Pre-Feasibility Study for Methane Drainage and Utilization at the Chinakuri Colliery, Sodepur Area West Bengal State, Burdwan District, India

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Prepared by:
Advanced Resources International, Inc.

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Disclaimer

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) authored this report based on information obtained from the coal mine partner, Eastern Coalfields Limited (ECL) of Coal India Limited (CIL).

Acknowledgements

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Executive Summary

The U.S. Environmental Protection Agency's (USEPA) Coalbed Methane Outreach Program (CMOP) 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. The work of CMOP and USEPA also directly supports the goals and objectives of the Global Methane Initiative (GMI), 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. An integral element of CMOP's international outreach in support of the GMI is the development of CMM pre-feasibility studies. 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.

Eastern Coalfields Limited (ECL), a leading coal company in India and a subsidiary of Coal India Limited (CIL), was selected as the recipient of a pre-feasibility study for CMM drainage at their Chinakuri Mines Group (Mines No. I, II, III). Advanced Resources International, Inc. (ARI) was tasked with developing a pre-feasibility study to assess the potential for a methane pre-drainage and utilization project at Chinakuri Mine No. I, which is located in the southwestern portion of the Raniganj Coalfield.

The Chinakuri Mine No. I is considered to be a highly gassy mine based on India's coal mine classification system. Seam R-IV (Dishergarh) was worked by Mine No. I until 2008 when existing longwall panels were exhausted. Galleries and longwall panels at Mine No. I were developed up to a depth of approximately 2,300 feet (ft), or 700 meters (m), but were halted due to lack of equipment and difficult mining conditions associated with gas outbursts and general gassiness of the seam. Substantial coal reserves remain in the virgin area of Seam R-IV at depths greater than 2,300 ft (700 m). Future extraction is planned for the down-dip portion of the seam located in the southern part of the mine boundary. The unmined portions of Seam R-IV are slated to be mined within the next year or two, which makes the seam an ideal target for pre-drainage.

ECL does not currently implement a gas drainage program at any of its coal mines. In the past, the mines of the Chinakuri Mines Group managed coal mine gas solely through ventilation. However, methane emissions from the virgin area of Mine No. I are projected to be very high, which will impact mine safety, productivity, and ventilation requirements. To help mitigate the projected high methane emission levels, CIL and ECL have expressed an interest in pursuing a methane pre-drainage program at Mine No. I. Developing a CMM project at this mine would contribute to the national goal of increasing domestic natural gas and coal production, while allowing the country to maintain its commitments made at the Paris Climate Summit. The proposed CMM project at Chinakuri Mine No. 1 would also allow CIL to show leadership in the burgeoning CMM sector and help bring the company closer to achieving the CMM/CBM production target of 5 million cubic meters per day recently requested by the government.

The principal objective of this pre-feasibility study is to evaluate the technical and economic feasibility of using long in-mine horizontal boreholes drilled down-dip into the virgin seam of the southern mine boundary to drain methane in advance of mining, and to utilize the drained gas to generate electricity for on-site consumption. The primary market available for a CMM utilization project at the Chinakuri Mine No. I is power generation using internal combustion engines. 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 performed in association with this pre-feasibility study, the mine could be capable of operating as much as 4.4 megawatts (MW) of electricity capacity.

CMM gas production profiles were generated for a total of six project development scenarios, as highlighted in Exhibit 1. The development scenarios were designed to evaluate the optimum number of pre-drainage boreholes to drill in each panel (i.e., 1, 2, or 3 wells per panel). In addition, the effect of pre-drainage duration (i.e., 1 year or 3 years of pre-drainage) and the resulting reduction in methane content of the coal seams was also assessed.

Scenario	Wells Per Panel	Years of Pre-Drainage
1	1	1
2	2	1
3	3	1
4	1	3
5	2	3
6	3	3

Exhibit 1: Summary of Project Development Scenarios for Mine No. 1

Based on the mine map provided by ECL, the total project area encompasses 4,250 acres (ac), or 17 square kilometers (sq. km). Under all six development scenarios it is assumed a total of 16 longwall panels, each measuring 4,920 ft (1,500 m) in length by 490 ft (150 m) in width, will be developed within the project area. Assuming a longwall face advance rate of 13.5 ft per day (ft/d), or 4 meters per day (m/d), each longwall panel will take approximately one year to mine. With one year of pre-drainage at each longwall panel, degasification and mining of the 16 longwall panels will be completed over a project life of 17 years, while utilizing three years of pre-drainage at each longwall panel will result in a 19-year project life (assuming only one active longwall face at a time). The development of 16 longwall panels will require a total of 16 to 48 boreholes depending on the development scenario selected.

The results of the economic assessment are summarized in Exhibit 2. Based on the forecasted gas production, the breakeven cost of producing CMM through in-seam drainage boreholes is estimated to be between $1.04 and $2.30 per million British thermal units (MMBtu) ($34 and $75 per 1000 cubic meters, 1000m^3). This compares favorably to the domestic natural gas price set by the government, which is currently $4.24/MMBtu ($139/1000m^3). The results of the economic assessment indicate the lowest CMM production costs are associated with the one borehole per panel cases, with 3 years of pre-drainage (Scenario 4) preferred over one year (Scenario 1).

In terms of utilization, the power production option is 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. The breakeven power price is estimated to be between $0.0478 and $0.0596 per kilowatt-hour (kWh). The results of the economic assessment indicate the lowest power price is associated with the one borehole per panel case with three years of pre-drainage (Scenario 4). According to the most recent data available (2015-16), ECL's average purchase price for electricity was $0.1070/kWh. When compared to the breakeven power sales price for Scenario 4 of $0.0478/kWh, utilizing drained methane to produce electricity would generate profits of more than $59 per megawatt-hour (MWh) of electricity produced.

While the power production option is currently economically feasible, removing the cost of mine degasification from downstream economics, as a sunk cost, would reduce the marginal cost of electricity and improve the economics even further. In addition, net emission reductions associated with the destruction of drained methane are estimated to average just under 80,000 tonnes of carbon dioxide equivalent (tCO_2e) per year over the life of the project for the optimal development scenario.

Scenario	Description	Max Power Plant Capacity (MW)	Fuel Cost ($/MMBtu)	Breakeven Power Price ($/kWh)	Net CO_2e Reductions (tCO_2e/yr)
1	1 in-seam horizontal borehole per panel with 1 year of pre-drainage	2.5	1.41	0.0509	61,000
2	2 in-seam horizontal boreholes per panel with 1 year of pre-drainage	3.4	1.74	0.0542	85,000
3	3 in-seam horizontal boreholes per panel with 1 year of pre-drainage	3.6	2.30	0.0596	90,000
4	1 in-seam horizontal borehole per panel with 3 years of pre-drainage	3.6	1.04	0.0478	79,000
5	2 in-seam horizontal boreholes per panel with 3 years of pre-drainage	4.2	1.45	0.0516	95,000
6	3 in-seam horizontal boreholes per panel with 3 years of pre-drainage	4.4	1.95	0.0565	97,000

Exhibit 2: Summary of Economic Results

1 Introduction

The U.S. Environmental Protection Agency's (USEPA) Coalbed Methane Outreach Program (CMOP) 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 work of CMOP and USEPA also directly supports the goals and objectives of the Global Methane Initiative (GMI), 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.

An integral element of CMOP's international outreach in support of the GMI is the development of CMM pre-feasibility studies. These studies provide a 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. In recent years, CMOP has sponsored feasibility and pre-feasibility studies in such countries as China, India, Kazakhstan, Mongolia, Poland, Russia, Turkey and Ukraine.

Eastern Coalfields Limited (ECL), a leading coal company in India and a subsidiary of Coal India Limited (CIL), was selected as the recipient of a pre-feasibility study for CMM drainage at their Chinakuri Mines Group (Mines No. I, II, III). Advanced Resources International, Inc. (ARI) was tasked with developing a pre-feasibility study for a methane pre-drainage and utilization project at Chinakuri Mine No. I, which is located in the southwestern portion of the Raniganj Coalfield.

The Chinakuri Mine No. I is considered to be a Degree III gassy mine, the highest category for methane emissions in India. Seam R-IV (Dishergarh) was worked by Mine No. I until 2008 when existing longwall panels were exhausted. Galleries and longwall panels at Mine No. I were developed up to a depth of approximately 2,300 ft (700 m), but were halted due to lack of equipment and difficult mining conditions associated with gas outbursts and general gassiness of the seam. Substantial coal reserves remain in the virgin area of Seam R-IV at depths greater than 2,300 ft (700 m). Future extraction is planned for the down-dip portion of the seam located in the southern part of the mine boundary, which is slated to be mined within the next year or two.

ECL does not currently implement a gas drainage program at any of its coal mines. In the past, the mines of the Chinakuri Mines Group managed coal mine gas solely through ventilation. However, methane emissions from the virgin area of Mine No. I are projected to be very high, which will impact mine safety, productivity, and ventilation requirements. To help mitigate the projected high methane emission levels, CIL and ECL have expressed an interest in pursuing a methane pre-drainage program at Mine No. I. The principal objective of this pre-feasibility study is to evaluate the technical and economic feasibility of using long in-mine horizontal boreholes drilled down-dip into the virgin seam of the southern mine boundary to drain methane in advance of mining, and to utilize the drained gas to generate electricity for on-site consumption.

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 Indian Coal Industry

Coal is the largest component of India's energy sector. India is the third largest coal market in the world, with coal representing 58 percent of the country's total primary energy consumption in 2015 (BP, 2016). Coal's primary use in India is power generation, which accounted for 65 percent of India's coal consumption in 2014, and 62 percent of India's total installed power capacity as of April 2016 (EIA, 2016). Coal demand in India has grown by more than 7 percent per year over the past decade, while coal production has lagged behind with a 5 percent growth rate over the same period, leading to increases of imported coal by more than 13 percent a year (EIA, 2016; USEPA, 2015). However, recent regulatory reforms are focused on increasing domestic coal production to reduce imports and promote energy security (EIA, 2016).

In 2015, as part of India's 12th Five Year Plan (2012-2017), the country announced an aggressive coal production target of 1.5 billion tons by 2020, which is double the 2015 production level (EIA, 2016). CIL, the world's biggest coal producer, plans to increase annual production to about 1 billion tons in the next four years, with private sector and captive mines expected to account for the remainder of the targeted production increase (Loh, 2016). In June 2016, India's Ministry of Coal called for all government owned and operated thermal power producers to halt all coal imports and source coal feedstocks from CIL (Daws, 2016).

At the end of 2015, India's total proved reserves of coal were 60,600 million tonnes (Mt) (ranked fifth globally), with 93 percent being anthracite or bituminous coal, and the remaining 7 percent being sub-bituminous or lignite. (BP, 2016). The majority of India's coal reserves are located in the eastern half of the country, ranging from Andhra Pradesh, bordering the Indian Ocean, to Arunachal Pradesh in the extreme northeast of the country (USEPA, 2015).

In 2015, India ranked third in global coal production with 677 Mt of production (BP, 2016). Between 1981 and 2015, India's coal production increased by 547 Mt (Exhibit 3). According to EIA (2016), the country's largest coal producer, CIL, is responsible for producing over 80 percent of India's coal, with Singareni Collieries Company Limited (SCCL) responsible for another 10 percent of production. The remaining 10 percent of coal production is met by captive producers, which represent private industries mining coal for their own use. However, government allocated blocks issued to private companies for their own use were voided in 2015, with the government planning to re-auction them for sale. The goal of the reform is to create a more transparent, competitive bidding system for coal production rights, which the government hopes will help attract private investment in the coal sector and support domestic coal production (EIA, 2016).

