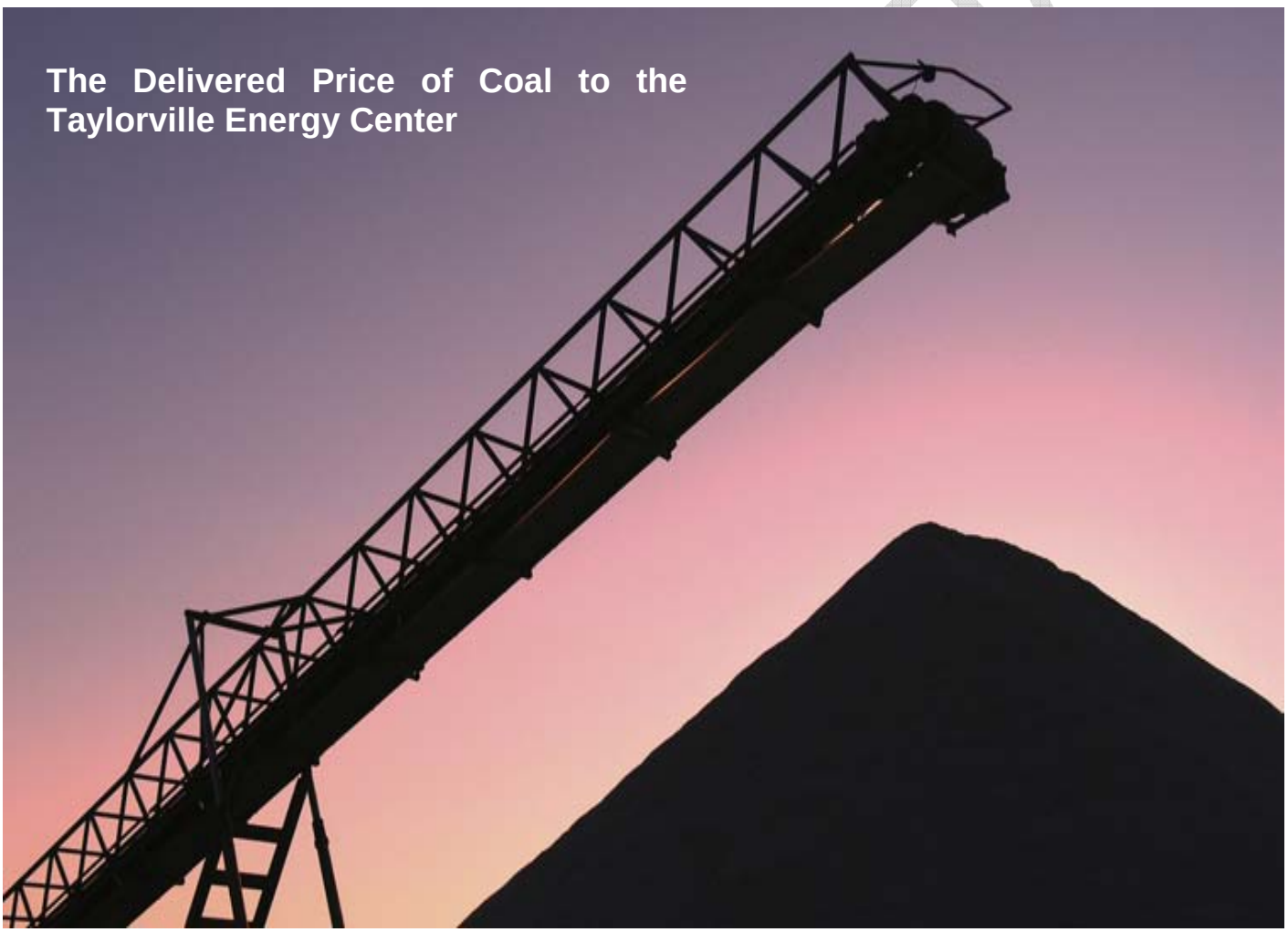
Exhibit 6.0

Wood Mackenzie Study
The Delivered Price of Coal to the Taylorville Energy Center



The Delivered Price of Coal to the Taylorville Energy Center

October, 2009

Wood Mackenzie

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Executive Summary

Wood Mackenzie has been retained by Tenaska Taylorville, LLC to forecast the delivered price of coal, inclusive of the Illinois Fuel Use Tax, at the Taylorville Energy Center (TEC), a planned integrated gasification combined cycle facility about two miles northeast of Taylorville, Christian County, Illinois. The forecast was developed using proprietary modelling software after careful identification of and adjustment for the quality characteristics of individual Illinois coals and the mode or modes of coal transportation from coal source to the TEC. The final forecast was represented in both 2009$/st and 2009$/mmBtu terms.

The TEC facility is required to consume, pursuant to requirements provided in Illinois Senate Bill 1987 (SB 1987), coal mined in Illinois. Depending on the energy content of the coal selected for use, TEC will use between 2.1 and 2.4 Mst of coal per year.

U.S. power generators are adding environmental equipment to coal plants in response to increasingly stringent emission regulation and the use of this new equipment is having the effect of increasing demand for the higher sulfur Illinois coal. The abundant, accessible and easily mineable Illinois coal supply is expanding to meet this increased demand. No shortage of Illinois coal is expected over the forecast period from 2015 through 2045. With no looming supply shortage, there is little upward pressure on coal price beyond that normally associated with the cost of mining.

There is variability in both the cost of mining and the quality of coal across Illinois owing to differences in geology and geography. Coal sources near TEC have transportation cost advantages but suffer from quality disadvantages to mines more distant to TEC. Generally, the quality advantage enjoyed by mines distant to TEC is outweighed by the transportation advantage of mines near TEC.

While it is possible to determine the expected least cost source of coal to TEC from all the sources available to the plant over time, reason and prudence dictate that forecasting a delivered price at TEC should be done by basing the forecast upon the average delivered price of a group of coal sources. The forecast delivered price at TEC is defined as the lowest average delivered price at TEC from one of six subdivisions that represent geographical mining areas of the Sate of Illinois. The least cost coal, fully evaluated for energy content, sulfur and transportation, is derived from Subdivision 3 (West-Central Illinois). Mining Subdivision 3 (West-Central Illinois) is the mining region geographically closest to TEC wherein transportation costs from mine to TEC will be lower than from other regions. Our forecast of the delivered price at TEC, inclusive of the Illinois Fuel Use Tax, is shown in Exhibit 1.

Exhibit 1 – Delivered Price Forecast of Coal to TEC, 2009 $

Year	FOB Mine Price, $/st	Transportation & Handling, $/st	Delivered Price, $/st	Delivered Price, $/mmBtu	Year	FOB Mine Price, $/st	Transportation & Handling, $/st	Delivered Price, $/st	Delivered Price, $/mmBtu
2015	41.38	4.50	45.88	2.20	2031	46.64	4.45	51.09	2.38
2016	41.95	4.49	46.44	2.23	2032	47.02	4.44	51.46	2.40
2017	42.01	4.41	46.42	2.22	2033	46.77	4.46	51.24	2.39
2018	41.68	3.62	45.31	2.15	2034	46.96	4.46	51.43	2.39
2019	41.39	3.55	44.95	2.14	2035	47.17	4.43	51.59	2.40
2020	42.08	3.66	45.74	2.15	2036	47.04	4.36	51.41	2.38
2021	42.41	3.75	46.16	2.16	2037	46.73	4.39	51.12	2.37
2022	42.92	3.65	46.58	2.18	2038	47.00	4.42	51.42	2.38
2023	42.02	3.59	45.61	2.14	2039	47.65	4.45	52.10	2.41
2024	42.17	3.53	45.70	2.15	2040	47.44	4.51	51.95	2.40
2025	41.39	3.52	44.91	2.11	2041	47.72	5.03	52.75	2.43
2026	41.48	3.57	45.06	2.12	2042	47.80	5.23	53.03	2.44
2027	42.92	3.66	46.57	2.19	2043	47.39	5.27	52.66	2.42
2028	43.09	3.71	46.80	2.20	2044	47.54	5.31	52.86	2.43
2029	43.19	3.74	46.93	2.21	2045	47.53	6.03	53.56	2.47
2030	45.18	4.12	49.31	2.31					

Source: Wood Mackenzie

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Introduction

Project Definition and Overview

Tenaska Taylorville, LLC is developing an integrated gasification combined cycle facility about two miles northeast of Taylorville, Christian County, Illinois. The SNG Island will produce pipeline quality substitute natural gas (SNG) that will be used to fuel a conventional, nominal 730 MW (gross), combined cycle power block. The facility is owned by Christian County Generation, L.L.C. and is located on about 886 acres of land allowing sufficient space for significant coal storage and efficient coal delivery and handling mechanisms (Taylorville Energy Center Web Site: 24 July 2009.) The facility is known as the Taylorville Energy Center (TEC).

Coal for the TEC gasifiers will be supplied from within Illinois pursuant to requirements provided in Illinois Senate Bill 1987 (SB 1987) which was designed to support the development of environmentally sound facilities while simultaneously providing electricity consumers with rate protection. Thus, the facility envisions capture of 50% minimum of CO_2 plant emissions thereby qualifying as a source of long-term cost-based electricity to Illinois utilities and alternative retail electricity suppliers.

Four-year construction and eight-month shake-out periods imply a possible commercial operations start date of late 2014 or early 2015.

It is expected that TEC coal supply will come from either the Illinois Herrin #6 or Springfield #5 coal seams located in Illinois. Coal volume delivered annually will be dependent on many factors; including the energy content of the particular coal(s) used to supply the plant but will range generally from 2.1 to 2.4 million short tons per annum (Mstpa).

Specifications of coal used by the plant are shown in Exhibit 2.

Exhibit 2 – Coal Specifications for Use at TEC

Quality	Measurement	Specification
Heating Value	Minimum, as received	10,450 Btu/Lb
Sulfur	Minimum, as received	1.7 LbS / mmBtu
Sulfur	Maximum, as received	6.78 $LbSO_2$ / mmBtu
Ash	Maximum, as received	17% by weight
Moisture	Maximum, as received	17% by weight
Chlorine	Maximum, dry	0.35 % by weight in ash
Grindability	Minimum, as received	45

Source: Tenaska Taylorville, LLC

Scope of Work

Wood Mackenzie was engaged as a third party fuel consultant to identify and characterize available Illinois coals suitable for use at TEC and to forecast the delivered price of coal over the 30-year period of 2015 through 2045. Specifically, Wood Mackenzie was selected to:

- Identify quality characteristics (energy, sulfur, ash and chlorine content) of coal available in Illinois, with emphasis on Subdivision 3 (West Central Illinois), Subdivision 5 (Southwestern Illinois) and Subdivision 6 (Southeastern Ilinois).(Keystone 2007:568);
- Estimate the annual average coal price, in 2009 constant US dollars per short ton ($/st) free on board (FOB) mine, available in each of the above regions for the years 2015 through 2045;
- Identify the mode or modes of coal transportation from each of the above three regions to the TEC;
- Estimate the average annual cost of coal transportation, including applicable fuel adjustment charges and the cost of equipment, from each of the above regions for the years 2015 through 2045, expressed in 2009 constant $/st;
- Estimate the annual average Illinois Fuel Use Tax on coal from each of the above regions for the years 2015 through 2045 in 2009 constant dollars;
- Estimate the average annual delivered coal cost in 2009 constant $/st and in 2009 constant US dollars per million Btu ($/mmBtu) from each of the above regions for the years 2015 through 2045;
- Provide a comprehensive electronic and written (six copies) report.

All forecast work was developed to be reflective of, and fully integrated with, the Wood Mackenzie forecast view for all energy industry fuels, including natural gas and oil. FOB mine prices, transportation costs and delivered prices were forecasted using a combination of PRISM™ (our integrated linear programming model that optimizes fuel choices and emissions control

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under various supply, environmental, and transportation constraints) and various proprietary algorithms and aggregation methodologies. In this manner, the least cost delivered fuel solution at the TEC facility was determined.

A full description of the forecasting methodology can be found later in this report.

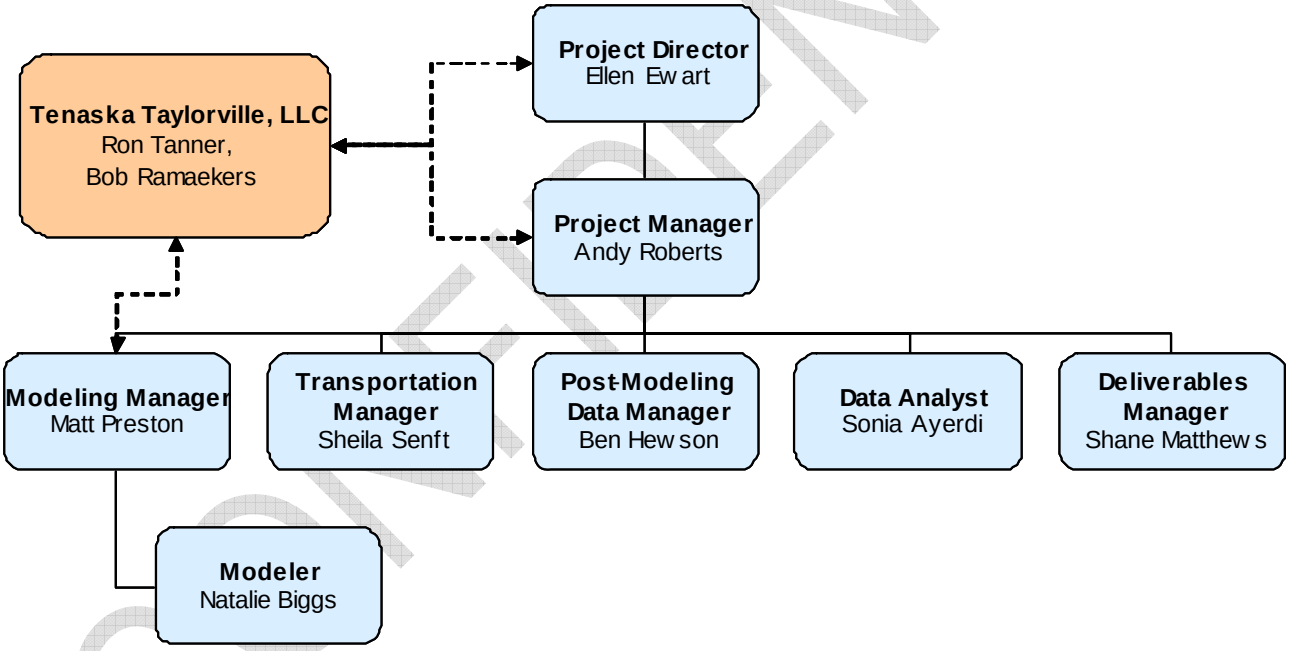
Wood Mackenzie

Wood Mackenzie is well known throughout the energy industry for detailed understanding of the key issues that affect the energy business (for both companies and shareholders) and the assets that underpin the performance of companies. Our competence ranges from the mine to the energy consumer. We also have expert regional researchers and consultants who are in regular touch with the key decision makers in every important energy producing and consuming region and through detailed analysis understand the issues that they face. Further information about Wood Mackenzie can be found in Appendix B.

Project Team

A project team was assembled and assigned to work on the deliverables of the project. Each project team member was responsible for understanding the work to be completed, planning assigned activities in detail, completing assigned work within the agreed-upon budget, timeline, and quality expectations, informing the project manager of issues, scope changes, risk, and quality concerns and proactively communicating work status and managing work expectations. The project team was "cross-functional" having multiple internal and external reporting responsibilities. The structure of the project team can be found in Exhibit 3.

Exhibit 3 – Project Team



Source: Wood Mackenzie

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Discussion

The delivered price of coal at TEC is a function of the FOB mine price of coal selected for use at the plant and the cost of transportation to move that coal to the plant. Since TEC will use Illinois coal and since Illinois coal is in widespread demand, then the FOB price of coal suitable to TEC is a function of the supply and demand of that coal. Moving coal from mine to TEC could be done using either or combinations of truck, rail or barge modes of transportation. Supply, demand and transportation factors are discussed below.

In the following discussion, our modelling, historical and forecast Illinois coal supply and production, historical and forecast demand for Illinois coal will be discussed. The calculation of delivered price at TEC in aggregate and in mining subdivision detail will be discussed and actual forecast prices will be shown.

PRISM™ Model

The Wood Mackenzie coal team has developed a proprietary coal choice and electricity dispatch model (PRISM™) that allows us to provide forecast information on coal volumes and pricing for numerous varieties of coal. We modified our PRISM™ model data to include the TEC facility and plant parameters as a consumption point. Furthermore, we defined a set of modelling parameters for use in our PRISM™ model that are reflective of the TEC plant characteristics and demand, its possible sources, the time frame involved (2015 – 2045) and environmental constraints. Further details about PRISM™ can be found in Appendix C.

Illinois Coal Supply

Significant coal resource and reserve exists in Illinois that has been and will continue to be exploited despite an increasingly onerous regulatory environment. Illinois coal is usually easily mined from stable geologies and has high energy content but suffers from generally higher sulfur content and, occasionally, higher chlorine content. Coal in Illinois is mined by regional, national and international coal companies. Typically, the coal is railed or barged to market, usually but not always outside Illinois, but sometimes trucked to local power plants.

Geology

The Illinois coal resource is part of a major eastern coal field known as the Illinois Basin, which is constituted of coals in Illinois, Indiana and western Kentucky. The coal seams in the Illinois Basin are found in rocks of the Pennsylvanian age which were deposited about 300 million years ago. The most important economic coals in these rocks are part of the Carbondale Formation and include the long-mined Springfield and Herrin coal seams.

The most important structural feature of the Illinois Basin coal field is the La Salle Anticlinal Belt. This structure, and other minor structural features, ensures that Illinois coal outcrops along the edges of the basin in western Illinois and Indiana but reaches significant depth of up to 1,500 feet in southern Illinois in the center of the basin. (U.S. Geological Survey. Professional Paper 1625-D:A4-A5).

Within Illinois, the two most significant coal seams are the Springfield No. 5 seam and the Herrin No. 6 seam. Where mined, the Springfield No. 5 coal typically averages between 4 feet and 6 feet thick and is overlain by shale. In southern Illinois, this coal seam is locally thicker, but often parted by interburden shale owing to contemporaneous deposition with the Galatia channel system. Mined Herrin No. 6 seam coal is typically at least 6 feet thick although thinner and more irregular in southern Illinois where it is often parted by interburden shales from the Walshville channel system. It is usually overlain by shales and, nearby the Walshville channel, sometimes cut out by sandstones.

Coal Quality

Generally, Illinois coal is of high-volatile bituminous rank with energy contents typically ranging from about 11,000 Btu / lb (free of moisture and mineral matter, or mmf) to about 15,000 Btu / lb (mmf). Energy content increases with both southerly direction and, less apparently, with increased depth. The increase in moisture content with geographical direction is partly related to moisture content which declines in the southerly direction.

Chlorine content in Illinois coal is widely thought to increase with depth of coal occurrence. However, the chlorine content of coal has been found to be more closely correlated with the chlorine content of the groundwater than with depth, implying that the increase in chlorine content of coal with depth is a result of the increase in salinity of groundwater with depth (Illinois State Geological Survey. Circular 372:1). Typically, chlorine ranges from less than 0.10% at the outcrops to over 0.50% where the coal is very deep.

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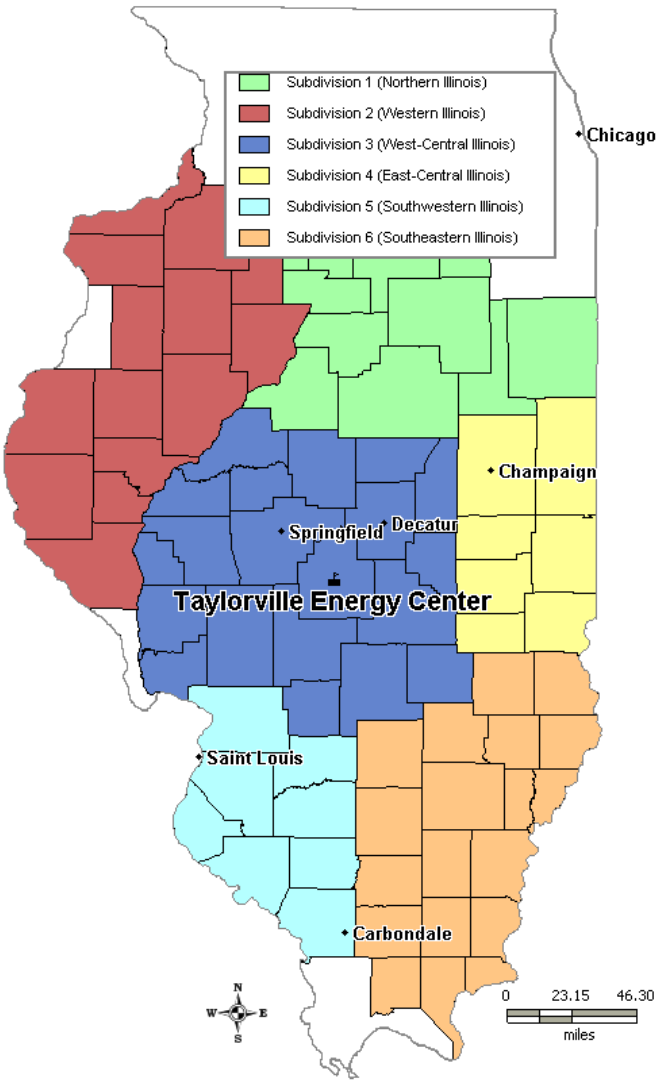
Ash content is quite variable in the state, within limits of about 6% by weight to about 14% by weight (on a shipped basis). Raw coal is, naturally, higher in ash content than washed coal and can reach ash contents of over 20% thereby causing significant energy content deterioration.

In Illinois, most of the mineable coals are high in sulfur content. Sulfur is present in both organic and pyritic forms with very little sulfate sulphur present. The actual sulfur content of a particular coal is partly a function of the nature of the overlying strata. When the overlying strata are marine shales or limestone, then the sulfur content is usually higher (averaging between 3.0% and 5.5% by weight). When the overlying strata are both non-marine and in excess of 20 feet thick then the sulfur content is often much lower, averaging 2.5%, but sometimes as low as 1.0% (Keystone 2007:568).

Mining Regions

There are six major mining regions in Illinois (Keystone 2007:570-573). These are the Subdivision 1 (Northern Illiniols), Subdivision 2 (Western Illinois), Subdivision 3 (West-Central Illinois), Subdivision 4 (East-Central Illinois), Subdivision 5 (Southwestern Illinois), and Subdivision 6 (Southeastern Illinois) areas. Of these, the majority of coal production is concentrated in the Subdivision 3 (West-Central Illinois), Subdivision 5 (Southwestern Illinois) and Subdivision 6 (Southeastern Illinois) areas. The TEC facility is located in the center of the state, the center of the Illinois coal basin and the center of Subdivision 3 (West-Central Illinois). See Exhibit 4.

Exhibit 4 – Illinois Mining Subdivisions



Source: Wood Mackenzie; Keystone; Ventyx

Historically, the Danville and Colchester coals were mined in Subdivision 1 (Northern Illinois), but there are no active mines in this subdivision at this time. A small amount of exploration activity has occurred on the western side of this region, but there is little current potential for new coal mines in this area.

Long ago, large underground mines accessed the Springfield coal in Subdivision 2 (Western Illinois). Later, surface mines became prevalent. Now, a little mining of the Colchester coal occurs in this subdivision in Fulton County.

In Subdivision 3 (West-Central Illinois), the Herrin coal is important. Large mines have operated in the past in this area, especially around Springfield. Several mines have operated in the recent past, are currently in operation or are planned for later operation, in the area surrounding the TEC facility, including mines in Logan, Macoupin, Montgomery and Christian counties.

Little mining and exploration activity is occurring in the Subdivision 4 (East-Central Illinois) where the Danville and Herrin coals predominate. In the recent past, mines in Douglas and Vermillion County were in operation.

Southern Illinois coal production has been and still is significant. In Subdivision 5 (Southwestern Illinois) the coals are shallower and lower in chlorine. Surface and shallow underground mines operate in much of this area from the Herrin coal. Shallow underground mining is possible owing to the stable limestone cover. Most of the current production occurs in Randolph, Perry and Jackson counties.

Herrin and Springfield coal are produced in the Subdivision 6 (Southeastern Illinois) from many, mostly underground, coal mines in Franklin, Gallatin, Saline, White, Wabash and Williamson counties. There is some outcrop coal in Gallatin, Saline and Willliamson counties that has been extensively mined.

Resource and Reserve

Illinois has the largest bituminous coal resource in the U.S. The demonstrated reserves (that portion of the coal resource that is generally considered accessible and economic) are also very large, with only Montana having more.

Most of the coal considered economically mineable in Illinois is in the Herrin seam in the southern portion of the state although significant mineable resource occurs in northern Illinois where geologic disturbances, such as clay dikes, sometimes disrupt the coal seam. Note in Exhibit 5 that recent investigators have found that the Herrin and Springfield resources are of approximately equal size, each equal to over 1,000 years of current state production of coal.

Exhibit 5 – Remaining Illinois Coal Resource in Major Coal Seams, Bt

Date	Reference	Springfield Coal	Herrin Coal
1952	Cady	238.5	62.6
1974	Hopkins and Simon	42.6	65.8
1978 and 1982	Treworgy, Bargh and	56.0	70.1
2000	Daumberger	61.7	78.9

Source: USGS

From Exhibit 6 it can be seen that the majority of the coal resource exists in Subdivision 3 (West-Central Illinois) and Subdivision 6 (Southeastern Illinois). However, there is also a significant amount of Herrin coal in the shallower Subdivision 5 (Southwestern Illinois). Note also that the majority of all coal resource is greater than 150 feet in depth and in seams of greater than 42 inch thickness. Of note is the sizeable amount of shallower coal in thick seams in Subdivision 5 (Southwestern Illinois).

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Exhibit 6– Remaining Illinois Coal Resource by Subdivision, Depth and Coal Seam Thickness

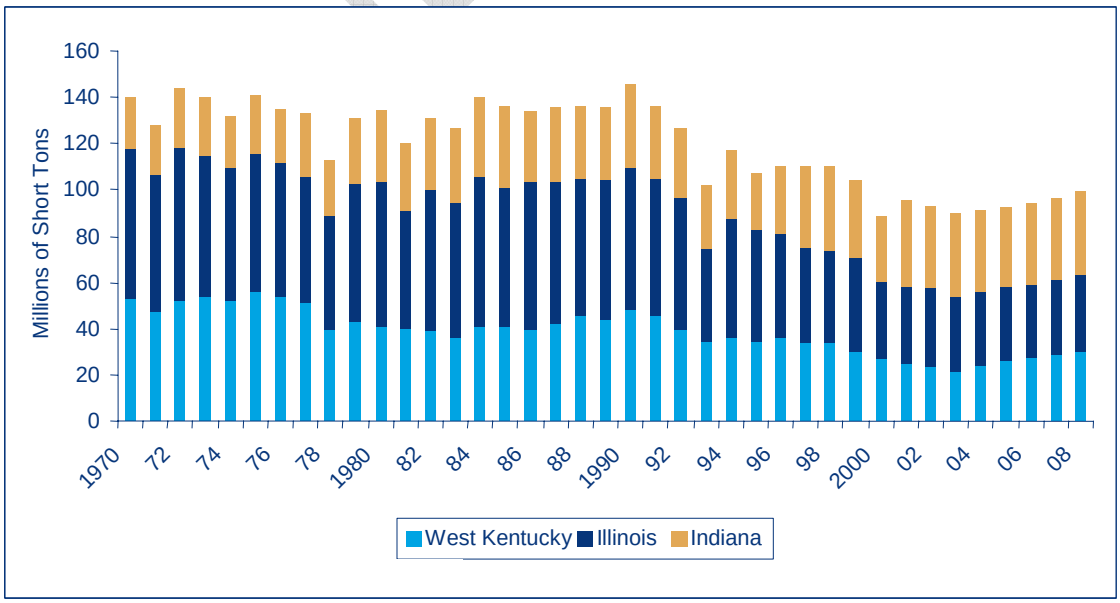
Subdivision	Coal Depth (feet)	Springfield Coal				Herrin Coal			
		Coal Thickness (Inches)				Coal thickness (Inches)			
		>14-28	>28-42	>42	All	>14-28	>28-42	>42	All
Northern	0-150			37	37	77	140	170	390
	>150		2,200	2,500	4,700		330	62	390
	Subtotal			2,500	4,700	77	470	230	780
Western	0-150	380	450	1,200	2,000	15	470	2,000	2,500
	>150		68	480	550		130	320	450
	Subtotal	380	520	1,700	2,600	15	600	2,300	2,900
West-Central	0-150			1,100	1,100	98	600	300	990
	>150		2,400	15,600	18,000		2,800	23,400	26,100
	Subtotal		2,400	16,700	19,100	98	3,400	23,700	27,200
East-Central	0-150	17	9	13	39	81	56	470	610
	>150		1,700	3,700	5,400		2,200	5,200	7,400
	Subtotal	17	1,700	3,700	5,500	81	2,300	5,700	8,000
Southwestern	0-150	12	98	250	360	2	17	2,400	2,500
	>150		89	300	380		150	11,200	11,300
	Subtotal	12	190	550	740	2	170	13,600	13,800
Southeastern	0-150		4	370	370	3	47	580	630
	>150		5,400	23,200	28,600		4,900	20,800	25,700
	Subtotal		5,400	23,600	29,000	3	4,900	21,400	26,300
Illinois Total	0-150	410	560	3,000	4,000	280	1,300	5,900	7,600
	>150		11,900	45,800	57,700		10,500	60,900	71,400
	Subtotal	410	12,500	48,800	61,700	280	11,800	66,800	78,900

Source: USGS

Supply, Production and Major Producers

Illinois coal is similar to other Illinois Basin coals and shares similar markets. Production of Illinois Basin coal has fallen from its historical peak levels due to Clean Air Act legislation (see Exhibit 7). Since 2003, production levels have rebounded slightly due to the addition of scrubbers to many eastern power plants and, to a lesser extent, to the growing export market. Power generators can no longer burn coal without sulfur mitigation plans. The resultant "scrubber market" combined with renewed interest in coal gasification and coal-to-liquids operations have created a resurgence of interest in the use of Illinois coal.

