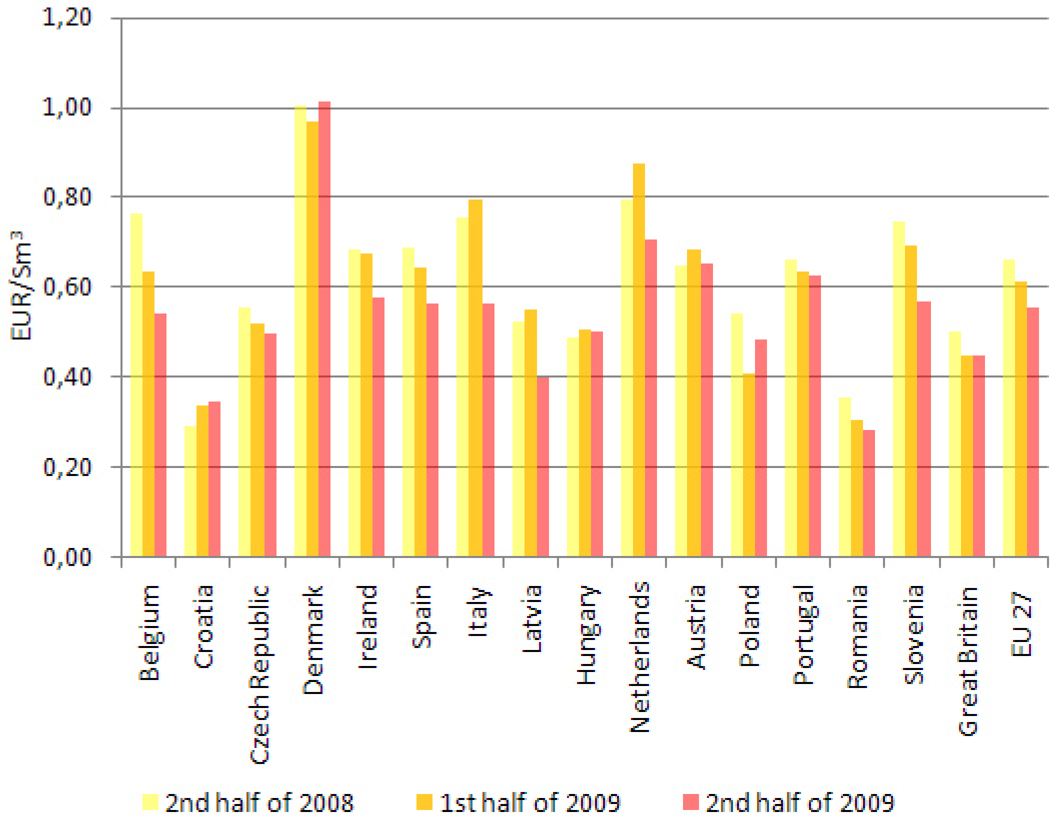
Table 3 Residential Gas Prices (2009)

Group	Consumption (m^3)		Price (€/m^3)
	From	To	
d_1	0	529	0.82
d_2	529	5,287	0.63
d_3	5,287		0.61

Source: Energy Agency

Residential prices are quite high in Slovenia. Average EU prices for the d_2 group were €0.58/m^3 as compared to €0.63/m^3 shown above. The comparison with other EU prices is shown below.

Figure 14 EU Residential Prices – d2



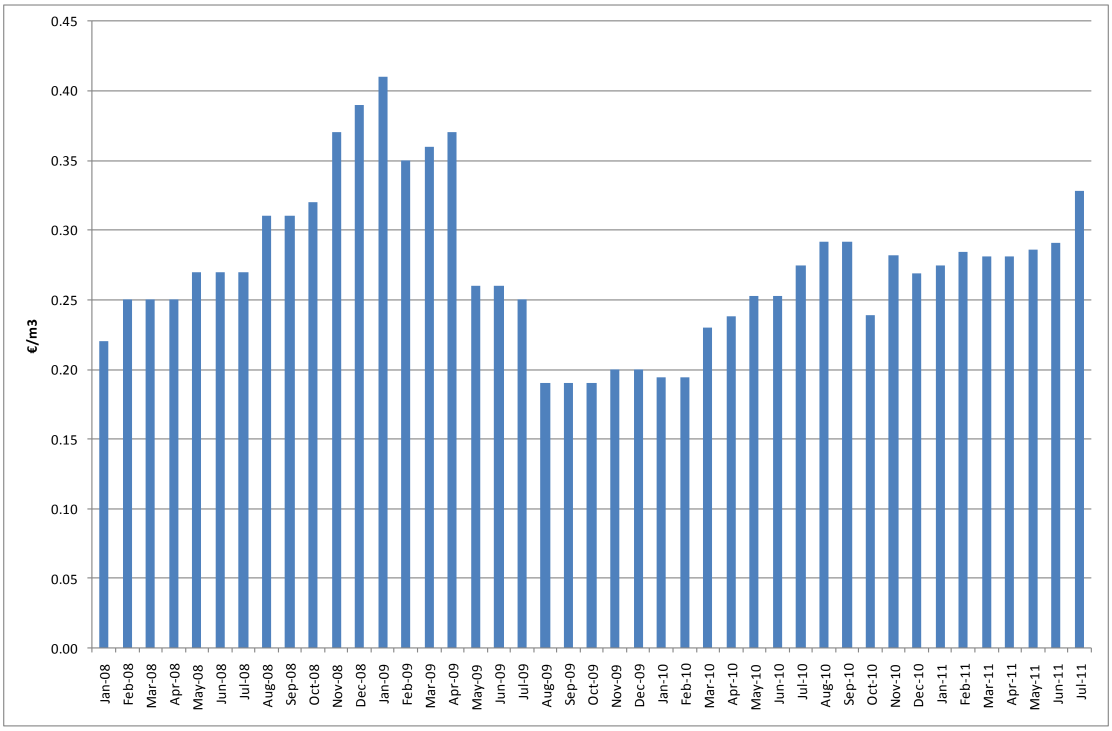
Source: Energy Agency

5.2. *Wellhead Prices*

Gas prices are published by Geoplin the gas transportation company (see Figure 15). The prices are the costs of imported gas based on contracts with importers. These prices are used to determine the price to be paid by shippers for imbalances[1]. It should be noted that these prices are for gas purchased and sold at short notice and are expected to be a little higher than those for a long-term contract. The gas price assumptions used in the economic analysis are given in Section 11.1.

[1] For positive imbalances shippers will sell at 91% of the balancing price; for negative imbalances shippers will buy at 115% of the balancing price.

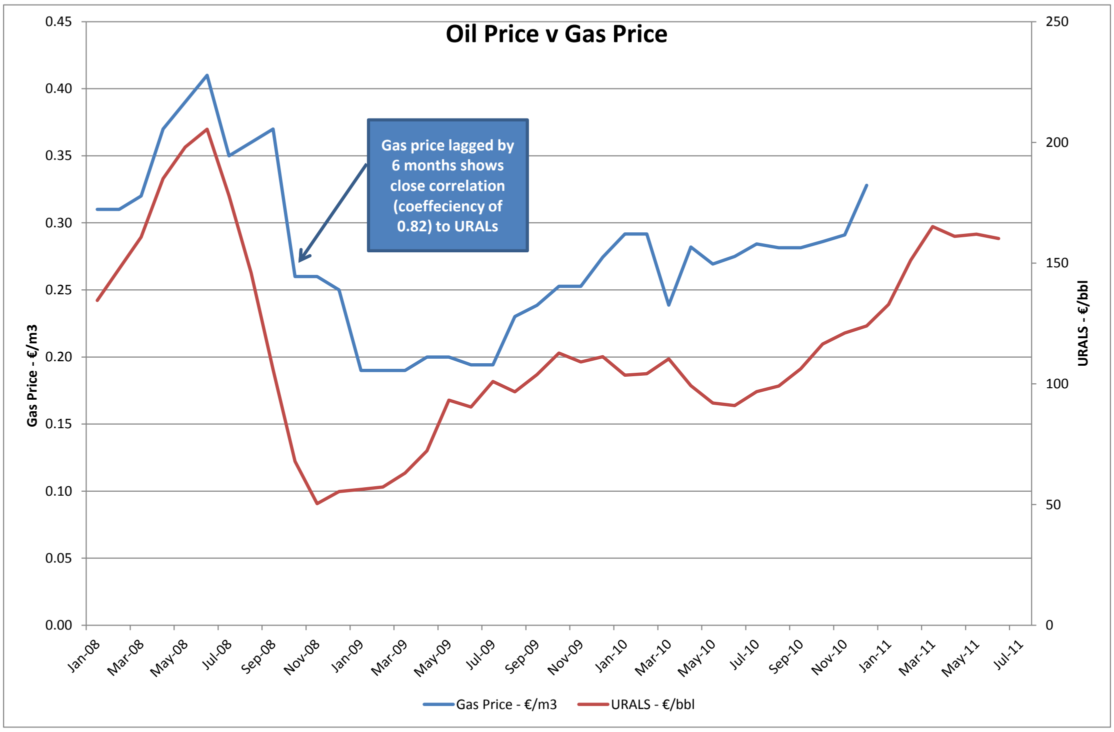
Figure 15 Geoplin Gas Prices



Source: Energy Agency, Geoplin

Long-term gas contracts used by Gazprom relate the gas price to the price of oil and oil products. There is a six month lag between the gas price and the oil prices. This link is shown in Figure 16.

