BEFORE THE PUBLIC UTILTIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

In the Matter of the Complaint by Oak Tree Energy LLC against NorthWestern Energy for refusing to enter into a Purchase Power Agreement

EL11-006

Prefiled Direct and Rebuttal Testimony of

Steven E. Lewis

On behalf of NorthWestern Energy

January 12, 2012

EXHIBIT
NW
6
3-24-12 CW
depobook.com

Table of Contents

Exhibits

Testimony

Introduction and Qualifications

Q: Please state your name and business address.

A: My name is Steven E. Lewis. I am a principal and employee of Lands Energy Consulting. My business address is 2719 California Avenue SW Suite 5, Seattle, Washington 98116.

Q. Briefly describe your education and business experience.

A. I hold a Bachelor of Science degree in physics with a minor in math from Gonzaga University in Spokane, Washington. I graduated in 1989. I started working in the electric utility business as a summer intern in 1987 at the Bonneville Power Administration and commenced full-time employment in the utility sector in 1990. Between 1990 and 2001, I held positions with both Puget Sound Energy and Seattle City Light, where I was responsible for managing utility power supplies in a reliable and economic manner. I have been with Lands Energy as a principal since 2001. During my time with Lands Energy, I have advised a variety of utilities, power producers, and energy trading companies on their activities in the energy markets. I have worked since 2001 on projects on behalf of NorthWestern Energy, working for both their South Dakota and Montana offices. The work with the South Dakota office included providing a wholesale electricity price forecast and facilitating two Requests for Proposals (RFPs). My curriculum vitae is included as Exhibit SEL-01.

Purpose of Testimony

Q What is the purpose of your testimony?

A. To provide information related to the price forecast for wholesale electricity in South Dakota, to rebut certain parts of the testimony of J. Richard Lauckhart, and to provide information regarding NorthWestern Energy's recent solicitations for renewable energy.

Q. Please summarize your testimony.

A. My testimony includes:

- A review of the methodology Lands Energy used to prepare a price forecast for wholesale electricity in the South Dakota region;
- Rebuttal to the Prefiled Direct Testimony of Mr. J. Richard Lauckhart on behalf of Oak Tree Energy, particularly to the Black & Veatch price forecast provided therein; and

- Observations derived from the solicitations we have conducted for NorthWestern Energy for generating resources in South Dakota.

Electricity Price Forecast for South Dakota

Q. Did Lands Energy provide NorthWestern Energy with an electricity price forecast for South Dakota?

A. Yes. In October 2011, we prepared a price forecast for NorthWestern Energy for wholesale power prices for South Dakota. The forecast provided the prices NorthWestern Energy would expect in the wholesale spot market for any purchases or sales of electricity during the forecast period. The forecast Heavy Load Hour (HLH or "On-Peak") price was $32.32/MWh for calendar year 2012 and rose to $61.58/MWh in 2031. The forecast Light Load Hour (LLH or "Off-Peak") price was $20.02/MWh in 2012 and rose to $37.60/MWh in 2031. The forecast is included as Exhibit SEL-02.

Q. Briefly describe the process you use to forecast electricity prices.

A. The process we employ with customers is to use forward electricity markets to the extent possible into the future. By "forward electricity markets," we mean markets where electricity is transacted for delivery at a specified later date. This gives the clearest indication of what the combined market valuation is for electricity at that later time period. Beyond that date, we supplement the forecast by using forward natural gas markets, which are similar to the forward electricity markets; but natural gas trades further into the future than electricity so the curve can be built out further in time. Beyond that, we employ a fixed yearly escalator to project those forward prices further out into the future. In this case the forcast was developed in this manner for the following time periods:

- Forward Electricity Prices: November 2011 – March 2013
- Forward Natural Gas Prices: April 2013 – September 2015
- Long-Term Escalation: October 2015 – December 2031

Q. Is this the process you used to forecast South Dakota prices for NorthWestern Energy?

A. Yes. In this case, though, we had to account for the fact that there are no points on the power grid in South Dakota where electricity market prices are easily available or transparent.

Q. What did you do to obtain forward electricity prices?

A. We considered which points on the grid are nearest to South Dakota electrically and provide good market price transparency. We concluded that the Minnesota Hub, which is operated by the Midwest ISO (MISO), was reasonably close, and we could obtain price history for that point from the MISO website. Unfortunately, the Minnesota Hub, while having good transparency for historical market prices, does not have similar transparency for forward prices; so we had to look a bit further geographically. In this case, we used Cinergy, which is also operated by MISO and is a trading point in Indiana. Both the historical and forward prices are readily available for the Cinergy delivery point. The price histories for both Cinergy and the Minnesota Hub were analyzed for the period October 2010 through September 2011 to determine the relationship between those two points. The Minnesota Hub consistently prices lower than Cinergy. The monthly historical comparison of the two points is included as Exhibit SEL-03. The forward prices for Cinergy were obtained from Argus Media, a third-party market price provider. A copy of their October 16, 2011 ARGUS US ELECTRICITY publication is included as Exhibit SEL-04. These forward prices were then adjusted using the historical relationship to arrive at a forward price for the Minnesota Hub through March 2013.

Q. Where did you obtain forward natural gas prices?

A. Forward natural gas prices were obtained for AECO[1], a trading point on the gas pipeline network in Alberta, Canada. The AECO prices are readily available on the Internet. As with the forward electricity prices, the forward natural gas prices are for contracts being put in place now for later delivery of natural gas. As such, they reflect the market's current thinking on the supply and demand dynamics for that period of time. The AECO natural gas prices from October 17, 2011, are included as Exhibit SEL-05.

Q. How were the natural gas prices used?

A. For the period when both electricity and natural gas prices were available, which was November 2011 through March 2013, the relationship between the two was established by computing a monthly market Imputed Heat-Rate (IHR), which is the electricity price divided by the natural gas price. The monthly IHR was then used to compute a forecast of the electricity prices for the longer period for which we had natural gas prices, through September 2015. This is a reasonable approach because natural gas units are typically the most expensive units running in a region and these units operating at the top of the supply curve set the electricity wholesale prices based on a combination of their operating efficiency, the natural gas prices, and incremental costs. Therefore, it is reasonable to use this relationship between the two energy markets to extend the electricity natural gas prices. By applying the natural gas market in this manner, the electricity market forecast was extended through September 2015.

Q. How was the forecast beyond September 2015 generated?

A. An annual escalator of 2.7% was applied to the final year's prices to extend the forecast through 2031. The 2.7% was computed from national GDP values for the period 2006–2008. More current GDP values could have been incorporated, but inclusion of the economic numbers from

[1] AECO stands for Alberta Energy Company.

the last few years would have decreased the annual escalator to at least 2.1% and resulted in a lowering of our forecast. The GDP and annual inflation values are included in Exhibit SEL-06.

Q. Is this a reasonable method to forecast prices for South Dakota?

A. Yes. Using the forward markets for electricity and natural gas grounds the forecast using actual transactions for future delivery of the two commodities. It therefore incorporates the collective wisdom of all the market participants at the time a forecast is prepared. Lands Energy has used this method of price forecasting to advise numerous clients on the wholesale energy markets and specifically to support resource management decisions. This method provides a sound basis for making resource planning decisions.

Q. Don't energy prices change dramatically at times?

A. Yes, wholesale energy prices—and particularly electricity prices—are notoriously volatile. It is reasonable to expect that prices will change, perhaps even drastically, during the forecast period. It is also reasonable, however, to expect that prices would change in a downward direction just as much as they might change in an upward direction. Any consideration of price changes should consider the potential for both upward and downward changes. Most recently, the development of extraction methods to access shale gas combined with the overall slowing of the U.S. economy produced a significant downward shift in prices between 2008 and today. The understanding of the impact of the shale gas extraction methods will have on natural gas and electricity markets has been unfolding over the last couple years. Exhibit SEL-07 is the Time magazine article from April 2011 that had the advances in shale gas as the cover story.

Observations of the Black & Veatch Forecast

Q. Have you reviewed the material provided by J. Richard Lauckhart in his direct testimony submitted on behalf of Oak Tree Energy?

A. Yes, I have.

Q. Specifically, did you review the price forecast provided by Mr. Lauckhart?

A. Yes. I reviewed the Black & Veatch electricity price forecast for WAPA for 2011 through 2035. This forecast is found in the Excel workbook titled "EL11-006_Oak Tree_EX 3_Summary and BrownValue_AvoidedCost.xls" on the tab labeled "WAPA Monthly." This would be an alternate forecast of wholesale electricity prices to the one we provided to NorthWestern Energy.

Q. Do you believe this forecast should be used to set avoided costs and ultimately purchase power prices for NorthWestern?

A. No. The Black & Veatch forecast provided in Mr. Lauckhart's testimony is clearly too high.

Q. What is the basis of your conclusion?

A. I have taken a number of factors into consideration. First, the forecast is from Fall 2010, so it is over a year old. The Black & Veatch forecast for just the first year, 2011, was also significantly higher than actual market data. The forecast then continues to exceed current forward market prices through 2015. And finally, the price increases included for carbon emissions starting in 2016 appear to be quite high.

Q. Please explain the differences observed for 2011?

A. Since the Black & Veatch forecast was prepared in 2010, we have one year of data for which we can compare the forecast to actual spot market values. The Black & Veatch On-Peak and Off-Peak price forecasts average 14% and 30% higher respectively than the actual monthly On-Peak and Off-Peak prices reported by MISO for the Minnesota Hub for the calendar year. In fact, only one month, July 2011, had actual prices higher than the Black & Veatch forecast. A detailed table and chart are included as Exhibit SEL-08.

Q. Please also explain the differences observed through 2015?

A. For the first four years (2012–2015), their forecast is 23% to 40% higher than the forward market values we computed using the MISO forward markets. A detailed comparison is available in Exhibit SEL-09. In addition, as referenced in the Prefiled Direct and Rebuttal Testimony of Bleau LaFave and documented in Exhibit BJL-4, the pricing for February 2011 would have been even lower than the prices we produced in October 2011.

Q. And what differences were observed after 2015?

A. In 2016, their forecast takes a dramatic jump upwards, particularly during Off-Peak hours. The increase causes a much more pronounced price increase between 2016 and 2031 than we had in our forecast.

Q. What is the basis for their large escalation in 2016?

A. In reviewing some of the other documents provided by Mr. Lauckhart, specifically the PowerPoint presentation titled "Energy Market Perspective: Midwest Baseline," it is apparent that the Black & Veatch forecast incorporated significant price increases in 2016 based on an assumption that carbon penalties would commence and add operating costs to generating units emitting greenhouse gases. You can see how they explain the difference between their no carbon-cost projections and with carbon-cost projections in slide 27 of their presentation material. This slide is included as SEL-10 for easy reference.

Q. Does your forecast include carbon emission costs?

A. The forecast referenced in my testimony so far has not included any carbon emission cost numbers. We did, however, provide NorthWestern with a forecast including a projected carbon emission cost; but the impact on our electricity price forecast is much smaller, indicating that our carbon emission cost projection must also be lower than Black & Veatch's. Our carbon projection was $5/ton starting in 2015 and shifting to $10/ton starting in 2020 and rising to $15/ton in 2025. Our forecast with the carbon cost adders and how it compares to the Black & Veatch forecast is included in Exhibit SEL-09. During this part of the forecast window, the Black & Veatch forecast is 49% to 109% higher than ours.

