U.S. EPA Coalbed Methane OUTREACH PROGRAM

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Application of Longhole Directional Drilling for Methane Drainage at the Amasra Hard Coal Mine: Amasra, Turkey

U.S. Environmental Protection Agency
February 2015

Application of Longhole Directional Drilling for Methane Drainage at the Amasra Hard Coal Mine
Amasra, Turkey

Pre-feasibility Study for
Coal Mine Methane Drainage and Utilization

Sponsored by:
U.S. Environmental Protection Agency, Washington, DC USA

Prepared by:
Advanced Resources International, Inc.
REI Drilling, Inc.

February 2015

Disclaimer

This report was prepared for the U.S. Environmental Protection Agency (USEPA). This analysis uses publicly available information in combination with information obtained through direct contact with mine personnel. USEPA does not:

(a) make any warranty or representation, expressed or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any apparatus, method, or process disclosed in this report may not infringe upon privately owned rights;
(b) assume any liability with respect to the use of, or damages resulting from the use of, any information, apparatus, method, or process disclosed in this report; or
(c) imply endorsement of any technology supplier, product, or process mentioned in this report.

Acknowledgements

This publication was developed at the request of the United States Environmental Protection Agency (USEPA), in support of the Global Methane Initiative (GMI). In collaboration with the Coalbed Methane Outreach Program (CMOP), Advanced Resources International, Inc. (ARI) and REI Drilling, Inc. (REI) authored this report based on information obtained from the coal mine partner, HEMA.

Table of Contents

List of Figures

List of Tables

Executive Summary

With funding from the United States Environmental Protection Agency (USEPA), under the auspices of the Global Methane Initiative (GMI), this pre-feasibility study evaluates the technical and economic viability of methane drainage utilizing longhole directional drilling at the Amasra Hard Coal Mine in Turkey.

Hema Energi (HEMA) is currently developing a 5 million metric tonne (Mt) per year mine in Amasra, Turkey. The mine is located on a coal license obtained from TTK and will supply a 1,320 megawatt (MW) mine-mouth power plant currently under development. HEMA has been working on developing the coalbed methane resources outside of the mining areas and they would now like to initiate degasification efforts at the mine itself. The coal seams in the Zonguldak coal region where the Amasra Mine is located are known to be very gassy and over the years there have been several disastrous explosions resulting in numerous fatalities. HEMA realizes that an aggressive pre-mine drainage program will substantially reduce the methane content of the coal in advance of mining, thus making the mining environment safer and more productive.

Extending over an area of 50 square kilometers (km^2) the mine is located in north-central Turkey within the Zonguldak Coal Basin, approximately 250 kilometers (km) to the west of Istanbul on the Black Sea coast. After obtaining a coal license from TTK, HEMA has the right to mine below -400 meters (m) on 14 km^2 of the area with the remaining 35.6 km^2 to be mined from the surface. Total coal resources for the mine are estimated at 573 Mt. To initiate development of these resources, a mining plan covering 13 km^2 has been prepared with the mine area divided into three blocks, namely the East Block, West Block, and Southeast Block.

The Amasra Mine presents an ideal site for a pre-mine drainage CMM program for several reasons. Firstly, the company is committed to developing this new mine and has already spent nearly $100 million on developing the production shafts. Secondly, being a new mine, it will likely be very gassy and thus, will benefit greatly from pre-mine drainage. Lastly, the mine is located within the environs of the town of Amasra which provides a ready market for the produced gas. We believe that a pre-feasibility study at the Amasra Mine is well justified given the high likelihood of project implementation and the resulting methane reductions.

The principal objective of this pre-feasibility study is to assess the technical and economic viability of methane drainage utilizing longhole directional drilling at the Amasra Hard Coal Mine, and using this gas to produce electricity or compressed natural gas (CNG). The proposed gas drainage approach discussed in this study will focus on the East Block since it will be the first area to be mined. However, it is envisioned that the proposed drilling program will also be utilized in the West and Southeast blocks. For the East Block, the proposed gas drainage approach is to use a combination of in-seam drilling in advance of mine developments, and gob gas drainage via horizontal gob boreholes. Flanking in-seam boreholes to shield and drain gas ahead of development galleries are proposed with horizontal gob boreholes (HGBs) drilled into the gob area above the formation to drain gas as longwall mining progresses.

The use of longhole directional drilling will allow for longer length and more accurate placement of boreholes for improved in-seam methane drainage efficiency. In addition, longhole directional drilling allows for the implementation of innovative gob gas drainage techniques that may be more efficient than cross-measure boreholes and at lower cost than superjacent techniques. Other benefits of longhole directional drilling include the ability to steer boreholes to stay in-seam, flank projected gateroads, or hit specific targets such as adjacent coal seams or gas bearing strata. This technique promotes a more focused, simplified gas collection system with improved recovered gas quality because of the reduced amount of wellheads and pipeline infrastructure. Additionally, the proposed drainage approach is less labor intensive, can be accomplished away from mining activity with proper planning, and provides additional geologic information (such as coal thickness, faults, and other anomalies, etc.) prior to mining.

The primary markets available for a CMM utilization project at the Amasra Mine are power generation using internal combustion engines and vehicle fuel in the form of CNG. Given the relatively small CMM production volume, as well as the requirement for gas upgrading, constructing a pipeline to transport the gas to demand centers would be impractical. Based on the gas supply forecasts generated in this pre-feasibility study, the mine could be capable of operating as much as 8.8 MW of electricity capacity or produce over 1.5 million diesel liter equivalents (DLE) per month. Generating electricity on site is attractive, because the input CMM gas stream can be utilized as is, with minimal processing and transportation. Additional generating sets can be installed relatively cheaply and infrastructure for the power plant and distribution system is already planned. While the CNG utilization option requires significant processing of the CMM gas stream to increase its methane concentration and remove contaminants, the current high price of transportation fuel in Turkey improves the economics of this utilization option. However, this option should be investigated more thoroughly in a full-scale feasibility study, should the project advance to that development stage.

The proposed pre-drainage project – which utilizes long, in-seam boreholes to drain gas ahead of mining – focuses on mining of the six coal seams (EC100 through EC600) located in the East Production Block. Based on the mine maps provided by HEMA, a total of 42 individual longwall panels are scheduled to be mined over a 24-year period. The mining plan is to work from the upper coal seam (EC100) down to the lower ones (EC200 – EC600). Flanking in-seam boreholes are utilized to drain gas ahead of development galleries. Long directionally drilled boreholes cover the entire length of each panel from a single setup location, allowing drainage of multiple mining levels.

Based on the mine development schedule provided by HEMA, boreholes were assumed to be drilled and put on production three to five years prior to the initiation of mining activities at each panel. CMM gas production profiles were generated for a total of four project development cases:

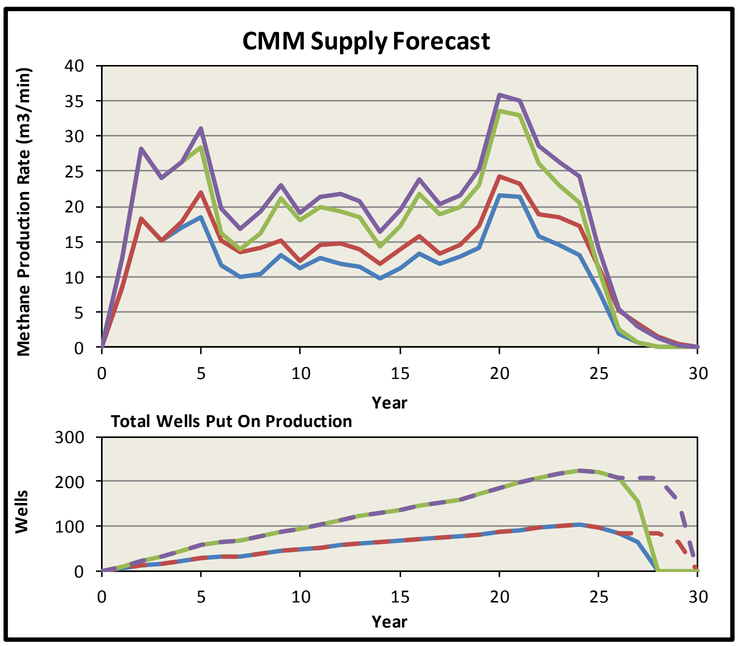
- Case 1: 2 wells drilled per panel; 3 years pre-drainage
- Case 2: 2 wells drilled per panel; 5 years pre-drainage
- Case 3: 4 wells drilled per panel; 3 years pre-drainage
- Case 4: 4 wells drilled per panel; 5 years pre-drainage

The methane drainage approach proposed at this mine also includes a large gob degasification program involving horizontal gob boreholes (HGBs). HGBs will be drilled into the gob area above the formation to drain gas as longwall mining progresses. HGBs will also be drilled between the EC300 and EC400 seams due to the separation of the seams. A total of 19 HGBs are assumed to be drilled in the East Production Block prior to the start of mining. Upon completion, HGBs will be placed on vacuum once mining progresses. The production duration of each HGB is dependent on the length of time it takes to mine each longwall panel, and it is assumed that each HGB continues to produce gob gas for an additional three months after the panel is mined through. Underground, the in-seam gas collection system is assumed to be integrated with the gob gas drainage system (i.e., combined pipelines). The development of the HGB portion of the project is assumed to be the same for all four in-seam gas drainage cases.

Based on the forecasted gas production, as shown in Figure 1, the breakeven cost of producing gas through in-seam drainage boreholes is estimated to be between \$64 and \$91/1000 cubic meter (m^3) (\$2.33 and \$3.15 per million British thermal unit {MMBtu}). The results of the economic assessment indicate the lowest CMM production costs are associated with the 2 wells drilled per panel cases, with 5 years of pre-drainage (Case 2) preferred over 3 years (Case 1).

Summary of Economic Results

CMM Supply



Case	Wells per Panel	Years of Pre-Drainage	Breakeven Gas Price $/1000m3
1	2	3	71.93
2	2	5	63.57
3	4	3	90.85
4	4	5	84.00

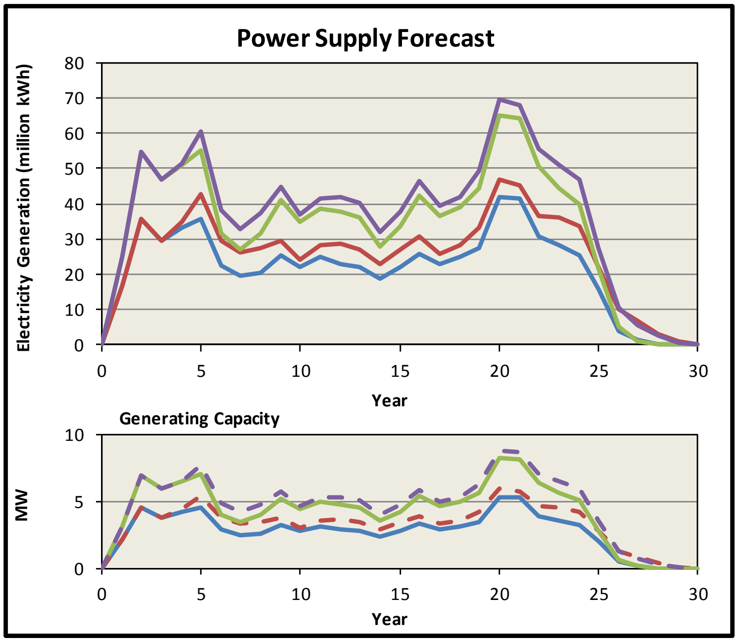
Case	Description
1	2 wells per panel; 3 years pre-drainage
2	2 wells per panel; 5 years pre-drainage
3	4 wells per panel; 3 years pre-drainage
4	4 wells per panel; 5 years pre-drainage

Figure 1: Summary of Economic Results for the CMM Project

As shown in Figure 2, the breakeven power sales price, inclusive of the cost of methane drainage, is estimated to be between \$0.049 and \$0.056 per kilowatt-hour (kWh). Based on a breakeven CMM price of \$64 per thousand cubic meters (1000m^3) (\$2.33/MMBtu) (Case 2), the mine could generate power at a price equivalent to \$0.049/kWh. A CMM-to-power utilization project at the mine would be economically feasible if the mine currently pays a higher price for electricity.

Summary of Economic Results

Power Supply



Case	Wells per Panel	Years of Pre-Drainage	Breakeven Power Price $/kWh
1	2	3	0.0526
2	2	5	0.0485
3	4	3	0.0561
4	4	5	0.0533

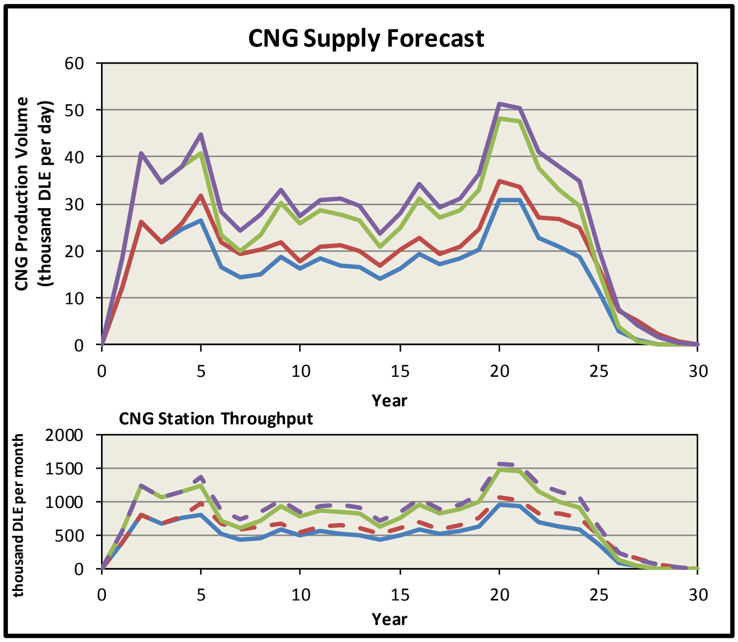
Case	Description
1	2 wells per panel; 3 years pre-drainage
2	2 wells per panel; 5 years pre-drainage
3	4 wells per panel; 3 years pre-drainage
4	4 wells per panel; 5 years pre-drainage

Figure 2: Summary of Economic Results for Power Project

As shown in Figure 3, the breakeven CNG sales price, inclusive of the cost of methane drainage, is estimated to be between $0.22 and $0.26/DLE ($0.84 and $0.98 per diesel gallon equivalent {DGE}). Due to economies of scale associated with CNG station capacity, the optimal case for CNG production is Case 4, which produces CNG at a price equivalent to $0.22/DLE ($0.84/DGE). A CMM-to-CNG utilization project at the mine would be economically feasible if the mine currently pays a higher price for transportation fuel (e.g., CNG or diesel fuel).

Summary of Economic Results

CNG Supply



Case	Wells per Panel	Years of Pre-Drainage	Breakeven CNG Price $/DLE
1	2	3	0.260
2	2	5	0.235
3	4	3	0.236
4	4	5	0.222

Case	Description
1	2 wells per panel; 3 years pre-drainage
2	2 wells per panel; 5 years pre-drainage
3	4 wells per panel; 3 years pre-drainage
4	4 wells per panel; 5 years pre-drainage

Figure 3: Summary of Economic Results for CNG Project

The most effective gas drainage program for the mine is likely to be a combination of horizontal gob gas boreholes combined with in-seam gas drainage boreholes, both drilled from within the mine. Due to the relatively low permeability of the coals, the drainage efficiency improves as more wells per panel are drilled, and as drainage time increases. Based on the forecasted gas production, the breakeven cost of producing CMM through in-seam drainage boreholes combined with HGBs is estimated to be between $64 and $91/1000 m^3 ($2.33 and $3.15/MMBtu). The results of the economic assessment indicate the lowest CMM production costs are associated with the 2 wells drilled per panel cases, with 5 years of pre-drainage (Case 2) preferred over 3 years (Case 1).

In terms of utilization, the power and CNG options both appear to be economically feasible. More rigorous engineering design and costing would be needed before making a final determination of the best available utilization option for the drained methane. As of the end of 2013 the average rate of electricity for industrial customers was S0.1038/kWh (inclusive of all taxes and levies). When compared to the breakeven power sales price calculated in the economic analysis, utilizing drained methane to produce electricity could generate profits of between $48 and $55 per megawatt-hour (MWh) of electricity produced. In terms of transportation fuels, the current diesel price in Turkey is $2.07 per liter (l). With a breakeven CNG sales price estimated to be between $0.22 and $0.26/DLE, utilizing drained methane to produce CNG could generate profits of between $1.81 and $1.85 per DLE of CNG sold.
Both potential utilization options appear to be economically feasible and removing the cost of mine degasification from downstream economics, as a sunk cost, would reduce the marginal cost of electricity and CNG production and improve the economics. Furthermore, depending on the development approach and utilization option selected for the project, net emission reductions associated with the destruction of drained methane are estimated to range between 2.2 million and 3.8 million tonnes of carbon dioxide equivalent (tCO2e) over the 30-year project life.

1 Introduction

Under the auspices of the Global Methane Initiative (GMI), the U.S. Environmental Protection Agency (USEPA) works with coal mines in the U.S. and internationally to encourage the economic use of coal mine methane (CMM) gas that is otherwise vented to the atmosphere. Methane is both the primary constituent of natural gas and a potent greenhouse gas when released to the atmosphere. Reducing emissions can yield substantial economic and environmental benefits, and the implementation of available, cost-effective methane emission reduction opportunities in the coal industry can lead to improved mine safety, greater mine productivity, and increased revenues.

The GMI is an international partnership of 42 member countries and the European Commission that focuses on cost-effective, near-term methane recovery and use as a clean energy source. USEPA, in support of the GMI, has sponsored feasibility and pre-feasibility studies in China, India, Kazakhstan, Mongolia, Poland, Russia and Ukraine. These studies provide the cost-effective first step to project development and implementation by identifying project opportunities through a high-level review of gas availability, end-use options, and emission reduction potential. This study extends USEPA pre-feasibility support to Turkey. As a major coal mining country and one with significant challenges related to methane emissions into mine workings, success in delivering CMM projects in Turkey will contribute greatly to reducing regional and global methane emissions.

The principal objective of this pre-feasibility study is to assess the technical and economic viability of methane drainage utilizing longhole directional drilling at the Amasra Hard Coal Mine. The Amasra Hard Coal Mine is an excellent candidate for increased methane use and abatement, and was chosen for this pre-feasibility study on the following basis:

- Hema Energi is currently developing a 5 million ton per year mine in Amasra, Turkey. The mine is located on a coal license obtained from TTK and will supply a 1,320 MW mine-mouth power plant currently under development. Based on the mining plan, coal production from the East Block is expected to commence in 2015.
- The coal seams in the Amasra Mine area are known to be very gassy and over the years there have been several disastrous explosions resulting in numerous fatalities. HEMA realizes that an aggressive pre-mine drainage program will substantially reduce the methane content of the coal in advance of mining, thus making the mining environment safer and more productive.
- Being a new mine, it will likely be very gassy and thus, will benefit greatly from pre-mine drainage.
- The company is committed to developing this new mine and has already spent nearly $100 million on developing the production shafts.
- The mine is located within the environs of the town of Amasra which provides a ready market for the produced gas.

We believe that a pre-feasibility study at the Amasra Mine is well justified given the high likelihood of project implementation and the resulting methane reductions. This pre-feasibility study is intended to provide an initial assessment of project viability. A final Investment Decision (FID) should only be made after completion of a full feasibility study based on more refined data and detailed cost estimates, completion of a detailed site investigation, implementation of well tests, and possibly completion of a Front End Engineering & Design (FEED).

2 Background

2.1 The Turkish Coal Industry

Coal exploration and mining in the Zonguldak Basin began in the 18th century and continues to be a source of energy and coking coal for the region to this day. Hard coal resources in the basin are estimated at 1,335 million tonnes (Mt), with proven reserves of 534 Mt (EUROCOAL, 2014). Coal resources associated with the Amasra Hard Coal Mine are estimated to be 573 Mt, which represents about 43% of Turkey's total hard coal resources, with 265 Mt of economical reserves being reported (HEMA, 2014). At the end of 2012, Turkey's total proved reserves of coal were 2,343 Mt, with 23% being hard coal and the remaining 77% being lignite (BP, 2013).

In 2012, Turkey ranked 12th in global coal production with 70 Mt of production (EIA, 2013) with roughly 95% being lignite (EUROCOAL, 2014). Between 1980 and 2012, Turkey's coal production increased by 51 Mt for a compound average growth rate (CAGR) of roughly 4%. Over the same period, coal consumption has enjoyed a CAGR of 5% increasing by 78 Mt tons to a total of 98 million tons in 2012 (EIA, 2013). As shown in Figure 4, in order to account for the growing imbalance between supply and demand, Turkey now imports 29 Mt of coal, representing 29% of the country's total coal consumption (EIA, 2013).

In 2012, coal accounted for 26% of Turkey's total energy consumption by fuel (BP, 2013). Of this, a large majority is used for power generation. According to EUROCOAL, coal is responsible for producing 26.1% of Turkey's gross electricity production (2010) while natural gas provides 46.5%, hydropower provides 24.5%, oil provides 1.0%, and wind and other renewables provide the remaining 1.9%. Currently, the majority of Turkey's coal-fired power plants use lignite, with only one power station (300 MW) fueled with domestic hard coal from the Zonguldak Basin; the Iskenderun power plant (1,200 MW) uses imported hard coal (EUROSTAT, 2014). As envisioned, the Amasra Hard Coal Mine will feed the 1,320-MW mine-to-mouth Amasra Bartın power station, which has been proposed by Hema Elektrik (HEMA, 2014).

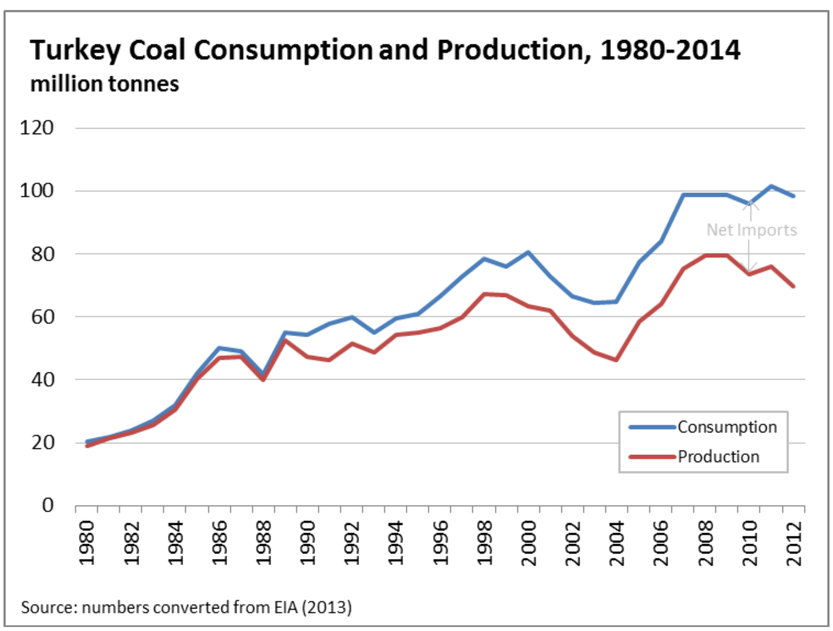


Figure 4: Turkey Coal Consumption and Production, 1980-2014

2.2 Coal Mine Methane in Turkey

Limited information is available on CMM emissions from active mines in Turkey, and the Global Methane Initiative International CMM Projects Database currently identifies no active projects in Turkey (GMI, 2014). Figure 5 shows methane (CH_4) emissions from coal mining in Turkey. The majority of coal produced in Turkey is lignite of which approximately 90% is produced from opencast mines (EUROCOAL, 2014). As a result, CH_4 emissions from surface coal mines were roughly 60 billion grams (Gg), or roughly 60,000 tonnes (t), in 2012 while underground mines accounted for 31 Gg of CH_4 (31,000 t) (TurkStat, 2014).

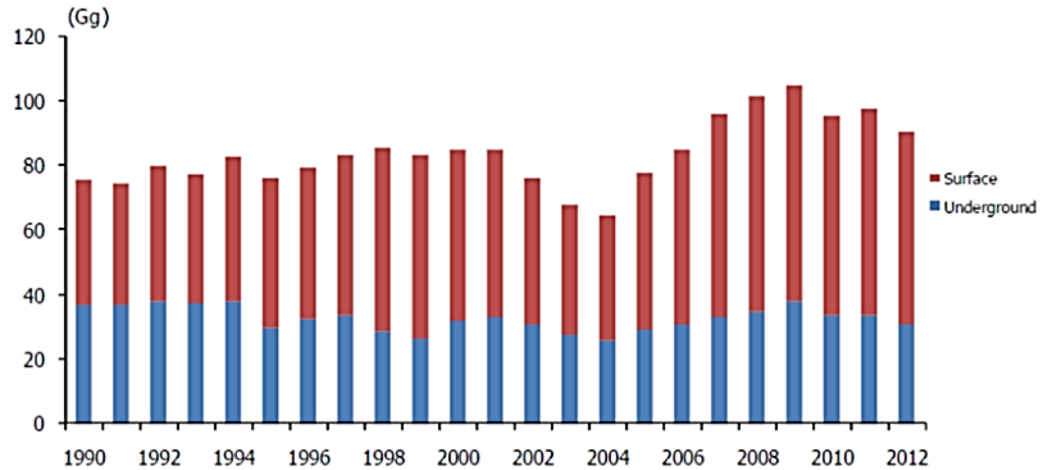


Figure 5: Turkey's CH4 Emissions from Coal Mining (TurkStat, 2014)

2.3 Amasra Coal Project

Hema Energi is currently developing a 5 Mt per year mine in Amasra, Turkey. The mine is located on a coal license obtained from TTK and will supply a 1,320 MW mine-mouth power plant currently under development (Figure 6). Based on the mining plan, coal production from the East Block is expected to commence in 2015. The coal seams in the Amasra Mine area are known to be very gassy and over the years there have been several disastrous explosions resulting in numerous fatalities. HEMA realizes that an aggressive pre-mine drainage program will substantially reduce the methane content of the coal in advance of mining, thus making the mining environment safer and more productive.