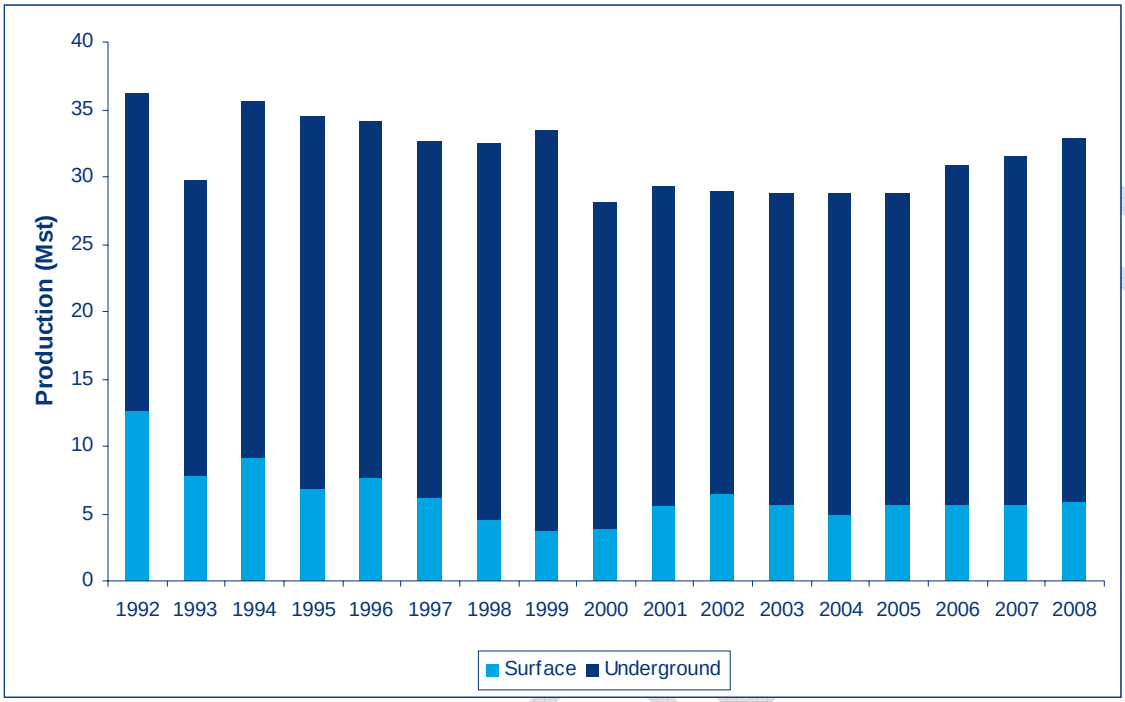
Exhibit 7– Illinois Basin Coal Production by State and by Year, Mst



Source: Wood Mackenzie CoalBase

Illinois coal production patterns are similar to those in the wider Illinois Basin. Total mine production is up (see Exhibit 8) and union representation is down. Note in Exhibit 8 that coal production in Illinois was 34 Mst in 2008, which was slightly higher than the five-year production average of 32 Mst. Illinois coal producers anticipate continued growth in the size of the "scrubber market" that could be served by coal produced in Illinois and they plan to add significant new mine capacity.

Exhibit 8 – Illinois Coal Production by Type of Mine and by Year, Mst



Source: Ventyx

Current production is controlled by a handful of companies. Peabody remains the largest coal producer in Illinois, followed by Knight Hawk /Arch, American Coal (Murray Energy), Alliance Coal, the International Coal Group, and The Cline Group.

An overview of each major producer in Illinois follows.

Alliance Resource Partners

Alliance Resource Partners (ARP) is the second largest Illinois Basin (ILB) coal producer with production and excellent reserves in each state. Alliance's Illinois operations under White County Coal, LLC consist of one mine (Pattiki II) which produced 2.7 million short tons in 2008 and 2.9 million short tons in 2007. Plans are to produce about 3.0 Mstpa for the foreseeable future.

ARP controls more than 500 Mst of economically underground mineable reserves in the ILB but at Pattiki II, their only Illinois mine, reserves are about 55 Mst. The company has the reputation of being the most efficient continuous mining operator in the ILB. All production is non-union. All Illinois Alliance production is thermal quality with high sulfur values and less than 0.2% chlorine of dry ash. In Illinois, the Pattiki mine is served by the EVW Railway and has excellent access to the Ohio River though its Mt. Vernon coal terminal. The company also has excellent access to the CSX Railroad in Evansville.

Arch Coal, Inc. / Knight Hawk Coal, LLC

Arch Coal, one of the nation's largest coal producers, controls about 577.0 Mst of reserves in Illinois. It has no production today in the basin but has plans to develop the 374.0 Mst Denmark Deep/Pinckneyville reserve in the southern part of the state as the Lost Prairie mine. With permitting expected to take 12 to 24 months to complete, the 3 Mst per year operation will begin continuous miner operations in 2013.

In 2006, Arch purchased a one-third interest in Knight Hawk Coal, LLC for a cost of US$15 million in cash and 30.0 Mst of coal reserves. It is believed Arch will hire Knight Hawk to develop Lost Prairie. Knight Hawk was founded in April 1997 and began mining in May 1998. Knight Hawk controls about 115.0 Mst of coal reserves in southern Illinois. Its total production in 2008 was 3.6 Mst from five surface and underground operations located in the southwestern part of the state of Illinois.

Those mines form a single complex and include Creek Paum, Royal Falcon, and Prairie Eagle (surface and underground operations), and Red Hawk. Plans are to expand to more than 8.0 Mst per year by 2011. Increased production will come from the new Royal Falcon mine and the new Hawkeye mine. Coal can be blended at Prairie Eagle. Knight Hawk's long term production falls back to 5.5 Mst per year in the years after 2012.

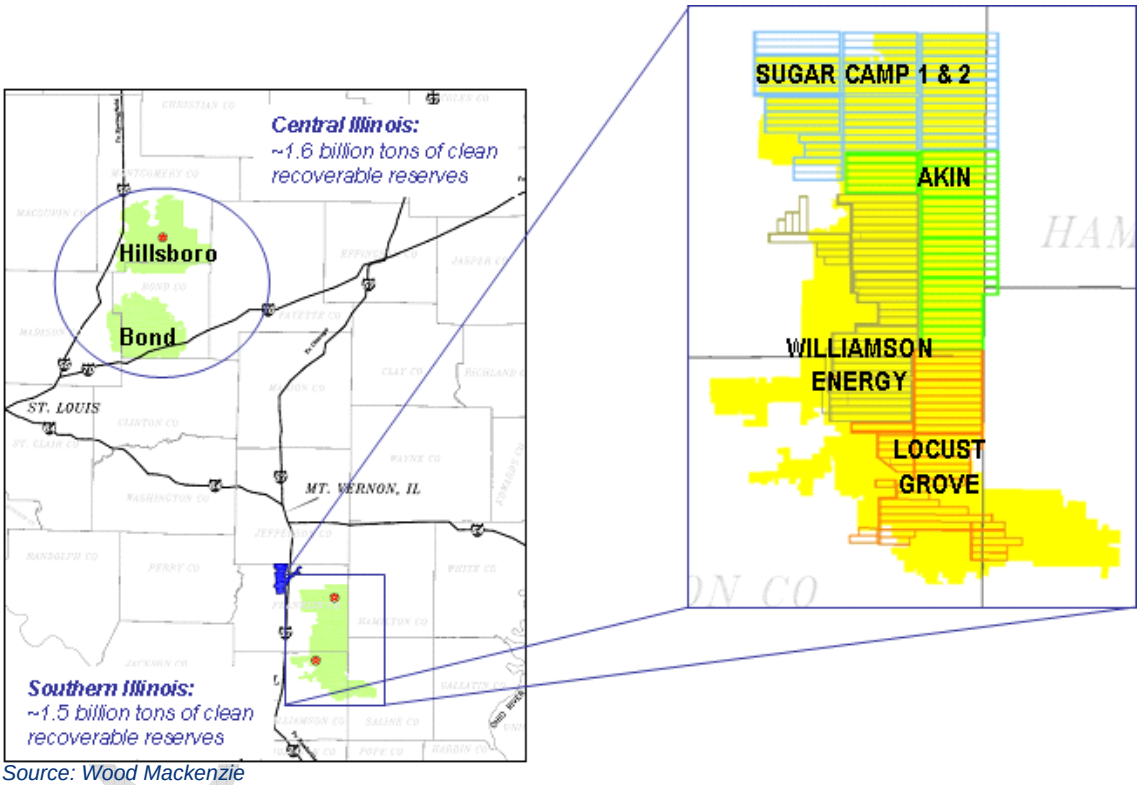
Knight Hawk has several transportation options. Coal is currently trucked to Carbondale where it is loaded on the Canadian National Railway (CN) or to the Lone Eagle Dock on the upper Mississippi River. About 75% of the coal is trucked to the river and only a small portion of the coal is railed. The current rail infrastructure is quite limited – only 21 cars can be loaded per day.

If Knight Hawk can expand its rail-delivered markets, plans are in place to develop a unit train loadout at Percy, Illinois, near the Prairie Eagle mine. This would include a 70-car loadout that could be expanded to handle a 100-car unit train. The current site configuration would require that trains be backed into the loadout.

Cline Group

Chris Cline, who began as a Central Appalachian coal producer, is becoming a significant producer in the ILB, controlling 1.6 Bt of recoverable coal in central Illinois and 1.5 Bt of recoverable coal in southern Illinois. Company production in 2008 was 5.5 Mst from one longwall mine, Pond Creek. The company has plans to produce 20.0 million short tons in 2011 and more than 70.0 Mst per year by 2020. Cline operations can be seen in Exhibit 9.

Exhibit 9 – Cline operations in Illinois



Source: Wood Mackenzie

Cline operates under a business model using several sale/leaseback "tolling" arrangements with Natural Resource Partners (NRP). In this production-oriented arrangement Cline must pay royalties to NRP. One of the results of this arrangement is that NRP benefits when there is higher production from the mines. Fortunately for both parties, Cline has some of the lowest-cost mines in Illinois. They use state-of-the-art equipment, efficient contractors and have the ability to blend various qualities. As they expand their production and transportation capabilities, their low cost operations will create challenges for higher cost Illinois producers.

Operating and organized under several affiliates, Cline operates and plans to open several mega longwall mines over the next several years. Pond Creek (Mach No. 1) longwall mine, which is the most productive and lowest cost longwall operation in the US, is currently Cline's only operating mine in Illinois. It is nearly twice as productive as the next most productive longwall mine in the US (Bailey/Enlow Fork). 2009 production will likely to be lower due to a longwall move made during 1Q09 and a longwall move planned in November 2009.

Cline's west central operations are Shay No. 1 (the former Monterey mine), Hillsboro/Deer Run (project is called Artemas), and Bond County. Shay No. 1 mine is being operated under Macoupin Energy on leased property owned by NRP. Production at Shay is scheduled to resume in 3Q09 with annual production reaching 3 Mst by 2011. Hillsboro/Deer Run mine, in west central Illinois, is a $350 million project that will extract coal from the No. 6 seam, which lies about 480 feet below the surface. The mine is expected to be in partial production in 2010 and be mining at an average rate of 9 Mst per year by late 2011 once the longwall is operational. Artemas holds about 1.0 billion tons of reserves.

Cline projects planned for southern Illinois include the Sugar Camp, Akin and Locust Grove projects. Sugar Camp's start-up is scheduled for late 2009 with full production of 4.8 Mst per year by 2011. Locust Grove is not likely to begin production until 2013. To mitigate the high chlorine found in the southern Illinois coal, Cline plans are to build a blending facility on the Ohio River near the town of Mt. Vernon, Indiana. Artemas and Sugar Camp production could be blended at this site.

All of Cline's longwall mines are designed to match Pond Creek productivity by utilizing efficient contract miners to operate the mines. The operations and projects are summarized in Exhibit 10.

Exhibit 10 – Cline Group Illinois Projects

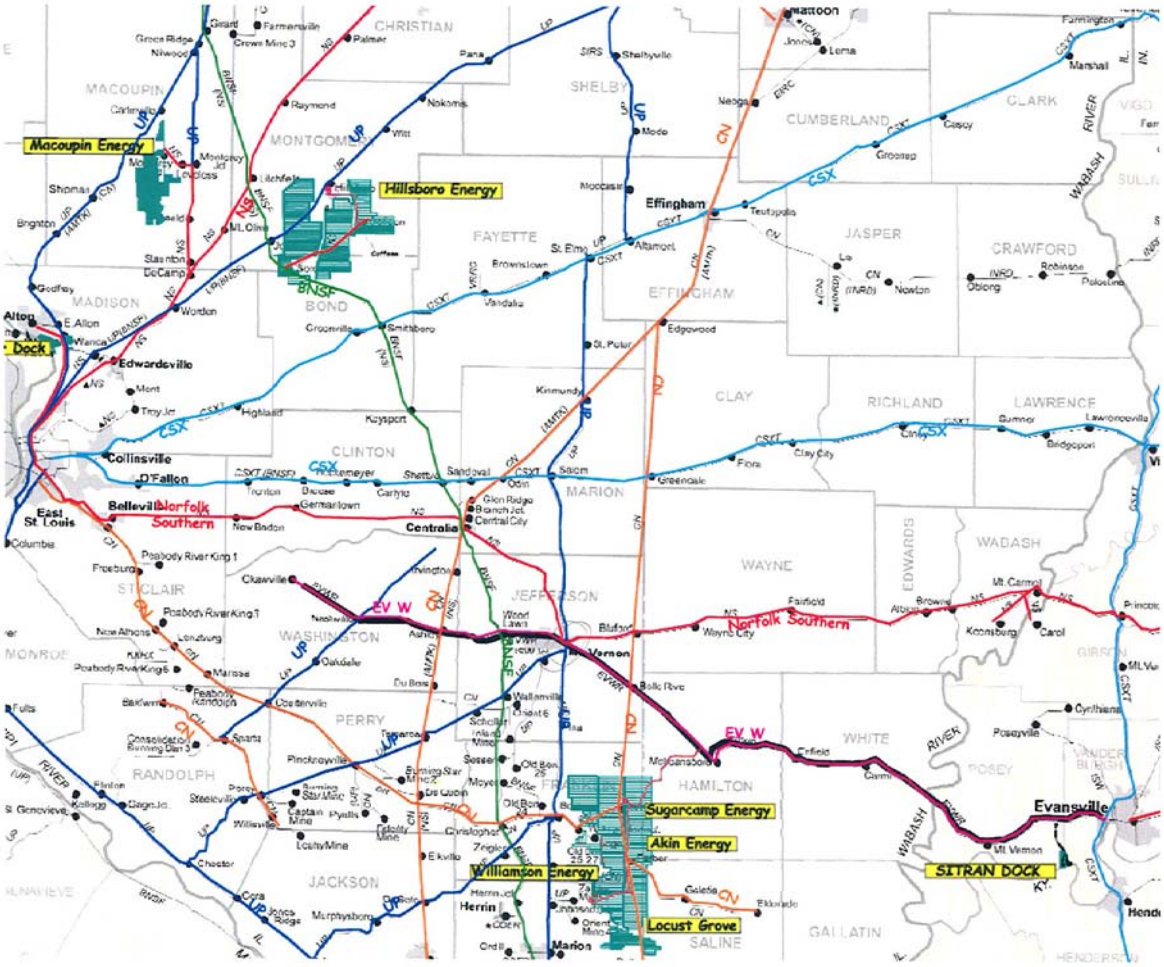
Development	Timing	Tonnage (Mstpa)	Method
Pond Creek No. 1	Dev 2007	7.0	Longwall
Shay No. 1	Dev 2009	3.0	Longwall
Sugar Camp 1	Dev 2008	8.9	Longwall
Sugar Camp 2	Dev 2012	7.9	Longwall
Locust Grove	Dev 2013	6.8	Longwall
Artemas/Deer Run 1	Dev 2010	8.1	Longwall
Akin (TVA)	Dev 2014	9.1	Longwall
Artermas/Deer Run 2	Dev 2013	8.3	Longwall
Bond County East	Dev 2016	7.1	Longwall
Bond County West	Dev 2017	7.1	Longwall

Source: Wood Mackenzie

All of the Cline operations have multiple transportation options. Artemas/Hillsboro and Macoupin Energy are both served by the Norfolk Southern and UP railroads and are both within trucking distance of TEC. Sugar Camp, Pond Creek, and Locust Grove all have direct access to the CN railroad. Cline has an agreement with the Evansville Western that connects all of its southern Illinois coal to class I carriers and to the river.

Cline is proposing to build a barge loading and blending facility east of the Alliance operation near Mt. Vernon, Indiana. Served by the EVW Railroad, plans are to blend its high chlorine production from Sugar Camp with low chlorine production from Artemas/Hillsboro. See Exhibit 11.

Exhibit 11 – Cline's Illinois operations and transportation network access



Source: Wood Mackenzie

Energy Coal Resources

Energy Coal Resources has a small operation that was recently reactivated, the Illinois # 1 mine, and is in the process of permitting its Ewing coal reserves in Franklin County. Energy Coal resources has several units, including Appalachian Fuels (currently in bankruptcy proceedings) and Illinois Fuel, which is the unit permitting the Ewing reserves.

The original Ewing permit called for longwall mining, but the application was withdrawn and resubmitted in early 2009 as a room-and-pillar mine which will allow for earlier permitting of the mine. The property, which was leased from the Tennessee Valley Authority (TVA) about 10 years ago, must be in production by 2012, or the lease will be voided. It is believed that the mine will eventually be permitted as a longwall property. The new permit will cover the Herrin #6 coal seam, consisting of 228 million tons of contiguous non-reserve coal deposits. Development of this project is contingent upon financing as a stand-alone project.

Foundation/Alpha

Foundation's Wabash mine reopening will likely be delayed due to Foundation's wider merger with Alpha.

International Coal Group (ICG)

ICG's Viper mine successfully expanded production to 2.0 million short tons in 2008. The expansion was in anticipation to supply the new Dallman 4 unit, which is coming on line in 2009. ICG has 1.7 Mstpa committed to the plant. Viper coal was also committed to the Secure Energy gasification project; however, delays in the project resulted in Secure Energy being required to renegotiate for coal supply.

The Viper mine is about 20 miles north of Springfield. Coal is typically trucked to its final destination and is within trucking distance of TEC. Truck rates will vary significantly, depending on whether or not there is a backhaul opportunity.

Reserves at Viper, which mines the Springfield #5 seam, exceed 65 Mst.

Peabody Energy

Peabody Energy, the nation's largest coal producer and a significant international producer, has a long history in Illinois and has been one of the most successful mining companies in the state. In 2008, the company produced 11 million short tons of coal in Illinois from five underground and surface mines – Gateway, Willow Lake, Wildcat Hills surface and underground, and Vermillion Grove. We have identified a minimum of 3.0 Bst of recoverable coal controlled by Peabody in Illinois. Total reserves could exceed 5.0 billion tons.

The company has numerous projects and expansion possibilities which would allow production to expand to more than 22 Mst per year with potential to expand to more than 40.0 Mst per year if demand warrants the increase. Peabody plans to open two new mine-mouth operations – one to serve the Prairie State Energy Center in Illinois and the other to serve a proposed coal-to-gas plant in Kentucky.

Depending on the operation/reserve, Peabody's mines have excellent access to rail (CSX, UP, CN, EVW and the NS) and to river docks on the Ohio and Mississippi rivers.

We have divided Peabody's reserves and operations into three separate regions: southwestern Illinois, southeastern Illinois and other Illinois.

Southwestern Illinois

Peabody has a 1.5 Bst reserve base in this region with a typical quality of 11,100 Btu/lb and 5.2 lbSO_2/mmbtu coal (washed). The Gateway underground continuous miner (CM) mine produces about 3.2 Mst per year of coal and will be replaced by the Gateway North mine in the next few years. Peabody's 6.0 Mst per year Lively Grove CM mine is in development to supply the Prairie State Energy Campus in the 2011/2012 time frame. It will ship a raw product. The Mary's River mine is a proposed 0.5 - 1.0 Mst per year mine that is expected to open by 2012. Yet another proposed mine, Fayetteville, is expected to be a 4.0 Mst per year CM underground mine southeast of St. Louis that could open in the 2013.

Southeastern Illinois

In southeastern Illinois Peabody has a minimum 0.75 Bst reserve base with a typical quality of 12,000 Btu/lb and 4.9 lbSO_2/mmbtu coal (washed). Production averages about 6.5 Mst per year and all this coal is trucked to river docks on the Ohio River. The Wildcat Hills/Cottage Grove surface mine produces about 2.0 Mst per year but will be replaced by mines in other smaller reserve blocks over the next few years. The Wildcat Hills underground produces about 0.6 Mst per year but has the potential to expand to 1.5 Mst per year. The Willow Lake underground mine is a 3.7 - 4.0 Mst per year CM mine. When this reserve depletes in the next seven years, it will be replaced by mines developed in other reserves controlled by Peabody in the area, including Harrisburg West and Eagle Valley.

Other Peabody mines/reserves in Illinois

Peabody does not have any operating mines in other regions of Illinois, but the following items are of note. The Mine No. 11 CM mine project in Christian County could be opened as a large operation to supply local as well as potential distant markets. Mine No. 11 would be within trucking distance of TEC. Peabody has taken over all of the Freeman United's reserves in the state of Illinois and created a relationship with Springfield Coal, a small producer of some of these reserves. Peabody's reserve position has blocked The Cline Group from consolidating its Deer Run (Hillsboro) and Bond County reserves. Peabody has closed the 1.1 Mst per year Vermillion Grove CM mine near Danville in the eastern part of the state.

Springfield Coal

Springfield Coal is a small producer whose annual production of 1.4 Mst is primarily from its Crown III mine. The Crown III mine is within trucking distance of TEC. Closures at its Crown II, Orient, and Industry mines will be partially offset by the new North Grindstone mine and a surface mine, Banner, which is still in the permitting process. The Grindstone mine will be operated by Black Nugget. Springfield's plan to open the small, truck only Banner mine, continues to be challenged.

White Oak Resources LLC

White Oak plans to open a very large longwall mine complex in southern Illinois. Although it is managed by coal industry veterans, little is known about the company's backers. One of the investors is Bridgecor Capital Ltd of Houston, Texas.

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Plans are to open several 7.0 Mst per year longwall mines in Hamilton County where the Herrin No. 6 seam is 6 - 8 feet thick. The company plans to build one mine northwest and one mine northeast of McLeansboro, IL, and it has a third mine area in early planning southeast of the city.

White Oak estimates it has 900 million tons of reserves in place at an average thickness of about 6.5 feet, which makes it well suited for longwall mining. It plans to break ground in Q309, assuming it can meet the corrections requested in July, 2009 by the Illinois Office of Mines & Minerals. The company expects to reach full production of 7.5 Mst per year of clean coal in 2012. White Oak Mine No. 2, identical to Mine No. 1, will be located adjacent to the first mine and will be ready to operate in 2014. By the middle of the next decade White Oak plans to be producing about 15 Mst per year of production. These are deep mines planning to operate about 1,000 feet below the surface.

150-car unit trains are planned that will be served by the EVW Railroad. Plans are to build a barge loadout on the Ohio River near the town of Mt. Vernon, Indiana – about 42 miles away. This dock may be the same that Cline is considering.

Rhino Energy

Development of Rhino's Taylorville CM mine in Christian County is proceeding at a slow pace. The mine is slated to produce 2 – 3 Mst per year of high sulfur Herrin No. 6 seam coal. Taylorville would be an underground mine where coal would be conveyed to a prep plant for processing. The clean coal would be conveyed to a truck and/or train loadout. Rhino's proposed mine would be within trucking distance of TEC.

Murray Energy

The American Coal Company, a subsidiary of Murray Energy operates the 7.0 Mst per year Galatia longwall complex in southern Illinois. The complex consists of three portals named Galatia North, New Future, and New Era. Galatia North was shut down in 2008 due to Mine Safety & Health Administration (MSHA) safety rule concerns.

New Future produces a low sulphur 11,700 Btu/lb, 2.2 $lbSO_2$/mmbtu coal from the Springfield seam. Production will continue in this seam for another three years then switch to the Herrin seam. The New Era mine produces about an 11,700 Btu/lb, 4.2 $lbSO_2$/mmbtu coal from the Herrin seam. Most of the coal produced at the Galatia complex is high in chlorine (exceeding 0.3% of dry ash).

Total production for 2009 will be less than in previous years as a result of decreased demand. The Galatia is served by the CN railroad.

Other Producers

At one time **CONSOL Energy** controlled significant reserves throughout the coal-bearing seams in Illinois. CONSOL does not currently plan to develop any of the reserves it still controls. Some of the reserves are in poor quality coal, some are too close to urban areas, and others would require significant infrastructure to be developed. Reserves still under control by CONSOL could conceivably be leased to another company for development.

The **Embarras Valley** coal has been earmarked for a 4.3 Mst per year jet fuel project proposed by American Clean Coal Fuels (ACCF). A few years ago more than 150 property owners in Hugo, Cole, Douglas, and Edgar counties joined together to lease reserves to ACCF. The estimated start-up date of the plant is 2013.

Drummond Coal announced a coal-to-liquids project several years ago that would utilize its Fayette/Montgomery County coal reserves. Nothing yet has occurred on these reserves and we are not expecting Drummond to develop them anytime soon. The Drummond coal reserves would be within trucking distance of TEC.

Forecast Supply

Existing Illinois producers are all planning expansions and many newcomers are entering the market with plans to develop a multitude of mines. Illinois' production is poised to expand more than two-fold in the next 10 years. A new supply environment is developing in Illinois in which high cost producers will be under pressure to reduce costs as a result of significant low cost competition.

Several very low cost and extremely efficient underground longwall operations may come on line in the next ten years, with The Cline Group's operations leading the way. However, many of these new longwall operations will produce coals with relatively high chlorine content, while many of the other mines being planned will be low in chlorine content. Chlorine is an issue with most consumers because it can contribute to corrosion in boilers and scrubbers. This will result in some creative blending scenarios over the next several years as high chlorine producers try to mitigate this issue by blending their output with low chlorine coals.

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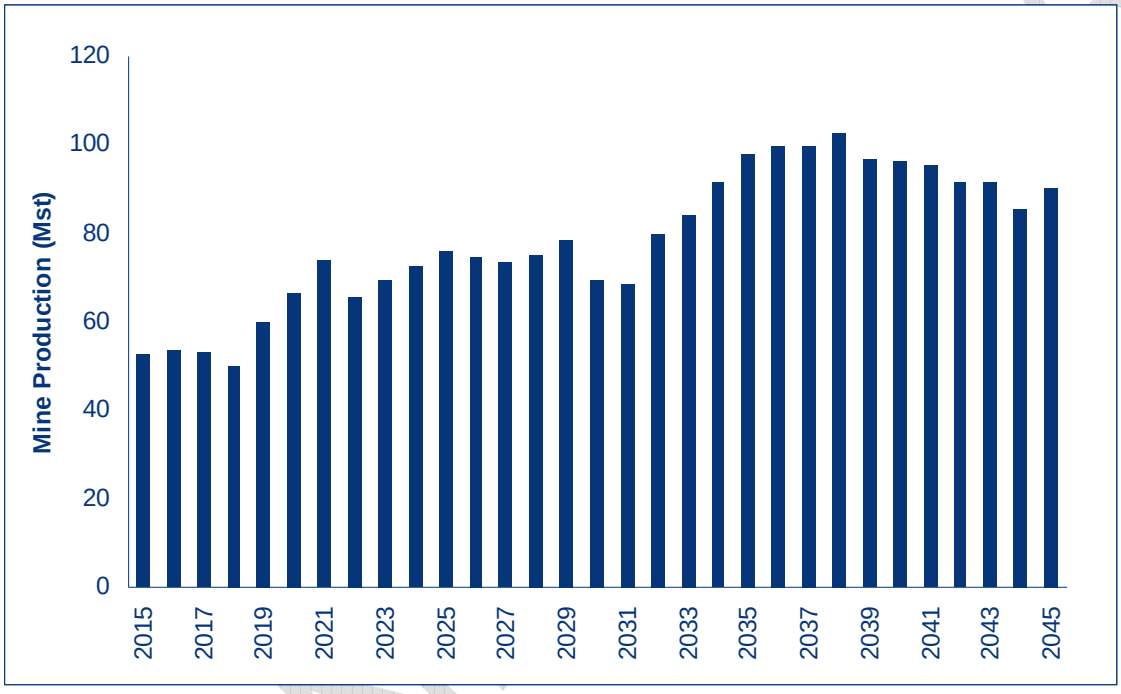
There are at least an additional 10, 7+ Mst per year "Cline-type" longwall systems planned in Illinois. Historically, because of their close proximity to the nation's river system, West Kentucky producers had the lowest costs in the barge markets; however, this is not always the case anymore and the growing favorable cost environment for Illinois coals will affect supply/demand economics. Although future Illinois production is the lowest cost in the barge, it has a transportation disadvantage compared to West Kentucky mines going upriver from Evansville that must be overcome through pricing to become more competitive in that market. Today, and in the future, Illinois by far has the lowest costs in the railcar. These factors will help create conditions conducive to abundant future production of Illinois coal and its growing acceptance in the marketplace. All this will influence the market-clearing price of Illinois coals.