Figure 16 Oil Price v Gas Price



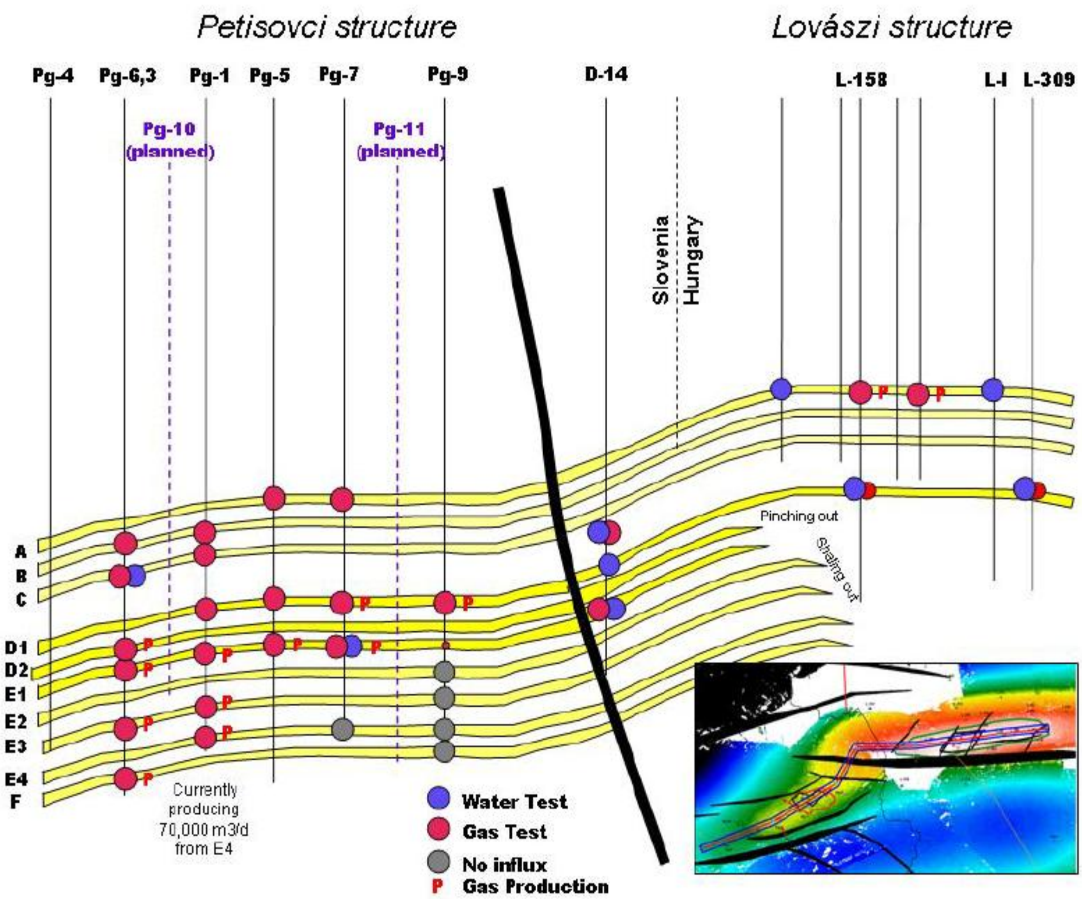
Source: PDC

6. Resource Estimate

6.1. Background

Production started from the A-F reservoirs in 1961. There has been no production from the K reservoir. It has been identified from the Pg-11 well that the upper K sands are also Miocene sands. A strike cross-section is shown in Figure 17.

Figure 17 Field Cross-Section



6.2. A-F Sands

An evaluation of the volumetric resources of the A-F reservoirs in the Petiśovci – Lovászi field was carried out in October 2010 by RPS. A summary of this is provided in Table 4. RPS did not provide details of the breakdown of the resources between Slovenia and Hungary and did not calculate recovery factors. Total mean in-place resources are calculated as 437.1 bscf.

Table 4 Miocenc A-F GIIP (bscf)				
Sand	**P90**	**P50**	**P10**	**Mean**
A1	35.7	70.5	131	78.4
B3	54.5	119.0	256.0	142.0
C	22.3	52.3	119.0	63.8
D1	3.8	8.2	15.3	9.0
D2	10.6	26.6	61.4	32.4
E1	33.9	69.3	140.0	80.6
E4	12.1	26.1	55.6	30.9
Total	**172.9**	**372.0**	**778.3**	**437.1**

Source: RPS

Production by well is shown in Table 5

Table 5 Miocene A-F Production (bscf)				
Well	**Sands**	**Start Year**	**End Year**	**Production (bscf)**
PG-1	E1	1961	2002	3.35
PG-2	D1	1970	1987	0.02
PG-2	D2	1967	1987	0.05
PG-2	E1	1962	1980	0.07
PG-2	G	1997	-	0.01
PG-3	D2 - E4	1964	1997	0.14
PG-5	E1	1987	2002	3.78
PG-6	E1, E3	1989	1993	0.13
PG-6	D2, E1, E3	1993	1997	0.03
PG-7	D1	1991	1997	0.21
PG-7	E1	1989	1990	0.22
PG-8	E1	1989	1997	0.20
Total				**8.21**

Source: Ascent

Production by reservoir is shown in Table 6

Table 6 Cumulative Production (bscf)			
Sands	**GIIP Mean (bscf)**	**Production (bscf)**	**% of GIIP**
D1	9.0	0.23	2.6
D2	32.4	0.05	0.2
E1	80.6	7.78	9.7
E4	30.9	0.14	0.4

Source: Ascent

6.3. *K Sands*

Ascent carried out a Monte Carlo simulation of the K Sand GIIP. The results are shown in Table 7 and show a P50 GIIP of 264.11 bscf.

Table 7 K Sand GIIP (bscf)

Sand	P90	P50	P10	Most Likely
K	192.02	264.11	326.29	278.95

Source: Ascent

7. Well Productivity

7.1. *A-F Sands*

Gas is to be found in seven separate sands. In this study three sands are considered for re-completion being D2, E1 and E4. These three sands have a P50 GIIP of 122 bscf and constitute 33% of the total P50 GIIP assessed by RPS. All of these sands have been previously produced albeit with varying decrees of success.

7.1.1. E1 Production Capability

The E1 sand has been produced from the Pg-1 and Pg-5 wells with a total of around 7 bscf having been produced. For the purposes of this study the RPS P50 assessment of a GIIP of 69.3 bscf has been used. It can be noted that the E1 sand is not present in the Lovászi structure in Hungary. Looking at the E1 sand polygons (see Figure 18) a recompletion of the Pg-11 well would have potential as it is located in an unproduced area.

The production history of the Pg-1 and Pg-5 wells is shown below.

Figure 18 E1 Sand Polygons

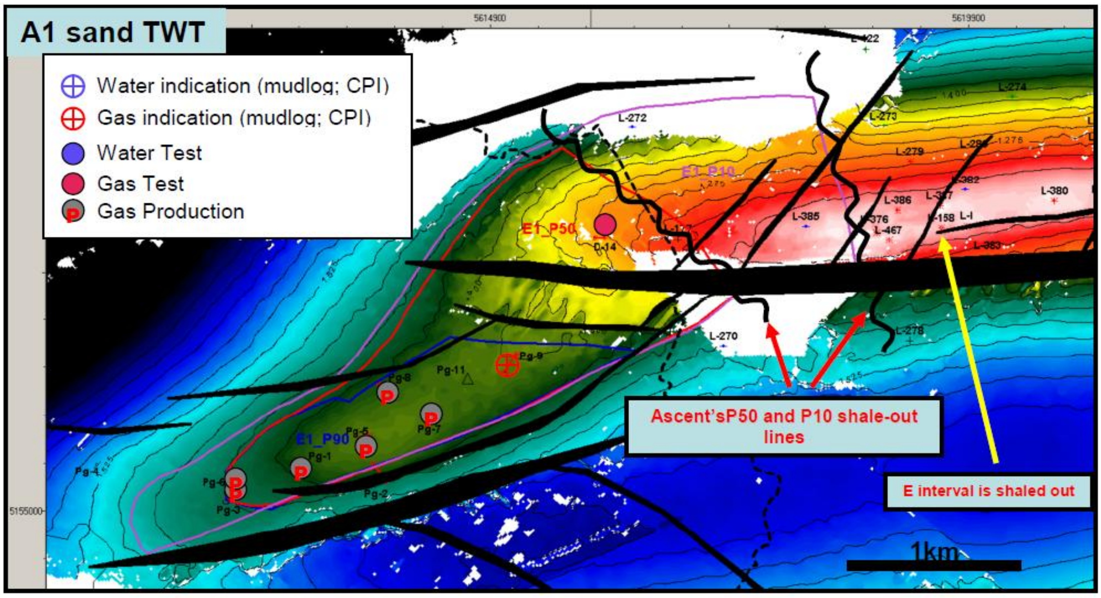


Figure 7. Ascent's E1 volumetric polygons: P10 (magenta) P50 (red) and P90 (blue). Note: the structure map is the A1 sand TWT, CI=25ms.

Figure 19 Pg-1 Production History

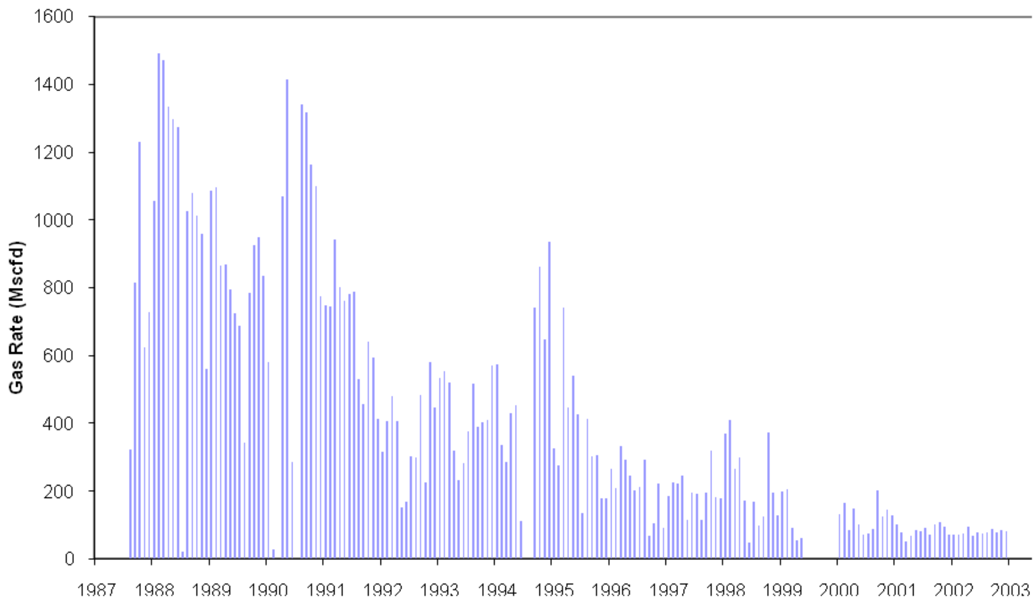
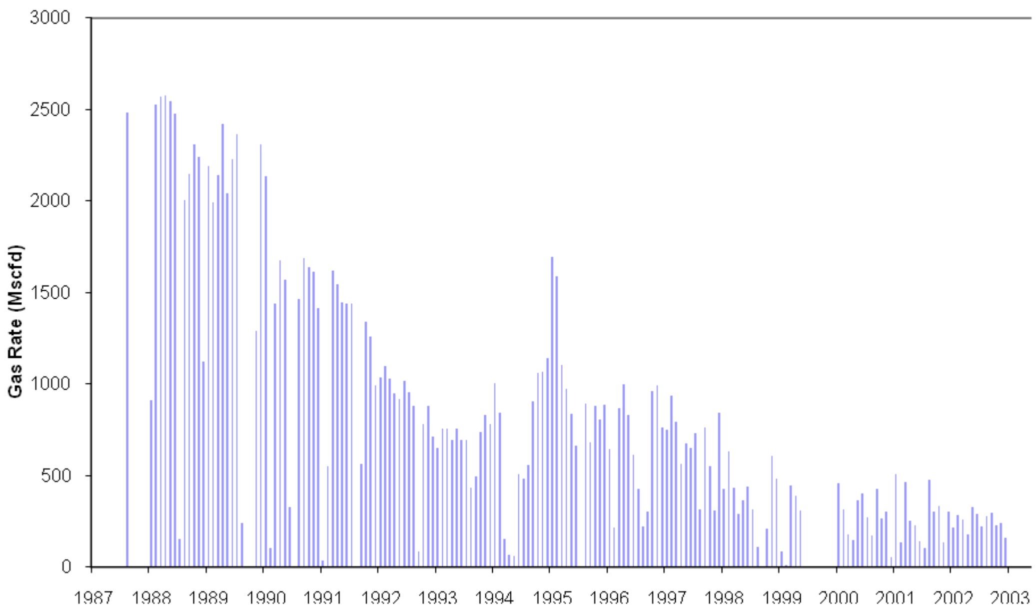
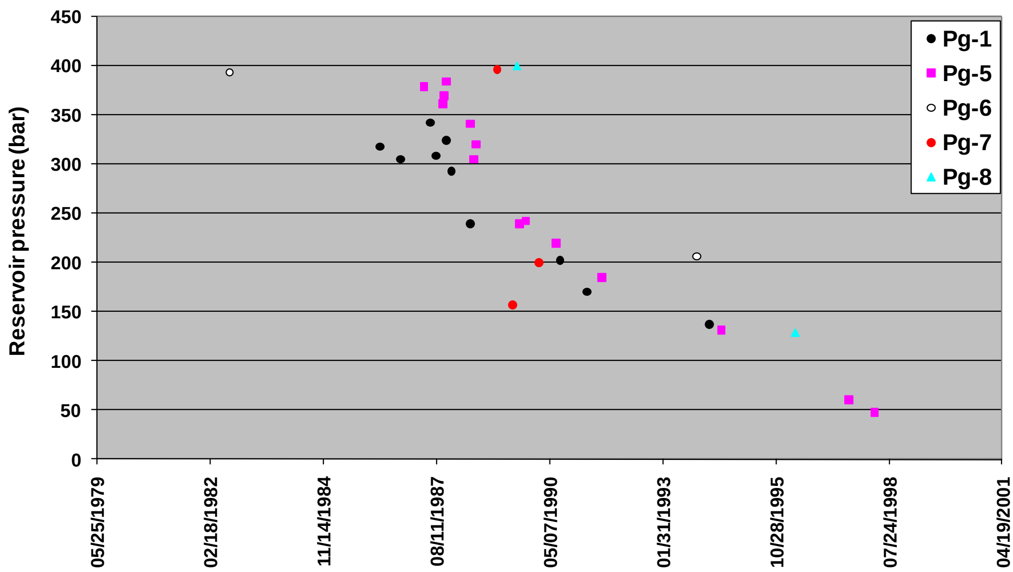