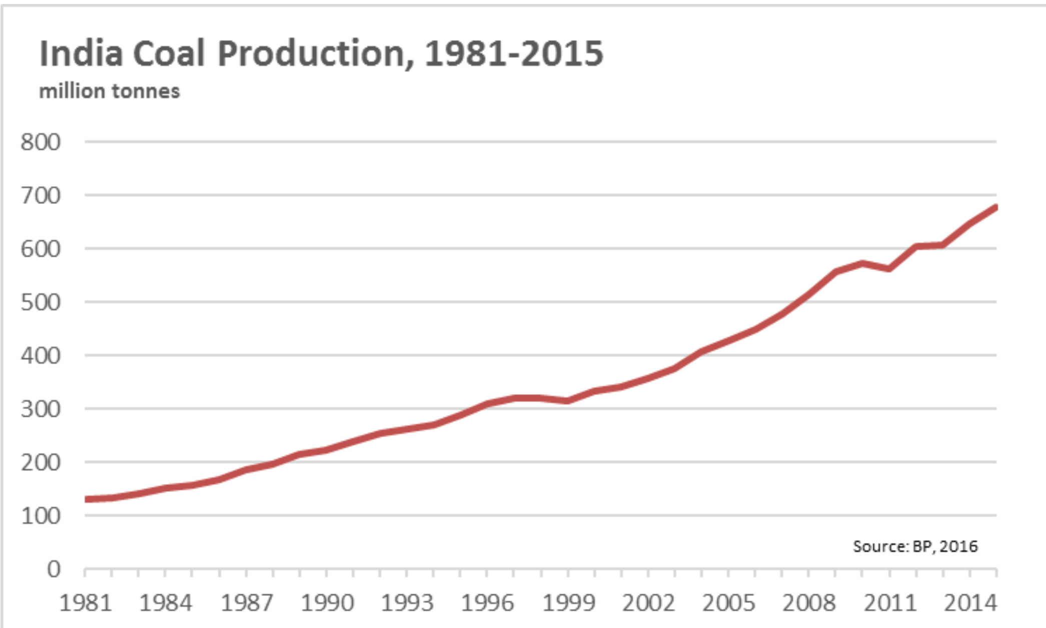

Exhibit 3: Coal Production in India

2.2 Coal Mine Methane in India

Most coal mines in India are classified as Degree I or II gassy mines indicating that they are moderately gassy as shown in Exhibit 4 (USEPA, 2015). However, as India's demand for coal increases from year to year, so will emissions from coal mining activities as the country's easily accessible shallow coal reserves are depleted and deeper, gassier coal seams are exploited. Although the number of deep underground coal mines in India is small they will continue to be developed with India's rapidly growing coal demand, especially in light of the newly enacted ban on thermal coal imports announced by the Ministry of Coal (Daws, 2016). CMM emissions in India have risen from 35 billion cubic feet (Bcf) (1,007 million cubic meters, Mm^3) in 2000 to an estimated 49 Bcf (1,397 Mm^3) at the end of 2015 (USEPA, 2015).

Degree I	Percentage of inflammable gas in the general body of air near seam workings does not exceed 0.1 percent and the rate of emission per tonne of coal produced does not exceed 1 cubic meter (m^3) (35.31 cubic feet, ft^3)
Degree II	Percentage of inflammable gas in the general body of air near seam workings is more than 0.1 percent and the rate of emission per tonne of coal produced does not exceed 1 m^3 (353 ft^3)
Degree III	The rate of emission of inflammable gas per tonne of coal produced exceeds 10 m^3 (353 ft^3)

Exhibit 4: Gassy Mine Classification System of India

India's current administration has called for an increase in domestic oil and gas production to reduce the country's dependence on fossil fuel imports. By 2020, the government hopes to reduce India's import dependence by 10 percent (PTI, 2016). Development of natural gas from coal seams (CBM or CMM) is a priority for both government and industry. To boost domestic natural gas production, the Ministry of Petroleum and Natural Gas is initiating policy changes designed to increase natural gas production from CBM blocks to 353 million cubic feet per day, MMcfd (equivalent to 10 million cubic meters per day, Mm^3/d) by 2017-18 from the current level of under 53 MMcfd (1.5 Mm^3/d) (Saikia, 2015). Since 2013, CIL has been licensed by the government to produce natural gas from coal seams in its existing mines (Saran & Gupta, 2016). The government is now asking the state-owned mine to accelerate CBM exploration with a goal of ramping up its output to a minimum of 177 MMcfd (5 Mm^3/d) from current levels of less than 35 MMscfd (1 MMm^3/d), which is produced from coal blocks in partnership with Oil and Natural Gas Corporation Limited (ONGC) (Saikia, 2015).

According to the Directorate General of Hydrocarbons (DGH), a large portion of India's prospective CBM area has yet to be explored. Of the 26,000 square kilometers with potential CBM resources, exploration activities have been initiated in only about half of the area (Saikia, 2015). CIL holds 20 percent of India's estimated 60 billion tonnes of coal resources, and the company has coal mines in eight states, which are estimated to hold between 3.5 to 4 trillion cubic feet (Tcf) of CBM reserves. Furthermore, much of CIL's acreage is gaseous and considered safe to mine only after pre-drainage of methane. Extracting CBM/CMM before the mining of coal seams will grant CIL access to significant quantities of coal reserves in areas of Jharkhand and West Bengal (PTI, 2013). With 81 percent of the country's prospective CBM area currently overlapped by coal mining areas held by CIL, the lifting of rules that previously did not allow for simultaneous extraction of methane and coal could help CIL unlock up to 100 million tons of medium grade coking coal and 1 Tcf of gas (PTI, 2013).

While recent policy changes will undoubtedly prove favorable for state-owned CIL, the Petroleum and Natural Gas Ministry recently clarified that existing private operators already undertaking CBM exploration and production projects at coal blocks allocated to them by the government would have to pursue new licenses from the government under the Hydrocarbon Exploration and Licensing Policy (HELP). The newly unveiled HELP calls for a composite uniform license for exploration for and production of all forms of hydrocarbons from a single asset block, open acreage, revenue sharing contracts, and freedom of pricing and marketing of oil and gas produced from a block (Das, 2016).

2.3 Eastern Coalfields Limited

Eastern Coalfields Limited (ECL) is a subsidiary of Coal India Limited (CIL), a state owned coal mining company. CIL is the largest coal producer in the world, operating in 81 mining lease areas spread across eight provincial states, through seven wholly owned mining subsidiaries and one mine planning and consulting company. CIL produces 81 percent of India's total coal, which accounts for 40 percent of India's total commercial energy requirements (CIL, 2015). CIL commands 74 percent of India's coal market and accounts for 76 percent of total thermal power generation capacity in India's utility sector (CIL, 2015). In 2013 ECL produced 33.9 Mt, the highest output since the company's inception.

ECL is situated in the states of West Bengal and Jharkhand, with operations in the Raniganj, Saherjuri, and Hura coalfields. ECL currently holds a mining lease area of 186,500 ac (754.75 sq. km), and a surface rights area of 58,600 ac (237.18 sq. km) (ECL, 2015). Currently, ECL owns 98 operating mines of which 77 are underground mines and 21 are opencast mines (ECL, 2015). As of 2012, ECL held total estimated coal reserves of 49.17 billion tonnes (Gt) at up to 600 m in depth, of which 30.61 Gt were in West Bengal and 18.56 Gt were in Jharkhand. Total proved reserves are 12.42 Gt in West Bengal and 4.52 Gt in Jharkhand (ECL, 2015).

3 Summary of Mine Characteristics

ECL is currently planning future extraction in the down-dip portion of the virgin seam, Seam R-IV, which is located in the southern portion of the mine boundary. In Mine No. I, coal was previously extracted by the longwall stowing method. Most of the roadways were developed by road header machines equipped to handle difficult geo-mining conditions and gassiness of the seam. Galleries and longwall panels were developed at Mine No. I up until 1994 to a depth of approximately 2,300 ft (700 m), but was halted due to lack of equipment, technological knowhow, difficult mining conditions associated with gas outbursts, and general gassiness of the seam. The last available longwall panel was exhausted in November 2008, leaving the down-dip portion of the mine the only remaining option for development at Mine No. I.

The Chinakuri Blocks located in the Raniganj Coalfield cover an area of about 395,000 ac (1600 sq. km). The major part of the Coalfield lies east of the Bahadar River in the Burdwan district of West Bengal. Smaller parts lie in the Birbhum, Bankura, and Purulia districts of West Bengal, and the Dhanbad and Santhal Parganas districts of Jharkhand. The area forms an alluvial plane with very gently undulating topography. The elevation varies between 295 ft (90 m) to 459 ft (140 m) from mean sea level. The Damodar River is the main canal and the area is drained by three small nallas within the blocks.

The Raniganj Coal Basin is bounded to the north, west, and south by the Archeans; the eastern boundary of the coal basin is unknown. The eastern boundary is concealed under a thick cover of Laterite and alluvium, along with the Panchets and Durgapur formations. The oldest sedimentary formation is the Talchir formation, which is exposed along the northwestern margin of the basin and un-conformably overlies the Archeans. The Barakar, Barren Measures (Ironstone shale), Raniganj, and Panchet formations are exposed successively from north to south. In the southwestern and southcentral parts of the basin, two patches of Supra-Panchets are exposed. The eastern part of the basin is predominantly covered by laterite and alluvium. Intrusions in the form of thin sills and dykes composed of dolerite and mica peridotite have been observed.

The geologic structure of the Raniganj Coal Basin is simple. The regional dip of the basin is towards the south. In the northern part of the basin, the regional dip is approximately five degrees and throughout the basin the dip rarely exceeds 10 degrees. The southern margin of the coalfield is marked by the Main Boundary Fault, which consists of a series of normal faults. The northern limit of the basin is of natural disposition. The basin is traversed by numerous small and large faults with a characteristic northwest to southeast trend and a down throw toward the northeast.

The Chinakuri Mine blocks are located in an area that has a humid tropical climate. Through the summer months (March through May) the temperature ranges from 30 degrees Celsius to 40 degrees Celsius. Through the winter (November through January) the temperature can drop down to 10 degrees Celsius at night. The relative humidity varies from 45 percent to 98 percent and the average yearly rainfall is approximately 49 inches (in) (1250 millimeters, mm) per year, the majority of which precipitates during June through October. The area is often subjected to a cyclonic storm locally referred to as "Kalbaissakhi" from April through June.

The Chinakuri mining area is located in the southwestern part of the Raniganj Coalfield, under the administrative control of the Sodepur Area of ECL, in the Burdwan District of West Bengal State (see Exhibit 5). The present leasehold of the mine is 5,020 ac (2031.5 hectares, ha). It is currently the deepest mine in India. The pits of the colliery are located to the north of the Damodar River, while the mine workings extend to the south. Its coordinates are 23 degrees 41 minutes east and 86 degrees 52 minutes north.

The mine is connected to G.T. Road by Radhanagar Road at Neamatpur only 3.7 miles (mi) (6 km) from the mine block. The nearest railway stations are Sitarampur, 5.0 mi (8 km) away, and Asansol, 10.0 I (16 km) away. The nearest railway stations are part of Eastern Railways. The nearest airport is Dumdum (Kolkata), which is approximately 137 mi (220 km) away, and the nearest seaport is Koalta, which is approximately 130 mi (210 km) away. The closest settlement is the Asansol Township, which is about 7.5 mi (12 km) away from the mine.