With several new entrants, production capability is poised to increase to well over 100 Mst over time. Of course, end markets will ultimately determine how much coal is actually produced. As can be seen in Exhibit 12, our PRISM™ modelling indicates that, in the forecast period defined in this work, coal production in the state of Illinois will grow by over 70% from about 50 Mst in 2015 to about 90 Mst in 2045. Planned production is much greater than these forecast levels which indicate that not all planned production will be economically competitive with nearby and, in some cases, distant mines.

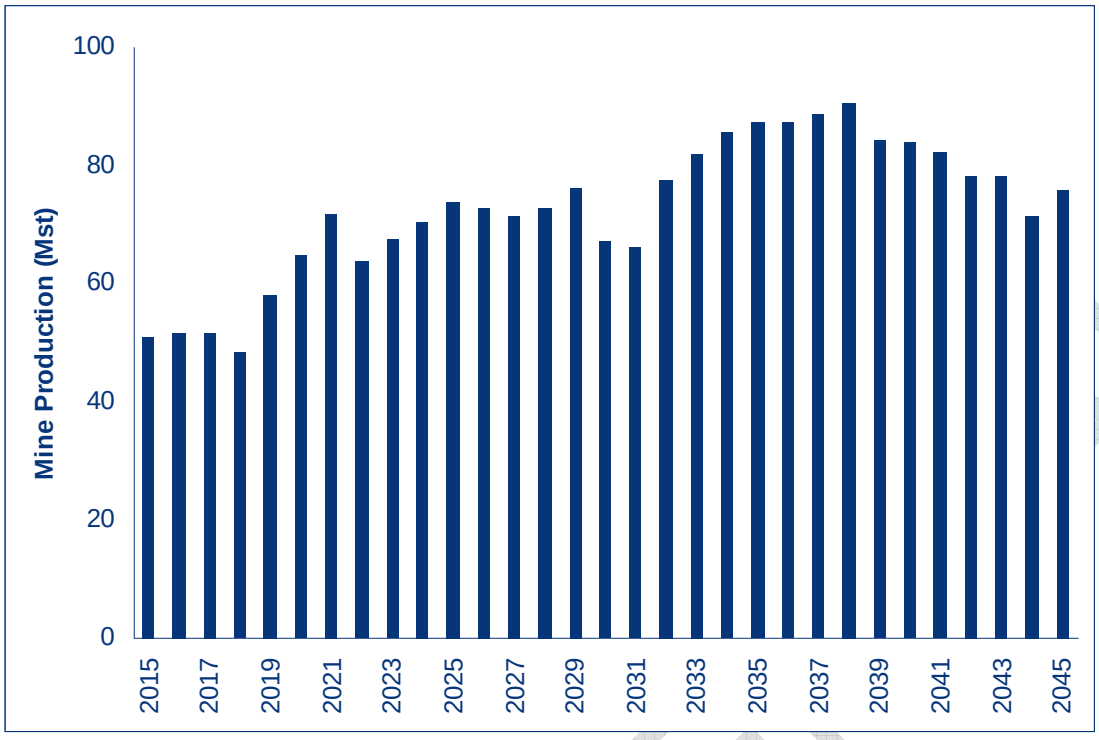
Exhibit 12 – Forecast Coal Production in Illinois, Mst



Source: Wood Mackenzie

Not every mine or potential mine in Illinois has coal quality suitable for use at TEC. After exclusion for quality reasons, the total coal production from mines and potential mines that are reasonable potential suppliers to TEC can be seen in Exhibit 13. Note that, even in this subset of mines with suitable coal quality, coal production is expected to grow almost 40% from about 44 Mst in 2015 to over 60 Mst in 2045. Thus, coal usage at TEC from mines capable of providing coal to the plant ranges from about three percent to about five percent of the total production at those same mines. Put another way, the mines that make up the potential supply for TEC offer a significant potential source of supply for TEC.

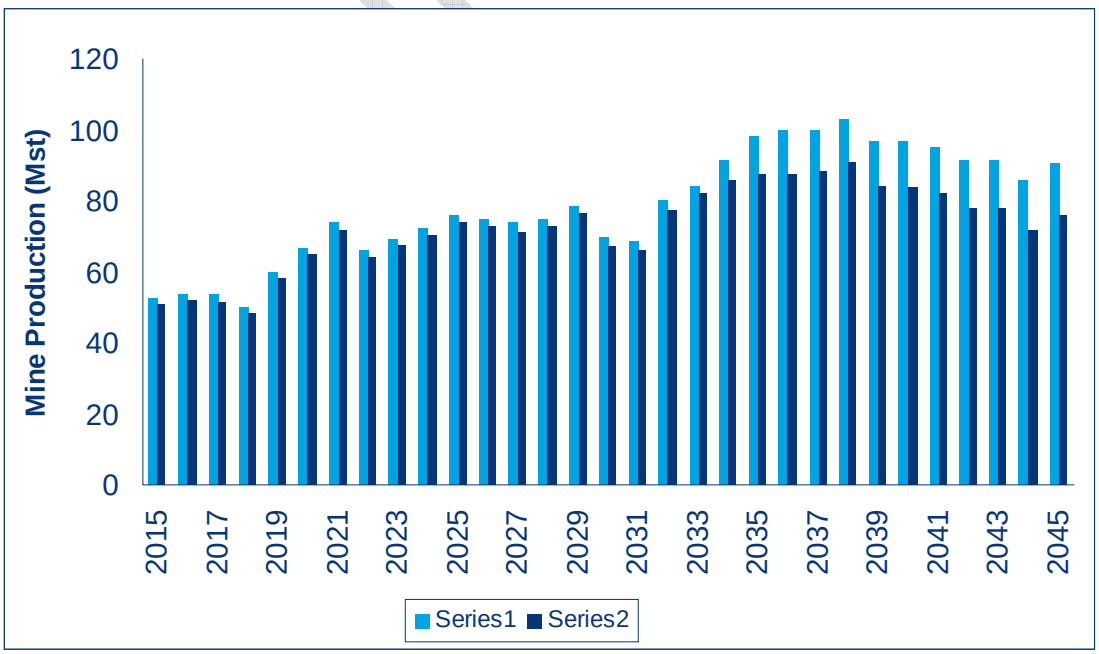
Exhibit 13 – Forecast Coal Production in Illinois of Coal Suitable to the TEC Facility, Mst



Source: Wood Mackenzie

A comparison of the total coal forecasted to be produced in Illinois with that portion suitable for use at TEC can be seen in Exhibit 14. Note that the majority of coal produced in Illinois will be suitable for use a TEC. It is assumed that some of the really high sulfur coals will be washed to improve quality. It is also assumed that any coal reserve currently characterized as having a wide range of chlorine content will be mined in such a way as to allow the production of at least some low chlorine content coal that conforms to the TEC requirements.

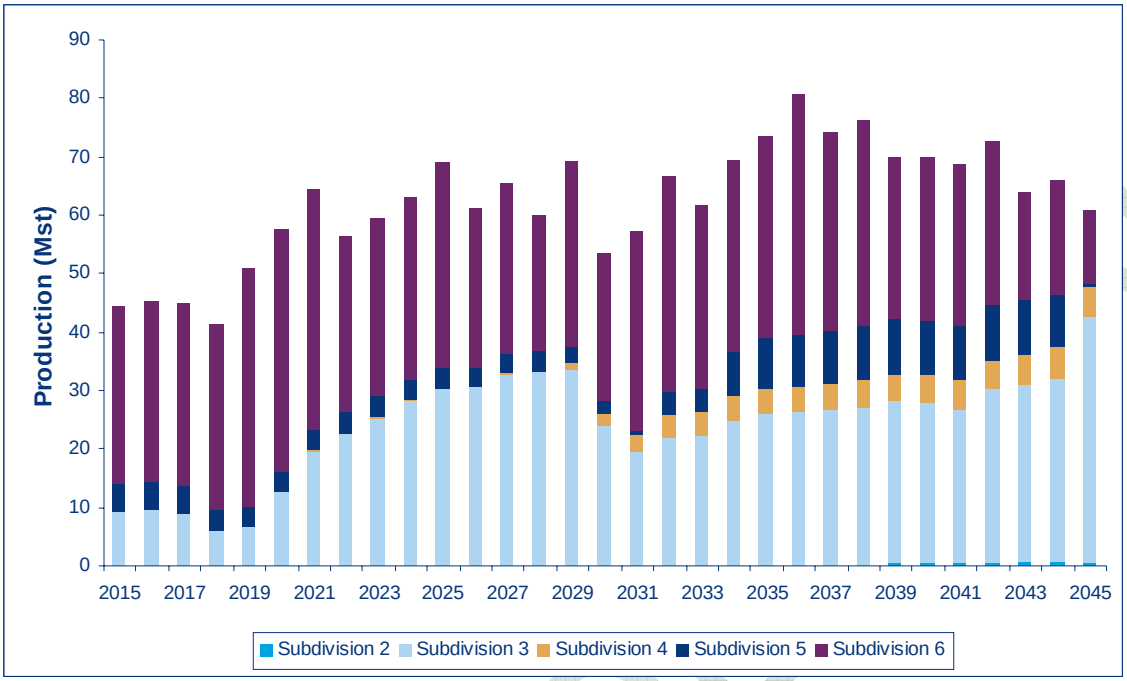
Exhibit 14 – A Comparison of Total Forecast Illinois Coal Production to Production of Coal Suitable to TEC, Mst



Source: Wood Mackenzie

Of the six mining subdivision in Illinois, Subdivision 6 (Southeastern Illinois) produces the largest amount of coal at this time and is expected to remain the largest producer for some time. However, coal mines in Subdivision 3 (West-Central Illinois) will begin to significantly expand production in 2020, eventually reaching a level greater than the total production in any other Illinois mining subdivision. See Exhibit 15.

Exhibit 15 – Forecast Coal Production by Illinois Mining Subdivision, Mst



Source: Wood Mackenzie

Coal in Subdivision 3 is nearest the TEC facility. See Exhibit 16 to view a map detailing the Illinois mining subdivisions and locations of various mines and potential mines in the area. Additional information about the numbered mines and potential mines shown on this map can be found in Appendix D. Some of this coal is close enough to be trucked to TEC as noted previously, but much of it can be both trucked and railed owing to its proximity to various railroad lines.

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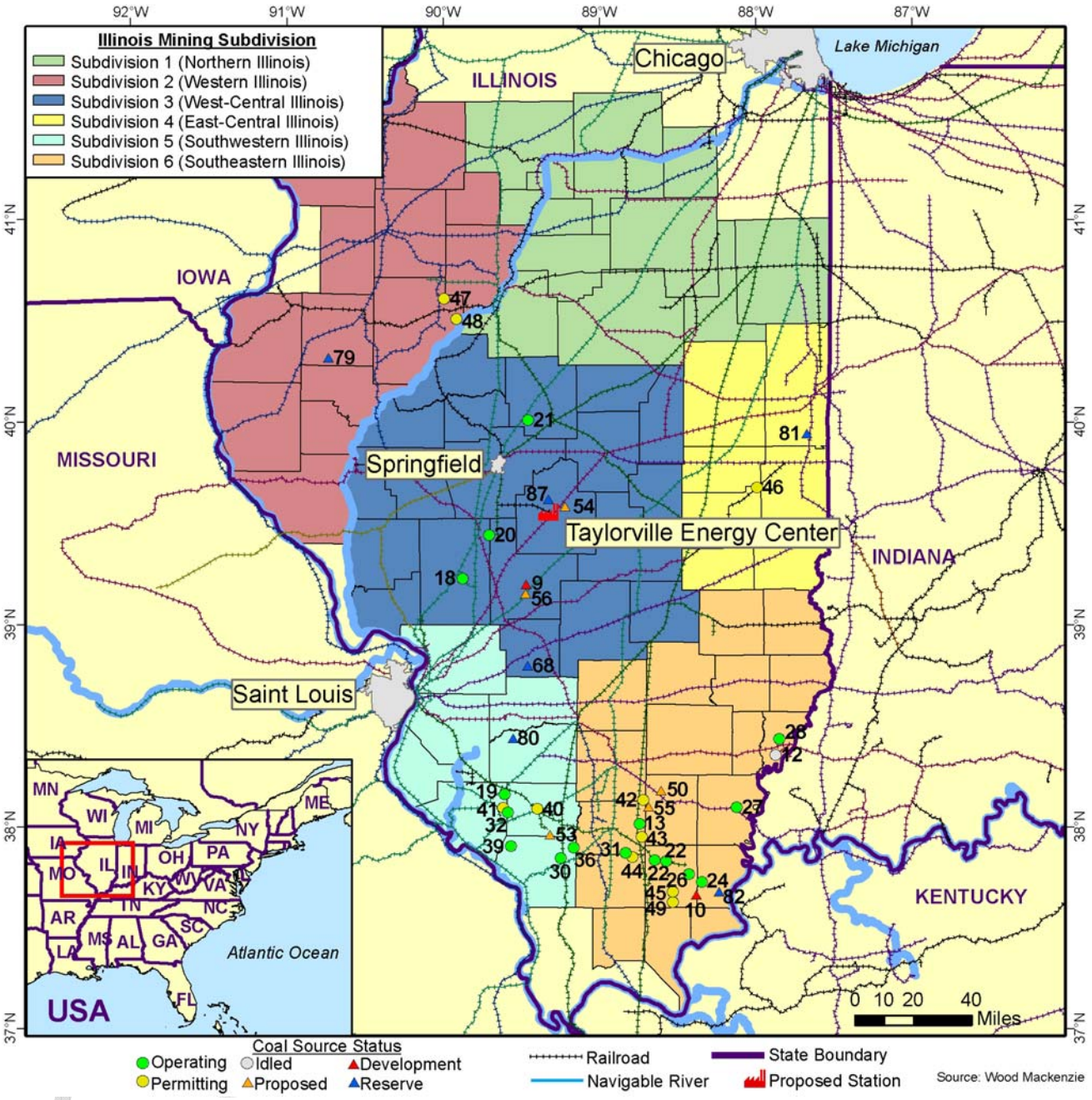
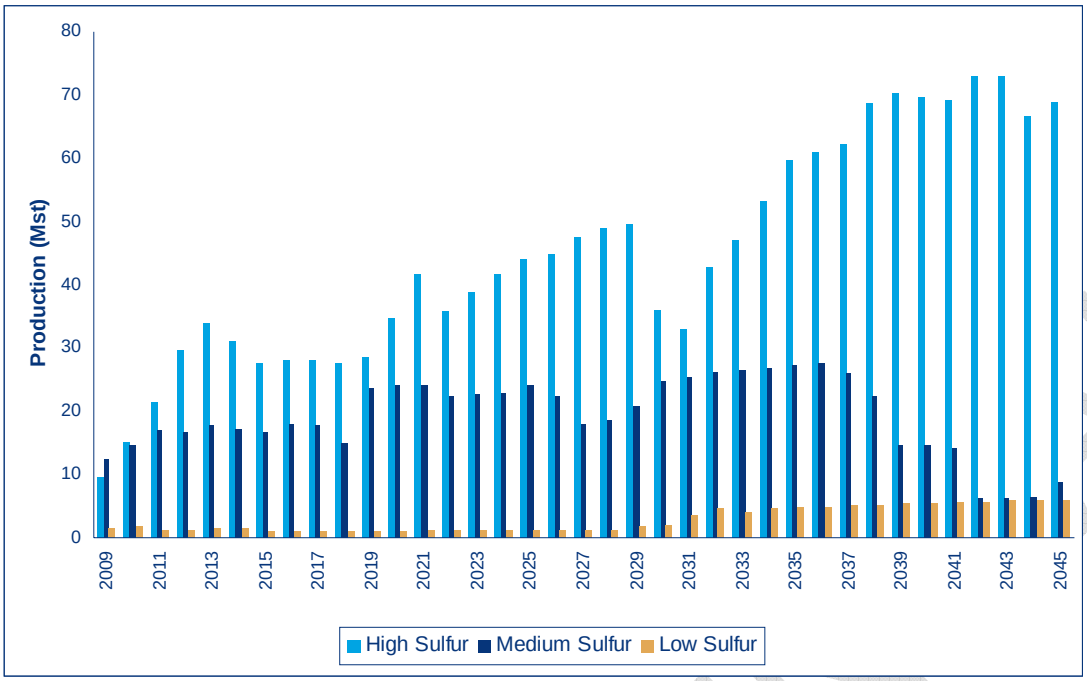
Exhibit 16 – Location of Existing and Planned Illinois Mines, Projects and Reserves



Source: Wood Mackenzie

Most of the coal produced in Illinois will continue to contain a high sulfur content. Note in Exhibit 17, that more high sulfur coal is produced over time and this coincides with increases, especially in the eastern U.S., in sulfur handling facilities at utilities (i.e. scrubbers). By the end of the forecast period there is very little low and medium sulfur coal produced in Illinois.

Exhibit 17 – Production of Illinois Coal by Sulfur Content, Mst



Source: Wood Mackenzie

The chlorine content of produced Illinois coal also changes over time. Note in Exhibit 18 that we expect the average high and low levels of produced chlorine to decline slightly in response to customer's continued concerns over the impacts of chlorine on their boilers.

Exhibit 18 – Production of Illinois Coal by Chlorine Content, Mst

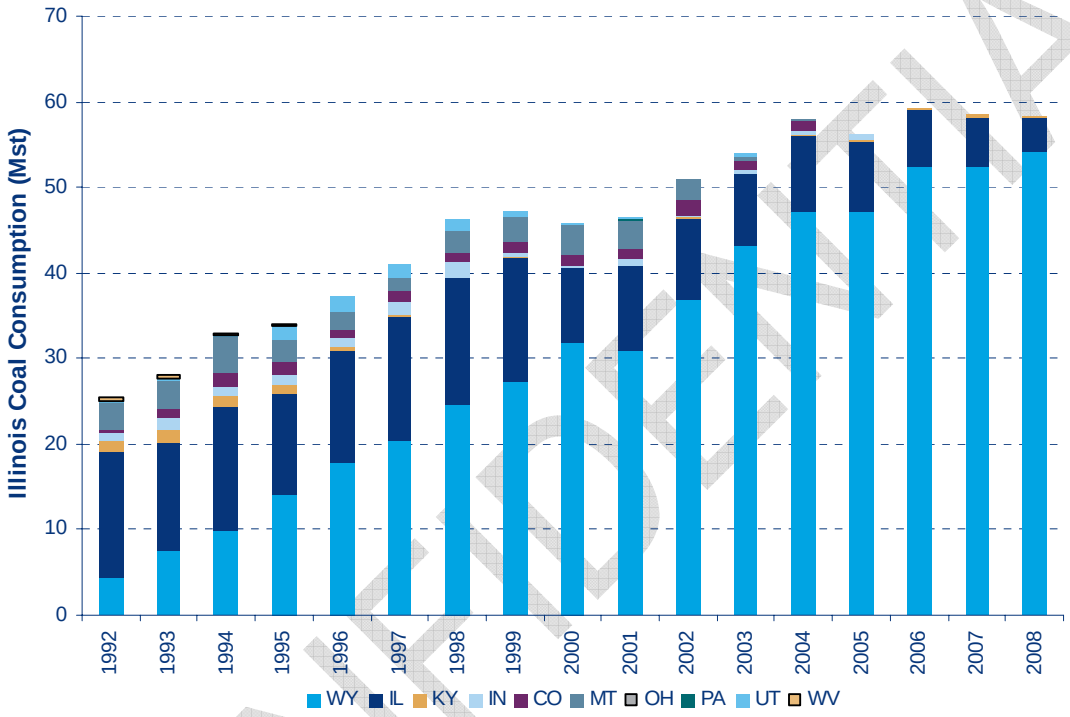
Source: Wood Mackenzie

Illinois Coal Demand

In this previous section, Illinois coal supply was described. The market for that coal also impacts its price and this market is summarized in this section. Some small but significant amounts of Illinois coal are exported and/or consumed in local industrial markets on an annual basis. However, most Illinois coal is consumed in the process of generating power. The demand for this utility coal is characterized below.

Historically, the demand for coal for power generators inside Illinois has been strong and has been met increasingly by coal produced outside the state. Historically, Illinois producers were the primary suppliers of coal to Illinois power generators, but as the cost of environmental externalities has grown, very low sulfur coal from Wyoming has become the primary source. See Exhibit 19.

Exhibit 19 – Historical Source of Coal Used by Power Generators in Illinois, Mst



Source: Ventyx, Wood Mackenzie

Going forward, several basic trends are apparent regarding the source of coal to Illinois power generators. These are:

- throughout the forecast period, there will be a reduction in the total amount of coal consumed by power generators in Illinois;
- the amount of coal produced in Illinois that is consumed in Illinois will remain fairly constant over time;
- the amount of coal produced in Wyoming and consumed by Illinois power generators is forecast to decrease steadily throughout the forecast period.
- the total amount of Montana coal consumed throughout the forecast period will grow as Wyoming coal consumption decreases. See Exhibit 20.

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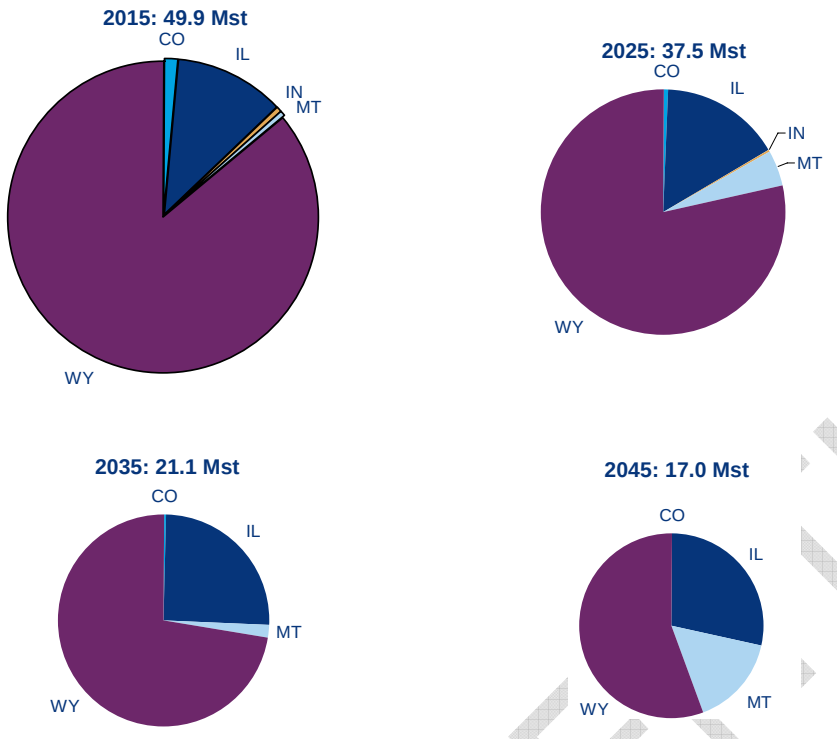
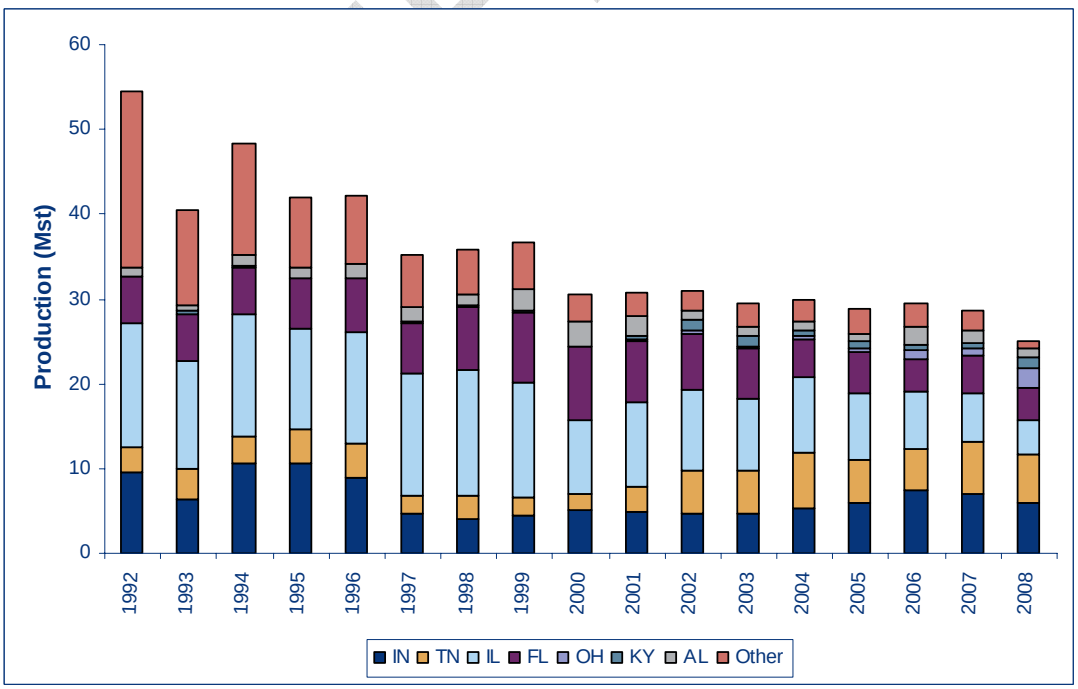
Exhibit 20 – Forecast Source of Coal Used by Power Generators in Illinois, Mst



Source: Wood Mackenzie

The Clean Air Act of 1990 was instrumental in the decline in use of coal produced in Illinois. As a result of this legislation, the amount of coal produced in Illinois has declined in almost every year since 1992. Nearly all states consume fewer Illinois tons in total than they did a decade ago. See Exhibit 21.

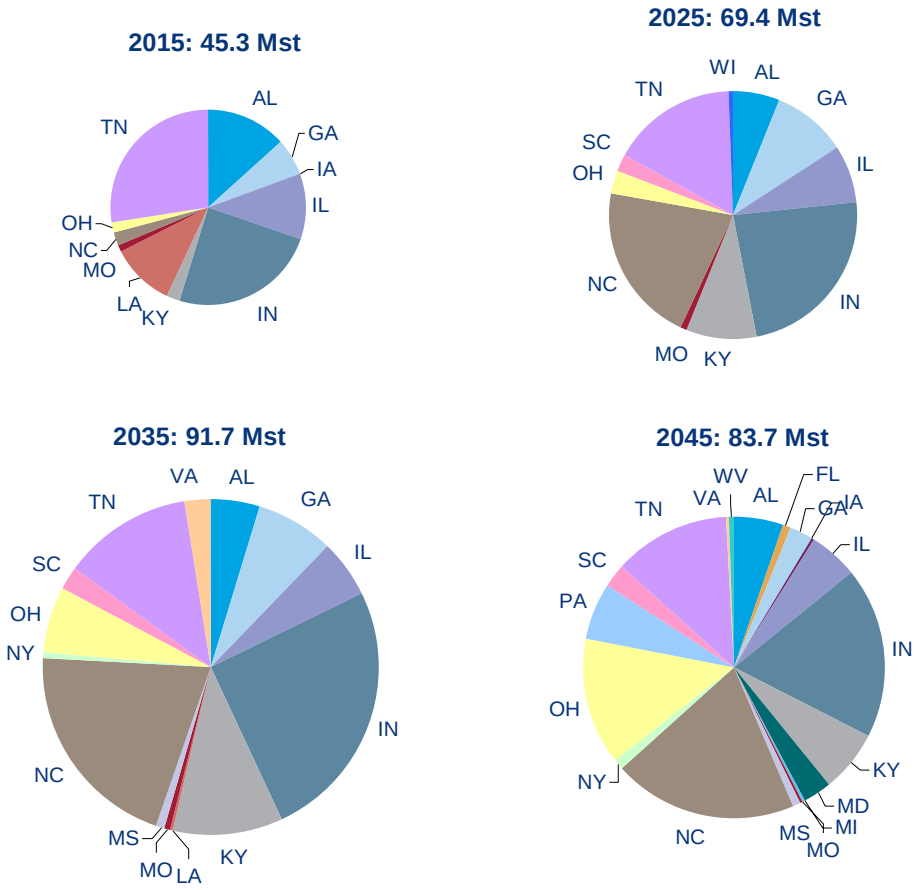
Exhibit 21 – Historical Distribution of Coal Produced In Illinois Ultimately Used by Power Generators, Mst



Source: Wood Mackenzie; Ventyx

Going forward, our PRISM™ modelling indicates a growing demand for Illinois coal by power generators across the eastern U.S.; however, as previously noted, Illinois power generators will continue to consume about the same amount of Illinois coal over the forecast period. Power generators in Indiana, Kentucky, North Carolina and Ohio will consume considerably more coal than in the past. See Exhibit 22.

Exhibit 22 – Forecast Distribution of Coal Produced in Illinois Ultimately Used by Power Generators, Mst



Source: Wood Mackenzie

Illinois Coal Transportation Infrastructure

Illinois has a well-developed coal transportation delivery network. Illinois coal producers have ready access to several class I carriers: the CN, NS, CSX, BNSF, and UP railroads. Several regional shortline carriers also provide service, including the EVW, Paducah & Louisville (PAL), and the Illinois & Midland Railroad (I&M).