Figure 20 Pg-5 Production History



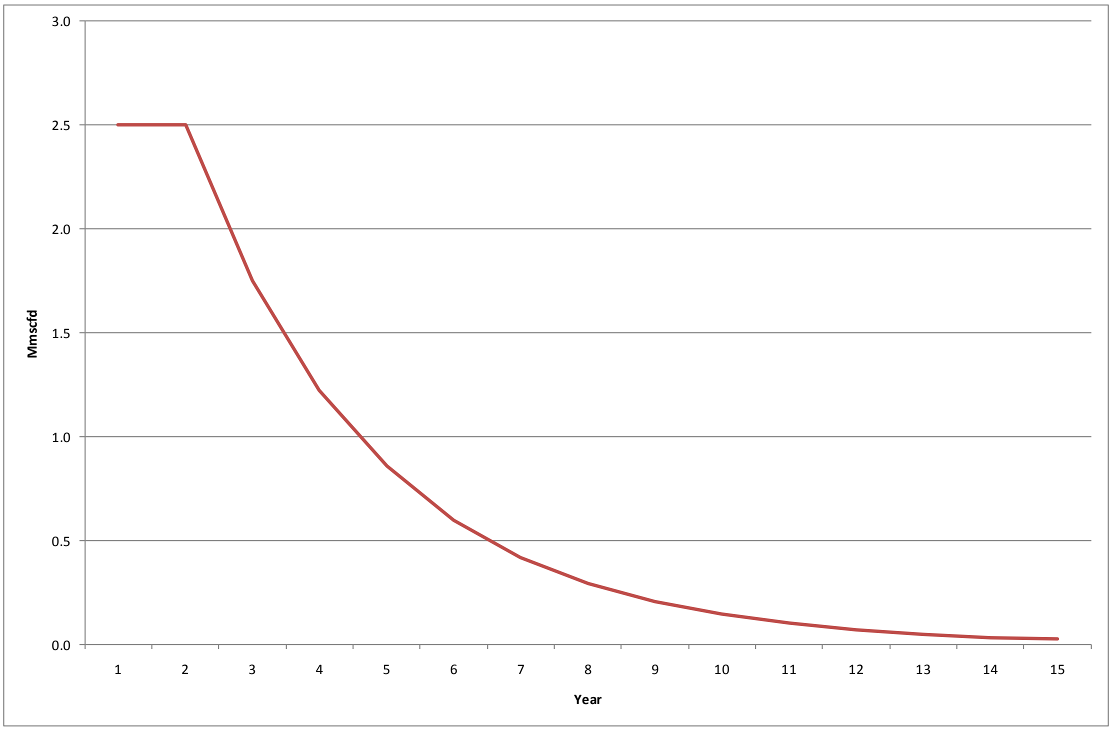
The pressure history of the E1 reservoir is shown in Figure 21 below.

Figure 21 Pressure Performance E1 reservoir



An E1 well type curve (see Figure 22) has been prepared based on an initial rate of 2.5 Mmscfd and a 30% annual decline rate. Total production over 15 years is 3.9 Bscf.

Figure 22 E1 Well Type Curve

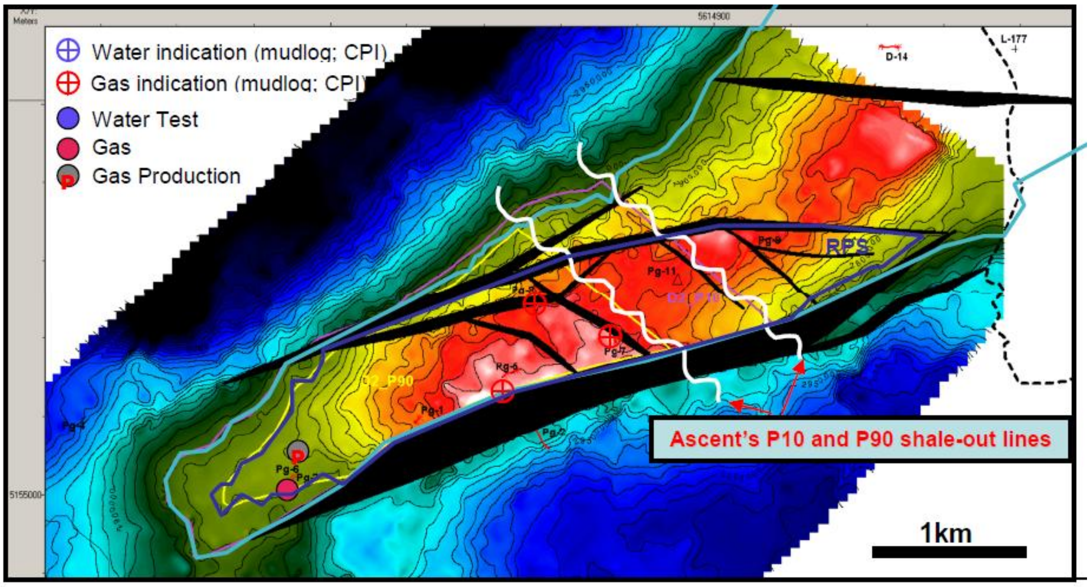


7.1.2. D2 Production Capability

The D2 sand has been produced in minor quantities from the Pg-6 well in the period 1993-1997. Gas has also been tested in the Pg-3 well. According to RPS there are gas indications in the mud log for wells Pg-5, Pg-7 and Pg-8 and there also appear to be no water indications.

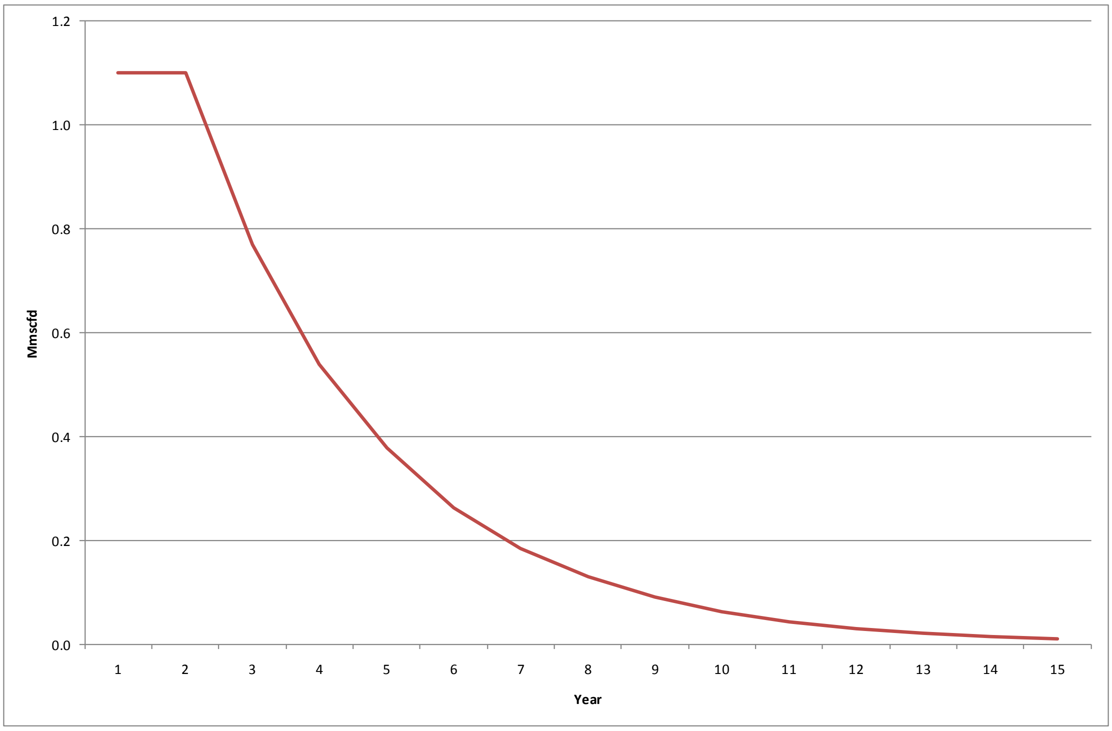
For the purposes of this study the RPS P50 assessment of a GIIP of 26.6 bscf has been used. Reservoir quality is poor in the east and it appears that no resources are shown on the RPS P50 basis in the Lovászi structure in Hungary. It is clear that there are unproduced resources to the north of Pg-1 (see Figure 23 below).

Figure 23 D2 Sand Polygons



A D2 type well curve (see Figure 24) has been prepared taking into account the lower net pay porosity product of this sand as compared to the E1 sand. This has an initial production rate of 1.1 Mmscfd and a 30% annual decline rate. Total production over 15 years is 1.7 bscf.