The Amasra Mine presents an ideal site for a pre-mine drainage CMM program for several reasons. Firstly, the company is committed to developing this new mine and has already spent nearly $100 million on developing the production shafts. Secondly, being a new mine, it will likely be very gassy and thus, will benefit greatly from pre-mine drainage. Lastly, the mine is located within the environs of the town of Amasra which provides a ready market for the produced gas. We believe that a pre-feasibility study at the Amasra Mine is well justified given the high likelihood of project implementation and the resulting methane reductions.

Figure 6: Map of Amasra Project Location (HEMA, 2013)

2.4 HEMA Energi

Hema Enerji, a subsidiary of Turkish conglomerate Hattat Holding, is developing the 5 Mt per year Amasra Hard Coal Mine. In addition to coal mining, the company is also involved in the oil, natural gas, and power sectors in the West Black Sea Region. Hattat Holding was founded in 1996 and currently includes 21 companies in its diversified portfolio, which has interests in industry, energy, tourism, real estate, and construction. Hattat Holding, which currently employs around 4,000 people, has the operation rights for the Zonguldak Kandilli, Amasra, and Bartın coal sites, and methane research rights in Zonguldak, Amasra, Bartın, and Kastamonu.

3 Summary of Mine Characteristics

Extending over an area of 50 km^2 the mine is located in north-central Turkey within the Zonguldak Coal Basin, approximately 250 km to the west of Istanbul on the Black Sea coast (Figure 7). After obtaining a coal license from TTK, HEMA has the right to mine below -400 m on 14 km^2 of the area with the remaining 35.6 km^2 to be mined from the surface. Total coal resources for the mine are estimated at 573 Mt. To initiate development of these resources, a mining plan covering 13 km^2 has been prepared with the mine area divided into three blocks, namely the East Block, West Block, and Southeast Block (Figure 8).

The surface above the mine is characterized as uneven and hilly with steep slopes present towards the coast. The mine area is crisscrossed by numerous rivers (e.g., Bartın and Karacay rivers) and intermittent streams with lands dedicated to agriculture and livestock. Several settlements are located above the mine (e.g., Bostanlar village, Karayusuflar, and Camlık quarters) at elevations ranging between +250 and +300 m. With coal being produced at elevations between -450 and -500, 700 to 800 m of overburden separates these settlements from the mined seams.

The Amasra region experiences a typical Black Sea climate with temperatures between seasons, and between day and night, being fairly consistent. As observed at the Bartın Meteorology Station, the highest temperatures are in July and the lowest temperatures fall in October with average annual precipitation of between 1000-1200 millimeters (mm) (Yılmaz, 2010).

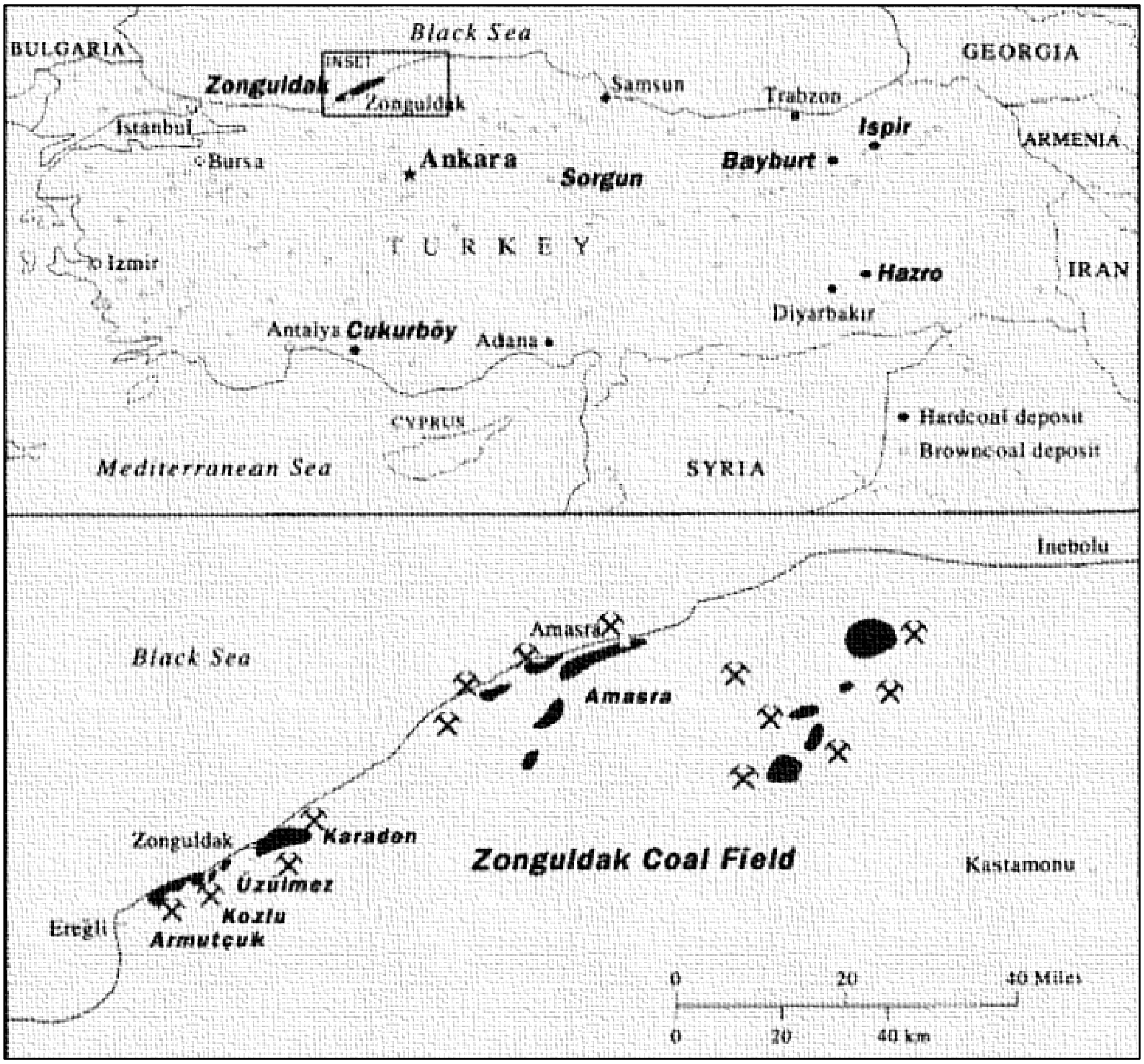


Figure 7: Map Location of the Zonguldak Coal Field and the City of Amasra (Schwochow, 1997)

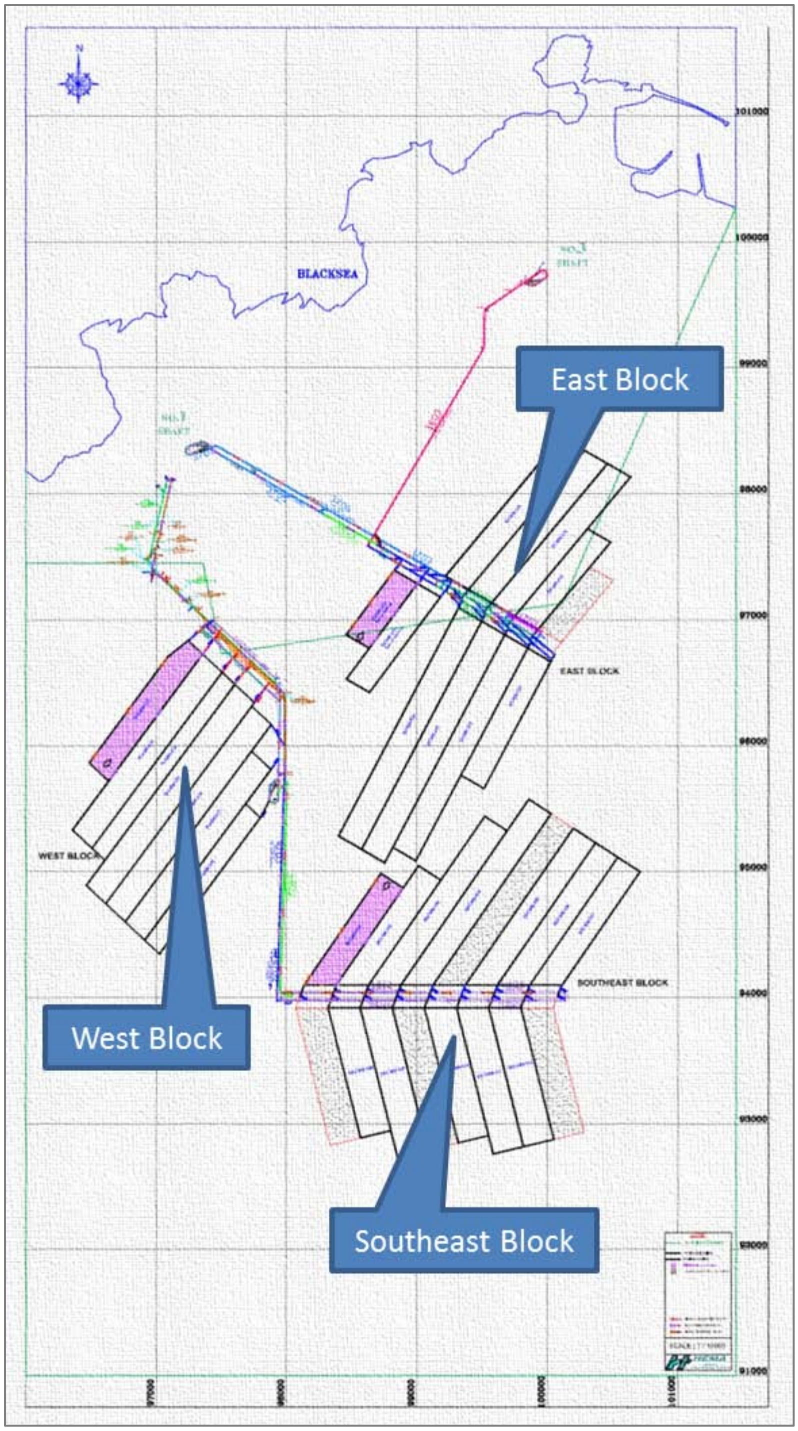


Figure 8: Mine Layout Indicating Location of East, West, and Southeast Production Blocks

3.1 Coal Production

TTK has approved the mining plan for the Amasra Hard Coal Mine, as developed by HEMA. The integrated plan covers all aspects of mine development including the layout of longwall panels, ventilation system design, electrical distribution system, gas drainage system, water pumping system, roadways, coal transportation system, and men and material haulage systems. HEMA's design takes into consideration the proximity of the coal seams to be mined, the likely geotechnical conditions, and the need to operate effectively and safely.

The production layout is based on the utilization of mechanized systems to fully extract the seams without pillars. Based on geologic conditions, namely the location of faults, HEMA has divided the license area into three production blocks. The mine is designed to achieve peak coal production of approximately 5 Mt per year. Figure 9 shows annual coal production for the East, West, and Southeast blocks as estimated by HEMA (AHPG, 2013).

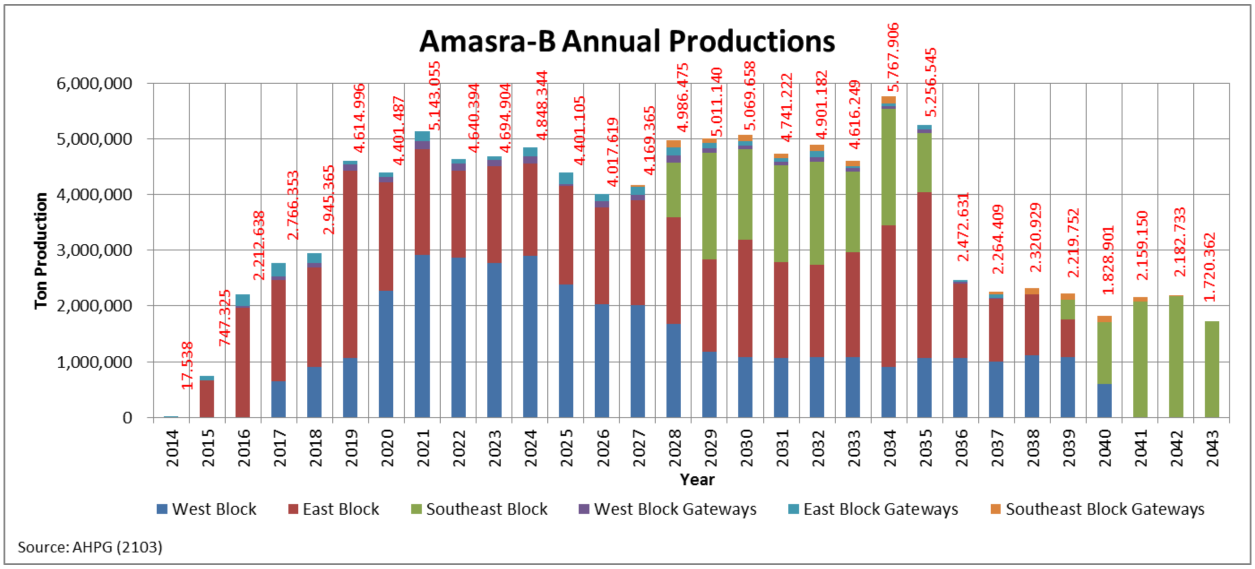
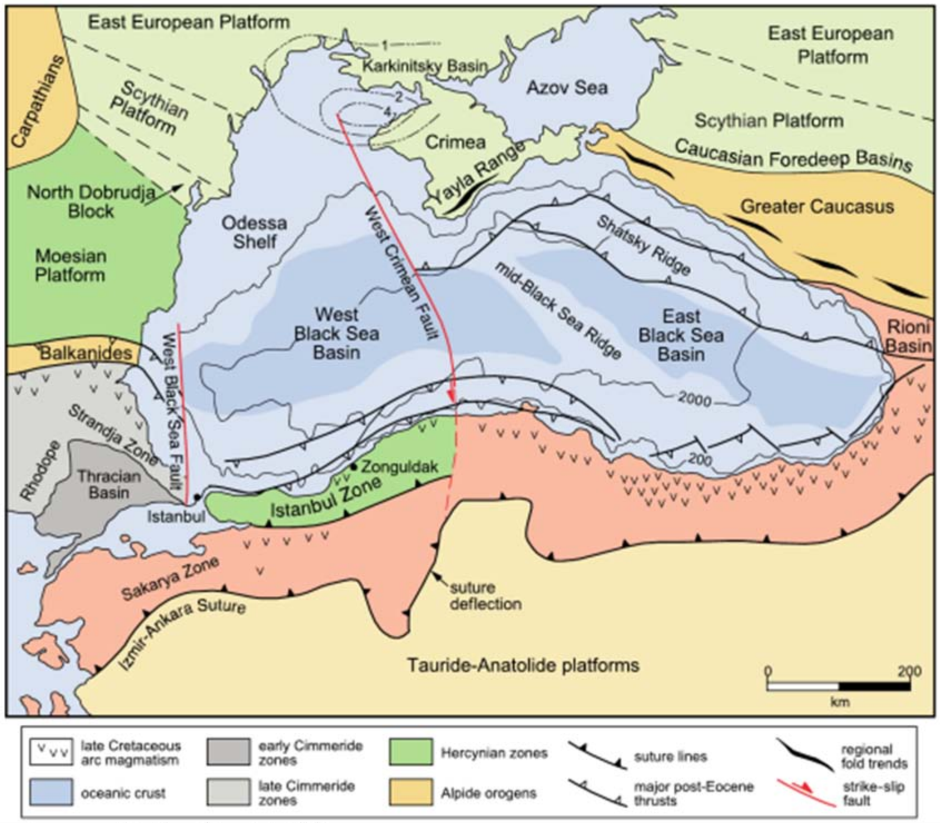


Figure 9: Coal Production Estimate for Amasra Hard Coal Mine (AHPG, 2013)

3.2 Geological Characteristics

3.2.1 Regional Geology and Tectonics

The Amasra region of the Zonguldak Coal Basin overlays a Precambrian basement consisting of granites and amphibolites (Sınayuç & Gümrah, 2009) and is a part of the Western Pontides tectonic province. Topographically, the area is characterized as mountainous with steep slopes that plunge into the sea. The Zonguldak Coal Basin is part of a Hercynian continental sliver, which stretches from Istanbul to Amasra and is commonly referred to as the Istanbul zone. The area was part of a thick Ordovician-Carboniferous age sedimentary package, which was deposited on the south-facing continental margin of Laurasia (Tüysüz, 1999). In the Cretaceous, the Istanbul zone was rifted away from Laurasia as a result of back-arc extension created by the northward-subducting Neotethys, and drifted south along two transform faults shown in Figure 10, the Western Black Sea fault to the west and the West Crimean fault to the east (Tüysüz, 1999). During the Early Eocene the Istanbul zone was incorporated into the Alpine Orogenic belt of northern Turkey.



Source: modified from Okay et al., 1994

Figure 10: Tectonic map of the Black Sea Region (Okay & Görür, 2007)

The structure of the Istanbul zone, shown in Figure 10, is very complex due to extensive faulting and folding that occurred in the pre-Cretaceous Hercynian and the late-Cretaceous Alpine orogenies (Karacan & Okandan, 2000). Carboniferous sediments were buried 300 m to 2500 m and subsequently uplifted and eroded during the Hercynian orogeny in the Late Carboniferous. In the Eocene the Carboniferous sediments were reburied to greater than 4000 m by a thick series of cretaceous carbonate sediments and thereafter uplifted and eroded in the Alpine Orogeny (Raven Ridge Resources, Inc., 1998). Two separate major deformational events are interpreted from faults that cut through the Carboniferous strata, but not the cretaceous strata (Hercynian in age, syndepositional with coal) and faults that cut through both the carboniferous and cretaceous (Alpine in age).

The Zonguldak basin is defined structurally by en echelon anticlines and synclines that trend approximately east-west. These structures are intersected and in some cases truncated by faults throughout the basin. There are three main orientations of faults in the Istanbul zone: N-S, E-W, and NNW-SSE. The Midi fault trends E-W and is believed to be active since the Carboniferous, and is penecontemporaneous with the Carboniferous formations (Raven Ridge Resources, Inc., 1998). The area to the north of the Midi fault was down thrown while the area to the south of the fault was uplifted, and subsequently eroded. Carboniferous strata are largely absent immediately south of the fault due to the tectonic history, but it is believed that Carboniferous strata are present farther south of the fault. The Okusne fault truncates the midi fault and Kozlu formation to the west and is oriented N-S. The West Crimean fault is the eastern boundary of the Zonguldak basin (Burger, Bandelow, & Bieg, 2000). The northern boundary of the Zonguldak basin is the subject of some debate as it extends out beneath the Black Sea.

3.2.2 Lithology

The coal bearing formations within the Zonguldak basin include the Alacaagzi, Kozlu, and Karadon, oldest to youngest respectively (Figure 11). The formations are Westphalian stage Carboniferous clastic sedimentary packages developed on Visean age carbonates of the Yilani formation (Karayigit, Gayer, & Demirel, 1997). The coal bearing formations are unconformably overlain by Cretaceous units, which are generally composed of limestone and dolomitic limestone (Hoşgörmez, et al., 2002). The coal seams present in these formations were deposited as part of a progradational delta and flood plain system (Tüysüz, 1999). This structural regime is a complex set of vertical and horizontal dipping coal beds that create lateral discontinuity throughout the basin.

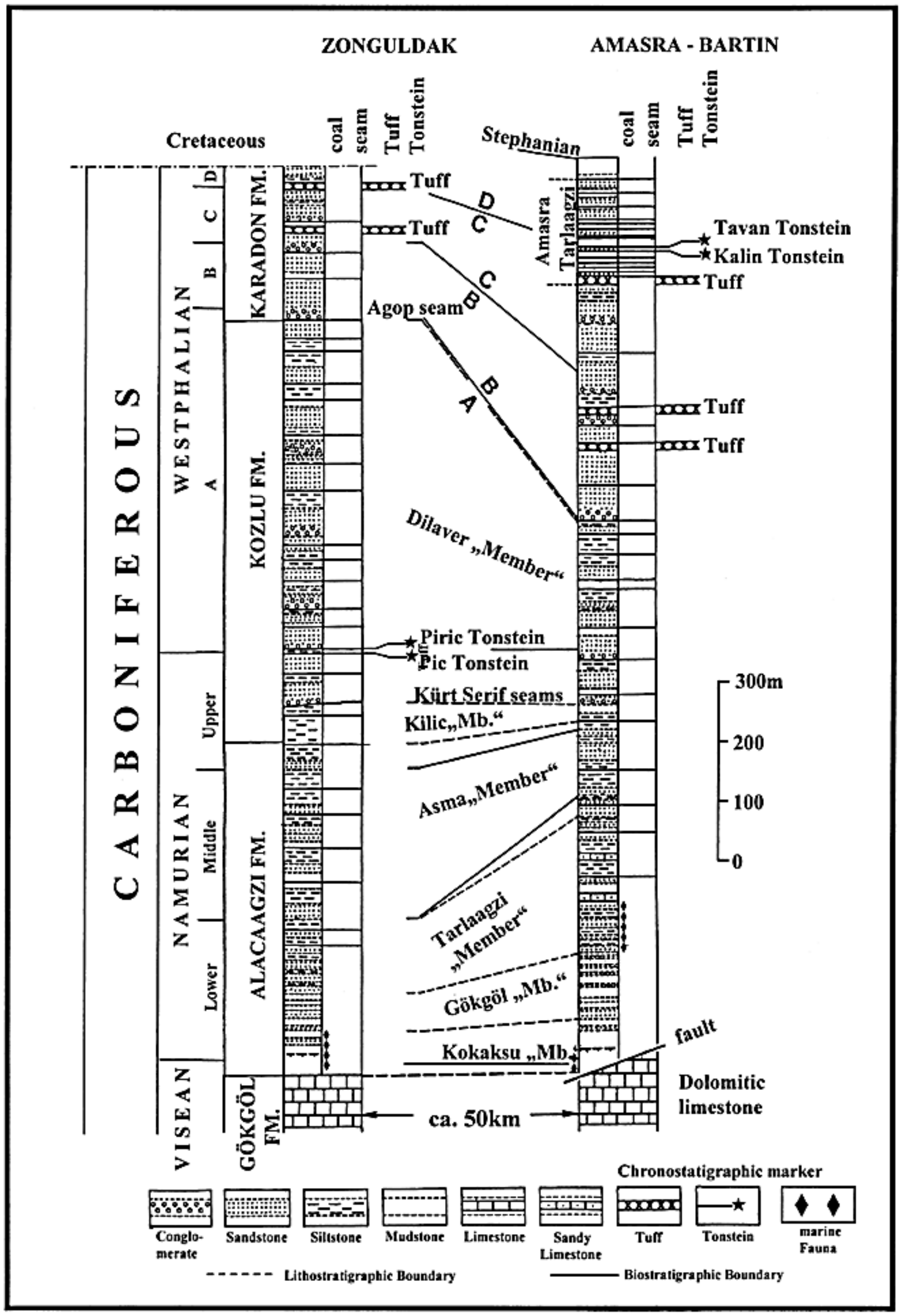


Figure 11: Correlated stratigraphic column of Carboniferous formations in the Zonguldak and Amasra regions (Burger, Bandelow, & Bieg, 2000)

The Namurian age Alacaagzi formation marks the transition from carbonate platform rocks to continental-derived clastic rocks (Raven Ridge Resources, Inc., 1998). The Alacaagzi formation is a succession of grey-greenish mudstones, siltstones, and thin sandstones with thinning coal seams interbedded in the upper section. The Alacaagzi formation has thin coal seams that are laterally extensive and are lenticular in shape (Raven Ridge Resources, Inc., 1998).

Coal deposits from the Westphalian are prevalent worldwide. The Kozlu and Karadon formations host the Westphalian coal deposits, but are separated both geographically and temporally (Raven Ridge Resources, Inc., 1998). The Kozlu coal seams are Lower Westphalian (A) in age and found throughout the basin, and the Karadadon coal seams, which are Upper Westphalian (B, C, and D) in age, are found almost exclusively in the Amasra region.

The Kozlu formation is divided into the Kilic and Dilaver members. Rock analysis reveals that coal seams within these members have a total organic content (TOC) of 7.5 to 85.2% with organic matter that is predominantly vitrinite rich and type III kerogen (Hoşgörmez, et al., 2002). The lithology of the Kilic member is a coarse-grained sandstone conglomerate interbedded with coal seams that fine upward into the Dilaver formation. The Dilaver member is an interbedded claystone, coal, and conglomerate that coarsens upward into the Karadon formation (Raven Ridge Resources, Inc., 1998).