At least 21 river docks and/or ports have experienced activity in recent years. Recent activity is common at the Peabody facility at Shawneetown on the Ohio River but long term improvements continue along the Ohio River. The McAlpine Locks project near Louisville will be complete this year, and a 1929-era dam at Olmstead, Illinois, is being replaced to improve traffic from the lower Ohio River to the Mississippi River system. The Olmstead project won't be complete until 2018. Because of limited dock space, both White Oak and Cline/Williamson Energy are investigating building a new dock to handle production in the future. White Oak and Cline are reportedly looking at adding a facility in the Mt. Vernon, Indiana area to be served by the EVW Railroad.

Illinois coal mines have numerous transportation options at their disposal. The well-developed infrastructure includes about 7,200 miles of rail track and more than 1,000 miles of navigable waterways. About eight Illinois mines are served exclusively by truck and the rest are served by rail. Nine docks have also handled Illinois coal production in recent years.

The state is served by five class I railroads: Canadian National (CN), Norfolk Southern, CSX, BNSF, and UP. Estimates are that CN carries almost 50% of all rail coal in Illinois. Knight Hawk, The Cline Group, and Murray's Galatia mine are the primary CN originations. Norfolk Southern originates coal at Shay (Monterey) and Friendsville. Additionally, Cline is working

with the NS to expand its loading and blending options. The UP and BNSF load from only a few mines, including Peabody's Gateway; and the CSX originates no coal since Vermilion Grove closed.

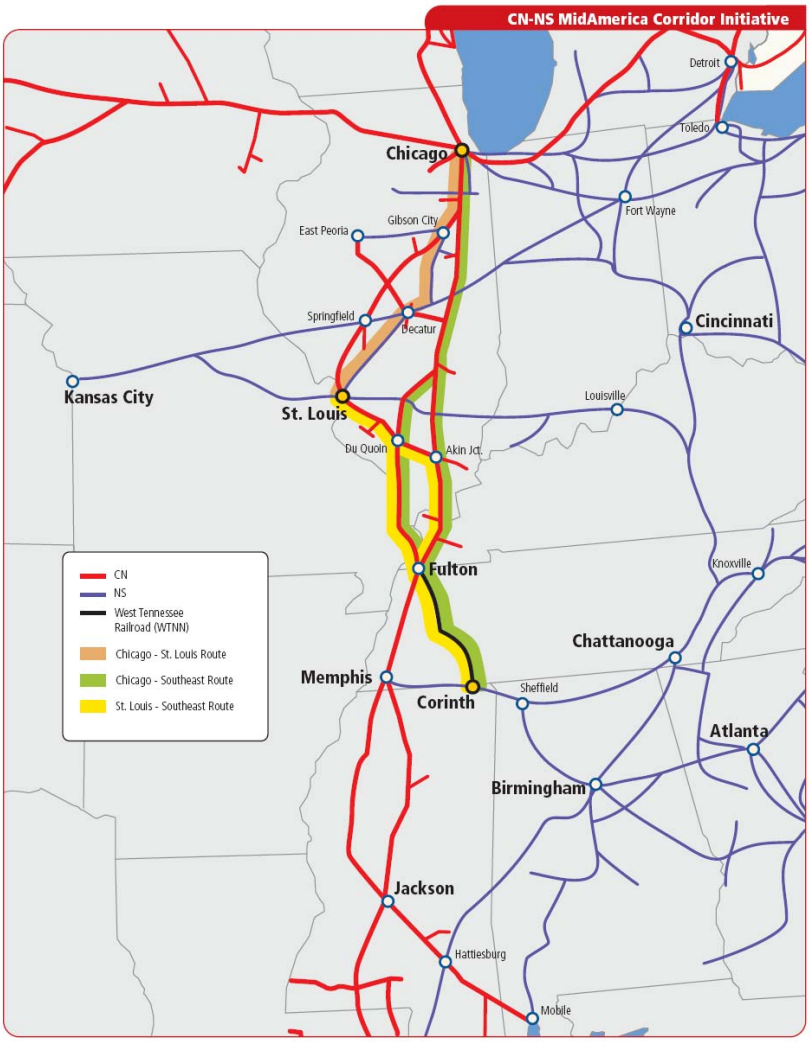
In February, 2009, CN and Norfolk Southern announced an initiative to create a "MidAmerica Corridor" in which the railroads will share track between Chicago, St. Louis, Kentucky, and Mississippi to establish shorter and faster routes for merchandise and coal traffic moving between the Midwest and Southeast.

This initiative has three components. First, NS will haul CN freight between Chicago and St. Louis, reducing the distance between these points for CN shipments by 60 miles and providing improved connections to other rail carriers through the St. Louis gateway. Second, NS will use CN's routes between St. Louis and Fulton, Ky., as part of a new, more efficient route from the Midwest to the Southeast, saving more than 50 miles on NS shipments. Third, CN will haul NS freight between Chicago and Fulton, shortening NS's Chicago-to-Birmingham route by almost 100 miles.

Access to Southern Illinois coal gives NS an opportunity to expand its coal business, and gives CN an advantage in transporting more of Cline's coal. Another potential component will improve efficiencies in moving Illinois coal within the state. Coal originating at one of Cline's operations headed for one of the Illinois coal-fired plants will also be able to reduce hauling distances. For coal heading to a NS destination, the crew-change requirement is still in place. However, the initiative is still in its infancy, and the desire to originate coal could lead to some creative opportunities for both producers and end users.

As part of the MidAmerica Corridor, CN and NS plan to create a new coal gateway at Corinth, Miss., to better link NS-served southeastern utility plants with CN-served Illinois Basin coal producers. See Exhibit 23.

Exhibit 23 – CN-NS MidAmerica Corridor Map



Source: Canadian National

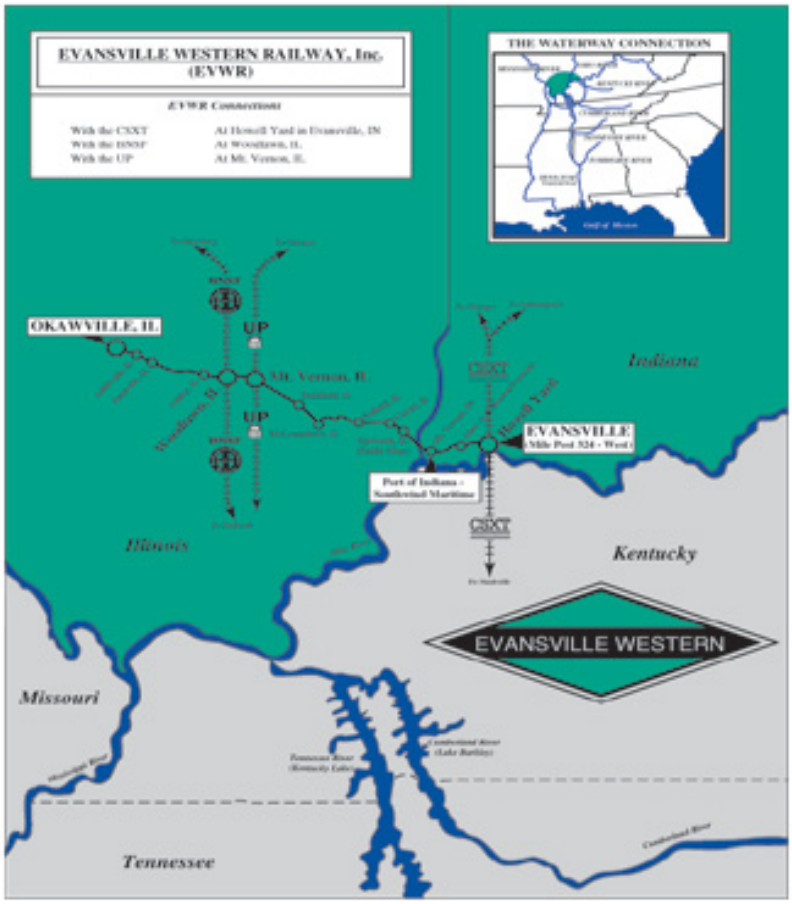
The Illinois Region of Genesee & Wyoming includes the Illinois & Midland and Tazewell & Peoria and serves greater Peoria, Springfield, Havana and Taylorville. The I&M maintains 120 miles of track in Illinois. The other large regional railroad in Illinois is the Evansville Western. The Evansville Western can load coal from Pattiki, and it is part of the Cline initiative, which includes blending and transporting coal via the Evansville Western in Evansville for transfer to the NS or to barges. CN acquired a major portion of another Midwest carrier this year, the Elgin, Joliet & Eastern Railway (EJ&E). The EJ&E primarily serves the Chicago area.

Exhibit 24 and 25 show the rail system of regional railroads in Illinois that are important to moving coal from potential sources in Illinois to TEC.

Exhibit 24 – Map of the Illinois & Midland Railroad

Source: IMRR

Exhibit 25: Evansville Western Railroad System



Source: EWRR

The Evansville Western Railway, Inc. operates over 124.5 miles of rail between Evansville, IN and Okawville, IL, including a branch line at Mt. Vernon, IN. It connects with three Class 1 carriers in Evansville, IN, and in Mt. Vernon and Woodlawn, IL.

All Illinois mines are served, at least, by truck. Mines that ship exclusively by truck include Viper, Wildcat Hills, Willow Lake, I-1 Surface, and the Springfield Coal mines. Many of these mines have access to the docks that serve the Illinois coalfields. All of the Knight Hawk mines are truck-served but all are within a few miles of both rail and barge loadouts. Trucking coal is generally considered a more viable option for distances of less than 75 miles one way. At the short distance, the trucking companies can compete with rail, and the transportation rates can be in parity. The cost of railcars may give the edge to trucking, but backhaul opportunities may keep costs down for both rail and trucking.

Illinois has numerous docks on the river system to transload coal from trucks and railcars into barges. No mines currently load coal onto barges directly from the mine, but Knight Hawk, Alliance, and Peabody all have major dock facilities. At least twelve docks or ports have seen activity in recent years.

In determination of rail rates, base rates were constructed on the basis of proprietary work. The base rate assumed a unit train originating on the CN and arriving at TEC on the NS will need to change crews in East St. Louis. The CN/NS initiative is in its earliest stages, so the potential efficiencies and cost savings are still unknowns. We are assuming there will be at least $1.50/ton savings in transferring from CN to NS, as compared to transferring from another class 1 railroad. At some point the station at Tolano could be developed, which would shorten the rail haul from several mines. This will require some capital investment, and there are current no plans to develop Tolano.

For mines that load by truck and take the coal to a prep plant before loading it onto the railcar, we are assuming there is a slight charge to transfer the coal from truck to railcar.

Unit train size is 130 cars, and coal trucks are assumed to carry 25 tons per truck.

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Base rates were established for each coal source option (as above) and two annual adjustments were made. The first adjustment was the addition of a fuel surcharge the amount of which was based on the Wood Mackenzie long term macro oil forecast, which was applied to the per-ton-mile fuel surcharge currently in place by the NS railroad. The second adjustment resulted from the application of an algorithm designed to reflecting real rate increases and/or decreases beginning in 2012, which is partially based on the Wood Mackenzie GDP growth rate forecast for the US. We assumed that the cost of private railcars will range from $1.15 per ton to $1.45/ton, depending on the origin of the coal. Base rates, transfer fees, railcar costs, etc., are added together to create a total rate.

Illinois Coal Price

Coal price is a function of supply and demand. The PRISM™ model was used to meet the nation's electricity demand at the lowest possible cost while complying with emissions regulations. In so doing, a price forecast for dozens of national coals is derived.

The Determination of Delivered Price at TEC

Generic Illinois prices and forecast mine production, both from the PRISM™ model, were used to develop an actual estimate of delivered price at TEC by employing a series of supply cost and quality adjustments and data aggregations.

These supply cost estimates (for each mine, nationally) were used as inputs in the previously described global dispatch model, PRISM™. The dispatching model simulates national supply and global demand to arrive at, among other results, a market driven price for each bundled coal quality. The modeled price, called its FOB price, is merely the price one could expect to realize for sale at the mine. Additional costs are incurred to get the coal from the mine terminal to its desired destination. These additional costs are based on delivery mode, location and distance as well as transfer costs between various transport modes. All transport costs are then added to the modeled FOB price thus resulting in unique delivered price from each mine origination to the ultimate destination.

It was necessary, first, to determine only those mines and potential mines with quality within the specification required at TEC. Note that these were all from within Illinois, by statute. A list of suitable mines was created, as was a quality profile for each one containing information about energy content, sulfur, ash and chlorine content. Because each mine is unique in its supply profile, it has a unique cost profile as well. Deeper reserves typically, but not always, have higher costs given their higher manpower and equipment needs. In the dispatch model, each coal group has a range of similar coal qualities, but is assigned the same FOB price; therefore, it was necessary to normalize each mine in the list of mines suitable for use at TEC against a standard metric. This is referred to as the "Adjusted FOB" price. Normalizing in this way differentiates FOB prices according to coal quality by allowing qualities above the standard to have a higher FOB price and those below the standard to have a lower FOB price.

For this project, two specific adjustments were made to normalize for heat content and sulfur. The FOB coal price for each mine was multiplied by the ratio of the respective mine versus the standard. For instance, the Illinois Mid-Sulfur FOB price was $42.06 in the year 2009. If coal from Mine 'A' had a heat content of 11,900 BTU/lb and the standard heat content was 11,600 BTU/lb, then the Adjusted FOB price for Mine 'A' would be [$42.06 * (11,900/11,600) = $43.15]. Because the coal at Mine 'A' had a higher BTU/lb than the standard, its price was adjusted upward.

A similar adjustment is made to account for sulfur. Sulfur is reported in terms of pounds of SO_2 per million Btu ($LbSO_2$ / mmBtu). The FOB price adjustment is the product of the model-determined 'Allowance Price' times the quantity [(standard Btu * $LbSO_2$ / mmBtu) - (respective mine Btu * $LbSO_2$/mmBtu)]. As an example, the standard used for Illinois Mid-Sulfur is 11,600 Btu and 3.5 $LbSO_2$ / mmBtu respectively. Therefore, for Mine 'A' in 2009, the adjustment would be [$47.15 * ((11,600 Btu * 3.5 $LbSO_2$ / mmBtu) - (11,900 Btu * 4.03 $LbSO_2$ / mmBtu)) /1,000,000 = $ -0.35]. Because the coal at Mine 'A' had a lower sulfur quality than the standard, its price was adjusted downward. To make up the fully adjusted FOB price, the sulfur adjustment is added to the heat content adjustment so that the resulting price [$43.15 + $-0.35 = $42.80]. The model-determined SO_2 allowance price forecast used in this sulfur adjustment process can be found in Exhibit 26.

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Exhibit 26 – SO_2 Allowance Price Forecast, 2009 $/st of SO_2 Emitted

Year	Price		Year	Price
2015	130.1		**2031**	103.6
2016	177.0		**2032**	69.2
2017	204.6		**2033**	61.1
2018	128.0		**2034**	48.9
2019	140.7		**2035**	38.0
2020	163.1		**2036**	32.9
2021	176.0		**2037**	30.2
2022	119.8		**2038**	23.5
2023	205.1		**2039**	20.3
2024	205.4		**2040**	20.3
2025	260.8		**2041**	14.5
2026	236.3		**2042**	11.9
2027	212.9		**2043**	0.0
2028	178.8		**2044**	0.0
2029	173.5		**2045**	0.0
2030	130.1			

Source: Wood Mackenzie

Finally, the Illinois Fuel Use Tax of 6.25% (which is based on the Adjusted FOB price) was calculated. For example, the previous, partially adjusted FOB price of $42.80 would have an Illinois Fuel Use Tax of $42.80 * .0625, or $2.67. The final Adjusted FOB price then becomes $42.80 + $ 2.675 = $ 45.47. To the final Adjusted FOB price, previously calculated truck, rail, barge and transfer costs are added to so that a final delivered price can be determined thus creating a unique and differentiable price between each potential origination point and TEC. Finally, it is necessary to normalize the final Adjusted FOB price so that all prices are reported on the same energy content basis.

This process is repeated for the modeled results in each year of the forecast. The actual reported delivered price at TEC is calculated in this manner, but is a function of the mines used in the process. It is thus possible to use this process, but apply it only to mines in a given subdivision to produce an average price by subdivision. If TEC were successful in buying the least expensive delivered coal available each year, then that would form the basis of the final price forecast. However, it is a better approximation of delivered price to assume that the price at TEC will be the average of a range of coals from within a particular subdivision.

The availability of coal at TEC from mines in Illinois is affected by the development of new mines in the state. This development, in turn, is a function of the demand for that mine's coal in the total marketplace, not just at TEC. As such, our PRISM™ model will not develop every possible mine and make it available to TEC; rather it will make an economic decision based upon minimizing total electricity costs.

Coal nearest the TEC facility is produced in Subdivision 3 (West-Central Illinois). This coal can be either trucked or, in some cases, railed to TEC. Transportation and handling (T&H) costs are low from this region owing to the proximity of the mines to the TEC facility. The results of our modeling, adjustments and aggregations for Subdivision 3 (West-Central Illinois) can be seen in Exhibit 27 through Exhibit 35.

Note in Exhibits 27 through 62, there are instances of significant change in the year-to-year price values. For example, there is a large change in the year 2045 maximum price in Exhibit 29. These sudden changes in maximum and minimum price on a year-to-year basis are the result of either a reserve depletion or a reserve addition to the mix of available coals. (In the case of the year 2045 maximum price in Exhibit 29, for example, a reserve was depleted thereby increasing the transportation cost from an alternate reserve.) However, regarding the general increase in price from 2027 through 2031, prices increase as a result of an increase in demand for high sulfur Illinois Basin coal on the back of the closure of some large eastern coal mines in Appalachia. This increase in demand drives prices upward.

Where there were very few source possibilities in a given region for a given period of time, such as in Figure 36 for the years 2031 through 2045, then the determination of maximum and minimum price was considered to have little value and was eliminated.

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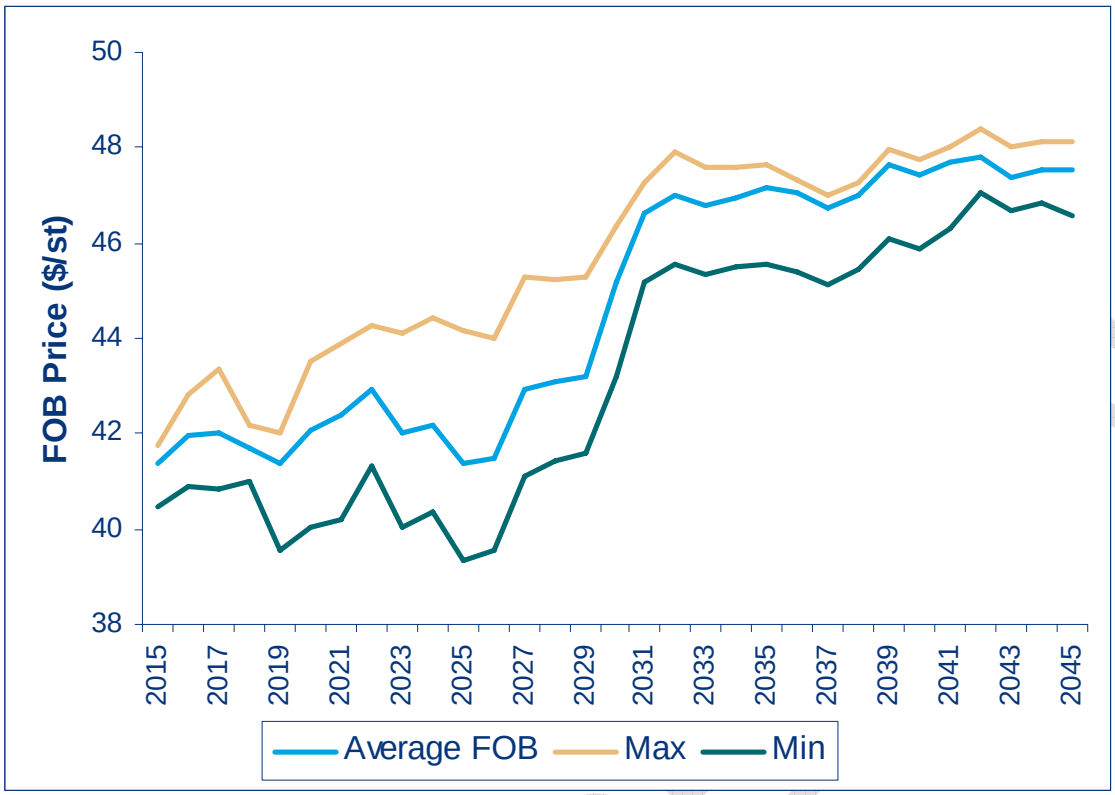
Exhibit 27 – FOB Price of Coal from Subdivision 3 (West-Central Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 28 – FOB Price of Coal from Subdivision 3 (West-Central Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average FOB Price	$41.38	$41.95	$42.01	$41.68	$41.39	$42.08	$42.41	$42.92	$42.02	$42.17	$41.39	$41.48	$42.92	$43.09	$43.19	$45.18
Max	$41.77	$42.82	$43.38	$42.16	$42.02	$43.54	$43.87	$44.29	$44.10	$44.42	$44.14	$44.02	$45.31	$45.21	$45.26	$46.37
Min	$40.46	$40.88	$40.86	$41.00	$39.53	$40.03	$40.18	$41.30	$40.04	$40.34	$39.36	$39.56	$41.10	$41.45	$41.56	$43.19

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average FOB Price	$46.64	$47.02	$46.77	$46.96	$47.17	$47.04	$46.73	$47.00	$47.65	$47.44	$47.72	$47.80	$47.39	$47.54	$47.53
Max	$47.25	$47.90	$47.59	$47.61	$47.62	$47.31	$46.98	$47.29	$47.98	$47.77	$48.02	$48.42	$47.99	$48.15	$48.13
Min	$45.17	$45.56	$45.35	$45.48	$45.58	$45.42	$45.13	$45.42	$46.08	$45.88	$46.33	$47.06	$46.68	$46.84	$46.56

Source: Wood Mackenzie

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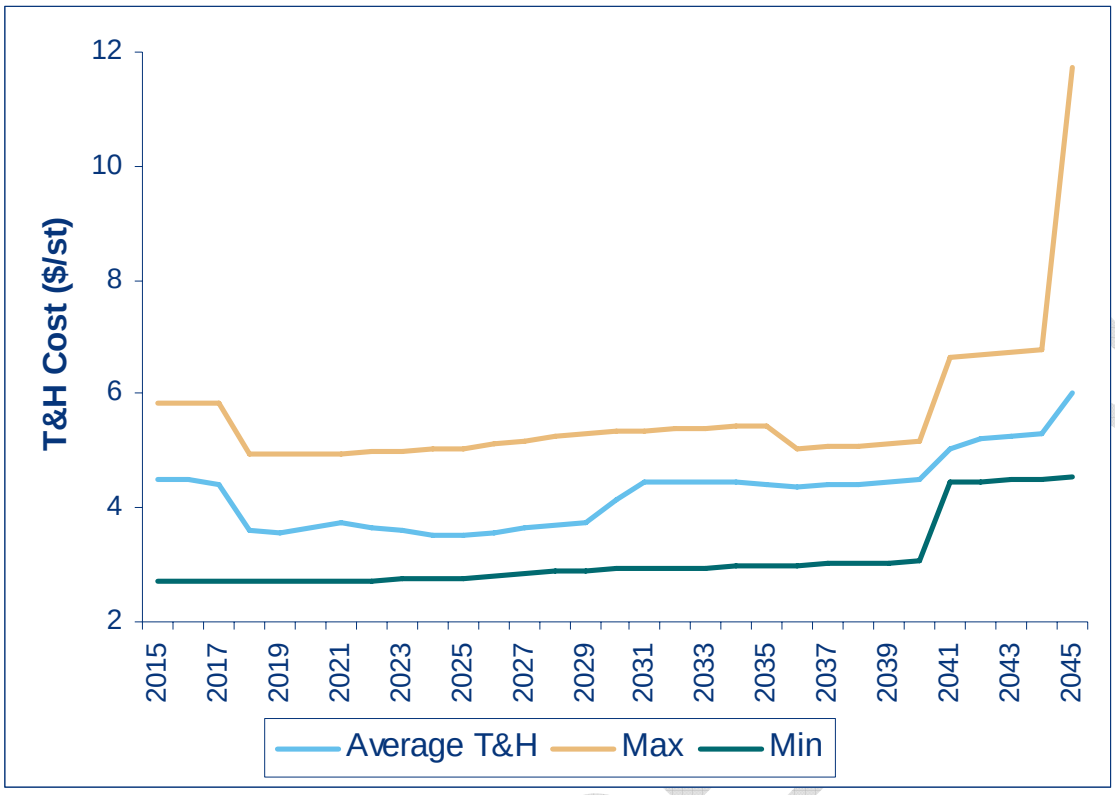
Exhibit 29 – T&H Cost of Coal Delivered to TEC from Subdivision 3 (West-Central Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 30 – T&H Cost of Coal Delivered to TEC from Subdivision 3 (West-Central Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average T&H Cost	$4.50	$4.49	$4.41	$3.62	$3.55	$3.66	$3.75	$3.65	$3.59	$3.53	$3.52	$3.57	$3.66	$3.71	$3.74	$4.12
Max	$5.82	$5.82	$5.84	$4.93	$4.94	$4.94	$4.96	$4.97	$5.00	$5.03	$5.05	$5.12	$5.19	$5.26	$5.29	$5.33
Min	$2.70	$2.70	$2.70	$2.70	$2.71	$2.71	$2.72	$2.73	$2.74	$2.76	$2.77	$2.81	$2.85	$2.88	$2.90	$2.92

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average T&H Cost	$4.45	$4.44	$4.46	$4.46	$4.43	$4.36	$4.39	$4.42	$4.45	$4.51	$5.03	$5.23	$5.27	$5.31	$6.03
Max	$5.35	$5.37	$5.40	$5.42	$5.45	$5.04	$5.07	$5.09	$5.12	$5.15	$6.66	$6.69	$6.73	$6.77	$11.74
Min	$2.93	$2.95	$2.96	$2.97	$2.99	$3.00	$3.02	$3.03	$3.05	$3.06	$4.44	$4.46	$4.49	$4.51	$4.54

Source: Wood Mackenzie

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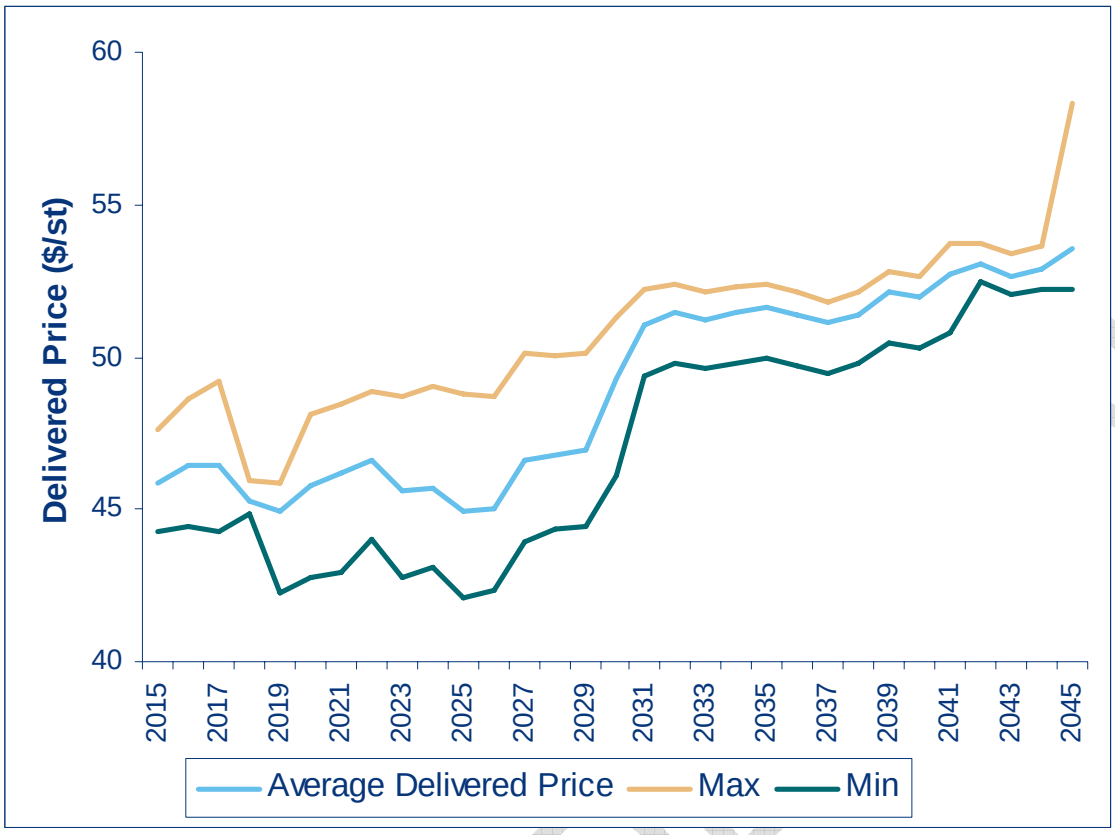
Exhibit 31 – Delivered Price of Coal at TEC from Subdivision 3 (West-Central Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 32 – Delivered Price of Coal at TEC from Subdivision 3 (West-Central Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$45.88	$46.44	$46.42	$45.31	$44.95	$45.74	$46.16	$46.58	$45.61	$45.70	$44.91	$45.06	$46.57	$46.80	$46.93	$49.31
Max	$47.59	$48.64	$49.22	$45.93	$45.89	$48.10	$48.43	$48.86	$48.71	$49.05	$48.79	$48.74	$50.09	$50.05	$50.13	$51.28
Min	$44.27	$44.42	$44.24	$44.86	$42.24	$42.74	$42.90	$44.03	$42.78	$43.10	$42.13	$42.37	$43.95	$44.33	$44.46	$46.11