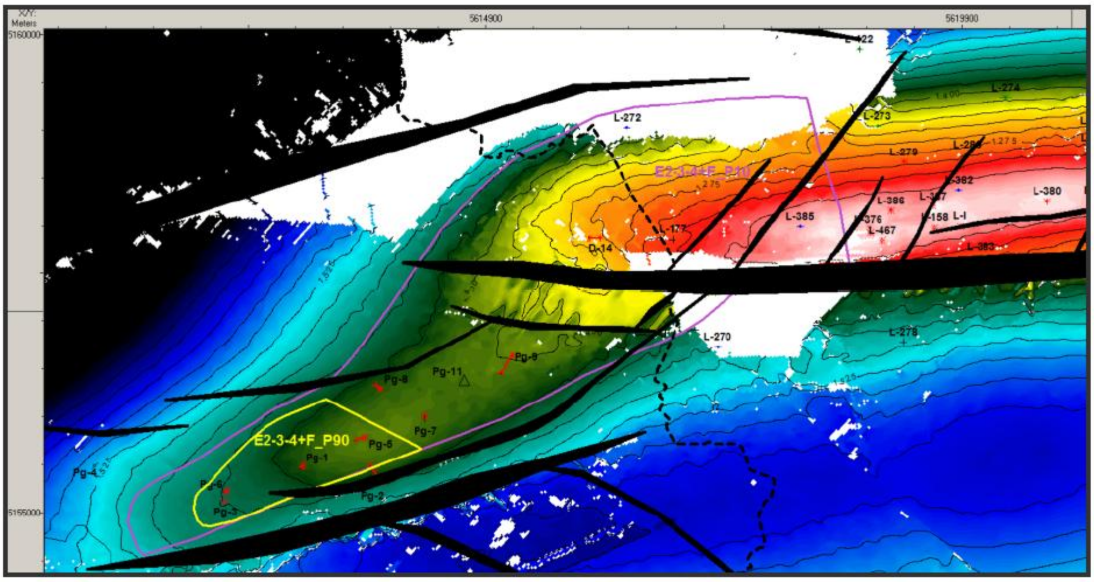
Figure 24 D2 Well Type Curve



7.1.3. E4 Production Capability

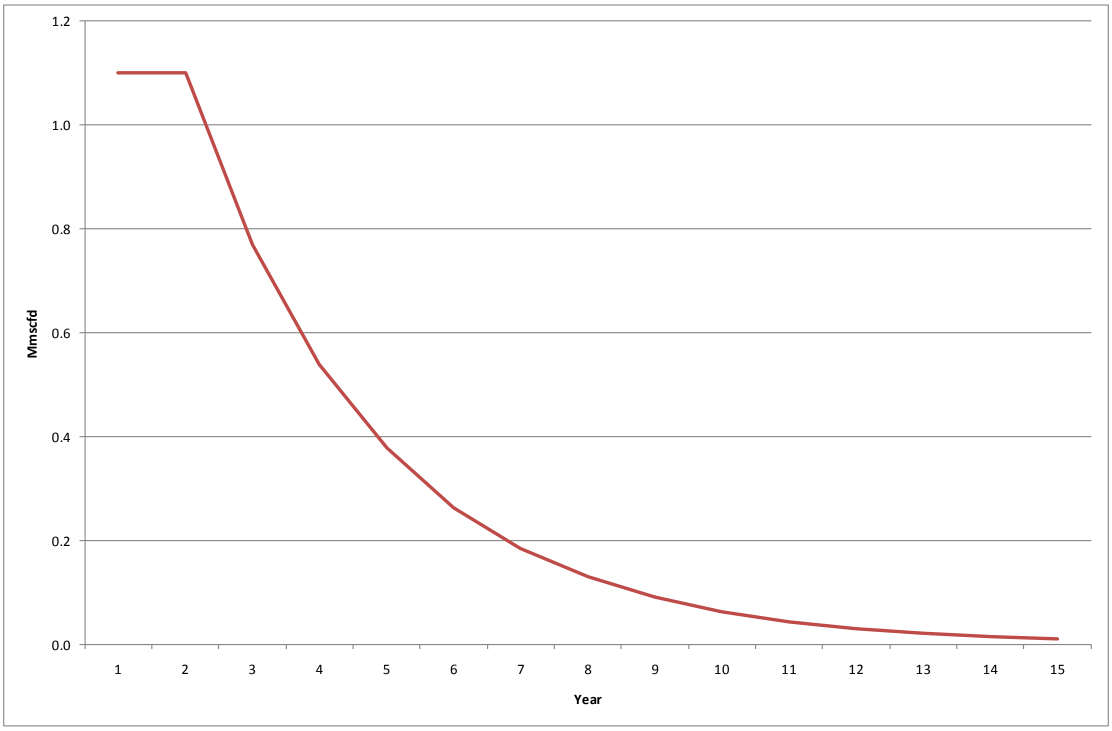
The E4 sand has been produced in minor quantities from Pg-1, Pg-3 and Pg-6. Looking at the E4 sand polygons (see Figure 25) a recompletion of well Pg-10 might have potential. For the purposes of this study the RPS P50 assessment of a GIIP of 26.1 bscf has been used. Reservoir quality is poor in the east and it appears that no resources are shown on the RPS P50 basis in the Lovászi structure in Hungary.

Figure 25 E4 Sand Polygons



The Pg-1 well has recently been deepened and recompleted in the E4 sand. An E4 type well curve (see Figure 26) has been prepared taking into account the lower net pay porosity product of this sand as compared to the E1 sand. This has an initial production rate of 0.9 Mmscfd and a 30% annual decline rate. Total production over 15 years is 1.4 bscf.

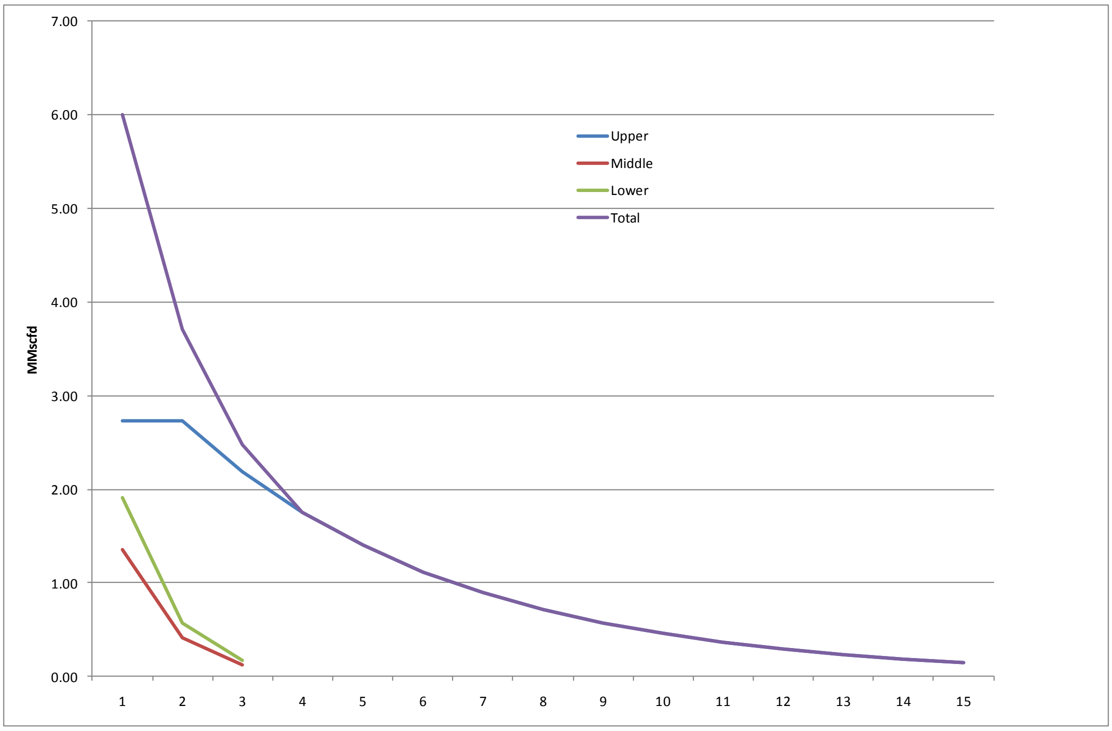
Figure 26 E4 Well Type Curve



7.2. *K Sand Production Capability*

The K sand production capability is shown in Figure 27. The initial production level is based on the recent work carried out on the frac design for Pg-10. An upper section of the K sand is expected to produce significantly better than the middle and lower sections. The type well has an initial rate of 6 Mmscfd and declines at 20% per annum. Total recovery per well is 7.4 bscf.

Figure 27 K Well Type Curve



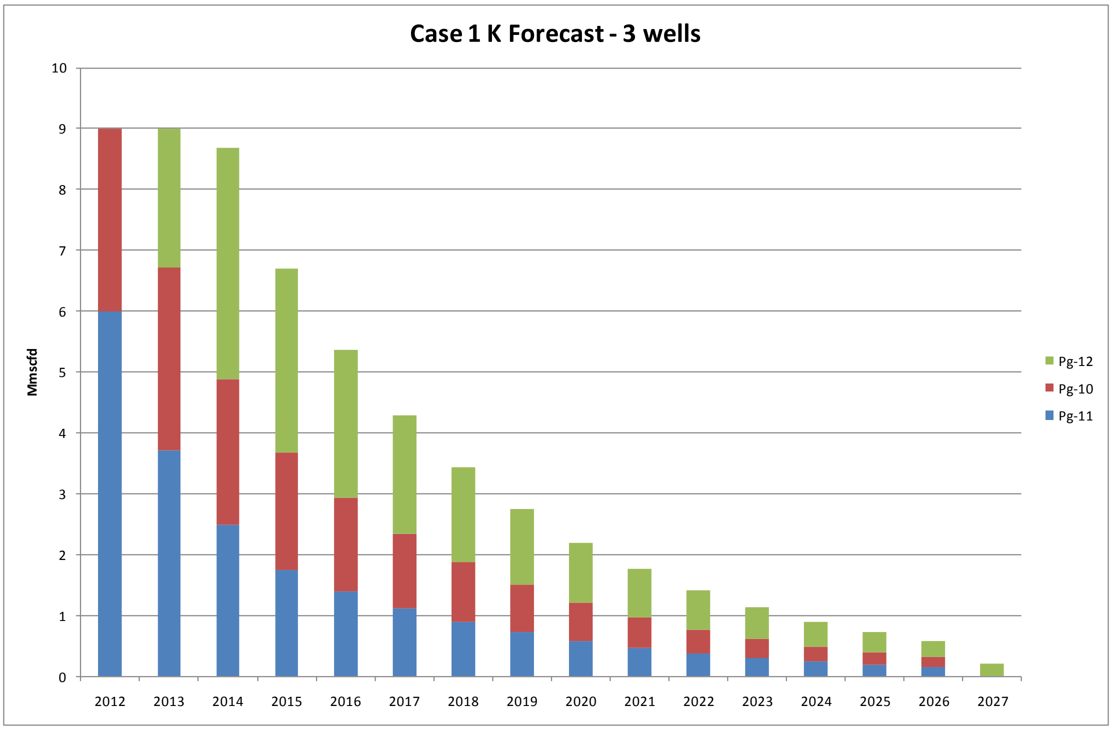
8. Production Profiles

8.1. Case 1

This case involves the use of the three K sand wells being produced through the existing facilities. Well Pg-11 is assumed to produce at 6 Mmscfd and well Pg-10 at 3 Mmscfd. Well Pg-12 is assumed to produce at 4.5 Mmscfd. The production profile is shown in Figure 28.

