Appendix 4.C

Fuel Price Forecasts

The following appendices comprise Appendix 4.C:

Appendix 4.C.1 Consensus Forecasting Approach Discussion

Introduction

An investigation was performed to identify the best possible commodity forecasts to use in KCP&L fuel pricing models. The investigation sought to determine if there was an individual Consultant/Forecaster among the Consultants whose forecasts are currently purchased by KCP&L, that was consistently better performing than other Forecasters, and that the consistency was not only maintained across time but also from multiple perspectives from which a forecast might be utilized or upon which the forecasts can be compared and judged.

The investigation identified a wide variation among forecasters from year to year as to which was the "Best". A more detailed investigation revealed significant academic research in the area for forecasting and forecast averaging. This academic research not only proved the robust nature and reliability of forecast averaging, but showed that an average of forecasts can significantly reduce forecast risk through incorporating the information available to a greater number of forecasters. It also indicated that averaging a small number of forecasters is all that is required to utilize most of the gains from increasing the number of forecasters. The reasons behind the superior performance of forecast averaging are numerous, but are summarized in a simplified manner by Ilan Yaniv, who wrote, "A subjective estimate about an objective event can be viewed as the sum of the "truth", random error, and constant bias."[1] The result of the averaging process is that the random errors, and to an extent the bias as well, cancels each other out when forecasts from multiple sources are averaged, which produces a result that can be summarized from the Yaniv example as the "truth" plus a random error significantly smaller than in the individual sources on which the averages are based.

Testing the academic results against existing Powder River Basin coal price forecasts already purchased by KCP&L showed that in practice, the academic results were

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[1]Yaniv, Ilan, Hebrew University of Jerusalem, "The Benefit of Additional Opinions", Current Directions in Psychological Science, 2004, No.13, p.76-79

repeated with real world data, implying that combining existing Consultant's forecasts into an average forecast produces a composite forecast that consistently has the highest probability of accuracy on an annual basis.

Background

In developing long-term forecast prices for any commodity it is necessary to review a variety of data sources in the effort to gain an adequate knowledge of the current and future factors likely to influence the supply and demand for the commodity. Quite often this requires referring to certain industry experts, often impartial industry specific consultants or economists that have collected significant information about the commodity in question and have significant knowledge and experience within the industry. These industry experts generally have many years in the industry analyzing and forecasting supply, demand, and price for a select few commodities in which they specialize. As such these experts often produce some of the most widely influential and accepted price forecasts within their area of expertise.

When planning decisions require making projections of future market supply, demand, or price, experts are often the only available resource upon which future projections can rely. However, when presented with several different expert sources from which to choose, the question will invariably arise as to which experts' forecast should be chosen. Usually this is based upon some measure of which expert is most "accurate".

Selecting the most "accurate" of all experts is certainly the most desirable pathway if the accuracy could be known a priori, but unfortunately this idyllic concept encounters several problems. The problems include determining the relativistic frame of reference from which the relative accuracy can be measured and compared, so as to provide the colloquial "apples to apples" comparison. For example, the forecaster that is most accurate in the near term may be different from the one that has the smallest number of periods in error, and both of these references may differ from the expert whose forward curve has the smallest mean error relative to the actual forward once that actual forward is known.

Additional difficulties may arise even within a relative frame of reference, because forecast experts are much like Wall Street mutual fund managers. This year's best performer in a specific reference category may not be next year's best performer in that category. These differences likely result from the annual or periodic variance in information quality and quantity accessible to each forecaster, as well as the differences in weight that each forecaster may place on that variable information.

If the relativistic definition of forecast accuracy is the forecast that is least wrong (i.e. has the smallest error to actual), then without perfect information it is difficult, if not impossible, to consistently select the most accurate forecaster for each year, since the best forecast can't be identified until after the actual value is known.[2] Since such identification is not feasible, the consistently best performing forecast a priori is often a simple average of several individual forecasts.[3] This alternative suggests that logic for the preferred solution may be found in a comparison with Portfolio Theory.

Portfolio theory holds that by diversifying investments through placing smaller amounts in numerous assets, rather than investing everything in a single risky asset, the risk of loss is greatly reduced, while the average expected performance may improve. Such improvement comes not from increasing the odds of making the right pick every time, but rather from decreasing the odds of making the worst pick, and spreading the risk implications of the worst pick across the entire portfolio, thereby minimizing its impact. In much the same way, placing reliance on a portfolio of individual forecasts by industry experts should reduce the price risk resulting from the inevitable forecasting error, while the incorporation of each experts' additional unique information should improve overall forecast performance across many different frames of reference. Robert Clemen, Professor of Decision Sciences at Duke University, expressed this concept when he wrote, "no matter how many methods an expert uses, the results are limited by the expert's personal set of information. In contrast, a new expert has a possibly distinctive set of information, which, at least in principle, could provide further improvement even if many experts have already been consulted."[4]

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[2] Yaniv, Ilan, Hebrew University of Jerusalem, "The Benefit of Additional Opinions", Current Directions in Psychological Science, 2004, No.13, p.76-79
[3] Clemen, Robert T. and Winkler, Robert L., "Combining Economic Forecasts" Journal of Business & Economic Statistics, Jan.1986, v.4, No.1, p.39-46
[4] Clemen, Robert T. and Winkler, Robert L., "Multiple Experts vs. Multiple Methods: Combining Correlation Assessments", Decision Analysis v.1, No.3, Sept. 2004, p.167-176

Additionally, the simple average of a portfolio of expert price forecasts provides something no individual forecast can provide, and that is a method for measuring the statistical variability, or uncertainty, in the forecast price. Most individual forecasters do not provide a probabilistic range around their forecast price, and only JD Energy provides a high and low case (without probabilities), but with a portfolio of forecasts the range and variability can be calculated quantitatively for the average forecast, which permits establishing confidence intervals as the upper and lower ranges around the base case composite.

Supporting Research

Whether referred to as average forecast, consensus forecast, or combinatorial forecast, the concept of combining forecasts has been the subject of numerous academic investigations during the last four decades. Considerable academic research tested various methods for selecting and/or combining forecasts and estimates. Some of the most extensive research on the subject during the past 20+ years is the work of Dr. Robert T. Clemen and Dr. Robert L. Winkler, of the Fuqua School of Business at Duke University. Dr. Clemen demonstrated the extensive nature of this forecasting research in a paper published by the International Journal of Forecasting in 1989, which is titled: "*Combining Forecasts: A Review and Annotated Bibliography*." In this paper, Dr. Clemen compiles a list of 209 research documents totaling more than 2000 pages, plus 11 books and theses, all investigating and demonstrating the scientific validity for combining forecasts. Since the publication of this paper an additional eighteen years of research by Robert Clemen and others has continued to demonstrate the superior benefits of combining forecasts in numerous applications ranging from psychology and medicine to engineering and economics, with the central conclusion being that forecast accuracy is significantly improved by combining multiple individual forecasts and that the simple averaging of forecasts often produces results superior to more complicated combinatorial methods.[5]

When averaging multiple forecasts there are several assumptions that apply. The two most important assumptions are:

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[5] Clemen, Robert T., "Combining Forecasts: A Review and Annotated Bibliography", International Journal of Forecasting, v.5, 1989, p.559-583

A Priori belief that all expert forecasts are interchangeable provided the forecasters are all of the same caliber (implied by simple average). The closer to the time period being forecast, the lower the expected forecast error to actual, and the lower the general variation among forecasters

The extensive academic research into the methods and practice of combining forecasts has produced many highly supportive results. The following list compiles eight consistent findings that are most relevant to the combining of available energy price forecasts.

Academic Research Results:

- Simple average of forecasts can significantly improve results
- Simple averaging has been demonstrated to be more robust and perform better than more complex methods
- Increasing number of individual forecasts decreases variability, implying a large risk reduction
- Increasing number of experts increases accuracy
- Increasing number of forecasting methods increases accuracy
- Gains are greater from adding more experts than from adding more methods, with improvement from each additional expert equal to approximately four additional methods
- Majority of forecasting improvement occurs from the first 3-4 experts, with rapidly diminishing returns from addition of more experts
- Simple averaging method and complex Bayesian statistical method will converge to the same forecast result when number of forecasts is large (n>=30)

Usage

The practice of combining forecasts is widely used and accepted by central bankers, corporate executives, and government agencies around the world. Examples of this acceptance are the numerous consumers of forecasting products from a firm called Consensus Economics (www.consensuseconomics.com). Since 1989 Consensus Economics has applied the theory of combining multiple expert forecasts to produce an average monthly forecast for important macroeconomic variables such as GDP, PPI, CPI, currency exchange, etc, that are relied upon by both governments and industry.

Since the focus of their business is forecasting broad economic indicators for more than 70 countries worldwide, they do not produce specific energy related forecasts such as Powder River Basin coal or Henry Hub natural gas. However, the concepts supporting their forecasting method are well researched, and as prior academic research has demonstrated, can be applied to improve forecasts for a wide range of variables and commodities. Consensus Economics web site provides links to additional supporting research. However, Consensus Economics is not the only source to report the acceptance of forecast averaging on the part of government Central Bankers. In a 2001 paper titled, "Testing for Forecast Consensus", U.S. Federal Reserve Chairman Ben Bernanke is quoted as saying that consensus forecasts can be used to add credibility to monetary policy.[6]

There are many reasons for using a combination of expert forecasts, but the most common are:

- Incorporate additional distinctive information
- Simple averages do not require data fitting
- Simple averages do not require complex relativistic comparisons of expert accuracy
- Numerous academic studies prove that the average of multiple expert judgments is superior to individual judgments
- Random error by forecasters is averaged, cancelling individual biases
- A Portfolio of individual forecasts minimizes potential forecast error, thereby reducing risk
- Variation of individual forecasts around an average provides a reasonable measure of implied forecast uncertainty

Testing

As part of the effort for determining the highest quality forecast available for KCP&L forecasting needs, it is apparent that academic research findings should be tested on available consultant forecasts. Given that coal is the largest expense component of the KCP&L fuel portfolio, and since there are fewer coal forecast sources available than for the more open and heavily traded crude oil and natural gas sources, it is clear that the

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[6] Gregory, Allan W., Smith, Gregor W. and Yetman, James, "Testing for Forecast Consensus, Journal of Business and Economic Statistics, Jan. 2001, v.19, Issue 1, p.34-43

tests should be performed using Powder River Basin coal price forecasts, and specifically the 8400 BTU coal forecast since that is, by tonnage, the largest quality component within the coal portfolio. The forecasts analyzed were from [redacted]

The Consultant forecasts for PRB coal were chosen to test the academic findings against actual data. The forecasts were selected on the basis of the following five criteria:

- Forecasts from consultants used and respected throughout utility and mining industries
- Forecasts from consultants previously, currently, or routinely used by and readily available to KCP&L
- Forecasts that project ten years or more into the future
- Forecasts of same region and coal type
- Forecast series immediately available at least as far back as 2002-03

Three forecasting sources met all of the criteria. The three sources were [redacted], with the limiting factors being the unavailability of [redacted] forecasts prior to 2003, and changes in the [redacted] coal product definitions between 2000 and 2003.

Forecasts from the three consultants, plus an average of the three forecasts, provided four forecasts that could be compared and tested from several relative perspectives. The four forecasts were then compared for accuracy against the yearly average of actual Coal Daily settlement prices for PRB 8400 BTU coal.

Mean Squared Error

Although there are many relative perspectives from which the forecasts can be compared, the first comparison chosen was to mathematically compare the statistical "fit" or deviation of the historic forecast curves to the actual price curve. This was done through calculation of the Mean Squared Error (MSE) for each of the four forecast curves for each forecast year beginning with the 2003 forecasts. MSE essentially measures the deviation of the entire curve from the actual curve, with the lowest MSE value representing the curve with the smallest overall deviation.

Table-1 Forecast Error Minimization as Measured by MSE – from Best to Worst **<u>Highly Confidential</u>**

Forecast Year	Best	2nd	3rd	Worst
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

On a percentage basis the MSE results in the above table are as follows:

Table-1A Forecast Error Measured by MSE as Percentage of Total Forecasts <u>Highly Confidential</u>****

Forecast Source	Best	2nd	3rd	Worst
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Measuring the relative forecast error by MSE shows that [redacted] forecasts had the smallest error in 50% of the forecast years measured, but [redacted] also produced the worst forecast 25% of the time, and has not produced a forecast with minimum error since 2004. This sample set suggests that choosing [redacted] as the preferred forecast would have resulted in the best or second best forecast 75% of the time, but would not have had a top performing forecast since before the recent price spikes of 2005-06, and would also have resulted in being saddled with the worst forecast 25% of the time. Looking for the next best performer from the MSE perspective, the Average of the forecasts stands out. The Average was the best performer 25% of the time, and like [redacted] it was best or second best 75% of the time, but unlike [redacted], the Average was never the worst performer. Just as the academic research suggests, the Average forecast seems to have minimized the risk of error, and consistently performed better than the forecast from any other source. It is apparent that "before the fact" it was not possible to know which of the three consultants would perform best in a given year, and even the consultant with the highest probability of performing well still had a very risky probability of being the absolute worst choice a whopping 25% of the time. Only the Average appears to provide a reasonably confident assurance, "before the fact", that the forecast will be of good quality.

