APPENDIX 4D
FUEL PRICE FORECASTING

** PUBLIC **

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SECTION 1: CONSENSUS FORECASTING APPROACH DISCUSSION

1.1 INTRODUCTION

An investigation was performed to identify the best possible commodity forecasts to use in GMO fuel pricing models. The investigation sought to determine if there was an individual Consultant/Forecaster among the Consultants whose forecasts are currently purchased by GMO 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. Such an investigation was previously performed by Kansas City Power & Light, and used the same data sources available to GMO. That analysis confirmed what academic and governmental research had already demonstrated which is that a consensus forecast is the most consistent performer.

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

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

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 showed that in practice, the academic results were 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.

1.2 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

[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

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]

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.

1.3 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

[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

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:

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.

1.4 <u>ACADEMIC RESEARCH RESULTS:</u>

- Simple average of forecasts can significantly improve results

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

- 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)

1.5 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

1.6 TESTING

As part of the effort for determining the highest quality forecast available it is apparent that academic research findings should be tested on available

[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

consultant forecasts. Given that coal is the largest expense component of a fuel portfolio, and since the coal market is less liquid and there are fewer coal forecast sources available than for the more open and heavily traded crude oil and natural gas markets, it is clear that testing 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 routinely used by and readily available to GMO
- 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.

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1.7 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. The analysis did this through calculation of the Mean Squared Error (MSE) for each of 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. The data on which the test was performed is displayed in Appendix I, and the results are tabulated below in Table 1.

Table 1: Forecast Error Minimization as Measured by MSE – from Best to Worst ** Highly Confidential **

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 2: Forecast Error Measured by MSE as Percentage of Total Forecasts Highly Confidential ****

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. This sample set suggests that choosing ** [redacted] **as the preferred forecast would have resulted in

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the best or second best forecast 75% of the time, but would not have had a top performing forecast since before the 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.

1.8 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

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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 3: 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]

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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.

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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.

1.9 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 4 and Table 5:

Table 4: First-Year Forecast Accuracy (PRB 8400, Calendar Years 2003-2006) ** Highly Confidential **

	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 5: First-Year Forecast Accuracy as Percent of All Test Case Forecasts Highly Confidential****

	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

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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.

1.10 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 6 below:

Table 6: 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]

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

Results displayed in Table 6 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.

1.11 REFERENCES:

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

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

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www.consensuseconomics.com

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

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]

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

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Appendix I

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

[redacted]

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Forecasts Used in Calculating Average for Analysis Highly Confidential****

[redacted]

B) Difference between Forecast Price and Coal Daily Price Highly Confidential****

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

[redacted]

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****<u>Highly Confidential</u>****

Percent difference between Forecast and Actual

[redacted]

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C) Forecast Averages and Standard Deviations<u>Highly Confidential</u>****

[redacted]

SECTION 2: COAL

2.1 FORECASTS

A composite coal price forecast was created by combining the forecasts from the Energy Information Administration, Energy Ventures Analysis, Hill & Associates (Wood Mackenzie), 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) from December 2008.

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%.

2.1.1 GLOBAL INSIGHT

Global Insight, Inc.

1000 Winter Street

Waltham, MA. 02451-1241

U.S. Energy Outlook - December 2008

The 30-Year Focus Fourth Quarter Trend Forecast - November 2008

2.1.2 ENERGY INFORMATION ADMINISTRATION

Office of Integrated Analysis and Forecasting

U.S. Department of Energy

Washington, D.C. 20585

Annual Energy Outlook 2008 – June 2008

2.1.3 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 2008

2.1.4 HILL & ASSOCIATES INC.

Hill & Associates, Inc., A Wood Mackenzie Company

222 Severn Avenue

Annapolis, MD. 21403

"Powder River Basin Coal Supply, Demand, and Prices 2007-2016", November 2007 (Due to forecast revision caused by market turmoil during 4Q2008 the 2008 forecast release was delayed)

PRB N. Wright Super Compliance 8800

PRB S. Gillette Super Compliance 8400

2.1.5 JD ENERGY INC.

JD Energy, Inc.

P.O. Box 1935

Frederick, MD. 21702-0935

Quarterly Coal Forecast - August 2008 - Long-Term Forecast

JD Energy Coal Monthly – December 2008 - First three years (2008-2010)

2.2 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.

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, with the reserves in Wyoming being the largest in the United States. 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 (EIA) at the end of 2006 reported 17,195,000,000 tons of surface mineable recoverable reserves in Wyoming. Given estimated 2008 Wyoming PRB production of 436 million tons, the current EIA estimate indicates 39 years of supply from currently reported reserves.

More specific to the Powder River Basin, and including the Montana reserves, Hill & Associates states that at the present extraction rate of 500 million tons per year, there are more than 50 years of known PRB reserves with a breakeven production cost of $10 per ton or less.

At the end of 2007 total PRB air permit capacity allowed for 771 million tons of production, of which only 436 million tons (56.5%) are presently being used, which indicates 335 million tons per year of additional environmentally permitted capacity exists beyond current usage rates. Existing load out capacity is 556 million tons which is a production level not expected until sometime near 2020.

Present mines have the ability to easily expand, and there are several projects, such as Peabody's School Creek, that are ready to be developed into new mines if the demand warrants it, giving current PRB producers the potential to expand production to between 600 and 700 million tons per year. The reopening of Arch's Coal Creek mine in 2008 and the expected development of Peabody's School Creek mine account for 50 million tons of additional capacity available as demand grows. Forecasters project an additional 50 million tons are readily available through expansion at existing PRB mines. Taken together the presently available expansion capacity is at least 100 million tons, and is enough to supply currently forecast demand growth to 2020.

Sometime after 2020 when demand is forecast to exceed 500 million tons, development will advance northward in the PRB, and already known reserves in the Sheridan, Wyoming and Decker, Montana areas will then be developed and added to reported company reserves.

Although there is no shortage of available coal in the ground, access to those reserve is becoming more costly. Since 1999 the cost of new coal reserves purchased from the Federal Government through Lease By Application (LBA) has increased at a compound annual rate of 22.3%, going from $0.20 per ton in 1998 to $1.00 per ton by 2006 for 8800 Btu/Lb coal. The next round of LBA bids are expected to significantly exceed $1 per ton.