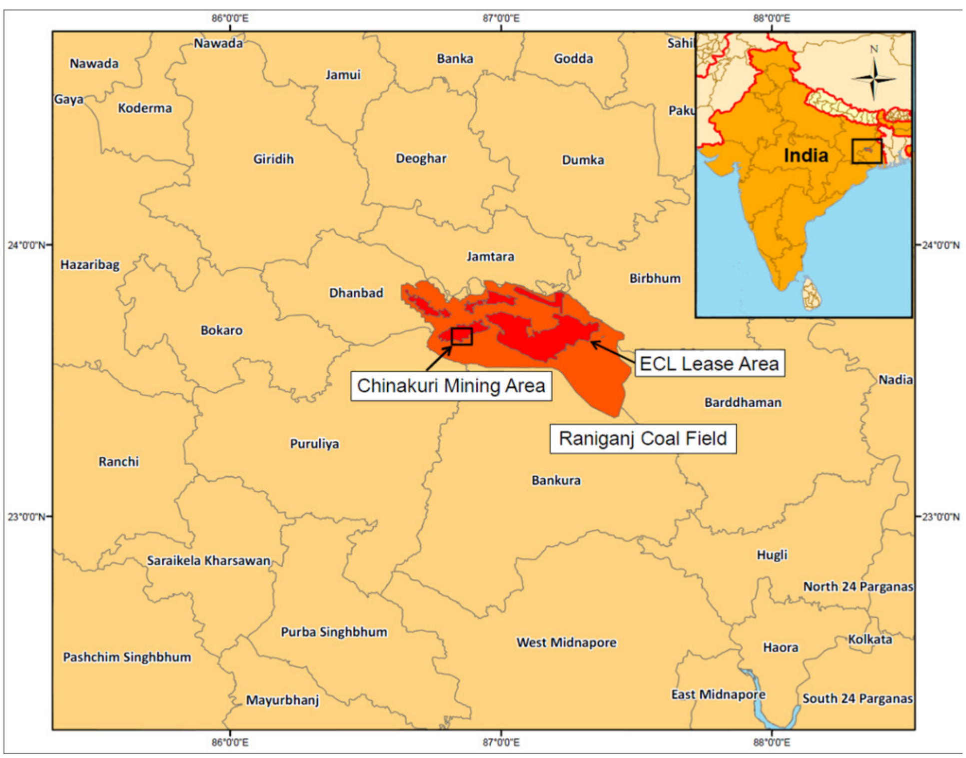

Exhibit 5: Chinakuri Mine Location Map

The boundary of Chinakuri Mine No. I is delineated into Parabelia, Seetalpur, Chinakuri 3 pit, and Bejdih Colliery in the north. In the east, it is delineated into the Patmohana Colliery, and in the west it is delineated into the Dubeshwari and Bhamuria Collieries. The southern boundary is mostly undeveloped. The present leasehold of the mine falls either fully or partially into the Chinakuri Sodepur, Chinakuri Bejdih, Parabelia, Parabelia South, Madhukundah North, and Daishergarh C geologic blocks. About 246 boreholes have been drilled by various agencies in the six geologic blocks containing the mine. Out of the 246 boreholes, 66 lie within the leasehold area of the mine. According to data provided by ECL, 68.46 Mt of coal reserves are present within the virgin areas of Chinakuri Mine No. I (see Exhibit 6).

Virgin Areas	Reserve (Mt)
Below the River	10.54
Southeast of the River	15.48
Southeast of the River (Area of most dip)	15.13
Total Virgin	**68.46**
Developed Areas (Room and Pillar)	**Reserve (Mt)**
West Side Area	1.18
East Side Area	2.96
Total Developed	**4.14**
Grand Total	**72.6**

Exhibit 6: Seam R-IV Reserve Details

A total of ten standard coal seams are present in the Raniganj coalfield, of which seams R-VII, R-IV, R-X, and partially R-II have been worked or are currently being worked within the Chinakuri Colliery. Mining activity in the Chinakuri leasehold area is currently focused on the development of seam R-VII at Chinakuri Mine No. III. Chinakuri Mine No. II has exhausted its reserves. A stratigraphic column showing the ten Chinakuri Mine coal seams, as represented in Borehole CNK-16, is presented in Exhibit 7, and summary information for the coal seams is provided in Exhibit 8.

Galleries and longwall panels were developed at Mine No. I up until 1994 to a depth of 2,300 ft (700 m), but was halted due to lack of equipment, technological knowhow, and difficult mining conditions associated with gas outbursts. The last available longwall panel was exhausted in November 2008. Chinakuri Mine No. I has previously used the longwall stowing method of mining and plans to continue using longwall mining for future development of seam R-IV. Presently, there is no active mining in the southern boundary of Chinakuri Mine No. I, which is the area of interest for the current pre-feasibility study, but the unmined portions of Seam R-IV are slated to be mined within the next year or two.

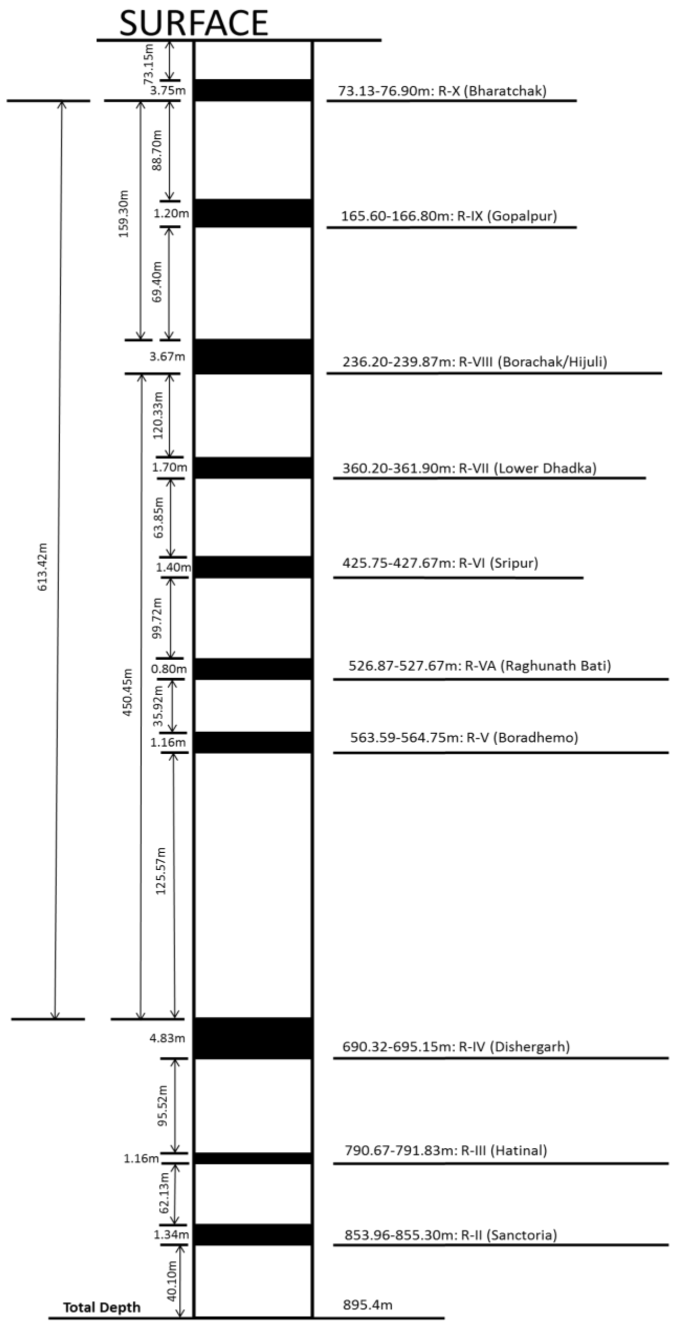

Exhibit 7: Stratigraphic Column as Represented in Borehole CNK-16

Seam	Thickness (m)	Parting (m)	Depth (m)	Gradient	Grade	Total Geologic Reserve (Mt)	Status
R-X (Bharatchak)	3.75	-	73.15	1 in 5.6	G-3	Exhausted	Worked by Chinakuri Mine No. II Exhausted
R-IX (Gopalpur)	1.20	88.70	165.60	1 in 6.0	G-4	14.48	Virgin
R-VIII (Borachak/ Hijuli)	3.67	69.40	236.20	1 in 6.3	G-4	22.00	Presently being worked by Chinakuri Mine No. III and Parbelia Colliery
R-VII Lower (Dhadka)	1.70	120.33	360.20	1 in 6.0	G-4	12.94	Virgin
R-VI (Sripur)	1.40	63.85	425.75	1 in 6.4	G-5 G-6	4.94	Virgin
R-VA (Raghunath Bati)	0.80	99.72	526.87	1 in 6.5	G-4	15.80	Virgin
R-V Bora (Dhemo)	1.16	35.92	563.59	1 in 6.5	G-4	20.11	Virgin
R-IV (Dishergarh)	4.83	125.57	690.32	1 in 4.6	SC-I	72.60	Worked by Chinakuri Mine No. I with future expansion planned in the South
R-III (Hatnal)	1.16	95.52	790.67	1 in 4.0	G-4	25.42	Virgin
R-II (Sanctoria)	1.34	62.13	853.96	1 in 5.0	SC-1	28.10	Virgin

Exhibit 8: Summary of Chinakuri Mine Coal Seams Represented in Borehole CNK-16

The coal thickness of Seam R-IV varies from 8.7 ft to 18.2 ft (2.64 m to 5.54 m). On the western side of the existing pits the coal thickness is between 9.8 f and 11.5 ft (3 m and 3.5 m), while on the eastern side it ranges between 13.1 ft and 14.8 ft (4 m and 4.5 m). The Strike varies from NE-SW to ENE-WSW and the dip varies from 2.5 degrees to 10 degrees. In part of the Parbelia block the dip increases to 14 degrees. In the past, workings of this seam were primarily restricted to the areas in the north and to the shaft levels. In the south Seam R-IV remains virgin where its depth exceeds 1,968 ft (600 m) and its gradient is approximately 1 in 10 towards the southwest. The grade of the coal is Semi-Coking-I to Semi-Coking-II. The ultimate and proximate analysis results of Seam R-IV are presented below in Exhibit 9 and Exhibit 10, respectively. Mine characteristics and reservoir parameters specific to the Chinakuri Mine No. I are discussed in more detail in the reservoir simulation section (see section 4.3.2 Model Preparation and Runs).

Carbon %	Hydrogen %	Oxygen %	Nitrogen %	Sulphur %
82.7-83.8	5.6-5.7	8.1-9.2	2.12-2.18	0.28-0.31

Exhibit 9: Ultimate Analysis of Seam R-IV Coal

Ash %	Moisture %	Volatiles %	Calorific Value, kcal/kg	Caking Index	Avg. Seam Thickness, m	Seam Gradient, Deg.	Density Volume, g/cc
12.7-15.1	1.0-2.0	35.3-36.2	6790-6955	13	3.2-4.0	8-12	1.32-1.42

Exhibit 10: Proximate Analysis of Seam R-IV Coal

4 Gas Resources

4.1 Overview of Gas Resources

India's CMM emissions were estimated by USEPA (2012) to be 49 billion cubic feet (Bcf) (1,397 Mm^3) in 2015. The latest available (2012) estimate developed by the CSIR-Central Institute of Mining and Fuel Research (CSIR-CIMFR) pegs methane emission from coal mining activities in India at 40 Bcf (1,142 Mm^3), up nearly 40 percent from the 29 Bcf (828 Mm^3) estimated in 1991 (CSIR-CIMFR, 2016). Currently, drainage of CMM in India is limited, and there are no active commercial projects for the recovery and use of CMM in the country (USEPA, 2015). As mentioned previously, coal blocks held by CIL overlap 81 percent of India's potential area exploitable by CBM/CMM, and up until recently, government policy was unclear regarding the simultaneous extraction of methane and coal coproduction. In terms of India's CBM resources from virgin coal seams, estimates vary depending on coal rank, burial depth, and geotectonic settings, with the DGH estimating India's 44 major coal and lignite fields contain 120 trillion cubic feet (Tcf), or 3.4 trillion m^3, of CBM resources (USEPA, 2015).