Count of Forecasts

Another perspective for measuring the quality of a forecast is to look at the absolute number of times the forecaster was correct, independent of the statistical fit of the total dataset. This does not measure the overall relationship between points forming a curve as with the MSE, rather this method just looks at all the years forecast by a consultant in a given forecast year, and counts each year of the forecast independent of the other years, simply measuring how many times the forecaster got relatively close to actual over the duration of the forecast.

Since forecasters being absolutely correct for any given year are akin to a golfer hitting a hole-in-one (but with smaller probability), it is not probable that a small sample will provide any statistically perfect information, and true to this theory the present data set does not have any perfect matches between forecast and actual. However, since the more achievable goal seems to be the minimization of forecast error, it is reasonable to count the number of occurrences within a minimum error of actual to see how often a forecaster gets within the proverbial ballpark. The test dataset produces a count of at least one forecaster for each forecast year if the minimum error is no more than 10% from actual. With the test dataset, each consultant has four measurable forecast points for the 2003 forecast, three for the 2004 forecast, two for 2005, and one for 2006, summing to a total number of ten possible points.

Table-2 Count of Forecast Points Within 10% of Actual (PRB 8400) **Highly Confidential**

Forecast Year	2003	2004	2005	2006	Sum	% of Possible	Years With Close Points
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Measuring accuracy by counting the total number of forecasts that fall close to the actual value indicates that the best forecaster may be [redacted], since that consultants forecasts for this sample set were within 10% of actual more of the time (40%) than any other forecaster, and is within 10% of actual for at least one year of the measurable forecast in three of the four forecasts. However, [redacted] was by far the worst overall forecaster when measured by MSE, as demonstrated in Table-1 and Table-1A. Likewise, the forecaster with the largest number of best MSE forecasts, [redacted], appears by the Count method to be the worst performer, with only one close forecast point out of ten possible points and only one forecast year (2005) having any forecast points within 10% of actual. When looking at performance from this perspective and comparing it to the MSE perspective, it is evident that the overall best and worst performers from one perspective trade places when viewed from the other perspective.

Further analysis of the Count method shows that the second best performance measured by this metric is the Average of forecasts. The Average had 30% of all points within 10% of actual, and was most consistent with three of the four forecasts having at least one year falling within 10% of actual. The Average produced the second best overall results by both the Count metric and the MSE metric, while the best and worst performers swapped positions, suggesting that the Average may be the most consistent performer. These results seem to confirm what the voluminous academic research has already shown, which is that the most robust forecast is consistently achievable by averaging multiple forecasts, and that the average of forecasts will minimize the risk of forecast error.

First Year of Forecast

A third metric from which to measure a forecaster is their ability to correctly forecast the near-term or immediate future. Just as it is easier to predict what the weather will be tomorrow than it is to predict the weather a month or a year from today, due to familiarity or temporal proximity, it should also be less difficult to predict the next forecast period than one ten years in the future. Being closer to tomorrow than to next month, it is easier to know with a higher probability tomorrow's most likely outcomes. Likewise, there should be an expectation that the first year of a commodity price forecast be more accurate than later years simply because of more high quality information with higher probability outcomes.

Furthermore, given the time value of money, the early years of a price forecast are weightier and therefore error risk is potentially more costly than in later years when time provides room to maneuver by exercising alternative options, and inflation erodes financial value. Therefore, the first year of a forecast is, financially speaking, the most valuable or costly forecast year depending on your point of reference. It also provides the starting point for all remaining forecast years in a forecast curve, so being as accurate as possible in year number one should help provide a firm foundation for the remainder of the forecast curve.

The reference data, consisting of forecasts from [redacted], and an average of these forecasts, shows that [redacted] got the most first year forecasts closer to actual than others. A tabulation of first year forecast accuracy is displayed below in Table-3.

Table-3 First-Year Forecast Accuracy (PRB 8400, Calendar Years 2003-2006)<u>Highly Confidential</u>****

	Count of Forecasts in Category (max possible = 4)			
Forecast	**Best**	**2nd**	**3rd**	**Worst**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table-3A First-Year Forecast Accuracy as Percent of All Test Case Forecasts<u>Highly Confidential</u>****

	Percent of Total Forecasts			
Forecast	**Best**	**2nd**	**3rd**	**Worst**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Testing the forecasts from yet a different perspective, the results once again show the best performer will vary from year to year, and from this particular perspective (best first year accuracy) the top performer differs from the top performers in the previously tested MSE and "Count of Points" perspectives. The results displayed in Table-3 and Table-3A demonstrates that all test case forecasts were best in accuracy at least once, with the exception of [redacted]. [redacted], with two first year bests, had more first year accuracy bests than the other forecasts at 50% of the sample set, and a total of 75% of first and second best. The next best first year forecast performer was the Average of forecasts, with one best and two second bests, for a total percentage of first and second best performances of 75% just like [redacted]. While the best performer from the "Count of Points" accuracy tests, [redacted], was only the third best performer in the first year of the forecasts tested. [redacted], which was the most accurate performer by the MSE statistical testing method, proved to have the worst accuracy in 100% of the first year forecasts.

The first year accuracy test once more demonstrates the superiority of the Average of forecasts. The simple Average produced the best outcome 25% of the time, and either best or second best 75% of the time, while never producing a worst outcome. With other forecasts swinging wildly from best to worst depending on the relative perspective from which their performance is considered, the Average consistently performed as either a best or second best choice, regardless of perspective. Furthermore, given that it is the only choice that could "before the fact" be consistently expected to perform with a high degree of accuracy, it appears as the best forecast choice among the forecasts that were available for testing.

Summary

In summary, the results of the accuracy tests applied to available PRB 8400 coal forecasts demonstrated findings consistent with the academic research of forecast averaging, and indicate that the most consistent forecast across a variety of reference points is the simple Average of available expert/consultant forecasts. The results are tabulated in Table-4.

Table-4 Results of Accuracy Testing by Method (PRB 8400, Calendar Years 2003-2006) Highly Confidential****

Perspective	Best	2nd	3rd	Worst
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Results displayed in Table-4 are consistent with academic research that indicates the Average forecast is simply the best choice in terms of probable accuracy independent of the method for determining that accuracy. The robust nature of the statistical Average forecast is noted by its consistent performance across each of the perspectives considered. Additionally, as noted in the results for each perspective, the forecaster that is labeled "Best" under each perspective in Table-4, also had a demonstrated probability of being "Worst" in at least one out of four forecasts for that perspective, while the Average was never "Worst" in any year of any forecast from any perspective tested, which implies that the Average is truly the "Best" available forecast. Simply stated, if the objective is to minimize forecasting risk and individual bias, employ the maximum amount of available market information, and consistently have a high probability of choosing a good performing forecast for each time period, then the best forecast is the Average of a portfolio of individual forecasts. The Average forecast also provides something the other individual forecasts lack, which is the added benefit of being able to statistically determine a range of possible forecast outcomes based upon desired confidence intervals.

References:

1) Clemen, Robert T. and Winkler, Robert L., "Combining Economic Forecasts", Journal of Business & Economic Statistics, Jan.1986, v.4, No.1, p.39-46

2) Clemen, Robert T., "Combining Forecasts: A Review and Annotated Bibliography", International Journal of Forecasting, v.5, 1989, p.559-583

3) Clemen, Robert T. and Winkler, Robert L., "Multiple Experts vs. Multiple Methods: Combining Correlation Assessments", Decision Analysis v.1, No.3, Sept. 2004, p.167-176

4) Consensus Economics
www.consensuseconomics.com

5) Gregory, Allan W., Smith, Gregor W. and Yetman, James, "Testing for Forecast Consensus, Journal of Business and Economic Statistics, Jan. 2001, v.19, Issue 1, p.34-43

6) Sternstein, Martin, PhD, "Statistics", 1996, Barron's Educational Series Inc., Hauppauge, NY 11788, ISBN: 0-8120-9311-9

7) Yaniv, Ilan, Hebrew University of Jerusalem, "The Benefit of Additional Opinions", Current Directions in Psychological Science, 2004, No.13, p.76-79

Forecast Sources:

[redacted]

[redacted]

[redacted]

[redacted]

Appendix I

A) Powder River Basin 8400 BTU Coal Price Forecasts**<u>Highly Confidential</u>**

Hill & Associates

[redacted]	[redacted]
Nominal [redacted]	[redacted]
Nov-03	[redacted]
Nov-04	[redacted]
Nov-05	[redacted]
Nov-06	[redacted]

JD Energ[redacted]

PRB 8400[redacted]	[redacted]
Nominal [redacted]	[redacted]
Apr-03	[redacted]
Dec-03	[redacted]
Feb-04	[redacted]
Mar-04	[redacted]
May-04	[redacted]
Sep-04	[redacted]
Mar-05	[redacted]
May-05	[redacted]
Jan-06	[redacted]
Mar-06	[redacted]
Aug-06	[redacted]

Energy V[redacted]

PRB 8400[redacted]	[redacted]
Nominal [redacted]	[redacted]
Aug-03	[redacted]
Aug-04	[redacted]
Aug-05	[redacted]
Aug-06	[redacted]

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Forecasts Used in Calculating Average for Analysis**<u>Highly Confidential</u>**

PRB 8400		
		[redacted]
Hill	Nov-03	
JDE	Dec-03	
EVA	Aug-03	
Ave		
Std		
PRB 8400		
Hill	Nov-04	
JDE	Sep-04	
EVA	Aug-04	
Ave		
Std		
PRB 8400		
Hill	Nov-05	
JDE	May-05	
EVA	Aug-05	
Ave		
Std		
PRB 8400		
Hill	Nov-06	
JDE	Aug-06	
EVA	Aug-06	
Stdev		
Ave		
Coal Daily(P+1) Ave		

B) Difference between Forecast Price and Coal Daily Price**<u>Highly Confidential</u>**

Deviation from Actual Actual value for 2007-2011 are assumed to be the most recent (2006) forecast

			2002	[redacted]
	actual		$ 4.91	
2003	Hill	1		
2003	JDE	3		
2003	EVA	4		
2003	Ave	2		
			2002	
2004	Hill	1		
2004	JDE	3		
2004	EVA	4		
2004	Ave	2		
			2002	
2005	Hill	2		
2005	JDE	3		
2005	EVA	4		
2005	Ave	1		
			2002	
2006	Hill	4		
2006	JDE	2		
2006	EVA	1		
2006	Ave	3		

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Percent difference between Forecast and Actual

Highly Confidential

		2002	[redacted]
	actual		
2003	Hill		
2003	JDE		
2003	EVA		
2003	Ave		

		2002	[redacted]
2004	Hill		
2004	JDE		
2004	EVA		
2004	Ave		

		2002	[redacted]
2005	Hill		
2005	JDE		
2005	EVA		
2005	Ave		

		2002	[redacted]
2006	Hill		
2006	JDE		
2006	EVA		
2006	Ave		

C) Forecast Averages and Standard Deviations**Highly Confidential**

[redacted]

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Appendix 4.C.2 Natural Gas

A composite Henry Hub natural gas price forecast was created by combining the forecasts from the Energy Information Administration (EIA), Energy Ventures Analysis (EVA), Global Insight (GI), and PIRA Energy Group (PIRA). Each source provided a base case forecast in nominal dollars, with the exception of the EIA, which used constant 2005 dollars. The EIA forecast was converted to nominal dollars using Global Insight's GDP implicit price deflator (JPGDP). The price deflator was the Global Insight quarterly long-term forecast for JPGDP from December 2006 overlaid with the Global Insight quarterly short-term forecast for JPGDP from March 2007. The short-term forecast provided new information for the forecast curve out to 2017. The change in the front end of the forecast curve created an offset between the long and short-term forecasts in 2018. Since the EIA natural gas forecast was the only natural gas forecast source requiring conversion to nominal dollars, the Global Insight Long-Term forecast (December 2006) closest to the actual run date of the EIA forecast was used, in combination with the Short-Term forecast (March 2007) closest to the date the forecast was released by EIA. Once all natural gas price forecasts were in nominal dollars the forecasts were combined by equal weight to create a composite price forecast representing the expected or base case consensus among the major forecast sources.

The variation of individual forecasts within the composite are then used within a t-distribution to mathematically calculate high and low forecast price curves representing the 90th and 10th percentiles of the t-distribution. The three resultant price curves with their probability of occurrence are base 50%, high 25%, and low 25%.