2.3 DISCOVERY RATES

Present PRB coal reserves are very large, and yet they only represent 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 50 years of known reserves already in front of existing mining operations, 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 that remains undeveloped, but could be developed if economic conditions warranted such development.

In addition to available PRB coal reserves, producers of Rocky Mountain coal are expected to continue finding sufficient economically available coal resources to maintain the current production level through at least 2030, with the limiting factor for Rockies expansion being the railroads, not coal reserves. Furthermore, there are reserves being added to production in the Illinois Basin. The increase in Illinois reserves is expected to allow production to grow annually through at least 2030 by adding another 50 million tons to annual production. This anticipated growth of Illinois Basin coal supply is an increase of approximately 49% above present rates over the next two decades, indicating abundant resources are available to meet demand.

2.4 USAGE RATES

In the twelve year period from 1992 to 2007 demand grew from 227 million tons per year to 436 million tons per year; an average growth rate of 13.9 million tons per year. Hill & Associates projects PRB demand growing to 597 million tons by 2019, an average growth of 16 million tons per year, with a high range of 625 million tons and a low range of 545 million tons.

At present production rates excess capacity exists in the PRB because of expansions resulting from the previous period of high prices in 2005-06, as well as from additional capacity increases added during the brief price spike that occurred in the first half of 2008. When these capacity additions are combined with already high consumer inventory levels and a weaker economic outlook after the second half of 2008, near to intermediate-term production capacity in the PRB exceeds consumer demand. The demand growth required to consume current excess capacity is not anticipated until sometime during 2010 at the earliest, and that growth is dependent on demand from new coal fired power generation coming on-line. With a weak economy and tougher environmental requirements, many planned additions were delayed or cancelled during 2008, resulting in much new demand growth reliant on coal fired power generation already under construction. Beyond the demand from new generation, additional increases in the consumption rate of PRB coal, as well as Rockies coal, will be entirely dependent on the railroads willingness to accept additional business to transport coal to more distant markets, and the rates they will require to move that additional coal to consumers geographically outside the present market.

United States coal supply is forecast to experience a major demand shift from low sulfur to high sulfur resources between 2008 and 2014 as increasingly more coal fired generation is scrubbed, removing the low sulfur advantage that PRB coal producers once held. Wood Mackenzie (Hill & Associates) has forecast that by 2014 there will be 112 GW of scrubbed generation capacity representing the equivalent of 359 million tons of coal demand with significant new coal source flexibility. The primary beneficiaries of the shift in supply sources will be both the Illinois Basin and Northern Appalachia in the near-term, and Illinois in the long-term. However, unless anticipated railroad rate increases become cost prohibitive, PRB coal is still expected to expand its market share through 2030 due to its lower production cost advantage and more favorable geology.

2.5 PROFITABILITY/FINANCIAL CONDITION OF PRODUCERS

Powder River Basin production capacity has been significantly consolidated between 1990 and 2007, with three companies, Peabody, Arch, and Rio Tinto controlling 77 percent of total PRB market share. Of the largest producers Peabody Energy has the largest market share at 29 percent.

The single most important factor in determining a producer's profitability is production cost, and the most important factor for production cost other than labor is the stripping ratio. Current mine strip ratios are between 1.4:1 and 4.4:1, but these ratios will increase over time as a reserve is mined. The PRB average strip ratio was at it lowest point in 1990, and has since increased steadily at a rate that represents an approximately 4% annual increase at current rates of production, thus making the cost of producing coal increasingly expensive over time with each additional ton mined. Strip ratios are growing more rapidly than the average among the mines of the South Gillette and Wright areas of the southern PRB, where the highest BTU and lowest sulfur coals are produced.

Productivity gains can help offset the cost increases caused by rising strip ratios. Many gains in productivity come from organizational changes such as mine consolidation and increased use of computerized control systems and automation, while other gains come from equipment modifications such as the use of draglines, larger trucks and shovels, and in pit conveyor systems. From 1985 to 2001 the PRB experienced productivity increases, but since 2001 the productivity of PRB mines has been declining. The future outlook for productivity is mixed, with some forecasters being optimistic about renewed productivity gains, while others are less optimistic. Without renewed growth, productivity will not be the cost reduction factor it once was for producers, requiring long-term pricing increases to maintain profit margins.

The four largest coal producers in the Powder River Basin are Peabody Energy, Arch Coal, Rio Tinto, and Foundation Coal, with Peabody Energy and Arch Coal accounting for almost 50% of production.

Peabody, Arch, and Foundation are domestic based producers whose mining focus is entirely on coal production. Peabody and Arch are both headquartered in St. Louis, Missouri and Foundation is based in Linthicum Heights, Maryland.

Rio Tinto is based in London, England and is one of the largest fully diversified mining companies in the world, with the company's U.S. coal portfolio, including all PRB mines, operating as Rio Tinto Energy America (RTEA). RTEA's $1,869 million net revenue in 2008 accounted for 17% of the Energy and Minerals Division net revenue, and RTEA's net profit of $147 million in 2008 accounted for 4% of the parent company's worldwide net profit, up from 1.8% of net profit in 2007, largely because of record high energy prices during the first half of 2008. With RTEA between 2% and 4% of parent company profits and its capital expenditures also at a similar level, it is a relatively small component in the parent company's portfolio, and not one that is generating excess returns. As a result, in 2008 Rio Tinto placed RTEA up for sale but is yet to announce a buyer.

In summary, four major PRB producers account for 88 percent of PRB coal production, all are profitable, and three have double digit returns on equity, while two are highly leveraged with total debt to equity ratios greater than one.

Peabody Energy

Market Share 29%, ROE = 35%, Total Debt / Equity 0.84

Arch Coal

Market Share 20%, ROE = 18%, Total Debt / Equity 0.83

Rio Tinto

Market Share 28%, ROE = 14%, Total Debt / Equity 1.85

Foundation Coal

Market Share 11%, ROE = 0.3%, Total Debt / Equity 2.74

The two financially strongest producers in the PRB are Peabody Energy and Arch Coal which together account for nearly half of all production. Both companies are very profitable based on their return on equity (ROE), and both have lower debt ratios than their competitors. While two major producers have high debt ratios, at least one of those highly leverage producers, Rio Tinto, has placed its mines up for sale and those operations will pass to another producer or producers in the future. In the longer-term, given the increasing market share and importance of PRB coal in the nation's electricity generation, it is unlikely the financial failure of a single producer would halt shipments from the PRB. In the event of the financial difficulty of one of the primary producers, there is a high degree of probability that another energy producer or investment fund will step in and acquire the PRB assets of the struggling firm at a discount, and continue producing coal. Also, given an increasing strategic importance of PRB coal to the stability of base load generation for a large portion of the United States it is likely the Federal Government would intervene if necessary to maintain the flow of coal to electricity generators.