Q. Do you believe your carbon cost adder to be reasonable?

A. The commencement of any sort of emission cost adder has been speculative and difficult to forecast for some time now due to the political nature of the proposed regulations. Four years ago, we and others were projecting a much sooner start to these regulations and costs as the Waxman-Markey bill[2] had passed the house in June 2009 and the Kerry-Boxer bill[3] was being discussed in Senate committee in November of that year. Since then, no climate change legislation has been pursued with any fervor at the national level, indicating a definite slowing in the political process with regard to implementing these new regulations. At this time, a cautious approach seems reasonable, particularly when considering long-term purchases, which is what our projection reflects.

Q. Have you reviewed the prices at which Oak Tree Energy proposes to sell their output?

A. Yes, the price is $54.40/MWh in 2012 escalating at 2.5% annually thereafter, which is equivalent to $65.10/MWh on a levelized basis.

Q. How does this compare to their price forecast?

A. It is $5.30/MWh higher than their market price forecast on a levelized basis over 20 years and it is particularly higher than their forecast in the initial four years prior to the onset of their forecasted carbon emission prices. During this period, their offer price is $18.20/MWh higher than the Black & Veatch forecast price. Obviously, comparisons to our price forecast would produce even greater differences.

---

[2] H.R. 2454: The American Clean Energy and Security Act of 2009.

[3] S. 1733: The Clean Energy Jobs and American Power Act.

South Dakota Resource Solicitations

Q. Has Lands Energy conducted resource solicitations on behalf of NorthWestern Energy?

A. Yes. We have facilitated two solicitations for South Dakota resources. We facilitated the 2007/2008 solicitation for wind resources that resulted in the Power Purchase Agreement (PPA) for output from the Titan I Wind Project and also facilitated a renewable resource Request For Information (RFI) in 2009/2010 that was concluded without the selection of a power supply resource.

Q. How many responses were received in response to the renewable resource RFI?

A. Lands Energy received 26 proposals from 19 distinct entities. Some respondents submitted multiple proposals, which accounts for the difference in number of proposals and the number of entities.

Q. Did Oak Tree Energy submit a proposal in response to the RFI?

A. No. We did not receive a proposal from Oak Tree Energy.

Q. Did Lands Energy receive proposals for wind PPAs as part of the RFI?

A. Yes. Most of the proposals were for wind projects.

Q. Were prices submitted that were competitive with the prices Oak Tree has indicated they would like to sell to NorthWestern Energy?

A. Yes. Included in the responses were seven proposals with levelized PPA pricing below $60/MWh. The lowest levelized price offer was for $54.90/MWh.

Q. Did you consider these offers to be viable?

A. Yes. Among these seven proposals were wind developers with proven track records.

Q. Did NorthWestern Energy pursue any of these proposals?

A. No. Northwestern determined after redoing its load and resource outlook that additional wind was not needed in its portfolio, and NorthWestern terminated the RFI without pursuing any of the proposals.

Q. Does that conclude your testimony?

A. Yes, it does.

Affidavit of Steven E. Lewis

STATE OF WASHINGTON)
: ss
COUNTY OF KING)

Steven E. Lewis, being first duly sworn upon oath, states and alleges as follows:

1) I am a principal and employee of Lands Energy Consulting.

2) I have read this document and am familiar with its contents, and the same are true to the best of my knowledge and belief.

Further affiant sayeth naught.

Dated at Seattle, Washington, this 12 day of January, 2012.

Steven E. Lewis

SIGNED AND SWORN to before me this 12 day of January, 2012, by Steven E. Lewis.

LEE M. TILLMAN
NOTARY PUBLIC
STATE OF WASHINGTON
COMMISSION EXPIRES
APRIL 9, 2015

Notary Public, Washington
My appointment expires: 4/9/2015

STEVEN E. LEWIS

SLewis@landsenergy.com ♦ 206-726-3695

SUMMARY OF QUALIFICATIONS

19 years of professional experience in the energy industry. Expertise in all areas of power management and utility operations, including energy trading, risk management, power resource planning and acquisition, power plant development and acquisition, transmission contracting and issues, hydro operations, control area operations, state and federal electricity rates and regulation.

PROFESSIONAL EXPERIENCE

LANDS ENERGY CONSULTING

Seattle, Washington 2001-Present

Principal Consultant

Part owner and president of Lands Energy Consulting. A partial list of clients includes: NorthWestern Energy, The BPA Slice Customers (18 northwest public utilities), Snohomish PUD, Seattle City Light, the Confederated Tribes of the Colvilles, PNGC, The City of Victorville, California, Astrum Utilities, the lawfirm of Forsberg & Umlauf PS. Key projects Mr. Lewis has lead include:

- Facilitate numerous structured resource solicitations including recent RFPs for NorthWestern Energy. These resulted in completed purchase contracts for the 135 MW Judith Gap Wind Project in Montana and the 25 MW Titan I Wind Project in South Dakota. Judith Gap was selected from a robust response to an open solicitation and was approved by the Montana PSC following detailed filings and testimony offered by Mr. Lewis.
- Facilitate numerous structured resource solicitations including recent RFPs for NorthWestern Energy. These resulted in completed purchase contracts for the 135 MW Judith Gap Wind Project in Montana and the 25 MW Titan I Wind Project in South Dakota. Judith Gap was selected from a robust response to an open solicitation and was approved by the Montana PSC following detailed filings and testimony offered by Mr. Lewis.
- Guide the development of risk management strategies and trading/scheduling practices for northwest hydroelectric based utilities, including Snohomish PUD and Seattle City Light. Snohomish PUD owns and operates the Jackson project, which is primarily a water supply project with power generation as a secondary output. They also purchase the largest amount of Slice contract power from BPA, which provides Snohomish with the flexibility and decision-making responsibility associated with a 5% share of BPA's generating capability. Seattle City Light is 90% hydroelectric based on 2006 actual energy production.
- Mr. Lewis has also supported BPA's Slice contract customers in the development of scheduling practices and optimization strategies for their contracted scheduling flexibility. The Slice contract customers are 11 Northwest public utilities who purchase over 22% of BPA's generating capability on a percentage of system capability basis, which includes rights to both short-term (within-day, within-month) as well as long-term (month-to-month) scheduling flexibility.
- Facilitate multi-million dollar one- and two-year sales of hydroelectric output of the Wells dam in central Washington for one of the project participants. The sales have gone to numerous purchasers and have included minute-to-minute dispatch

flexibility. Sales have been facilitated through competitive processes and have required close coordination with the project operator, and the potential purchasers.

- Lands Energy has also supported clients in the development of operating, marketing and scheduling strategies for renewable energy, including non-dispatchable resources such as wind project output.

SEATTLE CITY LIGHT 1999-2001
Seattle, Washington
Power Marketer

Directed all within-month marketing in conformance with the overall utility resource hedging strategy. Ensured a short-term operation of Seattle's generating assets optimizing their economic value within operating, regulatory, and reliability constraints. Included in Seattle's portfolio is over 2,000 mw of hydro-electric generating assets, multiple long-term contracts for power purchases/sales, 1,312 mw of long term firm transmission rights on the BPA main grid, and 160 mw of capacity ownership on the NW/SW AC Intertie. The hydroelectric assets include a number of large storage and run-of-river projects (Boundary, Ross, Diablo, and Gorge) as well as two smaller storage projects with first purpose water supply uses (Cedar River and Tolt River Projects).

Lead the negotiation for purchase of a 10-year power purchase contract from the Klamath Falls cogeneration project, including the execution of the first gas derivative hedge by Seattle City Light in order to mitigate the gas price exposure contained in the electricity purchase contract.

PUGET SOUND ENERGY 1990 - 1999
Seattle, Washington
Senior Electricity Trader (Title upon departure)

Puget's designated operations liaison with Duke Energy during the Puget/Duke operating and trading alliance. Coordinated trading and marketing activity between Duke's trading floor in Salt Lake City and Puget's trading floor in Bellevue. Worked with Duke's origination staff in the marketing of non-standard product offerings within the Northwest. Reviewed the modeling of Puget's resource assets within trading books at Duke, and evaluated the performance of the hedging activities within those books.

Prior to the alliance with Duke, developed Puget's forward electricity trading operation. Initiated Puget's trading through the brokered over-the-counter electricity markets for western points of receipt. Helped establish and develop fundamental analysis techniques to support trading efforts. Trading goals for Puget included both hedge trading around their existing asset base and speculative trading within a well-defined value-at-risk mechanism.

Developed and maintained operational models for the optimization of Puget's hydroelectric generating projects. This included both spreadsheet tools and coding of computer programs to meet refill, flood control, and reliability uses of the projects while maximizing the financial value. Projects included the Upper and Lower Baker projects, the White River project, Snoqualmie Falls, as well as over 1,000 MW of participant rights in the five non-federal Mid-Columbia projects (Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids).

Maintained and ran a stand-alone copy of the Northwest Power Pool's hydroelectric regulation model. The primary purpose of this model was to support coordination of the northwest hydroelectric system as called for under the Pacific Northwest Coordination Agreement. Puget's independent model runs were made to support short-term operational strategies as well as to provide input to the long-term production costing models uses for ratemaking purposes.

BONNEVILLE POWER ADMINISTRATION SUMMER 1988
Portland, Oregon
Engineering Intern

Designed and programmed various aspects of the Accelerated California Market Estimator ("ACME") computer model, which simulates an economic dispatch of the Southwest electric generating resources in order to forecast the Southwest electric market through identification of the marginal resources. ACME was a subroutine of the SAM model, which was run for various purposes, including value justification of the construction of the Third AC Intertie to California.

EDUCATION

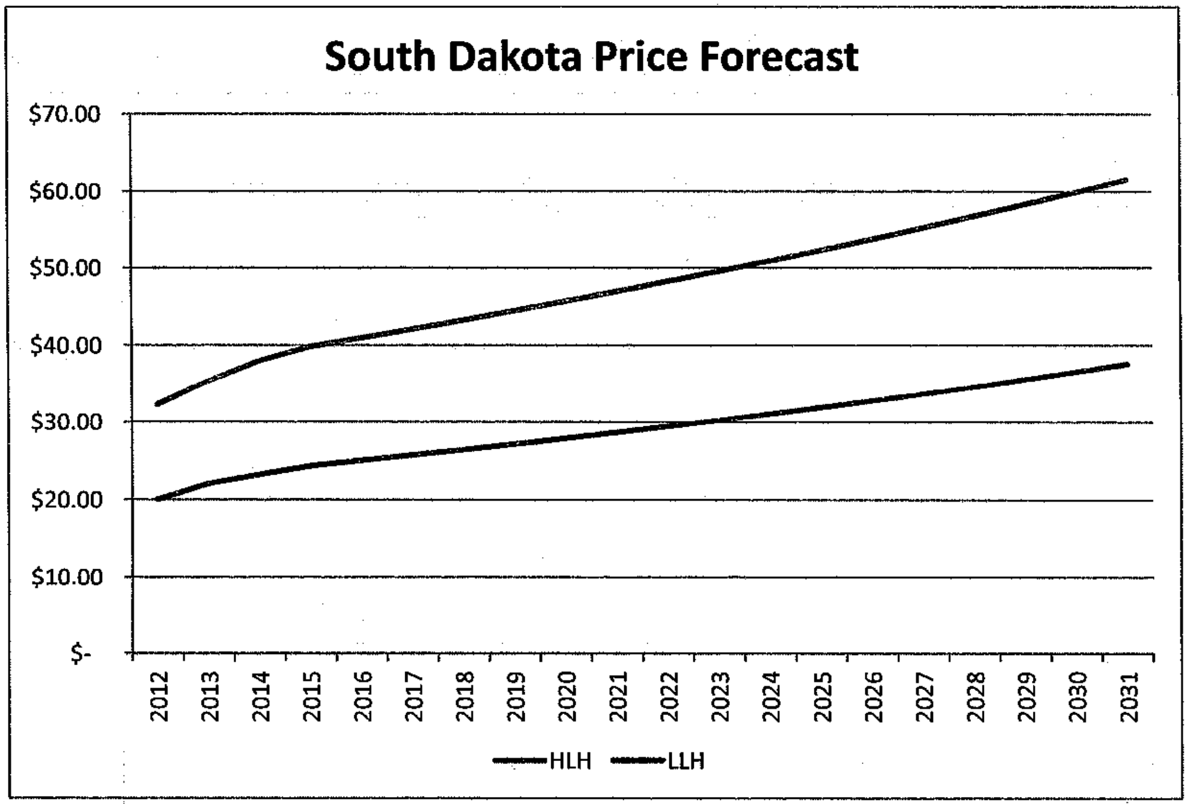
GONZAGA UNIVERSITY, Spokane, Washington
Bachelor of Science, Physics with a Mathematics Minor
Magna Cum Laude