The Kilic member is a basal Westphalian A age coal bearing sequence approximately 300m thick at Armutcuk, where it is the major coal bearing interval and increases in thickness to the east. The Kilic lateral continuity is limited in the Zonguldak region due to non-deposition or erosion. The Dilaver member is the upper member of the Kozlu Formation and is also a Westphalian A coal bearing sequence and is the main coal bearing interval at Zonguldak. The Karadon formation is the uppermost Carboniferous formation and lies directly beneath the Zonguldak formation, a massive cretaceous limestone unit, and is time transgressive and usually consists of coarse grained sediments.

The Karadon formation, which is pervasive throughout the Amasra region, is dominated by sandstones and conglomerates with coals and subordinate siltstones and claystones (Karayigit, Gayer, & Demirel, 1997) and ranges from 260 m to 700 m thick. A fireclay is present at the base of the Karadon formation, but is not laterally continuous throughout the basin. This fireclay is thought to provide a seal over the Kozlu formation, and may play an important role in containing methane gas accumulations.

The spatial and temporal relationship between these formations is important in understanding the depositional environment. The ages and locations of the coal bearing formations described above illustrate that coal deposits are older in the west and become younger to the east. The Westphalian B, C, and D Karadon formation is the coal bearing interval at Amasra (Raven Ridge Resources, Inc., 1998). The coal bearing formations imply that the progradational delta of the Wesphalian system was building in a west to east direction.

3.3 Mining and Geologic Conditions of Operations

Mine reserves are comprised of six seams in the East Production Block, seven seams in the West Production Block, and two seams in the Southeast Production Block. Coal seams are generally 1-3 m in thickness with interburden thickness varying from 1-40 m between seams. With overburden depths ranging from 700 m to 800 m the mine will utilize the multi-seam longwall mining method to extract coal. A total of 103 longwall panels have been identified for development, with 42 in the East Production Block, 38 in the West Production Block, and 23 in the Southeast Production Block (Table 1).

Coal Seam	EAST PRODUCTION BLOCK Panels Mined	Coal Thickness (m) Min	Max	Avg	WEST PRODUCTION BLOCK Panels Mined	Coal Thickness (m) Min	Max	Avg	SOUTHEAST PRODUCTION BLOCK Panels Mined	Coal Thickness (m) Min	Max	Avg
100	2	1.25	1.62	1.44	7	0.88	2.06	1.51				
200	2	1.61	1.65	1.63	7	1.50	2.31	1.76				
300	9	1.58	2.74	2.10	7	1.29	1.65	1.46				
400	10	1.80	3.29	2.50	7	0.94	2.32	1.37	12	1.10	3.21	2.17
500	10	1.63	3.72	2.52	5	0.94	1.50	1.22	11	1.00	1.65	1.28
600	9	0.86	1.17	1.01	1	0.80	0.80	0.80				
700					4	1.06	1.85	1.36				

Table 1: Coal Thickness Range by Seam for the East, West, and Southeast Production Blocks

The rank of the coals is High Vol. Bituminous A-B and the gas content of the coal seams is between 6 and 13 m^3/ton. The coal seams overlying the mining area are greater than 250 m above the uppermost EC100 seam, and additional investigation is needed to determine any gas contribution of the immediate adjacent strata and any residual coal from the working seam.

Due to the low permeability of the coal seams, estimated to be approximately 1 millidarcy (mD) or less, longer drainage times will be required to achieve a reduction of methane levels in advance of mining. Longhole in-seam directional drilling will have great application at this mine property due to the use of multi-seam longwall mining. However, the final approach for in-seam methane drainage will require further investigation and discussion with mine management.

The mining plan proposed by HEMA utilizes a fully mechanized production system with shearer loaders/plow and compatible powered support. Drum shearers with a 0.80 m cutting depth will advance at a rate of 7.29 to 12.34 meters per day as coal is produced from faces ranging between 207 and 240 m in length. Mining will be conducted in four shifts, three of which will be for production and one for maintenance. With an estimated coal thickness of 2 m, production from a shearer loader is expected to produce 6000 ton run-of-mine (ROM) coal per day, while a plow is projected to produce 3500 ton ROM coal per day (AHPG, 2013).

The design of the underground workings and the layout of the panels are heavily influenced by the presence of faults. For example, Figure 12 is a diagram of the East Production Block showing the location of the proposed longwall panels. The East Block area covers 4.2 km^2 and is bounded by the Central Fault at the west, Tuna Fault at the North, an anomaly at the east, and the Fault No.2 at the south. The East Block will be the first area mined and, as such, will be the focus of the pre-feasibility study. The inclinations of the seams of the East Block vary between 6^o and 12^o, and the production panels are named EC100-101, EC100-102 and so on from north to south. Longwall faces will be operated as single cut, retreat, and back-caving. The tailgate will also be allowed to cave, but the maingate will be supported with 4 to 8 m wide pack walls in order to be maintained for the next panel. The maingate of a former panel will be used as the tailgate of the latter panel. The selection of the back-caving U-type longwall production method is due to the high spontaneous combustion risk associated with Westphalia-C coal in the production Block. The subsidence associated with caving has been calculated to be 54 to 64 centimeters (cm) after 8 to 10 years. “Filling” will be conducted in order to minimize the subsidence; however, expropriation of settlements located above the mining area is planned, if necessary (AHPG, 2013).

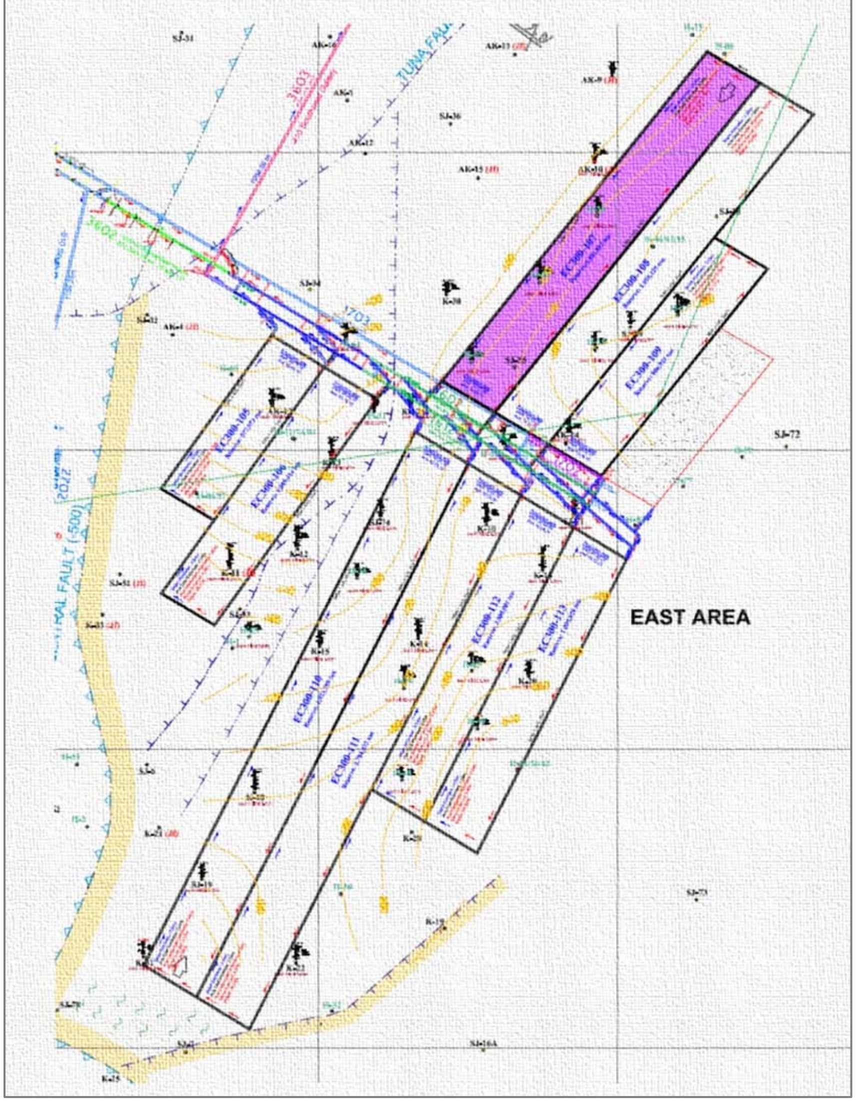


Figure 12: Location of Longwall Panels of the East Production Block

3.4 Coal Seam Characteristics

A total of 222 boreholes have been drilled by HEMA throughout the license area, with additional boreholes planned to be drilled as part of the drilling program. HEMA has 6 drilling rigs working on the Amasra Project, and has experienced core recoveries in the coal bearing strata averaging 99.55%. From the borehole data, cross-sections have been prepared and a tectonic map of the field has been developed. Coal seam correlations indicate a total of 6 coal seams in the East Block, which are WC aged and occur in the Karadon formation, numbered EC-100, 200, 300, 400, 500 and 600. The reserves of the 4.2 km^2 East Block are calculated to be approximately 45.0 Mt. In the Southeast Block, 2 coal seams, which are WG aged and occur in the Karadon formation, are numbered SEC-400 and 500. The reserves of the 3.7 km^2 Southeast Block are calculated to be approximately 21.0 Mt. Finally, in the West Block a total of 7 coal seams, which are WA aged and occur in the Kozlu formation, are numbered WA-100, 200, 300, 400, 500, 600, and 700. The reserves of the 4.1 km^2 West Block are calculating to be approximately 37.0 Mt (AHPG, 2013). The following sections discuss the characteristics of the coal seams in more detail.

3.4.1 Density

Petrophysical analyses were conducted on 5 HEMA density logs and a pay flag curve was constructed using a density cut off of 2.0 grams per cubic centimeter (gm/cc). Minimum and average densities were computed from the coal seams identified by the play flag curve. Table 2 shows the minimum and average densities from the well log analysis exercise.

CALCULATED DENSITY				
WELL	Mean	Min	Mean	Min
	(tons/acre•ft)		gm/cc	
HEMA 23	2,315	1,964	1.94	1.86
HEMA 24	2,239	1,883	1.64	1.37
HEMA 25	2,415	1,938	1.62	1.36
HEMA 26	2,256	1,869	1.74	1.40
HEMA 27	2,377	1,883	1.63	1.35
Wtd Avg.	2,322	1,908	1.68	1.38

Table 2: Minimum and average density of the HEMA wells in Amasra

3.4.2 Proximate Analysis

The parameter most commonly used to describe coal rank is vitrinite reflectance, which is the percentage of light reflectance, measured microscopically in immersion oil, from the polished surface of a vitrinite maceral when illuminated with plane-polarized white light. In coal, vitrinite reflectance values vary systematically with carbon content and are widely used as a thermal maturity, or rank, indicator (McCune, 2002). Figure 13 provides the various parameters that are used to characterize coal by rank.

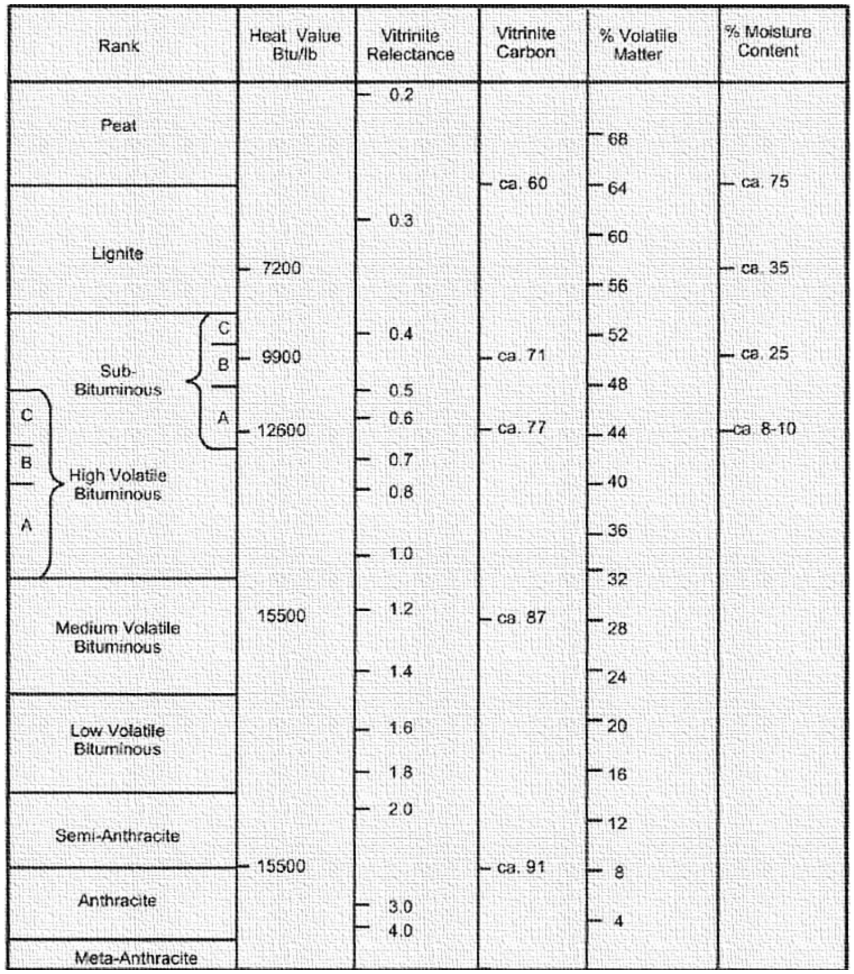


Figure 13: The relationship between coal type and the parameters of Heat Value, Vitrinite reflectance, Vitrinite Carbon, Volatile matter and Moisture content. (McCune, 2002)

Petrographic analysis was performed on five samples taken from the Zonguldak and Armutcuk regions. The thermal maturity of the samples ranged from 0.92 to 1.29% R_o (Table 3). The rank of coals found in the Zonguldak and Armutcuk regions were high volatile A to medium volatile bituminous coal (Raven Ridge Resources, Inc., 1998). Samples taken from the Amasra region, shown in Table 4 have a thermal maturity of 0.58 to 1.04 % R_{max} (Karayigit, Gayer, & Demirel, 1997). These values were determined from samples taken from 9 well cores in the Westphalian D and A and the Namurian formation in the Amasra Coal fields (Wells K-3, K-4, K-8, K-9, K-11, K-12, K-16, K-7, k-24). Westphalian C and D coals have a thermal maturity of 0.58 to 0.83 %R_{max} and a mean value of 0.74 %R_{max}. Westphalian A-B coal has a thermal maturity of 0.69-1.04% R_{max} and a mean value of 0.85% R_{max}. Namurian coal has a thermal maturity of 0.70 to 0.73% R_{max} and a mean value of 0.71% R_{max} (Karayigit, Gayer, & Demirel, 1997). All of the coal samples taken from Amasra fall within the three high volatile bituminous coal subcategories of the American Society for Testing Materials (ASTM) standards, ranging from high volatile C bituminous coal to high volatile A bituminous coal (Trinkle and Hower, 1984).

Zonguldak/Armutcuk Reflectance (Raven Ridge 1998)			
Mine Area	Depth (m)	Sample Number	% Ro
Karadon	360	7935	1.29
Karadon	560	7934	1.12
Kozlu	560	7942	1.16
Armutcuk	Not Provided	7941	0.92

Table 3: Vitrinite reflectance values of Zonguldak and Armutcuk

Amasra Reflectance (Karayigit et al. 1998)			
Formation	Vitrinite Max	Vitrinite Avg	Vitrinite Min
	(% Rmax)	(% Rmax)	(% Rmax)
Westphalian D-C	0.83	0.74	0.58
Westphalian A-B	1.04	0.85	0.69
Namurian	0.73	0.71	0.7

Table 4: Virtrinite reflectance values of the Amasra region

Additionally, coal samples taken during gallery developments and from boreholes were collected by HEMA and sent to accredited laboratories for analysis where moisture, ash, volatile matter, fixed carbon, total sulphur content, FSI, and calorific value measured. Analysis results for the East, Southeast, and West blocks are summarized in Table 5, Table 6, and Table 7, respectively (AHPG, 2013). The results from the proximate analysis indicate that the Zonguldak Coal basin has dry coals with moisture content less than 5%. The amount of ash in the study group suggests that the ash content increases towards the southwest in the Zonguldak region while volatile matter decreases.

	Test Type	Moisture (%)	Ash (%)	Volatile Matter (%)	Fixed Carbon (%)	Total Sulphur (%)	FSI	Upper CV (kcal/kg)	Lower CV (kcal/kg)
EC100	Original Basis	2,58	30,40	27,74	39,29	0,68	1	5102	4906
	Dry Basis	-	31,25	28,47	40,28	0,70		5236	5050
EC200	Original Basis	2,39	31,81	27,19	38,61	0,98	1	4970	4778
	Dry Basis	-	32,64	27,84	39,52	1,00		5087	4905
EC300	Original Basis	2,73	26,88	28,68	41,21	0,60	1	5433	5219
	Dry Basis	-	27,76	29,44	42,27	0,61		5574	5372
EC400	Original Basis	2,22	25,47	29,80	42,51	0,86	1	5569	5343
	Dry Basis	-	26,09	30,46	43,45	0,88		5684	5476
EC500	Original Basis	2,15	22,41	31,50	43,94	0,78	1	5857	5317
	Dry Basis	-	22,96	32,17	44,87	0,80		5979	5762
EC600	Original Basis	1,98	30,99	29,18	37,55	0,52	1	5152	4957
	Dry Basis	-	31,67	29,78	38,23	0,53		5252	5064
Ave.	Original Basis	2,27	26,44	29,79	41,25	0,69	1	5503	5209
	Dry Basis	-	27,12	30,46	42,21	0,71		5622	5418

Table 5: Coal Analysis Results for East Block Coals (AHPG, 2013)

	Test Type	Moisture (%)	Ash (%)	Volatile Matter (%)	Fixed Carbon (%)	Total Sulphur (%)	FSI	Upper CV (kcal/kg)	Lower CV (kcal/kg)
SEC400	Original Basis	2,06	22,21	32,11	43,63	0,83	2	5932	5714
	Dry Basis	-	22,71	32,77	44,52	0,85		6053	5845
SEC500	Original Basis	2,21	25,93	29,75	42,11	0,93	2	5555	5344
	Dry Basis	-	26,47	30,44	43,08	0,95		5685	5482
Ave.	Original Basis	2,13	24,07	30,93	42,87	0,88	2	5743	5529
	Dry Basis	-	24,59	31,61	43,80	0,90		5869	5664

Table 6: Coal Analysis Results for Southeast Block Coals (AHPG, 2013)

	Test Type	Moisture (%)	Ash (%)	Volatile Matter (%)	Fixed Carbon (%)	Total Sulphur (%)	FSI	Upper CV (kcal/kg)	Lower CV (kcal/kg)
WA100	Original Basis	1,50	15,89	33,50	49,10	1,09	3	6809	6568
	Dry Basis	-	16,13	34,01	49,85	1,11		6912	6677
WA200	Original Basis	1,25	14,86	33,07	49,84	0,63	3	6850	6604
	Dry Basis	-	15,14	33,71	50,82	0,64		6983	6744
WA300	Original Basis	2,20	16,00	30,28	51,52	0,55	4	6714	6471
	Dry Basis	-	16,43	30,94	52,62	0,57		6859	6593
WA400	Original Basis	2,43	8,20	32,21	57,16	0,46	4	7502	7242
	Dry Basis	-	8,13	33,03	58,58	0,47		7690	7438
WA500	Original Basis	1,84	9,68	32,55	55,93	0,49	5	7492	7161
	Dry Basis	-	9,85	33,17	56,98	0,50		7556	7307
WA600	Original Basis	1,53	20,79	29,78	47,90	0,74	5	6498	6271
	Dry Basis	-	21,07	30,26	48,68	0,75		6553	6381
WA700	Original Basis	1,42	38,34	23,51	36,73	0,55	4	4731	4562
	Dry Basis	-	38,88	23,85	37,26	0,56		4800	4637
Ave.	Original Basis	1,74	17,68	30,70	49,74	0,64	4	6657	6411
	Dry Basis	-	17,95	31,28	50,68	0,66		6765	6540

Table 7: Coal Analysis Results for West Block Coals (AHPG, 2013)

4 Gas Resources

4.1 Overview of Gas Resources

The coals of the Zonguldak Basin are known to be gassy. According to a geological assessment commissioned by TTK to evaluate the CBM potential of the coals in the production area, the in-situ methane content ranges from 6 to 13 m^3/t. As shown in Table 8, the specific emissions of Karadon and Kozlu District colliery drifts measured between 10.1 and 11.5 m^3/t mined in 1997, and together both collieries liberated almost 22 million cubic meters (Mm^3) of methane. When factoring in the gas content of adjacent seams, total methane emissions of 16 m^3/t are estimated (AHPG, 2013).

Mining District	Annualized Methane Liberated (m^3)	Annualized Coal Production (tonnes)	Specific Emissions (m^3/ton mined)
Karadon District	7.746.683	675.074	11,5
Kozlu District	14.130.940	1.400.482	10,1
Average	21.877.62.3	2.075.556	10,5

Table 8: Liberated Methane Measurement at TTK Colliery Drifts in 1997 (AHPG, 2013)

The mine ventilation plan proposed by HEMA includes the use of shaft number 1 for intake air and shaft number 3 for return air. Two exhaust fans will be installed at shaft number 3 (1 main and 1 backup fan), and are designed to work with 4800-9000 Pascal depression and up to 430 cubic meters per second (m^3/sec) flow rate. When designing the ventilation plan for the mining area HEMA took into consideration all Turkish Mining Regulations, the anticipated methane emissions from each of the seams in the respective areas, the assumed level of methane drainage capture, maximum acceptable velocities and international good practice. The key design parameters of the ventilation plan include:

- Maximum 0.87% methane in all return roadways;
- Maximum 1.25% methane at production face;
- Two simultaneously working longwalls (12,000 t/d for East and 7,000 t/d for Southeast);
- 5 m^3/t methane emission during mining after drainage; and
- Ventilation velocity within the regulated limits (AHPG, 2013).

4.2 Proposed Gas Drainage Approach

The proposed gas drainage approach discussed in this study will focus on the East Block since it will be the first area to be mined. However, it is envisioned that the proposed drilling program will also be utilized in the West and Southeast blocks. For the East Block, the proposed gas drainage approach is to use a combination of in-seam drilling in advance of mine developments and gob gas drainage via horizontal gob boreholes. Flanking in-seam boreholes to shield and drain gas ahead of development galleries are proposed with horizontal gob boreholes drilled into the gob area above the formation to drain gas as longwall mining progresses.

The use of longhole directional drilling will allow for longer length and more accurate placement of boreholes for improved in-seam methane drainage efficiency. In addition, longhole directional drilling allows for the implementation of innovative gob gas drainage techniques that may be more efficient than cross-measure boreholes and at lower cost than superjacent techniques. Other benefits of longhole directional drilling include the ability to steer boreholes to stay in-seam, flank projected gateroads, or hit specific targets such as adjacent coal seams or gas bearing strata. This technique promotes a more focused, simplified gas collection system with improved recovered gas quality because of the reduced amount of wellheads and pipeline infrastructure. Additionally, the proposed drainage approach is less labor intensive, can be accomplished away from mining activity with proper planning, and provides additional geologic information (such as coal thickness, faults, and other anomalies, etc.) prior to mining.

4.2.1 In-Seam Gas Drainage Boreholes

In-seam gas drainage boreholes will be drilled in parallel to advance and flank the gateroad developments. Figure 14 illustrates the proposed placement of the gas drainage boreholes. The long directionally drilled boreholes will cover the entire length of each panel from a single setup location to shield and drain gas ahead of development galleries. As shown in Figure 15, the boreholes will be drilled down-dip and, depending on drilling conditions and hole deviations, can be drilled up to 1500+ meters. The ability to drain multiple mining levels for each panel from a single setup location will be advantageous at this mine property due to the use of multi-seam longwall mining. Coordination of drilling operations with mine plans is vital to the success of an in-seam drainage program.