2.6 CAPACITY, PROFITABILITY, EXPANSION POTENTIAL OF PRESENT AND FUTURE TRANSPORT OPTIONS

In 2006, the BNSF and UP railroads hired CANAC of Montreal, Canada to analyze the requirements for expanding the PRB Joint-Line capacity from 350 million tons in 2006 to 500 million tons by 2012. The recommended expansion plan under which the railroads are now working is designed to give the Joint-Line the capacity to ship 458 million tons by 2009, with 500 million ton capacity expected no later than 2012.

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 the DM&E was purchased by 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. Canadian Pacific places the completion date of the DM&E connection into the PRB as being no earlier than 2012, assuming STB approval and the time necessary for CP executives to decide if they want to proceed with the project. If built, the DM&E line will provide another 100 million tons of capacity to compete with the BNSF-UP Joint-Line.

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. Approximately 70 percent of all domestic coal shipments are by rail, 12 percent 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.

The major railroads serving the PRB are Union Pacific and BNSF. The primary cost issues faced by these railroads have been escalations in capital equipment costs and fuel expenses, however, the railroads have successfully passed rising fuel costs on to consumers in the form of fuel surcharges. They have also covered their rising capital costs through rate increases of between 30 percent and 100 percent since 2000, depending on distance from the PRB, with the smallest increases being for the longest shipments. These rate increases have slowed the expansion of PRB coal into the eastern U.S. market, and have increased the profitability of both railroads. Both Union Pacific and BNSF serve the mines of the Rocky Mountain region and the PRB, and both are profitable with a return on equity (ROE) of 14.5 percent for Union Pacific and 17.3 percent for BNSF.

2.7 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. Rail transportation is not likely to see as great an impact from CO2 cost due to less emission intensity per ton-mile for rail transportation and also because of the railroads ability to pass additional costs on to consumers, which may result in strengthening the near monopoly railroads already exercise in the coal transportation market.

2.8 POTENTIAL GOVERNMENT RESTRICTIONS ON USE OF FUEL FOR ELECTRICITY GENERATION

Coal represents the primary energy 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.

If there are restrictions placed on coal, the most likely restrictions will be indirect in nature. Any indirect reduction in coal generation intensity is likely to occur slowly and be drawn out across many years. Regulation of carbon dioxide emissions could place an indirect limitation upon coal use by making coal more expensive, reducing the cost advantage coal has over competing energy sources such as natural gas and renewables, and gradually shifting the installed generation capacity away from present coal intensity levels. However, United States domestic coal reserves are the largest reserves in the world, and domestic production is not only large enough to make the nation completely self sufficient in coal, it also makes the United States a net exporter of coal. The large domestic coal reserve gives United States consumers a degree of energy security in electricity markets that does not exist elsewhere in the domestic energy marketplace. Any indirect restriction on coal usage is likely to be balanced by the competing desires for energy security and energy self sufficiency.

Among possible indirect restrictions on coal, carbon dioxide restrictions on emissions from fossil fuels at electricity generating stations may place sub-bituminous coals such as PRB coal at a disadvantage to bituminous coal in eastern U.S. markets. Sub-bituminous coals emit on average 212.7 pounds of CO_2 per mmBtu, and bituminous coals emit on average 205.3 pounds of CO_2 per mmBtu, giving a 3.6% CO_2 penalty to PRB coal when competing with bituminous coals, placing sub-bituminous coal at a slight disadvantage in the marketplace.

A second disadvantage placed on PRB coal by CO_2 regulation would also come from transportation costs. 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. Any increase in fuel cost due to CO_2 regulation that impacts rail transportation will ultimately be passed directly on to consumers as part of the fuel surcharge, resulting in the most distant PRB consumers facing the greatest cost burden from CO_2 regulation.

2.9 ACCURACY OF PREVIOUS FORECASTS

Academic, governmental, and industrial research shows that a consensus forecast approach consistently produces the most accurate forecasts. Existing research demonstrates that "forecast accuracy" is relative to the perspective of the analysis being performed. The solution to the relative nature of "forecast accuracy" is to utilize consensus forecasting, which combines the forecasts from multiple qualified sources, making it somewhat independent of any one individual forecaster having a "bad" year. Additionally, the consensus method provides a measure of forecast uncertainty through the statistical distribution of the individual forecasts being averaged, and has a mathematically defined impossibility of being the worst choice in any given year. Defining accuracy as the forecast that consistently has the smallest price error risk makes the consensus forecast the most robust forecast.

2.10 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, GMO 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 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:

2.10.1 WESTERN RAIL RATES

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 and may result in long-term prices trending flat or lower.

Anything that may impact the cost structure of railroads, whether that is broad economic price inflation driving up capital costs or CO_2 regulation driving up fuel costs will ultimately be passed through by the railroads and borne by consumers, which can make products that are shipped long distances such as PRB coal less competitive in the market place and either force coal producers to lower prices or lose market share through the loss of more distant customers.

2.10.2 PRODUCTIVITY

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.

2.10.3 U.S. DOLLAR AND GLOBAL FREIGHT RATES

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.

If the dollar weakens in value, 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.

If the dollar strengthens in value as it has during the fourth quarter of 2008, 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.

A decline in global ocean freight rates can also reduce demand for U.S. coal 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 both PRB and Appalachian coal prices.

2.10.4 COAL PRICING BASED ON SULFUR CONTENT AND SO_2 RETROFITTING

Flue Gas Desulphurization (FGD) installations and the value of coal based on sulfur content is a primary driver. The rapid pace of FGD installations in the eastern U.S. is expected to continue driving a shift toward higher sulfur but more local 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 a market shift toward higher sulfur Illinois and Appalachian coal to materialize will likely result in a continuation of a rising long-term PRB price trend.