Exhibit SEL-02

Lands Energy Consulting
South Dakota Price Forecast
NorthWestern Energy

Oct-11

	HLH	LLH
2012	$ 32.32	$ 20.03
2013	$ 35.41	$ 22.04
2014	$ 38.01	$ 23.20
2015	$ 39.85	$ 24.33
2016	$ 40.95	$ 25.00
2017	$ 42.08	$ 25.69
2018	$ 43.24	$ 26.40
2019	$ 44.43	$ 27.13
2020	$ 45.66	$ 27.88
2021	$ 46.92	$ 28.64
2022	$ 48.21	$ 29.43
2023	$ 49.54	$ 30.25
2024	$ 50.90	$ 31.08
2025	$ 52.31	$ 31.94
2026	$ 53.75	$ 32.82
2027	$ 55.23	$ 33.72
2028	$ 56.75	$ 34.65
2029	$ 58.32	$ 35.61
2030	$ 59.93	$ 36.59
2031	$ 61.58	$ 37.60
Levelized	$ 44.12	$ 27.00



Historical Minnesota and Cinergy Hub Prices

	Minnesota		Cinergy		Difference	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Oct-10	$ 31.94	$ 18.02	$ 32.95	$ 24.14	$ (1.01)	$ (6.12)
Nov-10	$ 32.39	$ 17.31	$ 35.77	$ 25.43	$ (3.38)	$ (8.12)
Dec-10	$ 35.85	$ 22.95	$ 44.72	$ 30.82	$ (8.87)	$ (7.87)
Jan-11	$ 36.95	$ 25.84	$ 45.31	$ 33.53	$ (8.36)	$ (7.69)
Feb-11	$ 31.61	$ 18.74	$ 39.30	$ 29.48	$ (7.69)	$ (10.74)
Mar-11	$ 31.83	$ 19.76	$ 38.49	$ 30.64	$ (6.66)	$ (10.88)
Apr-11	$ 35.23	$ 20.54	$ 41.18	$ 30.31	$ (5.95)	$ (9.77)
May-11	$ 30.85	$ 15.55	$ 42.94	$ 28.29	$ (12.10)	$ (12.74)
Jun-11	$ 29.12	$ 15.63	$ 46.42	$ 25.48	$ (17.30)	$ (9.85)
Jul-11	$ 48.61	$ 28.14	$ 59.74	$ 35.67	$ (11.13)	$ (7.53)
Aug-11	$ 40.02	$ 22.13	$ 45.02	$ 28.67	$ (5.00)	$ (6.54)
Sep-11	$ 29.99	$ 17.07	$ 35.17	$ 24.72	$ (5.18)	$ (7.64)
Oct-11	$ 32.51	$ 18.88	$ 35.40	$ 27.46	$ (2.90)	$ (8.58)
Nov-11	$ 31.68	$ 16.70	$ 33.32	$ 24.79	$ (1.64)	$ (8.10)
Dec-11	$ 32.01	$ 20.31	$ 33.21	$ 26.18	$ (1.20)	$ (5.87)
Avg	$ 34.53	$ 20.14	$ 42.25	$ 28.93	$ (7.72)	$ (8.79)

Exhibit SEL-04

Argus US Electricity

Incorporating the Energy Market Report

argus
www.argusmedia.com

Power Market Prices and Analysis | Issue 11-200 | 17 October 2011

Day-ahead peak prices

Trade date 17-Oct-11

	$/MWh	Price*	Change	Low	High	MW	Trades
East	NY G	49.25	2.25	48.75	49.75	-	-
	PJM W	42.00	-0.25	41.50	42.50	-	-
	NE Pool	46.00	-5.00	45.50	46.50	-	-
ERCOT	Houston	36.25	-6.00	35.75	36.75	-	-
	North	30.67	-7.00	30.50	31.00	225	4
	South	35.75	-2.75	35.25	36.25	-	-
	West	18.00	-11.00	17.50	18.50	-	-
Midwest	Cinergy	36.75	1.75	36.25	37.25	-	-
	N. Ill.	35.00	5.00	34.50	35.50	-	-
	PJM AD	39.50	2.50	39.00	40.00	-	-
Southeast	Entergy	33.25	-1.00	32.75	33.75	-	-
	Southern	35.00	0.00	34.50	35.50	-	-
West	COB	29.46	2.15	29.00	30.00	325	10
	Four Corners	39.75	5.25	39.25	40.25	-	-
	Mead	38.75	3.75	38.25	39.25	-	-
	Mid-C	27.42	1.50	27.00	28.75	2,725	101
	Mona	35.00	6.00	34.50	35.50	-	-
	NP 15	38.00	5.00	37.50	38.50	-	-
	Palo Verde	39.18	3.50	37.50	41.00	600	24
	SP 15	39.00	3.50	38.50	39.50	-	-

Day-ahead off-peak prices

Trade date 17-Oct-11

	$/MWh	Price*	Change	Low	High	Volume	Trades
East	NY G	28.25	-4.75	27.75	28.75	-	-
	PJM W	31.50	0.50	31.00	32.00	-	-
	NE Pool	33.50	-0.50	33.00	34.00	-	-
ERCOT	Houston	20.75	-1.50	20.25	21.25	-	-
	North	21.45	0.01	21.25	21.55	200	3
	South	21.00	-1.00	20.50	21.50	-	-
	West	11.75	-3.25	11.25	12.25	-	-
Midwest	Cinergy	28.00	3.25	27.50	28.50	-	-
	N. Ill.	21.25	10.50	20.75	21.75	-	-
	PJM AD	31.00	3.00	30.50	31.50	-	-
Southeast	Entergy	25.75	0.75	25.25	26.25	-	-
	Southern	26.25	0.25	25.75	26.75	-	-
West	COB	28.31	2.95	27.70	29.00	175	6
	Four Corners	22.75	-1.50	22.25	23.25	-	-
	Mead	23.25	-2.75	22.75	23.75	-	-
	Mid-C	26.41	2.02	25.50	28.50	1,650	66
	Mona	19.25	-4.75	18.75	19.75	-	-
	NP 15	24.25	-3.00	23.75	24.75	-	-
	Palo Verde	24.00	-2.00	23.50	24.50	-	-
	SP 15	24.00	-3.00	23.50	24.50	-	-

* When MW and trade number are blank, the low/high/price represent bid/ask/assessment. When MW and trade number have values, low/high/price represent low trade, high trade and volume-weighted average

News

East

New York dailies decreased today on slightly lighter loads forecast for tomorrow. **New York Zone G's peak day-ahead declined 1.8pc to $49.23/MWh.** New York City's peak daily went down 2pc to $50.80.

Continued on page 2

Midwest

Weekend prices in the Southwest Power Pool (SPP) were more volatile than during the 8-9 October weekend, creating locational price differentials within the footprint. Peak and off-peak averages fell sharply from the previous weekend.

Continued on page 5

West

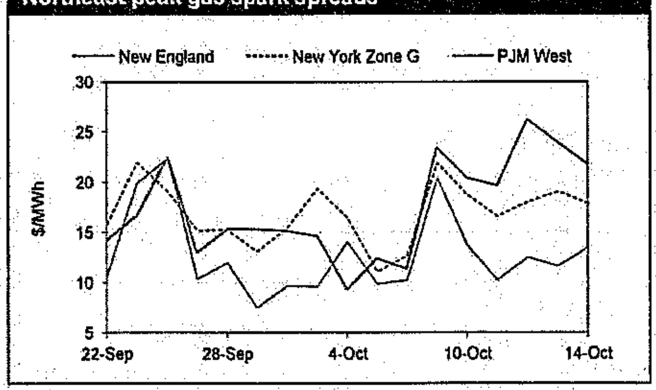
Peak prices popped for tomorrow on divergent weather patterns. SP 15 approached $40 and was up 13pc. NP 15 lagged SP 15 by $1 but gained 15pc. Mid-Columbia gained 6pc on the day to $27.42/MWh, only 4pc more than off-peak.

Continued on page 9

ERCOT

ERCOT North next-day peak dropped 19pc to $30.67/MWh today in the *Argus* index on a drastically reduced demand forecast for tomorrow, off-peak was unchanged at $21.44.

Northeast peak gas spark spreads



Inside

East Markets

Continued from page 1

• Average daily peak load in New England on 18-23 October is 15,673MW, 1pc lower than the projected peak for 11-16 October, according to the grid operator's forecast. **Outages are forecast to total 63,154MW, 9pc lower than forecasted outages for the prior period.**

• **Heating demand in eastern states this week is forecast to be well below normal for this time of year.** New England is projected to have 34pc fewer heating degree days (HDDs) than normal for the week ending 22 October, according to the National Weather Service's Climate Prediction Center. The mid-Atlantic is forecast to have 27pc fewer HDDs than usual. New York is projected to have 26pc fewer HDDs.

• Operators returned the 498MW Ginna reactor in New York State to full output today after the nuclear plant automatically tripped off line on 12 October. **The station was running at 49pc of power yesterday,** *Argus* data show.