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$51.09	$51.46	$51.24	$51.43	$51.59	$51.41	$51.12	$51.42	$52.10	$51.95	$52.75	$53.03	$52.66	$52.86	$53.56
Max	$52.18	$52.39	$52.15	$52.28	$52.38	$52.12	$51.83	$52.12	$52.80	$52.62	$53.71	$53.75	$53.42	$53.61	$58.30
Min	$49.40	$49.80	$49.61	$49.80	$49.96	$49.74	$49.47	$49.79	$50.46	$50.29	$50.77	$52.47	$52.04	$52.23	$52.23

Source: Wood Mackenzie

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Exhibit 33 – Quality of Coal in Subdivision 3 (West-Central Illinois)

Quality Parameter		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BTU/lb	Weighted Avg	10,433	10,434	10,443	10,522	10,523	10,626	10,675	10,660	10,649	10,639	10,635	10,636	10,632	10,633	10,634	10,675
	Max	10,538	10,538	10,538	10,538	10,538	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895	10,895
	Min	10,300	10,300	10,300	10,499	10,499	10,499	10,499	10,499	10,499	10,499	10,499	10,499	10,499	10,499	10,499	10,499
% Sulfur	Weighted Avg	2.75	2.76	2.85	3.58	3.60	3.53	3.49	3.52	3.55	3.57	3.58	3.58	3.57	3.57	3.57	3.47
	Max	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80
	Min	1.50	1.50	1.50	3.28	3.28	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20	3.20
LbS02 / mmBtu	Weighted Avg	5.24	5.26	5.42	6.81	6.84	6.65	6.55	6.62	6.67	6.72	6.74	6.74	6.72	6.72	6.72	6.51
	Max	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21
	Min	2.90	2.90	2.90	6.24	6.24	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87
LbS / mmBtu	Weighted Avg	2.62	2.63	2.71	3.40	3.42	3.33	3.27	3.31	3.34	3.36	3.37	3.37	3.36	3.36	3.36	3.25
	Max	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61
	Min	1.45	1.45	1.45	3.12	3.12	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94
% Ash	Weighted Avg	8.85	8.85	8.88	9.08	9.05	8.61	8.40	8.44	8.47	8.50	8.51	8.50	8.53	8.53	8.53	8.43
	Max	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20	9.20
	Min	8.50	8.50	8.50	9.00	8.76	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60
% Chlorine	Weighted Avg High	0.20	0.20	0.20	0.21	0.22	0.22	0.22	0.22	0.22	0.23	0.23	0.23	0.22	0.22	0.22	0.21
	Max	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	Min	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.13	0.13	0.13	0.13
	Weighted Avg Low	0.20	0.20	0.20	0.21	0.21	0.21	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	Max	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	Min	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.13	0.13	0.13	0.13

Quality Parameter		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
BTU/lb	Weighted Avg	10,711	10,728	10,729	10,743	10,767	10,798	10,800	10,801	10,803	10,811	10,847	10,864	10,863	10,861	10,862
	Max	10,895	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	10,900	11,000	11,000	11,000	11,000
	Min	10,499	10,499	10,499	10,499	10,499	10,538	10,538	10,538	10,538	10,538	10,555	10,700	10,700	10,700	10,640
% Sulfur	Weighted Avg	3.38	3.34	3.34	3.30	3.27	3.25	3.24	3.24	3.24	3.22	3.12	3.09	3.09	3.09	3.14
	Max	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.80	3.47	3.20	3.20	3.20	3.90
	Min	3.20	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90	2.90
LbS02 / mmBtu	Weighted Avg	6.33	6.23	6.23	6.16	6.09	6.02	6.02	6.01	6.01	5.97	5.75	5.70	5.70	5.70	5.80
	Max	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	7.21	6.58	5.98	5.98	5.98	7.33
	Min	5.87	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32	5.32
LbS / mmBtu	Weighted Avg	3.16	3.12	3.12	3.08	3.05	3.01	3.01	3.01	3.00	2.98	2.88	2.85	2.85	2.85	2.90
	Max	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.61	3.29	2.99	2.99	2.99	3.67
	Min	2.94	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66
% Ash	Weighted Avg	8.34	8.40	8.39	8.44	8.45	8.42	8.42	8.42	8.41	8.40	8.30	8.32	8.32	8.32	8.63
	Max	9.20	9.20	9.20	9.20	9.20	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	10.60
	Min	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60	7.60
% Chlorine	Weighted Avg High	0.20	0.21	0.21	0.22	0.22	0.23	0.23	0.23	0.24	0.23	0.23	0.23	0.23	0.23	0.22
	Max	0.25	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
	Min	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.17	0.17	0.17	0.10
	Weighted Avg Low	0.20	0.19		0.18	0.18	0.17	0.17	0.17	0.17	0.17	0.16	0.17	0.17	0.17	0.17
	Max	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.20	0.25	0.25	0.25	0.25
	Min	0.13	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10

Source: Wood Mackenzie

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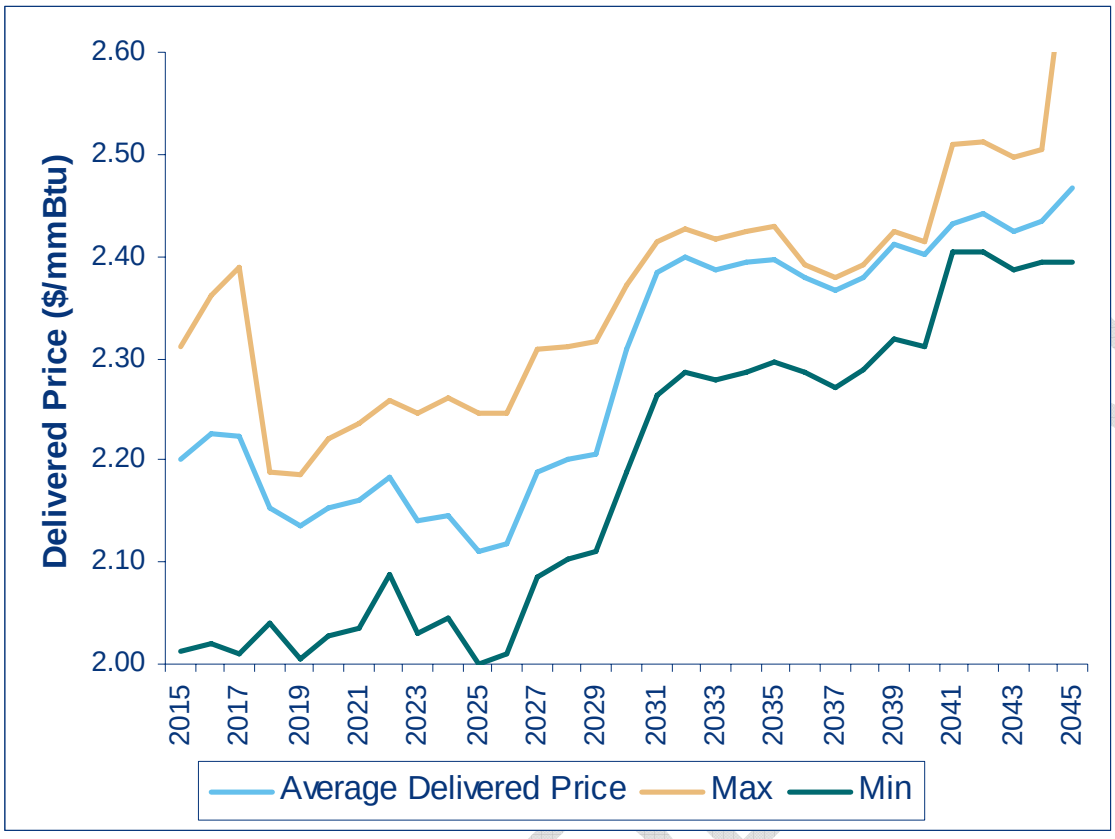
Exhibit 34 – Delivered Price of Coal at TEC from Subdivision 3 (West-Central Illinois), Graph, 2009 $/mmBtu



Source: Wood Mackenzie

Exhibit 35 – Delivered Price of Coal at TEC from Subdivision 3 (West-Central Illinois), Table, 2009 $/mmBtu

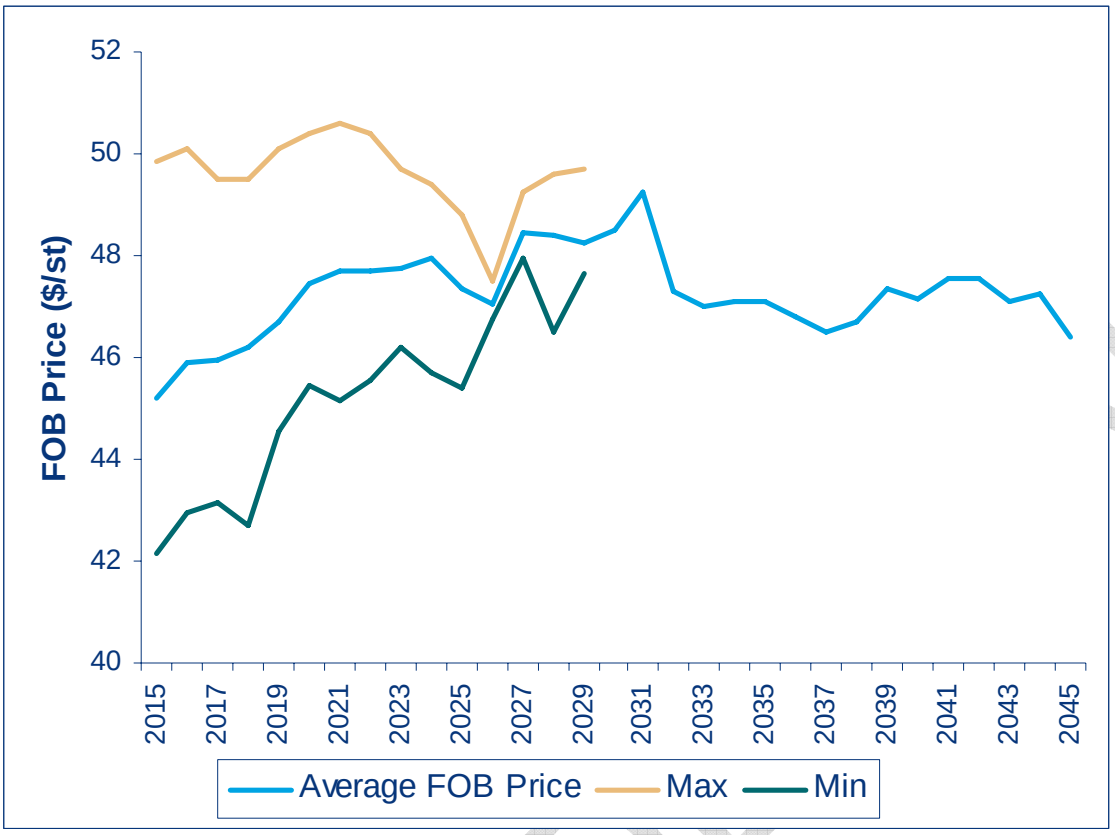
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$2.20	$2.23	$2.22	$2.15	$2.14	$2.15	$2.16	$2.18	$2.14	$2.15	$2.11	$2.12	$2.19	$2.20	$2.21	$2.31
Max	$2.31	$2.36	$2.39	$2.19	$2.19	$2.22	$2.24	$2.26	$2.25	$2.26	$2.25	$2.25	$2.31	$2.31	$2.32	$2.37
Min	$2.01	$2.02	$2.01	$2.04	$2.00	$2.03	$2.04	$2.09	$2.03	$2.04	$2.00	$2.01	$2.09	$2.10	$2.11	$2.19

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$2.38	$2.40	$2.39	$2.39	$2.40	$2.38	$2.37	$2.38	$2.41	$2.40	$2.43	$2.44	$2.42	$2.43	$2.47
Max	$2.42	$2.43	$2.42	$2.42	$2.43	$2.39	$2.38	$2.39	$2.42	$2.42	$2.51	$2.51	$2.50	$2.51	$2.74
Min	$2.26	$2.29	$2.28	$2.29	$2.30	$2.28	$2.27	$2.29	$2.32	$2.31	$2.40	$2.40	$2.39	$2.39	$2.39

Source: Wood Mackenzie

In Subdivision 5 (Southwestern Illinois) there is also significant coal available to TEC. This coal will always be railed to TEC. Coal from this region is slightly higher in energy content (11,256 Btu/lb in 2015) than in Subdivision 3 (West-Central Illinois) and a bit lower in sulfur content (4.7 $LbSO_2$/mmBtu in 2015). However, transportation and handling costs are higher from this region than those in Subdivision 3 (West-Central Illinois) simply due to the greater distance the coal must travel. The results of our modeling, adjustments and aggregations for Subdivision 5 (Southwestern Illinois) can be seen in Exhibit 36 through Exhibit 44.

Exhibit 36 – FOB Price of Coal from Subdivision 5 (Southwestern Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

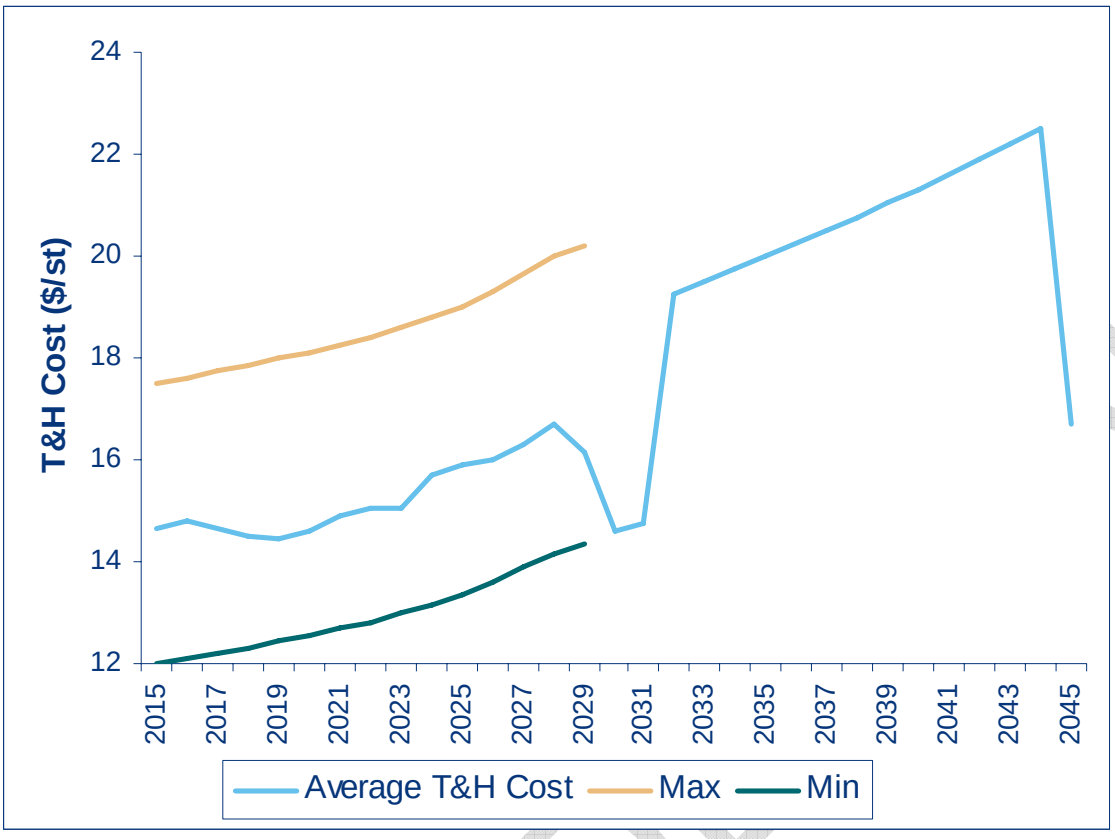
Exhibit 37 – FOB Price of Coal from Subdivision 5 (Southwestern Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average FOB Price	$45.19	$45.91	$45.96	$46.22	$46.71	$47.44	$47.70	$47.69	$47.73	$47.94	$47.35	$47.07	$48.47	$48.41	$48.26	$48.50
Max	$49.86	$50.12	$49.52	$49.50	$50.11	$50.41	$50.61	$50.40	$49.70	$49.40	$48.80	$47.49	$49.23	$49.58	$49.70	
Min	$42.16	$42.94	$43.14	$42.70	$44.53	$45.46	$45.13	$45.55	$46.22	$45.71	$45.42	$46.77	$47.94	$46.51	$47.64	

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average FOB Price	$49.24	$47.32	$47.02	$47.08	$47.11	$46.80	$46.48	$46.72	$47.35	$47.15	$47.55	$47.55	$47.12	$47.27	$46.38
Max															
Min															

Source: Wood Mackenzie

Exhibit 38 – T&H Cost of Coal Delivered to TEC from Subdivision 5 (Southwestern Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 39 – T&H Cost of Coal Delivered to TEC from Subdivision 5 (Southwestern Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average T&H Cost	$14.63	$14.78	$14.65	$14.52	$14.47	$14.58	$14.92	$15.06	$15.07	$15.72	$15.88	$15.98	$16.28	$16.71	$16.13	$14.58
Max	$17.51	$17.61	$17.75	$17.85	$18.00	$18.10	$18.25	$18.40	$18.59	$18.79	$18.99	$19.32	$19.66	$20.01	$20.22	
Min	$11.98	$12.08	$12.21	$12.31	$12.44	$12.55	$12.68	$12.82	$12.99	$13.16	$13.33	$13.61	$13.89	$14.17	$14.35	

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average T&H Cost	$14.76	$19.25	$19.49	$19.73	$19.98	$20.23	$20.49	$20.76	$21.03	$21.31	$21.59	$21.88	$22.18	$22.49	$16.71
Max															
Min															

Source: Wood Mackenzie

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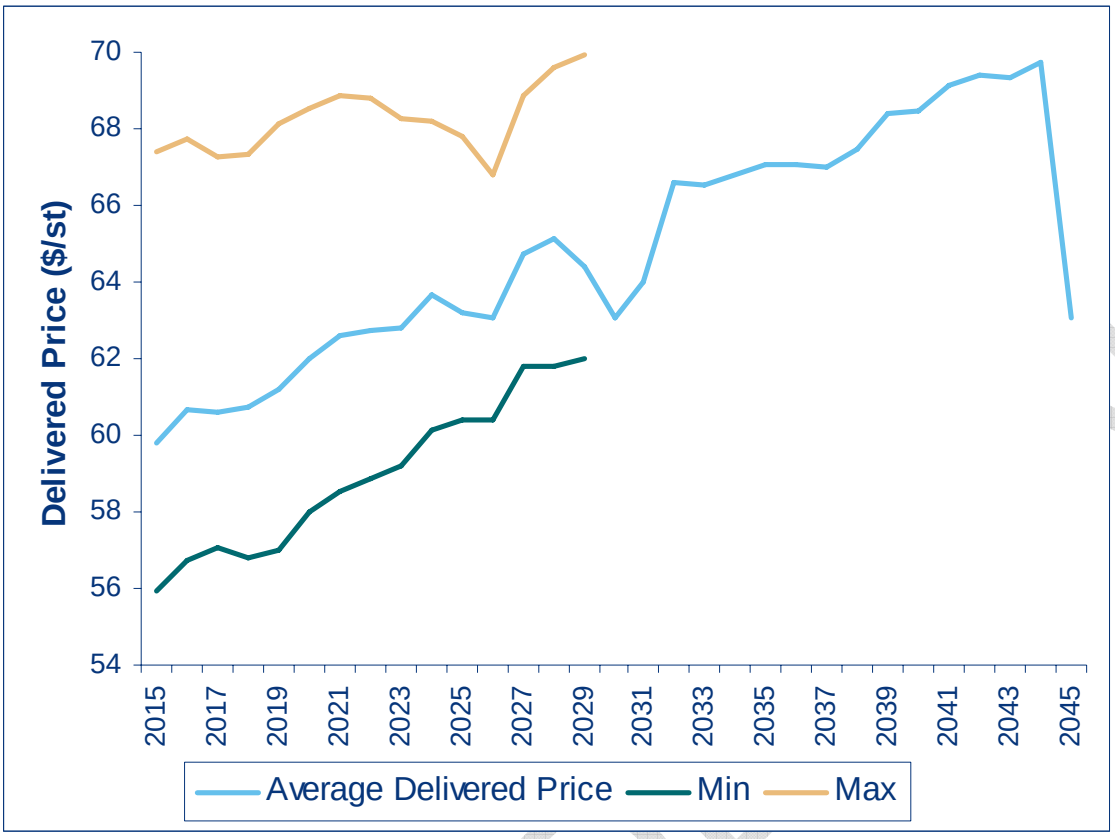
Exhibit 40 – Delivered Price of Coal at TEC from Subdivision 5 (Southwestern Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 41 – Delivered Cost of Coal at TEC from Subdivision 5 (Southwestern Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$59.83	$60.69	$60.61	$60.74	$61.18	$62.02	$62.61	$62.75	$62.80	$63.66	$63.23	$63.05	$64.76	$65.12	$64.39	$63.08
Max	$67.38	$67.72	$67.27	$67.35	$68.10	$68.51	$68.86	$68.80	$68.29	$68.19	$67.79	$66.81	$68.90	$69.59	$69.92	
Min	$55.93	$56.76	$57.03	$56.82	$56.97	$58.01	$58.53	$58.86	$59.20	$60.14	$60.38	$60.38	$61.82	$61.79	$61.99	

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$63.99	$66.57	$66.51	$66.80	$67.08	$67.03	$66.97	$67.47	$68.38	$68.45	$69.14	$69.43	$69.30	$69.76	$63.09
Max															
Min															

Source: Wood Mackenzie

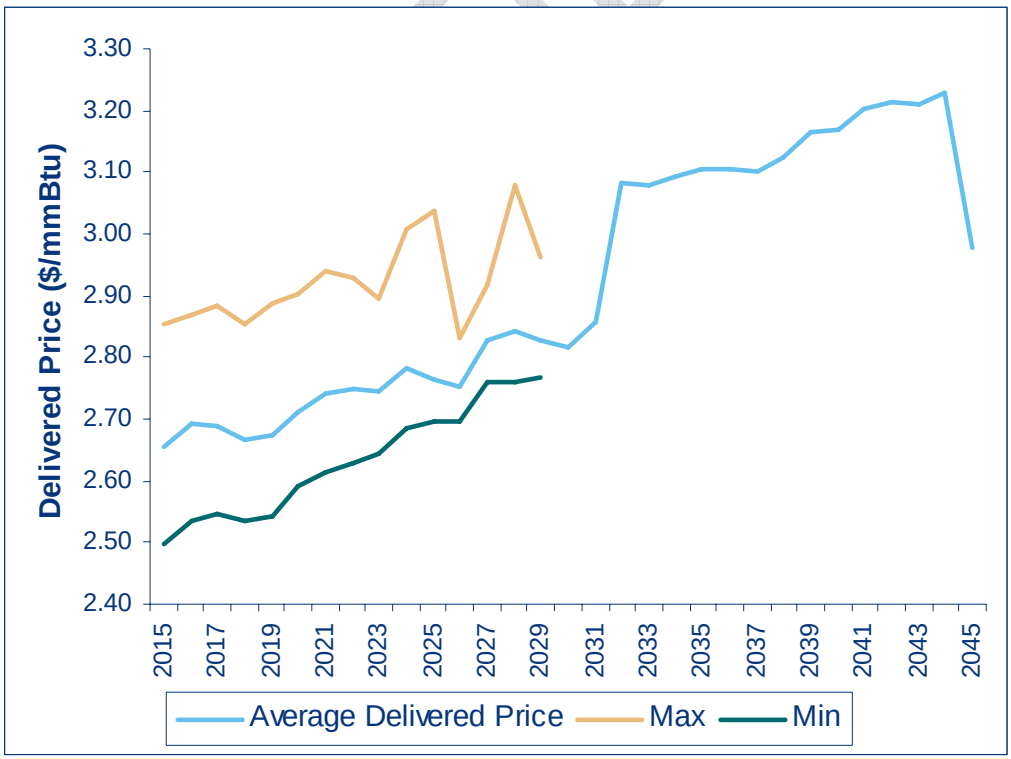
Exhibit 42 – Quality of Coal in Subdivision 5 (Southwestern Illinois)

Quality Parameter		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BTU/lb	Weighted Avg	11,256	11,257	11,262	11,376	11,419	11,420	11,407	11,408	11,423	11,436	11,433	11,449	11,449	11,440	11,381	11,200
	Max	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	11,800	
	Min	10,683	10,683	10,683	10,683	11,200	11,200	11,165	11,165	11,200	11,165	11,165	11,200	11,200	11,165	11,200	
% Sulfur	Weighted Avg	2.63	2.65	2.63	2.56	2.51	2.51	2.54	2.54	2.50	2.48	2.48	2.44	2.44	2.47	2.57	2.90
	Max	3.00	3.20	3.20	3.20	3.00	3.00	3.20	3.20	3.00	3.20	3.20	2.90	2.90	3.20	2.90	
	Min	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80	
LbS02 / mmBtu	Weighted Avg	4.70	4.72	4.69	4.51	4.43	4.42	4.46	4.46	4.41	4.34	4.35	4.30	4.30	4.32	4.54	5.18
	Max	5.47	5.70	5.70	5.70	5.36	5.36	5.70	5.70	5.36	5.70	5.70	5.18	5.18	5.70	5.18	
	Min	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	3.05	
LbS / mmBtu	Weighted Avg	2.35	2.36	2.34	2.25	2.21	2.21	2.23	2.23	2.21	2.17	2.17	2.15	2.15	2.16	2.27	2.59
	Max	2.73	2.85	2.85	2.85	2.68	2.68	2.85	2.85	2.68	2.85	2.85	2.59	2.59	2.85	2.59	
	Min	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	1.53	
% Ash	Weighted Avg	9.60	9.61	9.72	9.67	9.64	9.64	9.63	9.63	9.64	9.58	9.59	9.59	9.59	9.59	9.70	10.01
	Max	10.50	10.50	10.50	10.50	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	
	Min	8.44	8.44	8.44	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	9.00	
% Chlorine	Weighted Avg High	0.12	0.12	0.13	0.13	0.14	0.14	0.13	0.13	0.14	0.14	0.14	0.14	0.14	0.14	0.13	0.10
	Max	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	
	Min	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	
	Weighted Avg Low	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	Max	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	
	min	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	

Quality Parameter		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
BTU/lb	Weighted Avg	11,200	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,600
	Max															
	Min															
% Sulfur	Weighted Avg	2.90	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.20
	Max															
	Min															
LbS02 / mmBtu	Weighted Avg	5.18	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	5.56	6.04
	Max															
	Min															
LbS / mmBtu	Weighted Avg	2.59	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	3.02
	Max															
	Min	2.59	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	2.78	3.02
% Ash	Weighted Avg	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	10.01	8.90
	Max															
	Min															
% Chlorine	Weighted Avg High	0.10	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	Max															
	Min															
	Weighted Avg Low	0.10	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.15
	Max															
	Min															

Source: Wood Mackenzie

Exhibit 43 – Delivered Price of Coal at TEC from Subdivision 5 (Southwestern Illinois), Graph, 2009 $/mmBtu



Source: Wood Mackenzie

Exhibit 44 – Delivered Price of Coal at TEC from Subdivision 5 (Southwestern Illinois), Table, 2009 $/mmBtu

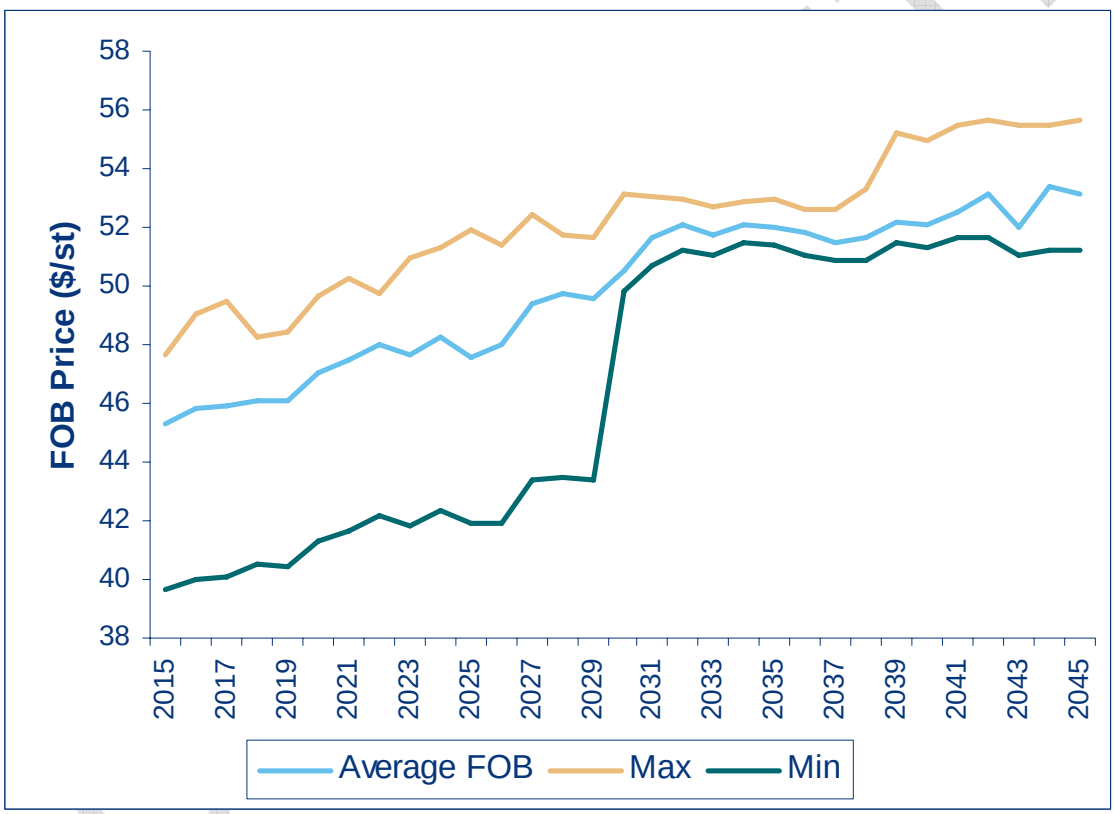
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$2.65	$2.69	$2.69	$2.67	$2.67	$2.71	$2.74	$2.75	$2.75	$2.78	$2.76	$2.75	$2.83	$2.84	$2.83	$2.82
Max	$2.85	$2.87	$2.88	$2.85	$2.89	$2.90	$2.94	$2.93	$2.89	$3.01	$3.04	$2.83	$2.92	$3.08	$2.96	
Min	$2.50	$2.53	$2.55	$2.54	$2.54	$2.59	$2.61	$2.63	$2.64	$2.68	$2.70	$2.70	$2.76	$2.76	$2.77	

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$2.86	$3.08	$3.08	$3.09	$3.11	$3.10	$3.10	$3.12	$3.17	$3.17	$3.20	$3.21	$3.21	$3.23	$2.98
Max															
Min															

Source: Wood Mackenzie

There are very significant coal reserves in Subdivision 6 (Southeastern Illinois). This coal will be either railed to TEC directly or transported to the river, barged to a transloader near East St. Louis, Illinois and then railed to TEC. Some of the best coal in Illinois can be found in this subdivision, averaging about 11,701 Btu/lb and 4.63 $LbSO_2$/mmBtu in 2015. Its distance from TEC, however, adds greatly to its delivered cost and the extra energy content is not sufficient to compensate for the higher transportation and handling costs. The results of our modeling, adjustments and aggregations for Subdivision 6 (Southeastern Illinois) can be seen in Exhibit 45 through Exhibit 53.