SECTION 3: NATURAL GAS

3.1 FORECASTS

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. The EIA forecast was converted to nominal dollars using Global Insight's GDP implicit price deflator (JPGDP).

Once all natural gas 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%.

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.

3.1.1 GLOBAL INSIGHT

Global Insight, Inc.

1000 Winter Street

Waltham, MA. 02451-1241

U.S. Energy Outlook - December 2008

Natural Gas Monthly - December 2008

The 30-Year Focus Fourth Quarter Trend Forecast - November 2008

3.1.2 ENERGY INFORMATION ADMINISTRATION

Energy Information Administration

Office of Integrated Analysis and Forecasting

U.S. Department of Energy

Washington, D.C. 20585

"Annual Energy Outlook 2008"

3.1.3 ENERGY VENTURES ANALYSIS INC.

Energy Ventures Analysis, Inc.

1901 North Moore Street, Suite 1200

Arlington, VA. 22209-1706

"The Long-Term Outlook", Vol.2, August 2008

3.1.4 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 was sourced from PIRA's Retainer Client Seminar Projections and Presentations, North American Natural Gas, Section VII, Table VII-1, New York, October 2008

3.2 PRESENT RESERVES

The *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2007 Annual Report* released February 2009 estimates technically recoverable resources of dry natural gas (discovered, unproved, and undiscovered) at 1,533 trillion cubic feet, which is about 79 times the 2007 dry gas production level of 19.4 trillion cubic feet. U.S. proved reserves[7] of 237 trillion cubic feet at the end of 2007 is 13% greater than the proven reserves at the end of 2006. The 26.6 trillion cubic foot increase in proven reserves is a reserve growth rate that replaced 137% of the natural gas consumption rate.

[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.

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 29,091 billion cubic feet in 2007. This was 59 percent more than the prior 10-year average (18,357 billion cubic feet) and 25 percent more than in 2006, and with the abundance of new shale gas fields coming online, the growth is anticipated to be even greater for 2008. The majority of natural gas total discoveries in 2007 were from extensions[8] to existing gas fields. Field extensions were 27,107 billion cubic feet, 25 percent more than in 2006 and 82 percent more than the prior 10-year average (14,924 billion cubic feet). New field discoveries were 796 billion cubic feet, 95 percent more than the volume discovered in 2006 and 49 percent less than the prior 10-year average (1,555 billion cubic feet).

New reservoir discoveries in old fields were 1,188 billion cubic feet, 3 percent more than 2006 and 37 percent less than the prior 10-year average (1,878 billion cubic feet).

3.3 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.

Natural gas demand is expected to increase from about 23 trillion cubic feet per year (tcf/y) in 2007 to about 29 tcf/y by 2030. That is about a 1 percent per

[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.

annum growth. The primary driver for that increase in expected growth comes from gas consumption for electricity 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 coal, nuclear, and natural gas-fired generation capacity that will be built, and the cost of natural gas relative to other fuels, and total gas demand for electricity generation is expected to grow from 8.4 billion cubic feet per day to 27.2 billion cubic feet per day by 2030, or about a 5 percent per annum growth rate. Natural gas used for the residential, commercial and industrial sectors combined was forecast to grow through 2030 at rates ranging from 0.0% to 1.1%. The demand for these sectors is driven by demographics and economic growth.

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.

In addition to growth projections for installed natural gas generation capacity, the forecasts also assume an additional 100 GW of installed solid fuel generation capacity by 2030, with approximately 40 percent being coal and 60 percent nuclear. Any failure to meet that capacity with some combination of coal and nuclear will result in a capacity shortfall that natural gas generation will be forced to cover, raising natural gas usage levels and prices much higher than forecast.

3.4 PROFITABILITY/FINANCIAL CONDITION OF PRODUCERS

The Energy Information Administration's *Performance Profiles of Major Energy Producers* 2007 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).

In *Performance Profiles* EIA reported that Return on Net Investment In Place (ROI) for the oil and natural gas production segment fell to 15 percent in 2007 from 18 percent in 2006. Despite the decline, the 2007 ROI remained higher than the average (13.9 percent) over the past 10 years. ROI for domestic oil and natural gas production fell less than that of foreign production, which saw ROI decline from 23.7 to 18.8 percent. [EIA-Profiles Fig. 4]

The EIA Profiles report also noted that the Return on Equity (ROE) in 2007 for the major producers was 23 percent, which was the third highest every recorded by EIA.

3.5 CAPACITY, PROFITABILITY, EXPANSION POTENTIAL OF PRESENT AND FUTURE TRANSPORT OPTIONS

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.

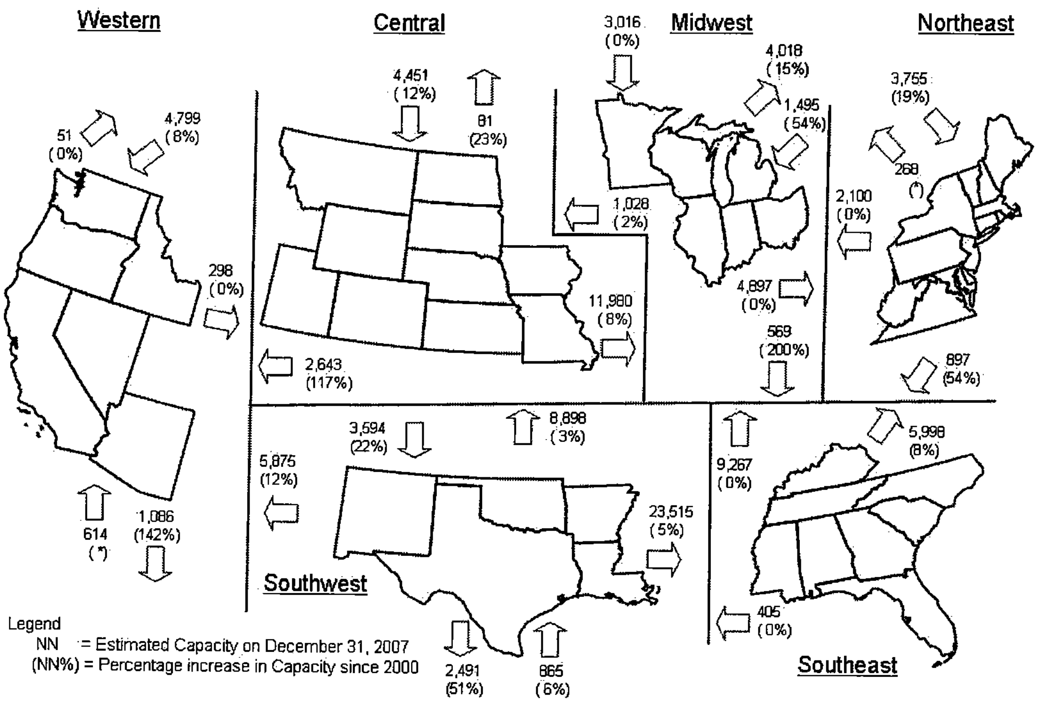
- 399 underground natural gas storage facilities.