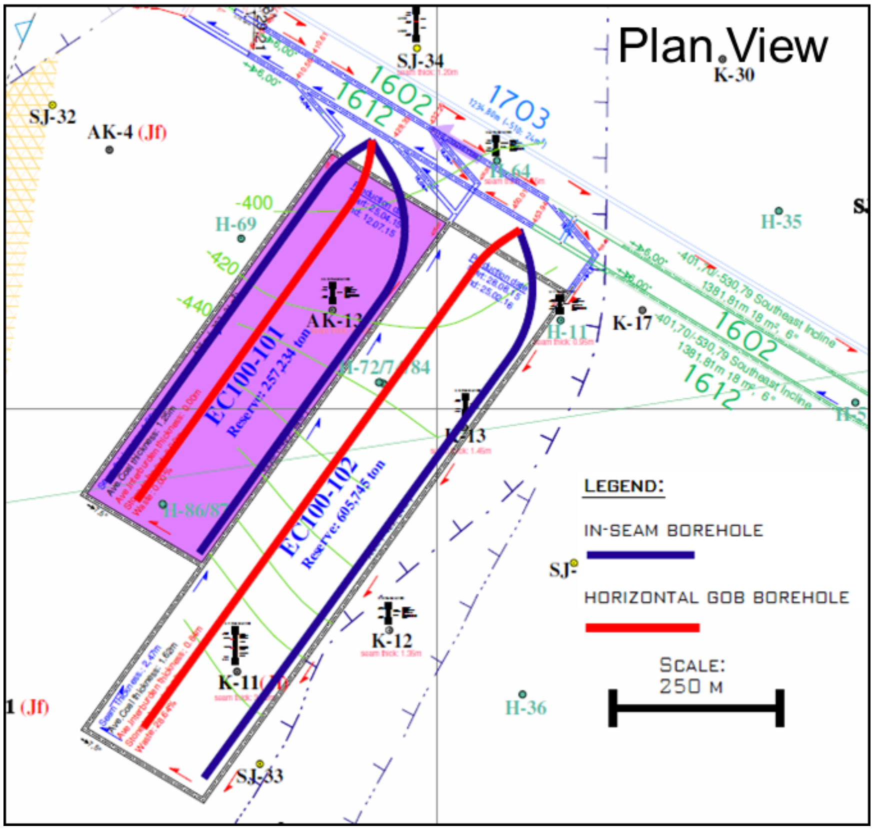


Figure 14: Diagram of Proposed Gas Drainage Approach (Plan View)

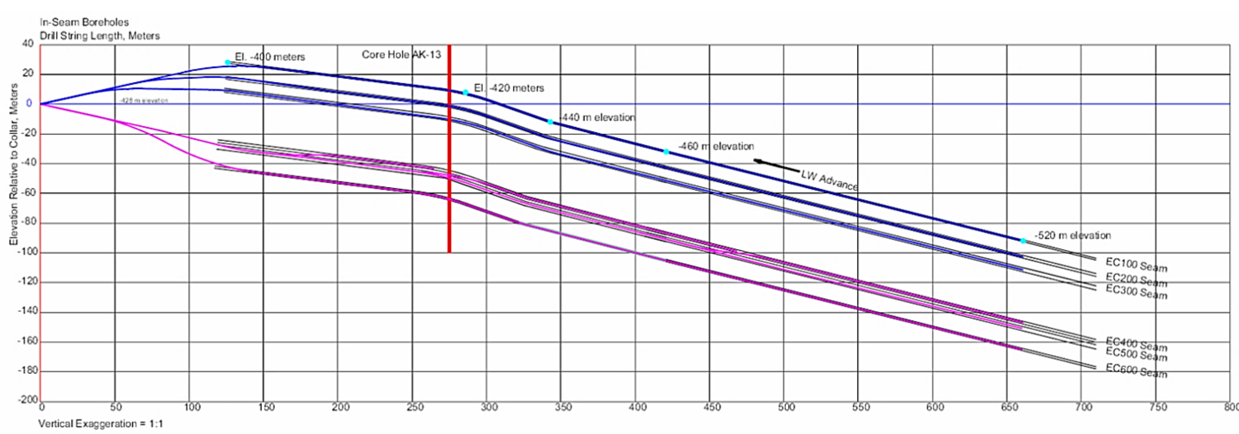


Figure 15: Cross Section View of In-Seam Gas Drainage Borehole Placement

4.2.2 Horizontal Gob Boreholes

Horizontal gob boreholes (HGBs) will be drilled into the gob area above the formation to drain gas as longwall mining progresses. Gob boreholes are generally placed at a distance of greater than five times the mining height above the rubble zone in order to remain intact after undermining of the longwall panel; typical placement is 20 to 30 m above the mining level. As shown in Figure 16, the HGBs will be drilled parallel to the mining direction on the up-dip and tailgate (ventilation return) side of the longwall panel. Due to separation between the EC300 and EC400 seams (up to 44 meters), it is recommended that a horizontal gob borehole be placed between these seams. It would not be expected for the gob to extend through the EC300 and EC400 interburden after longwall mining. Upon completion, gob boreholes are typically placed on vacuum (-10 to -20 kilopascal {kPa}) once mining progresses.

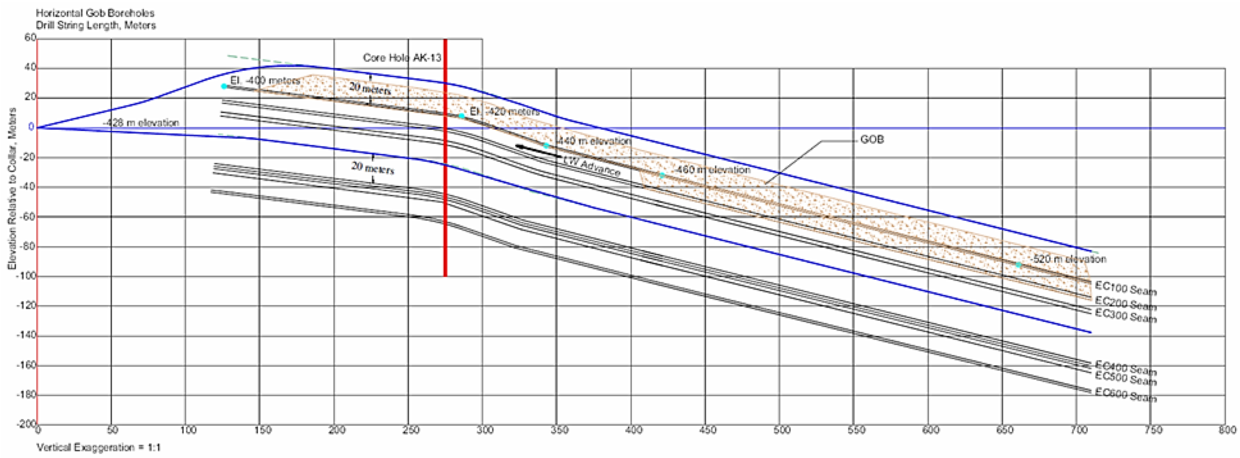


Figure 16: Cross Section View of Horizontal Gob Borehole Placement

4.3 Estimating Production from In-Seam Gas Drainage Boreholes

The objectives of this pre-feasibility study are to perform an initial assessment of the technical and economic viability of methane drainage utilizing longhole directional drilling in the mine area, and to identify end-use options. The gas production profiles generated for both the pre-drainage in-seam gas drainage boreholes and the horizontal gob boreholes will form the basis of the economic analyses performed in Section 7 of this report. Additionally, estimating the gas production volume is critical for planning purposed and the design of equipment and facilities.

A reservoir model designed to simulate five-year gas production volumes from pre-drainage boreholes located in the study area was constructed. The following sections of the report discuss the construction of the in-seam gas drainage borehole model, the input parameters used to populate the reservoir simulation model, and the simulation results.

4.3.1 COMET3® Model

The reservoir model was constructed using ARI's proprietary reservoir simulator, COMET3®. A total of two single-layer models were constructed in order to calculate gas production for a longwall panel located within the project area. The models were designed to simulate production from long directionally drilled boreholes drilled from within the mine and spaced according to two well spacing cases: 250 m and 83 m between wells (2 and 4 wells per panel, respectively). The models were each run for five years in order to simulate gas production rates and cumulative production volumes from a typical longwall panel within the project area.

A typical longwall panel at the mine is estimated to have a face width of 250 m and a panel length of 700 m covering an aerial extent of 17.5 hectares (ha) (43 acres {ac}). Based on these dimensions, model grids were created in COMET3® to accommodate each of the well spacing scenarios. The model grid for the 250 m well spacing case (2 wells per panel) consisted of 65 grid-blocks in the x-direction, 42 grid-blocks in the y-direction, and one grid-block in the z-direction. The model grid for the 83 m well spacing case (4 wells per panel) consisted of 65 grid-blocks in the x-direction, 44 grid-blocks in the y-direction, and one grid-block in the z-direction. The total area modeled is roughly 51 ha (125 ac) and 34 ha (83 ac) for the 2- and 4-wells per panel cases, respectively. The model areas include the 17.5 ha (43 ac) longwall panel area as well as a boundary area to account for migration of gas from coal seams of adjacent panels. The model layout for each of the well spacing cases is shown in Figure 17.

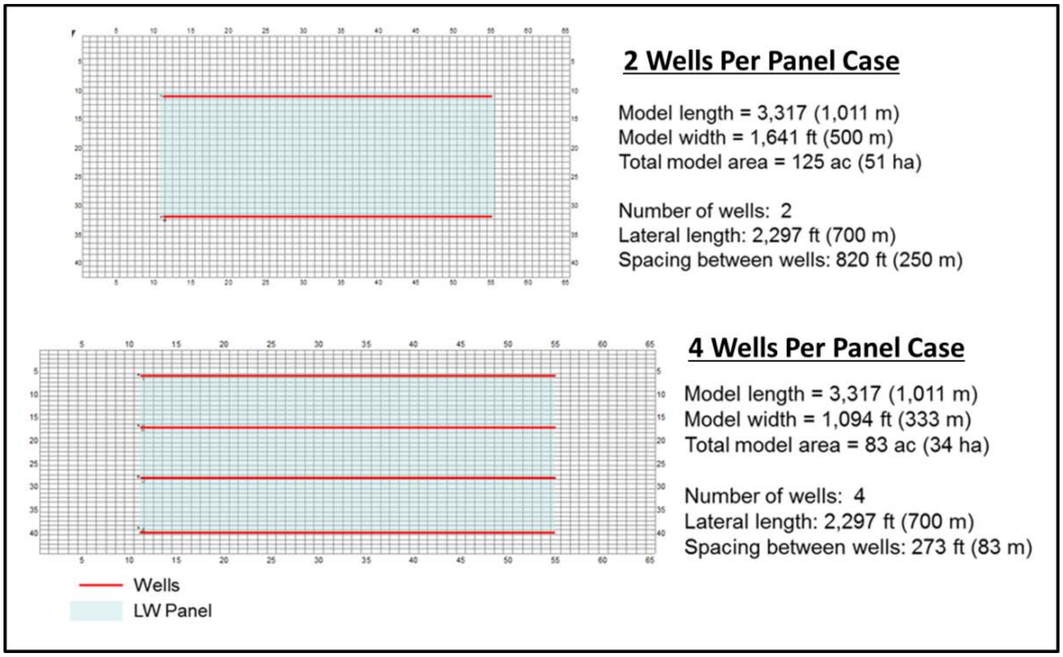


Figure 17: COMET® Model Layout for In-Seam Gas Drainage Borehole Well Spacing Cases

4.3.2 Model Preparation & Runs

The input data used to populate the reservoir model were obtained primarily from the geologic and reservoir data provided by HEMA. Any unknown reservoir parameters were obtained from analogs within the Zonguldak Coal Basin. The input parameters used in the COMET3® reservoir simulation study are presented in Table 4-2, followed by a brief discussion of the most important reservoir parameters.

Reservoir Parameter	Value(s)	Notes
Avg. Coal Depth, m	500	Based on mine data
Avg. Coal Thickness, m	2	Based on mine data
Coal density, g/cc	1.68	Log analysis
Pressure Gradient, kPa/m^3	9.80	Assumption
Initial Reservoir Pressure, kPa	4896	Calculated from Avg. depth and pressure gradient
Initial Water Saturation, %	100	Assumption
Langmuir Volume, m^3/tonne	13.81	Isotherm analysis
Langmuir Pressure, kPa	1966	Isotherm analysis
In Situ Gas Content, m^3/tonne	9.85	Calculated from reservoir pressure and isotherm
Desorption Pressure, kPa	4896	Assumes fully saturated conditions; Desorption pressure equal to initial reservoir pressure
Sorption Times, days	17	Analog (Sinayuc and Gumrah, 2009)
Fracture Spacing, cm	2.54	Analog
Absolute Cleat Permeability, md	0.5	Analog
Cleat Porosity, %	2	Analog
Relative Permeability	Curve	Analog; See following slide
Pore Volume Compressibility, kPa^{-1}	27.6 x 10-4	Assumption
Matrix Shrinkage Compressibility, kPa^{-1}	6.9 x 10-6	Assumption
Gas Gravity	0.6	Assumption
Water Viscosity, (mPa·s)	0.44	Assumption
Water Formation Volume Factor, reservoir barrel per stock tank barrel (RB/STB)	1.00	Calculation
Completion and Stimulation	Assumes skin factor of 2 (formation damage)	
Pressure Control	In-mine pipeline with surface vacuum station providing vacuum pressure of -13.5 kPa	
Well Spacing	Two cases: 250 m (2 wells per panel) and 83 m (4 wells per panel) between wells	

Table 9: COMET3® Input Parameters Used to Simulate In-Seam Gas Drainage Borehole Production

4.3.2.1 Permeability

Coal bed permeability, as it applies to production of methane from coal seams, is a result of the natural cleat (fracture) system of the coal and consists of face cleats and butt cleats. This natural cleat system is sometimes enhanced by natural fracturing caused by tectonic forces in the basin. The permeability resulting from the fracture systems in the coal is called "absolute permeability" and it is a critical input parameter for reservoir simulation studies. Absolute permeability data for the coal seams in the study area were not provided. However, permeability values in the Zonguldak coal basin can range between 0.1 md and 100 md (Sınayuç & Gümrah, 2009). For the current study, permeability values were assumed to be 0.5 mD.

4.3.2.2 Langmuir Volume and Pressure

The Langmuir volume and pressure values were taken from the methane adsorption isotherm work performed on HEMA CBM-1 coal samples. The average of the raw isotherms was thought to be most representative of the conditions in the Amasra area. The corresponding Langmuir volume used in the reservoir simulation models for the Amasra area is 13.81 m^3/t (442.5 standard cubic feet per ton {scf/ton}) and the Langmuir pressure is 1,966 kPa (285.2 pounds per square inch absolute {psia}). Figure 18 depicts the methane isotherms utilized in the reservoir simulations.

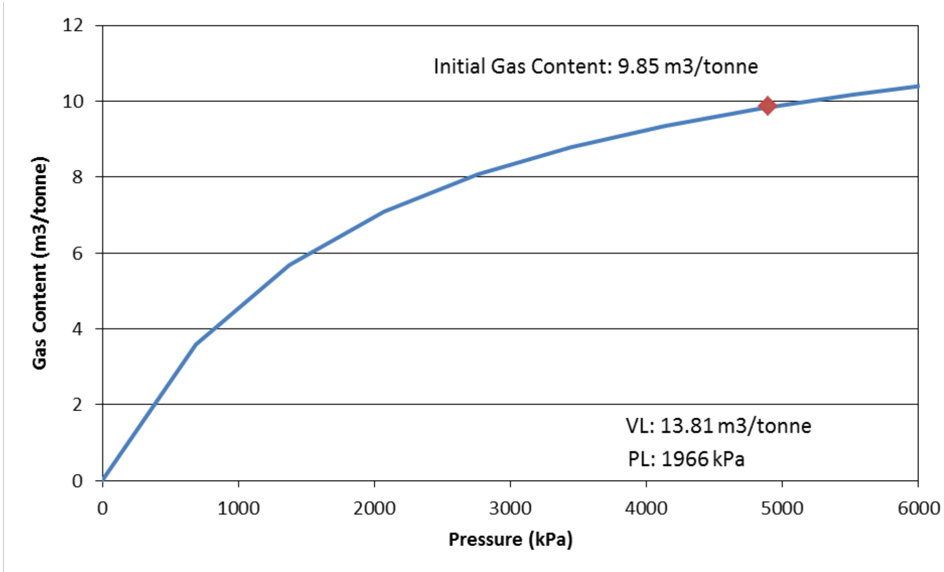


Figure 18: Methane Isotherm Used in Simulation

4.3.2.3 Gas Content

Gas desorption analyses performed during the coring program indicate a high level of dispersion. Due to the limited amount of data available, coal seams were assumed to be fully saturated with respect to gas despite the fact that some of the desorption data falls below the adsorption isotherm. As a result, an initial gas content value of 9.85 m^3/t (316 scf/ton) was used in the simulation study as calculated by the isotherm (Figure 18).

4.3.2.4 Relative Permeability

The flow of gas and water through coal seams is governed by permeability, of which there are two types, depending on the amount of water in the cleats and pore spaces. When only one fluid exists in the pore space, the measured permeability is considered absolute permeability. Absolute permeability represents the maximum permeability of the cleat and natural fracture space in coals and in the pore space in coals. However, once production begins and the pressure in the cleat system starts to decline due to the removal of water, gas is released from the coals into the cleat and natural fracture network. The introduction of gas into the cleat system results in multiple fluid phases (gas and water) in the pore space, and the transport of both fluids must be considered in order to accurately model production. To accomplish this, relative permeability functions are used in conjunction with specific permeability to determine the effective permeability of each fluid phase.

Relative permeability data for the coal of the project area was not available. Therefore, the relative permeability curve used in the simulation study was obtained from an analogous coal basin. Figure 19 is a graph of the relative permeability curves used in the reservoir simulation of the study area.

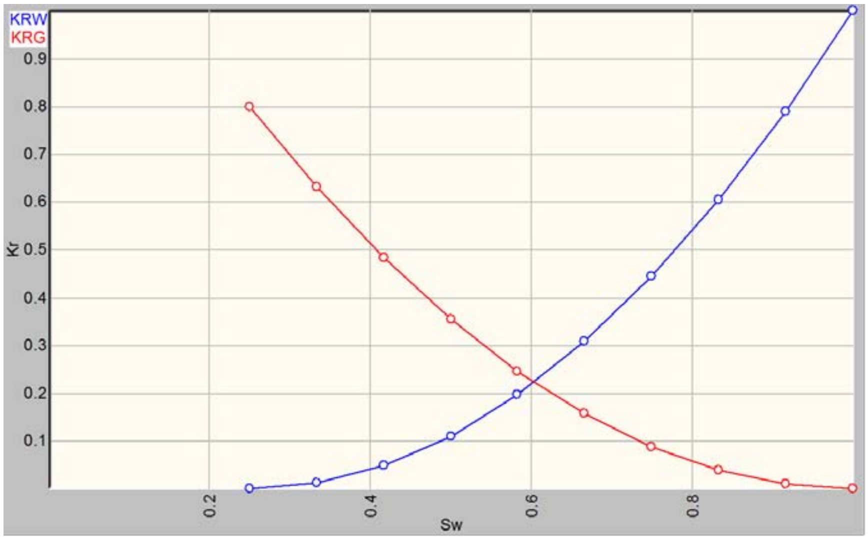


Figure 19: Relative Permeability Curve Used in Simulation

4.3.2.5 Coal Seam Depth and Thickness

Based on mine data, the coal seams in the East Block range in depth from 400 m to 530 m below sea-level with coal seams ranging between 1 and 3 m in thickness. For modeling purposes, the depth to the top of the coal reservoir was assumed to be 500 m, and the coal thickness is taken to be 2 m.

4.3.2.6 Reservoir and Desorption Pressure

Initial reservoir pressure was computed using a hydrostatic pressure gradient of 9.8 kPa/m^3 (0.433 psi/ft) and the midpoint depth of the coal seam. Because the coal seams are assumed to be saturated with respect to gas, desorption pressure is set equal to the initial reservoir pressure for the seam. The resulting initial and desorption pressures used in the model is 4,896 kPa (710 psia).

4.3.2.7 Porosity and Initial Water Saturation

Porosity is a measure of the void spaces in a material. In this case, the material is coal, and the void space is the cleat fracture system. Since porosity values for the coal seams in the mine area were not available, a value of 2% was used in the simulations. Typical porosity values for coal range between 1% and 3%. The cleat and natural fracture system in the reservoir was assumed to be 100% water saturated. This assumption is consistent with drilling information and well test data.

4.3.2.8 Sorption Time

Sorption time is defined as the length of time required for 63% of the gas in a sample to be desorbed. In this study a 17 day sorption time was used, which is consistent with the coals in the region. Production rate and cumulative production forecasts are typically relatively insensitive to sorption time.

4.3.2.9 Fracture Spacing

A fracture spacing of 2.54 centimeters (1 inch) was assumed in the simulations. In COMET3®, fracture spacing is only used for calculation of diffusion coefficients for different shapes of matrix elements and it does not materially affect the simulation results.

4.3.2.10 Well Spacing

As discussed previously, two well spacing cases were modeled consisting of 250 m between wells and 83 m between wells, or 2 and 4 wells per panel, respectively.

4.3.2.11 Completion

Long in-seam boreholes with lateral lengths of 700 m are proposed to be drilled and completed in the longwall panel. For modeling purposes, a skin value of 2 is assumed (formation damage).

4.3.2.12 Pressure Control

For the current study, an in-mine pipeline with a surface vacuum station providing a vacuum pressure of -13.5 kPa (2 psi) was assumed. In coal mine methane operations, low well pressure is required to achieve maximum gas content reduction. The wells were allowed to produce for a total of five years.

4.3.3 In-Seam Gas Drainage Borehole Model Results

As noted previously, two reservoir models were created to simulate gas production for a representative longwall panel located at the Amasra Hard Coal Mine. Each of the models was run for a period of five years and the resulting gas production profiles, as well as the methane content of the coal seams, are highlighted in the following sections.

4.3.3.1 Simulated Gas Production Profiles

Simulated gas production rate and cumulative gas production for an average well within the longwall panel are shown in Figure 20 and Figure 21, respectively.

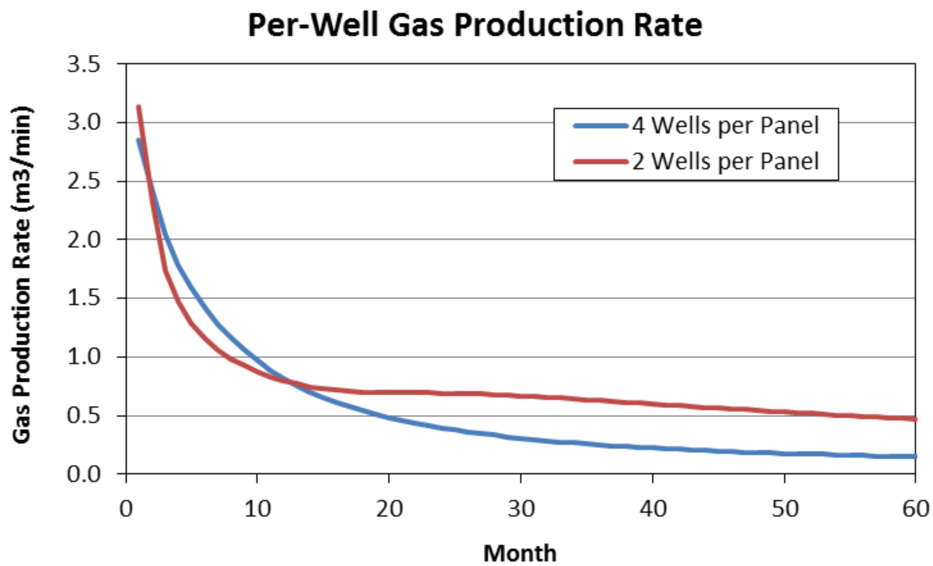


Figure 20: Simulated Per-Well Gas Production Rate

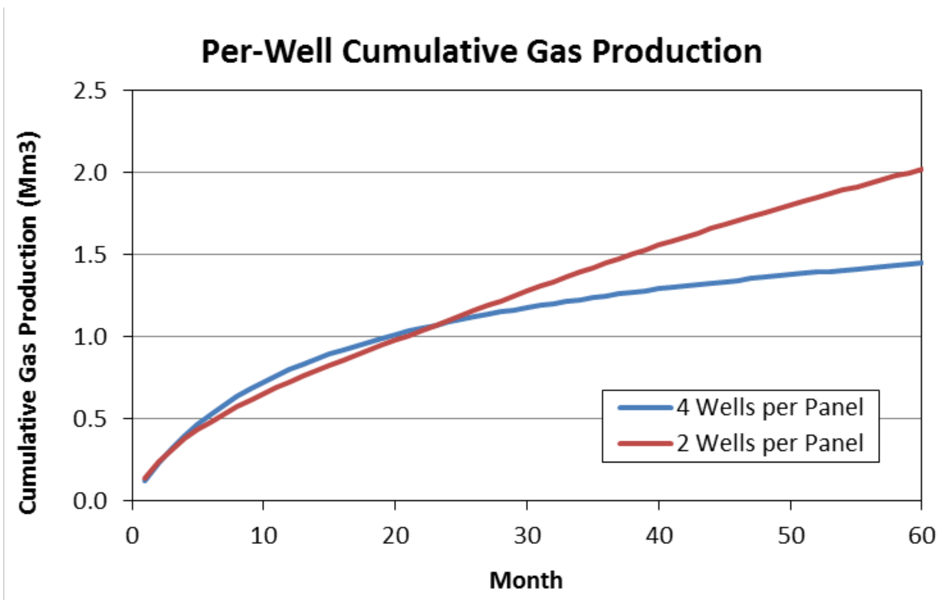


Figure 21: Simulated Per-Well Cumulative Gas Production

4.3.3.2 Simulated Reduction of Coal Seam Gas Content

One of the benefits of pre-drainage is the reduction of methane content in the coal seams prior to mining. Figure 22 and Figure 23 illustrate the reduction in in-situ gas content in the coal seam over time utilizing the 2 wells per panel and 4 wells per panel spacing cases, respectively. Figure 23 illustrates the improvement in drainage efficiency associated with the reduction in well spacing. All gas contents represent averages from within the longwall panel area only.