The New York Mercantile Exchange (NYMEX) forward price curve for Henry Hub natural gas goes forward five years; for four of those five years the NYMEX price is used as the base forecast for natural gas, with the consensus forecast gradually taking over from the NYMEX curve during year five. This gradual change occurs by decreasing the weighting of the NYMEX price by 1/12 and increasing the weighting of the consensus price by 1/12 for each month of year five, such that the forecast price is 100% consensus by the first month of year six, and the consensus forecast remains the forecast basis through year thirty of the forecast. The high and low consensus forecasts differ from the base forecast in the treatment of NYMEX forward prices during the first five years of the forecast. When calculating the statistical distribution that determines the high and low price forecasts, the NYMEX forward prices are treated as an equal weight component of the consensus for the five years that the NYMEX forwards are present, rather than being the sole basis of the forecast.

Global Insight

Global Insight, Inc.
1000 Winter Street
Waltham, MA. 02451-1241

The Global Insight source data for Henry Hub natural gas price is split between the short-term and long-term forecasts. The long-term forecast issued August 30, 2007 was the Global Insight forecast used for the price forecast to 2037. Overlaid on this price curve was the more recent Global Insight short-term forecast from Novvember 2007. The short-term forecast covered the period 2007 to 2017. The period from 2018 to 2037 is covered by the Global Insight long-term forecast.

The Global Insight natural gas forecast sources:

Short-Term Henry Hub Natural Gas Forecast in Nominal $
2007-2017
U.S. Short-Term Forecast Tables (Excel) [2007 11 7] - (ZIP; 5Mb)
GI_030707_ShortTerm_JPGDPforEIAOil_WebTables.xls

Long-Term Henry Hub Natural Gas Forecast in Nominal $
2018-2037
U.S. Long-Term Forecast Tables - Baseline (Excel) [2007 8 30] - (ZIP; 4Mb)
Global_Insight_LongTerm_JPGDP_HH_WTI_A_T300807.xls

Energy Information Administration
Annual Energy Outlook 2007 - With Projections to 2030, February 2007

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, D.C. 20585

The EIA source data for natural gas price comes from the long-term forecast issued in the Annual Energy Outlook 2007 (February 2007 - November 2006 model run), which is used for the price forecast to 2030.

Long-Term Henry Hub Natural Gas Forecast in 2005$
2007-2030
Annual Energy Outlook Reference Case Forecast, November 2006
Natural gas forecast data in file:
EIA_aeo2007_92-118_sup_ogc.xls

The Long-Term forecast was converted from constant 2005$ to nominal dollars for development of the consensus forecast. The conversion of EIA's long-term forecast to nominal dollars was done in KCP&L workbook file EIA_2007_Forecasts.xls, using Global Insight's Implicit Price deflator (JPGDP) for the conversion to nominal.

The JPGDP forecasts used to convert the EIA natural gas price forecast to nominal dollars are sourced from the following two Global Insight spreadsheet tables:

JPGDP
U.S. Long-Term Forecast Tables - Baseline (Excel) [2006 12 4] - (ZIP; 4Mb)
T301106.xls

JPGDP
U.S. Short-Term Forecast Tables (Excel) [2007 3 7] - (ZIP; 5Mb)
GI_030707_ShortTerm_JPGDPforEIAOil_WebTables.xls

Energy Ventures Analysis Inc.

Energy Ventures Analysis, Inc.
1901 North Moore Street, Suite 1200
Arlington, VA. 22209-1706

"The Long-Term Outlook", August 2007, (p.4-53)
Forecast in Nominal dollars

PIRA Energy Group, Inc.

PIRA Energy Group
3 Park Avenue, 26th Floor
New York, NY. 10016-5989

The PIRA Henry Hub natural gas price forecast in nominal dollars was sourced from PIRA's "Long-Term Henry-Hub Gas Prices Forecast" posted on the PIRA web site 7/26/07.

Present Reserves

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2006 Annual Report* released December 2007 estimates technically recoverable resources of dry natural gas (discovered, unproved, and undiscovered) at 1,533 trillion cubic feet. Adding the 2006 U.S. proved reserves[7] of 211 trillion cubic feet that yields a technically recoverable resource target of 1,744 trillion cubic feet, which is about 94 times the 2006 dry gas production level of 18.5 trillion cubic feet.

Discovery Rates

Total discoveries of dry natural gas reserves attributed to the drilling of exploratory wells, which include field extensions, new field discoveries, and new reservoir discoveries in old fields, were 23,342 billion cubic feet in 2006. This was 35 percent more than the prior 10-year average (17,255 billion cubic feet) and 1 percent more than in 2005. The

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[7] EIA defines proved reserves as those volumes of oil and gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

majority of natural gas total discoveries in 2006 were from extensions[8] to existing gas fields. Field extensions were 21,778 billion cubic feet, 3 percent more than in 2005 and 61 percent more than the prior 10-year average (13,522 billion cubic feet). New field discoveries were 409 billion cubic feet, 57 percent less than the volume discovered in 2005 and 75 percent less than the prior 10-year average (1,659 billion cubic feet). New reservoir discoveries in old fields were 1,155 billion cubic feet, 4 percent less than 2005 and 44 percent less than the prior 10-year average (2,074 billion cubic feet).[9]

Usage Rates

Environmental constraints contained in the Clean Air Act of 1990 insured a growing demand for natural gas. For the past 15 years, industrial consumers and power generators have become increasingly dependent on natural gas-based technologies for meeting their energy requirements and for satisfying more stringent air quality standards.

Between 2006 and 2020 natural gas demand is expected to increase from about 22 trillion cubic feet per year (tcf/y) to about 26 tcf/y. That is about a 1 percent per annum growth. The primary driver for that increase is expected growth in gas consumption for power generation.

Natural gas used for electricity generation is expected to grow at a faster rate through 2020 than any other major consuming sector. Forecast growth rates through 2020 for the electric sector ranged from 1.3% to 2.7%. Variation in projected natural gas demand in the electric power sector is the result of different projections for the amount of natural gas-fired generation capacity that will be built and the cost of natural gas relative to other fuels. Natural gas used for the residential, commercial and industrial sectors combined was forecast to grow through 2020 at rates ranging from 0.0% to 1.1%. The demand for these sectors is driven by demographics and economic growth.

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[8] Extensions are the reserves credited to a field because of enlargement of its proved area. Normally the ultimate size of newly discovered fields is determined by wells drilled in years subsequent to discovery. When such wells add to the proved area of a previously discovered field, the increase in proved reserves is classified as an extension. Additional wells provide more information and reduce the uncertainty of the reserves estimate. As additional wells are drilled, the geometry of the reservoir and, consequently, its bulk volume, become more clearly defined. This process accounts for the large extensions to proved reserves.

[9] Energy Information Administration, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2006 Annual Report", p.ix and Table D3, December 2007

The growth projections assumed "incremental policy measures" regarding environmental pressures that would cause natural gas demand to increase. The adoption of policies to limit or reduce greenhouse gas emissions could significantly increase natural gas usage for electric generation above levels shown in current forecasts.

Profitability/Financial Condition of Producers

The Energy Information Administration's *Performance Profiles of Major Energy Producers* 2006 provides a financial review and analysis of the domestic and worldwide activities and operations of the major U.S.-based energy-producing companies. *Performance Profiles* examines companies' operations on a consolidated corporate level, by individual lines of business, by major functions within each line of business, and by various geographic regions. The report focuses on annual aggregate changes in profits, cash flow, and investment in the United States and international energy industry, and also explores changes in the majors' exploration and development expenditures, reserve additions, and refining costs and margins. The analysis in the report is based on detailed financial and operating data and information submitted each year to the EIA on Form EIA-28, the Financial Reporting System (FRS).[10]

In *Performance Profiles* EIA reported that:
Return on net investment in place (ROI) for the oil and natural gas production segment fell to 20 percent in 2006 from 24 percent in 2005. Despite the large decline, the 2006 ROI remained higher than any other year in the FRS survey except 2005. ROI for domestic oil and natural gas production fell farther than that of foreign production, which considerably widened the spread between foreign and domestic.[11]

Capacity, Profitability, Expansion potential of present and future transport options

[10] Energy Information Administration, "Performance Profiles of Major Energy Producers 2006", p1, December 2007
[11] Energy Information Administration, "Performance Profiles of Major Energy Producers 2006", pp 3-4, December 2007

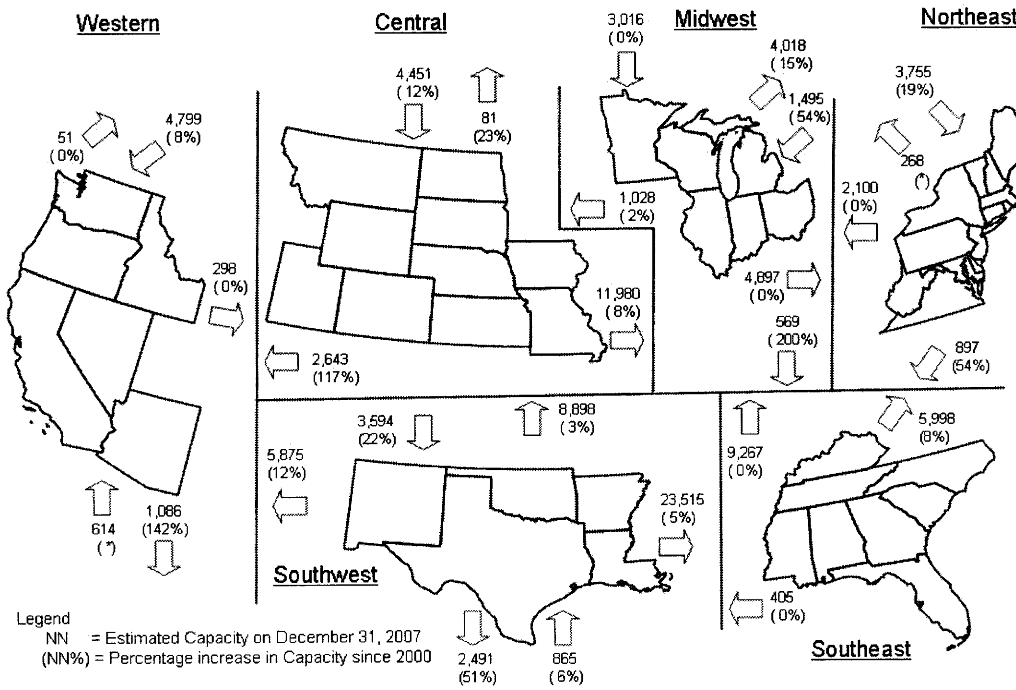
The U.S. natural gas pipeline network is a highly integrated transmission and distribution grid that can transport natural gas to and from nearly any location in the lower 48 States. The natural gas pipeline grid comprises:

- More than 210 natural gas pipeline systems
- 302,000 miles of interstate and intrastate transmission pipelines.
- More than 1,400 compressor stations that maintain pressure on the natural gas pipeline network and assure continuous forward movement of supplies.
- More than 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points that provide for the transfer of natural gas throughout the United States.
- 29 hubs or market centers that provide additional interconnections.
- 399 underground natural gas storage facilities.
- 49 locations where natural gas can be imported/exported via pipelines.
- 7 LNG (liquefied natural gas) import facilities and 100 LNG peaking facilities.

Interstate natural gas pipeline systems account for more than 150 Bcf/d (54.8 tcf/y) of total U.S. natural gas transportation capacity and approximately 215,000 miles of natural gas pipeline. Interregional capability of this system is illustrated below.

Interregional Natural Gas Transmission Pipeline Capacity in 2007

(Million cubic feet per day)



* Capacity was not in place in 2000.
Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Pipeline Capacity Database, as of December 31, 2007.

As shown above there has been significant capacity increase since 2000. More increases are expected as new natural gas pipelines built out of the two major expanding natural gas production areas in the United States, northeast Texas and the Rocky Mountain area. In the Unita/Piceance Basin of western Colorado/eastern Utah and Green River and Powder River Basins of Wyoming. Additionally, in the northeast Texas area, particularly the Barnett Shale and Bossier Formations of the Fort Worth Basin, increasing production and the discovery of additional proved natural gas reserves have resulted in more natural gas pipeline capacity being proposed for development over the next several years. Most of the latter capacity will be directed toward interconnections with the interstate natural gas pipeline network in Louisiana and Mississippi that serves the Midwest, Northeast, and Southeast regional markets. Not only has the expanding development in these producing areas increased the demand for additional natural gas pipeline capacity per se, the economic need to reach additional far-off markets and network interconnections has motivated the design of more long-distance natural gas pipeline projects.