- 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.

Table 7: 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.

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 REX-West segment of the pipeline reaching Audrain County, Missouri, began service in 2008, bringing additional transportation capacity to 1.6 Bcf per day into the Midwest.

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 service as far as Lebanon, Ohio by June 2009, and complete full service to the Clarington Hub by November 2009.

(http://www.kindermorgan.com/business/gas_pipelines/rockies_express/)

The completion of the REX system will have a profound effect on several segments of the industry, particularly since the completion of the project will likely correspond with a significant increase in non-conventional gas production from shale in the midcontinent and eastern U.S., and with a likely increase in U.S. LNG imports. Among the likely impacts will be a re-routing of gas flows on some major pipelines to handle the volume of shale gas production coming from the Barnett and Hainesville shales, and a decline in natural gas prices in the eastern U.S. as that market gets flooded with supply from the Rockies, from shale production, and from LNG all competing for the same pipeline space. Similarly, the possibility of the Gulf Coast region being long on supply for the first time has enormous implications for industry participants, especially ammonia and petrochemical production, and for the competitive structure of the natural gas and chemical industries.

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. At the present time the officially stated online dates for the pipeline projects are 2014 for the Mackenzie and 2018 for Alaska, but most forecasts indicate these dates are likely to slip, with Energy Ventures stating the earliest online dates will be closer to 2017 and 2022 at the earliest and may still slip further. With the rapidly growing shale gas reserves in the Lower-48 and Western Canada, it is believed the need for either of the arctic pipelines is no longer urgent and their start dates will be pushed back even further.

3.6 EFFECTS OF GOVERNMENT REGULATION, COMPETITION, ENVIRONMENTAL LEGISLATION ON TRANSPORT

In 2006, former Gov. Frank Murkowski settled in principle with BP, Exxon Mobil Corp. and ConocoPhillips on fiscal terms — taxes and royalties — for producing Alaska 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 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 Gov. Sarah Palin to chart another course, while refusing to continue negotiations with 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 from 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. 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 2007. Only one is likely to survive the competition in a pipeline race that has the attention of state and federal lawmakers, and the TransCanada pipeline project faces another hurdle in that it does not have any capacity commitments from major holders of gas reserves, namely BP, Conoco, and Exxon. Lack of firm commitments will prevent the TransCanada project from getting adequate financing. Forecasts assume the parties will eventually resolve their differences and complete a pipeline by 2022, with expectations favoring the Alaska Gas Pipeline.

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 according to the companies involved in the project. 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.

3.7 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.

3.8 ACCURACY OF PREVIOUS FORECASTS

Academic, governmental, and industrial research shows that a consensus forecast approach consistently produces the most accurate forecasts. Existing research demonstrates that "forecast accuracy" is relative to the perspective of the analysis being performed. The solution to the relative nature of "forecast accuracy" is to utilize consensus forecasting, which combines the forecasts from multiple qualified sources, making it somewhat independent of any one individual forecaster having a "bad" year. Additionally, the consensus method provides a measure of forecast uncertainty through the statistical distribution of the individual forecasts being averaged, and has a mathematically defined impossibility of being the worst choice in any given year. Defining accuracy as the forecast that consistently has the smallest price error risk makes the consensus forecast the most robust forecast.

3.9 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, Arctic natural gas pipeline(s), and natural gas imports, specifically LNG. Each of these drivers is briefly discussed below.

3.9.1 DEMAND - USAGE

Total lower 48 natural gas demand is projected to grow from about 22 trillion cubic feet in 2007 to between 23 and 28 trillion cubic feet by 2030, depending on the forecast, with the Energy Information Administration (EIA) forecast at the low end of the demand range and the forecast from Energy Ventures Analysis at the higher end of the range.

3.9.2 DEMAND – NATURAL GAS USED FOR ELECTRICITY GENERATION

In all of the underlying forecasts, the most significant uncertainty in the outlook for natural gas demand and its impact on price is how much new coal, nuclear, and renewable generation capacity gets built through 2020. The power generation sector is expected to dominate any increase in natural gas demand during the forecast period, with natural gas demand for electricity generation growing at a faster rate through 2016 than any other major consuming sector. In the Energy Information Administration's base case, total natural gas consumption peaks at 23.8 trillion cubic feet in 2016, and then declines to 22.7 trillion cubic feet by 2030 due to the impact of forecast higher natural gas prices after 2016, while other forecasts indicate less new coal and nuclear generation capacity being built, placing greater demand on natural gas for electricity generation, resulting in natural gas demand as high as 28 trillion cubic feet per year. According to the EIA base forecast, generally rising natural gas prices after 2016 will encourage electricity generators to increase their use of renewable fuels and less expensive coal.

3.9.3 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 2030 at rates ranging from 0.0% to 1.1%. Fuel substitution options for residential, commercial, and industrial sectors are limited. Consequently, these sectors are less sensitive to price change, and their demand is driven by demographics and economic growth.

The greatest unknown for natural gas demand from sources other than electricity generation is presently included in the Industrial sector, and is the potential demand for natural gas as a transportation fuel in alternative fuel vehicles. At the present time, the gasoline-electric hybrid vehicle appears to increasingly be the dominant technology rather than natural gas. As a result, consumption of natural gas is forecast to grow at a rate of 4.2 percent per annum, from 24 billion cubic feet per year in 2005 to 55 billion cubic feet per year by 2025, with the majority of the increase coming from fleet vehicles. Any un-anticipated shift toward natural gas and away from gasoline and diesel in the personal automobile market could drive a major increase in natural gas demand beyond levels currently forecast.