On a more local level, Seam R-IV at Chinakuri Mine No. I is considered to be highly gassy with specific emission rates estimated to range from 160 standard cubic feet per ton (scf/ton) to 640 scf/ton (5 cubic meters per tonne, m^3/t, to 20 m^3/t) of coal mined (ECL, 2015). Moreover, results of gas desorption tests performed in conjunction with the coring program for a CBM project in the Raniganj coal basin yielded gas contents for Seam R-IV ranging from 27 scf/ton to 412 scf/ton (1.4 m^3/t to 12.9 m^3/t) with an average of 186 scf/ton (5.8 m^3/t). Based on the average Seam R-IV gas content, it is estimated that the virgin portion of the study area holds approximately 11.6 Bcf, or 328 Mm^3, of gas resources.

4.2 Proposed Gas Drainage Approach

The objectives of this pre-feasibility study are to perform an initial assessment of the technical and economic viability of methane pre-drainage utilizing long in-mine horizontal boreholes drilled down-dip into the virgin seam of the southern mine boundary to drain methane in advance of mining, and to utilize the drained gas to generate electricity for on-site consumption. Exhibit 11 is a mine map illustrating the study area for the proposed pre-feasibility study at the Chinakuri Mine No. I. The gas production profiles generated for the horizontal pre-drainage 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.

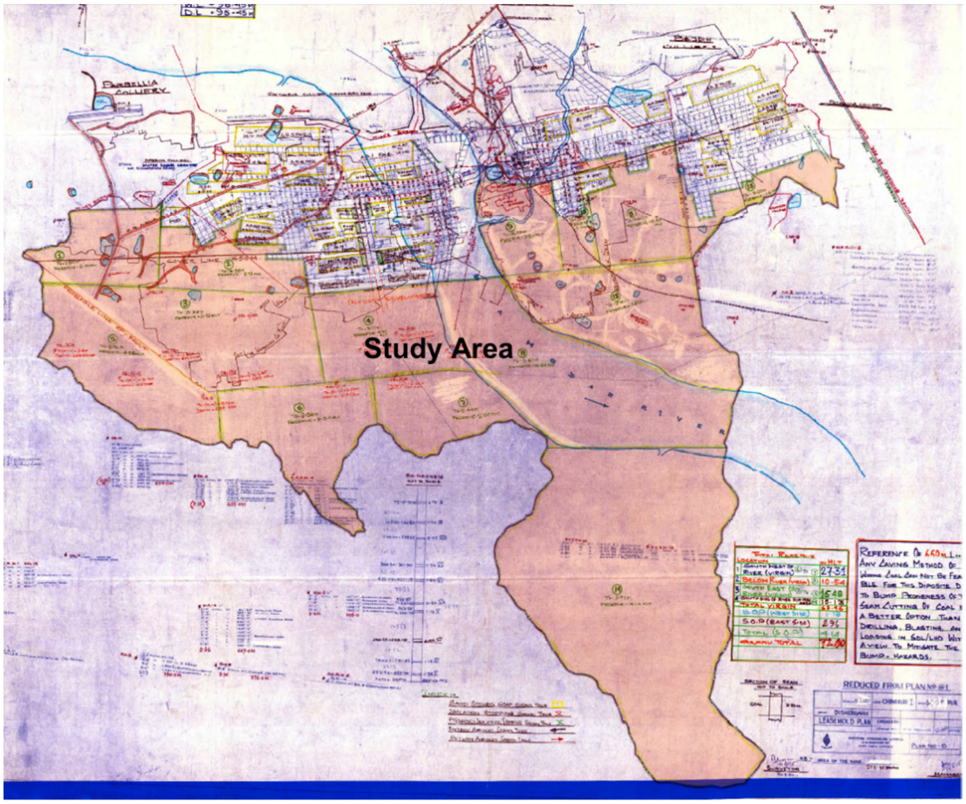

Exhibit 11: Mine Map Illustrating the Chinakuri Mine No. I Study Area

4.3 Estimating Production from In-Mine Horizontal Pre-Drainage Boreholes

Three reservoir models designed to simulate gas production volumes from horizontal pre-drainage boreholes were constructed. The following sections of this report discuss the construction of the gas drainage borehole models, the input parameters used to populate the reservoir simulation models, and the simulation results.

4.3.1 Simulation Model

A total of two single-layer models were constructed in order to calculate gas production for a longwall panel located within the study area. The models were designed to simulate production from long directionally drilled boreholes drilled down-dip into virgin areas from existing mine workings according to three separate well spacing cases: Case 1 utilizes 1 borehole per longwall panel, Case 2 utilizes 2 boreholes per longwall panel spaced 490 ft (150 m) apart, and Case 3 utilizes 3 boreholes per longwall panel spaced 246 ft (75 m) apart. All boreholes are drilled into a coal block with a dip angle of 6 degrees and are assumed to be 4,920 ft (1,500 m) in lateral length. 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 study area.

A typical longwall panel targeting Seam R-IV at the mine is estimated to have a face width of 490 ft (150 m) and a panel length of 4,920 ft (1,500 m) covering an aerial extent of 56 ac (22.5 ha). Based on these dimensions, model grids were created to accommodate each of the well spacing scenarios. The model grid setup consisted of 65 grid-blocks in the x-direction, 43 grid-blocks in the y-direction, and one grid-block in the z-direction; the total area modeled is roughly 145 ac (50 ha). The model area includes the 56 ac (22.5 ha) 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 Exhibit 12.

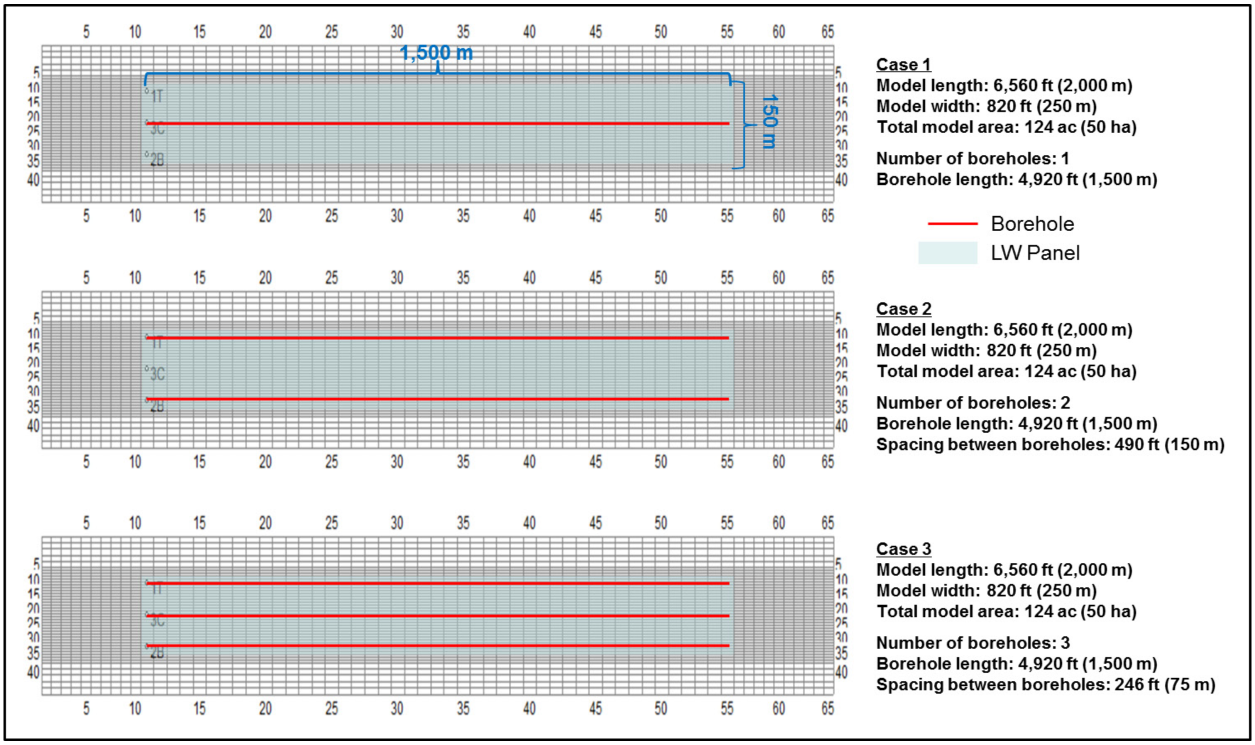

Exhibit 12: Model Layout for In-Seam Horizontal Pre-Drainage Borehole Well Spacing Cases

4.3.2 Model Preparation and Runs

The input data used to populate the reservoir models were obtained primarily from the geologic and reservoir data provided by ECL and the Central Mine Planning Design Institute (CMPDI). Where appropriate, supplemental geological and reservoir data from analogous projects were also used. The input parameters used in the reservoir simulation study are presented in Exhibit 13, followed by a brief discussion of the most important reservoir parameters.

Reservoir Parameter	Value(s)	Source / Notes
Coal Depth (Top), ft	2296	Based on mine data for Seam R-IV
Avg. Coal Thickness, ft	11.0	Based on mine data; Average for Seam R-IV
Coal Density, g/cc	1.37	Based on mine data; Average for Seam R-IV
Pressure Gradient, psi/ft	0.433	Assumption
Initial Reservoir Pressure, psia	997	Calculated from depth and pressure gradient
Initial Water Saturation, %	100	Assumption
Langmuir Volume, scf/ton	393	Analog; Isotherm analysis (Seam R-IV)
Langmuir Pressure, psia	615	Analog; Isotherm analysis (Seam R-IV)
In Situ Gas Content, scf/ton	243	Calculated from reservoir pressure and isotherm
Desorption Pressure, psia	997	Analog; Desorption pressure equal to initial reservoir pressure (fully saturated conditions)
Sorption Times, days	3.06	Analog
Fracture Spacing, in	2.56	Analog
Absolute Cleat Permeability, md	1.26	Analog
Cleat Porosity, %	2.5	Analog
Relative Permeability	Curve	Analog; See Exhibit 15
Pore Volume Compressibility, psi^{-1}	4×10^{-4}	Analog
Matrix Shrinkage Compressibility, psi^{-1}	1×10^{-6}	Analog
Gas Gravity	0.6	Assumption
Water Viscosity, (cP)	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 +3 (formation damage)	
Well Operation	In-mine pipeline with surface vacuum station providing vacuum pressure of 2 psia	
Borehole Placement	Three cases: 1, 2 &3 in-seam horizontal boreholes per panel	

Exhibit 13: Reservoir Parameters for Horizontal Pre-Drainage Borehole Simulation

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 is a critical input parameter for reservoir simulation studies. Absolute permeability data for the coal seams in the study area were not provided. For the current study, permeability values were assumed to be 1.26 millidarcy (md) based on the results of field tests conducted at a nearby property in the Raniganj coal basin.