• Exelon continued to bump up capacity at its 1,112MW Peach Bottom Unit 3 reactor in Pennsylvania following the unit's maintenance and refueling outage. **The unit was operating at 68pc of capacity today, up 37 percentage points from yesterday.**

• **Southeastern nuclear capacity jumped 10.72 percentage points over the past week to 90.53pc** following the restart of several reactors from maintenance outages. Northeastern output increased 2.62 percentage points over the same period to 80.35pc

• **PJM West's peak load will increase 9pc 17-20 October, likely putting upward pressure on dailies this week.**

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	16	18
Peak	NYISO G	12,116	20.80	16.73	8.60	0.47	-11.73	-23.92
	PJM West	10,714	14.56	10.64	2.80	-5.04	-16.80	-28.56
	NE Pool	11,690	18.46	14.52	6.65	-1.22	-13.03	-24.83
	Southern	9,162	8.26	4.44	-3.20	-10.84	-22.30	-33.76
Off-peak	NYISO G	6,950	-0.21	-4.27	-12.40	-20.53	-32.73	-44.92
	PJM West	8,036	4.06	0.14	-7.70	-15.54	-27.30	-39.06
	NE Pool	8,513	5.95	2.02	-5.85	-13.72	-25.53	-37.33
	Southern	6,872	-0.49	-4.31	-11.95	-19.59	-31.05	-42.51

Forward markets $/MWh

	PJM West				NEPOOL			New York A			New York G			New York J		
	Peak			Off-Peak	Peak		Off-Peak	Peak		Off-Peak	Peak		Off-Peak	Peak		Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price
Nov-11	44.00	16.42	3.70	34.70	48.35	20.56	38.50	38.95	11.51	32.90	50.50	20.05	37.95	55.05	25.93	39.55
Dec-11	52.25	15.43	12.05	41.55	64.85	24.74	52.25	41.85	12.10	36.75	65.40	25.08	50.55	72.10	29.12	53.85
Jan-12	56.25	13.97	16.55	46.15	75.95	19.04	58.25	46.80	14.53	38.55	75.50	26.85	56.50	85.15	30.41	58.60
Feb-12	53.25	13.56	14.35	45.70	67.75	13.57	56.35	45.00	13.29	38.65	67.40	20.64	56.60	76.00	24.62	58.70
Mar-12	48.30	17.15	9.00	38.15	50.45	10.41	39.80	40.45	9.58	34.55	54.25	17.43	40.25	61.00	24.04	42.25
Apr-12	47.40	18.07	8.60	35.30	45.45	12.27	35.90	39.00	9.11	33.65	48.85	17.49	39.75	54.95	23.17	41.20
Win-12	54.75	13.80	15.45	45.95	71.85	16.27	57.35	45.90	13.91	38.60	71.45	23.78	56.55	80.60	27.54	58.65
Spr-12	47.85	17.61	8.45	36.75	48.00	11.39	37.90	39.75	9.37	34.10	51.60	17.51	40.00	58.05	23.68	41.75
Sum-12	59.90	29.66	20.20	38.20	55.30	23.80	38.65	45.15	12.25	36.20	65.10	33.46	43.70	73.80	41.88	48.30
Q4-12	47.50	13.48	8.10	37.90	53.70	18.21	42.45	40.55	7.44	34.90	54.85	17.89	42.45	60.25	23.15	43.90
Win-13	56.85	14.43	16.75	47.80	73.40	15.72	58.90	48.05	11.23	40.35	73.85	23.73	56.70	82.70	28.45	59.75
Spr-13	50.15	16.06	9.75	39.05	50.80	9.43	39.75	41.40	6.96	35.65	55.30	16.59	41.70	61.70	22.50	44.00
Sum-13	62.75	29.85	21.05	41.70	58.40	23.61	42.20	47.90	11.57	37.30	70.95	35.88	46.50	80.75	45.54	52.45
Q4-13	50.50	14.24	10.10	39.50	55.85	17.56	43.10	42.75	6.42	35.60	58.40	18.50	42.50	63.75	23.78	45.30
Cal-12	51.45	18.55	11.85	38.35	54.30	17.20	41.75	41.80	9.88	35.20	58.30	22.39	43.85	65.25	28.29	45.95
Cal-13	54.05	18.56	13.45	40.30	56.65	16.33	43.50	44.00	8.30	36.30	62.15	22.88	44.85	69.25	29.14	48.05
Cal-14	57.05	20.37	15.35	43.40	58.50	16.78	44.90	46.60	8.66	38.50	64.45	23.71	47.05	71.30	29.79	49.70
Cal-15	59.55	19.65	16.75	45.80	60.25	14.89	45.75	48.80	8.97	39.95	67.25	23.29	49.10	74.75	28.83	51.80

East Markets

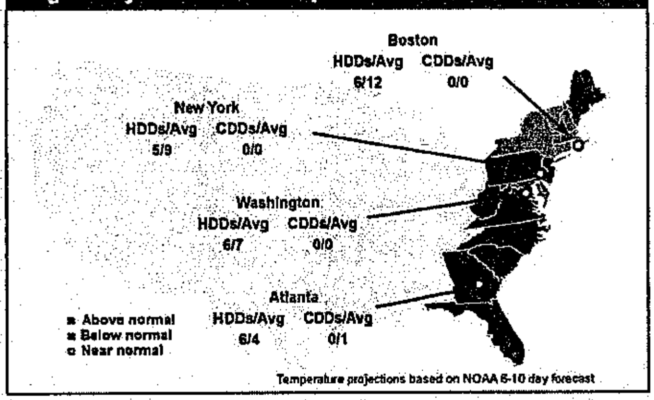
Spot natural gas in $/mmBtu

Location	Average	Low	High
Col Gas Appalachia	3.795	3.700	3.850
Dominion South Point	3.800	3.752	3.830
Florida Gas, zone 3	3.695	3.605	3.720
Texas Eastern zone M3	3.920	3.770	3.970
Transco zone 4	3.690	3.630	3.755
Transco zone 6 NY	3.955	3.870	4.060

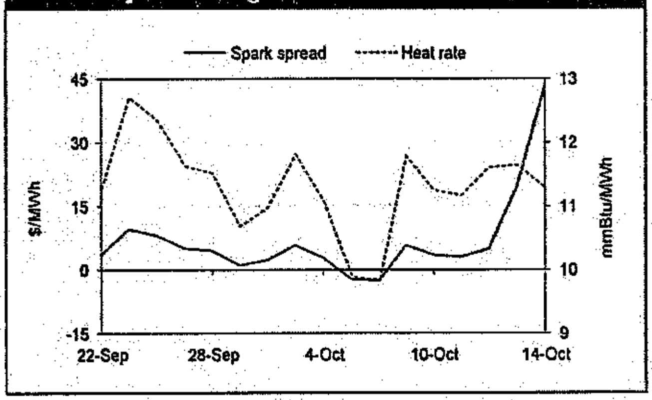
Forward natural gas in $/mmBtu

Location	November	Nov 2011-Dec 2011	Nov 2011-Mar 2012
Columbia Gas App.	3.718	3.906	4.044
Dominion South Pt.	3.773	4.001	4.044
Florida Gas Zone 3	3.748	—	4.062
Texas Eastern M-3	4.028	4.901	5.429
Transco Zone 4	3.693	—	4.027
Transco Zone 6 NY	4.228	5.836	6.759

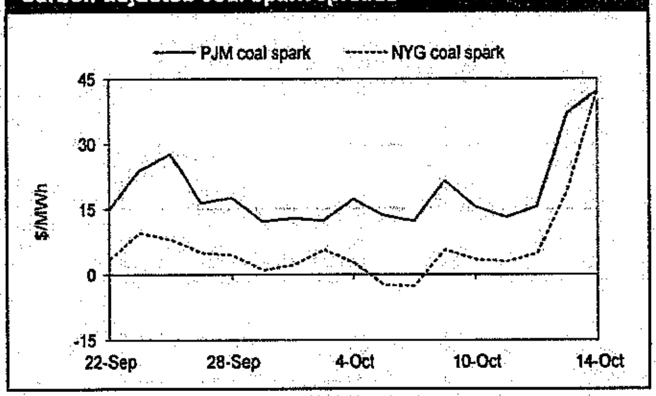
Degree days outlook vs temperature: 23-Oct



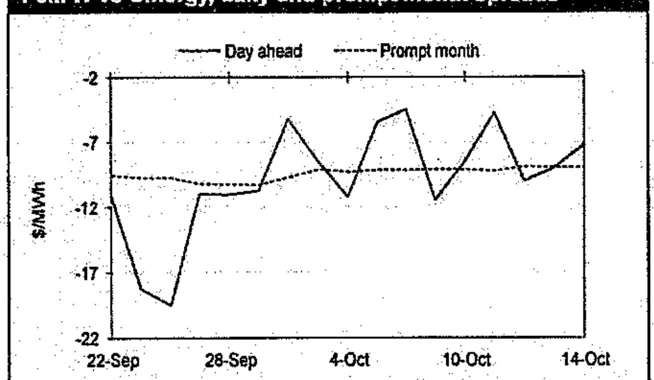
Carbon-adjusted coal generation: NYG



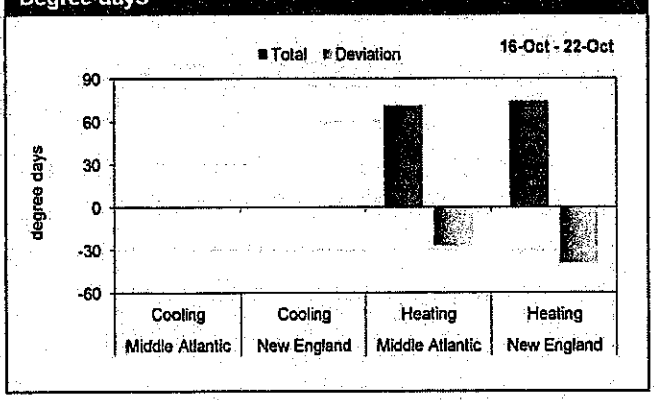
Carbon-adjusted coal spark spreads



PJM W vs Cinergy, daily and prompt month spreads



Degree days



Implied gas spark spreads

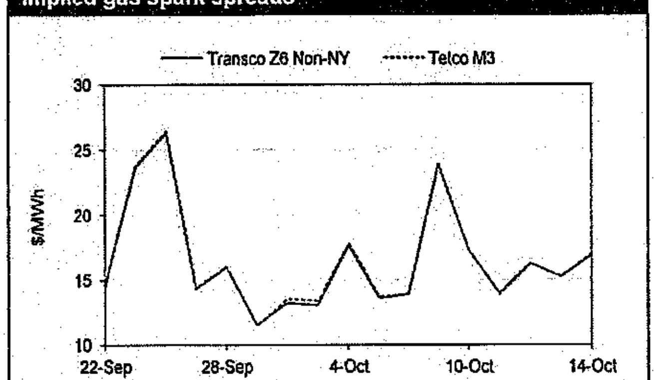
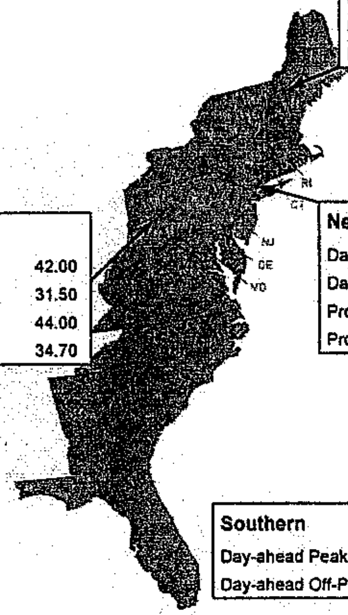


Exhibit SEL-04

East Prices at a Glance $/MWh

Day ahead markets for 17-Oct-11

New England	
Day-ahead Peak	46.00
Day-ahead Off-Peak	33.50
Prompt Peak	48.35
Prompt Off-Peak	38.50



PJM West	
Day-ahead Peak	42.00
Day-ahead Off-Peak	31.50
Prompt Peak	44.00
Prompt Off-Peak	34.70

New York zone G	
Day-ahead Peak	49.25
Day-ahead Off-Peak	28.25
Prompt Peak	50.50
Prompt Off-Peak	37.95

Southern	
Day-ahead Peak	35.00
Day-ahead Off-Peak	26.25

Day-ahead minus hourly spread

14-Oct-11	Peak	Off-Peak
ISO NE		
Internal Hub	2.87	-0.03
Phase I/II	2.01	-0.09
NY ISO		
Zone A	2.57	1.41
Zone G	2.14	1.88
Zone J	5.73	2.40
Cross Sound	-1.03	1.89
PJM		
PJM Western Hub	-0.42	1.46
PJM Eastern Hub	-0.35	3.00
PJM Dominion Hub	1.17	1.16
PJM New Jersey Hub	2.24	10.00