3.9.4 SUPPLY – USAGE

In order for the natural gas market to increase from the current demand level of approximately 22 tcf to projected levels as high as 28 tcf by 2030, natural gas supply will have to increase substantially. It is apparent that traditional conventional 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. Three significant evolving sources are unconventional domestic production, Arctic gas, and liquefied natural gas (LNG), with most forecasts shifting from LNG as the primary future source only a year ago to now relying very heavily on domestic unconventional production to fill out the long-term supply portfolio.

3.9.5 SUPPLY – DOMESTIC PRODUCTION

All underlying forecasts hold the general premise that future new discovery of conventional natural gas reservoirs are expected to be smaller, deeper, riskier and more expensive to develop. However, total natural gas production is forecast to grow through 2030 with new incremental production of lower 48 onshore natural gas coming primarily from unconventional resources that are less constrained by the costs and risks of conventional resources.

Domestic conventional gas production is forecast to decline from 6.6 trillion cubic feet in 2006 to 4.4 trillion cubic feet by 2030. Unconventional onshore gas production, and after 2020 Arctic natural gas, are expected to combine and offset the conventional decline with combined production growth of 2.2 trillion cubic feet, from 8.9 trillion cubic feet in 2006 to 11.5 trillion cubic feet in 2030. Given the prolific nature of the shale gas resource, there is potential for growth to exceed the forecast. In 2008 unconventional production accounted for 46 percent of all domestic natural gas production, and represented an even higher percentage of drilling activity. The most important sources of new production in the long-term supply portfolio are the unconventional gas plays.

3.9.6 UNCONVENTIONAL DOMESTIC PRODUCTION

The most promising of the unconventional resources are the rapidly developing shale gas reserves such as the Barnett Shale in Texas, the Fayetteville Shale in Arkansas, and the Haynesville Shale in Louisiana. According the USGS, the Barnett shale play alone represents an estimated resource of 26 trillion cubic feet. The shale gas resources are much more prolific than previously forecast, and they have unique characteristics such as minimal exploration risk, large aerial extent, and very long-lived production profiles that are uncommon to more traditional conventional natural gas reservoirs.

In addition to the rapidly developing shale gas reserves, other unconventional resources include Coalbed Methane, with production currently coming from resources such as the San Juan Basin in New Mexico and the Black Warrior Basin in Alabama. Additional unconventional resources include Tight Sands such as the Jonah Field and Pinedale Anticlines in Wyoming. In the case of the Pinedale Anticline production is already near 0.4 trillion cubic feet and only 8 percent of the field has been developed.

In order for the domestic gas market to supply the upper end of projected 2030 demand forecasts of approximately 28 trillion cubic feet, production will need to rise more than 15 billion cubic feet per day from current levels, even as present conventional production falls by 6 billion cubic feet per day as those reserves deplete. These newly emerging supply sources are expected to combine with Arctic natural gas to fill that gap and meet currently projected demand.

3.9.7 <u>SUPPLY – ARCTIC NATURAL GAS PIPELINE(S)</u>

A major uncertainty is the likelihood and timing of two proposed Arctic natural gas pipelines. Assumptions range from only the Mackenzie Delta pipeline being built with most of that volume being retained for the Canadian market, to both the Mackenzie Delta and Alaska pipelines being built and operational by 2022, and delivering as much as 3.5 tcf per year to the lower-48.

With the Arctic pipelines representing potentially up to 10% of future supply, a significant delay and/or cancellation of either the Alaska or Mackenzie Delta natural gas pipeline could have a major impact on the overall long-term outlook for the supply and price of natural gas after 2020, and will place greater reliance on domestic unconventional production.

In late 2008 as projected costs increased and projected gas demand declined, development of the Mackenzie Delta pipeline became much more questionable, and EIA now projects that the natural gas prices in their Annual Energy Outlook

2008 Reference Case can no longer justify development of the Mackenzie pipeline.

3.9.8 <u>SUPPLY – LIQUIFIED NATURAL GAS (LNG)</u>

All of the underlying forecasts expect the high natural gas prices experienced in 2007 and the first half of 2008 to stimulate the construction of LNG terminal capacity significantly increasing LNG imports. LNG imports are forecast to grow from about 0.5 tcf to 2.8 tcf per year by 2030. 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, but the U.S. is expected to be the successful bidder for no more than 20 percent of global LNG supplies in any given year, with importation levels fluctuating widely with price. When international natural gas prices are higher than domestic prices LNG import volumes will decline, and when international prices are lower than domestic prices, LNG import volume will increase.

Every segment of the LNG chain (i.e., liquefaction, shipping and regasification) underwent a period of rapid expansion due to high natural gas prices in 2007-2008. Various contributing forecasts assumed that U.S. LNG imports would likely increase to somewhere between 4 tcf and 6.9 tcf per year by 2030, and would become the primary incremental supply resource as domestic conventional reserves were depleted. However, the rapid increase in domestic unconventional natural gas reserves and increasing international competition for LNG cargoes now result in forecast LNG imports averaging no more than 2.8 tcf per year by 2030 with a range between 1.7 tcf and 4.5 tcf per year.

SECTION 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.

4.1 FORECASTS

A composite crude oil 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. The EIA forecast was converted to nominal dollars using Global Insight's GDP implicit price deflator (JPGDP).

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.

4.1.1 GLOBAL INSIGHT

Global Insight, Inc.

1000 Winter Street

Waltham, MA. 02451-1241

U.S. Energy Outlook - December 2008

Petroleum Monthly - December 2008

The 30-Year Focus Fourth Quarter Trend Forecast - November 2008

The Global Insight No.2 fuel oil forecast is sourced from the Global Insight Cost Analyzer 2008Q3 data series PPI324110413.

4.1.2 ENERGY INFORMATION ADMINISTRATION

Annual Energy Outlook 2008 - With Projections to 2030, June 2008

Energy Information Administration

Office of Integrated Analysis and Forecasting

U.S. Department of Energy

Washington, D.C. 20585

Short-Term Energy Outlook, November 2008

Annual Energy Outlook Reference Case Forecast, June 2008

The EIA source data for crude oil prices is split between the short-term and long-term forecasts. The long-term forecast issued in June 2008 is from the EIA Annual Energy Outlook 2008. Overlaid on this price curve was the more current EIA Short-Term Outlook from November 2008. The short-term forecast covered the period 2009 to 2010. The period from 2011 to 2030 is covered by EIA's forecast in the Annual Energy Outlook 2008.