Total recovery from this case is 21.2 bscf.

Figure 28 Case 1 K Forecast – 3 Wells

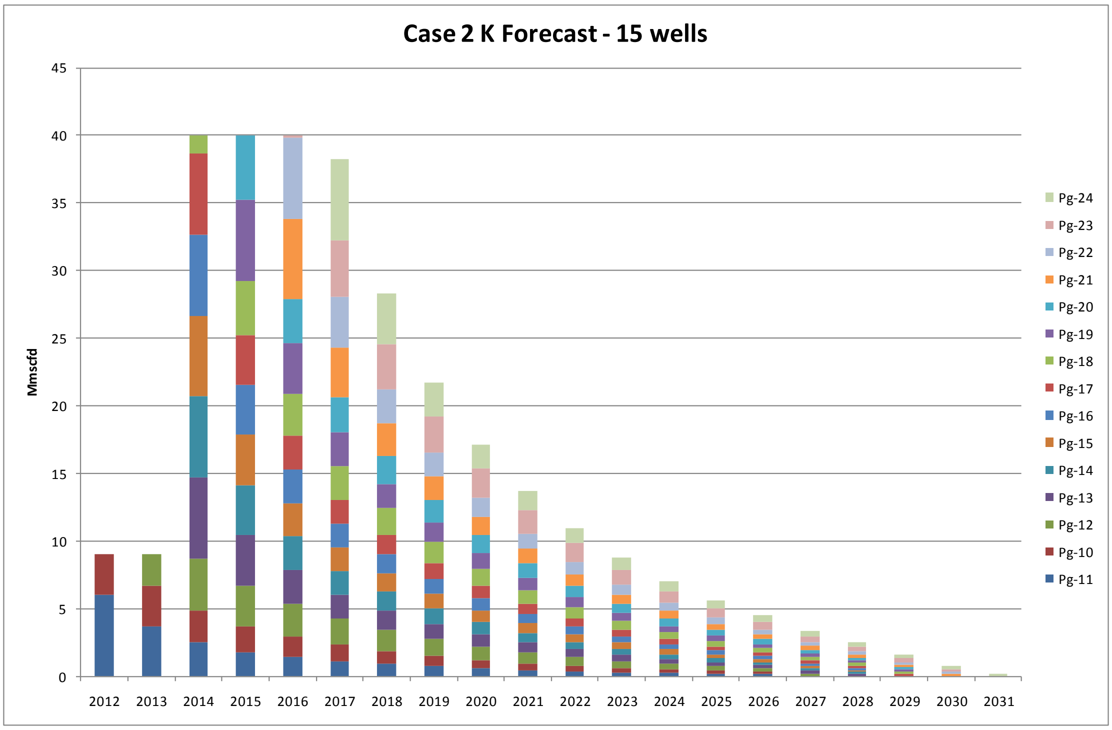


8.2. Case 2

This involves fifteen wells produced through a new production facility capable of handling 40 Mmscfd. The production profile is shown in Figure 29.

Total recovery is 110.3 bscf.

Figure 29 Case 2 K Forecast – 15 Wells

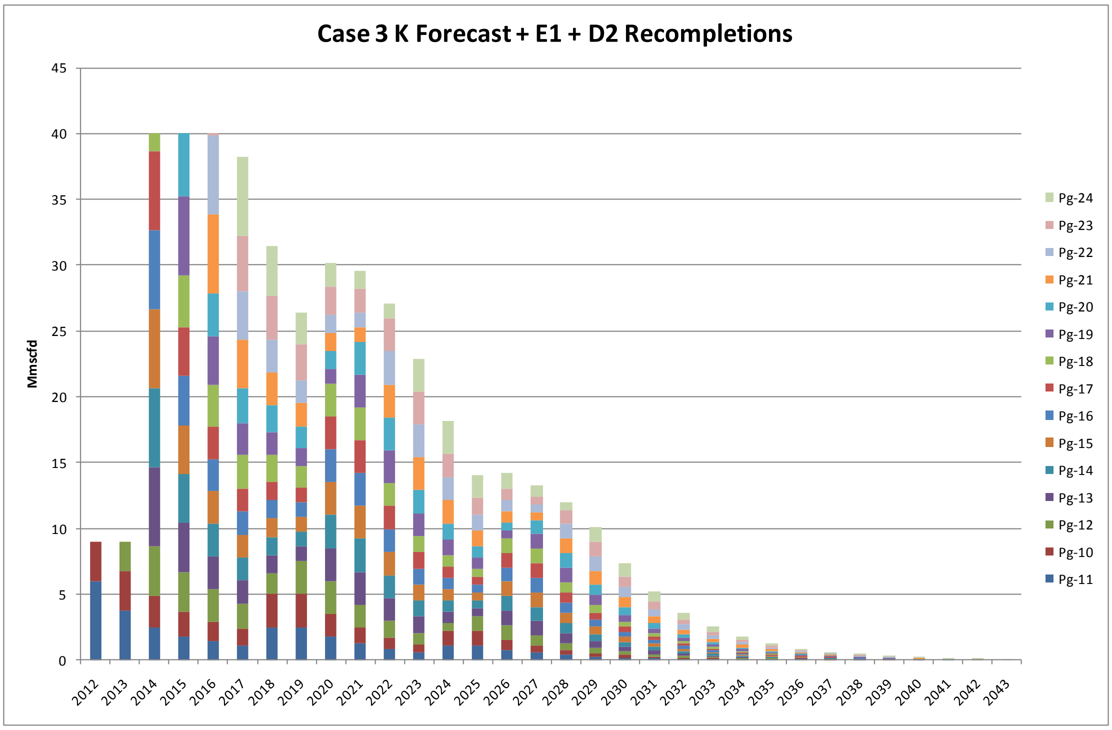


8.3. Case 3

This case involves re-completing fifteen low production K sand wells after six years of production to E1 wells and then further re-completions to D2 wells. The production profile is shown in Figure 30.

Total recovery is 86.6 bscf from the K sand, 51.6 bscf from the E1 sand and 26.0 bscf from the D2 sand.

Figure 30 Case 3 K Forecast 15 wells + E1 + D2 Recompletions

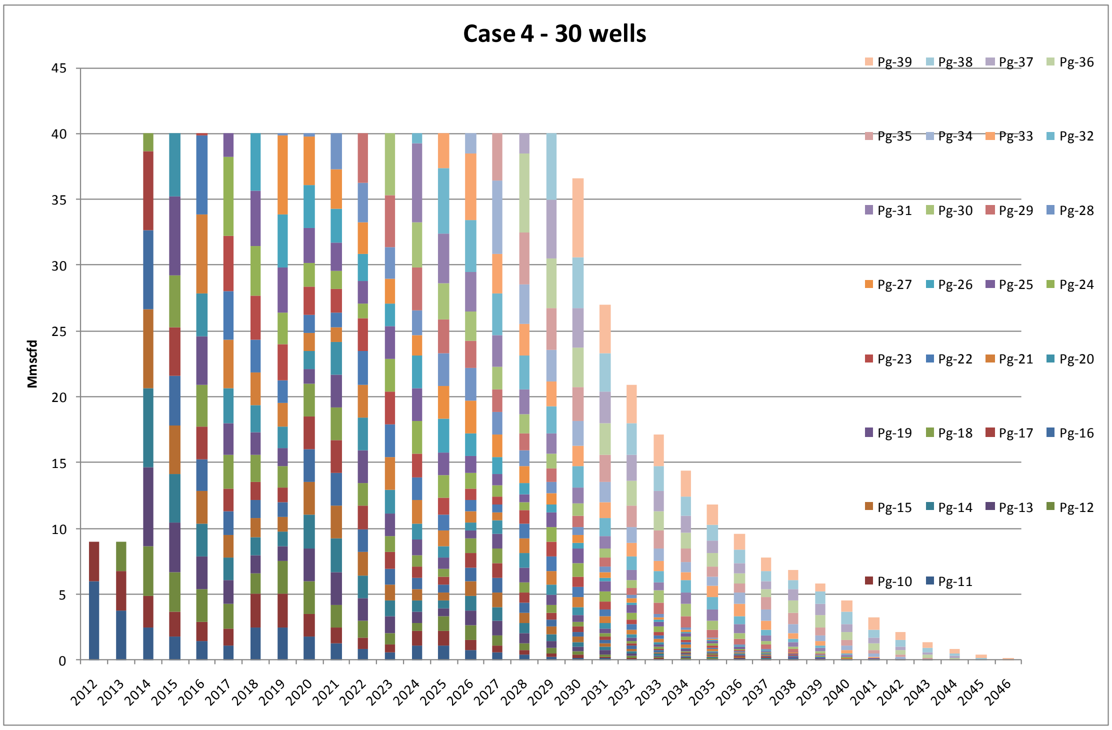


8.4. *Case 4*

This case involves the drilling of thirty K sand wells which are re-completed to E1 wells then to D2 wells, then to E4 wells. The production profile is shown in Figure 31.

Total recovery is 187.0 bscf from the K sand, 67.1 bscf from the E1 sand, 27.5 bscf from the D2 sand and 14.2 bscf from the E4 sand.