Hourly price averages

	Peak		Off-peak	
	14-Oct-11	13-Oct-11	14-Oct-11	13-Oct-11
ISO NE				
Internal Hub	48.72	43.45	32.56	32.56
Phase I/II	49.51	42.89	32.29	32.30
NY ISO				
Zone A	37.72	37.69	31.00	29.66
Zone G	46.36	43.17	33.37	31.99
Zone J	47.08	43.50	33.34	31.95
Cross Sound	49.93	52.15	32.85	31.53
PJM				
PJM Western Hub	40.92	48.27	30.29	34.12
PJM Eastern Hub	42.81	53.35	28.86	33.08
PJM Dominion Hub	40.21	51.70	31.00	35.00
PJM New Jersey Hub	40.93	57.34	21.91	32.83

Emissions-adjusted day-ahead power prices

	SO_2	RGGI	All credits
Peak			
Nepool	46.28	47.91	48.19
New York G	49.33	51.16	51.23
PJM West	42.08	43.91	43.98
Off-peak			
Nepool	33.78	35.41	35.69
New York G	28.33	30.16	30.23
PJM West	31.58	33.41	33.48
24-hour emissions-adjusted pricing, all credits			
Nepool	42.11	43.74	44.02
New York G	42.33	44.16	44.23
PJM West	38.58	40.41	40.48

Day-ahead peak spreads

	New England	NY G	PJM West	Cinergy	AEP Dayton	Northern Ill	Southern
New England	—	-3.25	4.00	9.25	6.50	11.00	11.00
NY G	3.25	—	7.25	12.50	9.75	14.25	14.25
PJM West	-4.00	-7.25	—	5.25	2.50	7.00	7.00
Cinergy	-9.25	-12.50	-5.25	—	-2.75	1.75	1.75
AEP Dayton	-6.50	-9.75	-2.50	2.75	—	4.50	4.50
Northern Ill	-11.00	-14.25	-7.00	-1.75	-4.50	—	0.00
Southern	-11.00	-14.25	-7.00	-1.75	-4.50	0.00	—

Sources: ISOs, Argus assessments

Midwest Markets

Continued from page 1

- Peak-hour locational imbalance prices at many generation points in SPP had a much wider range this weekend than last. **Peak averages ranged from $11.63 at Nebraska Public Power District's Cooper plant in the north to $40/MWh at the New Mexico interties.** Last weekend's range was $25.75 to $39.62. Peak fell 18pc week-to-week to about $28; off-peak dropped 33pc to $17.

- *Falling temperatures and reduced cooling demand are expected* to reduce peak loads this week in Texas. **ERCOT calls for peak demand of 36,564MW tomorrow, a 27pc decrease from today's expected peak demand.** The National Weather Service is calling for a high of 70°F (21.1°C) tomorrow in Dallas following today's high of 90°F.

- **Cooling degree days (CDDs) in Texas are forecast to drop** 44pc over the seven days ending 20 October to about 36 CDDs according to forecaster MDA Federal. The result will be 2pc fewer CDDs than normal.

- Maximum hourly wind output during the light-load hours tomorrow in ERCOT is expected to be lower than during those same hours today. **But mid-day peak-hour wind generation tomorrow is expected to exceed today's.** Maximum hourly output from 10am to 6pm CT tomorrow is forecast to average 68pc more than it did today.

- Average peak demand in ERCOT for the week ending 23 October will be 38,717MW, according to ERCOT's models today. This is 10pc less than the average for the 10-16 October period because high temperatures will probably come into line with historical norms. **Month-to-date peak demand in ERCOT has averaged 43,192MW, 11pc more than during the same period last year.**

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	Cinergy	9,709	10.26	6.47	-1.10	-8.67	-20.03	-31.38
	N. Ill.	9,174	8.30	4.48	-3.15	-10.78	-22.23	-33.67
	PJM AD	10,408	12.94	9.14	1.55	-6.04	-17.43	-28.81
	Entergy	8,974	7.31	3.61	-3.80	-11.21	-22.33	-33.44
Off-peak	Cinergy	7,398	1.51	-2.28	-9.85	-17.42	-28.78	-40.13
	N. Ill.	5,570	-5.45	-9.27	-16.90	-24.53	-35.98	-47.42
	PJM AD	8,169	4.44	0.64	-6.95	-14.54	-25.93	-37.31
	Entergy	6,950	-0.19	-3.89	-11.30	-18.71	-29.83	-40.94

Forward markets $/MWh

	Cinergy				Northern Illinois				PJM AD				ERCOT North			
	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price
Nov-11	35.45	8.43	5.25	26.40	34.00	6.91	12.40	22.25	38.45	11.99	6.05	31.85	31.35	6.22	7.35	24.25
Dec-11	40.00	11.23	9.80	28.65	39.50	10.80	17.90	26.55	43.50	14.73	11.00	34.05	34.05	7.24	9.95	27.60
Jan-12	43.15	13.33	11.15	32.90	43.95	14.34	20.15	33.50	47.15	17.05	16.75	37.95	37.90	10.39	14.40	31.30
Feb-12	41.75	12.00	10.05	32.45	42.90	13.15	19.30	33.05	46.10	16.49	16.10	37.50	38.00	10.42	13.70	31.40
Mar-12	38.15	8.54	4.85	30.35	37.70	8.16	13.60	26.65	42.20	12.59	10.60	35.05	34.50	6.78	9.50	26.95
Apr-12	37.35	7.88	5.15	27.60	37.40	8.98	13.40	24.05	41.30	11.83	10.70	31.65	34.95	7.51	10.95	26.85
Win-12	42.45	12.63	10.15	32.70	43.45	13.77	19.65	33.30	46.65	16.83	15.95	37.75	37.95	10.37	13.65	31.35
Spr-12	37.75	8.21	5.25	29.00	37.55	8.57	13.55	25.35	41.75	12.21	10.85	33.35	34.70	7.12	10.20	26.90
Sum-12	46.15	15.91	13.35	28.80	48.25	18.92	24.05	29.35	51.75	22.00	20.65	34.85	70.65	42.09	45.95	37.00
Q4-12	37.25	5.40	4.75	28.40	35.90	4.61	11.90	24.75	40.65	9.08	9.85	33.40	36.95	6.99	12.45	28.10
Win-13	43.80	9.29	11.00	35.55	44.45	10.43	19.75	34.45	48.10	13.38	16.60	41.05	43.55	11.21	18.25	35.10
Spr-13	40.40	6.87	7.60	30.85	39.05	6.29	14.25	27.90	44.45	10.78	12.65	35.80	39.20	7.56	13.80	32.05
Sum-13	49.45	15.92	15.45	31.70	51.10	18.48	25.60	30.50	55.50	22.32	22.60	37.00	77.15	45.30	51.25	39.20
Q4-13	39.50	4.57	5.60	29.85	38.55	4.11	13.75	26.10	43.60	8.81	11.80	34.75	40.45	7.27	15.05	31.15
Cal-12	40.05	9.67	7.35	28.80	40.15	10.40	16.05	26.90	44.30	14.20	13.20	33.85	43.95	15.46	19.35	30.25
Cal-13	42.60	8.58	9.00	31.00	42.25	9.00	17.25	28.35	47.20	13.32	15.20	36.00	48.70	16.57	23.20	33.95
Cal-14	46.35	10.30	11.75	34.25	44.70	8.79	18.80	30.80	50.40	14.28	17.40	39.75	52.00	17.77	25.40	36.45
Cal-15	49.25	11.59	13.55	36.95	46.90	10.78	20.00	33.05	53.20	15.33	19.10	42.40	55.10	19.12	27.30	38.05

Midwest Markets

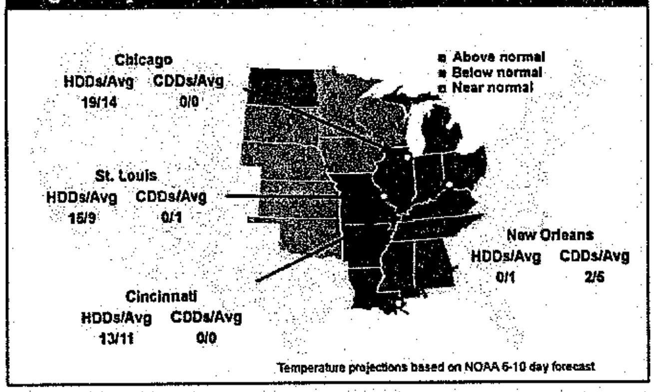
Spot natural gas in $/mmBtu

Location	Average	Low	High
CenterPoint	3.530	3.465	3.600
Chicago Citygates	3.815	3.770	3.890
Mich Con Citygates	3.835	3.792	3.880
NGPL Texok Zone	3.650	3.590	3.690
NNG Ventura	3.780	3.770	3.800
Panhandle OK Mainline	3.525	3.470	3.545

Forward natural gas in $/mmBtu

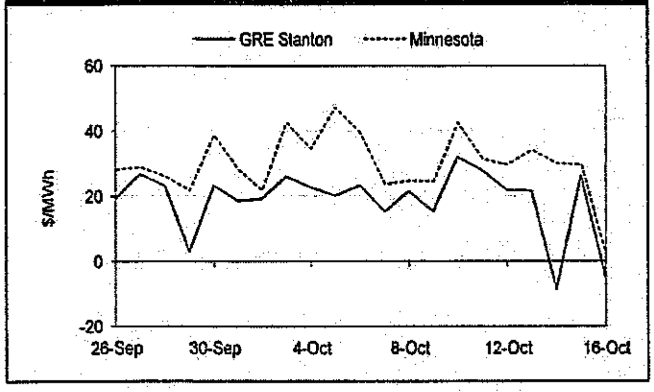
Location	November	Nov 2011-Dec 2011	Nov 2011-Mar 2012
CenterPoint	3.531	—	3.979
Chicago Citygates	3.837	—	4.319
MichCon Citygate	3.908	—	4.332
NGPL Texok Zone	3.603	—	4.023
NNG Ventura	3.763	—	4.267
Panhandle OK Mainline	3.521	—	3.974