4.3.2.2 Langmuir Volume and Pressure

Laboratory measured Langmuir volumes and pressures for the study area were not available. However, Langmuir volume and pressure values from isotherm analyses conducted on Seam R-IV in conjunction with a CBM project in the Raniganj coal basin were utilized in the current study. The corresponding Langmuir volume used in the reservoir simulation models for the project area is 393 scf/ton (12.3 m^3/t) and the Langmuir pressure is 615 pounds per square inch absolute (psia) (4,240 kilopascal, KPa). Exhibit 14 depicts the methane isotherm utilized in the horizontal pre-drainage borehole simulations.

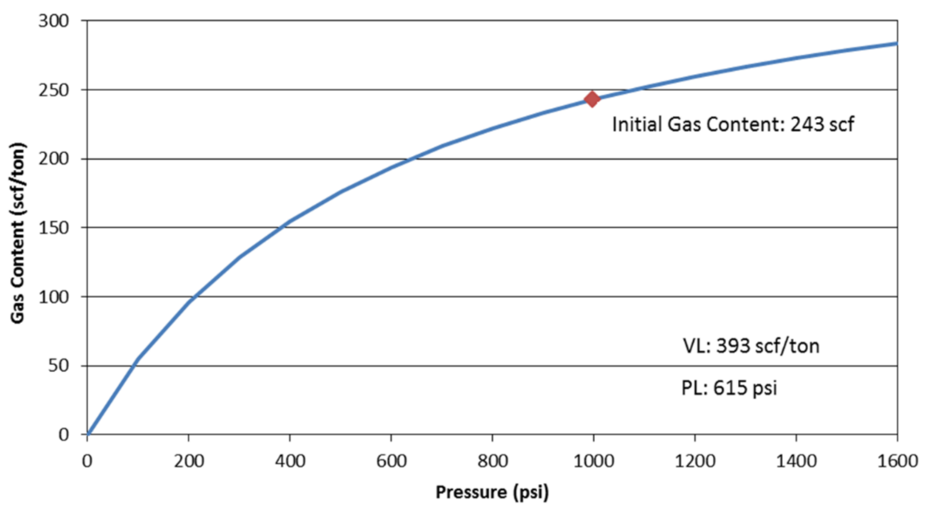

Exhibit 14: Methane Isotherm Used in Horizontal Pre-Drainage Borehole Simulation

4.3.2.3 Gas Content

No gas desorption analyses data were available for Seam R-IV within the study area. Due to the lack of data, coal seams were assumed to be fully saturated with respect to gas. As a result, an initial gas content value of 243 scf/ton (7.6 m^3/t) was used in the simulation study as calculated by the isotherm (Exhibit 14).

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 the results of reservoir simulation history matching performed in association with a CBM project in the Raniganj coal basin. Exhibit 15 is a graph of the relative permeability curves used in the reservoir simulation of the study area.

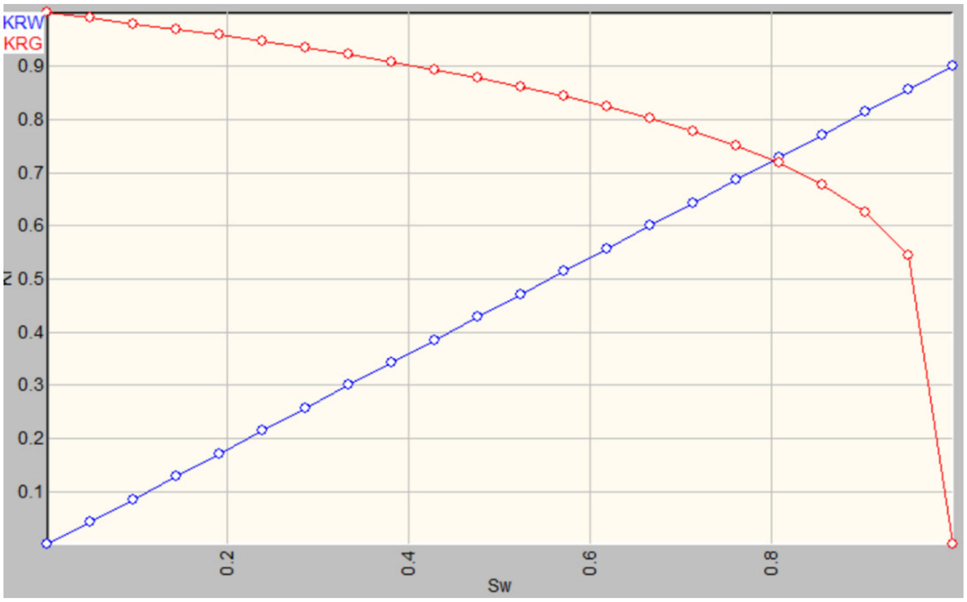

Exhibit 15: Relative Permeability Curve Used in Simulation

4.3.2.5 Coal Seam Depth and Thickness

Based on mine data, Seam R-IV ranges in depth from 1,640 ft to 2,345 ft (500 m to 715 m) with the seam ranging between 8.7 ft and 18.2 ft (2.7 m and 5.5 m) in thickness. For modeling purposes, the depth to the top of the coal reservoir was assumed to be 2,296 ft (700 m), and the coal thickness is taken to be 11.0 ft (3.3 m).

4.3.2.6 Reservoir and Desorption Pressure

Initial reservoir pressure was computed using a hydrostatic pressure gradient of 0.433 psi/ft (9.8 kPa/m) 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 997 psia (6,874 kPa).

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 2.5% 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 from analogous coal in the Raniganj basin.

4.3.2.8 Sorption Time

Sorption time is defined as the length of time required for 63 percent of the gas in a sample to be desorbed. In this study a 3.06 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 2.56 in (65 mm) was assumed in the simulations, which is consistent with data from field tests conducted at a nearby CBM project. In the model, 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 Borehole Spacing

As discussed previously, three borehole spacing cases were modeled: Case 1 utilizes 1 borehole per longwall panel, Case 2 utilizes 2 boreholes per longwall panel spaced 490 ft (150 m) apart, and Case 3 utilizes 3 boreholes per longwall panel spaced 246 ft (75 m) apart.

4.3.2.11 Completion

Long in-seam boreholes with lateral lengths of 4,920 ft (1,500 m) will be drilled into the longwall panel. For modeling purposes, a skin value of 2 is assumed (formation damage).

4.3.2.12 Well Operation

For the current study, an in-mine pipeline with a surface vacuum station providing a vacuum pressure of 2 psi (13.8 kPa) 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 Model Results

As noted previously, three reservoir models were created to simulate gas production for the study area located at the Chinakuri Mine No. I. Each of the models was run for a period of five years and the resulting gas production profiles and reduction in methane of the coal seams were calculated. Simulated gas production rate and cumulative gas production for a typical longwall panel within the study area are shown for Case 1, Case 2, and Case 3 in Exhibit 16, Exhibit 17, and Exhibit 18, respectively.