One major interstate pipeline project that is and will have significant impact on the Midwest is the Rockies Express. Kinder Morgan Energy Partners, Sempra Pipelines & Storage and ConocoPhillips teamed up to build one of the largest natural gas pipelines ever constructed in North America. The $4.4 billion 1,678-mile Rockies Express (REX) project will give producers in the Rocky Mountain region the ability to deliver natural gas to markets in the Midwest and eastern parts of the country. REX will also help ensure reliable sources of affordable natural gas for consumers in those markets as well. The project is being anchored by long-term, firm transportation contracts with a number of shippers for virtually all of the 1.8 billion cubic feet per day (657 billion cubic feet per annum) of available capacity on REX.

The pipeline originates at the Meeker Hub in Rio Blanco County, Colorado and extends to the Clarington Hub in eastern Ohio. The initial 136-mile segment of the pipeline from the Meeker Hub in Rio Blanco County, Colorado, to the Wamsutter Hub in Sweetwater County Wyoming, has been completed was approved for service in February 2006. Construction on the 191-mile portion from Wamsutter to the Cheyenne Hub in Weld County, Colorado, began in July 2006 and was placed in service on February 14, 2007.

The 713-mile REX-West segment of the pipeline, which runs from the Cheyenne Hub to Audrain County, Missouri, was authorized by FERC order issued April 19, 2007. Service began January 12, 2008, on approximately 500 miles of Rockies Express-West (REX-West) from the Cheyenne Hub in Weld County, Colorado, to the ANR delivery point in Brown County, Kansas. When the remaining 213-mile section of REX-West which continues eastward to Audrain County, Missouri, came on line, it brought capacity to about 1.5 Bcf per day.

On April 30, 2007 Rockies Express filed with FERC an application for authorization to construct the REX-East portion, which when approved by FERC, will extend the pipeline another 638 miles to the Clarington Hub in Monroe County, Ohio. The REX-East portion

is expected to begin partial service on December 30, 2008, and full service in June 2009.
(http://www.kindermorgan.com/business/gas_pipelines/rockies_express/)

The completion of the REX system will have a very profound effect on several segments of the industry, particularly since the completion of the final phases of the project will correspond with a likely significant increase in U.S. LNG imports. Among the likely impacts will be reduced utilization of some of the major interstate pipelines, which could lead to a decontracting of capacity for selected pipelines. Similarly, the possibility of the Gulf Coast region being long on supply for the first time has enormous implications for industry participants and the competitive structure of the industry.[12]

Two pipelines that have long been under consideration and will significantly affect the U.S. market are the Arctic gas pipelines. The smaller MacKenzie Valley Pipeline and the much larger Alaskan Natural Gas Transmission System (ANGTS), represent a major source of gas supply in almost all long-term projections, as their combined fully expanded capacity will be 7.9 BCFD (2,883 billion cubic feet per annum). In 2007, Exxon announced that the Mackenzie Delta gas pipeline was not economically viable. At the core of this economic dilemma are rapidly increasing costs for these pipelines and the failure of other affected parties to share in costs for these projects or to come to terms. If these projects either are cancelled or delayed beyond 2020, it is unlikely that there will be adequate gas supply to meet projected demand. As a result, gas prices will rise to very high levels.[13]

Effects of government regulation/competition/environmental legislation on transport

Two years ago, former Governor Frank Murkowski settled in principle with BP, Exxon Mobil Corp. and ConocoPhillips on fiscal terms — taxes and royalties — for producing the North Slope gas. The deal would have frozen oil taxes for 30 years and gas taxes for up to 45 years for the three major oil companies, but it did not guarantee a pipeline

[12] EPRI, "U.S. Natural Gas Supply Equation and Price Envelope", No. 01014146, p7-16, Electric Power Research Institute, Palo Alto, CA., December 2007
[13] EPRI, "U.S. Natural Gas Supply Equation and Price Envelope", No. 01014146, p7-12, Electric Power Research Institute, Palo Alto, CA., December 2007

would get built. The Legislature would not vote on it because lawmakers believed it was too much of a giveaway to the energy industry. That prompted then newly elected Governor Sarah Palin to chart another course, while refusing to continue negotiations the oil companies. Palin introduced the Alaska Gasline Inducement Act — or AGIA — early in 2007 as a means to stimulate competition among oil companies as well as the independent pipeline companies. Apparently the AGIA coupled with high natural gas prices has done that.

Two of the world's largest oil companies unveiled plans April 8, 2008, to jointly develop a multibillion dollar pipeline to be anchored Alaska's energy-rich North Slope. Britain's BP PLC and ConocoPhillips, based in Houston, said they plan to spend $600 million in the first phase of the project over the next three years, beginning this summer. The project's cost estimates exceed $30 billion. Meanwhile, Alaska is also reviewing a proposal by TransCanada Corp., which submitted its application for a state-backed license in November. Only one is likely to survive the competition in a pipeline race that has the attention of state and federal lawmakers.

The April 8, 2008, announcement to start the project represents the first visible steps toward pipeline construction on a project. The first phase of the pipeline project involves field work this summer and securing long-term commitments from gas companies to send gas down the pipeline. Much of that commitment is likely to come from BP, ConocoPhillips and Exxon Mobil Corp. The three companies hold leases to nearly 35 trillion cubic feet of North Slope gas. No timeline was announced for construction and completion, but the companies have said it would be at least 10 years before gas begins to flow. That means Alaska's gas could enter America's market by about 2019.

It is assumed that none of the proposals could receive adequate financing without the backing of the three producers, who control the reserves. The request for new pipeline proposals and subsequent negotiations delayed the Alaska Natural Gas Transportation System (ANGTS) project at least two years with further delays possible if there is not an agreement with the producers. Included in the state of Alaska's new competitive bidding approach is a $500MM incentive payment, which seems large but will only pay for a small portion of the required infrastructure cost (e.g., roads) that eventually will be of benefit to the state.

The pipeline would eventually move about 4 billion cubic feet of natural gas per day to markets, about 6 percent to 8 percent of daily U.S. consumption, the companies said. The plan, dubbed "Denali — The Alaska Gas Pipeline," is to deliver natural gas via a 2,000-mile pipeline from the energy rich North Slope in Alaska to Alberta, Canada. Gas can then go into an existing pipeline system, or if necessary, BP and ConocoPhillips said it could build an additional 1,500-mile pipeline to U.S. markets.

Potential government restrictions on use of fuel for electricity generation

The severe pendulum swings in the natural gas market find their origins in how the market has been regulated. The very nature of market regulation inhibits prompt or appropriately measured market response to changing circumstances.

Natural gas regulation began with the Natural Gas Act of 1938. Since then it has been subjected to various court orders, Federal Power Commission and then Federal Energy Regulatory Commission price controls, the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA) and Natural Gas Policy Act of 1978 (NGPA).

The Powerplant and Industrial Fuel Use Act (FUA) was passed in 1978 in response to concerns over national energy security. The 1973 oil crisis and the natural gas curtailments of the mid 1970s contributed to concerns about U.S. supplies of oil and natural gas. The FUA restricted construction of power plants using oil or natural gas as a primary fuel and encouraged the use of coal, nuclear energy and other alternative fuels. It also restricted the industrial use of oil and natural gas in large boilers.

During the early 1980s, the demand for natural gas declined substantially, which contributed to a significant oversupply of gas for much of the decade. Residual fuel oil, the main target of the FUA, was used for peak electricity generation; most new base load power plants constructed in that decade were coal-fired or nuclear.

Falling natural gas demand and prices finally spurred enactment of the Natural Gas Utilization Act in 1987 which repealed sections of the FUA that restricted the use of natural gas by industrial users and electric utilities. As a result of the repeal, natural gas and oil could again be used to fuel large new baseload electric power plants. Because of the repeal, total natural gas consumption for electric generation and industrial processing increased by approximately 47% between 1988 and 2002.

While history shows that government restrictions can be placed on the use of specific fuels, none of the forecasts used to construct the consensus forecast assumed any restrictions on the use of natural gas as a fuel for electricity generation.

Accuracy of previous forecasts

The accuracy of the consensus forecast method and reasons for selecting it as the best forecast were discussed in "4.C.1: Consensus Forecasting Approach Discussion."

Identification of critical uncertainty factors driving price forecast/range of forecasts/probability distribution

Each forecaster identifies multiple drivers believed by that forecaster to be an important aspect of price formation. While most of the drivers identified by each forecaster are similar, there are also some minor differences among forecasters. It is these minor differences that are the additional information captured by the combinatorial or consensus forecasting method. However, since many of the major drivers are the same across all forecasters, the consensus forecast is weighted toward these drivers, while the variation in strength or direction placed upon those drivers by individual forecasters produces much of the variation in the consensus forecast. That variation is reflected within the statistical t-distribution and becomes a driver of the high and low consensus forecasts. Those common drivers with the greatest potential price impact for consideration as primary drivers are discussed below.

Natural gas drivers can be divided into demand and supply factors. Demand factors can be simply aggregated as natural gas used for electricity generation and all other uses of natural gas. The three main supply drivers are availability of domestic production, Artic natural gas pipeline(s), and natural gas imports, specifically LNG. Each of these drivers are briefly discussed below.

Demand: Total lower 48 natural gas demand is projected to grow from about 22 trillion cubic feet (tcf) in 2005 to between 24 and 26 tcf in 2020.

Demand – Natural Gas Used For Electricity Generation. In all of the underlying forecasts, natural gas used for electricity generation was found to grow at a faster rate through 2020 than any other major consuming sector. From 2020 through 2025 EIA lowered the growth rate of natural gas used for electricity generation below their forecasted growth rates for the commercial and industrial sectors. The growth rates through 2020 for the electric sector ranged from 1.3% to 2.7%. While the various forecasts recognized that GHG legislation could dramatically increase demand from electric generators, they assumed "incremental policy measures" resulting in minimal environmental pressure. Variation in projected natural gas demand in the electric power sector is the result of different projections for the amount of natural gas-fired generation capacity that will be built and the cost of natural gas relative to other fuels. As a sector, electric power has better fuel substitution options that most.

Demand – Natural Gas Used For All Major Sectors Except Electricity Generation. Natural gas used for the residential, commercial and industrial sectors combined was forecast to grow through 2020 at rates ranging from 0.0% to 1.1%. Those rates did not change significantly from 2020 through 2025. Fuel substitution options for residential, commercial, and industrial sectors are limited. Consequently, these sectors are less price sensitive and their demand is driven by demographics and economic growth.

Supply: In order for the natural gas market to increase from the current demand level of approximately 22 tcf to the projected levels of exceeding 26 tcf in 2025, natural gas supply will have to increase substantially. It is apparent that traditional supply areas will not be able to achieve this level of increase. Instead, the US market will have to rely on a series of evolving gas supply sources to fill in the projected gap between supply and demand. Two significant evolving sources are Arctic gas and liquefied natural gas (LNG). The largest one is LNG.

Supply – Domestic Production. All of the underlying forecasts hold to the general premise that discoveries of new conventional natural gas reservoirs are expected to be smaller and more expensive to develop. Incremental production of lower 48 onshore natural gas comes primarily from unconventional resources. That results in a tight band of slow growth rates ranging from 0.2% to 0.6%.

Supply – Arctic natural gas pipeline(s). A major uncertainty is the likelihood and timing of the two Arctic pipelines. If both are built, they are expected to be operational by 2025 and deliver about 2 tcf/y to the lower-48. If only the Mackenzie Delta pipeline is built, it is expected to be operational by 2020 and deliver about 0.5 tcf/y to the lower-48. The various assumptions range from only the Mackenzie Delta pipeline being built with most of that volume being retained for the Canadian market to both pipelines operational by 2025 and delivering as much as 3.5 tcf/y to the lower-48. With the Arctic pipelines representing up to 10% of supply, a significant delay and/or cancellation of either the Alaska or Mackenzie Delta natural gas pipeline would have a major impact on the overall long-term outlook for the supply and demand balance of natural gas.

Supply – Liquified Natural Gas (LNG). All of the underlying forecasts expect current high natural gas prices to stimulate the construction of new LNG terminal capacity resulting in significant growth of LNG imports. They expect LNG imports to grow from about 0.6 tcf/y to somewhere between 3.7 to 5.3 tcf/y by 2020. The U.S. faces intense competition with both Europe and Asia for available LNG supplies which contributes to uncertainty in determining how the global LNG supply will be distributed between North America, Europe, and Asia.

LNG imports are expected to meet much of the increased U.S. demand for natural gas. Every segment of the LNG chain (i.e., liquefaction, shipping and regasification) is undergoing a period of rapid expansion. The various contributing forecasts assume that U.S. LNG imports will likely increase to somewhere between 11 and 18.9 BCFD (4 – 6.9 tcf/y) by 2025. That means that LNG's share of lower-48 natural gas supply will increase from 3 percent to 17 percent or more.