4.1.3 <u>ENERGY VENTURES ANALYSIS INC.</u>

Energy Ventures Analysis, Inc.

1901 North Moore Street, Suite 1200

Arlington, VA. 22209-1706

"The Long-Term Outlook", August 2008

4.1.4 <u>PIRA ENERGY GROUP, INC.</u>

PIRA Energy Group

3 Park Avenue, 26th Floor

New York, NY. 10016-5989

The PIRA crude oil price forecast was sourced from PIRA's Retainer Client Seminar Projections and Presentations, North American Natural Gas, Section VII, Table VII-1, New York, October 2008

4.2 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 44% in 2008 to 51% by 2030.

Global oil reserve estimates vary depending upon the source, but present estimates are approximately 1.3 trillion barrels of proven reserves, or more than 40 years of supply at current consumption rates. 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.

The National Petroleum Council in 2007 gave 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.

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 before 2030.

In the United States the development of the Bakken field in North Dakota and eastern Montana is expected to halt the decline of Lower-48 oil production for several years with its reserves estimated between 3 and 4 billion barrels.

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 by 2030. While the global supply is large, the greatest uncertainties concerning reserves are the quantity that is actually recoverable, and the rate at which the recoverable resource can be produced.

The key consideration for energy supplies is not the total reserve base but produceability of those reserves. Over the next two decades, above ground risks related to geopolitics, technical issues and infrastructure capabilities, are more likely to affect oil production rates than are geological and volume limitations of the in-place reserve.

4.3 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 to technology advancements, exploration success, and enhanced recovery from existing fields.

In addition to the reported reserves of conventional oil, there are also very large non-conventional oil resources. 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. Most of the known non-conventional resources such as oil sands and oil shale are yet to be developed, and new discoveries will be made as these resources become economically viable. Additionally, sources of newly “discovered” supply may come from coal-to-liquids production and from the growing biofuels industry, neither of which are included in estimates of reserves, but will supplant a distinct volume of crude oil.

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 over the next 22 years. The forecast growth in non-conventional oil supply represents an annual growth rate of more than 8 percent.

New production capacity additions are forecast by most sources to increase significantly between 2008 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. IEA estimates the need for investment of additional 7 million barrels per day of capacity over and above the 23 million barrels per day of projects currently in development. A major escalation of oil prices would result from such a supply crunch, but given the global financial crisis and current economic environment there are serious doubts about the needed investment coming in time to avoid a future price spike.

U.S. domestic crude oil production is forecast to increase due to new discoveries and technological advancements that allow greater recovery from existing reserves. Domestic production is forecast to rise until 2018, peaking at 6.3 million barrels per day, before gradually declining to 5.6 million barrels per day in 2030, which is nearly 600,000 barrels higher than 2007 production.

4.4 USAGE RATES

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.

The longer-term outlook beyond 2015 has non-OPEC production flattening and then declining, making the world 100% dependent on OPEC for incremental growth. The transition to total dependence on OPEC is likely to result in a scarcity premium of $10 to $15 per barrel being added to the price of oil.

Global demand is forecast to grow from 82 million barrels per day in 2007 to 104 million barrels per day by 2030, with approximately 60% of the growth coming from countries that subsidize the cost of oil, and therefore have much less price elasticity in their demand. Future demand growth can be divided into two groups; those countries paying international prices and those with price subsidies. In countries paying international prices demand is forecast to grow at a rate of 0.3% annually, while those with oil and energy price subsidies are forecast to see demand continue growing at a 3.5% annual rate through 2030.

OPEC's own estimate for future global oil demand calls for an average growth of 1.7 percent per year, with total demand growing to 113 million barrels per day by 2030. This is an increase in demand of 29 million barrels per day from 2006 demand levels, but is 4 million barrels per day less than OPEC's 2007 estimate.

The transportation sector currently accounts for between 76 percent and 83 percent of global oil consumption and approximately 65 percent of all future demand growth is forecast to come from transportation.

The majority of world oil fields are expected to be past their peak production levels between 2015 and 2025, with only nine countries not past their peak production by 2025. Those nine countries, Saudi Arabia, Iran, Iraq, Venezuela, UAE, Kuwait, Nigeria, Libya and Canada, will supply more than 55 percent of world oil production in 2025.

4.5 PROFITABILITY/FINANCIAL CONDITION OF PRODUCERS

Fossil fuels are forecast to continue supplying the majority of the world's energy needs, with a forecast market share in excess of 85 percent in 2030.

Expansion of downstream 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. Maintaining that 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.

Crude oil prices are not expected to return to the less than $50 per barrel levels seen prior to 2005 for any prolonged period of time. 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.

Control of global oil production is increasingly shifting away from independent producers and toward national oil companies. Although the major independent western producers remain profitable at current and forecast prices, the reality is that as more production shifts to state run oil companies, political concerns take precedent over profitability for many of the primary global producers, and their financial health becomes increasingly interwoven with that of the state. Government take of the oil revenues in the top ten energy producing countries are forecast to rise from $80 billion in 2006 to $250 billion in 2030.

4.6 CAPACITY, PROFITABILITY, EXPANSION POTENTIAL OF PRESENT AND FUTURE TRANSPORT OPTIONS

The global oil export trade is forecast to grow from 52 million barrels per day in 2007 to 77 million barrels per day by 2030. The majority of this oil is shipped around the globe in tanker ships. The continuing oil demand growth will require the global tanker fleet to increase from 380 million deadweight tons in 2007 to 550 million deadweight tons by 2030, a compound annual growth rate of 1.6% throughout the period.

4.7 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.

U.S. government policies and regulation currently restrict developing domestic oil reserves in the Arctic National Wildlife Refuge (ANWR) in Alaska, as well as known fields offshore California and in the eastern Gulf of Mexico. The current moratorium on drilling in the eastern Gulf of Mexico is set to expire in 2012, and some states are lobbying to be allowed to end the moratorium and begin development off their coasts, but analysts believe this will not happen and the moratorium will likely be extended to 2022.

4.8 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 other major generation fuels, and oil price forecasts do not 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.