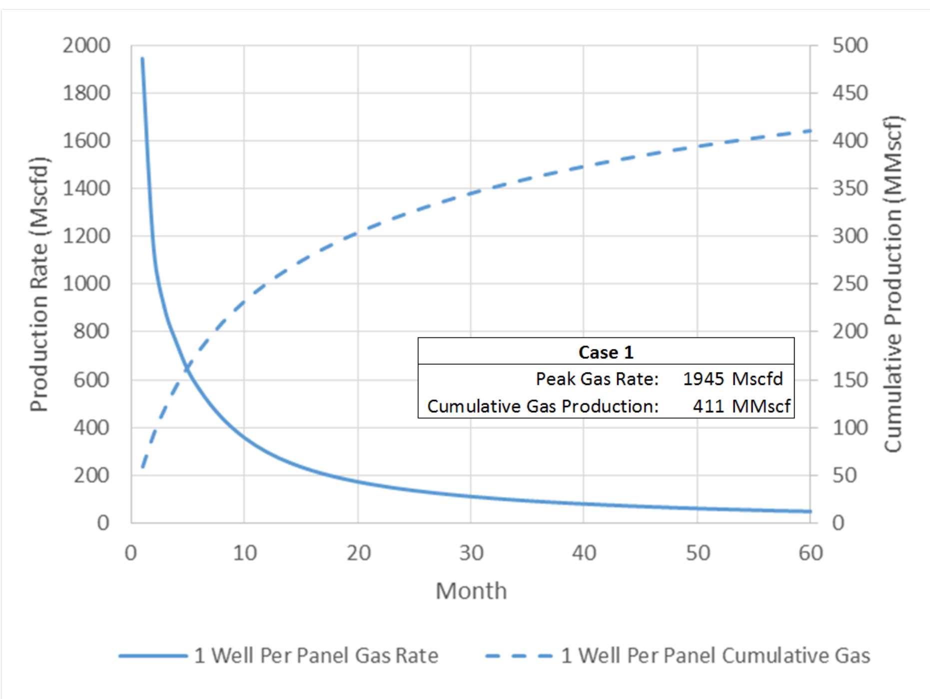

Exhibit 16: Case 1 Gas Rate and Cumulative Production

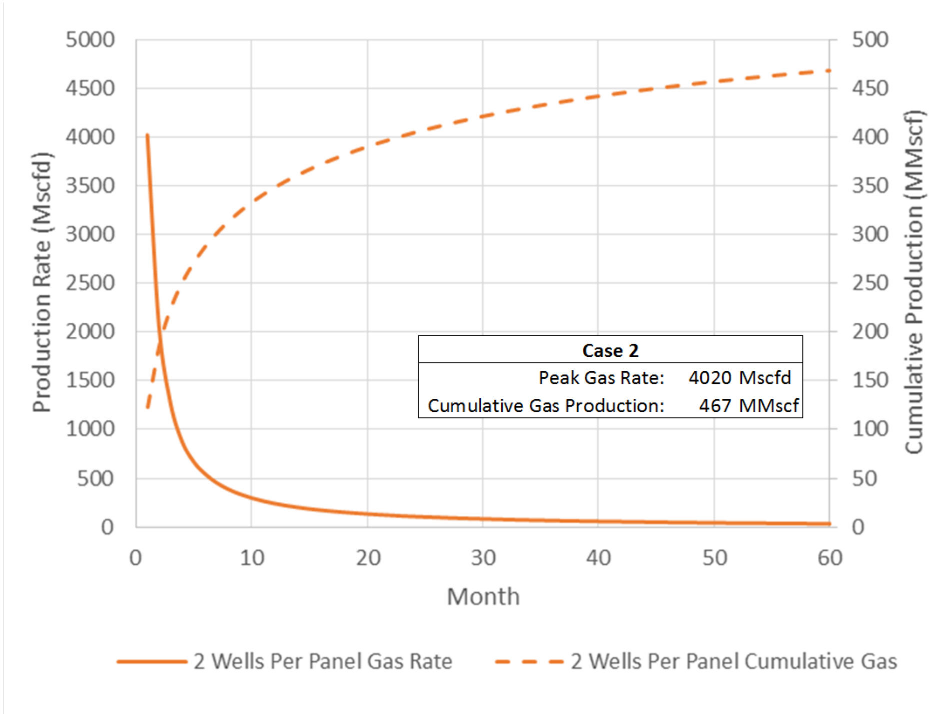

Exhibit 17: Case 2 Gas Rate and Cumulative Production

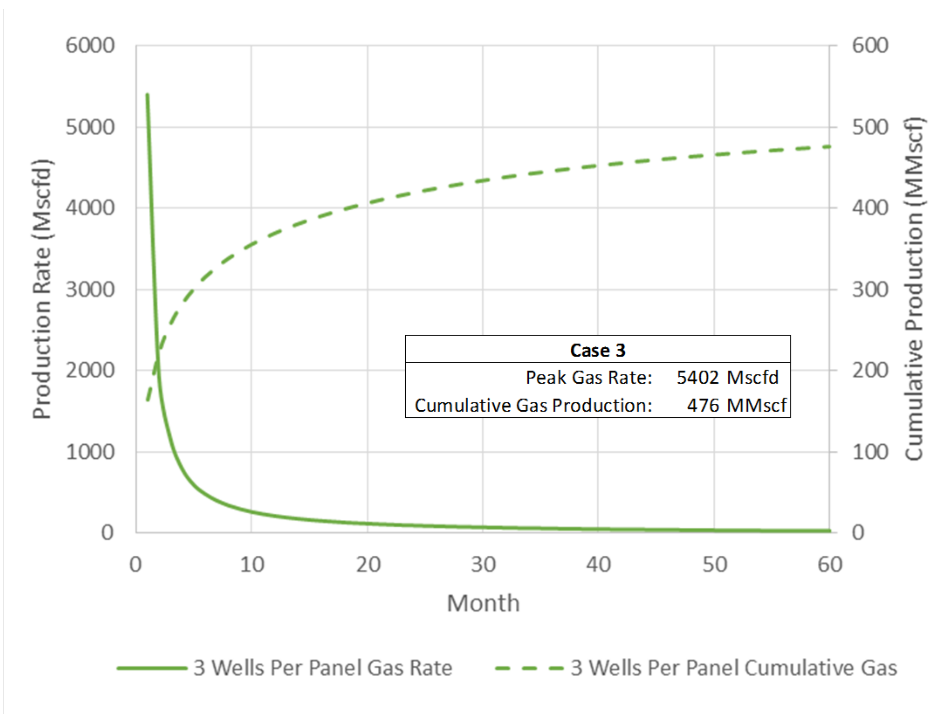

Exhibit 18: Case 3 Gas Rate and Cumulative Production

One of the benefits of pre-drainage is the reduction of methane content in the coal seams prior to mining. Exhibit 19, Exhibit 20, and Exhibit 21 show the simulated reduction in in-situ gas content in Case 1, Case 2, and Case 3, respectively, over time utilizing horizontal pre-drainage boreholes. Exhibit 22 compares the reductions in in-situ gas content over time by the borehole spacing case.

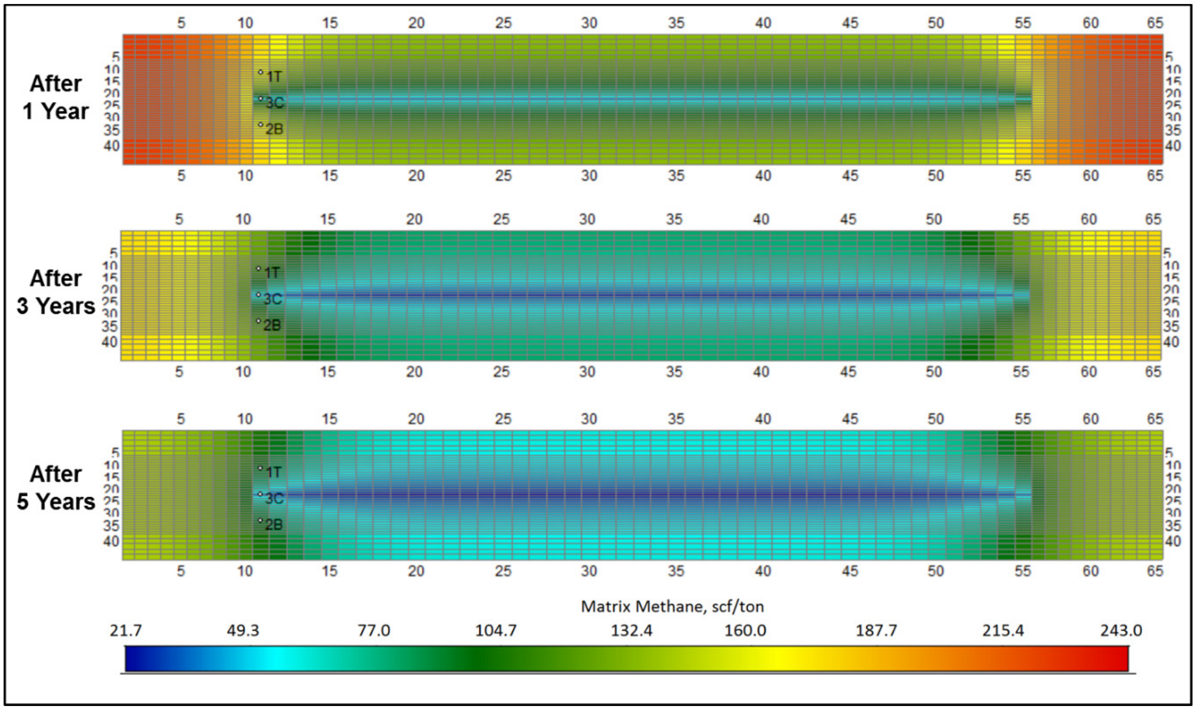

Exhibit 19: Reduction in In-Situ Gas Content Over Time for Case 1

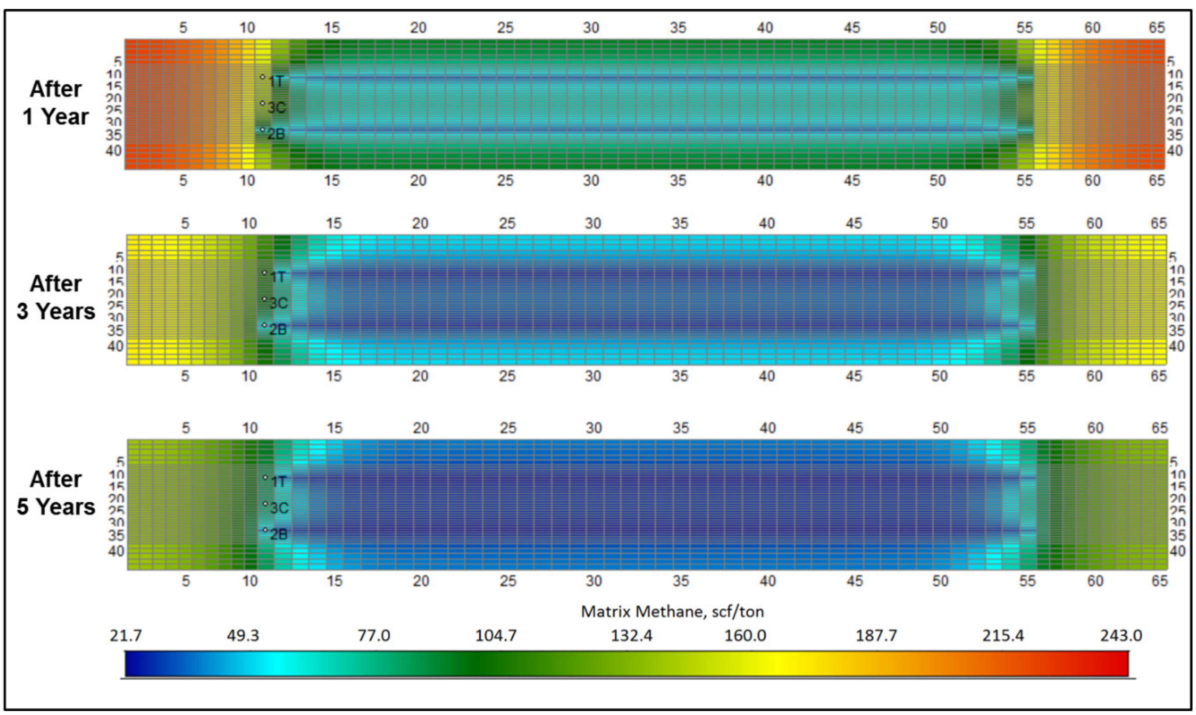

Exhibit 20: Reduction in In-Situ Gas Content Over Time for Case 2

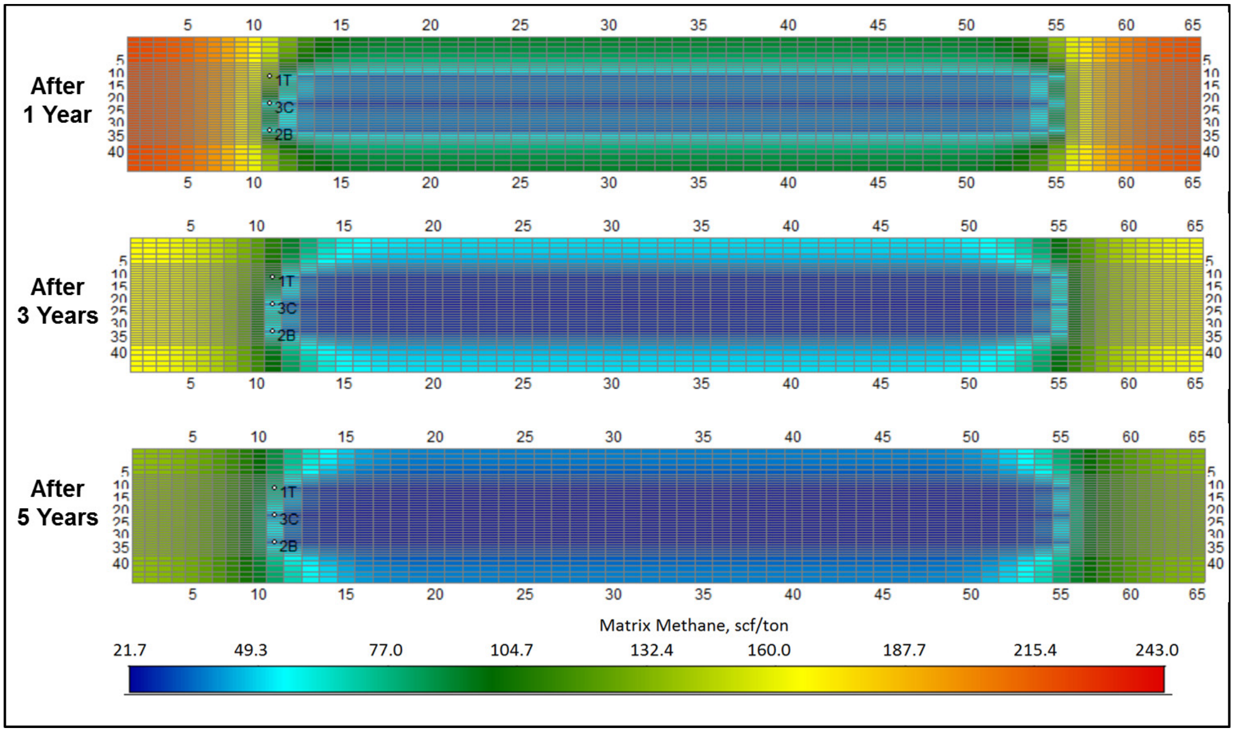

Exhibit 21: Reduction in In-Situ Gas Content Over Time for Case 3

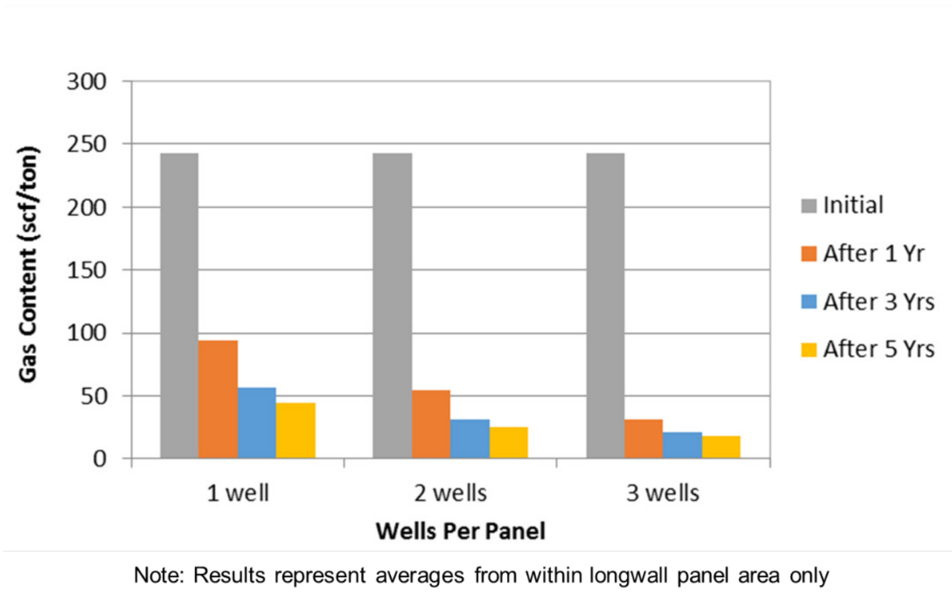

Exhibit 22: Comparison of Reduction in In-Situ Gas Content Over Time by Borehole Spacing Case