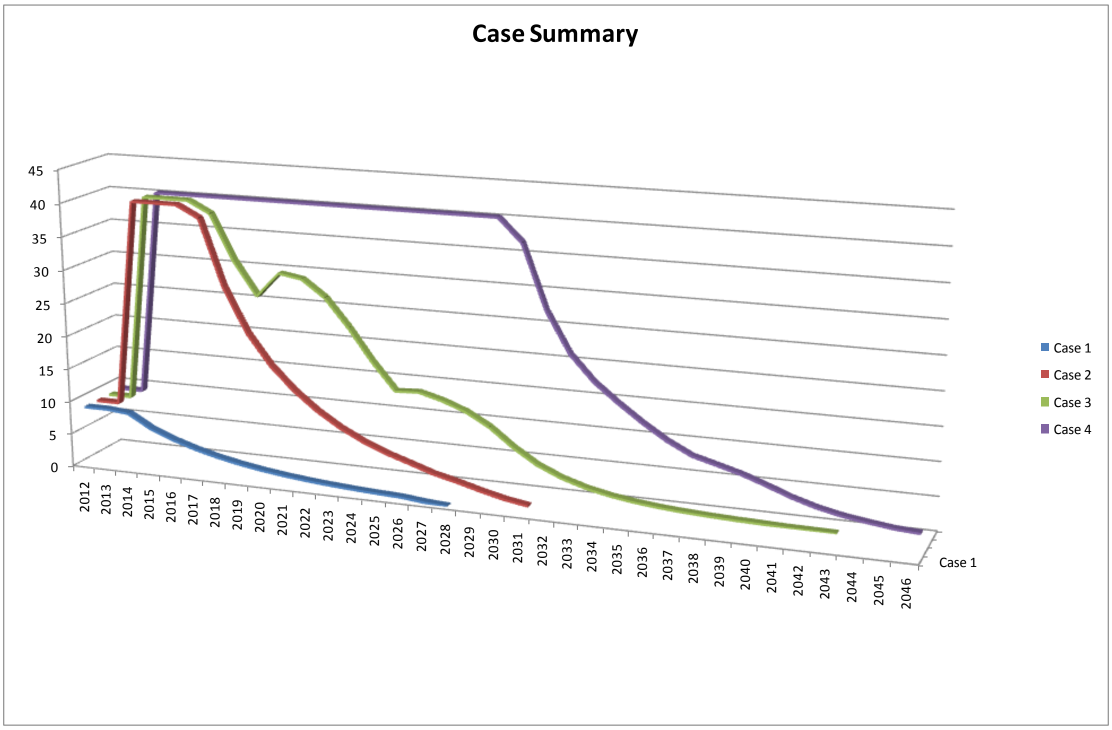
Figure 31 Case 4 K Forecast 30 Wells + E1 + D2 + E4 Recompletions



8.5. *Summary*

A comparison of the production forecast for the four cases is shown in Figure 32.

Figure 32 Gas Production Forecast Comparison



9. Development Assumptions

9.1. Case 1

This case, which is an early production scheme, assumes the use of the existing CPP facilities which have a design capacity of 15,000 m^3/hr (equivalent to 12.7 Mmscfd). Additional facilities will be required to treat the gas by removal of carbon dioxide and dehydration according to the study carried out by Rikopet in January 2011. This study assumed that these facilities could be designed and installed in seven months.

The case assumes for modelling purposes that production would start on 1 January 2012 from wells Pg-10 and Pg-11. Pg-11 has already been drilled and drilling of Pg-10 is in progress. Both wells will be fracced in the K sand. It is assumed that Pg-11 which is to be fracced first will produce at 6 Mmscfd and decline at 20% per year. It is also assumed that the Pg-10 well will produce at 3 Mmscfd and will decline at 20% per year. It is assumed that that the CO_2 content is 3% and this is excluded from the production profile and that the condensate content is 25 barrels/Mmscf.

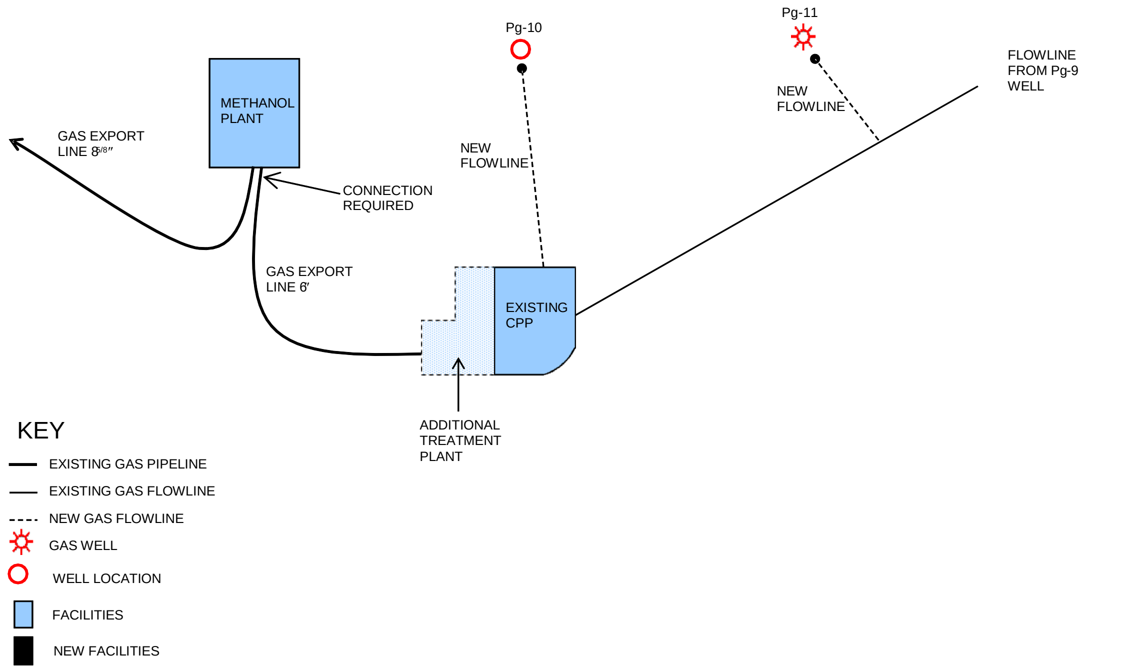
The planned production will involve a total plateau production of 9 Mmscfd. A third well will be drilled in 2012 to enable the plateau to be maintained in 2013.

The Pg-10 well will be connected directly to the CPP via a new flowline which will be approximately 0.5 km long. The Pg-11 well will be connected to the existing Pg-11 flowline through an approximately 140 metre connection. The connection for the third well will depend on its location. Pressure reduction will be required at the wells.

There is an existing 6” gas export line from the CPP to the methanol plant which is around 1.9 km in length. There is also an 8 5/8” gas import line from the gas transmission system to the methanol plant. A simple connection can be made between these two lines to allow gas export. There will be a requirement for odorisation of the gas which will need to be discussed with the gas transporter. It is understood that the 8 5/8” line does not have cathodic protection and its status will need to be checked.

A schematic of the proposed scheme is shown in Figure 33.

Figure 33 Early Production Scheme



9.2. *Case 2*

Case 2 involves the construction of a new production facility that would be able to process 50,000 m^3/hour of gas equivalent to 40 Mmscfd. The facility is assumed to be in operation by 1 January 2014. An additional twelve wells would be drilled according to the schedule shown in Table 8. It is assumed that these wells will produce 6 Mmscfd and decline at 20% per year. It is also assumed that that the CO_2 content is 3% and this is excluded from the production profile and that the condensate content is 25 barrels/Mmscf.

Table 8 Case 2 Well Count					
	2012	**2013**	**2014**	**2015**	**2016**
Well count	2	4	2	3	1

9.3. Case 3

Case 3 involves recompleting fifteen K sand wells to E1 sand wells then to D2 sand wells after the well has produced for six years from the E1 sand. The D2 sands produce at a rate of 1.1 Mmscfd for two years and thereafter decline at 30% per year. The CO_2 content has been taken as 4.25% and this is excluded from the production profile. Based on the production history the condensate content is 12 barrels/Mmscf. Workovers for the recompletions are carried out according to the following schedule in Table 9.

Table 9 Case 3 Workovers						
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Workovers	2	1	6	2	3	1

9.4. Case 4

This involves thirty K sand wells which are progressively re-completed to E1 sand wells, D2 sand wells and then E4 sand wells. The additional fifteen wells would be drilled according to the schedule shown in Table 10. Workovers for the recompletions are carried out according to Table 11.The E4 sands produce at a rate of 0.9 Mmscfd for two years and thereafter decline at 30% per year. The CO_2 content has been taken as 4.25% and this is excluded from the production profile. Based on the production history the condensate content is 12 barrels/Mmscf.

Table 10 Case 4 Additional Well Count					
2016	1	**2021**	1	**2026**	1
2017	1	**2022**	1	**2027**	2
2018	2	**2023**	2	**2028**	1
2019		**2024**	1	**2029**	1
2020		**2025**	1	**2030**	

Table 11 Case 4 Workovers					
2023	1	**2029**		**2035**	1
2024	1	**2030**		**2036**	1
2025	2	**2031**		**2037**	1
2026		**2032**		**2038**	2
2027		**2033**	2	**2039**	1
2028		**2034**	2	**2040**	1

10. Project Costs

10.1. Case 1

Capital costs for this case are shown in Table 12

Table 12 Case 1 Capital Costs

Drilling	€ million
Pg-12 Drilling	4.00
Pg-12 Frac	1.90
Pg-12 Completion	0.20
Total Drilling	6.10
Facilities	
Facilities	3.69
Metering	0.30
Odourisation	0.30
Total Facilities	4.29
Export Pipeline	
Test & repair 8 5/8" gas line	0.40
Connect 8 5/8" and 6" line	0.10
Total Export Pipeline	0.50
Flowlines	
Pg-11 0.14 km	0.07
Pg-10 0.5 km	0.25
Pg-12 2 km	1.00
Total Flowlines	1.32
Sub-total	12.21
Contingency (10%)	1.22
Project management (2%)	0.24
Total Costs (€ 2011)	**13.68**

Operating costs have been assumed at €300,000 per year.

10.2. Case 2

Capital costs for this case are shown in Table 13

Table 13 Case 2 Capital Costs

Drilling	€ million
Drilling 12 wells	48.00
Frac 12 wells	22.80
Complete 12 wells	2.40
Total Drilling	73.20
Design	
Detailed design	0.50
Total Design	0.50
Facilities	
Planning	0.20
Civils incl. access road	0.30
Electricity connection	0.20
Facilities	15.80
Test separator	0.40
Metering	0.40
Odourisation	0.30
Total Facilities	17.60
Export Pipeline	
New gas export line (3km)	1.50
Railway crossing	0.20
Total Export Pipeline	1.70
Flowlines	
Flowlines (30km)	15.00
Road and river crossings (10)	0.25
Wayleaves	0.30
Total Flowlines	15.55
Sub-total	108.55
Contingency (15%)	16.28
Project management (2%)	2.17
Insurance (1%)	1.09
Total Costs (€ 2011)	**128.09**

Operating costs have been assumed at €300,000 per year.

10.3. Case 3

Capital costs for this case are the same as Case 2. The operating costs include the workovers which are shown below in Table 14.

Table 14 Case 3 Operating Costs (€ million)

	Base Cost	E1 sand Workovers	D2 sand Workovers	Total
2014	0.3			0.3
2015	0.3			0.3
2016	0.3			0.3
2017	0.3	3.78		4.08
2018	0.3	1.89		2.19
2019	0.3	11.34		11.64
2020	0.3	3.78		4.08
2021	0.3	5.67		5.97
2022	0.3	1.89		2.19
2023	0.3		3.78	4.08
2024	0.3		1.89	2.19
2025	0.3		11.34	11.64
2026	0.3		3.78	4.08
2027	0.3		5.67	5.97
2028	0.3		1.89	2.19
2029	0.3			0.3
2030	0.3			0.3
2031	0.3			0.3
2032	0.3			0.3
2033	0.3			0.3
2034	0.3			0.3
2035	0.3			0.3
2036	0.3			0.3
2037	0.3			0.3
2038	0.3			0.3
2039	0.3			0.3
2040	0.3			0.3
2041	0.3			0.3
2042	0.3			0.3
2043	0.3			0.3

10.4. Case 4

Capital costs for this case are shown in Table 15.