4.9 ACCURACY OF PREVIOUS FORECASTS

Academic, governmental, and industrial research shows that a consensus forecast approach consistently produces the most accurate forecasts. Existing research demonstrates that "forecast accuracy" is relative to the perspective of the analysis being performed. The solution to the relative nature of "forecast accuracy" is to utilize consensus forecasting, which combines the forecasts from multiple qualified sources, making it somewhat independent of any one individual forecaster having a "bad" year. Additionally, the consensus method provides a measure of forecast uncertainty through the statistical distribution of the individual forecasts being averaged, and has a mathematically defined impossibility of being the worst choice in any given year. Defining accuracy as the forecast that consistently has the smallest price error risk makes the consensus forecast the most consistent forecast.

Given that the research literature demonstrated 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 will be consistent for crude oil or any other commodity. Furthermore, since the consensus forecasts for coal and oil utilize many of the same forecasters, the likelihood of consistent outcomes is further enhanced.

4.10 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 are economic growth and its correlation to energy demand. 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. Since the global financial crisis began in the second half of 2008, forecasts for the rate of economic growth have decreased, and when combined with political initiatives in major consuming regions the uncertainty in demand growth has grown significantly.

Demand uncertainty is becoming a serious issue for the major producers, especially OPEC. The uncertainty in demand is not only coming from uncertainty about the future growth of world economies, but also by the US Energy Security and Independence Act of 2007 (ESIA), and European Union proposals to further tighten CO2 caps and increase renewable mandates and biofuel targets. In their World Oil Outlook OPEC cites political initiatives in the United States and European Union as likely to reduce the current demand for OPEC production capacity 4 million barrel per day by 2020, creating an uncertainty of 9 million barrels per day in required OPEC production, ranging from 29 to 38 million barrels per day. The wide range of uncertainty results in an estimated investment uncertainty of more than $300 billion between now and 2020. Such investment uncertainty not only impacts OPEC, it impacts all major producers, state owned and multinationals alike. If too little investment is made and economic growth is underestimated, then prices could be much higher. Likewise, if otherwise adequate investment is made and growth is less than forecast then prices will trend much lower.

Other significant drivers are access to reserves, and geopolitical stability. With the Middle-east facing a nearly continual risk of conflict, Central Asia in political turmoil, Russia, Mexico, and Venezuela needing continued large energy sales to finance their government's, the stability of major OPEC and non-OPEC production is quite uncertain. Furthermore, many nations have taken political positions that are curtailing access to reserves, such as the United States Congress continuing to prohibit new offshore drilling, the chilling effect of Russia's punitive taxation schedules, and Venezuela's expropriation and nationalization of nearly all privately held natural resource production in that nation. All these actions are political in nature and ultimately they all produce the same result, which is reduced access to and lack of downstream investment in new oil reserves.

In the near and intermediate-terms oil prices are expected to moderate through 2012 as slow economic growth and new production already under development allow supply to grow faster than demand and OPEC spare capacity grows to more than 4 million barrels per day of crude oil and another million barrels per day of natural gas liquids (NGLs).

Long-term prices are expected to strengthen from 2016 to 2030 as the economies of developing nations accelerate demand for oil at the same time as non-OPEC production peaks and the world becomes entirely reliant on OPEC for incremental supply. Demand growth 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 increasingly 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.

SECTION 5: URANIUM

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.

The Energy Information Administration (EIA) forecasts strong growth in US nuclear power generation through 2030, with nuclear generated electricity growing from 787 billion kWh in 2006 to 917 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.

5.1 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.

5.1.1 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"

5.2 PRESENT RESERVES

Uranium is a naturally occurring metallic element that is found in a variety of different ores. Uranium is not a rare metal like gold. Uranium's concentration in the earth's crust is of similar abundance to 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.

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 exceed 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.

5.3 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 2008 Group

Overview that world wide conventional uranium resources that are economic to develop, up to a recovery cost of $130/kgU, totals approximately 16 million metric tonnes, which is more than 200 times the world uranium demand in 2008. Even when constraining this resource total to reasonably assured reserves, the current global reserve base is estimated at approximately 3.34 million metric tonnes of uranium, which is still more than 42 years of supply at the 2008 demand rate.

5.4 USAGE RATES

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% to 218 million pounds by 2025.

5.5 PROFITABILITY/FINANCIAL CONDITION OF PRODUCERS

The largest uranium producers in the world are Cameco, Rio Tinto, BHP Billiton, Areva, Kazatomprom, and Russia's AtomEnergoProm (AEP), which together combined to produce 79% of world, mined uranium supply. With the exception of Kazakhstan's Kazatomprom and Russia's AEP, the other four producers are all western based companies. Kazatomprom and AEP are privately held companies, with the Russian government having some involvement in AEP. 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 the United States.

Cameco, based in Saskatchewan, Canada, is the largest uranium producer in the world, responsible for approximately 15% 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 controls the world's highest grade reserves and lowest cost mining operations in northern Saskatchewan. The company is also presently the largest producer in the United States with in-situ production facilities in Nebraska and Wyoming. Cameco appears to be a financially stable and profitable company, with a return on equity of 15% in 2007, and 11.5% in 2008.

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. 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 was 34% in 2007 and 14% in 2008, while the return on equity of BHP-Billiton was 45% in 2007 and 34% in 2008.

Areva, based in France, is only the third largest uranium miner after Cameco and Rio Tinto, producing almost 15% of world supply. The French government currently owns 90% of Areva's shares.

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. The company is financially profitable and stable with 90% of its shares owned by the French government. Areva's return on equity was 11% in 2007 and 9% in 2008.

In summary, the major western producers account for 62% of world uranium production, are very profitable and have double digit returns on equity at the end of 2008.

Areva ROE = 9%

Cameco ROE = 11.5%

BHP-Billiton ROE = 34%

Rio Tinto ROE = 14%

5.6 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.

5.7 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.

Additionally, the US government is again reviewing the potential for reprocessing and recycling spent nuclear fuel, which if approved will result in the need for less long-term disposal capacity.

5.8 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.

5.9 ACCURACY OF PREVIOUS FORECASTS

Given that Energy Resources International (ERI) was the only complete, long-term nuclear fuel cycle forecast available to GMO 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. 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 few years.

5.10 IDENTIFICATION OF 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