5 Market Information

Presently there are no commercial-scale CMM projects in India, but the development of CMM is high on the agenda of the Indian coal mining industry. In order to support the growing energy requirements of the country, the coal mining industry in India is shifting from opencast to underground mining techniques. However, due to safety concerns related to methane, increased production from underground mines cannot be realized without the application of proper methane drainage and handling. If captured and utilized properly, methane recovered from existing coal mines will help to satisfy the demand for energy in the region while improving the local environment through the reduction of greenhouse gas (GHG) emissions.

India began awarding CBM blocks for exploration in 2001, and after more than a decade production is beginning to come online. According to the DGH, West Bengal has significant potential for CBM production with 7.7 Tcf (218 Gm^3) of CBM resources, or 8 percent of India's total CBM resources, located within the state. The Raniganj block in West Bengal has been developed and has an estimated gas potential of 1 Tcf (28 Gm^3). Total CBM production from India in 2014 amounted to about 7.4 Bcf (209 Mm^3) (EIA, 2016).

The Central Institute of Mining and Fuel Research (CIMFR) estimates demand for natural gas in India has been increasing by 6.8 percent per year over the last decade, and natural gas consumption has increased annually by approximately 6 percent from 2000 to 2014 (EIA, 2016). Coal production in India is also struggling to keep up with the rapidly growing coal demand causing power shortages and blackouts throughout the country. As a result, natural gas has been primarily used as a supplement to coal. As a cleaner and more efficient fuel than coal, natural gas is finding application in the power, transport, fertilizer, chemicals, and petrochemical industries. The majority of natural gas demand in 2014 came from the power sector (23%), the fertilizer industry (32%), and the replacement of LPG for cooking oil and other uses in the residential sector (14%) (EIA, 2016).

West Bengal State's gross state domestic product (GSDP) expanded at a compound annual growth rate (CAGR) of 11 percent from 2004-05 to 2014-15, and now represents India's 6th largest state economy with a current GSDP of US$ 133 billion (IBEF, 2015). The services sector is responsible for 65 percent of West Bengal's economic output with the primary and secondary sectors contributing 19 and 16 percent each, respectively (WBIC, 2015). The state's favorable location gives it a market advantage and it is a traditional market for eastern India, northeast India, Nepal, and Bhutan. It is located near the mineral rich states of Jharkhand, Bihar, and Odisha. It is also a strategic entry point to the markets in Southeast Asia. Most importantly West Bengal State offers great connectivity to the rest of India through a developed network of railways, roadways, sea ports, and airports (IBEF, 2015).

The proposed CMM project at Chinakuri Mine No. I is located in the Burdwan district of West Bengal state, about 7.5 mi (12 km) from Astanal. West Bengal State is the 13th largest state in India in terms of area, ranks 4th in terms of population, and ranks 1st in population density (CII, 2015). West Bengal State is 68 percent rural and 32 percent urban (COI, 2011). The state's largest industrial centers are Astanal, Kolkata, and Durgapur. A number of industries such as power, iron and steel, aluminum, fertilizer, and cement are concentrated in this region due to its proximity to large deposits of coal, iron, copper, bauxite, and other minerals. This region is also one of the most densely populated areas of the state.

Previous CMM feasibility studies conducted on mines using similar drainage approaches indicate that the primary utilization options for the drained gas from Chinakuri Mine No. I include flaring, boiler use, onsite electricity generation, and pipeline sales. Given the local and regional CMM market, onsite electricity generation appears to be the most practical utilization option. At this time, sales to natural gas pipelines or use as vehicle fuel (e.g., compressed natural gas) are neither technically nor economically viable. With respect to electricity markets, ECL's average purchase price for electricity was $0.1070/kWh, according to the most recent data available (2015-16). There is a strong case to use the incremental gas production for power generation at the Chinakuri Mine No. I.

6 Opportunities for Gas Use

Pre-drainage boreholes are the preferred recovery method for producing high-quality methane gas from coal seams because the recovered methane is not contaminated with ventilation air from the working areas of the mine (USEPA, 2013). Drained methane can be used to fire internal combustion engines that drive generators to make electricity for sale to the local power grid. The quality of methane required for use in power generation can be less than that required for pipeline injection. Internal combustion engine generators can generate electricity using gas that has heat content as low as 300 Btu/cf or about 30 percent methane. Mines can use electricity generated from recovered methane to meet their own on-site electricity requirements and can also sell electricity generated in excess of on-site needs to utilities. Coal mining is a very energy-intensive industry that could realize significant cost savings by generating its own power. Nearly all equipment used in underground mining runs on electricity, including mining machines, conveyor belts, ventilation fans, and elevators. Drained methane can also be used as a transportation fuel, as a petrochemical and fertilizer feedstock, as fuel for energy/heating requirements in industrial applications, and for on-site boilers that provide hot water or space heating to mine facilities (USEPA, 2013).

As noted in the Market Information section, the primary market available for a CMM utilization project at the Chinakuri Mine No. I is power generation using internal combustion engines. 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. Furthermore, ECL has indicated the mine currently does not have use for process heat, and the preferred use of drained gas is for power generation for the mine or for grid sales. Based on gas supply forecasts, the mine could be capable of operating as much as 4.4 MW of electricity capacity.

Generating electricity on site is attractive, because the input CMM gas stream can be utilized as is, with minimal processing and transportation, and additional generating sets can be installed relatively cheaply to accommodate increasing gas production as necessary. Coal mines are major power consumers with substations and transmission lines near large mining operations and accessible to CMM-based power projects.

7 Economic Analysis

7.1 Project Development Scenario

In order to assess the economic viability of the degasification options presented throughout this report, it is necessary to define the project scope and development schedule. The proposed pre-drainage project at Mine No. I, which utilizes long, in-seam boreholes to drain gas ahead of mining, focuses on the virgin portion of Seam R-IV at depths greater than approximately 2,300 ft (700 m). CMM gas production profiles were generated for a total of six project development scenarios as highlighted in Exhibit 23. The development scenarios were designed to evaluate the optimum number of pre-drainage boreholes to drill in each panel (i.e., 1, 2, or 3 wells per panel). In addition, the effect of pre-drainage duration (i.e., 1 year or 3 years of pre-drainage) and the resulting reduction in methane content of the coal seams was also assessed.

Scenario	Wells Per Panel	Years of Pre-Drainage
1	1	1
2	2	1
3	3	1
4	1	3
5	2	3
6	3	3

Exhibit 23: Summary of Project Development Scenarios

Based on the mine map provided by ECL, the total project area encompasses 4,250 ac (17 sq. km). Under all six development scenarios it is assumed a total of 16 longwall panels, each measuring 4,920 ft (1,500 m) in length by 490 ft (150 m) in width, will be developed within the project area. Assuming a longwall face advance rate of 13.5 ft per day (4 m/d), each longwall panel will take approximately one year to mine. With one year of pre-drainage at each longwall panel, degasification and mining of the 16 longwall panels will be completed over a project life of 17 years, while utilizing three years of pre-drainage at each longwall panel will result in a 19 year project life (assuming only one active longwall face at a time). The development of 16 longwall panels will require a total of 16 to 48 boreholes depending on the development scenario selected.

7.2 Gas Production Forecast

Gas production forecasts were developed using the simulation results and the development scenarios discussed above. The CMM production forecasts for Scenarios 1, 2, and 3 (one year of pre-drainage) are shown in Exhibit 24, and the production profiles for Scenarios 4, 5, and 6 (three years of pre-drainage) are presented in Exhibit 25.