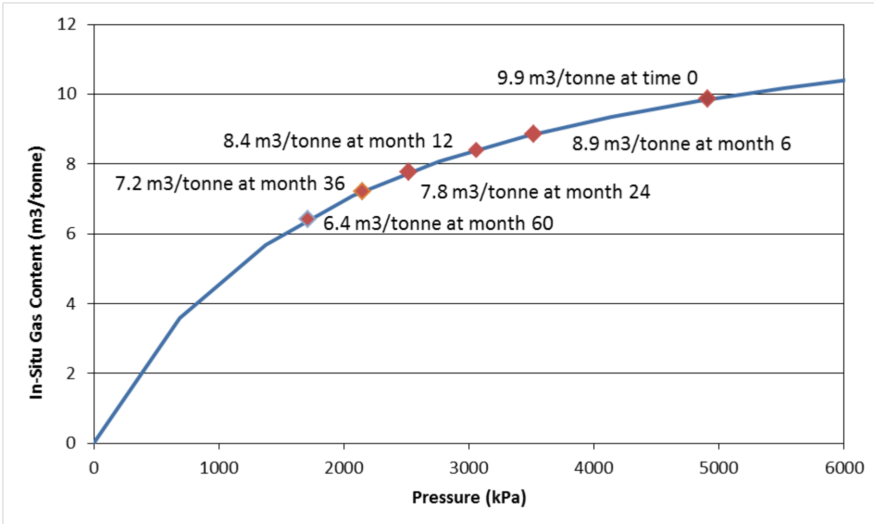


Figure 22: Simulated Reduction in Gas Content Over Time – 2 Wells Per Panel Case

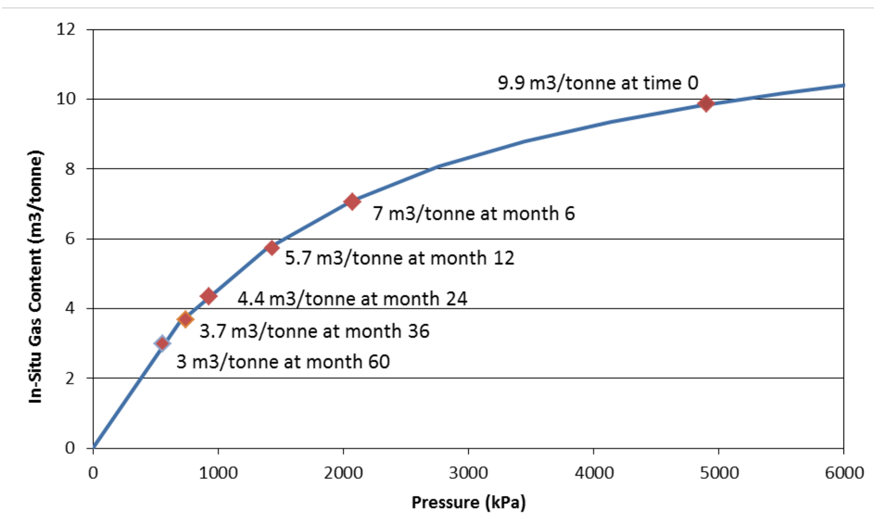


Figure 23: Simulated Reduction in Gas Content Over Time – 4 Wells Per Panel Case

Reduction in In-Situ Gas Content Over Time

2 Wells per Panel

Production Duration	Cumulative Gas Production (Mm3)	Reduction in Gas Content* (% Reduction)
After 6 Months	0.97	10%
After 1 Year	1.45	15%
After 2 Years	2.20	21%
After 3 Years	2.26	27%
After 5 Years	2.32	35%

* Calculated from within longwall panel area only

4 Wells per Panel

Production Duration	Cumulative Gas Production (Mm3)	Reduction in Gas Content* (% Reduction)
After 6 Months	2.12	29%
After 1 Year	3.21	42%
After 2 Years	4.36	56%
After 3 Years	4.42	63%
After 5 Years	4.49	70%

* Calculated from within longwall panel area only

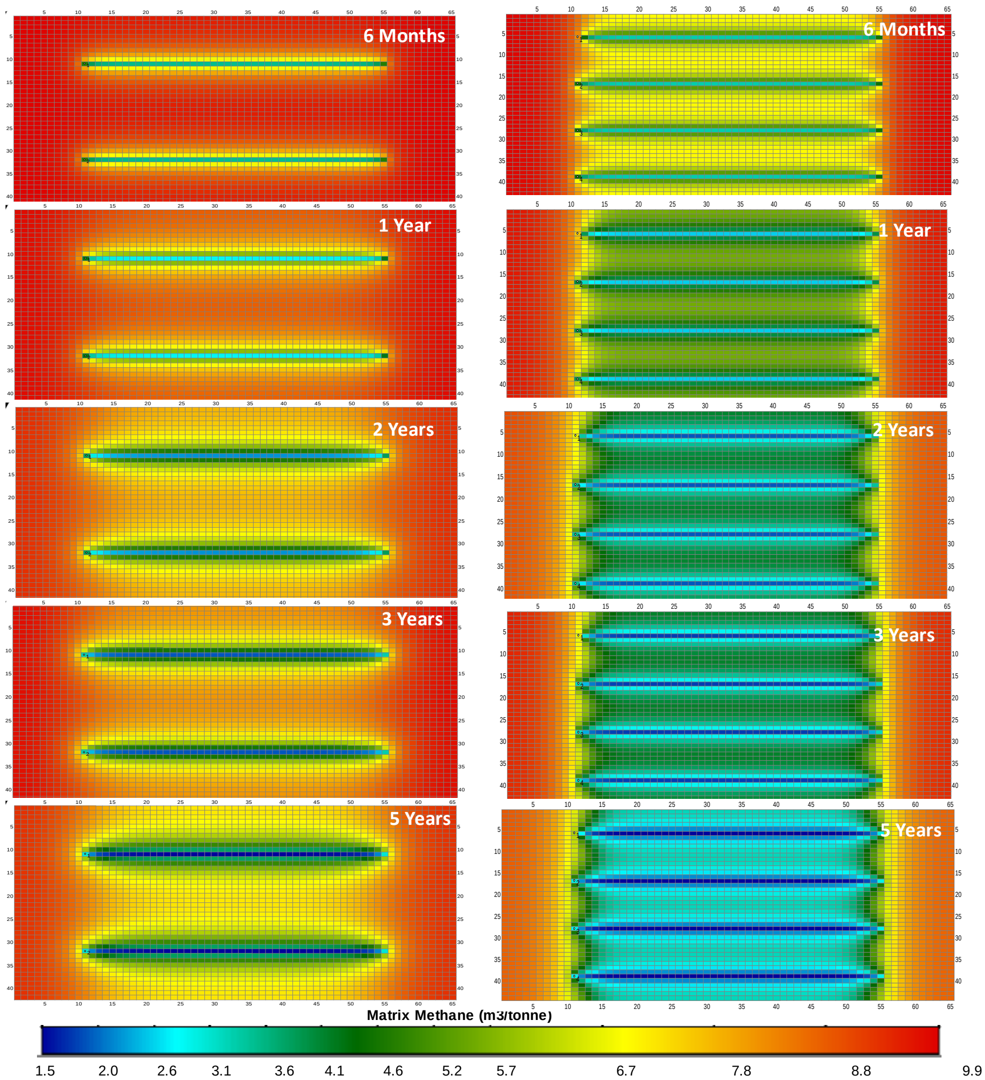


Figure 24: Illustration of Reduction in Gas Content Over Time

4.4 Estimating Production from Horizontal Gob Boreholes

Estimated gas production from HGBs was based on the gob gas flow projections shown in Figure 25, which represent gob gas flow rates (70% CH_4) for 1000 m gob borehole configurations. HGB performance is a function of borehole diameter, length, lining, wellhead vacuum, vertical placement above mining seam, and lateral placement along tension zones. As illustrated in Figure 25, gob gas flow rates typically increase as both the borehole diameter and wellhead vacuum pressure increase. Based on a panel length of 1000 m and an average face advance rate of 6.6 m/d, a longwall panel will take 5 months to mine through. Assuming a HGB with a 121 mm borehole diameter placed on 13.5 kPa of vacuum pressure, gob gas flow rates are estimated to be 8.4 cubic meters per minute (m^3/min) (5.9 m^3/min of pure CH_4). If the HGB continues to produce for 3 months following the completion of the longwall panel, total gob gas production is estimated at 2.9 Mm^3 (2.1 Mm^3 of pure CH_4).

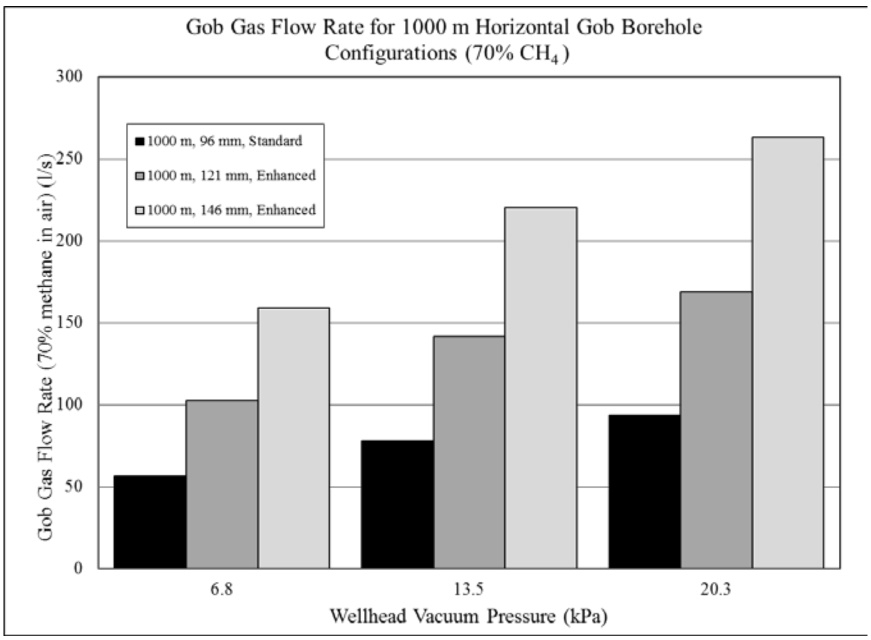


Figure 25: Gob Gas Flow Rate for 1000 m Gob Borehole Configurations (70% CH_4)

5 Market Information

The primary markets available for a CMM utilization project for the Amasra Hard Coal Mine are power generation using internal combustion engines and vehicle fuel in the form of compressed natural gas (CNG). At this time, sales to natural gas pipelines are neither technically nor economically viable.

With respect to electricity markets, the mine's power demand is estimated to be at least 62 MW, providing ample opportunity to offset power purchases with on-site generated electricity from CMM. Although the CMM-based power could be used on-site, HEMA would likely remain connected to the grid to ensure an uninterrupted supply of electricity. As of the end of 2013 the average rate of electricity for industrial customers was EUR 0.0763/kWh (inclusive of all taxes and levies), equivalent to USD 0.1038/kWh at current exchange rates (Figure 26).

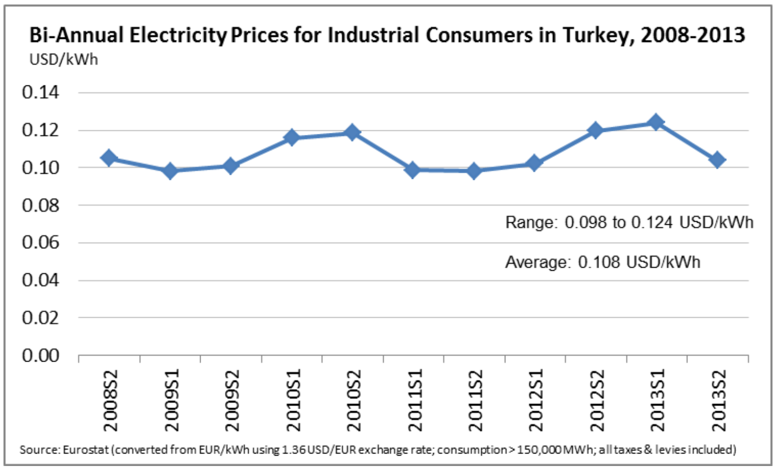


Figure 26: Bi-Annual Electricity Prices for Industrial Consumers in Turkey, 2008-2013

With respect to the market for transportation fuels, Turkey is known to have some of the highest gasoline prices of any country in the world. In recent years the Turkish government has ratcheted up the fuel tax in order to increase its revenue base; Turkey's gasoline tax is also considered one of the highest in the world (Randall, 2014). As shown in Table 10, the current gasoline price in Turkey is $2.38/l and the current diesel price is $2.07/l, which is equivalent to $9.00/gal and $7.82/gal, respectively (Fuel Prices Europe, 2014).

Fuel Prices in Turkey (16 June 2014)			
	EUR/l	USD/l	USD/gal
Unleaded Gasoline	1.75	2.38	9.00
Diesel	1.52	2.07	7.82
LPG	0.94	1.27	4.81

Source: http://www.fuel-prices-europe.info/index.php?sort=6

Table 10: Fuel Prices in Turkey, 16 June 2014

6 Opportunities for Gas Use

CMM, which is essentially natural gas, is the cleanest burning and most versatile hydrocarbon energy resource available. It can be used for power generation in either base load power plants or in combined cycle/co-generation power plants; as a transportation fuel; as a petrochemical and fertilizer feedstock; as fuel for energy/heating requirements in industrial applications; and for domestic and commercial heating and cooking (Table 11).

Sector	CMM/CBM Use
Electricity Generation	Fuel for base load power Combined cycle / co-generation power plants
Fertilizer Industry	Feedstock in production of ammonia and urea
Industrial	Fuel for raising steam Fuel in furnaces and heating applications
Domestic & commercial	Heating (spaces & water) Cooking
Transportation	Compressed natural gas vehicles
Petrochemicals	Feedstock for a variety of chemical products (e.g. methanol)

Table 11: Potential CMM Utilization Options

As noted in the Market Information section, the primary markets available for a CMM utilization project at the Amasra Hard Coal Mine are power generation using internal combustion engines and vehicle fuel in the form of CNG. Given the relatively small CMM production volume, as well as the requirement for gas upgrading, constructing a pipeline to transport the gas to demand centers would be impractical. Based on gas supply forecasts, the mine could be capable of operating as much as 8.8 MW of electricity capacity or produce over 1.5 million DLE per month.

Generating electricity on site is attractive, because the input CMM gas stream can be utilized as is, with minimal processing and transportation. Additional generating sets can be installed relatively cheaply and infrastructure for the power plant and distribution system is already planned. While the CNG utilization option requires significant processing of the CMM gas stream to increase its methane concentration and remove contaminants, the current high price of transportation fuel in Turkey improves the economics of this utilization option. However, this option should be investigated more thoroughly in the full-scale feasibility study, should the project advance to that development stage.

7 Economic Analysis

7.1 Development Scenario

In order to assess the economic viability of the two degasification options presented throughout this report, it is necessary to define the project scope and development schedule. Based on the mine maps provided by HEMA, a total of 42 longwall panels throughout 6 coal seams are scheduled to be mined in the East Production Block over a 24-year period once the mine is up and running. The specifics for the proposed pre-drainage and the gob gas projects are detailed in the next two sections of this report.

7.1.1 Pre-Drainage Project Development

The proposed pre-drainage project – which utilizes long, in-seam boreholes to drain gas ahead of mining – focuses on mining of the six coal seams (EC100 through EC600) located in the East Production Block. Based on the mine maps provided by HEMA, a total of 42 individual longwall panels are scheduled to be mined over a 24-year period. The mining plan is to work from the upper coal seam (EC100) down to the lower ones (EC200 – EC600). Flanking in-seam boreholes are utilized to drain gas ahead of development galleries. Long directionally drilled boreholes cover the entire length of each panel from a single setup location, allowing drainage of multiple mining levels.

Based on the mine development schedule provided by HEMA, boreholes were assumed to be drilled and come on production three to five years prior to the initiation of mining activities at each panel. CMM gas production profiles were generated for a total of four project development cases:

- Case 1: 2 wells drilled per panel; 3 years pre-drainage
- Case 2: 2 wells drilled per panel; 5 years pre-drainage
- Case 3: 4 wells drilled per panel; 3 years pre-drainage
- Case 4: 4 wells drilled per panel; 5 years pre-drainage

Depending on the development case, it is assumed drilling of wells and production of gas commences either 36 or 60 months in advance of mining of each longwall panel. CMM production from a panel ceases once mining of the panel begins, and the project will conclude when the last panel is mined through; total project life is 321 and 345 months from the initiation of gas drainage for the 3- and 5-year pre-drainage cases, respectively.

The results of the previously discussed simulations were used to derive a series of single-well type curves, which were combined with a schedule of wells drilled to calculate a CMM production profile for each project development case. The single well type curves used in the CMM production forecast are shown in Figure 20 and Figure 21, and the various drilling scenarios are presented in Figure 27.

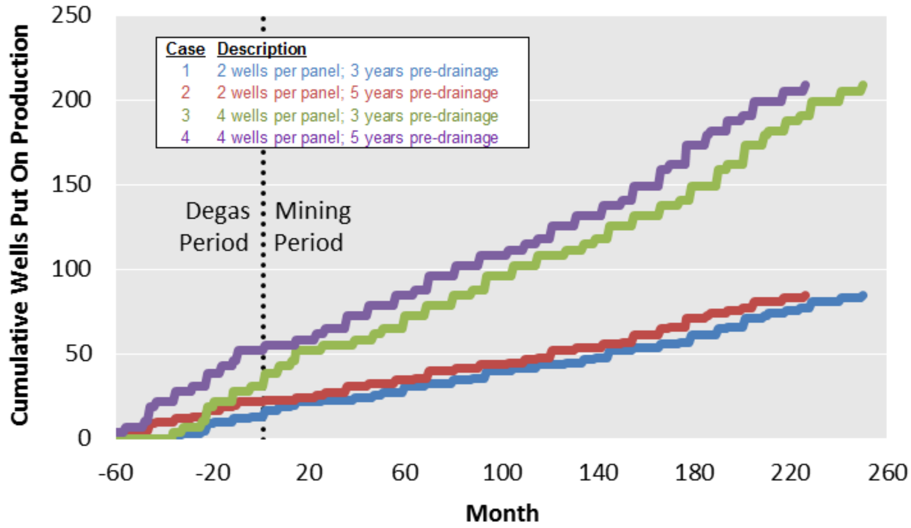


Figure 27: Drilling Scenarios for Pre-Drainage Development

7.1.2 Gob Gas Borehole Project Development

The methane drainage approach proposed at this mine includes a large gob degasification program involving HGBs. HGBs will be drilled into the gob area above the formation to drain gas as longwall mining progresses. HGBs will also be drilled between the EC300 and EC400 seams due to the separation of the seams. A total of 19 HGBs are assumed to be drilled in the East Production Block prior to the start of mining. Upon completion, HGBs will be placed on vacuum (-13.5 kPa) once mining progresses (Figure 28). The production duration of each HGB is dependent on the length of time it takes to mine each longwall panel, and it is assumed that each HGB continues to produce gob gas for an additional three months after the panel is mined through. Underground, the in-seam gas collection system is assumed to be integrated with the gob gas drainage system (i.e., combined pipelines). The development of the HGB portion of the project is assumed to be the same for all four in-seam gas drainage cases.

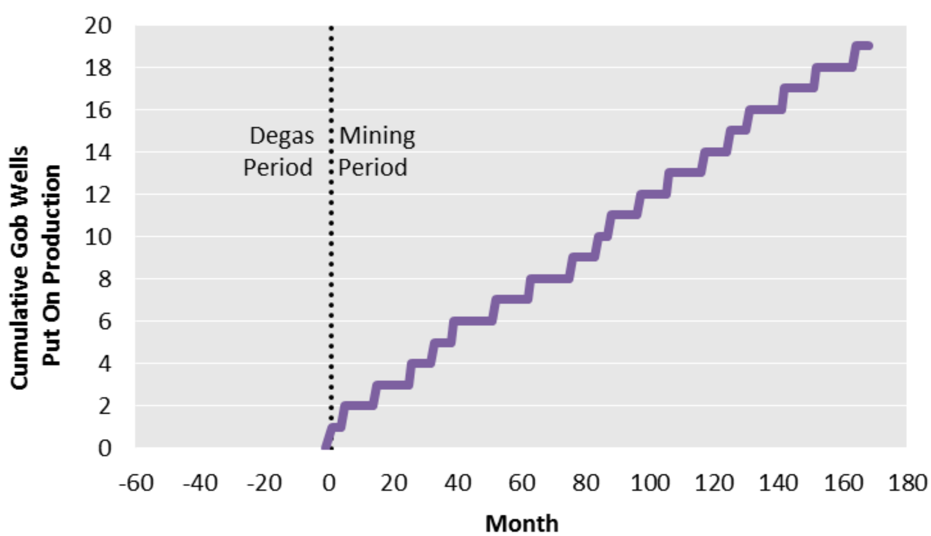


Figure 28: Drilling Scenario for Gob Gas Borehole Development

7.2 Gas Production Forecast

Gas production forecasts were developed using the previously established type curves (Figure 20 and Figure 21) and drilling cases (Figure 27 and Figure 28). The CMM production forecast for each project development case is shown in Figure 29 through Figure 32, and the gob gas forecast is presented in Figure 33.