Appendix 4.C.3 Coal

Forecasts

A composite coal price forecast was created by combining the forecasts from the Energy Information Administration, Energy Ventures Analysis, Hill & Associates, and JD Energy. Each source provided a base case forecast in either nominal or real dollars. All forecasts were converted to nominal dollars using Global Insight's GDP implicit price deflator (JPGDP). The price deflator is the Global Insight quarterly long-term forecast for JPGDP from August 2007 overlaid with the Global Insight quarterly short-term forecast for JPGDP from November 2007. The short-term forecast provided new information for the forecast curve out to 2017. The change in the front end of the forecast curve created an offset between the long and short-term forecasts in 2018. To transition the more current short-term curve into the long-term curve, the 2018 to 2020 period was calculated to gradually produce a smooth transition from the more current short-term data in 2017 to the earlier long-term data in 2021.

Once all coal price forecasts are in nominal dollars the forecasts are combined by equal weight to create a composite price forecast representing the expected or base case consensus among the major forecast sources. The variation of individual forecasts within the composite are then used within a t-distribution to mathematically calculate high and low forecast price curves representing the 90^{th} and 10^{th} percentiles of the t-distribution. The three resultant price curves with their probability of occurrence are base 50%, high 25%, and low 25%.

Global Insight

Global Insight, Inc.
1000 Winter Street
Waltham, MA. 02451-1241

The JPGDP forecasts are sourced from the following two Global Insight spreadsheet tables:

U.S. Long-Term Forecast Tables - Baseline (Excel) [2007 8 30] - (ZIP; 4Mb)
Global_Insight_LongTerm_JPGDP_HH_WTI_A_T300807.xls

U.S. Short-Term Forecast Tables (Excel) [2007 11 7] - (ZIP; 5Mb)
GI_030707_ShortTerm_JPGDPforEIAOil_WebTables.xls

Energy Information Administration

Annual Energy Outlook 2007 - With Projections to 2030, February 2007

PRB forecast data in file supplied by EIA:
aeo2007_d112106a_coal_production_and_prices_by_supply_curve_06_30.xls

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, D.C. 20585

Energy Ventures Analysis Inc.

Energy Ventures Analysis, Inc.
1901 North Moore Street, Suite 1200
Arlington, VA. 22209-1706

"Long-Term Outlook for Coal and Competing Fuels", September 2007, (p.3-63)
Forecast in Nominal dollars

Hill & Associates Inc.

Hill & Associates, Inc.

222 Severn Avenue
Annapolis, MD. 21403

"Powder River Basin Coal Supply, Demand, and Prices 2006-2015", November 2006, (p.5-27)

Base Case in 2006$
PRB N. Wright Super Compliance 8800
PRB S. Gillette Super Compliance 8400

JD Energy Inc.

JD Energy, Inc.
P.O. Box 1935
Frederick, MD. 21702-0935

All forecasts in nominal dollars

Long-Term Forecast
Quarterly Coal Forecast, August 2007
JD_QCF200708.xls

First three years (2007-2009) updated with JD Energy monthly forecast
JD Energy Coal Monthly, November 2, 2007
JDCM200710.xls & JDCM200710.pdf

Present Reserves

The National Academies of Science 2007 report on Coal Research and Development states a recoverable coal reserve in the US of 267 billion tons is the basis for an often quoted estimate of 250 years of coal supplies available in the United States. The Academies report goes on to say that they could not sufficiently confirm that 250 years of supply are available, but they did state the sufficiency, at present consumptions rates, to meet national demand for more than 100 years. Reserve estimates with higher certainty and also specific to individual producing regions is presently being compiled by the United States Geological Survey (USGS), and a new reserve estimate for the Powder River Basin is scheduled for release by the end of 2008.[14]

Globally the coal reserve base is larger than that for either oil or natural gas, and the United States has the largest coal reserves of any nation.

The Wyoming Geological Survey indicates more than 50% of the state is underlain by coal, with an in-place resource estimated of 1.45 trillion tons of coal.

The Energy Information Administration provides an estimate of surface mineable reserves in Wyoming and Montana. While it is not indicated how much of the Montana reserves are lignite and how much are sub-bituminous coal, it can be assumed that the majority of the Wyoming reserve are sub-bituminous PRB coal. At the end of 2006 the EIA reported 17,195,000 tons of surface mineable recoverable reserves in Wyoming. Given 2007 Wyoming PRB production of 431 million tons, the current EIA estimate indicates 40 years of supply. At a 500 million ton per year production rate, as anticipated by 2020, the currently reported reserve still represents 34 years of supply.[15]

[redacted]

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[14] Committee on Coal Research, Technology, and Resource Assessments to Inform Energy Policy, National Research Council, "Coal: Research and Development to Support National Energy Policy", p.44, Washington, D.C., 2007, http://www.nap.edu/catalog.php?record_id=11977#toc

[15] Energy Information Administration, "Annual Coal Report 2006", U.S. Department of Energy, November 2007

[16] Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.S-12, Annapolis, MD., November 2006

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**[redacted]

[redacted]

[redacted]

[redacted]

[redacted]**

Discovery Rates

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[17] Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", Annapolis, MD., November 2006
[18] Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.2-30, Annapolis, MD., November 2006
[19] Energy Ventures Analysis Inc., "Long-Term Outlook For Coal And Competing Fuels", p.3-56, Arlington, VA., September 2007
[20] Energy Ventures Analysis Inc., "Long-Term Outlook For Coal And Competing Fuels", p.3-56, Arlington, VA., September 2007

HC

Present reserves are very large, and yet they only representing a small portion of the much larger Powder River Basin that is underlain by the same coal seams presently being mined. The potential resource is so large, and with at least 65 years of known reserves already in front of them, there is little economic incentive for producers to conduct additional exploration beyond the current mining tracts, which dampens the rate of "new reserve" discoveries, but lack of new discovery does not in any way diminish the enormous future supply.

Further demonstrating the enormous resource potential in the PRB beyond the current reserves and their projections, there are also undeveloped reserves and or abandoned projects dating to the 1960s, 70s, and 80s when the greatest exploration surge occurred in the PRB. According to Hill & Associates, not counting currently existing mines, there were 62 projects with an additional 430 million tons per year of planned production.[21]

Usage Rates

**[redacted]

[redacted]

[redacted]

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[21] Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.2-31, Annapolis, MD., November 2006

[22] Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p. 5-26, Annapolis, MD., November 2006

[23] Energy Ventures Analysis Inc., "Long-Term Outlook For Coal And Competing Fuels", p.3-56, Arlington, VA., September 2007

HC

[redacted]**

Profitability/Financial Condition of Producers

**[redacted]

[redacted]

[redacted]

[redacted]

24 Global Insight, "U.S. Energy Outlook 2006", p.35, Waltham, MA., December 21, 2006
25 Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.2-28, Annapolis, MD., November 2006
26 Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.3-4 Annapolis, MD., November 2006
27 Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.3-5 Annapolis, MD., November 2006

HC

[redacted]

[redacted]

[redacted]**

The Dakota, Minnesota & Eastern (DM&E) Railroad still has a plan to expand into the PRB in spite of regulatory, environmental, and financing delays. By 2007 the railroad had cleared nearly all hurdles other than financing, but with its $2.5 billion Federal loan application through the Railroad Administration being turned down in February 2007, the development remains uncertain. However, in September 2007 it was announced that the DM&E was merging with the Canadian Pacific Railroad, which is expected to give the DM&E access to the financial capital necessary for construction of the 280 mile extension into the Powder River Basin, although the timing and construction are still uncertain. If built, the DM&E line would provide another 100 million tons of capacity in competition with the BNSF-UP Joint-Line.

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[28] Hill & Associates Inc., "Powder River Basin – Coal Supply, Demand, and Prices 20006-2015", p.4-6 Annapolis, MD., November 2006

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The primary modes of coal transportation are by truck, barge, and rail, with truck and barge relying on publicly owned and financed infrastructure, while rail relies upon privately owned, operated, and financed infrastructure. The largest quantities of coal are moved by barge and rail and this is likely to continue in the future since trucks are limited by the vehicle size that can travel on public road systems, which limits the quantity of coal that can be moved by truck. Waterway infrastructure can be expanded, but is presently in need of funding for repair. Railroad infrastructure, because of private funding, and significant investment in infrastructure since 2000, is in the best condition of the three modes of coal transport. Rail is also the mode with the easiest ability to expand capacity.

The vast majority of U.S. domestic coal shipments are handled by the nation's railroads. In 2004 64 percent of all domestic coal shipments were by rail, 12 percent were by truck, 12 percent by conveyor or pipeline, and the remainder by water transport. The largest coal supply source in the U.S. is the Powder River Basin, which is even more dependent on rail for transportation. Over 98 percent of coal shipments from the PRB are by rail.[29]

Effects of government regulation/competition/environmental legislation on transport

The primary modes of coal transportation are by truck, barge, and train. Regulatory uncertainties regarding carbon emissions could potentially impact truck transport the greatest because it is the most fuel intensive mode for moving coal.

Potential government restrictions on use of fuel for electricity generation

Coal represents the fuel source for more than 50% of electricity generation in the United States, and has the most abundant reserve base of any fossil fuel, making it extremely unlikely that its use as a fuel source would be directly restricted. However, regulation of carbon dioxide emissions could place an indirect limitation upon coal use.

In the case of carbon dioxide restrictions on emissions from fossil fuels at electricity generating stations, sub-bituminous coals, which include coal from the PRB, emit on

[29] Energy Information Administration, "Annual Energy Outlook 2007", p.54, U.S. Department of Energy, February 2007

average 212.7 pounds per mmBtu. Bituminous coals emit on average 205.3 pounds of CO_2 per mmBtu, placing sub-bituminous coal at a disadvantage to bituminous coals, giving a 3.6% CO_2 penalty to PRB coal when competing with bituminous coals. A second disadvantage placed on PRB coal by CO_2 regulation would come from transportation costs, because PRB mines are often at much greater distances from coal consumers than the bituminous mines of Appalachia and the Illinois Basin, requiring greater fuel consumption and therefore greater CO_2 emissions just to get the coal to consumers.[30]

Accuracy of previous forecasts

The accuracy of the consensus forecast method and reasons for selecting it as the best forecast were discussed in "4.C.1: Consensus Forecasting Approach Discussion."

Identification of critical uncertainty factors driving price forecast/range of forecasts/probability distribution

Each forecaster identifies many drivers believed by that forecaster to be an important aspect of price formation. While most of the drivers identified by each forecaster are similar, there are also some minor differences among forecasters. It is these minor differences that are the additional information captured by the combinatorial or consensus forecasting method. However, since many of the major drivers are the same across all forecasters, the consensus forecast is weighted toward these drivers, while the variation in strength or direction placed upon those drivers by individual forecasters produces much of the variation in the consensus forecast. That variation is reflected within the statistical t-distribution and becomes a driver of the high and low consensus forecasts. Given that the consensus forecast accounts for all of the information available to multiple forecasters and those forecasters arrive at many similar primary drivers, KCP&L chose those common drivers with the greatest potential price impact for consideration as primary drivers.

While all coal may face a primary uncertainty surrounding future carbon dioxide legislation and regulation, Powder River Basin coal prices in the long-term face

[30] Energy Ventures Analysis Inc., "Long-Term Outlook For Coal And Competing Fuels", p.3-69, Arlington, VA., September 2007

additional primary risk from uncertainties around the cost of coal transportation, mine productivity, value of the U.S. dollar and exports, and the impact of FGD installations on the value of low sulfur coal.

The following four drivers can be expected to have the greatest influence on PRB coal prices over the forecast period:

1. Western rail rates are a primary driver. If rail rates moderate, they will make it less expensive to ship coal a greater distance from the PRB. The ability to economically ship more coal a greater distance allows PRB coal to compete deeper into the eastern market where local coals have very short transportation distances and imported coals currently have cost advantages. A continuation of current western rail rates, or an increase in rates, will result in limiting the distance from the Powder River Basin at which PRB coals are economically competitive. By limiting PRB demand to existing customers in the mid-west and west, or potentially causing a loss of market share in the mid-west and south, the ability of PRB producers to charge premium prices will be eroded, resulting in prices trending lower.

2. Productivity is a primary driver. Since 2001 productivity at PRB mines has been declining. As productivity declines producer cost per ton rises, forcing producers to raise price to cover the higher costs. If the productivity decline continues, as some forecasters indicate, the price of PRB coal will be forced higher. If advances in technology or organization allow productivity gains to be realized and the declining productivity trend to be reversed, as some forecasters believe, PRB producer costs will decline and it will be possible for producers to cut prices in order to be more competitive and grow market share.