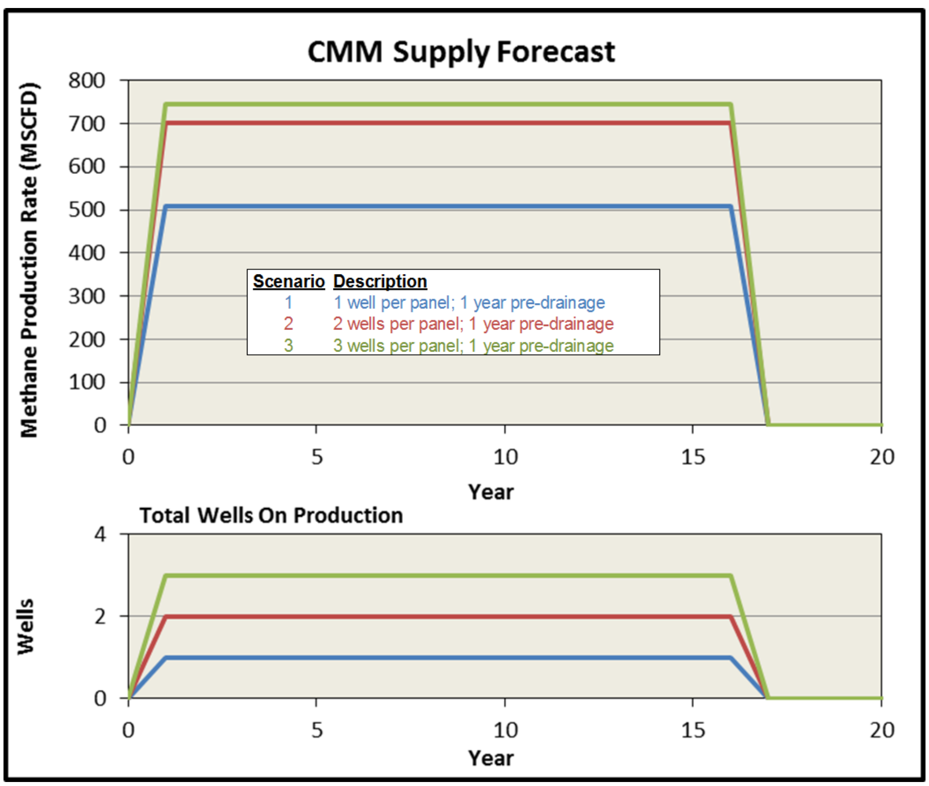

Exhibit 24: CMM Production Forecast for One Year of Pre-Drainage

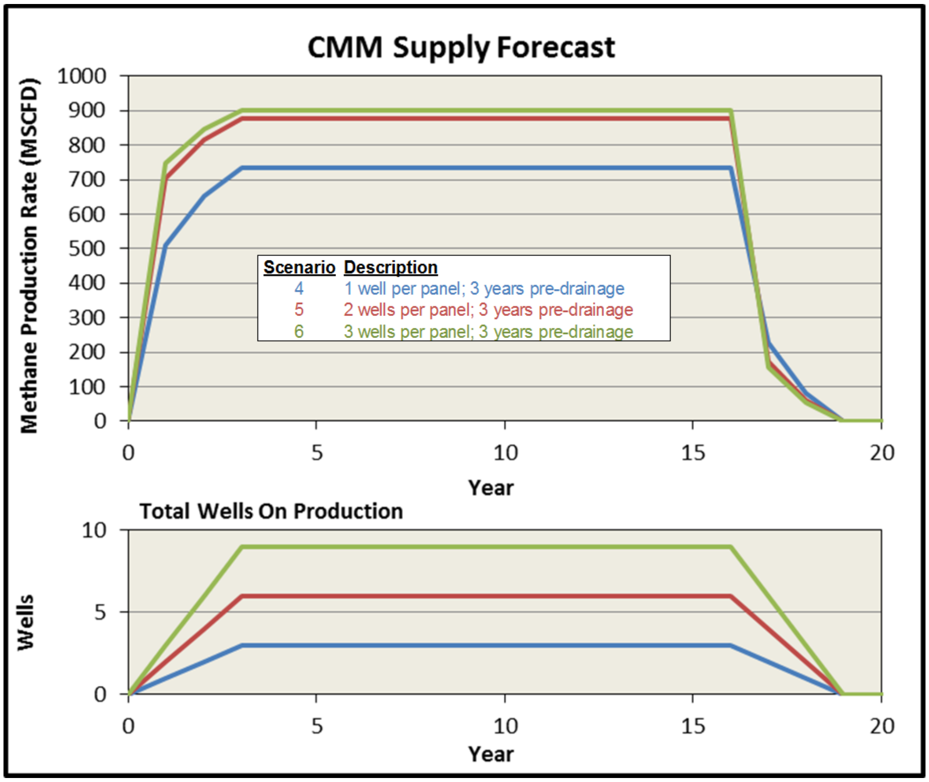

Exhibit 25: CMM Production Forecast for Three Years of Pre-Drainage

7.3 Project Economics

7.3.1 Economic Assessment Methodology

For each of the proposed six 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). 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 segment to calculate the fuel cost for the power plant. Likewise, a breakeven electricity price was calculated for the downstream segment, which can be compared to the current price of electricity observed at the mine in order to determine the economic feasibility of each potential development case. The results of the analyses are presented on a pre-tax basis.

7.3.2 Upstream (CMM Project) Economic Assumptions and Results

Cost estimates for goods and services required for the development of the CMM project at Chinakuri Mine No. I were based primarily on costs of analogous projects in the region and the U.S. A more detailed analysis should be conducted if this project advances to the full-scale feasibility study level. The capital cost assumptions, operating cost assumptions, and physical and financial factors used in the evaluation of upstream economics are provided in Exhibit 26.

Physical & Financial Factors	Units	Value
Royalty/PLP	%	10%
Price Escalation	%	3.0%
Cost Escalation	%	3.0%
Calorific Value of Drained Gas	Btu/cf	928
Capital Expenditures	**Units**	**Value**
Drainage System		
Well Cost	$/well	175,000
Surface Vacuum Station	$/hp	1,000
Vacuum Pump Efficiency	hp/mcfd	0.035
Gathering & Delivery System		
Gathering Pipe Cost	$/ft	40
Gathering Pipe Length	ft/well	135
Satellite Compressor Cost	$/hp	1,000
Compressor Efficiency	hp/mcfd	0.035
Pipeline Cost	$/ft	55
Pipeline Length	ft	10,560
Operating Expenses	**Units**	**Value**
Field Fuel Use (gas)	%	10%
O&M	$/mcf	0.10

Exhibit 26: Summary of Input Parameters for the Evaluation of Upstream Economics (CMM Project)

The economic results for the CMM pre-drainage project are summarized in Exhibit 27. Based on the forecasted gas production, the breakeven cost of producing CMM through pre-drainage boreholes is estimated to be between \$1.04 and \$2.30/MMBtu (\$34 and \$75/1000m^3). This compares favorably to the domestic natural gas price set by the government, which is currently \$4.24/MMBtu (\$139/1000m^3). The results of the economic assessment indicate the lowest CMM production costs are associated with the one borehole per panel cases, with 3 years of pre-drainage (Scenario 4) preferred over one year (Scenario 1).

Scenario	Wells per Panel	Years of Pre-Drainage	Breakeven Gas Price $/MMBtu
1	1	1	1.41
2	2	1	1.74
3	3	1	2.30
4	1	3	1.04
5	2	3	1.45
6	3	3	1.95

Exhibit 27: Breakeven Gas Price

7.3.3 Downstream (Power Project) Economic Assumptions and Results

The drained methane can be used to fuel internal combustion engines that drive generators to make electricity for use at the mine. 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 Exhibit 28.

Physical & Financial Factors	**Units**	**Value**
Generator Efficiency	%	35
Run Time	%	90
Capital Expenditures	**Units**	**Value**
Power Plant	$/kW	1,300
Operating Expenses	**Units**	**Value**
Power Plant O&M	$/kWh	0.02

Exhibit 28: Summary of Input Parameters for the Evaluation of Downstream Economics (Power Project)

The economic results for the power project are summarized in Exhibit 29. The breakeven power sales price, inclusive of the cost of methane drainage, is estimated to be between $0.0478 and $0.0596/kWh. The results of the economic assessment indicate the lowest power price is associated with the one borehole per panel case with three years of pre-drainage (Scenario 4). According to the most recent data available (2015-16), ECL's average purchase price for electricity was $0.1070/kWh. When compared to the breakeven power sales price for Scenario 4 of $0.0478/kWh, utilizing drained methane to produce electricity would generate profits of more than $59 per MWh of electricity produced.

Scenario	Wells per Panel	Years of Pre-Drainage	Breakeven Power Price $/kWh
1	1	1	0.0509
2	2	1	0.0542
3	3	1	0.0596
4	1	3	0.0478
5	2	3	0.0516
6	3	3	0.0565

Exhibit 29: Breakeven Power Price

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 Chinakuri Mine No. I. The project as proposed will use long in-mine horizontal boreholes drilled down-dip into the virgin seam of the southern mine boundary to drain methane in advance of mining, and to utilize the drained gas to generate electricity for on-site consumption. The analysis performed reveals that methane drainage using long in-mine horizontal boreholes is feasible, and could provide the mine with additional benefits beyond the sale of gas or power, such as improved mine safety and enhanced productivity.

Scenario	Description	Max Power Plant Capacity (MW)	Fuel Cost ($/MMBtu)	Breakeven Power Price ($/kWh)	Net CO_2e Reductions (tCO_2e/yr)
1	1 in-seam horizontal borehole per panel with 1 year of pre-drainage	2.5	1.41	0.0509	61,000
2	2 in-seam horizontal boreholes per panel with 1 year of pre-drainage	3.4	1.74	0.0542	85,000
3	3 in-seam horizontal boreholes per panel with 1 year of pre-drainage	3.6	2.30	0.0596	90,000
4	1 in-seam horizontal borehole per panel with 3 years of pre-drainage	3.6	1.04	0.0478	79,000
5	2 in-seam horizontal boreholes per panel with 3 years of pre-drainage	4.2	1.45	0.0516	95,000
6	3 in-seam horizontal boreholes per panel with 3 years of pre-drainage	4.4	1.95	0.0565	97,000

Exhibit 30: Summary of Economic Results

Based on the forecasted gas production, the breakeven cost of producing CMM through in-seam drainage boreholes is estimated to be between $1.04 and $2.30/MMBtu ($34 and $75/1000m^3). This compares favorably to the domestic natural gas price set by the government, which is currently $4.24/MMBtu ($139/1000m^3). As summarized in Exhibit 30, the results of the economic assessment indicate the lowest CMM production costs are associated with the one borehole per panel cases, with 3 years of pre-drainage (Scenario 4) preferred over one year (Scenario 1).

In terms of utilization, electricity generation by means of internal combustion engines is economically feasible. However, in order to optimize the utilization of drained methane from the project, more rigorous engineering design and costing would be needed before the final selection of gas generator sets is made. The breakeven power price is estimated to be between $0.0478 and $0.0596/kWh. As summarized in Exhibit 30, the results of the economic assessment indicate the lowest power price is associated with the one borehole per panel case with three years of pre-drainage (Scenario 4). According to the most recent data available (2015-16), ECL's average purchase price for electricity was $0.1070/kWh. When compared to the breakeven power sales price for Scenario 4 of $0.0478/kWh, utilizing drained methane to produce electricity would generate profits of more than $59 per MWh of electricity produced.

While the power production option is currently economically feasible, removing the cost of mine degasification from downstream economics, as a sunk cost, would reduce the marginal cost of electricity and improve the economics even further. In addition, net emission reductions associated with the destruction of drained methane are estimated to average just under 80,000 tonnes of carbon dioxide equivalent (tCO_2e) per year over the life of the project for the optimal development scenario.

The results of this high-level review of gas availability, end-use options, and emission reduction potential demonstrate the proposed CMM project at the Chinakuri Mine No. I is both technically and economically feasible, and ECL is encouraged to pursue a full-scale feasibility study to advance the project concept towards commercial operation. Based on the pre-feasibility study results, the future development and implementation of this project has the potential to lower ECL's electricity costs, unlock over 68 Mt of coal reserves, and improve mine safety. Lastly, ECL's advancement of this project would be in synergy with the government's overarching policy goals to:

- **Reduce GHG Emissions**: India stands committed to the global efforts to fight climate change, and as part of the agreement reached at the Paris Climate Summit, the country has pledged to reduce the emissions intensity of its GDP by 33 to 35 percent by 2030 from 2005 level. While India is looking to increase the use of renewable energy sources, the dominance of fossil fuels, in particular coal, will continue in the near future. The drainage, capture, and utilization of CMM that would otherwise be emitted to the atmosphere, however, will minimize the associated environmental impacts of coal mining.

- **Reduce Coal Imports**: Recent regulatory reforms are focused on increasing domestic coal production to reduce imports and promote energy security. In 2015, India announced an aggressive coal production target of 1.5 billion tons by 2020. In addition, in June 2016 the Ministry of Coal called for all government owned and operated thermal power producers to halt all coal imports and source coal feedstocks from CIL. However, much of the domestic coal resource is gaseous and considered safe to mine only after pre-drainage of methane.

- **Increase Domestic Natural Gas Production**: The government has a goal to reduce India's import dependence by at least 10 percent by 2020 (PTI, 2016). Development of natural gas from coal seams (CBM or CMM) is a priority for both government and industry. To boost domestic natural gas production, the Petroleum Ministry is initiating policy changes designed to increase natural gas production from CBM blocks to 353 MMcfd (10 Mm^3/d) by 2017-18 (Saikia, 2015). With 81 percent of the country's prospective CBM area currently overlapped by coal mining areas held by CIL, projects that simultaneously extract methane and coal could help CIL unlock up to 100 million tons of medium grade coking coal and 1 Tcf of gas (PTI, 2013).

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