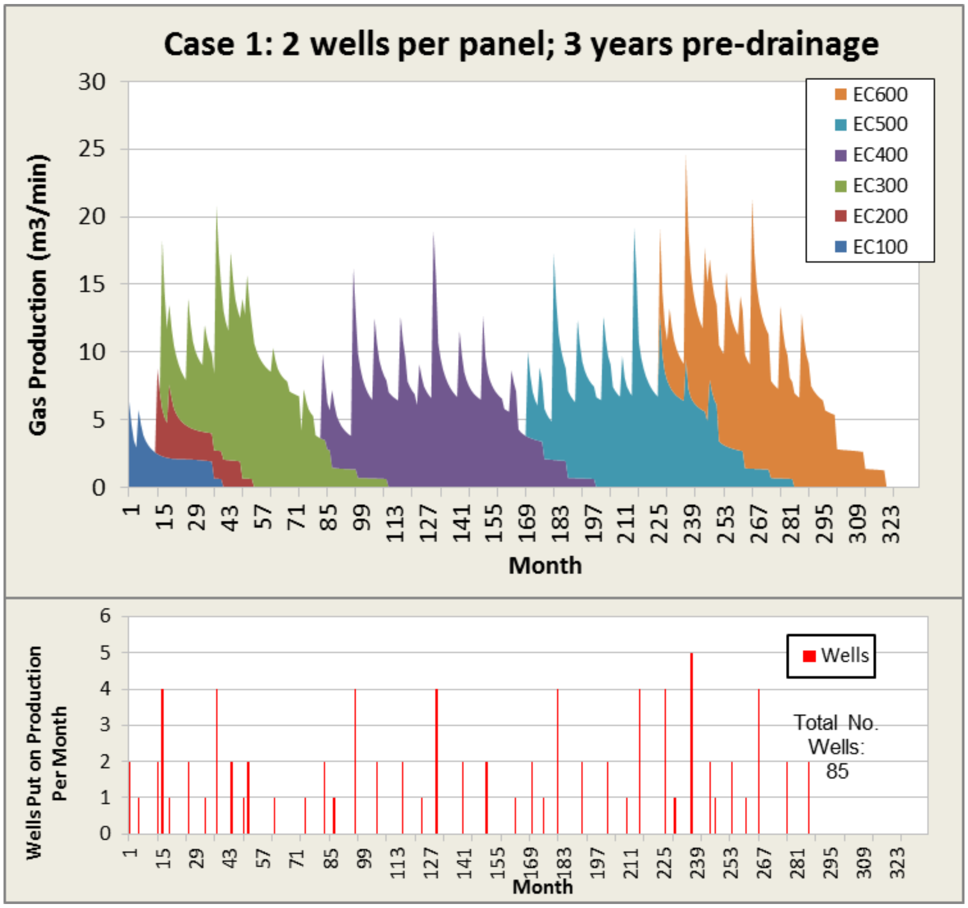


Figure 29: Pre-Drainage Gas Production Forecast for Case 1

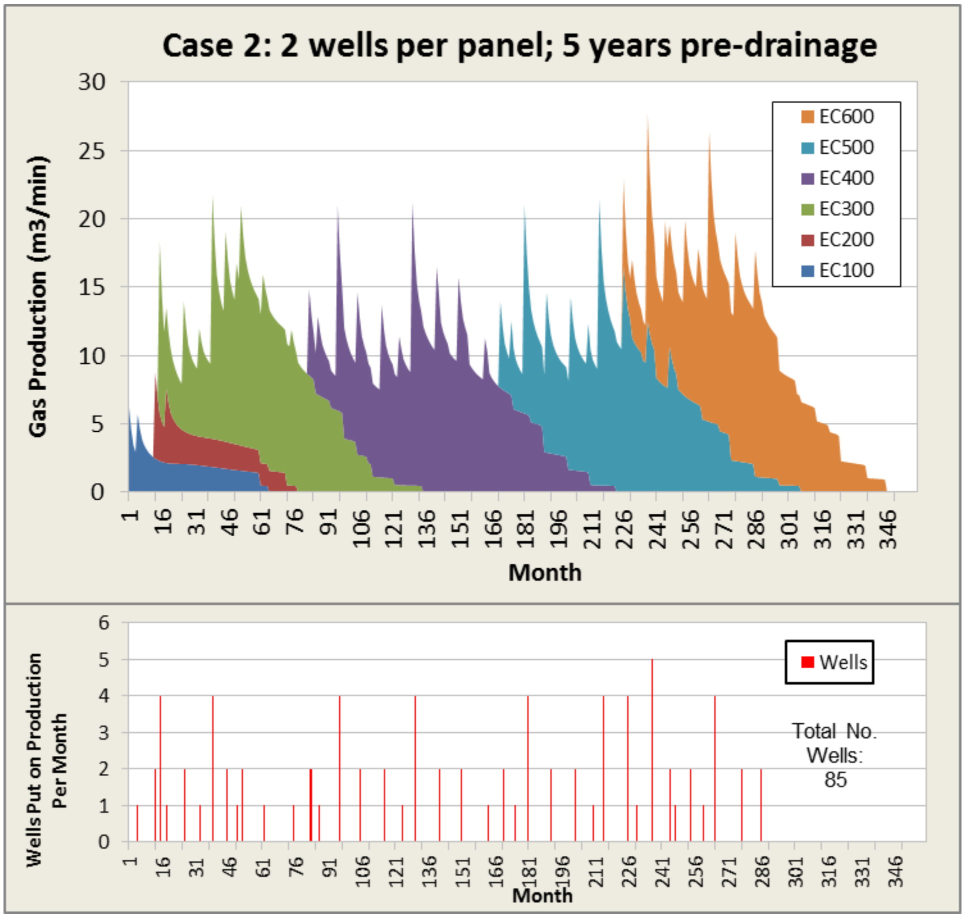


Figure 30: Pre-Drainage Gas Production Forecast for Case 2

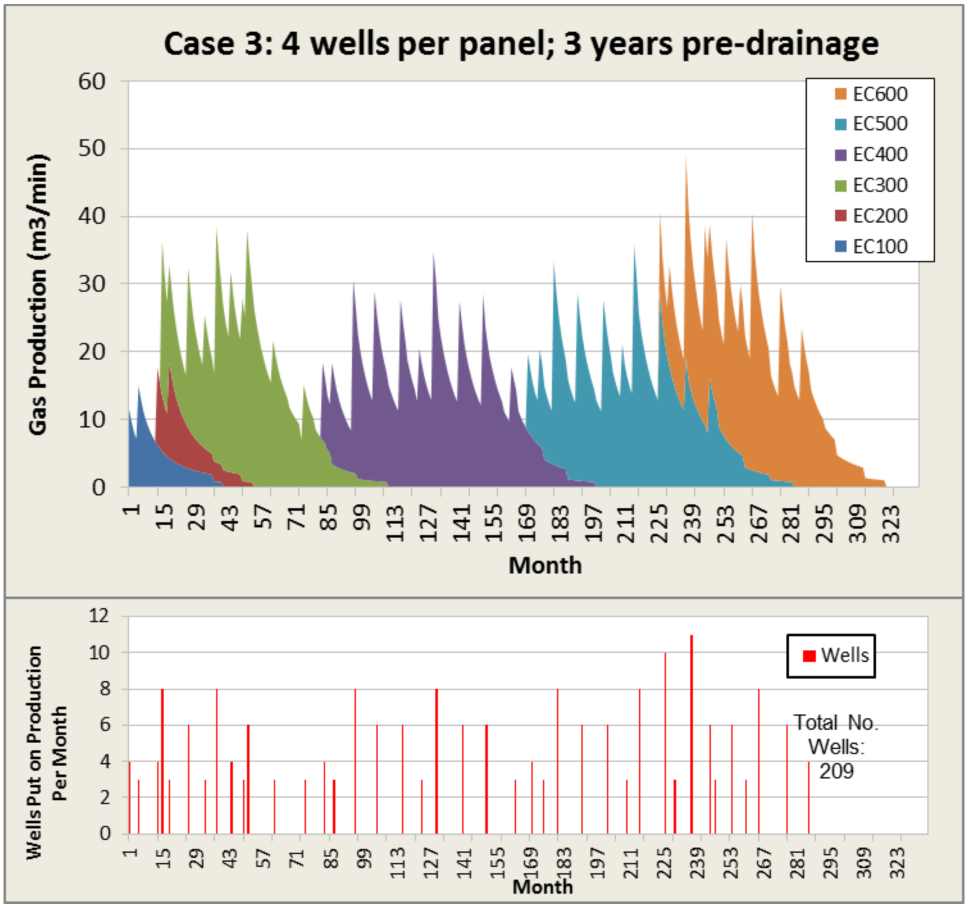


Figure 31: Pre-Drainage Gas Production Forecast for Case 3

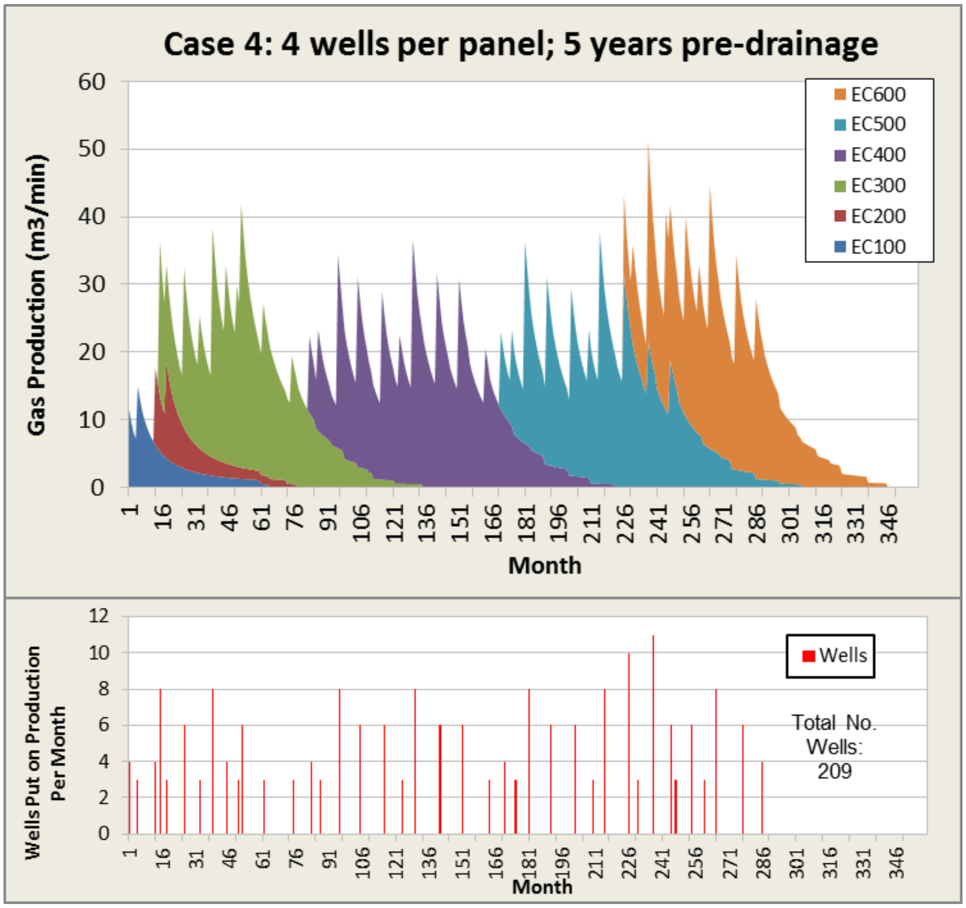


Figure 32: Pre-Drainage Gas Production Forecast for Case 4

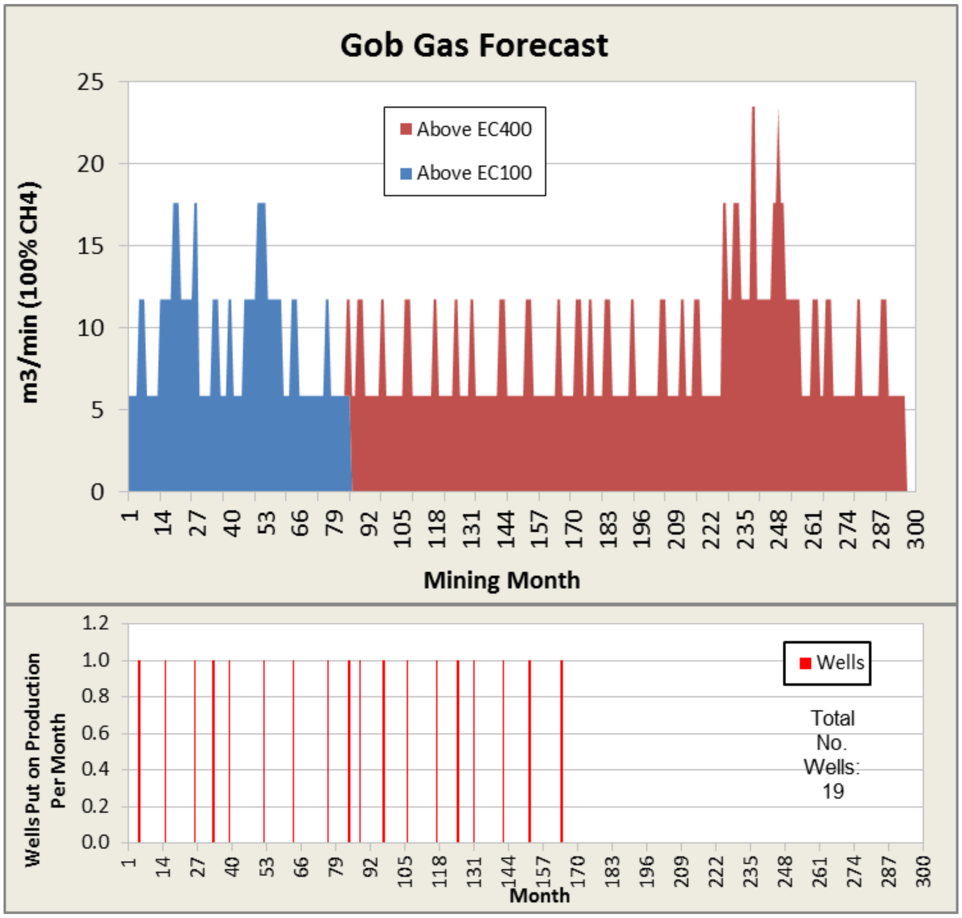


Figure 33: Gob Gas Production Forecast

7.3 Project Economics

7.3.1 Economic Assessment Methodology

For each of the proposed project development scenarios, discounted cash flow analyses were performed for the upstream portion (i.e., CMM production) and the downstream portion (i.e., electricity production or CNG production). A breakeven gas price was calculated in the upstream segment where the present value of cash outflows is equivalent to the present value of cash inflows. The breakeven gas price was then used in the downstream segments to calculate the fuel cost for the power plant and the feedstock cost for the CNG station. Likewise, breakeven electricity and CNG sales prices were calculated for the downstream segments, which can be compared to the current price of electricity or transportation fuel (e.g., CNG or diesel) observed at the mine in order to determine the economic feasibility of each potential CMM utilization option. The results of the analyses are presented on a pre-tax basis and the selection of a downstream utilization option is assumed to be mutually exclusive.

7.3.2 Upstream (CMM Project) Economic Assumptions and Results

Cost estimates for goods and services required for the development of the mine associated with the Amasra Hard Coal Mine were based on a combination of known average development costs of analogous projects in the region and the U.S., and other publically available sources (USEPA, 2009). The capital and operating costs used in the economic analysis are based on per well costs from oil and gas projects rather than on an underground mining analysis, which would most likely lower the costs. A more detailed analysis should be conducted if this project advances to the full-scale feasibility study level. Figure 34 presents a simplified schematic diagram of the CMM project and illustrates the major cost components for the CMM project, which include the in-seam and horizontal gob boreholes, gathering system, surface vacuum station, compressor, and pipeline to the sales system or utilization project. The capital cost assumptions, operating cost assumptions, and physical and financial factors used in the evaluation of upstream economics are provided in Table 12. A more detailed discussion of each input parameter is provided below.

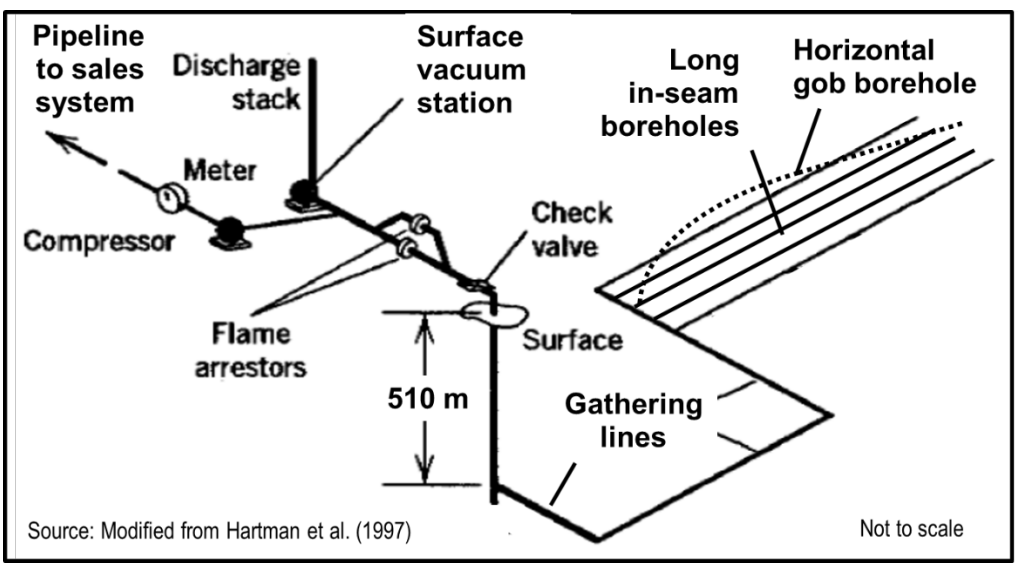


Figure 34: Simplified Schematic Diagram of CMM Project

CMM Supply Model Inputs					
Case		**1**	**2**	**3**	**4**
Wells per Panel		2	2	4	4
Years of Pre-Drainage		3	5	3	5
PHYSICAL & FINANCIAL FACTORS					
Royalty	%	12.5%	12.5%	12.5%	12.5%
Price Escalation	%	3.0%	3.0%	3.0%	3.0%
Cost Escalation	%	3.0%	3.0%	3.0%	3.0%
Calorific Value of Drained Gas	MJ/m3	34.58	34.58	34.58	34.58
Calorific Value of Gob Gas	MJ/m3	26.60	26.60	26.60	26.60
CAPEX					
Drainage System					
Well Cost	$/well	90,300	90,300	90,300	90,300
Surface Vacuum Station	$/W	1.34	1.34	1.34	1.34
Vacuum Pump Efficiency	W/1000m3/d	922	922	922	922
Gathering & Delivery System					
Gathering Pipe Cost	$/m	131	131	131	131
Gathering Pipe Length	m/well	354	354	144	144
Satellite Compressor Cost	$/W	1.34	1.34	1.34	1.34
Compressor Efficiency	W/1000m3/d	922	922	922	922
Pipeline Cost	$/m	180	180	180	180
Pipeline Length	m	1,999	1,999	1,999	1,999
OPEX					
Field Fuel Use (gas)	%	10%	10%	10%	10%
O&M	$/1000m3	17.66	17.66	17.66	17.66

Table 12: Summary of Input Parameters for the Evaluation of Upstream Economics (CMM Project)

7.3.2.1 Physical and Financial Factors

Royalty: Under the new Turkish Petroleum Law (Petroleum Law No. 6491 dated May 30, 2013), oil and gas producers are required to pay a Royalty corresponding to one eight (12.5%) of the petroleum produced.

Price and Cost Escalation: All prices and costs are assumed to increase by 3% per annum.

Calorific Value of Gas: The drained gas is assumed to have a calorific value of 34.58 megajoules per cubic meter (MJ/m^3) (928 Btu/cf) and the gob gas is assumed to have a calorific vale of 26.60 MJ/m^3 (714 Btu/cf). These numbers are based on a calorific value of 38.00 MJ/m^3 (1020 Btu/cf) for pure methane adjusted to account for lower methane concentration of the CMM gas, which is assumed to be 91% and 70% methane for drained and gob gas, respectively.

7.3.2.2 Capital Expenditures

The drainage system includes the in-seam and gob drainage wells and vacuum pumps used to bring the drainage gas to the surface. The major input parameters and assumptions associated with the drainage system are as follows:

Well Cost: A borehole with a lateral length of 700 m is assumed to cost $90,300 per well. This is based on the preliminary cost estimate provided by REI Drilling for Phase I Contract Drilling (Table 13). This estimate is based on 10,000 m of drilling and represents a cost of $129 per meter. Should the CMM project advance beyond the pre-feasibility stage, the implementation of an in-house drilling program by the mine operator should be considered as a way to reduce development costs. As the mine assumes this responsibility, drilling costs will be reduced over the project life.

Preliminary Cost Estimate

Phase I - Contract Drilling (10,000 meters)

1. Shipping (cost +15% + other fees)		$ 60,000
2. Placement fee $ 100k/mo.est. 6 months (includes engineering, labor and equipment)		600,000
3. Meter rate/Medium drilled: 10,000 m x $50/m		500,000
4. Expendable Materials (cost +15%):		60,000
5. Travel and per diem		70,000
	Est. TOTAL	US $1,290,000

Phase II – Equipment Purchase and Training

REI coordinate and turnkey procurement of directional drilling equipment supplies and training. Mine operator conducts in-house program.

1. VLI 1000 Drill w/ DDMS survey tool		$ 1,200,000
2. Spare Parts		200,000
3. Rods/Down hole Drilling Equipment		350,000
4. Wellhead, Drill Bits, Reaming, Fishing Supplies		75,000
5. Shipping and other fees		50,000
6. TRAINING (3 man-months)		200,000
	Est. TOTAL	US $2,075,000

Table 13: Preliminary Cost Estimate for Phase I and Phase II

Surface Vacuum Station: Vacuum pumps draw gas from the wells into the gathering system. Vacuum pump costs are a function of the gas flow rate and efficiency of the pump. To estimate the capital costs for the vacuum pump station, a pump cost of $1.34 per Watt (W) ($1000/hp) and a pump efficiency of 922 watts per thousand cubic meters per day (W/1000m^3/d) (0.035 hp/mscfd) are assumed. Total capital cost for the surface vacuum station is estimated as the product of pump cost, pump efficiency, and peak gas flow (i.e., $/W x W/1000m^3/d x 1000m^3/d).

Gathering & Delivery System Cost: The gathering system consists of the piping and associated valves and meters necessary to get the gas from within the mine to the satellite compressor station located on the surface, and the delivery system consists of the satellite compressor and the pipeline that connects the compressor to the sales system leading to the utilization project. The gathering system cost is a function of the piping length and cost per meter. For the proposed project, we assume a piping cost of $131/m ($40/ft) and roughly 30,000 m (98,000 ft) of gathering lines.

Satellite compressors are used to move gas through the pipeline connected to the end-use project. Similar to vacuum pump costs, compression costs are a function of the gas flow rate and efficiency of the compressor. To estimate the capital costs for the compressor, we assume a compressor cost of $1.34/W ($1000/hp) and an efficiency of 922 W/1000m^3/d (0.035 hp/mscfd). As with the vacuum pump costs, total capital cost for the compressor is estimated as the product of compressor cost, compressor efficiency, and peak gas flow (i.e., $/W x W/1000m^3/d x 1000m^3/d). The cost of the pipeline to the end-use project is a function of the pipeline length and cost per meter. For the proposed project, we assume a pipeline cost of $180/m ($55/ft) and length of 2,000 m (6,560 ft).

7.3.2.3 Operating Expenses

Field Fuel Use: For the proposed project, it is assumed that CMM is used to power the vacuum pumps and compressors in the gathering and delivery systems. Total fuel use is assumed to be 10%, which is deducted from the gas delivered to the end use.

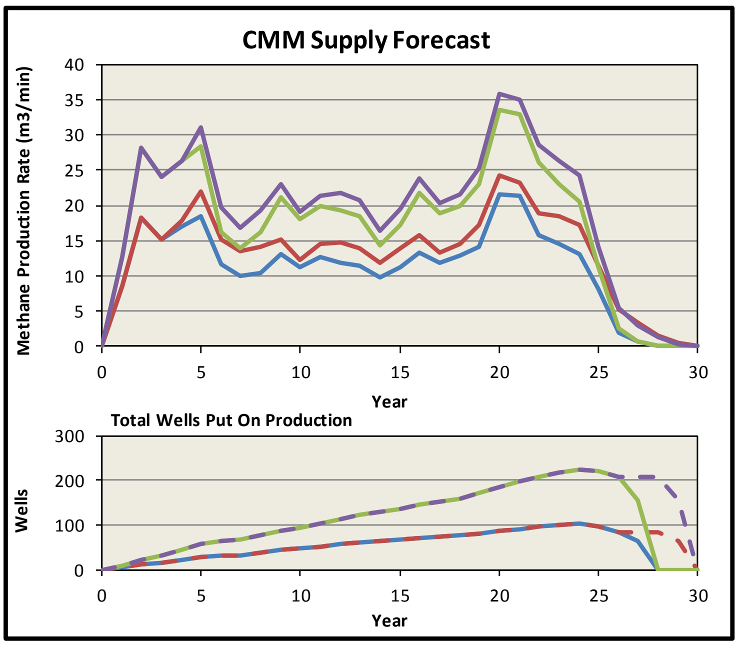
Normal Operating and Maintenance Cost: The normal operating and maintenance cost associated with the vacuum pumps and compressors is assumed to be \$17.66/1000m^3 (\$0.50/mcf).

7.3.2.4 Upstream (CMM Project) Economics

The economic results for the CMM project are summarized in Figure 35, and the pro-forma cash flows for each of the four proposed project development cases are summarized in Figure 39 through Figure 42 in the Appendix. Based on the forecasted gas production, the breakeven cost of producing gas through in-seam drainage boreholes is estimated to be between \$64 and \$91/1000 m^3 (\$2.33 and \$3.15/MMBtu). The results of the economic assessment indicate the lowest CMM production costs are associated with the 2 wells drilled per panel cases, with 5 years of pre-drainage (Case 2) preferred over 3 years (Case 1).

Summary of Economic Results

CMM Supply



Case	Wells per Panel	Years of Pre-Drainage	Breakeven Gas Price $/1000m3
1	2	3	71.93
2	2	5	63.57
3	4	3	90.85
4	4	5	84.00

Case	Description
1	2 wells per panel; 3 years pre-drainage
2	2 wells per panel; 5 years pre-drainage
3	4 wells per panel; 3 years pre-drainage
4	4 wells per panel; 5 years pre-drainage

Figure 35: Summary of Economic Results for the CMM Project

7.3.3 Downstream (Power Project) Economic Assumptions and Results

The drained methane can be used to fire internal combustion engines that drive generators to make electricity for use at the mine or for sale to the local power grid. The major cost components for the power project are the cost of the engine and generator, as well as costs for gas processing to remove solids and water, and the cost of equipment for connecting to the power grid. The assumptions used to assess the economic viability of the power project are presented in Table 14. A more detailed discussion of each input parameter is provided below.

Power Supply Model Inputs					
Case		**1**	**2**	**3**	**4**
Wells per Panel		2	2	4	4
Years of Pre-Drainage		3	5	3	5
PHYSICAL & FINANCIAL FACTORS					
Generator Efficienty	%	0.35	0.35	0.35	0.35
Run Time	%	0.90	0.90	0.90	0.90
CAPEX					
Power Plant	$/kW	1,300	1,300	1,300	1,300
OPEX					
Power Plant O&M	$/kWh	0.02	0.02	0.02	0.02

Table 14: Summary of Input Parameters for the Evaluation of Downstream Economics (Power Project)

7.3.3.1 Physical and Financial Factors

Generator Efficiency and Run Time:

Typical electrical power efficiency is between 30% and 44% and run time generally ranges between 7,500 to 8,300 hours annually (USEPA, 2009). For the proposed power project an electrical efficiency of 35% and an annual run time of 90%, or 7,884 hours, were assumed.

7.3.3.2 Capital Expenditures

Power Plant Cost Factor: The power plant cost factor, which includes capital costs for gas pretreatment, power generation, and electrical interconnection equipment, is assumed to be $1,300/kW.

7.3.3.3 Operating Expenses

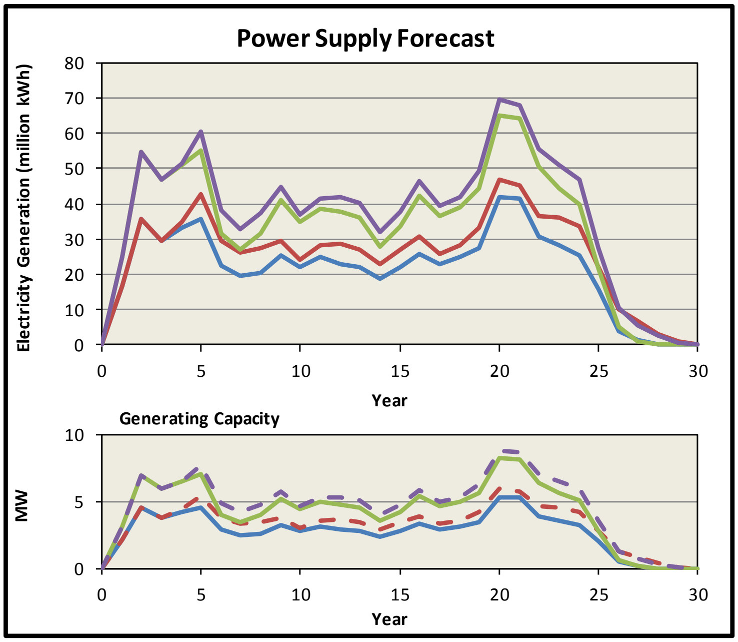
Power Plant Operating and Maintenance Cost: The operating and maintenance costs for the power plant are assumed to be 0.02/kWh.

7.3.3.4 Downstream (Power Project) Economics

The economic results for the power project are summarized in Figure 36, and the pro-forma cash flows for each of the four proposed project development cases are summarized in Figure 43 through Figure 46 in the Appendix. The breakeven power sales price, inclusive of the cost of methane drainage, is estimated to be between $0.049 and $0.056/kWh. Based on a breakeven CMM price of $64/1000m^3 ($2.33/MMBtu) (Case 2), the mine could generate power at a price equivalent to $0.049/kWh. A CMM-to-power utilization project at the mine would be economically feasible if the mine currently pays a higher price for electricity. Although power combined with CMM drainage appears to be economic, removing the cost of mine degasification from downstream economics as a sunk cost would significantly reduce the marginal cost of power.