3. The U.S. dollar and global freight rates combine as a primary driver. A weak dollar makes commodities priced in dollars, such as coal, more expensive to dollar based consumers, but it makes the commodity appear less expensive to the rest of the world, raising demand for U.S. coal exports. Although the great distance of the Powder River Basin from any coastal port makes the economics of PRB exports very difficult, the PRB may still be drawn upon to replace other

domestic coals such as those from Central Appalachia, which are drawn into the export market. In the event of a weak dollar, other domestic coals appear favorably priced relative to the rest of the world, and if ocean freight rates are also high, then the proximity to Europe and South America make the combined price of U.S. coal plus freight very competitive against more distant global sources and export demand will rise. Rising exports of other U.S. coals will drive higher demand for PRB coal within the U.S. as a replacement for the exported coal, which will result in increased PRB prices. Likewise, if the dollar strengthens, then export demand will drop and demand for PRB to replace those exports also falls, lowering PRB prices. A rising dollar can also have a second impact detrimental to PRB prices because it can make imports more attractive, further cutting into demand that might otherwise be served by PRB coal. Additionally, a decline in global ocean freight rates can also reduce demand for U.S. exports by making high quality coal from Colombia, Australia and Indonesia more competitive on a delivered price basis in the Atlantic Basin, thereby eliminating the demand for PRB as a replacement for exported coal and lowering PRB price.

4. FGD installations and the value of coal based on sulfur content is a primary driver. The base case pricing scenario is most likely to prevail unless the rapid pace of FGD installations in the eastern U.S. drives a shift to the high sulfur but more local eastern coals. Such a market shift will dampen the growth of long-term demand for PRB coal and may even reduce near-term demand, causing PRB prices to move lower. The failure of such a market shift to materialize would likely result in a continuation of present price trends.

Appendix 4.C.4 Fuel Oil

Oil fired power generation is not at the present time a major source of electricity generation, and there are no present price forecast scenarios between 2007 and the 2030's in which oil would become the lowest cost fuel option for generating electricity compared to other fossil fuels.

Forecasts

A composite crude oil price forecast was created by combining the forecasts from the Energy Information Administration (EIA), Energy Ventures Analysis, Global Insight, and PIRA Energy Group. Each source provided a base case forecast in nominal dollars, with the exception of the EIA, which used constant 2005 dollars. The EIA forecast was converted to nominal dollars using Global Insight's GDP implicit price deflator (JPGDP). The price deflator was the Global Insight quarterly long-term forecast for JPGDP from December 2006 overlaid with the Global Insight quarterly short-term forecast for JPGDP from March 2007. The short-term forecast provided new information for the forecast curve out to 2017. The change in the front end of the forecast curve created an offset between the long and short-term forecasts in 2018. Since the EIA crude oil forecast was the only oil forecast source requiring conversion to nominal dollars, the Global Insight Long-Term forecast (December 2006) closest to the actual run date of the EIA forecast was used, in combination with the Short-Term forecast (March 2007) closest to the date the forecast was released by EIA. Once all oil price forecasts are in nominal dollars the forecasts are combined by equal weight to create a composite price forecast representing the expected or base case consensus among the major forecast sources.

The variation of individual forecasts within the composite are then used within a t-distribution to mathematically calculate high and low forecast price curves representing the 90th and 10th percentiles of the t-distribution. The three resultant price curves with their probability of occurrence are base 50%, high 25%, and low 25%.

The New York Mercantile Exchange (NYMEX) forward price curve for no.2 oil goes forward 15 months; for those 15 months the NYMEX price is used as the forecast for no.2 oil. Since the historic correlation between the price of NYMEX no.2 oil and NYMEX WTI Crude oil is very strong (>0.95), forecast sources for crude oil are more numerous, and available crude oil forecasts extend a greater distance into the future than available no.2 oil forecasts, the consensus crude oil forecast is used as a proxy for no.2 oil beyond the 15 month NYMEX forward curve. This is done with the assumption that because of the strong historic price correlation, the rate of price change in no.2 oil will be approximately the same as that observed in crude oil; by applying the monthly rate of change in the crude oil price to the prior month's no.2 oil price, an expected no.2 oil price is projected from the consensus crude oil forecast.

Global Insight

Global Insight, Inc.
1000 Winter Street
Waltham, MA. 02451-1241

The Global Insight source data for crude oil prices is split between the short-term and long-term forecasts. The long-term forecast issued in December 2006 was the Global Insight forecast used for the price forecast to 2037. Overlaid on this price curve was the more recent Global Insight short-term forecast from March 2007. The short-term forecast covered the period 2007 to 2017. The period from 2018 to 2037 is covered by the Global Insight long-term forecast.

The Global Insight crude oil forecast sources:

Short-Term Crude Oil Forecast in Nominal $
2007-2017
U.S. Short-Term Forecast Tables (Excel) [2007 11 7] - (ZIP; 5Mb)
Global_Insight_JPGDP_US_Short-Term_Forecast_Tables_20071117_
GI_030707_ShortTerm_JPGDPforEIAOil_WebTables.xls

Long-Term Crude Oil Forecast in Nominal $
2018-2037
U.S. Long-Term Forecast Tables - Baseline (Excel) [2007 8 30] - (ZIP; 4Mb)

Global_Insight_LongTerm_JPGDP_HH_WTI_A_T300807.xls

No.2 Fuel Oil Forecast in Nominal $
Quarterly 2007-2017
The Global Insight no.2 fuel oil forecast is sourced from the Global Insight Cost Analyzer 2007Q3 data series PPI324110413.

Energy Information Administration
Annual Energy Outlook 2007 - With Projections to 2030, February 2007

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, D.C. 20585

The EIA source data for crude oil prices is split between the short-term and long-term forecasts. The long-term forecast issued in February 2007 (November 2006 model run) was the EIA forecast used for the price forecast to 2030. Overlaid on this price curve was the more current EIA short-term forecast from November 2007. The short-term forecast covered the period 2007 to 2008. The period from 2009 to 2030 is covered by EIA's long-term forecast in the Annual Energy Outlook 2007.

Short-Term Crude Oil Forecast in Nominal $
2007-2008
Short-Term Energy Outlook, November 6, 2007
Crude Oil forecast data in file:
EIA_steo_110607_base.xls

Long-Term Crude Oil Forecast in 2005$
2009-2030
Annual Energy Outlook Reference Case Forecast, November 2006
Crude Oil forecast data in file:
EIA_aeo2007_92-118_sup_ogc.xls

The Long-Term forecast is in constant 2005$, but needs to be in nominal dollars for development of the consensus forecast. The conversion of EIA's long-term forecast to nominal dollars was done in KCP&L workbook file EIA_2007_Forecasts.xls, using Global Insight's Implicit Price deflator (JPGDP) for the conversion to nominal.

The JPGDP forecasts used to convert the EIA crude oil price forecast to nominal dollars are sourced from the following two Global Insight spreadsheet tables:

JPGDP
U.S. Long-Term Forecast Tables - Baseline (Excel) [2006 12 4] - (ZIP; 4Mb)
GI_120406_LongTerm_JPGDPfor EIAOil_T301106.xls

JPGDP
U.S. Short-Term Forecast Tables (Excel) [2007 3 7] - (ZIP; 5Mb)
GI_030707_ShortTerm_JPGDPforEIAOil_WebTables.xls

Energy Ventures Analysis Inc.

Energy Ventures Analysis, Inc.
1901 North Moore Street, Suite 1200
Arlington, VA. 22209-1706

"The Long-Term Outlook", August 2007, (p.5-59)
Forecast in Nominal dollars

PIRA Energy Group, Inc.

PIRA Energy Group
3 Park Avenue, 26th Floor
New York, NY. 10016-5989

The PIRA WTI crude oil price forecast in nominal dollars was sourced from PIRA's "Long-Term Henry-Hub Gas Prices Forecast" posted on the PIRA web site 7/26/07.

Present Reserves

The world still has abundant oil resources, with supplies that should easily last through the forecast period. However, as existing fields are depleted the global reserve base of conventional oil will continue to shift toward OPEC countries, with OPEC's share of world supply shifting from 42% in 2007 to 52% by 2030.[31]

Global oil reserve estimates vary depending upon the source, but present estimates are approximately 1.4 trillion barrels of proven reserves. If probable and possible reserve categories are included, then the remaining global oil endowment is approximately 3.3 trillion barrels of crude oil. Approximately 75 percent of these reserves are in OPEC countries with current production to reserve ratios in those countries of 50 to 85 years. It should also be noted that these reserve estimates do not include non-conventional oil resources.[32]

The National Petroleum Council gives an estimate for total worldwide oil reserves in place as approximately 15 trillion barrels. Estimates for the quantity of recoverable conventional oil range between 1.5 and 3.4 trillion barrels. The global reserves of recoverable non-conventional oil have been estimated at 1.5 to 1.7 trillion barrels of recoverable oil. The geopolitical distribution of conventional oil is largely in the Middle East, West Africa, and Russia, while more than 80 percent of non-conventional reserves are located in Venezuela, Canada, and the United States.[33]

Crude oil reserves contained in oil shale worldwide are estimated at 3 trillion barrels, which is equivalent to the original supply of conventional oil. Approximately 50 percent of the world's oil shale resource is located in the United States, within the states of Wyoming, Colorado, and Utah. Present forecasts place pilot scale production commencing around 2020, with large scale production from oil shale not expected until 2030.[34]

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[31] INTERNATIONAL ENERGY AGENCY, "WORLD ENERGY OUTLOOK 2OO7: Executive Summary", Paris, France, 2007

[32] Energy Ventures Analysis Inc., "The Long-Term Outlook", Arlington, VA. , p.5-26, August 2007

[33] National Petroleum Council, "Facing the Hard Truths about Energy: A Comprehensive View to 2030 of Global Oil and Natural Gas Energy", p. 109, July 18, 2007

[34] National Petroleum Council, "Facing the Hard Truths about Energy: A Comprehensive View to 2030 of Global Oil and Natural Gas Energy", p. 202, July 18, 2007

The world is in no danger of running out of energy resources, but the ability to continue expansion of oil and natural gas production from conventional sources may be at risk of not keeping pace with projections of future demand growth to 2030. While the global supply is large, the greatest uncertainties are the quantity that is actually recoverable, and the rate at which the recoverable resource can be produced.[35]

'The key consideration for energy supplies is not endowment but producibility. Over the next 25 years, risks above ground - geopolitical, technical, and infrastructure - are more likely to affect oil and natural gas production rates than are limitations of the below ground endowment."[36]

The Energy Information Administration's base forecast in the Annual Energy Outlook 2007 indicates production increases from both OPEC and non-OPEC producers is expected through 2030, with the result that in constant 2005$ terms, long-term average prices will remain in the $50 to $60 per barrel range.[37]

Discovery Rates

Global oil resources are sufficient to meet demand through the forecast period. As evidence of this, OPEC cites the doubling since 1980 of US Geological Survey estimates for total recoverable reserves, from 1.7 trillion barrels to 3.3 trillion barrels, while cumulative production was less than one third as much. This reserve growth is attributed technology advancements, exploration success, and enhanced recovery from existing fields.[38]

[35] National Petroleum Council, "Facing the Hard Truths about Energy: A Comprehensive View to 2030 of Global Oil and Natural Gas Energy", p. 108, July 18, 2007
[36] National Petroleum Council, "Facing the Hard Truths about Energy: A Comprehensive View to 2030 of Global Oil and Natural Gas Energy", p. 18, July 18, 2007
[37] Energy Information Administration, "Annual Energy Outlook 2007", p. 4, U.S. Department of Energy, February 2007
[38] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p. 24, Vienna, Austria, 2007

Non-conventional oil can be defined as petroleum resources such as heavy oil, oil sands, and tar sands which have high viscosities, very slow flow rates, and require processing or dilution to flow through well pipe.[39]

In addition to the reported reserves of conventional oil, there are also very large non-conventional oil resources such as oil sands and oil shale yet to be explored and developed, plus additions from coal-to-liquids production and from the growing biofuels industry.