Degree days outlook vs temperature: 23-Oct

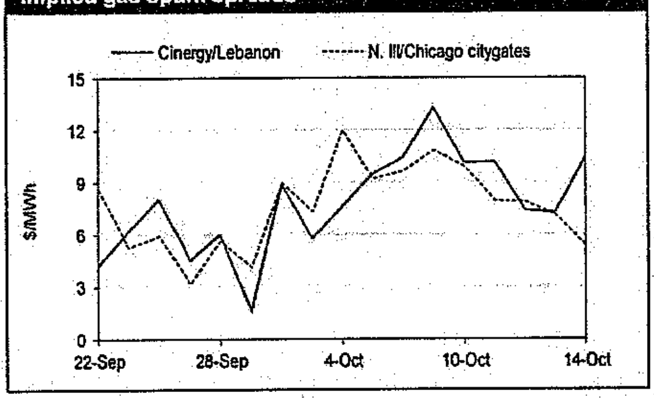


Temperature projections based on NOAA 6-10 day forecast

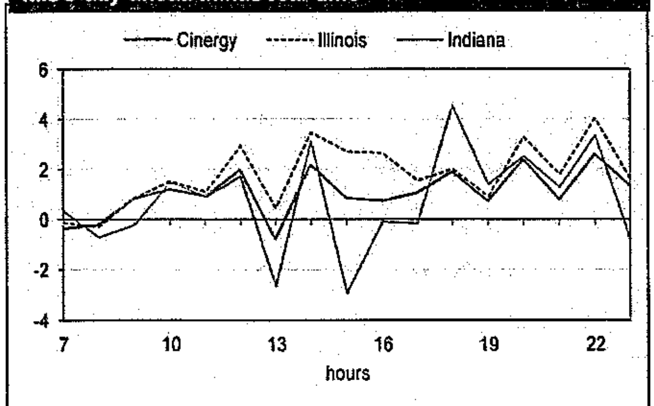
Average peak price



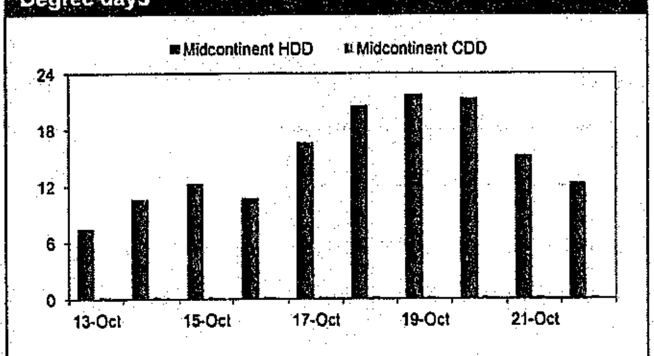
Implied gas spark spreads



MISO day-ahead minus real-time

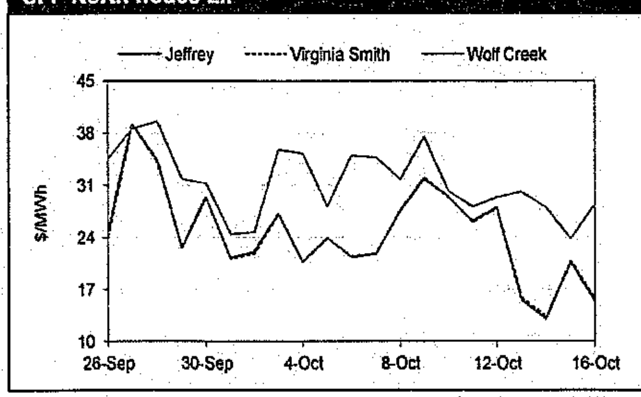


Degree days



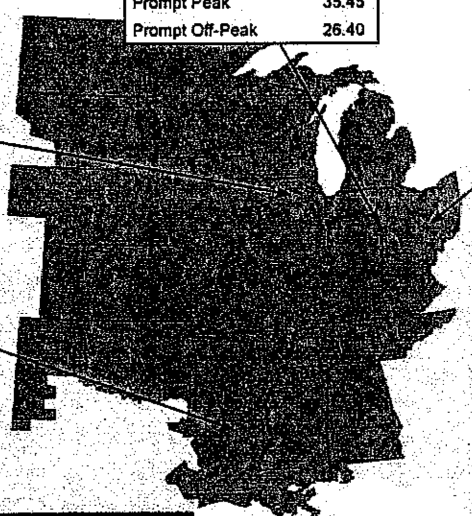
Data Source: AccuWeather

SPP North nodes LIP



Midwest Prices at a Glance $/MWh

Day ahead markets for 17-Oct-11



Day-ahead minus hourly spread

14-Oct-11	Peak	Off-Peak
MISO		
Cinergy	-1.39	-0.24
Indiana	3.18	-0.40
Michigan	-2.68	-1.43
Minnesota	0.03	3.48
Illinois	4.79	3.49
PJM		
Northern Ill	7.20	0.95
A-D	-0.18	1.72

SPP imbalance prices: Flow date — 14-Oct-11

	Peak	Off-peak
SPP North		
Cooper	7.95	13.90
Gentleman	13.26	14.80
Holcomb	17.71	15.45
Jeffrey	12.98	14.75
Emporia	22.57	17.13
Empire	27.49	17.57
Wolf Creek	28.01	17.61
WAPA-Nebraska	13.34	14.82
SPP East		
Sibley	34.00	19.13
Ameren Missouri	25.35	17.22
AECI	26.06	17.31
SPA-Arkansas	25.65	17.26
SPP South		
Sooner	26.32	17.44
Muskogee	26.53	17.46
Oneta	26.71	17.48
Redbud	26.35	17.47
Seminole	26.30	17.48
Kiamichi	26.19	17.47
Wilkes	25.64	17.31
Arsenal Hill	25.57	17.29
Entergy	25.24	17.21
Cleco	25.25	17.21
Ercot-East	25.69	17.32
Ercot-North	27.74	18.23
SPP West		
Tolk	35.35	21.45
WAPA-Colorado	13.85	14.94
Blackwater	24.88	17.33
EDDY	35.07	21.33

Emissions-adjusted day-ahead power prices

	SO_2 Peak	SO_2 Off-peak	24-hour average
Cinergy	36.83	28.08	33.91
Northern Ill	35.07	21.32	30.49
PJM A-D	39.58	31.08	36.74
Entergy	33.27	25.77	30.77

Hourly price averages

	Peak		Off-peak	
	14-Oct-11	13-Oct-11	14-Oct-11	13-Oct-11
MISO				
Cinergy	32.89	38.53	26.99	26.67
Indiana	28.36	38.85	27.34	27.01
Michigan	36.55	40.14	29.11	28.71
Minnesota	30.02	34.15	12.04	16.93
Illinois	23.24	25.58	16.86	18.51
PJM				
Northern Ill	24.05	36.95	9.80	26.73
A-D	37.43	43.82	29.78	33.60

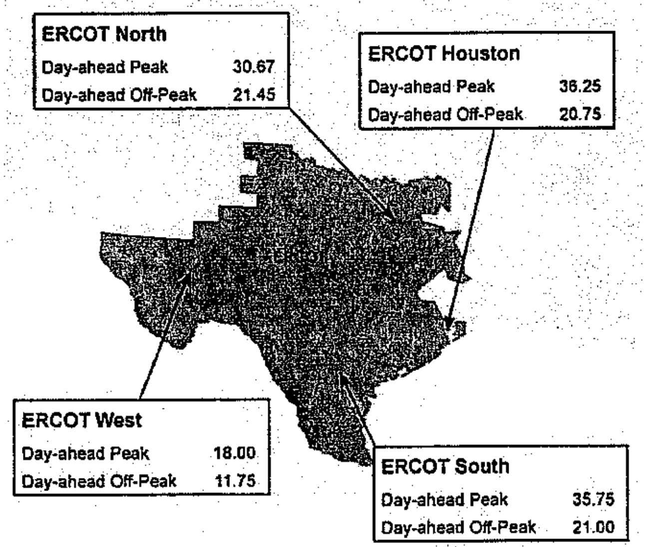
Day-ahead peak spreads

	Cinergy	Northern Ill	PJM A-D	PJM West	Entergy	Southern
Cinergy	—	1.75	-2.75	-5.25	3.50	1.75
Northern Ill	-1.75	—	-4.50	-7.00	1.75	0.00
PJM A-D	2.75	4.50	—	-2.50	6.25	4.50
PJM West	5.25	7.00	2.50	—	8.75	7.00
Entergy	-3.50	-1.75	-6.25	-8.75	—	-1.75
Southern	-1.75	0.00	-4.50	-7.00	1.75	—

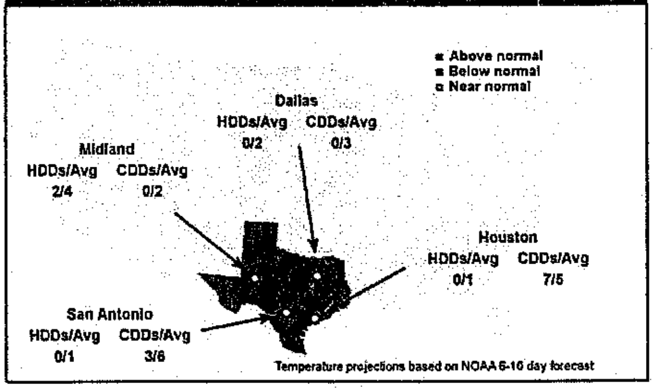
Sources: ISOs, Argus assessments

ERCOT Prices at a Glance $/MWh

Day ahead markets for 17-Oct-11



Degree days outlook vs temperature: 23-Oct



Day-ahead minus real time

16-Oct	Peak ($/MWh)	Off-peak ($/MWh)
Hubs		
Houston	-3.56	11.06
North	-6.20	4.27
South	-75.85	-8.47
West	-12.71	2.02
Load zones		
Houston	-3.41	11.26
North	-6.40	4.12
South	-112.90	-23.38
West	-56.50	0.70

Emissions-adjusted day-ahead power prices

	SO_2	Voluntary RECs	All credits
Peak			
Houston	36.27	37.80	37.82
South	35.77	37.30	37.32
North	30.69	32.22	32.24
West	18.02	19.55	19.57
Off-peak			
Houston	20.77	22.30	22.32
South	21.02	22.55	22.57
North	21.47	23.00	23.02
West	11.77	13.30	13.32
24-hour emissions-adjusted pricing, all credits			
Houston	31.35	32.88	32.90
South	31.10	32.63	32.65
North	27.87	29.40	29.42
West	16.19	17.72	17.74

Day-ahead nodal prices

18-Oct	Peak ($/MWh)	Off-peak ($/MWh)
Hubs		
Houston	38.00	20.68
North	27.27	19.75
South	37.36	22.85
West	21.99	11.72
Load zones		
Houston	39.25	20.64
North	27.30	19.69
South	40.36	24.23
West	27.45	13.36
Hub average	31.17	18.75
Bus average	30.00	19.54

Market-implied heat rates and spark spreads

		Heat rate	Spark spreads in 000 Btu/kWh at heating efficiencies of:					
		(Btu/kWh)	7	8	10	12	15	18
Peak	Houston	10,014	10.91	7.29	0.05	-7.19	-18.05	-28.91
	North	8,403	5.12	1.47	-5.83	-13.13	-24.08	-35.03
	South	9,972	10.66	7.07	-0.10	-7.27	-18.03	-28.78
	West	5,049	-6.95	-10.52	-17.65	-24.78	-35.48	-46.17
Off-peak	Houston	5,732	-4.59	-8.21	-15.45	-22.69	-33.55	-44.41
	North	5,877	-4.10	-7.75	-15.05	-22.35	-33.30	-44.25
	South	5,858	-4.09	-7.68	-14.85	-22.02	-32.78	-43.53
	West	3,296	-13.21	-16.77	-23.90	-31.03	-41.73	-52.42

West Markets

Continued from page 1

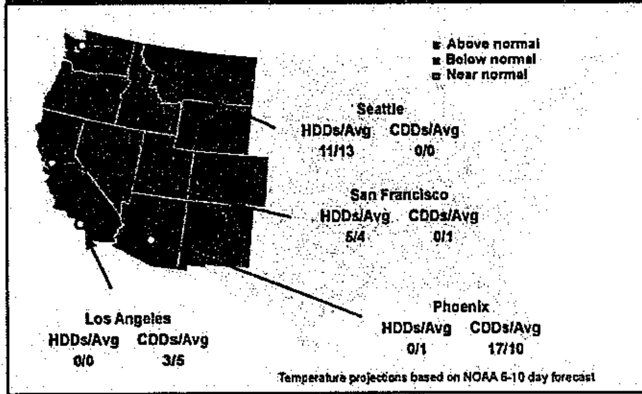
- **A full weekday load also boosted prices across the region.** Mona gained 21pc, Mead 10pc. Off-peak prices were inconsistent. Most locations were down around 10pc, but COB and Mid-Columbia gained by the same proportion.