Table 15 Case 4 Capital Costs

<u>Drilling</u>	€ million
Drilling 27 wells	108.00
Frac 27 wells	51.30
Complete 27 wells	5.40
Total Drilling	164.70
<u>Design</u>	
Detailed design	0.50
Total Design	0.50
<u>Facilities</u>	
Planning	0.20
Civils incl. access road	0.30
Electricity connection	0.20
Facilities	16.00
Test separator	0.40
Metering	0.40
Odourisation	0.30
Total Facilities	17.80
<u>Export Pipeline</u>	
New gas export line (3km)	1.50
Railway crossing	0.20
Total Export Pipeline	1.70
<u>Flowlines</u>	
Flowlines (45km)	22.50
Road and river crossings (20)	0.50
Wayleaves	0.40
Total Flowlines	23.40
Sub-total	208.10
Contingency (15%)	31.22
Project management (2%)	4.16
Insurance (1%)	2.08
Total Costs (€ 2011)	**245.56**

Operating costs are shown in Table 16.

Table 16 Case 4 Operating Costs (€ million)

	Base Cost	E1 sand Workovers	D2 sand Workovers	E4 sand Workovers	Total
2014	0.3				0.3
2015	0.3				0.3
2016	0.3				0.3
2017	0.3	3.78			4.08
2018	0.3	1.89			2.19
2019	0.3	11.34			11.64
2020	0.3	3.78			4.08
2021	0.4	5.67			6.07
2022	0.5	1.89			2.39
2023	0.5	1.89	3.78		6.17
2024	0.5	1.89	1.89		4.28
2025	0.5	1.89	11.34		13.73
2026	0.5		3.78		4.28
2027	0.5		5.67		6.17
2028	0.5		1.89		2.39
2029	0.5				0.5
2030	0.5				0.5
2031	0.5				0.5
2032	0.5				0.5
2033	0.5			3.78	4.28
2034	0.5			3.78	4.28
2035	0.5			1.79	2.29
2036	0.5			1.79	2.29
2037	0.5			1.79	2.29
2038	0.5			1.79	2.29
2039	0.5			1.79	2.29
2040	0.5			1.79	2.29
2041	0.5				0.5
2042	0.5				0.5
2043	0.5				0.5
2044	0.5				0.5
2045	0.5				0.5
2046	0.5				0.5

11. Economic Evaluation

11.1. Economic Model and Assumptions

An economic model was developed for the valuation of the four cases described above. The model assumptions are based on data provided by Ascent and PDC's understanding of the fiscal and contractual terms governing this asset. The licence for the field is valid until 15 November 2021 with an allowed extension of a maximum of 10 years and thus economic analysis has been carried out to 15 November 2031. NPVs have been estimated after tax cash flow as at 1 January 2012 attributable to a net economic interest in Ascent's Petišovci field using the pricing and inflation assumptions as described herein.

Ascent is subject to Slovenian Corporation Tax at 20% of profits. Investment incentive to reduce the taxable base by 40% of the amount in research and development and 30% of the amount in equipment or intangible assets has been assumed. The relief on investments is limited to EUR 30,000. VAT is chargeable at 20%.

Current net gas price (inclusive of VAT and taxes) is assumed at €7/mmcf index linked to oil based on Gazprom long-term gas contracts which are linked to oil and oil products with a six month lag. Three oil price scenarios were used in this analysis; constant flat price for a low price scenario, US Energy Information Administration (EIA) reference case forecast in real money for base case and EIA reference case nominal forecast for high price. The oil price forecasts and the resulting three gas price forecasts are presented below in Table 17

Table 17 Oil and Gas Price Forecasts

	Low Price			Base Price			High Price		
	Oil Price $/bbl	Gas Price €cts/Sm3	Gas Price €/mscf	Oil Price $/bbl	Gas Price €cts/Sm3	Gas Price €/mscf	Oil Price $/bbl	Gas Price €cts/Sm3	Gas Price €/mscf
2011	71.11	24.71	7.00	71.11	24.71	7.00	73.22	25.44	7.20
2012	71.11	24.71	7.00	76.37	25.62	7.26	79.79	26.58	7.53
2013	71.11	24.71	7.00	82.01	27.52	7.79	86.94	28.97	8.20
2014	71.11	24.71	7.00	88.07	29.55	8.37	94.74	31.57	8.94
2015	71.11	24.71	7.00	94.58	31.74	8.99	103.24	34.40	9.74
2016	71.11	24.71	7.00	97.14	33.31	9.43	108.21	36.74	10.40
2017	71.11	24.71	7.00	99.77	34.21	9.69	113.42	38.51	10.90
2018	71.11	24.71	7.00	102.47	35.14	9.95	118.88	40.36	11.43
2019	71.11	24.71	7.00	105.25	36.09	10.22	124.60	42.30	11.98
2020	71.11	24.71	7.00	108.10	37.07	10.50	130.60	44.34	12.56
2021	71.11	24.71	7.00	109.93	37.88	10.73	135.23	46.19	13.08
2022	71.11	24.71	7.00	111.78	38.52	10.91	140.03	47.83	13.54
2023	71.11	24.71	7.00	113.67	39.17	11.09	144.99	49.52	14.02
2024	71.11	24.71	7.00	115.59	39.83	11.28	150.14	51.28	14.52
2025	71.11	24.71	7.00	117.54	40.51	11.47	155.46	53.10	15.04
2026	71.11	24.71	7.00	118.63	41.03	11.62	159.81	54.78	15.51
2027	71.11	24.71	7.00	119.73	41.41	11.73	164.28	56.31	15.94
2028	71.11	24.71	7.00	120.84	41.80	11.84	168.87	57.88	16.39
2029	71.11	24.71	7.00	121.96	42.19	11.95	173.59	59.50	16.85
2030	71.11	24.71	7.00	123.09	42.58	12.06	178.45	61.17	17.32
2031	71.11	24.71	7.00	123.46	42.84	12.13	182.45	62.71	17.76
2032	71.11	24.71	7.00	123.83	42.97	12.17	186.54	64.11	18.15
2033	71.11	24.71	7.00	124.20	43.09	12.20	190.72	65.55	18.56
2034	71.11	24.71	7.00	124.57	43.22	12.24	195.00	67.02	18.98
2035	71.11	24.71	7.00	124.94	43.35	12.28	199.37	68.52	19.40
2036	71.11	24.71	7.00	124.94	43.42	12.29	203.36	69.97	19.81
2037	71.11	24.71	7.00	124.94	43.42	12.29	207.42	71.37	20.21
2038	71.11	24.71	7.00	124.94	43.42	12.29	211.57	72.80	20.61
2039	71.11	24.71	7.00	124.94	43.42	12.29	215.80	74.26	21.03
2040	71.11	24.71	7.00	124.94	43.42	12.29	220.12	75.74	21.45

An overriding royalty (ORR) is payable as shown below for the Joint Venture (JV). This is only paid for the Ascent 75% share of the JV.

Table 18 Overriding Royalty

JV Lands			
Oil + condensate (bopd)			ORR%
0	to	1000	3%
1000	to	2000	4%
2000	to	99999	5%
Other (Mmscfd)			ORR%
0	to	7	3%
7	to	14	4%
14	to	99999	5%

All products produced on non-JV lands pay 2.5% ORR. The Petišovci field is assumed wholly within JV lands. In addition, a 2% of royalty share is payable as management fee.

An escalation of 2.5% was assumed.

11.2. Case 1 Results

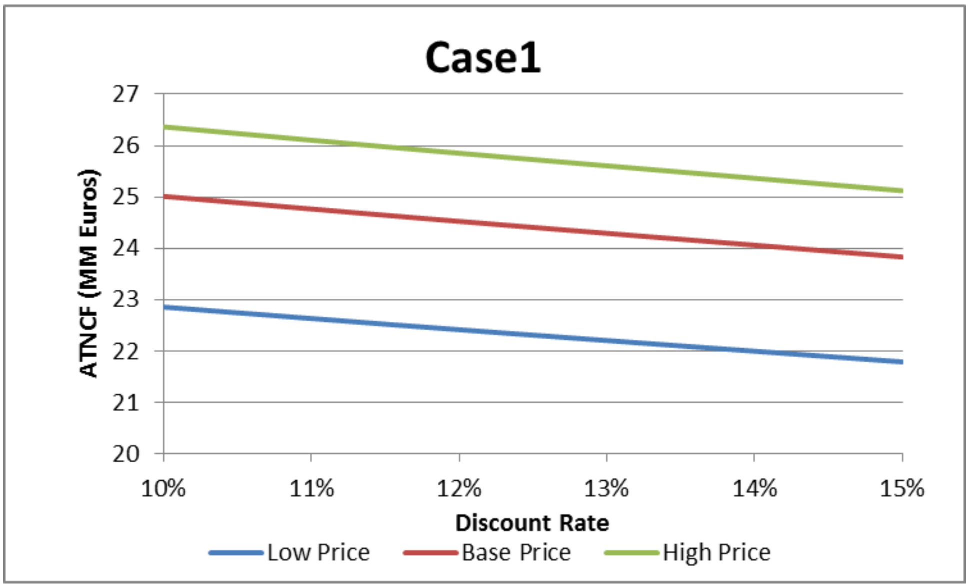
The results of Ascent share economic analysis for Case 1 using the base gas price and discounted on mid-year basis at 1 January 2012 net to Ascent are presented below.

Table 19 Case 1 Economic Results

ECONOMIC SUMMARY : Case1			
Reserves:	Oil	MMbbl	0.1
	Gas	Bcf	4.8
	Ngl	MMbbl	0.0
	Total	MMboe	0.9
Gross Revenue		MM Euros	43.0
Indirect Taxes		MM Euros	2.4
CAPEX		MM Euros	10.4
OPEX		MM Euros	0.5
Abandonment		MM Euros	0.4
Total Outflow		MM Euros	13.7
Net Cashflow Before Tax		MM Euros	32.1
Income Tax		MM Euros	7.4
Net Cashflow After Tax		MM Euros	24.7
Overriding Royalty		MM Euros	2.0
Net Cashflow After ORR		MM Euros	22.7
ECONOMIC INDICATORS			
NPV @ 10%		MM Euros	25.0
NPV @ 12%		MM Euros	**24.5**
NPV @ 15%		MM Euros	23.8
IRR		**%**	**214.4%**
Maximum Exposure		MM Euros	-5
NPV/Max Exp			5
NPV/bbl		Euros/bbl	198.8
NPV/boe		Euros/bbl	26.6
P10/I10			4.9
Payback Date			Jun 12
Payback from 1st Production			0 yrs 6 mths

The chart below shows discounted after tax net cash flow on the low, base and high gas price basis.