Exhibit 45 – FOB Price of Coal from Subdivision 6 (Southeastern Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

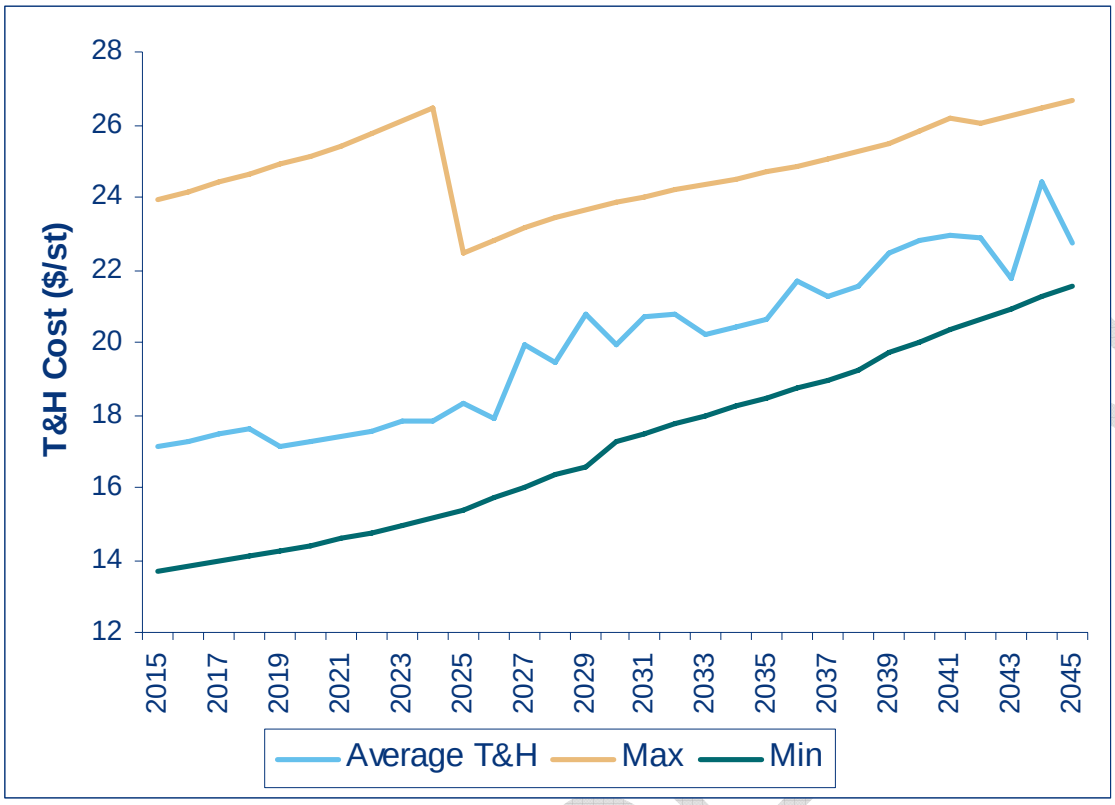
Exhibit 46 – FOB Price of Coal from Subdivision 6 (Southeastern Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average FOB Price	$45.33	$45.82	$45.93	$46.11	$46.13	$47.05	$47.47	$47.98	$47.67	$48.22	$47.59	$48.03	$49.39	$49.71	$49.55	$50.48
Max	$47.65	$49.00	$49.50	$48.22	$48.39	$49.65	$50.22	$49.72	$50.97	$51.32	$51.95	$51.41	$52.40	$51.71	$51.68	$53.09
Min	$39.67	$39.97	$40.08	$40.53	$40.45	$41.27	$41.67	$42.18	$41.85	$42.32	$41.90	$41.90	$43.40	$43.45	$43.42	$49.85

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average FOB Price	$51.63	$52.10	$51.72	$52.07	$52.00	$51.79	$51.44	$51.69	$52.15	$52.06	$52.49	$53.09	$51.97	$53.37	$53.09
Max	$53.03	$52.98	$52.71	$52.86	$52.98	$52.64	$52.58	$53.30	$55.21	$54.97	$55.48	$55.65	$55.50	$55.47	$55.64
Min	$50.72	$51.23	$51.03	$51.49	$51.43	$51.03	$50.86	$50.85	$51.51	$51.29	$51.66	$51.63	$51.05	$51.21	$51.19

Source: Wood Mackenzie

Exhibit 47 – T&H Cost of Coal Delivered to TEC from Subdivision 6 (Southeastern Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 48 – T&H Cost of Coal Delivered to TEC from Subdivision 6 (Southeastern Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average T&H Cost	$17.13	$17.28	$17.47	$17.60	$17.11	$17.24	$17.41	$17.57	$17.81	$17.82	$18.29	$17.90	$19.93	$19.42	$20.77	$19.95
Max	$23.96	$24.17	$24.44	$24.65	$24.93	$25.15	$25.43	$25.72	$26.07	$26.43	$22.49	$22.81	$23.14	$23.47	$23.64	$23.87
Min	$13.71	$13.83	$13.99	$14.12	$14.28	$14.41	$14.57	$14.74	$14.94	$15.15	$15.37	$15.69	$16.03	$16.36	$16.59	$17.28

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average T&H Cost	$20.71	$20.77	$20.18	$20.42	$20.63	$21.69	$21.24	$21.52	$22.48	$22.77	$22.97	$22.85	$21.76	$24.43	$22.76
Max	$24.03	$24.18	$24.35	$24.52	$24.69	$24.86	$25.05	$25.23	$25.47	$25.81	$26.16	$26.02	$26.24	$26.45	$26.68
Min	$17.50	$17.73	$17.97	$18.21	$18.46	$18.71	$18.97	$19.24	$19.75	$20.03	$20.32	$20.62	$20.92	$21.23	$21.55

Source: Wood Mackenzie

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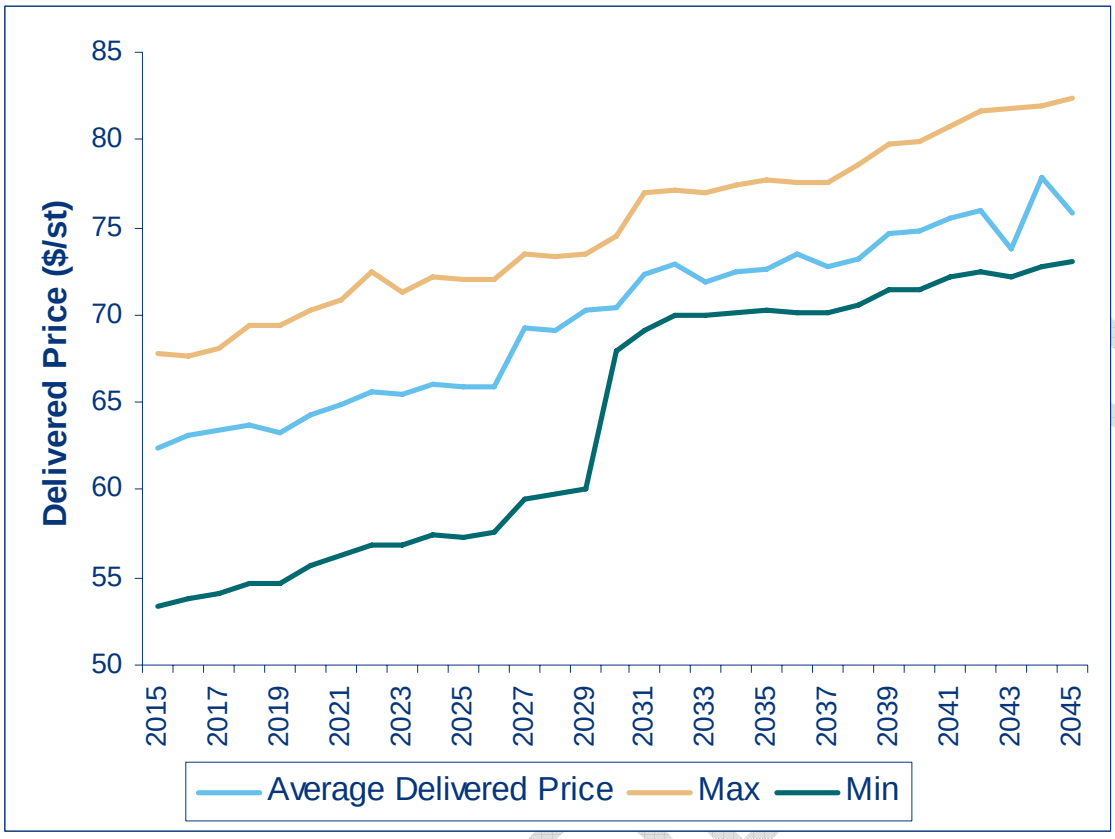
Exhibit 49 – Delivered Price of Coal at TEC from Subdivision 6 (Southeastern Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 50 – Delivered Price of Coal at TEC from Subdivision 6 (Southeastern Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$62.46	$63.10	$63.39	$63.71	$63.24	$64.29	$64.88	$65.55	$65.48	$66.04	$65.88	$65.93	$69.32	$69.13	$70.33	$70.43
Max	$67.74	$67.65	$68.05	$69.44	$69.45	$70.32	$70.88	$72.51	$71.34	$72.23	$72.08	$72.01	$73.47	$73.29	$73.55	$74.45
Min	$53.39	$53.80	$54.08	$54.65	$54.72	$55.68	$56.24	$56.92	$56.79	$57.47	$57.26	$57.59	$59.43	$59.82	$60.01	$67.87

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$72.34	$72.87	$71.90	$72.48	$72.63	$73.48	$72.69	$73.21	$74.63	$74.83	$75.46	$75.93	$73.73	$77.80	$75.85
Max	$76.98	$77.17	$77.00	$77.38	$77.67	$77.50	$77.63	$78.53	$79.69	$79.94	$80.75	$81.67	$81.74	$81.93	$82.32
Min	$69.10	$70.01	$70.02	$70.17	$70.32	$70.19	$70.07	$70.51	$71.43	$71.49	$72.15	$72.41	$72.10	$72.78	$73.09

Source: Wood Mackenzie

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Exhibit 51– Quality of Coal in Subdivision 6 (Southeastern Illinois)

Quality Parameter		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BTU/lb	Weighted Avg	11,701	11,701	11,701	11,701	11,742	11,742	11,740	11,726	11,726	11,246	10,488	11,363	10,158	11,270	10,259	11,345
	Max	12,086	12,086	12,086	12,086	12,086	12,086	12,086	11,900	11,900	12,086	12,086	12,086	12,086	12,086	12,086	12,086
	Min	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	10,298	11,600
% Sulfur	Weighted Avg	2.70	2.70	2.70	2.70	2.63	2.63	2.62	2.48	2.48	2.49	2.54	2.45	2.56	2.45	2.54	2.36
	Max	3.00	3.00	3.00	3.00	3.00	3.00	3.00	2.91	2.91	2.96	2.96	2.96	2.96	2.96	2.96	2.96
	Min	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.20	2.20	2.20	1.26
LbS02 / mmBtu	Weighted Avg	4.63	4.62	4.62	4.61	4.49	4.48	4.47	4.23	4.23	4.24	4.30	4.19	4.34	4.18	4.29	4.01
	Max	5.13	5.13	5.13	5.13	5.13	5.13	5.13	4.93	4.93	4.93	4.90	4.90	4.90	4.90	4.90	4.90
	Min	4.09	4.09	4.09	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	4.03	3.79	3.79	3.79	2.08
LbS / mmBtu	Weighted Avg	2.31	2.31	2.31	2.31	2.24	2.24	2.24	2.12	2.12	2.12	2.15	2.09	2.17	2.09	2.15	2.01
	Max	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.47	2.47	2.47	2.45	2.45	2.45	2.45	2.45	2.45
	Min	2.05	2.05	2.05	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	2.02	1.90	1.90	1.90	1.04
% Ash	Weighted Avg	8.73	8.73	8.73	8.72	8.36	8.36	8.34	8.07	8.07	8.24	8.43	8.21	8.21	7.94	8.06	7.72
	Max	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	13.28	9.19
	Min	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	7.00	7.00	7.00	7.00	7.00	6.68
% Chlorine	Weighted Avg High	0.35	0.35	0.35	0.35	0.34	0.34	0.34	0.31	0.31	0.31	0.31	0.32	0.32	0.34	0.34	0.35
	Max	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
	Min	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.25
	Weighted Avg Low	0.26	0.26	0.26	0.26	0.27	0.27	0.27	0.28	0.28	0.28	0.28	0.29	0.28	0.28	0.28	0.30
	Max	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.31
	min	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.25

Quality Parameter		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
BTU/lb	Weighted Avg	10,321	10,400	11,397	11,406	11,414	10,420	11,394	11,378	11,224	11,224	11,211	9,515	10,980	8,417	10,647
	Max	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,625	12,625	12,625	12,625	12,086	12,086	12,086
	Min	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,600	11,700	11,700	11,700	11,700
% Sulfur	Weighted Avg	2.47	2.46	2.37	2.35	2.35	2.46	2.35	2.36	2.36	2.36	2.37	2.57	2.38	2.64	2.27
	Max	2.96	2.96	2.96	2.96	2.96	2.96	2.96	2.96	3.31	3.31	3.31	3.31	2.96	2.96	2.96
	Min	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26
LbS02 / mmBtu	Weighted Avg	4.16	4.15	4.02	3.99	4.00	4.15	3.99	4.02	4.02	4.03	4.04	4.32	4.04	4.42	3.82
	Max	4.90	4.90	4.90	4.90	4.90	4.90	4.90	4.90	5.24	5.24	5.24	5.24	4.90	4.90	4.90
	Min	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08
LbS / mmBtu	Weighted Avg	2.08	2.08	2.01	1.99	2.00	2.08	1.99	2.01	2.01	2.01	2.02	2.16	2.02	2.21	1.91
	Max	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.62	2.62	2.62	2.62	2.45	2.45	2.45
	Min	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
% Ash	Weighted Avg	8.07	8.12	7.96	7.94	7.95	8.18	7.96	8.07	8.39	8.40	8.42	8.71	8.43	8.55	7.85
	Max	9.19	9.19	9.19	9.19	9.19	9.19	9.19	9.19	10.25	10.25	10.25	10.25	9.19	9.19	9.19
	Min	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68	6.68
% Chlorine	Weighted Avg High	0.33	0.33	0.34	0.34	0.34	0.33	0.34	0.35	0.37	0.37	0.36	0.31	0.34	0.32	0.39
	Max	0.44	0.44	0.44	0.44	0.44	0.44	0.44		0.44	0.44	0.44	0.50	0.50	0.50	0.50
	Min	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.20	0.20	0.20	0.20	0.25	0.25	0.25
	Weighted Avg Low	0.29	0.29	0.30	0.30	0.30	0.29	0.30	0.30	0.30	0.30	0.30	0.28	0.30	0.28	0.31
	Max	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.35	0.35	0.35	0.35
	Min	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.20	0.20	0.20	0.20	0.25	0.25	0.25

Source: Wood Mackenzie

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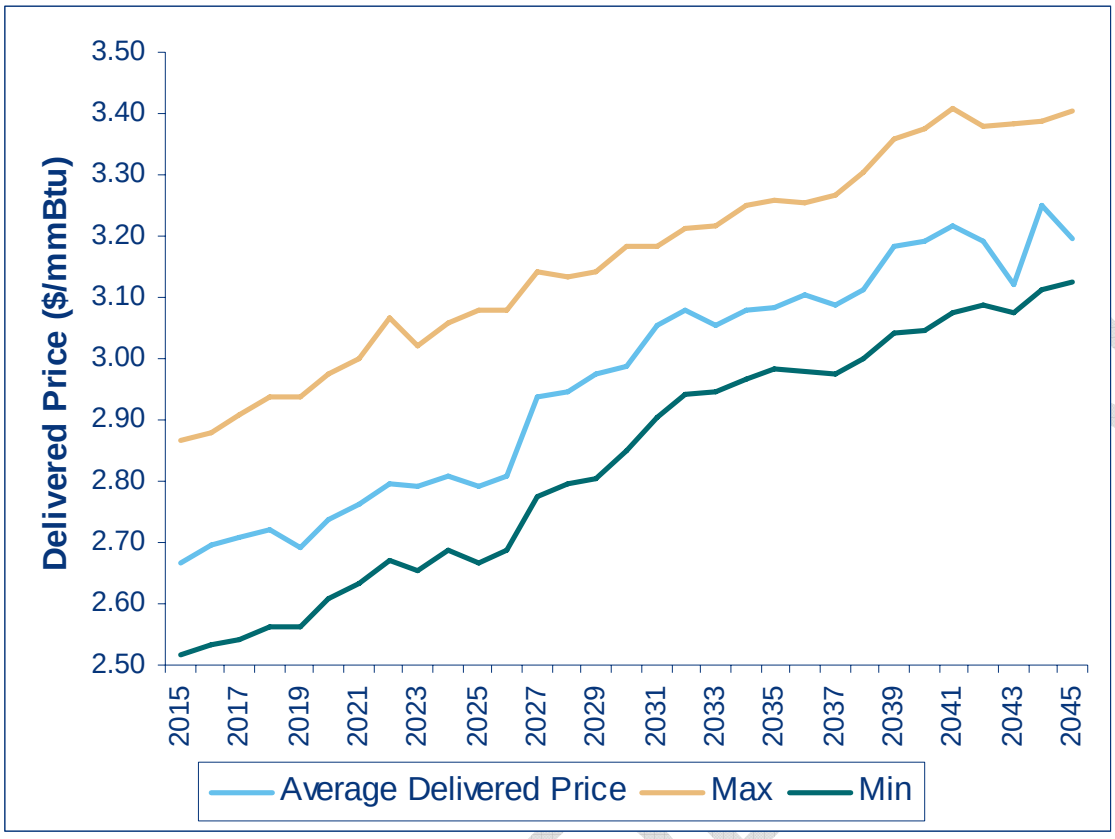
Exhibit 52 – Delivered Price of Coal at TEC from Subdivision 6 (Southeastern Illinois), Graph, 2009 $/mmBtu



Source: Wood Mackenzie

Exhibit 53 – Delivered Price of Coal at TEC from Subdivision 6 (Southeastern Illinois), Table, 2009 $/mmBtu

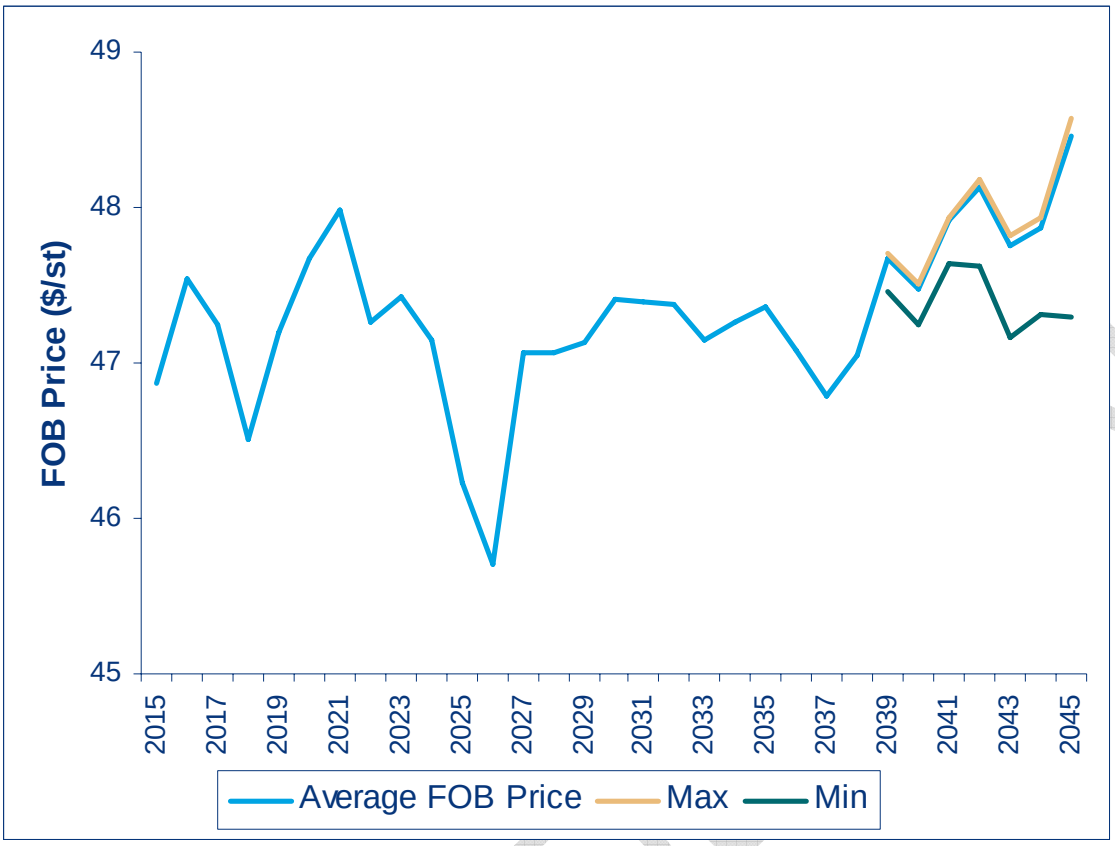
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$2.67	$2.70	$2.71	$2.72	$2.69	$2.74	$2.76	$2.80	$2.79	$2.81	$2.79	$2.81	$2.94	$2.95	$2.97	$2.99
Max	$2.87	$2.88	$2.91	$2.94	$2.94	$2.98	$3.00	$3.07	$3.02	$3.06	$3.08	$3.08	$3.14	$3.13	$3.14	$3.18
Min	$2.52	$2.53	$2.54	$2.56	$2.56	$2.61	$2.63	$2.67	$2.65	$2.69	$2.67	$2.69	$2.78	$2.80	$2.80	$2.85

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$3.05	$3.08	$3.05	$3.08	$3.08	$3.10	$3.09	$3.11	$3.18	$3.19	$3.22	$3.19	$3.12	$3.25	$3.20
Max	$3.18	$3.21	$3.22	$3.25	$3.26	$3.26	$3.26	$3.30	$3.36	$3.37	$3.41	$3.38	$3.38	$3.39	$3.41
Min	$2.90	$2.94	$2.94	$2.97	$2.98	$2.98	$2.98	$3.00	$3.04	$3.04	$3.08	$3.09	$3.07	$3.11	$3.12

Source: Wood Mackenzie

There are smaller reserves and active operations outside the subdivisions already mentioned. Specifically, these mines are located in the northern portion of Illinois in Subdivision 2 (Western Illinois) and Subdivision 4 (East-Central Illinois). Coal from these subdivisions would likely be railed to TEC. Typically, this coal is low in energy content, much like that in Subdivision 3 (West-Central Illinois), but variable in sulfur content. Some of this coal is actually low in sulfur content but most is above 5.0 $LbSO_2$/mmBtu. The results of our modeling, adjustments and aggregations for these other areas of Illinois can be seen in Exhibit 54 through Exhibit 62.