Oil production added from non-conventional sources is expected to grow significantly by 2030. Non-conventional production is forecast to rise to 7.3 million barrels per day by 2030; a supply addition of 6 million barrels per day.[40]

New production capacity additions are forecast by most sources to increase significantly between 2007 and 2012, but much uncertainty exists about the ability of these increases to offset output declines at existing fields and still provide enough supply to cover growth in demand. The International Energy Agency indicates a risk exists for a supply crunch by 2015 if the new additions can not keep pace with new demand and also offset production declines. A major escalation of oil prices would result from such a supply crunch.[41]

In the EIA base case U.S. crude oil production is forecast to increase due to new discoveries and technological advancements that allow greater recovery from existing reserves. In 2030 domestic production is forecast to be 5.7 million barrels per day, which is nearly 700,000 barrels higher than 2007 production.[42]

Usage Rates

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[39] National Petroleum Council, "Facing the Hard Truths about Energy: A Comprehensive View to 2030 of Global Oil and Natural Gas Energy", p. 97, July 18, 2007
[40] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p. 65, Vienna, Austria, 2007
[41] INTERNATIONAL ENERGY AGENCY, "WORLD ENERGY OUTLOOK 2OO7: Executive Summary", Paris, France, 2007
[42] Energy Information Administration, "Annual Energy Outlook 2007", p. 95, U.S. Department of Energy, February 2007

Intermediate-term supply fundamentals are improving due to worldwide inventory approaching record levels, increases in non-OPEC production, increases in OPEC spare capacity, and slowing global economies curbing demand growth.[43]

[redacted]

Global demand is forecast to grow from 83.7 million barrels per day in 2006 to 112.8 million barrels per day by 2025. Approximately 60% of the growth will come from countries that subsidize the cost of oil.[45]

The International Energy Agency is projecting global oil demand to be 116 million barrels per day by 2030. OPEC's own estimate for future global oil demand is 118 million barrels per day by 2030, assuming no change from current trends and global economic growth rates average 3.5% per year. This is an increase in demand of 34 million barrels per day from 2006, with developing nations accounting for 29 million (85%) of the 34 million barrel per day increase.[46]

The International Energy Agency is projecting a high growth scenario for global oil demand to be 120 million barrels per day by 2030. OPEC also projects global oil demand in high and low economic growth scenarios. In the high growth scenario demand rises to 125 million barrels per day by 2030, while in the low growth scenario worldwide demand is 102 million barrels per day. Compared to the OPEC base scenario, the high growth scenario only adds 7 million more barrels to daily demand while the low growth scenario subtracts 16 million barrels from daily demand, implying more downside risk to demand and economic growth.[47]

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[43] Energy Ventures Analysis Inc., "The Long-Term Outlook", p.5-2, Arlington, VA., August 2007
[44] Energy Ventures Analysis Inc., "The Long-Term Outlook", p.5-2, Arlington, VA., August 2007
[45] Energy Ventures Analysis Inc., "The Long-Term Outlook", p.5-3, Arlington, VA., August 2007
[46] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p. 21, Vienna, Austria, 2007
[47] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p. 75, Vienna, Austria, 2007

[redacted]

The transportation sector currently accounts for 50 percent of global oil consumption and **[redacted]

[redacted]

[redacted]**

Profitability/Financial Condition of Producers

Expansion of production capacity for non-OPEC producers is at least two times more costly than for OPEC producers, with the OPEC cost advantage growing throughout the forecast period.[51]

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[48] Energy Ventures Analysis Inc., "The Long-Term Outlook", p.5-8, Arlington, VA., August 2007
[49] Energy Ventures Analysis Inc., "The Long-Term Outlook", p.5-23, Arlington, VA., August 2007
[50] Energy Ventures Analysis Inc., "The Long-Term Outlook", p.5-26, Arlington, VA., August 2007
[51] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p.7, Vienna, Austria, 2007

Maintaining production capacity and keeping pace with demand growth is estimated to require $5.4 trillion in upstream development investments through 2030. Inadequate investment can restrict supply and drive oil prices much higher.[52]

Crude oil prices are not expected to return to the less than $50 per barrel levels seen prior to 2005. In the long-term prices are forecast to rise significantly from present levels as a scarcity premium is added due to all but eight countries having passed their production peak, and more than 50% of total supply being in the hands of OPEC. A supply scarcity premium is forecast to become a reality after 2015.

Capacity, Profitability, Expansion potential of present and future transport options

The global oil export trade is forecast to grow from 50 million barrels per day in 2006 to 63 million barrels per day by 2020. This growth will require the global tanker fleet to increase from 360 million dry weight tons in 2006 to 460 million dry weight tons by 2020, a compound annual growth rate of 1.8% throughout the period.[53]

Effects of government regulation/competition/environmental legislation on transport

Canada's production of heavy crude from the oil sands of Alberta releases six times more CO2 per barrel than conventional oil production. With Kyoto type CO2 regulation it is estimated that the cost of these extra CO2 emissions will add $0.25 to $0.30 to each barrel of Canadian heavy oil.

Environmental regulations have a significant impact on refined products segment of the global oil market. The variation of quality specific regulations between political jurisdictions at local and national levels contributes to greater fragmentation of the refined products market. This fragmentation reduces the fungibility and substitutability of fuel types across markets, increasing the risk of regulation induced shortages. The greater risk of shortages increases the price volatility in both refined product and crude oil markets.[54]

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[52] INTERNATIONAL ENERGY AGENCY, "WORLD ENERGY OUTLOOK 2OO7: Executive Summary", Paris, France, 2007

[53] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p.10, Vienna, Austria, 2007

[54] Organization of the Petroleum Exporting Countries, "World Oil Outlook 2007", p.10, Vienna, Austria, 2007

Potential government restrictions on use of fuel for electricity generation

There are no known proposals that would place restrictions on the use of oil and oil products to generate electricity. It is far more likely that the market itself will keep oil use very low in the generation order due to the already high price of oil relative to all other major generation fuels, and oil price forecasts do nothing to indicate a reversal of this trend. Since petroleum fuels already represent a very small, and declining proportion of electricity generation, and all forecast scenarios show oil will remain a significantly more expensive generation option than coal or natural gas throughout the forecast period, petroleum fuels are not likely to be a significant source fuel for electricity generation through 2030.

Accuracy of previous forecasts

The accuracy of previous forecasts was considered by KCP&L in an internal analysis paper titled "Energy Commodity Forecasting and Forecast Averaging."

In the KCP&L analysis past PRB coal price forecasts from sources currently available were analyzed to determine which forecaster was most "accurate." This analysis determined "forecast accuracy" is relative to the perspective of the analysis being performed. The analysis showed the apparent best forecaster from one perspective might be the worst from a different perspective and that even from a perspective which a forecaster appeared "most accurate"; there was a demonstrated probability of that forecaster turning in the worst forecast in another year. The solution to the relative nature of "forecast accuracy" was to utilize the widely used practice of consensus forecasting, which is accepted and supported in academic, government, and industrial circles. Back testing the consensus forecast against the individual forecasts demonstrated results consistent with academic research. The results showed that the consensus was consistently the forecast with the lowest risk of price error. The consensus was also consistently the best or second best forecast for any year or perspective tested, and the consensus also has a mathematically defined impossibility of being the worst choice in any given year. Determining the most accurate forecast as the one that consistently has the lowest risk of price error makes the consensus forecast the forecast of choice.

Given that the research literature demonstrated that the results of consensus forecasting were consistent and repeatable across a very broad spectrum of forecasts, it is assumed the consensus test results observed for PRB coal would be consistent for crude oil, natural gas, or any other commodities. Furthermore, since the consensus forecasts for coal, oil, natural gas, and emissions utilize many of the same forecasters, the likelihood of consistent outcomes is further enhanced.

Identification of critical uncertainty factors driving price forecast/range of forecasts/probability distribution

The most critical driver of all oil demand and the primary driver of oil price is economic growth. The primary differences between high and low oil price forecasts through 2030 are the forecaster's differing expectations for global economic growth, with growth in specific countries or regions having significantly more weight than others. Variations in forecast economic growth rates for the United States, China, India, and Western Europe play the largest role in determining ultimate demand.

Other significant drivers are production volume, access to reserves, and geopolitical stability.

Near-term and intermediate term oil prices are expected to moderate to 2012 as supply grows faster than demand and OPEC spare capacity returns to 4 million barrels per day or more.

Long-term price strength from 2015 to 2030 as the economies of developing nations accelerates global demand for oil at the same time as non-OPEC production peaks. Demand growth, greater than 3.9 percent annually, will be highest in countries such as Iran, China, Venezuela, and others that subsidize their domestic price of oil thereby keeping demand in those countries from efficiently responding to ever higher prices.

Both U.S. domestic production and non-OPEC production are forecast to peak in or near 2015, making the world completely dependent on OPEC to meet all incremental demand post-2015.

Appendix 4.C.5 Nuclear Fuel

Nuclear power generated from uranium in the United States and worldwide fell into a prolonged recession from the mid 1980's until 2002. Without construction of any new generation plants in the United States during this period, and only a small number internationally, the mined supply of uranium was more than enough to meet a stagnant demand, and the large number of uranium reserves discovered during the 1950's through 1970's left ample reserves on which to draw, all of which left market prices depressed for two decades. The prolonged period of depressed prices drew few mining companies to uranium exploration, and the excess supply supported the industry until the beginning of the present decade. The situation began to change after 2002 as much of the already mined supply stockpiles were consumed and newly mined uranium supply was not enough to cover existing demand, let alone any additional demand that would come from new plant construction. Concern about carbon dioxide emissions has led to resurgence in nuclear power interest worldwide, and plans have been announced worldwide for a large number of new plants to be constructed during the next ten years. Anticipation of this new demand has driven uranium market prices much higher and led to renewed exploration and development of new mines.

The uranium fuel cycle begins with mining of raw uranium ore which the mines process into standard uranium concentrate (U3O8) known as "yellowcake". The concentrate is then shipped from the mines and converted to a gas, uranium hexafluoride (UF6), which is used to separate the lighter and heavier uranium isotopes in order to concentrate the isotope U235 from its natural 0.71% of elemental uranium to the 3% to 4% concentration needed for a reactor. Once enriched, the uranium is processed into fuel pellets which are loaded into fuel rods. The fuel rods are grouped into clusters called fuel assemblies, and loaded into the core of nuclear reactors as fuel.

Worldwide nuclear generation capacity in 2006 was 368.4 GW from 430 plants in 31 countries, representing 16% of global electricity generation capacity. Worldwide generation capacity is forecast to rise to 412 GW by 2015 and 485 GW by 2025.[55]

[55] Energy Resources International, Inc., "2007 Nuclear Fuel Cycle Supply and Price Report", p.ES-2, Washington, D.C., 2007

The Energy Information Administration (EIA) forecasts strong growth in US nuclear power generation through 2030, with nuclear generated electricity growing from 780 billion kWh in 2005 to 896 billion kWh by 2030. To meet this generation growth most nuclear units are expected to apply for and receive license renewals, allowing them to continue operating through 2030. Four units, totaling 2.6 gigawatts of generation are projected to be retired by 2030, and new units are expected to be built adding more capacity than what is retired.[56]

Forecasts

There are not nearly as many economic consulting organizations that regularly produce and publish long-term forecasts for uranium as there are for natural gas, crude oil, or coal. Much of the lack of forecasts result from the prolonged 20 year recession in the nuclear industry, which caused few entities outside of existing power plants themselves to seek market information and long-term price forecasts for uranium. This lack of industry coverage is in the process of changing, but at the present time available sources are few, making it difficult to construct long-term consensus forecasts similar to those for fossil fuels and emissions. However, there is one forecaster, Energy Resources International (ERI) that does produce base case, high, and low long-term price forecasts. ERI also performs some comparison of portions of their forecasts to a small number of other forecasters, which provides a forecast view very similar to the consensus forecasts used for other fuel and emission commodities.

Energy Resources International, Inc.

Energy Resources International, Inc.
1015 18th Street, NW, Suite 650
Washington, D.C. 20036

"2007 Nuclear Fuel Cycle Supply and Price Report"

Present Reserves

[56] Energy Information Administration, "Annual Energy Outlook 2007", p.84, U.S. Department of Energy, February 2007

Uranium is a naturally occurring metallic element that is found in a variety of different ores, and is not scarce like gold, but rather of similar abundance in the earth's crust as zinc.

Further underscoring the relative abundance of naturally occurring uranium reserves is the comprehensive 2003 study, "The Future of Nuclear Power"; in which MIT research estimates indicated current global uranium supplies are sufficient to feed the deployment of 1,000 nuclear reactors over the next 50 years and to fuel those reactors for their entire 40 year operating lives.

Present worldwide production is dominated by Australia and Canada, which between them account for approximately 50 percent of world production. Kazakhstan is rapidly increasing production, has substantial reserves, and is expected to challenge for title of largest producer within the next ten years. However, Australia is expected to remain a dominant producing country for the foreseeable future. The single largest uranium reserve in the world is the Olympic Dam deposit in South Australia, with reserves estimated at 4 billion pounds. Production from this mine is expected to quadruple over the next fifteen years.

Newly mined supply currently constitutes about 59% of supplied uranium, with the remainder of supply coming from stockpiles. As new mines are opened and production increases at existing operations the mined output is expected to grow to 91% of supply by 2010, but stockpiles of already mined uranium and recycling will remain an important part of total uranium supply.

Commercial and non-commercial stockpiles represent a significant portion of present world uranium reserves. These already mined reserves include civilian and government inventories, nuclear weapons stockpiles, and the recycling of uranium and plutonium from spent fuel. Recycling is expected to grow from 6 million pounds of supply in 2006 to 10.3 million pounds of annual supply by 2016, while the inventory of already mined uranium, much of which is in government weapons stockpiles, corresponds to approximately one quarter of all uranium mined since 1942. Just the US Department of Energy's Highly Enriched Uranium (HEU) inventory represents a reserve equivalent to a mid-sized uranium mine. These stockpiles will continue working their way into the nuclear fuel supply through 2025.[57]

Inventories presently held by fuel suppliers and power plants add an estimated 537 million pounds of reserve, which is approximately 3.1 years of current world demand. Including Russian highly enriched uranium (HEU) and US Department of Energy (DOE) inventories brings worldwide, already mined uranium inventory to 761 million pounds, or enough uranium to supply approximately 4.5 years of present world demand.