- Below normal temperatures foreseen in the west this month by the Climate Prediction Center (CPC) of the National Weather Service have not occurred. For the rest of October, the CPC is looking at above average readings. Cooling degree days persist in the southwest, **but lower temperatures and high winds are predicted to move tonight from the Northwest to the central Rockies.**

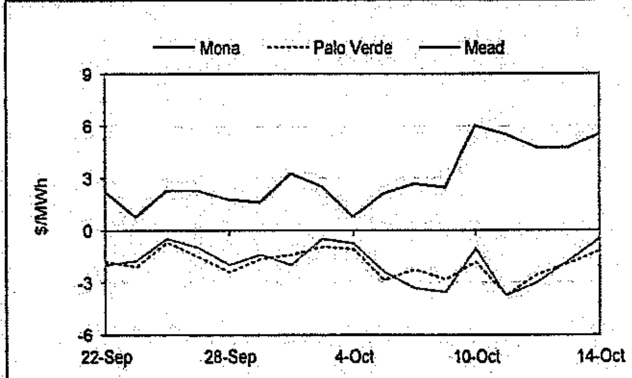
- La Niña conditions in the Pacific are expected to strengthen this winter, usually making the northwest extra wet. **The implicit forecast for more water seemed to depress November as the prompt through late last week.** California points and Mid-Columbia were down at least 7 pc for November for 1-13 October. But November Henry Hub gas futures rose 2pc the next day, so Mead and Palo Verde were little changed. SP 15, NP 15 and Mid-Columbia were down 3-4pc.

- Key nodes in the California Independent System Operator were around $25/MWh at 10:10am PT today. **But Friday, 14 October pricing was in the low-$90s for the peak hours.**

Degree days outlook vs temperature: 23-Oct



Four Corners daily peak spreads



Forward markets — $/MWh

	Mid-Columbia				Palo Verde				SP-15				NP-15			Mead		
	Peak			Off-Peak	Peak			Off-Peak	Peak			Off-Peak	Peak		Off-Peak	Peak		Off-Peak
	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Coal Spark	Price	Price	Gas Spark	Price	Price	Gas Spark	Price
Nov-11	29.65	5.78	9.75	26.60	31.35	6.36	7.35	23.20	32.75	7.34	15.45	25.30	33.60	7.14	27.05	33.55	8.00	23.35
Dec-11	35.15	9.46	15.15	30.00	32.75	5.73	8.65	24.50	34.75	7.80	17.35	26.60	35.75	7.82	28.60	35.05	7.82	24.65
Jan-12	32.30	6.12	11.80	27.05	33.10	4.82	8.10	25.20	35.70	7.84	13.30	26.90	35.55	6.64	28.60	36.35	8.07	27.90
Feb-12	31.05	4.94	10.95	25.20	33.00	5.84	7.30	25.00	35.45	7.45	11.85	26.70	35.20	6.22	28.40	36.20	8.27	27.40
Mar-12	28.25	2.21	8.55	21.80	32.65	4.44	6.15	23.95	35.10	7.31	11.00	25.55	34.65	5.88	27.20	35.80	7.59	26.30
Apr-12	27.40	1.85	7.50	18.00	33.65	6.56	8.05	22.85	34.15	6.43	11.15	21.50	33.65	4.88	20.20	36.35	8.49	24.95
Q1-12	30.45	4.34	10.35	24.75	32.90	5.04	7.20	24.75	35.40	7.54	12.00	26.40	35.10	6.19	28.10	36.10	7.96	27.25
Q2-12	23.05	-2.50	2.75	9.90	34.65	7.56	8.75	19.30	33.80	6.08	10.30	18.15	32.95	4.18	17.05	37.40	9.54	21.25
Q3-12	36.00	9.68	15.50	23.75	44.15	16.08	18.05	27.00	43.75	15.05	20.15	28.25	41.30	11.55	28.25	47.60	18.76	29.65
Q4-12	36.75	8.54	16.45	32.15	37.65	7.48	11.75	28.40	40.50	10.26	17.10	30.75	40.25	9.03	31.60	40.70	10.18	31.20
Q1-13	38.25	8.08	17.15	31.85	39.85	7.30	13.35	30.35	49.75	17.27	26.05	37.10	47.90	15.14	36.45	42.20	9.44	34.30
Q2-13	28.70	-0.56	7.50	14.75	39.85	9.05	13.15	23.75	45.20	13.84	21.30	25.35	42.90	10.14	25.05	42.30	10.80	26.90
Q3-13	43.00	13.32	21.30	30.10	52.50	21.00	25.20	32.75	59.65	27.59	34.75	38.25	56.50	23.74	38.50	55.60	23.40	37.15
Q4-13	43.50	10.25	22.30	34.10	41.75	8.43	15.05	32.35	53.30	19.98	29.40	38.35	53.20	20.44	40.20	44.25	10.58	36.70
Cal-12	31.55	4.95	11.15	22.70	37.30	11.26	11.30	24.90	38.35	12.17	14.75	25.95	37.40	10.17	26.30	40.40	14.01	27.35
Cal-13	38.35	7.69	17.05	27.75	43.50	15.15	16.70	29.85	51.95	23.25	27.85	34.80	50.15	20.40	35.10	46.10	17.19	33.80
Cal-14	43.50	9.34	21.20	31.15	48.35	16.22	20.65	32.50	58.25	25.91	33.55	38.45	56.10	23.34	39.10	51.80	19.18	37.45
Cal-15	48.25	15.98	24.85	33.80	53.20	19.18	24.60	35.85	63.60	29.44	38.30	41.85	61.20	26.06	42.50	56.35	21.91	39.65

West Markets

Western generating unit outages

Capacity	Unit	Owner	Fuel	Begins	Reason
11,872	Total CAISO units curtailed	various	various	NA	planned and unplanned
820	Big Creek	SCE	hydro	3-Oct-11	@108MW, unplanned
668	Colusa Generating Station	PG&E	gas	17-Oct-11	@282MW, planned
407	Helms Pump-Gen 2	PG&E	hydro	26-Sep-11	planned
933	Hyatt-Thermalito	CDWR	hydro	18-May-11	@503MW, planned/unplanned
366	Inland Empire 2	Calpine	gas	17-Oct-11	planned
525	Mountainview 3	SCE	gas	17-Oct-11	planned
741	Ormond Beach 1	GenOn	gas	14-Oct-11	unplanned
590	Sunrise 2	Edison Mission	gas	6-Oct-11	planned
625	Termoelectrica de Mexicali 1	Sempra	gas	5-Oct-11	@270MW, planned

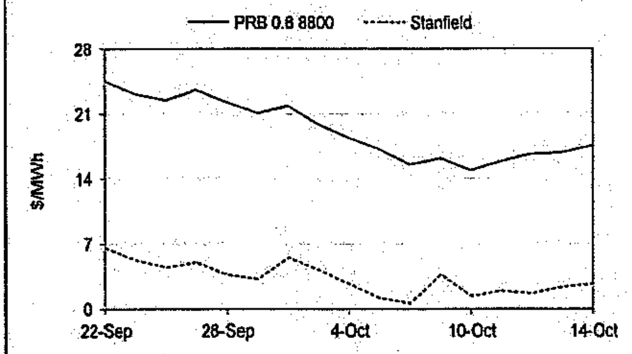
Spot natural gas in $/mmBtu

Location	Average	Low	High
PG&E Citygates	3.800	3.770	3.825
Stanfield	3.510	3.510	3.520
SoCal Gas Co	3.670	3.645	3.700
El Paso San Juan Basin	3.435	3.370	3.500
El Paso Permian Basin	3.540	3.440	3.565
El Paso, South Mainline	3.735	3.730	3.755
Northwest Sumas	3.470	3.440	3.530
Northwest Wyoming	3.495	3.440	3.530

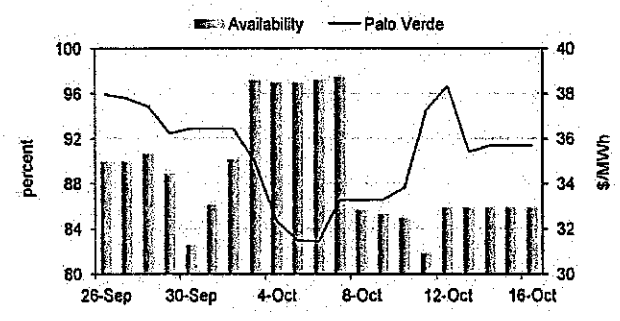
Forward natural gas in $/mmBtu

Location	November	Nov 2011-Dec 2011	Nov 2011-Mar 2012
El Paso Permian	3.461	—	3.809
El Paso San Juan	3.368	—	3.774
Northwest, Wyoming	3.486	—	3.849
Northwest PL at Sumas	3.568	—	3.984
PG&E Citygates	3.823	—	4.114
SoCal Gas	3.603	—	3.974

Mid-C spark spreads: Coal vs gas



West nuclear availability vs Palo Verde



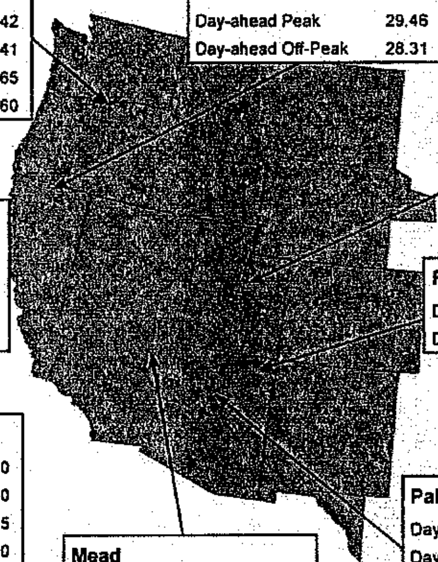
Nuclear availability data source: NRC

Market-implied heat rates and spark spreads

		Heat rate (Btu/kWh)	Spark spreads in 000 Btu/kWh at heating efficiencies of: 7	8	10	12	15	18
Peak	COB	8,027	3.77	0.10	-7.24	-14.58	-25.59	-36.60
	Four Corners	11,505	15.57	12.11	5.20	-1.71	-12.08	-22.44
	Mead	10,559	13.06	9.39	2.05	-5.29	-16.30	-27.31
	Mid-C	7,812	2.85	-0.66	-7.68	-14.70	-25.23	-35.76
	Mona	9,915	10.29	6.76	-0.30	-7.36	-17.95	-28.54
	NP 15	10,000	11.40	7.60	0.00	-7.60	-19.00	-30.40
	Palo Verde	10,676	13.49	9.82	2.48	-4.86	-15.87	-26.88
	SP 15	10,627	13.31	9.64	2.30	-5.04	-16.05	-27.06
Off-peak	COB	7,714	2.62	-1.05	-8.39	-15.73	-26.74	-37.75
	Four Corners	6,585	-1.44	-4.89	-11.80	-18.71	-29.08	-39.44
	Mead	6,335	-2.44	-6.11	-13.45	-20.79	-31.80	-42.81
	Mid-C	7,524	1.84	-1.67	-8.69	-15.71	-26.24	-36.77
	Mona	5,453	-5.46	-8.99	-16.05	-23.11	-33.70	-44.29
	NP 15	6,382	-2.35	-6.15	-13.75	-21.35	-32.75	-44.15
	Palo Verde	6,540	-1.69	-5.36	-12.70	-20.04	-31.05	-42.06
	SP 15	6,540	-1.69	-5.36	-12.70	-20.04	-31.05	-42.06

West Prices at a Glance $/MWh

Day ahead markets for 17-Oct-11



Mid-Columbia	
Day-ahead Peak	27.42
Day-ahead Off-Peak	26.41
Prompt Peak	29.65
Prompt Off-Peak	26.60