Exhibit 54 – FOB Price of Coal from Subdivisions 2 and 4 (Northern and East-Central Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 55 – FOB Price of Coal from Subdivisions 2 and 4 (Northern and East-Central Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average FOB Price	$46.87	$47.54	$47.25	$46.51	$47.19	$47.68	$47.98	$47.26	$47.43	$47.15	$46.24	$45.70	$47.07	$47.07	$47.13	$47.42
Max																
Min																

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average FOB Price	$47.39	$47.38	$47.15	$47.26	$47.36	$47.09	$46.78	$47.05	$47.68	$47.48	$47.91	$48.13	$47.76	$47.88	$48.46
Max									$47.71	$47.50	$47.94	$48.18	$47.82	$47.93	$48.58
Min									$47.45	$47.25	$47.64	$47.62	$47.16	$47.32	$47.30

Source: Wood Mackenzie

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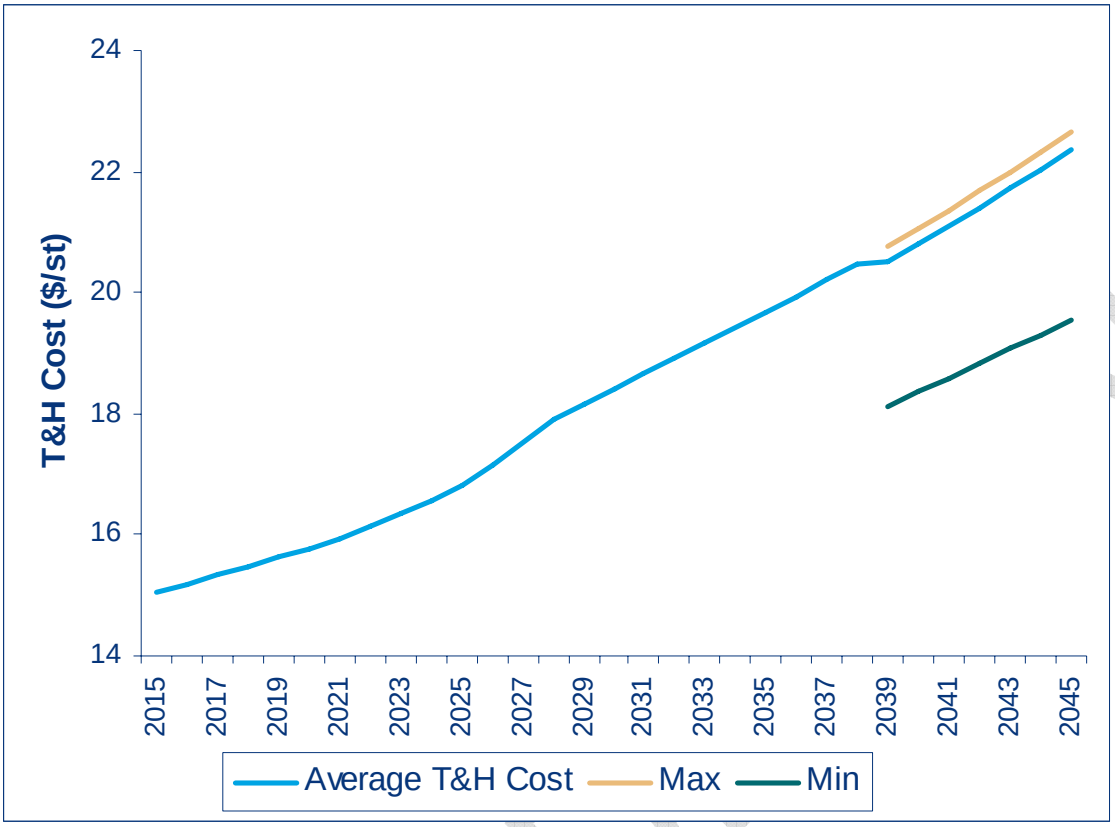
Exhibit 56 – T&H Cost of Coal Delivered to TEC from Subdivisions 2 and 4 (Northern and East-Central Illinois), Graph, $/st



Source: Wood Mackenzie

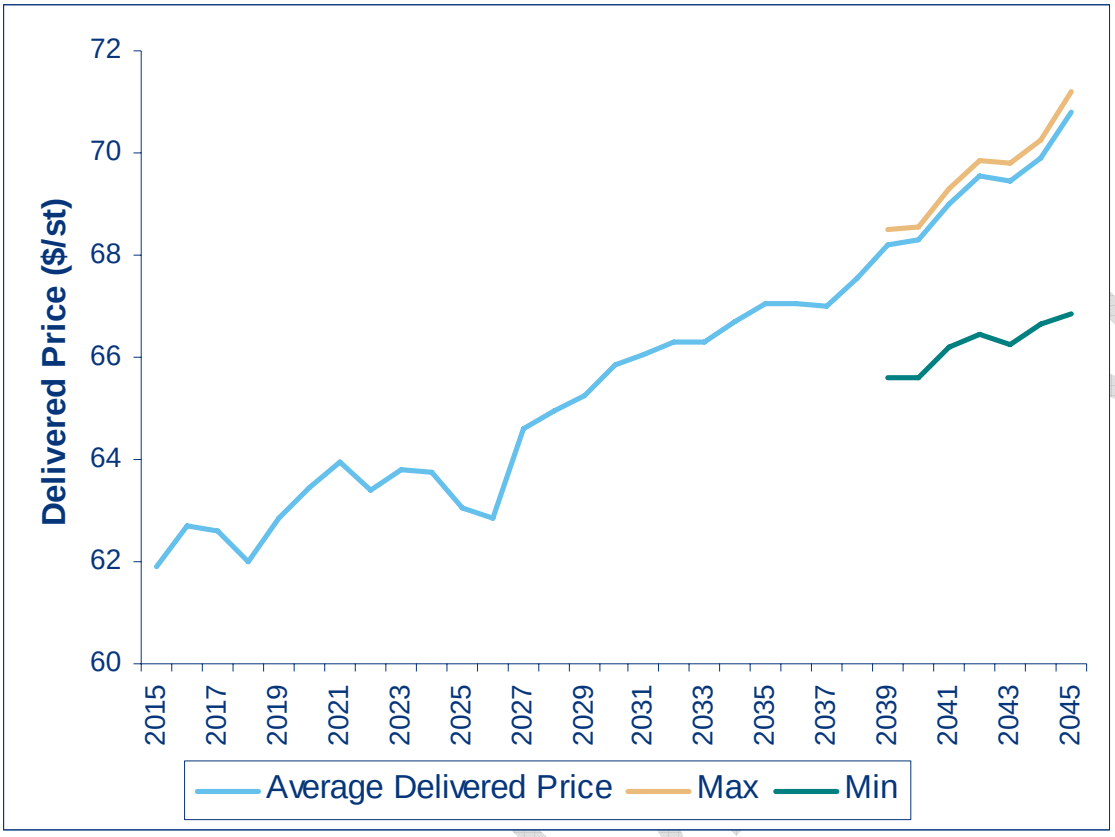
Exhibit 57 – T&H Cost of Coal Delivered to TEC from Subdivisions 2 and 4 (Northern and East-Central Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average T&H Cost	$15.03	$15.16	$15.33	$15.46	$15.64	$15.77	$15.95	$16.13	$16.35	$16.58	$16.81	$17.16	$17.53	$17.90	$18.14	$18.43
Max																
Min																

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average T&H Cost	$18.67	$18.91	$19.16	$19.42	$19.68	$19.94	$20.21	$20.49	$20.52	$20.80	$21.10	$21.40	$21.71	$22.03	$22.36
Max									$20.78	$21.07	$21.37	$21.67	$21.99	$22.31	$22.64
Min									$18.13	$18.36	$18.59	$18.82	$19.06	$19.31	$19.56

Source: Wood Mackenzie

Exhibit 58 – Delivered Price of Coal at TEC from Subdivisions 2 and 4 (Northern and East-Central Illinois), Graph, 2009 $/st



Source: Wood Mackenzie

Exhibit 59 – Delivered Price of Coal at TEC from Subdivisions 2 and 4 (Northern and East-Central Illinois), Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$61.90	$62.70	$62.58	$61.98	$62.83	$63.45	$63.93	$63.39	$63.78	$63.73	$63.04	$62.86	$64.60	$64.97	$65.27	$65.85
Max																
Min																

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Average Delivered Price	$66.06	$66.29	$66.31	$66.68	$67.03	$67.03	$66.99	$67.54	$68.20	$68.28	$69.01	$69.53	$69.47	$69.91	$70.81
Max									$68.48	$68.57	$69.31	$69.86	$69.81	$70.24	$71.21
Min									$65.59	$65.61	$66.22	$66.45	$66.23	$66.63	$66.86

Source: Wood Mackenzie

Exhibit 60 – Quality of Coal in Subdivisions 2 and 4 (Northern and East-Central Illinois)

Quality Parameter		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BTU/lb	Weighted Avg	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800
	Max																
	Min																
% Sulfur	Weighted Avg	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
	Max																
	Min																
LbS02 / mmBtu	Weighted Avg	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41
	Max																
	Min																
LbS / mmBtu	Weighted Avg	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
	Max																
	Min																
% Ash	Weighted Avg	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
	Max																
	Min																
% Chlorine	Weighted Avg High	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	Max																
	Min																
	Weighted Avg Low	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Max																
	min																

Quality Parameter		2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
BTU/lb	Weighted Avg	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,800	10,801	10,801	10,801	10,801	10,801	10,801	10,801
	Max									10,810	10,810	10,810	10,810	10,810	10,810	10,810
	Min									10,800	10,800	10,800	10,800	10,800	10,800	10,800
% Sulfur	Weighted Avg	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.46	1.46	1.45	1.45	1.45	1.44	1.44
	Max									2.87	2.87	2.87	2.87	2.87	2.87	2.87
	Min									1.30	1.30	1.30	1.30	1.30	1.30	1.30
LbS02 / mmBtu	Weighted Avg	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.69	2.69	2.69	2.68	2.68	2.67	2.67
	Max									5.31	5.31	5.31	5.31	5.31	5.31	5.31
	Min									2.41	2.41	2.41	2.41	2.41	2.41	2.41
LbS / mmBtu	Weighted Avg	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.35	1.35	1.34	1.34	1.34	1.34	1.34
	Max									2.65	2.65	2.65	2.65	2.65	2.65	2.65
	Min									1.20	1.20	1.20	1.20	1.20	1.20	1.20
% Ash	Weighted Avg	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	9.88	9.88	9.88	9.88	9.88	9.89	9.89
	Max									10.00	10.00	10.00	10.00	10.00	10.00	10.00
	Min									8.77	8.77	8.77	8.77	8.77	8.77	8.77
% Chlorine	Weighted Avg High	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.24	0.24
	Max									0.25	0.25	0.25	0.25	0.25	0.25	0.25
	Min									0.10	0.10	0.10	0.10	0.10	0.10	0.10
	Weighted Avg Low	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Max									0.15	0.15	0.15	0.15	0.15	0.15	0.15
	Min									0.10	0.10	0.10	0.10	0.10	0.10	0.10

Source: Wood Mackenzie

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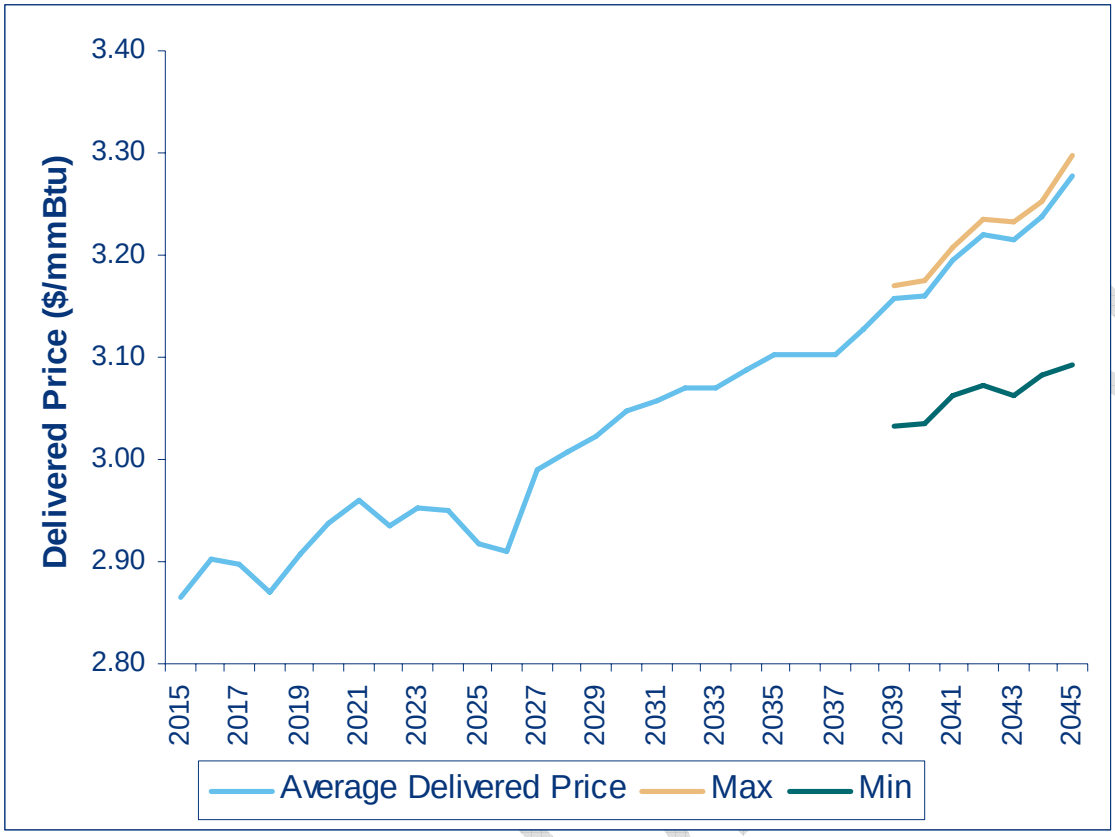
Exhibit 61 – Delivered Price of Coal at TEC from Subdivisions 2 and 4 (Northern and East-Central Illinois), Graph, 2009 $/mmBtu



Source: Wood Mackenzie

Exhibit 62 – Delivered Price of Coal at TEC from Subdivisions 2 and 4 (Northern and East-Central Illinois), Table, 2009 $/mmBtu

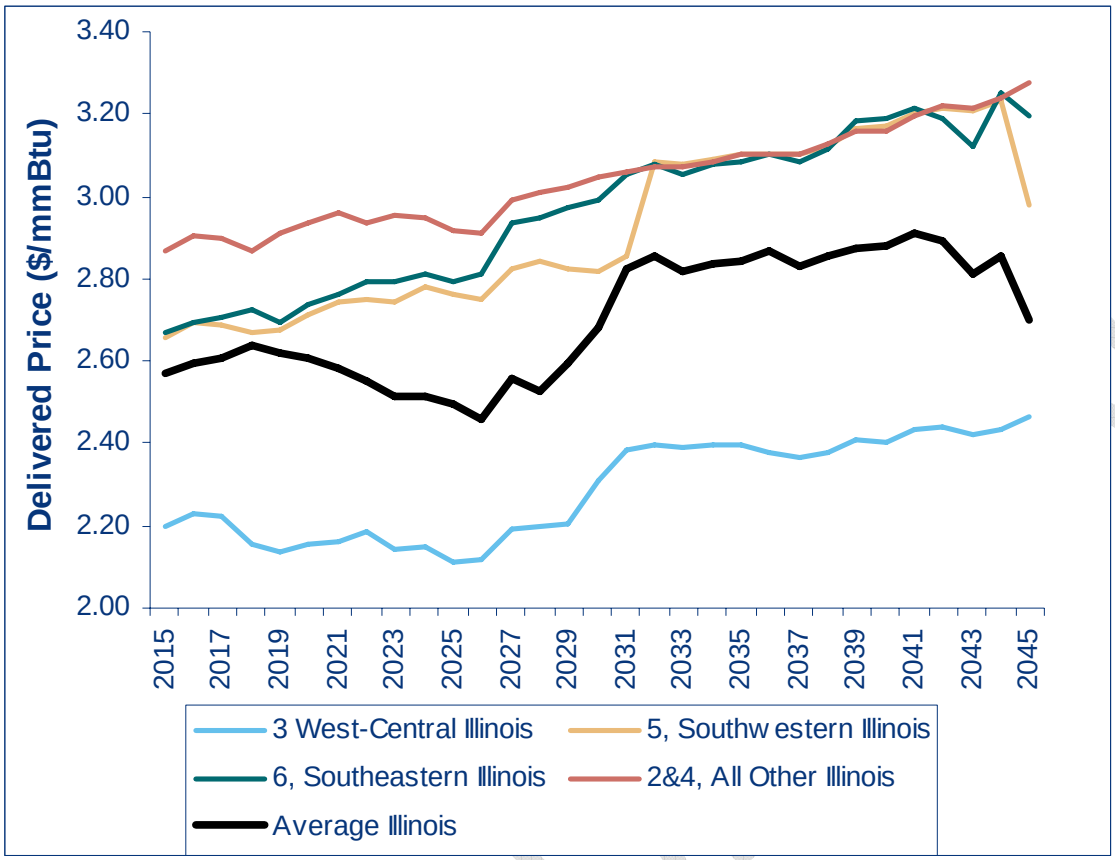
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Average Delivered Price	$2.87	$2.90	$2.90	$2.87	$2.91	$2.94	$2.96	$2.93	$2.95	$2.95	$2.92	$2.91	$2.99	$3.01	$3.02	$3.05
Max																
Min																

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	
Average Delivered Price	$3.06	$3.07	$3.07	$3.09	$3.10	$3.10	$3.10	$3.13	$3.16	$3.16	$3.19	$3.22	$3.22	$3.24	$3.28	
Max									$3.17	$3.17	$3.21	$3.23	$3.23	$3.25	$3.30	
Min									$3.03	$3.03	$3.06	$3.07	$3.06	$3.08	$3.09	

Source: Wood Mackenzie

A summary of the delivered price of coal at TEC from various subdivisions in Illinois can be found in Exhibit 63 and Exhibit 64. The lowest delivered price coal could be sourced locally from Subdivision 3 (West-Central Illinois). Typically, coal from this region can be expected to cost between $2.10/mmBtu and $2.20/mmBtu through 2029, and then rise to about $2.40/mmBtu thereafter. The cost of coal delivered to TEC from other regions is expected to range from $0.45/mmBtu to $0.80/mmBtu higher than that from Subdivision 3. Note that these are aggregated delivered prices and those prices from individual mines, even within a given subdivision, could be significantly higher or lower.

Exhibit 63 – Delivered Price of Coal at TEC from All Subdivisions in Illinois, Graph, 2009 $/mmBtu



Source: Wood Mackenzie

Exhibit 64 – Delivered Price of Coal at TEC from All Subdivisions in Illinois, Table, 2009 $/mmBtu

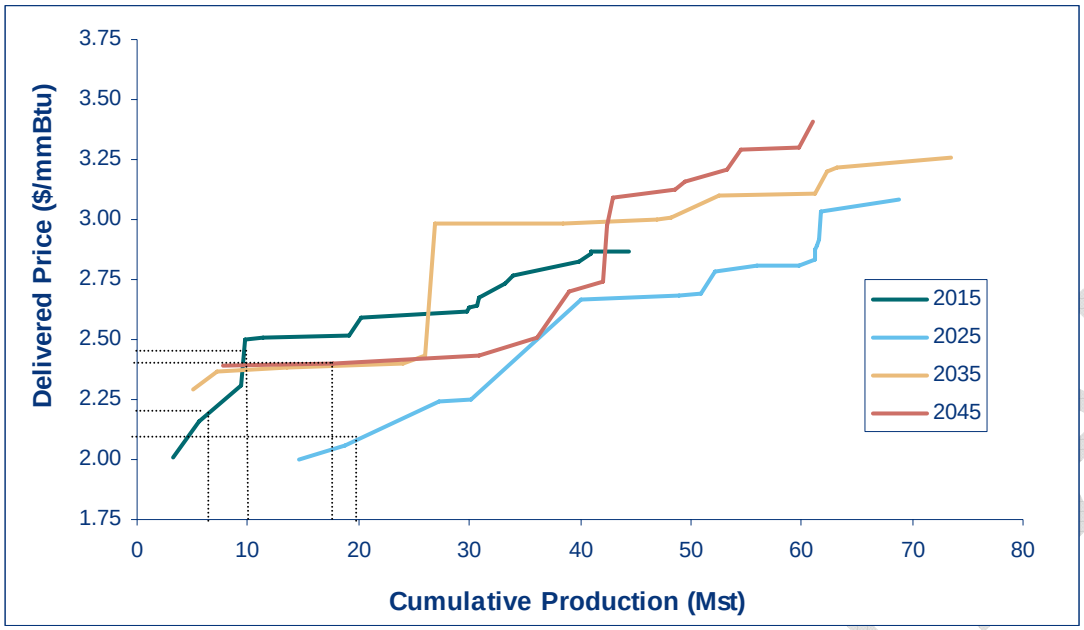
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
3 West-Central Illinois	$2.20	$2.23	$2.22	$2.15	$2.14	$2.15	$2.16	$2.18	$2.14	$2.15	$2.11	$2.12	$2.19	$2.20	$2.21	$2.31
5, Southwestern Illinois	$2.65	$2.69	$2.69	$2.67	$2.67	$2.71	$2.74	$2.75	$2.75	$2.78	$2.76	$2.75	$2.83	$2.84	$2.83	$2.82
6, Southeastern Illinois	$2.67	$2.70	$2.71	$2.72	$2.69	$2.74	$2.76	$2.80	$2.79	$2.81	$2.79	$2.81	$2.94	$2.95	$2.97	$2.99
2&4, All Other Illinois	$2.87	$2.90	$2.90	$2.87	$2.91	$2.94	$2.96	$2.93	$2.95	$2.95	$2.92	$2.91	$2.99	$3.01	$3.02	$3.05
Average Illinois	$2.57	$2.60	$2.61	$2.64	$2.62	$2.61	$2.58	$2.55	$2.51	$2.51	$2.49	$2.46	$2.56	$2.53	$2.60	$2.68

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
3 West-Central Illinois	$2.38	$2.40	$2.39	$2.39	$2.40	$2.38	$2.37	$2.38	$2.41	$2.40	$2.43	$2.44	$2.42	$2.43	$2.47
5, Southwestern Illinois	$2.86	$3.08	$3.08	$3.09	$3.11	$3.10	$3.10	$3.12	$3.17	$3.17	$3.20	$3.21	$3.21	$3.23	$2.98
6, Southeastern Illinois	$3.05	$3.08	$3.05	$3.08	$3.08	$3.10	$3.09	$3.11	$3.18	$3.19	$3.22	$3.19	$3.12	$3.25	$3.20
2&4, All Other Illinois	$3.06	$3.07	$3.07	$3.09	$3.10	$3.10	$3.10	$3.13	$3.16	$3.16	$3.19	$3.22	$3.22	$3.24	$3.28
Average Illinois	$2.82	$2.85	$2.82	$2.83	$2.84	$2.87	$2.83	$2.86	$2.87	$2.88	$2.91	$2.89	$2.81	$2.85	$2.70

Source: Wood Mackenzie

Delivered supply curves were developed allowing for a view of the full range of delivered prices that can be expected in a given year at TEC. Note in Exhibit 65 that through the year 2025, TEC can expect to pay between $2.00/mmBtu to and $3.00/mmBtu for Illinois coal depending upon actual coal selected. In the later years, TEC can expect to pay between about $2.25/mmBtu and $3.25/mmBtu. Achieving the lowest delivered prices shown in Exhibit 65 would require that TEC successfully outcompete all consumers for the given coal. It is more prudent to assume that TEC will achieve the average price of a grouping of the lowest cost coals, such as those in Subdivision 3 (West-Central Illinois). If the assumption is made that TEC will achieve the average forecast delivered price of coal from Subdivision 3 (West-Central Illinois) it can be seen in Exhibit 65 that TEC would in so doing be competing for the lowest priced 7 to 20 Mst (depending on the year) rather than just the lowest priced ~2 Mst (the plant requirement). This is a more reasonable assumption. Thus, it is logical to assume that the best estimate of delivered price at TEC is one that provides an opportunity for TEC to secure coal at the average delivered price from Subdivision 3 (West-Central Illinois) which was previously shown in Exhibit 64.

Exhibit 65 – TEC Delivered Supply Curve by Year for All Suitable Illinois Coal, Graph, 2009 $/mmBtu



Source: Wood Mackenzie

Illinois Fuel Use Tax

The State of Illinois imposes a "Fuel Use Tax" equivalent to 6.25% of the price of coal. This tax is not charged on the transportation component. This tax is known as the Illinois Retailers Occupation Tax, or Illinois Sales Tax. The tax is calculated to be 6.25% of the price of the coal, which in this case is 6.25% of the fully adjusted (for quality) FOB price. The amount of this tax, calculated on a 2009$/st basis, is shown in Exhibit 66.

Exhibit 66 – Illinois Fuel Use Tax by Subdivision, Table, 2009 $/st

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Subdivision 3, Avg	$2.43	$2.47	$2.47	$2.45	$2.43	$2.48	$2.49	$2.52	$2.47	$2.48	$2.43	$2.44	$2.52	$2.53	$2.54	$2.66
Subdivision 5, Avg	$2.66	$2.70	$2.70	$2.72	$2.75	$2.79	$2.81	$2.81	$2.81	$2.82	$2.79	$2.77	$2.85	$2.85	$2.84	$2.85
Subdivision 6, Avg	$2.63	$2.67	$2.67	$2.60	$2.52	$2.59	$2.67	$2.70	$2.70	$2.71	$2.71	$2.77	$2.79	$2.82	$2.80	$2.84
Other Illinois, Avg	$2.76	$2.80	$2.78	$2.74	$2.78	$2.80	$2.82	$2.78	$2.79	$2.77	$2.72	$2.69	$2.77	$2.77	$2.77	$2.79
Total Illinois, Avg	$2.61	$2.64	$2.61	$2.54	$2.46	$2.53	$2.62	$2.65	$2.66	$2.68	$2.68	$2.70	$2.70	$2.70	$2.66	$2.68

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Subdivision 3, Avg	$2.74	$2.77	$2.75	$2.76	$2.77	$2.77	$2.75	$2.76	$2.80	$2.79	$2.81	$2.81	$2.79	$2.80	$2.80
Subdivision 5, Avg	$2.90	$2.78	$2.77	$2.77	$2.77	$2.75	$2.73	$2.75	$2.79	$2.77	$2.80	$2.80	$2.77	$2.78	$2.73
Subdivision 6, Avg	$2.80	$2.83	$2.91	$2.92	$2.91	$2.97	$3.04	$3.06	$3.04	$3.06	$3.06	$3.05	$3.03	$3.04	$3.07
Other Illinois, Avg	$2.79	$2.79	$2.77	$2.78	$2.79	$2.77	$2.75	$2.77	$2.80	$2.79	$2.82	$2.83	$2.81	$2.82	$2.85
Total Illinois, Avg	$2.64	$2.63	$2.71	$2.70	$2.73	$2.82	$2.92	$2.93	$2.90	$2.91	$2.91	$2.91	$2.87	$2.89	$2.91

Source: Wood Mackenzie

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Conclusions

1. Real delivered price increase is a function of both increases in FOB mine prices and, to a somewhat greater extent, increases in transportation costs. These component price increases vary somewhat depending on the mining subdivision in which the coal is located and the mode of transportation employed from mine to TEC and are a function of items 2. through 7. below.

2. The demand for Illinois coal will increase substantially over time as power generators add environmental equipment that minimizes emissions of sulfur from higher sulfur content Illinois coal.

3. TEC must compete with consumers across the eastern U.S. for the use of Illinois coal.

4. Even Illinois coal mines with only local market reach will be influenced by the market clearing FOB mine prices obtained by the mines with which they compete when those competing mines have demand outside the local market. That is, Illinois coal mines with only local markets will have prices set by mines with which they have the potential to share market and customers.

5. Illinois coal supply will be sufficient to meet the increased demand for its coal.

6. Supply will grow sufficiently to keep coal prices from growing too rapidly. Given sufficient supply over time, coal prices will typically grow as a result of increases in cost of production and cost of transportation and handling.

7. Delivered coal prices will grow, in real terms, by between 12% and 20% between 2015 and 2045.

8. Higher energy content Illinois coal is, generally but not always, at further distance from TEC.

9. The higher energy content of the more distant coal is insufficient to fully compensate for the increased transportation cost of the distant coal.

9. The lowest delivered price coal, fully evaluated for energy content, sulfur and transportation, is most likely coal produced in the West-Central portion of Illinois, in which the TEC facility is located. Coal mined in this area will have the lowest total transportation and handling cost from mine to TEC.

11. Reason and prudence dictate that forecasting a delivered price at TEC should be done by basing the forecast upon the average delivered price of a group of coal sources.

11. The forecast delivered price at TEC should be defined as the lowest average delivered price at TEC from one of six Illinois Subdivisions that represent geographical mining areas of the state of Illinois.

12. The lowest average delivered price at TEC, and therefore our forecast of delivered price at TEC, is developed from Subdivision 3 (West-Central Illinois). Subdivision 3 (West-Central Illinois) is the mining region geographically closest to TEC wherein transportation costs from mine to TEC will be lower than from other regions. Our forecast of the delivered price at TEC is shown in Exhibit 67.

Exhibit 67 – Delivered Price forecast of Coal to TEC, Table, 2009 $/mmBtu

Year	FOB Mine Price, $/st	Transportation & Handling, $/st	Delivered Price, $/st	Delivered Price, $/mmBtu	Year	FOB Mine Price, $/st	Transportation & Handling, $/st	Delivered Price, $/st	Delivered Price, $/mmBtu
2015	41.38	4.50	45.88	2.20	2031	46.64	4.45	51.09	2.38
2016	41.95	4.49	46.44	2.23	2032	47.02	4.44	51.46	2.40
2017	42.01	4.41	46.42	2.22	2033	46.77	4.46	51.24	2.39
2018	41.68	3.62	45.31	2.15	2034	46.96	4.46	51.43	2.39
2019	41.39	3.55	44.95	2.14	2035	47.17	4.43	51.59	2.40
2020	42.08	3.66	45.74	2.15	2036	47.04	4.36	51.41	2.38
2021	42.41	3.75	46.16	2.16	2037	46.73	4.39	51.12	2.37
2022	42.92	3.65	46.58	2.18	2038	47.00	4.42	51.42	2.38
2023	42.02	3.59	45.61	2.14	2039	47.65	4.45	52.10	2.41
2024	42.17	3.53	45.70	2.15	2040	47.44	4.51	51.95	2.40
2025	41.39	3.52	44.91	2.11	2041	47.72	5.03	52.75	2.43
2026	41.48	3.57	45.06	2.12	2042	47.80	5.23	53.03	2.44
2027	42.92	3.66	46.57	2.19	2043	47.39	5.27	52.66	2.42
2028	43.09	3.71	46.80	2.20	2044	47.54	5.31	52.86	2.43
2029	43.19	3.74	46.93	2.21	2045	47.53	6.03	53.56	2.47
2030	45.18	4.12	49.31	2.31					

Source: Wood Mackenzie

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Appendix A: Glossary of Terms

BNSF	Burlington Northern Santa Fe Railroad
Btu	British thermal units
CAPP	Central Appalachia coal region
CN	Canadian National Railway
CSX	CSX Railroad
DCEO	Illinois Department of Commerce and Economic Opportunity
EGU	Electric generating unit
EJ&E	Elgin, Joliet and Eastern Railroad
EVW	Evansville and Western Railroad
FOB	Free on board
GDP	Gross domestic product
I&M	Illinois and Midland Railroad
ICC	Illinois Commerce Commission
ICG	International Coal Group
ILB	Illinois Basin coal region
Lb	Pound
LbSO2 / mmBtu	Pounds sulfur dioxide per million
mmBtu	Million Btu
mmf	Free of moisture and mineral matter
Mst	Million short tons
Mstpa	Million short tons per year
NRP	Natural Resource Partners
NS	Norfolk Southern Railroad
PAL	Paducah and Louisville Railroad
ROI	Return on investment
PRB	Powder River Basin coal region
S	Sulfur
SB 1987	Illinois Senate Bill 1987
SIP	State Implementation Plan
SNG	Substitute natural gas
SO2	Sulfur dioxide
TEC	Taylorville Energy Center
T&H	Transportation and handling
TVA	Tennessee Valley Authority
UP	Union Pacific Railroad
$/st	US dollars per short ton
$/mmBtu	US dollars per million Btu

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Appendix B: Wood Mackenzie

Our coal coverage is underpinned by region-by-region coverage worldwide. Our understanding of the reserves, production profiles and costs in these regions, together with our proprietary models, make us ideally placed to identify, screen and quantify these assets on a project-by-project basis.

Allied to this, our strategic understanding of the issues that companies and governments face (and their motivations, drivers and decision-making structures) makes us well-placed to assess the 'do-ability' of gaining access to a new investment opportunities, as well as their fit to the client's strategy. Underpinning all these capabilities is our ability to reliably forecast the future demand and price of coal.