Summary of Economic Results

Power Supply



Case	Wells per Panel	Years of Pre-Drainage	Breakeven Power Price $/kWh
1	2	3	0.0526
2	2	5	0.0485
3	4	3	0.0561
4	4	5	0.0533

Case	Description
1	2 wells per panel; 3 years pre-drainage
2	2 wells per panel; 5 years pre-drainage
3	4 wells per panel; 3 years pre-drainage
4	4 wells per panel; 5 years pre-drainage

Figure 36: Summary of Economic Results for Power Project

7.3.4 Downstream (CNG Project) Economic Assumptions and Results

The drained methane can also be used to produce compressed natural gas (CNG) for use as vehicle fuel. However, due to the methane concentration of the comingling of pre-drainage and gob gas, upgrading of the CMM may be necessary prior to converting the gas to CNG. The major cost component for the CNG project is the gas upgrade facility and the CNG station. The assumptions used to assess the economic viability of the CNG project are presented in Table 15. A more detailed discussion of each input parameter is provided below.

CNG Supply Model Inputs					
Case		**1**	**2**	**3**	**4**
Wells per Panel		2	2	4	4
Years of Pre-Drainage		3	5	3	5
PHYSICAL & FINANCIAL FACTORS					
Diesel Heating Value	MJ/l	35.80	35.80	35.80	35.80
Outlet Gas Methane Conc.	%CH4	94%	94%	94%	94%
CAPEX					
CNG Station Cost	$/DLE/mo	6.59	6.04	5.14	5.01
Gas Upgrade Facility	$,000	3,847	3,981	4,461	4,571
OPEX					
CNG Station O&M	$/DLE	0.08	0.07	0.06	0.06
Gas Upgrade Facility O&M					
Fixed	$,000/yr	300	300	300	300
Variable	$/1000m3	26.49	26.49	26.49	26.49

Table 15: Summary of Input Parameters for the Evaluation of Downstream Economics (CNG Project)

7.3.4.1 Physical and Financial Factors

Diesel Heating Value: Diesel liter equivalent (DLE) units are used to express a volume of CNG based on the energy equivalent to a liter (l) of diesel fuel. A diesel heating value of 35.80 MJ (128,450 Btu per gallon) was used in the CNG supply model in order to convert between gaseous and liquid fuel. This number is derived from the lower heating value of U.S. conventional diesel as utilized in Argonne National Laboratory's GREET model.

Outlet Gas Methane Concentration: It is assumed the CMM exiting the gas upgrading facility is 94% CH_4.

7.3.4.2 Capital Expenditures

CNG Station Cost: CNG stations costs include installation and the cost of a compressor package, a dryer, and onsite storage of CNG at 38 MPa (5500 psig). The station costs used in the CNG supply model were modified from Johnson (2010) as shown in Figure 37, which shows CNG station costs as a function of station size. The costs used in the economic model represent the average costs associated with transit and refuse fleets as presented by Johnson (2010). For the proposed project development cases, CNG station capital costs range between $5.01 and $6.59 per DLE produced per month with total capital costs ranging between $4.9 to 7.3 million.

Gas Upgrade Facility: The gas upgrade facility consists of a pressure swing adsorption (PSA) type system and a catalytic oxygen removal system. The PSA system is designed to remove nitrogen and carbon dioxide down to 4% of the gas stream, which includes the requisite dehydration and compression needed to process and discharge the gas at 900 psig. The cost of the facility is a function of the inlet gas flow rate and the methane concentration (USEPA, 2009). For the proposed project development cases, the gas upgrade facility costs range between $3.8 and $4.6 million.

7.3.4.3 Operating Expenses

CNG Station Operating and Maintenance Cost: Operating and maintenance costs associated with CNG station are assumed to range between $0.06 and $0.08 per DLE produced, as shown in Figure 37 (Johnson, 2010).

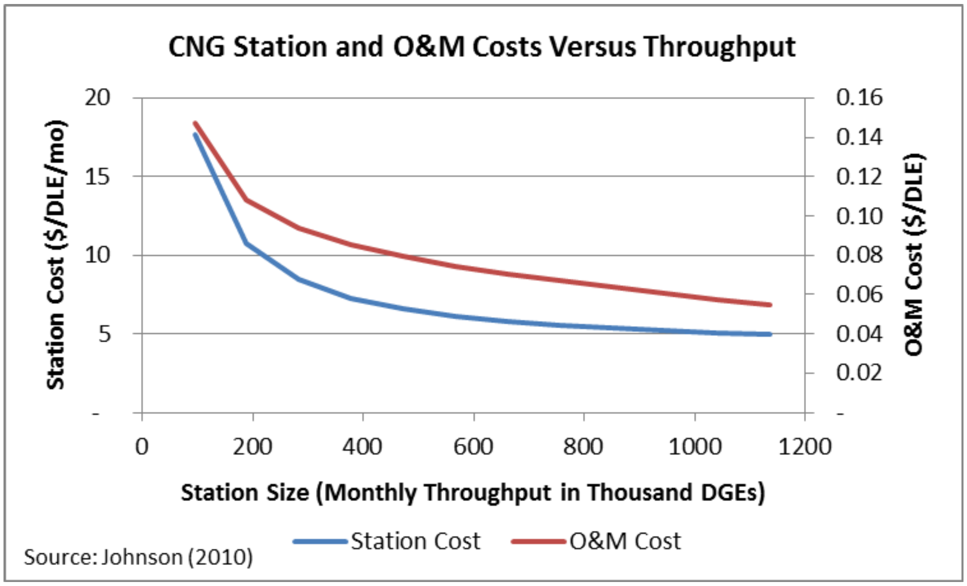


Figure 37: CNG Station and O&M Costs Versus Throughput (Johnson, 2010)

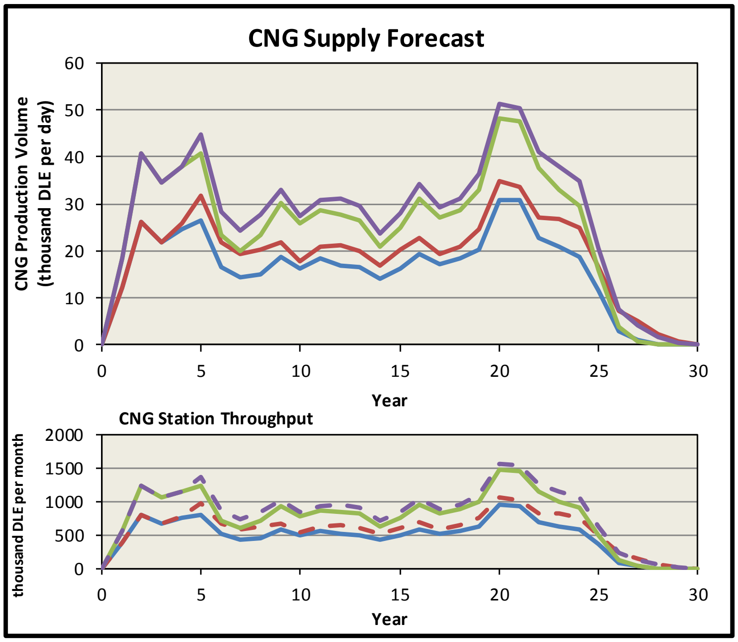
<u>*Gas Upgrade Facility Operating and Maintenance Cost*</u>: Operating and maintenance costs for the gas upgrade facility assume a fixed cost of $300,000 per year in addition to a variable cost of $26.49/1000m^3 of gas processed (USEPA, 2009).

7.3.4.4 Downstream (CNG Project) Economics

The economic results for the CNG project are summarized in Figure 38, and the pro-forma cash flows for each of the four proposed project development cases are summarized in Figure 47 through Figure 50 in the Appendix. The breakeven CNG sales price, inclusive of the cost of methane drainage, is estimated to be between $0.22 and $0.26/DLE ($0.84 and $0.98/DGE). Due to economies of scale associated with CNG station capacity, the optimal case for CNG production is Case 4, which produces CNG at a price equivalent to $0.22/DLE ($0.84/DGE). A CMM-to-CNG utilization project at the mine would be economically feasible if the mine currently pays a higher price for transportation fuel (e.g., CNG or diesel fuel). As with the power project, CNG production combined with CMM drainage appears to be economic and removing the cost of mine degasification from downstream economics as a sunk cost would significantly reduce the marginal cost of CNG production.

Summary of Economic Results

CNG Supply



Case	Wells per Panel	Years of Pre-Drainage	Breakeven CNG Price $/DLE
1	2	3	0.260
2	2	5	0.235
3	4	3	0.236
4	4	5	0.222

Case	Description
1	2 wells per panel; 3 years pre-drainage
2	2 wells per panel; 5 years pre-drainage
3	4 wells per panel; 3 years pre-drainage
4	4 wells per panel; 5 years pre-drainage

Figure 38: Summary of Economic Results for CNG Project

8 Conclusions, Recommendations and Next Steps

As a pre-feasibility study, this document is intended to provide a high level analysis of the technical feasibility and economics of the CMM project at the Amasra Hard Coal Mine. The analysis performed reveals that methane drainage using longhole directional drilling in association with the development of the Amasra Hard Coal Mine is feasible, and could provide the mine with additional benefits beyond the sale of gas such as improved mine safety and enhanced productivity.

The focus of this study was the East Block because it will be the first block mined. However, the proposed drainage approach should be applicable to the other coal blocks with some minor design modifications. The most effective gas drainage program for the mine is likely to be a combination of horizontal gob gas boreholes combined with in-seam gas drainage boreholes, both drilled from within the mine. Due to the relatively low permeability of the coals, the drainage efficiency improves as more wells per panel are drilled, and as drainage time increases. Based on the forecasted gas production, the breakeven cost of producing CMM through in-seam drainage boreholes combined with HGBs is estimated to be between $64 and $91/1000 m^3 ($2.33 and $3.15/MMBtu). The results of the economic assessment indicate the lowest CMM production costs are associated with the 2 wells drilled per panel cases, with 5 years of pre-drainage (Case 2) preferred over 3 years (Case 1).

In terms of utilization, the power and CNG options both appear to be economically feasible. More rigorous engineering design and costing would be needed before making a final determination of the best available utilization option for the drained methane. As of the end of 2013 the average rate of electricity for industrial customers was S0.1038/kWh (inclusive of all taxes and levies). When compared to the breakeven power sales price calculated in the economic analysis, utilizing drained methane to produce electricity could generate profits of between $48 and $55 per MWh of electricity produced. In terms of transportation fuels, the current diesel price in Turkey is $2.07/l. With a breakeven CNG sales price estimated to be between $0.22 and $0.26/DLE, utilizing drained methane to produce CNG could generate profits of between $1.81 and $1.85 per DLE of CNG sold.

Both potential utilization options appear to be economically feasible, and removing the cost of mine degasification from downstream economics, as a sunk cost, would reduce the marginal cost of electricity and CNG production and improve the economics even further. Furthermore, depending on the development approach and utilization option selected for the project, net emission reductions associated with the destruction of drained methane are estimated to range between 2.2 million and 3.8 million tonnes of carbon dioxide equivalent (tCO2e) over the 30-year project life. Should HEMA wish to continue with the proposed drainage plan, a phased project approach is recommended. The first phase would be to demonstrate the benefits of the proposed approach. The first steps would likely include the following:

- On-site scoping mission and meetings with mine technical personnel.
- Develop methane drainage approach and scope of work for demonstration project including estimated costs.
- Obtain budget approval for demonstration program.
- Meet to discuss and finalize project approach.
- Evaluate and approve drill room location and configuration and required utilities (water supply/discharge and electricity).
- Evaluate, design and install gas collection and safety system.

Once the first phase is completed and the results are evaluated, a corporate go/no-go decision should be made on whether or not to proceed with Phase II. The second phase would include equipment purchase and training to implement the proposed modern methane drainage technologies in house.

Appendix

Simple Economics (CMM)	
Case 1	1
HEMA CMM Pre-Feasibility Study	
2 wells per panel; 3 years pre-drainage	

Input Parameters		
Royalty	12.5%	
Price Escalation	3.0%	per year
Cost Escalation	3.0%	per year
Gas Price	2.64	$/MMBtu
	2.04	$/Mcf
Well Cost	90.3	$,000/well
Surface Vacuum Station	1000	$/hp
Vacuum Pump Efficiency	0.035	hp/mcfd
Gathering Pipe Cost	40	$/ft
Gathering Pipe Length	950	ft/well
Satellite Compressor Cost	1000	$/hp
Compressor Efficiency	0.035	hp/mcfd
Pipeline Cost	55	$/ft
Pipeline Length	6560	ft
Field Fuel Use (gas)	10.0%	%
O&M	0.5	$/mcf

Project Cashflow

Project Year	Gross Gas Prod. mmcf	Net Gas Prod. mmcf	Gas Price $/mcf	Net Revenue $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Wells Drilled	Net CH4 Prod mmcf
0	-	-	-	-	-	-	406.8	(406.8)	(406.8)	-	-
1	266.6	209.9	2.10	440.4	108.1	332.2	711.8	(379.6)	(786.4)	5	158.8
2	554.1	436.4	2.22	968.6	231.5	737.1	1,088.8	(351.7)	(1,138.1)	8	339.1
3	454.9	358.2	2.32	832.7	195.7	636.9	700.9	(64.0)	(1,202.1)	5	283.0
4	497.3	391.6	2.46	962.7	220.4	742.3	1,011.6	(269.3)	(1,471.4)	7	317.7
5	558.7	439.9	2.43	1,068.5	255.0	813.5	594.9	218.6	(1,252.8)	4	342.3
6	345.1	271.7	2.54	691.3	162.2	529.1	306.4	222.7	(1,030.1)	2	215.0
7	303.6	239.0	2.57	613.6	147.0	466.6	788.9	(322.3)	(1,352.4)	5	185.3
8	319.5	251.6	2.64	663.7	159.4	504.3	975.1	(470.8)	(1,823.1)	6	194.6
9	388.7	306.1	2.78	850.3	199.7	650.6	669.6	(19.0)	(1,842.1)	4	242.0
10	333.6	262.7	2.88	756.1	176.5	579.6	517.2	62.4	(1,779.7)	3	209.0
11-30	6,124.2	4,822.8		17,885.8	4,183.3	13,702.6	11,922.8	1,779.7		55	3,825.8
Total	10,146.1	7,990.1	3.22	25,733.7	6,038.8	19,694.9	19,694.9	0.0		104	6,312.6
											79%

Present Value Table

Discount Rate		Net Present Value
10%	-	(1,275.1)
15%	-	(1,255.1)
20%	-	(1,185.0)
25%	-	(1,112.6)
30%	-	(1,049.2)

Economic Parameters

Internal Rate of Return	0.0%
Payback Year	27.0
Net Income / Net Capital	1.0

Figure 39: CMM Project Cash Flow for Case 1 (2 wells per panel; 3 years pre-drainage)

Simple Economics (CMM)	
Case 2	2
HEMA CMM Pre-Feasibility Study	
2 wells per panel; 5 years pre-drainage	

Input Parameters		
Royalty	12.5%	
Price Escalation	3.0%	per year
Cost Escalation	3.0%	per year
Gas Price	2.33	$/MMBtu
	1.80	$/Mcf
Well Cost	90.3	$,000/well
Surface Vacuum Station	1000	$/hp
Vacuum Pump Efficiency	0.035	hp/mcfd
Gathering Pipe Cost	40	$/ft
Gathering Pipe Length	950	ft/well
Satellite Compressor Cost	1000	$/hp
Compressor Efficiency	0.035	hp/mcfd
Pipeline Cost	55	$/ft
Pipeline Length	6560	ft
Field Fuel Use (gas)	10.0%	%
O&M	0.5	$/mcf

Project Cashflow

Project Year	Gross Gas Prod. mmcf	Net Gas Prod. mmcf	Gas Price $/mcf	Net Revenue $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Wells Drilled	Net CH4 Prod mmcf
0	-	-	-	-	-	-	406.8	(406.8)	(406.8)	-	-
1	266.6	209.9	1.85	389.2	108.1	281.1	711.8	(430.8)	(837.6)	5	158.8
2	554.1	436.4	1.96	856.0	231.5	624.5	1,088.8	(464.3)	(1,301.9)	8	339.1
3	454.9	358.2	2.05	735.9	195.7	540.1	700.9	(160.8)	(1,462.7)	5	283.0
4	517.2	407.3	2.17	884.8	229.2	655.6	1,029.5	(373.8)	(1,836.5)	7	331.9
5	650.6	512.3	2.15	1,099.6	297.0	802.7	594.9	207.8	(1,628.7)	4	408.2
6	439.9	346.4	2.25	778.8	206.8	572.0	306.4	265.7	(1,363.0)	2	283.0
7	392.7	309.2	2.27	701.5	190.2	511.3	788.9	(277.6)	(1,640.6)	5	249.2
8	415.4	327.1	2.33	762.6	207.2	555.4	975.1	(419.7)	(2,060.3)	6	263.3
9	445.5	350.8	2.45	861.1	228.9	632.3	669.6	(37.3)	(2,097.6)	4	282.7
10	361.1	284.4	2.54	723.4	191.1	532.3	517.2	15.1	(2,082.6)	3	228.7
11-30	7,361.6	5,797.3		19,075.3	5,076.5	13,998.8	11,916.2	2,082.6		55	4,712.6
Total	11,859.4	9,339.3	2.88	26,868.2	7,162.1	19,706.1	19,706.1	(0.0)		104	7,540.4
											81%

Present Value Table		
Discount Rate		Net Present Value
10%	-	(1,515.8)
15%	-	(1,482.5)
20%	-	(1,393.2)
25%	-	(1,302.7)
30%	-	(1,223.4)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	26.8
Net Income / Net Capital	1.0

Figure 40: CMM Project Cash Flow for Case 2 (2 wells per panel; 5 years pre-drainage)

Simple Economics (CMM)	
Case 3	3
HEMA CMM Pre-Feasibility Study	
4 wells per panel; 3 years pre-drainage	

Input Parameters		
Royalty	12.5%	
Price Escalation	3.0%	per year
Cost Escalation	3.0%	per year
Gas Price	3.15	$/MMBtu
	2.57	$/Mcf
Well Cost	90.3	$,000/well
Surface Vacuum Station	1000	$/hp
Vacuum Pump Efficiency	0.035	hp/mcfd
Gathering Pipe Cost	40	$/ft
Gathering Pipe Length	433	ft/well
Satellite Compressor Cost	1000	$/hp
Compressor Efficiency	0.035	hp/mcfd
Pipeline Cost	55	$/ft
Pipeline Length	6560	ft
Field Fuel Use (gas)	10.0%	%
O&M	0.5	$/mcf

Project Cashflow

Project Year	Gross Gas Prod. mmcf	Net Gas Prod. mmcf	Gas Price $/mcf	Net Revenue $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Wells Drilled	Net CH4 Prod mmcf
0	-	-	-	-	-	-	425.7	(425.7)	(425.7)	-	-
1	375.7	295.9	2.50	740.4	152.4	588.0	1,075.3	(487.3)	(912.9)	9	237.0
2	812.0	639.5	2.65	1,693.0	339.2	1,353.8	1,826.9	(473.2)	(1,386.1)	16	523.9
3	683.1	537.9	2.77	1,491.4	293.9	1,197.5	1,293.7	(96.2)	(1,482.3)	11	446.6
4	734.7	578.6	2.93	1,696.5	325.6	1,370.9	1,575.6	(204.6)	(1,686.9)	13	487.8
5	816.1	642.7	2.90	1,861.9	372.5	1,489.3	1,247.7	241.6	(1,445.3)	10	526.8
6	466.8	367.6	3.03	1,115.5	219.5	896.0	514.1	382.0	(1,063.3)	4	302.3
7	406.2	319.9	3.06	979.4	196.7	782.7	1,191.3	(408.6)	(1,472.0)	9	258.9
8	467.0	367.8	3.15	1,157.2	233.0	924.2	1,636.1	(711.9)	(2,183.9)	12	300.3
9	596.3	469.6	3.31	1,555.7	306.3	1,249.4	1,123.4	125.9	(2,058.0)	8	390.8
10	507.5	399.6	3.43	1,372.0	268.5	1,103.5	1,012.5	91.0	(1,967.0)	7	333.6
11-30	9,158.5	7,212.3		31,855.4	6,248.0	25,607.3	23,640.4	1,967.0		129	6,000.3
Total	15,024.0	11,831.4	3.85	45,518.3	8,955.7	36,562.7	36,562.7	(0.0)		228	9,808.2
											83%

Present Value Table		
Discount Rate		Net Present Value
10%	-	(1,477.5)
15%	-	(1,445.8)
20%	-	(1,362.3)
25%	-	(1,279.1)
30%	-	(1,207.2)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	-
Net Income / Net Capital	1.0

Figure 41: CMM Project Cash Flow for Case 3 (4 wells per panel; 3 years pre-drainage)

Simple Economics (CMM)	
Case 4	4
HEMA CMM Pre-Feasibility Study	
4 wells per panel; 5 years pre-drainage	

Input Parameters		
Royalty	12.5%	
Price Escalation	3.0%	per year
Cost Escalation	3.0%	per year
Gas Price	2.91	$/MMBtu
	2.38	$/Mcf
Well Cost	90.3	$,000/well
Surface Vacuum Station	1000	$/hp
Vacuum Pump Efficiency	0.035	hp/mcfd
Gathering Pipe Cost	40	$/ft
Gathering Pipe Length	433	ft/well
Satellite Compressor Cost	1000	$/hp
Compressor Efficiency	0.035	hp/mcfd
Pipeline Cost	55	$/ft
Pipeline Length	6560	ft
Field Fuel Use (gas)	10.0%	%
O&M	0.5	$/mcf

Project Cashflow

Project Year	Gross Gas Prod. mmcf	Net Gas Prod. mmcf	Gas Price $/mcf	Net Revenue $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Wells Drilled	Net CH4 Prod mmcf
0	-	-	-	-	-	-	425.7	(425.7)	(425.7)	-	-
1	375.7	295.9	2.31	684.5	152.4	532.1	1,075.3	(543.1)	(968.8)	9	237.0
2	812.0	639.5	2.45	1,565.2	339.2	1,226.0	1,826.9	(601.0)	(1,569.8)	16	523.9
3	683.1	537.9	2.56	1,378.9	293.9	1,084.9	1,293.7	(208.8)	(1,778.5)	11	446.6
4	737.8	581.0	2.71	1,575.2	327.0	1,248.2	1,589.4	(341.2)	(2,119.7)	13	490.1
5	887.4	698.8	2.68	1,871.6	405.1	1,466.6	1,247.7	218.9	(1,900.9)	10	577.9
6	553.7	436.1	2.81	1,223.5	260.3	963.1	514.1	449.1	(1,451.8)	4	364.6
7	482.8	380.2	2.83	1,076.2	233.8	842.4	1,191.3	(348.9)	(1,800.8)	9	313.8
8	546.8	430.6	2.91	1,252.4	272.7	979.7	1,636.1	(656.4)	(2,457.2)	12	357.4
9	647.3	509.7	3.06	1,561.4	332.5	1,228.8	1,123.4	105.4	(2,351.8)	8	427.3
10	534.6	421.0	3.17	1,336.4	282.9	1,053.5	1,012.5	41.0	(2,310.8)	7	353.0
11-30	10,219.9	8,048.1		32,960.8	7,013.4	25,947.4	23,636.5	2,310.8		129	6,760.8
Total	16,481.2	12,978.9	3.58	46,486.0	9,913.3	36,572.7	36,572.7	(0.0)		228	10,852.5
											84%

Present Value Table		
Discount Rate		Net Present Value
10%	-	(1,758.0)
15%	-	(1,710.3)
20%	-	(1,604.0)
25%	-	(1,499.5)
30%	-	(1,409.0)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	26.9
Net Income / Net Capital	1.0

Figure 42: CMM Project Cash Flow for Case 4 (4 wells per panel; 5 years pre-drainage)

Simple Economics (Power)		Input Parameters		
Case 1		Power Sales Price	0.0526	$/kWh
HEMA CMM Pre-Feasibility Study		Generator Size	5.3	MW
2 wells per panel; 3 years pre-drainage		Power Plant Cost Factor	1300	$/kW
		Generator Efficiency	0.35	
		Run Time	90%	
		Price Escalation	3.0%	
		Cost Escalation	3.0%	
		Power Plant O&M	0.02	$/kWh
		Fuel Cost Switch	1	

Project Cashflow

Project Year	Generator Output MWh	Sales Price $/kWh	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Generator Sizing MW
0	-	0.0526	-	-	-	-	6,877.3	(6,877.3)	(6,877.3)	-	-
1	16,614.1	0.0542	900.3	440.4	342.3	117.7	-	117.7	(6,759.6)	158.8	2.1
2	35,479.3	0.0558	1,980.2	968.6	752.8	258.9	-	258.9	(6,500.8)	339.1	4.5
3	29,612.1	0.0575	1,702.3	832.7	647.2	222.5	-	222.5	(6,278.3)	283.0	3.8
4	33,238.9	0.0592	1,968.2	962.7	748.2	257.3	-	257.3	(6,021.0)	317.7	4.2
5	35,818.8	0.0610	2,184.6	1,068.5	830.5	285.6	-	285.6	(5,735.4)	342.3	4.5
6	22,499.9	0.0628	1,413.4	691.3	537.3	184.8	-	184.8	(5,550.7)	215.0	2.9
7	19,388.4	0.0647	1,254.5	613.6	476.9	164.0	-	164.0	(5,386.7)	185.3	2.5
8	20,359.8	0.0666	1,356.9	663.7	515.8	177.4	-	177.4	(5,209.3)	194.6	2.6
9	25,325.2	0.0686	1,738.4	850.3	660.9	227.2	-	227.2	(4,982.1)	242.0	3.2
10	21,865.0	0.0707	1,545.9	756.1	587.7	202.1	-	202.1	(4,780.0)	209.0	2.8
11-30	400,293.5		36,567.1	17,885.8	13,901.2	4,780.0	-	4,780.0		3,825.8	50.8
Total	660,494.9	0.0797	52,611.8	25,733.7	20,000.8	6,877.3	6,877.3	0.0		6,312.6	5.3