Figure 34 Case 1 Price Sensitivity



11.3. Case 2 Results

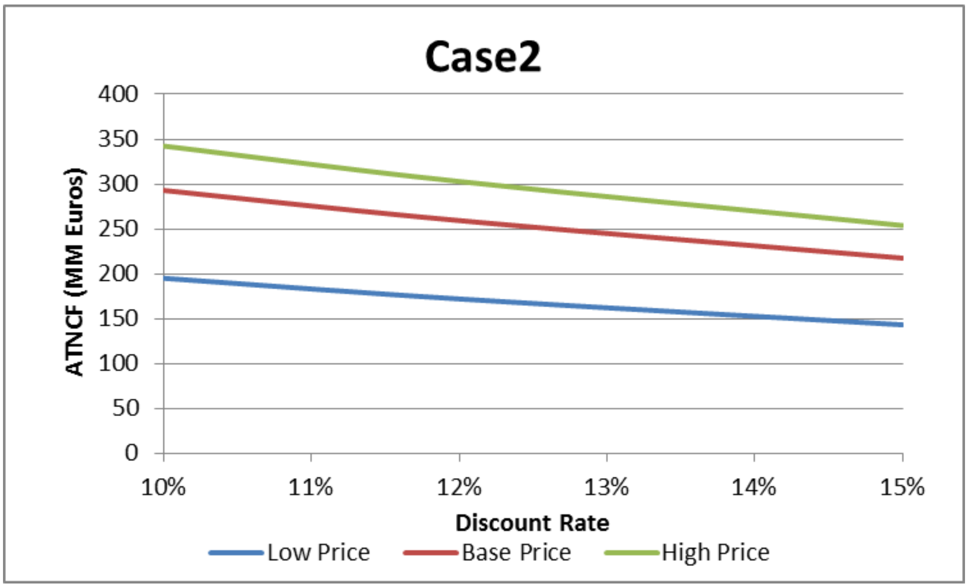
The results of Ascent share economic analysis for Case 2 using base gas price and discounted on mid-year basis at 1 January 2012 net to Ascent are presented below in Table 20.

Table 20 Case 2 Economic Results

ECONOMIC SUMMARY : Case2			
Reserves:	Oil	MMbbl	1.9
	Gas	Bcf	75.5
	Ngl	MMbbl	0.0
	Total	MMboe	14.5
Gross Revenue		MM Euros	879.1
Indirect Taxes		MM Euros	25.2
CAPEX		MM Euros	102.0
OPEX		MM Euros	5.4
Abandonment		MM Euros	0.0
Total Outflow		MM Euros	132.6
Net Cashflow Before Tax		MM Euros	771.7
Income Tax		MM Euros	152.8
Net Cashflow After Tax		MM Euros	618.8
Overriding Royalty		MM Euros	42.0
Net Cashflow After ORR		MM Euros	576.9
ECONOMIC INDICATORS			
NPV @ 10%		MM Euros	292.9
NPV @ 12%		MM Euros	**259.3**
NPV @ 15%		MM Euros	217.5
IRR		**%**	**86.5%**
Maximum Exposure		MM Euros	-66
NPV/Max Exp			4
NPV/bbl		Euros/bbl	133.3
NPV/boe		Euros/bbl	17.9
P10/I10			3.1
Payback Date			Dec 14
Payback from 1st Production			0 yrs 11 mths

Sensitivity to gas price is shown in Figure 35.

Figure 35 Case 2 Price Sensitivity



11.4. Case 3 Results

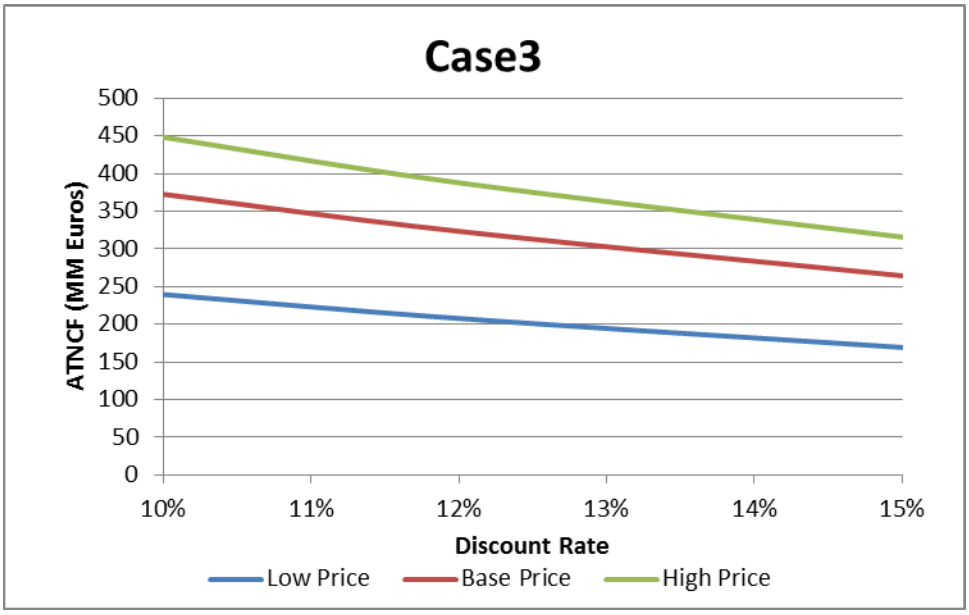
The results of Ascent share economic analysis for Case 3 using base gas price and discounted on mid-year basis at 1 January 2012 net to Ascent are shown in Table 21.

Table 21 Case 3 Economic Results

ECONOMIC SUMMARY : Case3			
Reserves:	Oil	MMbbl	2.2
	Gas	Bcf	111.0
	Ngl	MMbbl	0.0
	Total	MMboe	20.7
Gross Revenue		MM Euros	1,295.3
Indirect Taxes		MM Euros	38.2
CAPEX		MM Euros	102.0
OPEX		MM Euros	62.0
Abandonment		MM Euros	0.0
Total Outflow		MM Euros	202.1
Net Cashflow Before Tax		MM Euros	1,131.4
Income Tax		MM Euros	224.8
Net Cashflow After Tax		MM Euros	906.6
Overriding Royalty		MM Euros	62.8
Net Cashflow After ORR		MM Euros	843.8
ECONOMIC INDICATORS			
NPV @ 10%		MM Euros	372.6
NPV @ 12%		MM Euros	**323.5**
NPV @ 15%		MM Euros	264.4
IRR		**%**	**87.2%**
Maximum Exposure		MM Euros	-66
NPV/Max Exp			5
NPV/bbl		Euros/bbl	149.6
NPV/boe		Euros/bbl	15.7
P10/I10			3.9
Payback Date			Dec 14
Payback from 1st Production			0 yrs 11 mths

Sensitivity analysis to gas price is shown in Figure 36.

Figure 36 Case 3 Price Sensitivity



11.5. Case 4 Results

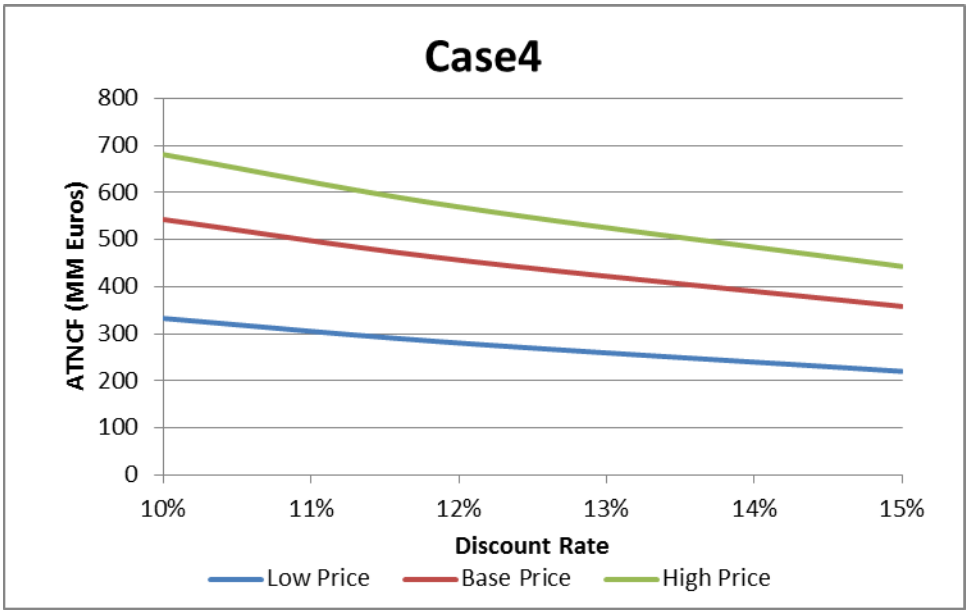
The results of Ascent share economic analysis for Case 5 using base gas price and discounted on mid-year basis at 1 January 2012 net to Ascent are shown in Table 22.

Table 22 Case 4 Economic Results

ECONOMIC SUMMARY : Case4			
Reserves:	Oil	MMbbl	4.0
	Gas	Bcf	186.1
	Ngl	MMbbl	0.0
	Total	MMboe	35.0
Gross Revenue		MM Euros	2,306.1
Indirect Taxes		MM Euros	67.3
CAPEX		MM Euros	221.0
OPEX		MM Euros	70.1
Abandonment		MM Euros	0.0
Total Outflow		MM Euros	358.4
Net Cashflow Before Tax		MM Euros	2,015.0
Income Tax		MM Euros	395.8
Net Cashflow After Tax		MM Euros	1,619.2
Overriding Royalty		MM Euros	111.3
Net Cashflow After ORR		MM Euros	1,507.9
ECONOMIC INDICATORS			
NPV @ 10%		MM Euros	542.5
NPV @ 12%		MM Euros	**456.5**
NPV @ 15%		MM Euros	358.0
IRR		**%**	**87.9%**
Maximum Exposure		MM Euros	-66
NPV/Max Exp			7
NPV/bbl		Euros/bbl	115.5
NPV/boe		Euros/bbl	13.1
P10/I10			3.9
Payback Date			Dec 14
Payback from 1st Production			0 yrs 11 mths

Sensitivity analysis to gas price is shown in Figure 37.

Figure 37 Case 4 Price Sensitivity



11.6. Economic Summary

An economic summary is shown in Table 23. It is based on the licence expiring on 15 November 2031 after a ten year extension.

Table 23 Economic Summary

Case	Gas recovered (bscf)	Net Present Value @ 12% (€ million)	Rate of Return (%)
1	4.8	24.5	214.4
2	75.5	259.3	86.5
3	111.0	323.5	87.2
4	186.1	456.5	87.9

12. Conclusions

The following conclusions can be made:

- Based on the assumptions made regarding the potential productivity of the K sands following fracture simulation, the economics of the field look very attractive for all four cases that were developed
- Case 1 which involved the use of existing facilities had a high rate of return but only recovered a small proportion of the gas in place
- Case 2 which was based on full-scale production with fifteen wells shows increased recovery and a higher net present value

- Case 3 with fifteen wells with recompletions to the D2 and E1 sands showed an increased recovery and a higher net present value when compared to Case 2
- Case 4 with thirty wells assumed recompletion of low rate K sand wells to E1, D2 and E4 sand wells and showed significantly improved recovery and a much higher net present value than the other cases