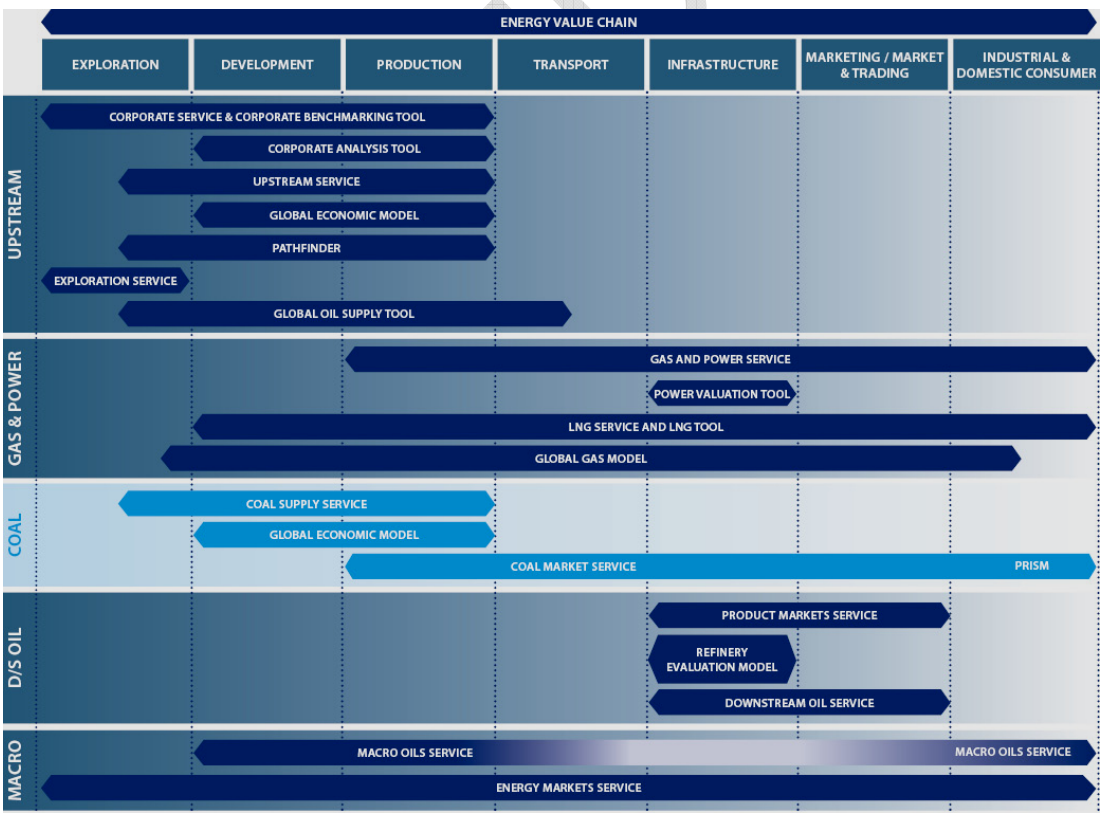
We undertake consulting assignments for all the leading players in the energy industry (including existing companies, potential new entrants and governments in our recent list of clients). These projects are based on (i) our deep understanding of the business; (ii) having the right team of people to analyse and interpret the issues, complications and questions; and (iii) the ability to deliver realistic answers and solutions for our clients.

We are following a creative and pragmatic approach to deliver reliable information and winning strategies to our clients. We have worked with them to provide dependable information and to help them achieve alignment of their businesses around clear strategic goals designed to enhance the value of their companies.

Over the past 30 years, Wood Mackenzie has helped more than 800 companies grow and become more profitable. We've also helped governments around the world to manage their energy sector more effectively. We have more than 400 analysts around the world, including specialists in all aspects of the energy, coal and metals industries. They draw on our extensive databases, a huge resource of authoritative analysis at asset, company, country and regional level. Our proprietary data and unique analytical tools allow our consultants to provide local insight with a global perspective. *Our integrated modelling approach ensures that our view is inclusive of all aspects of the energy industry and that our results are reflective of the interaction of all fuels.* We are trusted by clients worldwide to provide the insight and advice that underpins sustainable growth and competitive advantage in a rapidly changing market.

Our advice is built upon expertise across the entire energy value chain as seen in Exhibit 68.

Exhibit 68 – Wood Mackenzie Energy Value Chain Offerings



Source: Wood Mackenzie

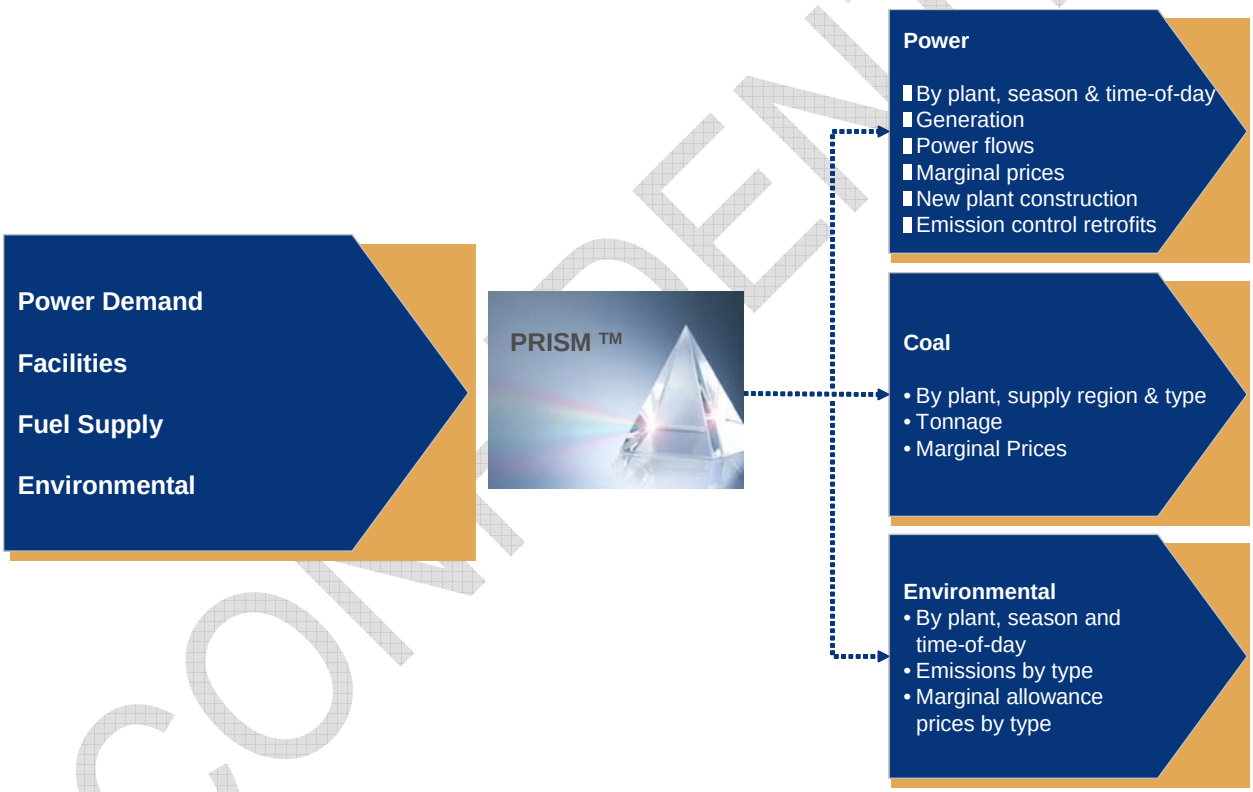
Appendix C: PRISM™ Modeling

The primary objective of the PRISM™ Coal and Power Model is to meet the nation's electricity demand at the lowest possible cost while complying with emissions regulations. The model has several ways of accomplishing this, including fuel switching, choosing to run one plant over another, adding cleanup equipment and/or adding new generation.

Most US coal is consumed by electricity generators and the price of thermal coal is driven by the electricity markets. It is important to recognize that US energy markets have sufficiently converged such that there can be no regional price forecasting solution that does not reflect the impact of national demand, supply and regulation of all fuels. We propose to forecast FOB mine prices using PRISM™, our integrated linear programming model that optimizes fuel choices and emissions control under various supply, environmental, and transportation constraints. PRISM™ provides a long term forecast of coal demand, coal prices, and emissions prices and is integrated with our other gas and power models, thereby providing an informed view of any segment of the entire North American market. Using PRISM™ in this work will provide a reliable forecast because it:

The primary objective of the PRISM™ Coal and Power Model is to meet the nation's electricity demand at the lowest possible cost while remaining within the emissions caps. The model has several ways of accomplishing this, including fuel switching, choosing to run one plant over another, and/or adding cleanup equipment or new generation.

Exhibit 69 – PRISM™ Model Diagram



Source: Wood Mackenzie

The flow diagram in Exhibit 69 (above) summarizes the methodology used in developing demand, supply, and price projections. The projection of coal demand for electrical generation combines a top-down (meeting electrical demand) approach with a bottom-up, or micro, analysis. The beginning point in the bottom-up analysis of demand entails developing detailed information on all existing power generating plants, including data on their current coal utilization, specifications, emissions control processes, regulatory limits, future plans, etc. This plant database includes or accounts for all known Electric Generating Unit (EGU) facilities, regardless of size. We combine many of the small municipal plants and carry their combined capacity and future coal use. In many cases, the list of plants is broken down to unit groupings to separate units that currently scrub or use different coal types from other units at the same plant. Projected additions to coal-fired capacity are treated similar to existing plants.

We populate 100 individual coal supply curves that vary by originating basin and quality. Each supply curve is linked to each EGU by stipulating an appropriate transportation cost. The optimization function selects the optimal coal source subject to

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the environmental and operating restrictions placed upon the EGU. The resulting selections then determine the cost of generating electricity, as well as the pollutant emission rates.

The availability of coal types into specific plants is based upon present usage patterns on a unit-by-unit basis, announced plans for fuel switching, and our judgment of which additional coals seem likely fuel candidates. The coal supply curves are built up from the hundreds of detailed cost estimates we have generated for over 1,000 mines across the United States. These curves are updated on an annual basis.

We utilize forecasts of regional growth in demand for electricity developed by Wood Mackenzie's *North America Power Service* in the current release of their long-term view. This regional electricity demand is then fed into the model, which dispatches all the plants in the U.S. simultaneously by time-of-day and season. Depending upon which case we are modeling, more or less power will be required from individual coal-fired plants, and these requirements are translated into demand for specific types of coal. Projections of industrial steam coal use and exports of steam coal are then added to utility coal demand, resulting in total U.S. steam coal demand for each of the 100 coal types defined in the model.

Existing plant cleanup equipment is updated on an annual basis. We then supplement this data with announcements of equipment that will be installed in the future (usually within ten years). This currently installed and announced cleanup equipment structure is important because the model considers only the operating cost for such equipment in arriving at the optimal solution (i.e capital costs are considered "sunk" in the case of existing and announced equipment). The model also has the ability to add cleanup equipment if it is economically justified, e.g. if the cost of adding a scrubber is less than the cost of other, options available to meet the electricity demand and remain within the SO_2 emission limit. In the case of optimizing equipment retrofits, the model considers the capital cost for such equipment as well as the operating cost in determining the best option. However, the cost of capital is amortized over a 20-year period and only the first year's capital cost is considered in the model decision. In subsequent years, the model only considers the operating costs for this equipment.

Plant-by-plant State Implementation Plan (SIP) constraints on SO_2 emissions are coded in the model, which cannot be offset with purchased allowances but are considered to be parallel with the CAIR SO_2 allowance system.

For all pollutants except NOx, the emission rates (before cleanup equipment acts on the exit gas stream) are keyed to the coal to be used. However, the NOx emission rates are much more dependent on the particular plant and its configuration than they are on the coal being burned. To be sure, there is a NOx difference between PRB coal and non-PRB coal in the same boiler, and we adjust for that inside the model. The primary NOx emission rate is based on recent EPA emissions reports. From these reports, we gather the ozone season emission rate and the type of de-NOx equipment installed. This approach is based upon the rationale that the NOx ozone season would be the absolute best possible rate for each plant and that if de-NOx equipment exists at a plant, it would most likely be used during this period. In those cases where a plant already has de-NOx equipment in place before its latest reported emission rate, we do a backward calculation using the model's assumed removal efficiency for that equipment to arrive at a raw emission rate for that plant.

The model includes options for the trading of emissions allowances. The prices reported for the emissions allowances are obtained from the "shadow price" of the constraining limit for each type of pollutant. Since this "shadow price" measures the economic value that could be realized if just one more unit of emission rights (i.e. one more allowance) were available, it is used to obtain the clearing price for the allowance that corresponds to the simultaneous solution for the prices of the various types of coal, dispatch decisions and/or emissions clean-up equipment retrofit decisions.

Penalties for converting a coal-fired plant to PRB coal (where such penalties are appropriate) are applied when a plant first takes PRB and incrementally as the plant burns more PRB. Once a plant has switched to 100% PRB coal in the model, the capital portion of the penalties no longer exists. Of course, any plant that is already handling and burning 100% PRB coal or has announced a switch to PRB is exempt from the application of usage penalties. In the case of announced switches to PRB, the plant would be subject to PRB penalties if the model chooses to burn PRB at that plant prior to the year of announcement.

Survey of Utility Compliance Plans

We maintain a database of all the major utilities, their plans for compliance with environmental regulations, announcements of plans to install or upgrade cleanup technology at existing coal plants, and reported and calculated efficiency rates. As plans change due to regulatory or financial hurdles, this information is updated. This data is used to "force" the technology onto coal plants in the announced year during the model runs. Since the lead times for ordering, permitting and constructing new environmental control equipment are significant, this database provides a solid foundation for anticipating utility compliance actions over the next five to10 years.

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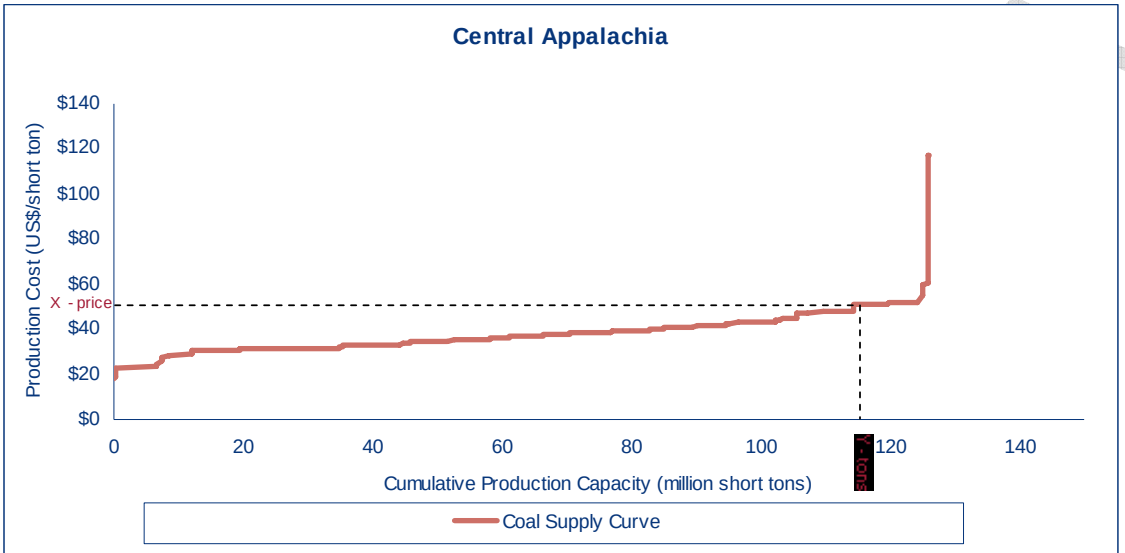
Mining Cost Supply Curves

The supply curves relating mining costs to production capacity are built up from mine-by-mine estimates of cash operating costs for all currently operating mines in the country. Much of the information on costs, qualities, and reserves is taken from the detailed county-by-county studies of coal supply that we publish annually. Costs for all active mines are estimated using models we have developed. Mine Safety and Health Administration (MSHA) databases provide information on active mines, production, employees, and man-hours worked, from which we calculate productivity. This base is supplemented with information from mine interviews concerning work schedules, equipment, percentages of washed coal, and trucking distances. In instances where trucking distances are not obtained by interviews, we measure the distance between the mine and the preparation plant via the most logical road. Costs for potential mines on undeveloped properties are estimated by comparing costs of similar active operations located nearby.

Exhibit 70 – Mining Cost Supply Curve Example, Stylized



Source: Wood Mackenzie

In the model, the market-clearing price for any coal is determined by the relationship between the final converged demand and the cost-supply curve for that coal. Referring to the Exhibit 70, above, this is demonstrated by the intersection of the vertical dashed line and the horizontal dashed line representing a hypothetical Y million ton steam coal demand at a "market clearing" coal price of under $X price per ton.

This marginal price is reported from the model as the market price for each coal type. In some regions, this price represents the cash cost of the marginal producer. In other regions, the PRB for instance, this price is well above the cash cost of the marginal producer and represents the value of an additional ton of this coal type to the marketplace.

Each mine in our mine curves also includes an estimate of the remaining recoverable reserves. As the modeling process steps through the years, the reserves at each cost step (below the marginal price) are reduced by the mine's capacity.

We address the development of new mine reserves in two basic ways:

- Identified undeveloped reserve blocks are generally entered as an individual mine with no initial capacity; and
- Identified and generic reserves are entered with existing mines with capacity additions.

In both cases, the model will activate the new reserves only if the following are true:

- There are at least seven years of reserves remaining at the new capacity;
- The marginal price of the particular coal type exceeds the operating cost by at least a pre-determined "trigger" level; and
- Opening the particular reserve is part of the overall optimal solution.

The mine triggers used in the model are roughly based on the margin (over cash operating cost) required to realize a 20-25% return on investment. We have elected to use relatively high hurdle rates for two reasons:

- Our model does not guarantee the rate of return as mine pricing reverts to incremental costs in succeeding years; and
- Uncertainty, consolidation and more sophisticated financing require respect for the inherent risk in coal mining.

The bottom line is that in the model, there is a balancing act, which mirrors what happens in the real world. In this balancing act, any shortening of a mine curve (due to exhaustion of reserves at individual mines, for example, or due to some governmental restriction on mining capacity) will likely lead to somewhat higher prices as demand hits higher on the shorter curve. These higher prices, in turn, cause more steps on the cost curve to "see" an acceptable Return on Investment (ROI), leading to capacity expansion for that step, if any is available. That expansion tends to drive prices back down.

There are two secondary methods by which capacity is added into the mine curves within the model. First, one of the inputs to the model is an assumption of future productivity growth for each of the 100 types of coal. This productivity assumption is important to capacity since a mine producing 1.0 Mstpa and experiencing a 10% gain in tons per man-hour could either produce 1.1 mmtpy with the same workforce after the productivity gain, or it could lay off approximately 9% of its workforce (1/110% = 91%) and produce the same 1.0 Mstpa with fewer workers. In the first case, we have a productivity-induced capacity increase. One of the model inputs involves our projection of what proportion of productivity gain goes toward capacity increase versus workforce reduction, and although the calculations are somewhat complicated, it works out that less than half of the productivity gain is going toward capacity in the model runs.

Second, there is a well-established pattern in the coalfields of mines running at their maximum capacity making small capacity gains (usually through equipment upgrades), even if the true ROI economics are not there to justify this "smaller than major expansion" level of capacity investment. Accordingly, we have a test in the model, which determines whether a step was 100% used in the previous year and has at least seven years of reserve life. If both of these conditions are met, then the mine capacity is very slightly stretched for that step (of the order of 1-2%) to reflect this real world phenomenon.

Both of these secondary capacity effects (productivity and stretch) are allowed to occur before making the economic "margin" test for bringing on major new expansion capital at a mine. The net effect is that a small amount of the "major capital" capacity expansion may be forestalled by the lesser amount of "creep" in capacity that occurs due to productivity gains and the stretch described above.

Electricity

The aspect of our detailed coal modeling which makes it unique is the fact that we simultaneously determine the electric plant dispatch changes due to each coal switch and environmental equipment addition. Our model uses input data on unit-by-unit generating cost projections, load profiles, seasonal electricity demand patterns, regional electricity growth rates, plans for new units, competitive costs of gas and coal-fired generation, etc. It also considers transmission constraints between all control centers as well as national and/or regional constraints on pollutant emissions. The model projects generation by plant for each season by time-of-day period in each year for a 20-year period.

Our goal each year, both in structuring the input data as well as in adapting the actual model logic, is to match real world decision-making as closely as possible. With regard to new generation capacity needs, the pattern followed in the model has the amount of new base-load generation capacity drawn from the most economic of new pulverized coal plants (New PC), new coal-fired integrated gasification combine cycle plants (New IG), gas-fired combined cycle plants (New CC), and/or gas turbine plants (New GT).

New generating capacity is added where the new generation is located based on an economic test that requires a minimum margin between the incremental operating cost of the new generation and the clearing price for electricity in the area. New capacity may also be added in any Control Area where any time-of-day block in any season violates a pre-determined reserve margin calculation. Only the amount of peaking capacity necessary to re-establish that reserve margin for each time-of-day period is added in that year's model run. Finally, with regard to the generating capacity additions, a number of "under construction" new electric generating plants are added into the model in the year they are expected to come online before the model tests the need for any new "generic" capacity.

We also bid the cost of emissions at the market clearing price of allowances into the dispatch cost for use in the electric portion of the integrated model.

The model includes a gas price elasticity formula that will modify the input gas price as the model's demand for gas changes from a presumed level. The model solves using the 'post-elasticity' gas price. Conceptually, for any given year, the model solves once at a pre-determined slate of plant-by-plant natural gas prices, all based upon differentials from a Henry Hub gas

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price, and then calculates the total amount of gas used in that solution. An estimate of non-electric generation gas use is then added to the utility total from the first model solution. This grand total gas consumption is used to arrive at a natural gas cost-supply curve to determine a new Henry Hub gas price, which determines a new slate of plant-by-plant gas prices. The new slate is then used to re-solve the dispatch model. In situations where a very high-cost coal plant is in close economic competition with a gas-fired plant, the effect of the higher gas prices is recognized by the dispatch optimization and the coal plant may dispatch higher in the second run than it did against lower gas pricing.

The model can utilize a conditional minimum capacity factor by time of day commonly called the "turn-down rate." A real world example would be, if a coal plant runs in the on-peak period during the day, or during the peak (or "spike") period it cannot simply turn off and go cold during the middle of the night (off-peak), when less electricity is needed. The model's turn-down rate requires that if such a coal plant runs at all during the day, then it must run in all time periods at a rate equal to, or higher than, the turndown rate. If it is not economical to run at the minimum turndown rate, then the plant is totally shut down and runs at 0% of capacity for all times of the day, either for economic or environmental reasons.

Where necessary, we use an empirically determined turndown rate for the plant using an analysis of the actual historic hourly dispatch of each plant across all seasons of the year. If a plant fairly consistently stayed above, say, 32% of its capacity, even in low-demand periods such as the middle of the night, then for that plant the turndown rate is set at 32% in the model.

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Appendix D: Illinois Mines, Developments, Projects and Key Reserves

Illinois Coal Sources

Coal Source Code	Illinois Subdivision	Illinois Subdivision Name	Coal Source Status	Mine Type	Btu / Lb	% Sulfur	$LbSO_2$ / mmBtu	% Ash	% Chlorine
43	6	Southeastern	Permitting	Underground	11,900	2.40	4.03	7.00	0.30
48	2	Western	Permitting	Surface	10,810	2.87	5.31	8.77	< 0.10
68	3	West Central	Reserve	Underground	11,100	3.10	5.59	9.00	< 0.20
39	5	Southwestern	Operating	Surface	11,165	3.00	4.58	9.06	< 0.10
39	5	Southwestern	Operating	Surface	11,165	2.57	4.60	9.06	< 0.10
39	5	Southwestern	Operating	Surface	11,200	3.20	5.70	10.00	< 0.10
20	3	West Central	Operating	Underground	10,555	3.47	6.58	9.00	0.13
50	6	Southeastern	Proposed	Underground	11,600	2.20	3.79	8.00	0.30 - 0.44
77	4	East Central	Reserve	Underground	11,300	1.20	2.12	8.00	< 0.10
78	4	East Central	Reserve	Underground	10,970	2.90	5.29	9.30	< 0.30
9	3	West Central	Development	Underground	10,895	3.20	5.87	7.60	0.20
56	3	West Central	Proposed	Underground	10,895	3.20	5.87	7.60	0.13
82	6	Southeastern	Reserve	Underground	12,338	2.95	4.80	10.05	0.25 - 0.30
30	6	Southeastern	Operating	Surface	11,238	3.33	5.93	11.78	< 0.10
46	4	East Central	Permitting	Underground	10,800	1.30	2.41	10.00	0.15 - 0.25
63	6	Southeastern	Proposed	Underground	11,300	2.20	4.20	9.00	0.30 - 0.44
55	6	Southeastern	Proposed	Underground	11,300	2.20	3.50	9.00	0.30 - 0.44
28	6	Southeastern	Operating	Surface	10,298	2.25	4.37	13.28	< 0.10
19	5	Southwestern	Operating	Underground	11,118	2.92	5.25	8.53	0.12
84	6	Southeastern	Reserve	Surface	11,474	2.72	4.74	11.65	< 0.10
10	6	Southeastern	Development	Surface	11,500	2.75	4.78	17.00	0.25 - 0.30
79	2	Western	Reserve	Surface	10,810	2.87	5.31	8.77	< 0.10
49	6	Southeastern	Permitting	Surface	12,625	3.31	5.24	10.25	< 0.20
44	6	Southeastern	Permitting	Underground	11,600	2.50	4.31	8.40	0.30
74	5	Southwestern	Reserve	Underground	10,790	4.10	7.60	10.10	< 0.20
41	5	Southwestern	Permitting	Surface	10,683	2.92	5.47	10.50	< 0.10
71	3	West Central	Reserve	Underground	10,730	3.20	5.96	9.20	< 0.10
58	6	Southeastern	Proposed	Underground	10,995	3.03	5.51	9.57	0.35
87	3	West Central	Reserve	Underground	10,538	3.80	7.21	8.76	0.20 - 0.25
51	6	Southeastern	Proposed	Underground	11,700	2.50	4.30	8.00	0.30 - 0.44
69	3	West Central	Reserve	Underground	11,000	3.00	5.50	9.00	< 0.25
67	3	West Central	Reserve	Underground	10,900	2.90	5.32	9.00	0.10 - 0.30
22	6	Southeastern	Operating	Underground	12,053	1.26	2.08	6.68	0.31 - 0.39
22	6	Southeastern	Operating	Underground	11,700	2.50	4.27	8.00	0.31 - 0.39
45	6	Southeastern	Permitting	Surface	10,800	2.70	5.00	11.70	< 0.10
54	3	West Central	Proposed	Underground	11,000	3.58	6.50	9.00	0.15
47	2	Western	Permitting	Surface	11,023	6.50	11.79	20.20	< 0.10
80	5	Southwestern	Reserve	Underground	10,600	3.20	6.04	8.90	0.15 - 0.20
27	6	Southeastern	Operating	Underground	11,815	2.91	4.93	6.89	0.19
40	5	Southwestern	Permitting	Underground	10,800	3.00	5.56	10.01	< 0.20
38	6	Southeastern	Operating	Underground	11,731	2.40	4.10	9.00	0.30
31	6	Southeastern	Operating	Underground	11,731	2.40	4.09	8.99	0.30
33	5	Southwestern	Operating	Underground	11,200	2.90	5.18	10.01	< 0.10
32	5	Southwestern	Operating	Surface	11,200	3.00	5.36	10.01	< 0.10
25	5	Southwestern	Operating	Surface	11,223	2.81	5.02	8.44	< 0.10
53	5	Southwestern	Proposed	Surface	11,223	2.81	5.02	8.44	< 0.10
81	5	Southwestern	Reserve	Underground	10,600	3.20	6.04	8.90	0.15 - 0.20
36	5	Southwestern	Operating	Underground	11,800	1.80	3.05	9.00	0.10 - 0.20
72	3	West Central	Reserve	Underground	10,640	3.90	7.33	10.60	< 0.20
18	3	West Central	Operating	Underground	10,285	0.89	1.72	8.30	0.17
18	3	West Central	Operating	Underground	10,300	1.50	2.90	8.50	0.17
18	3	West Central	Operating	Underground	10,700	3.20	5.98	8.50	0.17
73	5	Southwestern	Reserve	Underground	11,000	3.70	6.73	11.00	< 0.20
13	6	Southeastern	Operating	Underground	11,700	3.00	5.13	9.00	0.30 - 0.50
76	6	Southeastern	Reserve	Underground	11,900	1.70	2.86	7.00	0.35 - 0.50
65	5	Southwestern	Reserve	Surface	10,963	3.00	5.47	10.01	< 0.10
42	6	Southeastern	Permitting	Underground	11,700	2.50	4.27	8.00	0.30 - 0.5 (0.35)
21	3	West Central	Operating	Underground	10,499	3.28	6.24	9.20	0.16
12	6	Southeastern	Idled	Underground	10,846	1.44	2.65	12.36	0.20 - 0.25
34	6	Southeastern	Operating	Underground	12,086	2.96	4.90	9.19	0.25
24	6	Southeastern	Operating	Surface	12,086	2.96	4.90	9.19	< 0.10
26	6	Southeastern	Operating	Underground	12,086	2.96	4.90	9.19	0.25
26	6	Southeastern	Operating	Underground	12,086	2.96	4.90	9.19	0.25

Source: Wood Mackenzie