Total uranium supply reserves, which include mined uranium plus all sources of above ground uranium in inventory plus plutonium, is forecast by Energy Resources International to begin exceeding demand in 2008 and continue to exceed demand until at least 2020, with the actual length of excess supplies dependent upon the rate at which new nuclear power plants are built worldwide, and the rate of government stockpile releases.

Discovery Rates

Uranium exploration continues to be an active area for today's uranium mining companies, and is driven primarily by the currently elevated market price of uranium and the desire to find even lower cost reserves. However, with nearly one quarter of all uranium mined since 1942 still in above ground stockpiles, and a large number of known but undeveloped resources discovered during the exploration boom of the 1950's and 1960's still available for development, there is an ample resource base available to supply reactors for many years into the future. The French integrated nuclear company Areva states in their December 2007 Group Overview that world wide conventional uranium resources that are economic to develop, up to a recovery cost of $130/kgU, totals approximately 14.75 million metric tonnes, which is more than 200 times the world uranium demand in 2006. Even when constraining this resource total to reasonably assured reserves, the current global reserve base is estimated at approximately 4.75 million metric tonnes of uranium, which is still more than 67 years of supply at the 2006 demand rate.

Usage Rates

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[57] Energy Resources International, Inc., "2007 Nuclear Fuel Cycle Supply and Price Report", p.4-20, Washington, D.C., 2007

The United States accounts for about 4% of worldwide uranium production and produces about one sixth as much uranium as the world's current largest producer, Canada. The US reactor demand in 2006 was 53 million pounds, and was met by a diversity of supplies. Australia was the largest supplier of uranium to the US market at 26% of supply, followed by Russia (23%), Canada (20%), US sources (16%), Namibia (5%), Kazakhstan (2%), and the rest of the world at 7%. The large portion presently supplied by Russia is due to international treaty requiring Russia to supply weapons grade, Highly Enriched Uranium (HEU) to the US through 2013. Beyond 2013 the Russian supply to the US market is expected to decline, but will be made up by increases in mine output from Australia, Canada, and Kazakhstan, as well as additional domestic sources. This demand level for the United States is expected to remain stable through 2015 or later, until new reactors begin coming online.

Global demand is expected to grow rapidly due to multiple new reactors being constructed in Russia, India, and China. Worldwide demand for U3O8 is forecast to rise nearly 31%, from 167 million pounds in 2006 to 218 million pounds by 2025.[58]

Profitability/Financial Condition of Producers

The largest uranium producers in the world in 2006 are Cameco, Rio Tinto, BHP Billiton, Areva, Kazatomprom, and TVEL, which together combined to produce 79% of world mined uranium supply. With the exception of Kazakhstan's Kazatomprom and Russia's TVEL, the other four producers are all western based companies. Kazatomprom and TVEL are privately held companies, with the Russian government having some involvement in TVEL. Kazatomprom, based in Kazakhstan, has access to some of the most extensive low cost reserves in the world, and is a rapidly growing entity that is expected to soon rival the other major producers. In 2007 Kazatomprom was the world's second largest producer of mined uranium, supplying approximately 12% of global supply. The company has ambitious plans over the next ten years to integrate into every stage of the fuel cycle, becoming fully integrated like Areva.

The four western companies, Cameco, Rio Tinto, BHP Billiton, and Areva produced 62% of all global uranium production, mostly from reserves located in Canada, Australia, and

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[58] Energy Resources International, Inc., "2007 Nuclear Fuel Cycle Supply and Price Report", p.3-21, Washington, D.C., 2007

the United States. North American and Australian mines produced 50% of newly mined uranium in 2006.

Cameco, based in Saskatchewan, Canada, is the largest uranium producer in the world, responsible for approximately 20% of global uranium production. The company also operates uranium conversion facilities to produce uranium hexafluoride gas for enrichment. Cameco has a large reserve base, and will be bringing the highest grade uranium mine in the world into production in Canada before 2010. Cameco appears to be a financially stable and profitable company, with a return on equity of 15% in 2007.

Rio Tinto and BHP-Billiton are both Australian mining companies with uranium mining operations primarily in Australia and southern Africa, including Rio Tinto's rich Rössing deposit in Namibia, and BHP-Billiton's massive Olympic Dam deposit in Australia, which has the largest reserve of any deposit in the world. BHP-Billiton has made a bid to acquire Rio Tinto, which if successful would result in a combined company with about 28% of world production, vaulting the combined company past Cameco as the world's largest uranium producer. Independently, both companies are much diversified natural resource producers with global operations. A partial list of the products of Rio Tinto and BHP-Billiton not only includes uranium, but also crude oil, natural gas, coal, copper, zinc, iron, gold, diamonds, and industrial minerals to name a few. With such a diversified production portfolio, neither company is dependent on the uranium market for its profitability. However, both companies are quite profitable. The return on equity of Rio Tinto is 34% and the return on equity of BHP-Billiton is 45%.

Areva, based in France, is only the third largest uranium miner after Cameco and Rio Tinto, producing 15% of world supply in 2006. The French government currently owns 79% of Areva's shares but has announced plans to sell shares to raise capital, which will reduce the government ownership to 54%. Areva's return on equity is 11%.

At the end of 2007 Areva was the world's only fully integrated nuclear company. It is vertically integrated into every part of the nuclear fuel cycle from uranium mines, to construction and operation of nuclear reactors for electricity generation, to the recycling and disposal of waste. Not only is Areva fully integrated, but it has the largest market share of any company in each of its operating segments other than mining, where it is third largest. The company has a market share ranging between 15% and 30% in all the sectors in which it operates, other than treatment and recycling, where it has more than 70% of the market. Areva's stated strategy is to achieve a one third share of the market in each sector in which it operates.

In summary, the major western producers account for 62% of world uranium production, are very profitable and have double digit returns on equity.

Areva ROE = 11%
Cameco ROE = 15%
BHP-Billiton ROE = 45%
Rio Tinto ROE = 30%

Capacity, Profitability, Expansion potential of present and future transport options
Uranium at all points throughout the fuel cycle can be shipped by all common modes of transportation such as truck, rail, barge, or ship, with the only requirement being compliance with NRC and Department of Transportation regulations for packaging, which are not believed cost prohibitive. All regulation focuses on the packaging containers themselves, not the mode of transportation. At the present time there are no known transportation risks to the delivery of nuclear fuel supplies to power plants. Also, due to the high energy density of uranium fuel as compared to coal, the required annual shipping capacity for fuel is much less per megawatt generated, meaning that present transportation infrastructure is sufficient to handle present as well as any future increase in uranium shipping demand.

Effects of government regulation/competition/environmental legislation on transport

Spent fuel disposal and the transportation of spent fuel is an issue dependent on government regulation and/or legislation to resolve. At the present time, the spent fuel from US nuclear reactors is stored on-site at the reactors, but this storage capacity is being rapidly consumed. The US Department of Energy (DOE) has planned for the Yucca Mountain repository in Nevada to be operational, and begin accepting shipments of spent fuel by 2017. However, forecasts by consultants such as Energy Resources International place this on-line date closer to 2025. Much of the delay is in authorizing the Yucca Mountain operation, and a significant portion of the delay comes from safety and environmental concerns surrounding transport of spent fuel across the United States. There appears to be little opposition to the transportation of uranium ores and uranium fuel, but the opposition of individual states and municipalities to transport of nuclear waste material through their communities en route to storage repositories is something that will likely require US Congressional action to resolve.

Potential government restrictions on use of fuel for electricity generation

Government restriction on the use of nuclear power to generate electricity is not anticipated to become greater in the future. With the drive to reduce carbon dioxide emissions, and the desire by governments to reduce those emissions without harming economic growth, the energy resource most capable of achieving these wants and needs is nuclear energy. In complying with the Kyoto protocol, or other international agreements that may follow Kyoto, governments worldwide are much more likely to encourage rather than restrict nuclear power through 2030.

Government licensing renewals of ageing units will be required to meet future generation demand. Plants currently in operation are expected to provide 71% of generation in 2015, and forecast license renewals indicates these plants will still be providing 42% of all generation capacity by 2025. Any major government restriction on license renewals or slowing of the renewal process will have an adverse impact on available future generation capacity. However, governments in Europe and the United States are actively renewing licenses, and the current expectation is that licenses at nearly all existing generating plants will be renewed. Already planned license renewals indicate that by 2013, 82% of the US generation fleet will be more than 40 years old. With a rapidly ageing fleet needing replacement, rising power demand, and a commitment to reduce carbon dioxide emissions, the US government is likely to encourage rather than restrict nuclear fuels for electricity generation.

Accuracy of previous forecasts

Given that Energy Resources International (ERI) was the only complete, long-term nuclear fuel cycle forecast available to KCP&L at the time of the analysis, there was not an alternative pricing forecast with which to compare regarding accuracy, but ERI does provide comparison to other forecasters of their nuclear generation capacity forecasts upon which pricing models are developed. The generation capacity comparisons demonstrate the similarity of current capacity forecast averages and high-low range, which implies a relative expected similarity in uranium fuel demand.

The highly regulated and often secretive nature of the nuclear materials cycle makes accurate information and forecasts less available and shorter in term, at each step within the nuclear fuel cycle. The farther one proceeds from mining of the raw ores to fuel rod fabrication with enriched material, information availability and forecasts become greatly reduced, and accuracy of available forecasts becomes more questionable.

Additionally, the long period of recession within the nuclear industry from the early 1980's until 2002, a period marked by low uranium prices and no new orders for nuclear plant construction in the US, led to a lack of investment in the industry as a whole. This lack of investment in the nuclear industry included the media and information / forecasting services that cover the industry. The reduced demand growth for uranium and the abundant supply of uranium not only resulted in low fuel prices, but also reduced demand for forecasts. Many of the forecasting services were able to survive by providing shorter term forecasts to existing nuclear plants. Since most nuclear plants operated under long-term fuel contracts often extending 20 years or more, the majority of their concerns were regarding near-term or spot market prices for nuclear materials, often in the gasification and enrichment phases of the fuel cycle. The surviving forecasters targeted this need, resulting in most forecasts being five years or shorter. However, the situation is changing; with climate concerns and new emission regulations, there is renewed interest in nuclear power generation. With renewed interest in nuclear power, and the commodity boom driving investment demand for all natural resources, change is occurring rapidly. The renewed interest has resulted in a uranium futures contract now being traded on the New York Mercantile Exchange (NYMEX). These same forces are driving renewed interest in the media and forecasting services that cover the uranium and nuclear fuels industry. A growing demand for these services is improving the financial condition of companies providing these services, encouraging competitors to enter the field, and is expected to result in an increased number and diversity of long-term forecast sources becoming available within the next two years.

Identifies critical uncertainty factors driving price forecast/range of forecasts/probability distribution

A primary uncertainty is the license renewal of existing nuclear units.

A primary uncertainty is the construction rate of new nuclear reactors in the United States and worldwide. New power plant construction is expected to increase worldwide nuclear generation capacity at least 20% by 2025. Reactor demand for uranium fuel is forecast to rise along with construction, keeping pressure on long-term uranium prices.

Another factor that will impact nuclear fuel prices is the rising global demand for the capacity to convert uranium ore to uranium hexafluoride gas during the enrichment phase of fuel processing. Demand for gasification capacity within the fuel cycle is expected to rise rapidly and will require investment in new capacity by 2025. Additionally, the spare capacity for enrichment is tight at 700,000 standard work units (SWU), which represents about 1.5% of worldwide enrichment capacity. Construction of new centrifuge plants is planned, but there is forecast to be an enrichment capacity deficit equal to 3% of demand by 2011. There are available plants to fill this gap, but the enrichment capacity deficit is projected to grow to 14% of demand by 2021 unless additional investments are made to existing and new facilities to increase enrichment capacity.

The demand drivers for uranium prices during the forecast period are:

- New non-US nuclear plants coming on-line before 2015
- New US nuclear units coming on-line after 2015
- License renewals of US and non-US nuclear units
- Increased stockpiling of additional uranium by US utilities
- Carbon dioxide regulation

Supply drivers for prices during the forecast period are:

- Increasing cost of exploration and increasing need for more exploration
- Depletion of low-cost reserves driving producers to higher cost resources

- Russian highly enriched uranium (HEU) supply to US ending after 2013
- Market increasingly dependent on new mine production
- Investment required in uranium enrichment facilities

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