Present Value Table

Discount Rate		Net Present Value
10%	-	(4,738.6)
15%	-	(5,427.2)
20%	-	(5,803.7)
25%	-	(6,032.1)
30%	-	(6,183.0)

Economic Parameters

Internal Rate of Return	0.0%
Payback Year	27.0
Net Income / Net Capital	1.0

Figure 43: Power Project Cash Flow for Case 1 (2 wells per panel; 3 years pre-drainage)

Simple Economics (Power)
Case 2
HEMA CMM Pre-Feasibility Study
2 wells per panel; 5 years pre-drainage

Input Parameters		
Power Sales Price	0.0485	$/kWh
Generator Size	6.0	MW
Power Plant Cost Factor	1300	$/kW
Generator Efficiency	0.35	
Run Time	90%	
Price Escalation	3.0%	
Cost Escalation	3.0%	
Power Plant O&M	0.02	$/kWh
Fuel Cost Switch	1	

Project Cashflow

Project Year	Generator Output MWh	Sales Price $/kWh	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Generator Sizing MW
0	-	0.0485	-	-	-	-	7,743.4	(7,743.4)	(7,743.4)	-	-
1	16,614.1	0.0500	830.2	389.2	342.3	98.7	-	98.7	(7,644.7)	158.8	2.1
2	35,479.3	0.0515	1,826.0	856.0	752.8	217.2	-	217.2	(7,427.5)	339.1	4.5
3	29,612.1	0.0530	1,569.7	735.9	647.2	186.7	-	186.7	(7,240.8)	283.0	3.8
4	34,731.3	0.0546	1,896.3	884.8	781.8	229.7	-	229.7	(7,011.1)	331.9	4.4
5	42,709.1	0.0562	2,401.9	1,099.6	990.2	312.0	-	312.0	(6,699.1)	408.2	5.4
6	29,608.1	0.0579	1,715.1	778.8	707.1	229.2	-	229.2	(6,469.9)	283.0	3.8
7	26,069.9	0.0597	1,555.4	701.5	641.3	212.7	-	212.7	(6,257.2)	249.2	3.3
8	27,550.1	0.0615	1,693.0	762.6	698.0	232.5	-	232.5	(6,024.7)	263.3	3.5
9	29,579.6	0.0633	1,872.3	861.1	771.9	239.2	-	239.2	(5,785.5)	282.7	3.8
10	23,928.1	0.0652	1,560.0	723.4	643.1	193.5	-	193.5	(5,592.0)	228.7	3.0
11-30	493,078.0		41,970.7	19,075.3	17,303.3	5,592.0	-	5,592.0		4,712.6	62.5
Total	788,959.7	0.0746	58,890.6	26,868.2	24,279.0	7,743.4	7,743.4	(0.0)		7,540.4	6.0

Present Value Table

Discount Rate		Net Present Value
10%	-	(5,511.3)
15%	-	(6,270.5)
20%	-	(6,677.1)
25%	-	(6,919.8)
30%	-	(7,077.9)

Economic Parameters

Internal Rate of Return	0.0%
Payback Year	-
Net Income / Net Capital	1.0

Figure 44: Power Project Cash Flow for Case 2 (2 wells per panel; 5 years pre-drainage)

Simple Economics (Power)
Case 3
HEMA CMM Pre-Feasibility Study
4 wells per panel; 3 years pre-drainage

Input Parameters		
Power Sales Price	0.0561	$/kWh
Generator Size	8.2	MW
Power Plant Cost Factor	1300	$/kW
Generator Efficiency	0.35	
Run Time	90%	
Price Escalation	3.0%	
Cost Escalation	3.0%	
Power Plant O&M	0.02	$/kWh
Fuel Cost Switch	1	

Project Cashflow

Project Year	Generator Output MWh	Sales Price $/kWh	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Generator Sizing MW
0	-	0.0561	-	-	-	-	10,706.3	(10,706.3)	(10,706.3)	-	-
1	24,802	0.0578	1,434.3	740.4	510.9	183.0	-	183.0	(10,523.4)	237.0	3.1
2	54,816	0.0596	3,265.1	1,693.0	1,163.1	409.1	-	409.1	(10,114.3)	523.9	7.0
3	46,723	0.0614	2,866.6	1,491.4	1,021.1	354.0	-	354.0	(9,760.2)	446.6	5.9
4	51,043	0.0632	3,225.5	1,696.5	1,149.0	380.0	-	380.0	(9,380.3)	487.8	6.5
5	55,124	0.0651	3,587.9	1,861.9	1,278.1	448.0	-	448.0	(8,932.3)	526.8	7.0
6	31,626	0.0670	2,120.2	1,115.5	755.3	249.5	-	249.5	(8,682.8)	302.3	4.0
7	27,086	0.0691	1,870.3	979.4	666.2	224.7	-	224.7	(8,458.1)	258.9	3.4
8	31,422	0.0711	2,234.9	1,157.2	796.1	281.6	-	281.6	(8,176.5)	300.3	4.0
9	40,886	0.0733	2,995.2	1,555.7	1,066.9	372.6	-	372.6	(7,803.9)	390.8	5.2
10	34,902	0.0755	2,633.6	1,372.0	938.1	323.4	-	323.4	(7,480.4)	333.6	4.4
11-30	627,812		61,100.9	31,855.4	21,765.1	7,480.4	-	7,480.4		6,000.3	79.6
Total	1,026,242	0.0851	87,334.6	45,518.3	31,109.9	10,706.3	10,706.3	(0.0)		9,808.2	8.2

Present Value Table		
Discount Rate		Net Present Value
10%	-	(7,382.5)
15%	-	(8,457.3)
20%	-	(9,043.8)
25%	-	(9,398.7)
30%	-	(9,632.5)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	-
Net Income / Net Capital	1.0

Figure 45: Power Project Cash Flow for Case 3 (4 wells per panel; 3 years pre-drainage)

Simple Economics (Power)
Case 4
HEMA CMM Pre-Feasibility Study
4 wells per panel; 5 years pre-drainage

Input Parameters		
Power Sales Price	0.0533	$/kWh
Generator Size	8.8	MW
Power Plant Cost Factor	1300	$/kW
Generator Efficiency	0.35	
Run Time	90%	
Price Escalation	3.0%	
Cost Escalation	3.0%	
Power Plant O&M	0.02	$/kWh
Fuel Cost Switch	1	

Project Cashflow

Project Year	Generator Output MWh	Sales Price $/kWh	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Generator Sizing MW
0	-	0.0533	-	-	-	-	11,430.3	(11,430.3)	(11,430.3)	-	-
1	24,802	0.0549	1,362.3	684.5	510.9	166.8	-	166.8	(11,263.5)	237.0	3.1
2	54,816	0.0566	3,101.2	1,565.2	1,163.1	372.9	-	372.9	(10,890.6)	523.9	7.0
3	46,723	0.0583	2,722.6	1,378.9	1,021.1	322.6	-	322.6	(10,568.0)	446.6	5.9
4	51,277	0.0600	3,077.6	1,575.2	1,154.3	348.2	-	348.2	(10,219.8)	490.1	6.5
5	60,467	0.0618	3,738.0	1,871.6	1,402.0	464.5	-	464.5	(9,755.4)	577.9	7.7
6	38,148	0.0637	2,429.0	1,223.5	911.0	294.6	-	294.6	(9,460.8)	364.6	4.8
7	32,828	0.0656	2,153.0	1,076.2	807.5	269.3	-	269.3	(9,191.5)	313.8	4.2
8	37,399	0.0676	2,526.4	1,252.4	947.5	326.5	-	326.5	(8,865.0)	357.4	4.7
9	44,712	0.0696	3,111.0	1,561.4	1,166.8	382.9	-	382.9	(8,482.1)	427.3	5.7
10	36,939	0.0717	2,647.3	1,336.4	992.9	318.1	-	318.1	(8,164.1)	353.0	4.7
11-30	707,392		65,805.0	32,960.8	24,680.1	8,164.1	-	8,164.1		6,760.8	89.7
Total	1,135,503	0.0816	92,673.4	46,486.0	34,757.1	11,430.3	11,430.3	0.0		10,852.5	8.8

Present Value Table

Discount Rate		Net Present Value
10%	-	(8,034.8)
15%	-	(9,168.1)
20%	-	(9,779.3)
25%	-	(10,145.5)
30%	-	(10,384.8)

Economic Parameters

Internal Rate of Return	0.0%
Payback Year	29.0
Net Income / Net Capital	1.0

Figure 46: Power Project Cash Flow for Case 4 (4 wells per panel; 5 years pre-drainage)

Simple Economics (CNG)
Case 1
HEMA CMM Pre-Feasibility Study
2 wells per panel; 3 years pre-drainage

Input Parameters		
CNG Price	0.98	$/DGE
Diesel Heating Value	128450	Btu/gal
CNG Station Cost	19.76	$/DGE/mo
CNG Station O&M	0.23	$/DGE
CNG Station Size	248.0	10^3 DGE/mo
Outlet Gas Methane Conc.	94%	%CH4
Gob Gas Upgrade Facility	3847	$,000
Gob Gas Upgrade Facility O&M		
Fixed	300	$,000/yr
Variable	0.75	$/Mcf
Price Escalation	3.0%	
Cost Escalation	3.0%	
Fuel Cost Switch	1	

Project Cashflow

Project Year	CNG Volume 10^3 DGE	CNG Price $/DGE	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Station Sizing 10^3 DGE/mo
0	-	0.98	-	-	-	-	8,745.9	(8,745.9)	(8,745.9)	-	-
1	1,185.3	1.01	1,201.4	440.4	705.1	55.9	-	55.9	(8,690.0)	149.3	98.8
2	2,531.1	1.04	2,642.5	968.6	1,189.6	484.4	-	484.4	(8,205.6)	318.7	210.9
3	2,112.5	1.08	2,271.7	832.7	1,076.9	362.2	-	362.2	(7,843.4)	266.0	176.0
4	2,371.3	1.11	2,626.4	962.7	1,203.7	460.1	-	460.1	(7,383.3)	298.6	197.6
5	2,555.3	1.14	2,915.2	1,068.5	1,309.0	537.7	-	537.7	(6,845.6)	321.8	212.9
6	1,605.2	1.18	1,886.2	691.3	980.1	214.7	-	214.7	(6,631.0)	202.1	133.8
7	1,383.2	1.21	1,674.1	613.6	920.9	139.5	-	139.5	(6,491.4)	174.2	115.3
8	1,452.5	1.25	1,810.7	663.7	977.1	170.0	-	170.0	(6,321.5)	182.9	121.0
9	1,806.7	1.28	2,319.9	850.3	1,156.3	313.2	-	313.2	(6,008.3)	227.5	150.6
10	1,559.9	1.32	2,063.0	756.1	1,083.4	223.4	-	223.4	(5,784.8)	196.4	130.0
11-30	28,557.0		48,797.4	17,885.8	25,126.7	5,784.8	-	5,784.8		3,596.2	2,379.8
Total	47,119.9	1.49	70,208.4	25,733.7	35,728.8	8,745.9	8,745.9	0.0		5,933.9	248.0

Present Value Table		
Discount Rate		Net Present Value
10%	-	(5,780.7)
15%	-	(6,693.0)
20%	-	(7,205.0)
25%	-	(7,522.0)
30%	-	(7,735.4)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	22.1
Net Income / Net Capital	1.0

Figure 47: CNG Project Cash Flow for Case 1 (2 wells per panel; 3 years pre-drainage)

Simple Economics (CNG)

Case 2
HEMA CMM Pre-Feasibility Study
2 wells per panel; 5 years pre-drainage

Input Parameters		
CNG Price	0.89	$/DGE
Diesel Heating Value	128450	Btu/gal
CNG Station Cost	19.17	$/DGE/mo
CNG Station O&M	0.22	$/DGE
CNG Station Size	279.2	10^3 DGE/mo
Outlet Gas Methane Conc.	94%	%CH4
Gob Gas Upgrade Facility	3981	$,000
Gob Gas Upgrade Facility O&M		
Fixed	300	$,000/yr
Variable	0.75	$/Mcf
Price Escalation	3.0%	
Cost Escalation	3.0%	
Fuel Cost Switch	1	

Project Cashflow

Project Year	CNG Volume 10^3 DGE	CNG Price $/DGE	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Station Sizing 10^3 DGE/mo
0	-	0.89	-	-	-	-	9,332.3	(9,332.3)	(9,332.3)	-	-
1	1,185.3	0.92	1,086.6	389.2	688.3	9.1	-	9.1	(9,323.2)	149.3	98.8
2	2,531.1	0.94	2,389.9	856.0	1,152.5	381.4	-	381.4	(8,941.8)	318.7	210.9
3	2,112.5	0.97	2,054.6	735.9	1,045.0	273.7	-	273.7	(8,668.1)	266.0	176.0
4	2,477.7	1.00	2,482.0	884.8	1,204.1	393.1	-	393.1	(8,275.0)	312.0	206.5
5	3,046.9	1.03	3,143.7	1,099.6	1,445.2	598.9	-	598.9	(7,676.1)	383.7	253.9
6	2,112.3	1.06	2,244.8	778.8	1,141.8	324.1	-	324.1	(7,351.9)	266.0	176.0
7	1,859.8	1.09	2,035.8	701.5	1,079.6	254.7	-	254.7	(7,097.2)	234.2	155.0
8	1,965.4	1.13	2,215.9	762.6	1,153.6	299.8	-	299.8	(6,797.4)	247.5	163.8
9	2,110.2	1.16	2,450.6	861.1	1,246.8	342.6	-	342.6	(6,454.8)	265.7	175.9
10	1,707.0	1.20	2,041.8	723.4	1,115.9	202.5	-	202.5	(6,252.3)	215.0	142.3
11-30	35,176.3		54,933.6	19,075.3	29,606.0	6,252.3	-	6,252.3		4,429.8	2,931.4
Total	56,284.6	1.37	77,079.3	26,868.2	40,878.7	9,332.3	9,332.3	0.0		7,088.0	279.2

Present Value Table

Discount Rate		Net Present Value
10%	-	(6,244.9)
15%	-	(7,257.1)
20%	-	(7,822.3)
25%	-	(8,167.8)
30%	-	(8,396.3)

Economic Parameters

Internal Rate of Return	0.0%
Payback Year	22.1
Net Income / Net Capital	1.0

Figure 48: CNG Project Cash Flow for Case 2 (2 wells per panel; 5 years pre-drainage)

Simple Economics (CNG)
Case 3
HEMA CMM Pre-Feasibility Study
4 wells per panel; 3 years pre-drainage

Input Parameters		
CNG Price	0.89	$/DGE
Diesel Heating Value	128450	Btu/gal
CNG Station Cost	17.87	$/DGE/mo
CNG Station O&M	0.17	$/DGE
CNG Station Size	386.0	10^3 DGE/mo
Outlet Gas Methane Conc.	94%	%CH4
Gob Gas Upgrade Facility	4461	$,000
Gob Gas Upgrade Facility O&M		
Fixed	300	$,000/yr
Variable	0.75	$/Mcf
Price Escalation	3.0%	
Cost Escalation	3.0%	
Fuel Cost Switch	1	

Project Cashflow

Project Year	CNG Volume 10^3 DGE	CNG Price $/DGE	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Station Sizing 10^3 DGE/mo
0	-	0.89	-	-	-	-	11,360.0	(11,360.0)	(11,360.0)	-	-
1	1,769.4	0.92	1,627.9	740.4	796.2	91.3	-	91.3	(11,268.7)	222.8	147.4
2	3,910.6	0.95	3,705.9	1,693.0	1,427.4	585.5	-	585.5	(10,683.1)	492.5	325.9
3	3,333.3	0.98	3,253.5	1,491.4	1,301.6	460.6	-	460.6	(10,222.6)	419.8	277.8
4	3,641.4	1.01	3,660.9	1,696.5	1,433.3	531.1	-	531.1	(9,691.5)	458.6	303.4
5	3,932.5	1.04	4,072.3	1,861.9	1,566.6	643.8	-	643.8	(9,047.7)	495.2	327.7
6	2,256.2	1.07	2,406.5	1,115.5	1,078.4	212.5	-	212.5	(8,835.1)	284.1	188.0
7	1,932.3	1.10	2,122.8	979.4	1,004.3	139.1	-	139.1	(8,696.0)	243.3	161.0
8	2,241.7	1.13	2,536.6	1,157.2	1,139.2	240.2	-	240.2	(8,455.8)	282.3	186.8
9	2,916.8	1.17	3,399.6	1,555.7	1,408.9	435.0	-	435.0	(8,020.8)	367.3	243.1
10	2,489.9	1.20	2,989.1	1,372.0	1,297.8	319.3	-	319.3	(7,701.5)	313.6	207.5
11-30	44,788.3		69,349.1	31,855.4	29,792.2	7,701.5	-	7,701.5		5,640.3	3,732.4
Total	73,212.4	1.35	99,124.2	45,518.3	42,245.9	11,360.0	11,360.0	0.0		9,219.7	386.0

Present Value Table		
Discount Rate		Net Present Value
10%	-	(7,609.1)
15%	-	(8,787.7)
20%	-	(9,442.2)
25%	-	(9,843.4)
30%	-	(10,110.9)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	22.4
Net Income / Net Capital	1.0

Figure 49: CNG Project Cash Flow for Case 3 (4 wells per panel; 3 years pre-drainage)

Simple Economics (CNG)

Case 4
HEMA CMM Pre-Feasibility Study
4 wells per panel; 5 years pre-drainage

Input Parameters		
CNG Price	0.84	$/DGE
Diesel Heating Value	128450	Btu/gal
CNG Station Cost	17.66	$/DGE/mo
CNG Station O&M	0.16	$/DGE
CNG Station Size	412.1	10^3 DGE/mo
Outlet Gas Methane Conc.	94%	%CH4
Gob Gas Upgrade Facility	4571	$,000
Gob Gas Upgrade Facility O&M		
Fixed	300	$,000/yr
Variable	0.75	$/Mcf
Price Escalation	3.0%	
Cost Escalation	3.0%	
Fuel Cost Switch	1	

Project Cashflow

Project Year	CNG Volume 10^3 DGE	CNG Price $/DGE	Revenue $,000	Fuel Cost $,000	Operating Cost $,000	Operating Income $,000	Capital Cost $,000	Cashflow $,000	Cum. Cashflow $,000	Delivered CH4 mmcf	Station Sizing 10^3 DGE/mo
0	-	0.84	-	-	-	-	11,848.5	(11,848.5)	(11,848.5)	-	-
1	1,769.4	0.87	1,531.8	684.5	777.9	69.4	-	69.4	(11,779.2)	222.8	147.4
2	3,910.6	0.89	3,487.1	1,565.2	1,385.7	536.2	-	536.2	(11,243.0)	492.5	325.9
3	3,333.3	0.92	3,061.4	1,378.9	1,265.0	417.6	-	417.6	(10,825.4)	419.8	277.8
4	3,658.1	0.95	3,460.6	1,575.2	1,397.0	488.4	-	488.4	(10,336.9)	460.7	304.8
5	4,313.7	0.97	4,203.2	1,871.6	1,634.5	697.1	-	697.1	(9,639.8)	543.2	359.5
6	2,721.5	1.00	2,731.3	1,223.5	1,194.3	313.5	-	313.5	(9,326.3)	342.7	226.8
7	2,342.0	1.03	2,420.9	1,076.2	1,110.1	234.7	-	234.7	(9,091.6)	294.9	195.2
8	2,668.1	1.06	2,840.8	1,252.4	1,249.6	338.7	-	338.7	(8,752.8)	336.0	222.3
9	3,189.8	1.10	3,498.2	1,561.4	1,462.3	474.5	-	474.5	(8,278.3)	401.7	265.8
10	2,635.2	1.13	2,976.7	1,336.4	1,314.4	326.0	-	326.0	(7,952.3)	331.9	219.6
11-30	50,465.5		73,994.4	32,960.8	33,081.3	7,952.3	-	7,952.3		6,355.2	4,205.5
Total	81,007.1	1.29	104,206.5	46,486.0	45,872.1	11,848.5	11,848.5	(0.0)		10,201.3	412.1

Present Value Table

Discount Rate		Net Present Value
10%	-	(7,885.9)
15%	-	(9,164.1)
20%	-	(9,877.3)
25%	-	(10,313.1)
30%	-	(10,601.3)

Economic Parameters	
Internal Rate of Return	0.0%
Payback Year	22.0
Net Income / Net Capital	1.0

Figure 50: CNG Project Cash Flow for Case 4 (4 wells per panel; 5 years pre-drainage)

Works Cited

AHPG. (2013). *HEMA Amasra Hardcoal Production Project.*

BP. (2013). *BP Statistical Review of World Energy June 2013.*

Burger, K., Bandelow, F. K., & Bieg, G. (2000). Pyroclastic Kaolin Coal–tonsteins of the Upper Carboniferous of Zonguldak and Amasra, Turkey. *International Journal of Coal Geology*, 39-53.

EIA. (2013, May 30). *Turkey: Overview Data for Turkey*. Retrieved June 10, 2014, from U.S. Energy Information Administration: http://www.eia.gov/countries/country-data.cfm?fips=TU#ng

EUROCOAL. (2014). *Turkey*. Retrieved June 21, 2014, from EURACOAL - European Association for Coal and Lignite: http://www.euracoal.org/pages/layout1sp.php?idpage=475 1/2

EUROSTAT. (2014). *Supply, transformation, consumption - solid fuels - annual data*. Retrieved June 9, 2014, from EUROSTAT > Energy > Database: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database

Fuel Prices Europe. (2014, June 16). *Fuel Prices in Europe on June 16, 2014*. Retrieved June 16, 2014, from Fuel-prices-europe.info: http://www.fuel-prices-europe.info/index.php?sort=6

GMI. (2010, December). *Coal Mine Methane Country Profiles: Chapter 33: Turkey*. Retrieved June 10, 2014, from Global Methane Initiative: https://www.globalmethane.org/tools-resources/coal_overview.aspx

GMI. (2014). *GMI Database of Methane Sites and Activities*. Retrieved June 10, 2014, from Global Methane Initiative: https://www.globalmethane.org/activities/indexact2.aspx?sector=coal

HEMA. (2013). *HATTAT ENERJİ ve MADEN TİC. A.Ş.: Amasra Hardcoal Project - Resouce Estimation Study.*

HEMA. (2014). *Amasra Hardcoal Project*. Retrieved June 10, 2014, from HEMA website: http://www.hemaenerji.com/enerji-grubu-projeleri/amasra-tas-komuru-projesi

HEMA. (2014). *HEMA Amasra Thermal Power Plant Project*. Retrieved June 10, 2014, from HEMA website: http://www.hemaenerji.com/enerji-grubu-projeleri/hema-amasra-termik-santrali-projesi

Hoşgörmez, H., Yalçın, M. N., Cramer, B., Gerling, P., Faber, E., Schaefer, R. G., & Mann, U. (2002). Isotopic and Molecular Composition of Coal-bed Gas in the Amasra Region (Zonguldak Basin—western Black Sea). *Organic Geochemistry*, 1429-1439.

Johnson, C. (2010). *Business Case for Compressed Natural Gas in Municipal Fleets.*

Karacan, C. O., & Okandan, E. (2000). Fracturecleat Analysis of Coals from Zonguldak Basin. *International Journal of Coal Geology*, 109-125.

Karayigit, A. I., Gayer, R. A., & Demirel, I. H. (1997). Coal Rank and Petrography of Upper Carboniferous Seams in the Amasra Coalfield, Turkey. *International Journal of Coal Geology*, 277-294.

Okay, A. I., & Görür, N. (2007). Oil and Gas of the Greater Caspian Area. In P. O. Yilmaz, & G. H. Isaksen, *Oil and Gas of the Greater Caspian Area: AAPG Studies in Geology 55* (pp. xi, 169). AAPG.

Randall, T. (2014, June 2). *Pain at the Pump: Gasoline Prices by Country*. Retrieved June 16, 2014, from Bloomberg: http://www.bloomberg.com/visual-data/gas-prices/20142:Turkey:USD:g

Raven Ridge Resources, Inc. (1998). *Geological Resource Assessment of Coalbed Methane Potential for the Zonguldak Coal Basin, Turkey.* Grand Junction: Raven Ridge Resources, Inc.

Schwochow. (1997). *The International Coal Seam Gas Report.* Cairn Point Publishing.

Sınayuç, C., & Gümrah, F. (2009). Modeling of ECBM recovery from Amasra coalbed in Zonguldak Basin, Turkey. *International Journal of Coal Geology*, 162-174.

Sınayuç, Ç., & Gümrah, F. (2009). Modeling of ECBM Recovery from Amasra Coalbed in Zonguldak Basin, Turkey. *International Journal of Coal Geology*, 162-74.

TurkStat. (2014). *National Greenhouse Gas Inventory Report 1990-2012.*

Tüysüz, O. (1999). Geology of the Cretaceous Sedimentary Basins of the Western Pontides. *Geological Journal*, 75-93.

USEPA. (2009). *User's Manual for the Coal Mine Methane Project Cash Flow Model (Version 2).*

Yılmaz, M. (2010). *The Hydrogeological Report of Amasra Harccoal Basin.*