COB	
Day-ahead Peak	29.46
Day-ahead Off-Peak	28.31

Mona	
Day-ahead Peak	35.00
Day-ahead Off-Peak	19.25

NP-15	
Day-ahead Peak	38.00
Day-ahead Off-Peak	24.25
Prompt Peak	33.60
Prompt Off-Peak	27.05

Four Corners	
Day-ahead Peak	39.75
Day-ahead Off-Peak	22.75

SP-15	
Day-ahead Peak	39.00
Day-ahead Off-Peak	24.00
Prompt Peak	32.75
Prompt Off-Peak	25.30

Palo Verde	
Day-ahead Peak	39.18
Day-ahead Off-Peak	24.00
Prompt Peak	31.35
Prompt Off-Peak	23.20

Mead	
Day-ahead Peak	38.75
Day-ahead Off-Peak	23.25
Prompt Peak	33.55
Prompt Off-Peak	23.35

Day-ahead minus hourly spread

14-Oct-11	Peak	Off-Peak
CAISO		
COB	-65.98	-2.10
Four Corners	-61.69	-6.67
Mead	-61.02	-5.65
Mona	-50.00	-7.61
NOB	-58.14	-3.04
NP-15	-61.81	-5.01
Palo Verde	-57.51	-5.30
SP-15	-60.95	-5.25

Source: CAISO

Hourly price averages

	Peak		Off-peak	
	14-Oct-11	13-Oct-11	14-Oct-11	13-Oct-11
CAISO				
COB	93.51	22.59	27.79	23.40
Four Corners	95.19	29.19	27.17	23.14
Mead	96.27	28.17	27.53	23.40
Mona	78.75	-131.84	26.61	-167.60
NOB	97.81	34.21	28.04	23.81
NP-15	93.81	27.12	28.26	23.31
Palo Verde	92.92	29.61	27.11	23.06
SP-15	97.44	45.33	27.75	23.58

Source: CAISO

Emissions-adjusted day-ahead power prices

	SO_2		24-hour average
	Peak	Off-peak	
COB	29.47	28.32	29.09
Four Corners	39.77	22.77	34.10
Mead	38.76	23.26	33.59
Mona	35.02	19.27	29.77
Mid-C	27.43	26.42	27.09
NP-15	38.01	24.26	33.43
Palo Verde	39.20	24.02	34.14
SP-15	39.01	24.01	34.01

Day-ahead peak spreads

	COB	Four Corners	Mead	Mona	Mid-C	NP-15	Palo Verde	SP-15
COB	—	-10.29	-9.29	-5.54	2.04	-8.54	-9.72	-9.54
Four Corners	10.29	—	1.00	4.75	12.33	1.75	0.57	0.75
Mead	9.29	-1.00	—	3.75	11.33	0.75	-0.43	-0.25
Mona	5.54	-4.75	-3.75	—	7.58	-3.00	-4.18	-4.00
Mid-C	-2.04	-12.33	-11.33	-7.58	—	-10.58	-11.76	-11.58
NP-15	8.54	-1.75	-0.75	3.00	10.58	—	-1.18	-1.00
Palo Verde	9.72	-0.57	0.43	4.18	11.76	1.18	—	0.18
SP-15	9.54	-0.75	0.25	4.00	11.58	1.00	-0.18	—

Source: Argus assessments

Markets

Gas slips despite cooler forecasts

NYMEX gas for November delivery fell by 1.5¢/mmBtu, or 0.4pc, to settle at $3.688/mmBtu. The 12-month strip and the 2012-calendar strip were each down 1.1pc to $4.039/mmBtu and $4.153/mmBtu, respectively.

Heading into today's session, prices had climbed 6.1pc since 12 October on a wave of bargain buying following a US government report showing a massive build in natural gas inventories. The steep price increase spurred some traders, who had bet on higher prices, to sell off contracts today and take profits.

"After a considerably large move on [13-14 October], we are seeing some give-back," Summit Energy commodity analyst Matt Smith said.

At the same time, forecasters are predicting colder weather over the next few weeks that could stoke demand for the heating fuel. The National Weather Service sees below-normal temperatures across parts of the southeast and midcontinent from 22-26 October and cooler-than-normal temperatures across the eastern US the following week.

Colder weather could stunt the recent rapid growth natural gas inventories. The US Energy Information Administration (EIA) has reported a larger-than-average build in each of the last five weeks.

Nymex natural gas settlements $/mmBtu

Contract	Price	Change	Volume*
Nov-11 M1	3.688	-0.015	106,129
Dec-11 M2	3.903	-0.057	57,787
Jan-12 M3	4.037	-0.063	31,115
Feb-12 M4	4.052	-0.059	9,261
Mar-12 M5	4.020	-0.053	12,584
Apr-12 M6	4.008	-0.045	13,372
May-12 M7	4.044	-0.043	2,150
Jun-12 M8	4.086	-0.040	1,533
Jul-12 M9	4.131	-0.038	2,475
Aug-12 M10	4.155	-0.039	657
Sep-12 M11	4.156	-0.040	544
Oct-12 M12	4.192	-0.041	2,199
Nov-12 M13	4.342	-0.036	537
Dec-12 M14	4.607	-0.038	552
Jan-13 M15	4.747	-0.038	365
Feb-13 M16	4.725	-0.038	76
Mar-13 M17	4.660	-0.038	125
Apr-13 M18	4.539	-0.034	121
May-13 M19	4.557	-0.034	1

*Volume data estimated by Nymex, subject to verification.

argus

FOR FURTHER INFORMATION CONTACT:
Argus US Electricity
Publisher: Adrian Binks
CEO Americas: Euan Craik
Commercial Management: Karen Johnson
Business Development:
Caroline Gentry, Miles Weigel
Head of Gas & Power: David Givens
Data & Production:
Adam Schwartz, Andrew Sutton
Argus US Electricity Editorial:
Robert Mullin
Email: robert.mullin@argusmedia.com
Jessica Zahnow
Email: jessica.zahnow@argusmedia.com
Kim Moore
Email: kim.moore@argusmedia.com

Argus offices:
Argus Media Ltd, London (head office), UK
Tel: +44 20 7780 4200
Fax: +44 20 7780 4201
Argus Media, Inc. Houston, USA
Tel: +1 713 968 0000
Fax: +1 713 622 2991
Washington DC, USA
Tel: +1 202 775 0240
Fax: +1 202 872 8045
Jersey City, USA
Tel: +1 201 484 7200
Fax: +1 201 484 7201

Argus offices: (cont.)
Portland, USA
Tel: +1 503 222 7390
Fax: +1 503 242 2968
Moscow, Russia
Tel: +7 495 933 7571
Fax: +7 495 933 7572
Singapore
Tel: +65 6533 3638
Fax: +65 6533 4181
Tokyo, Japan
Tel: +81 3 5481 1805
Fax: +81 6 5481 1807

Customer services and support
Email: support@argusmedia.com
London: +44 20 7780 4200
Singapore: Dewati Kurniawan
+65 6496 9967
Houston: Zach Rhonheimer
+1 713 429 6311

Sales
Email: sales@argusmedia.com
Peter Brown +1 713 968 0011
Mike Horvith +1 713 429 6320
Ashli George +1 202 349 2869
Christina Vassil +1 202 349 2862

Home page: www.argusmedia.com

Argus North American Electricity Methodology

Prices are based on daily survey data received from the non-commercial departments of market participants. Day-ahead peak and off-peak volume-weighted price indexes and assessments are compiled based on this data. Argus publishes the total volume of trades reported, the number of transactions, the high price, low price, and the volume weighted average price where sufficient data exists.

In low-liquidity markets when insufficient data is received to support a volume weighted index calculation (less than three trades of 25MW minimum each are received) a clearly marked price assessment is made. Volume and number of trades are left blank when an assessment is made.

Peak and off-peak electricity price indexes are based on data submitted daily to Argus voluntarily by the risk-management divisions or non-commercial departments of market participants.

All data submitted is treated confidentially and used only to establish the index or form a market price assessment. The Argus electricity index procedures are audited at least annually by the company's global compliance officer.

Only firm deals equal to or greater than 25MW are included in each index. Firm delivery means that a contract for liquidated damages in the event of non-performance is in place. Swaps, contracts for difference, and derivative-linked deals are not included but financially settled deals are included where the price does not diverge from what is observed in the physical market.

In low-liquidity markets, Argus publishes assessments based on an intelligent range of trade. Argus assesses the range within which electricity did or could have traded, based on actual deals and bids and offers throughout the trading day for next-day power, historical price relationships and other market conditions.

Assessments are clearly identifiable from volume-weighted average indexes. The volume and number of trades will be blank where an assessment is made.

News

Exelon, EdF argue over utility

Exelon, Constellation Energy stakeholder EdF SA of France and Maryland regulators disagree over the affects of the US power companies' proposed merger.

EdF, which owns 7.3pc of Constellation and has a nuclear power joint venture with it, filed testimony with the Maryland Public Service Commission last week saying Exelon's acquisition would have "serious and negative ramifications for Maryland, as well as for EdF," and that the state agency should reject the merger. An Exelon spokesman told *Argus* the company is "perplexed" by EdF's testimony and that EdF will be "unharmed" by the transaction.

The commission will begin hearings on Exelon's proposed $7.9bn purchase of Constellation next week. It is expected to issue a decision in January.

"The proposed merger raises serious market power concerns," Jeffrey Johnson, a consultant to the chief executive of EdF Trading and a director at the EdF-Constellation joint venture Constellation Energy Nuclear Group (CENG), said in testimony to the commission filed on 12 October.

Other testimony filed last week by the Office of People's Counsel recommended that Constellation's Baltimore Gas & Electric (BGE) subsidiary be prohibited from asking for permission to increase rates for at least three years following the merger, contrary to the public service commission's staff recommendation. It also recommended Exelon be required to put up a $68mn "reliability fund" to "address the immediate impacts of the merger on BGE and commission decisions regarding the trade-off between reliability and rates."

The proposed merger has faced other challenges, including from Maryland officials who last month said it should proceed only if conditions are set to protect electricity consumers. The transaction received approval from the Public Utility Commission of Texas in August.

A primary concern for EdF is the size of Exelon's nuclear fleet, which accounts for about 20pc of US nuclear output. The merger might preclude CENG from buying more capacity within its home PJM Interconnection market and in other areas of the country because Exelon already is the largest US provider of nuclear energy, Johnson said.

The transaction also might hurt CENG because Exelon would want to support its wholly-owned nuclear plants more than the joint venture, Johnson said. And CENG "would be highly vulnerable" to job losses and a change in management as well as moving headquarters out of Maryland, which could affect state-based jobs and its tax revenue, he said.

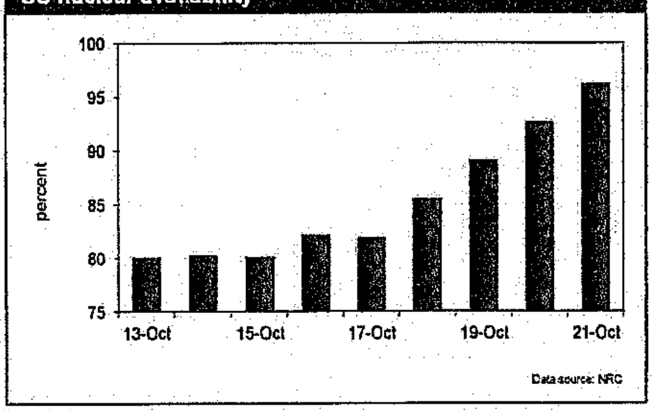
Johnson proposed that if regulators choose to approve the merger, they consider requiring "ring-fencing" to support CENG's autonomy, including entering a contract that would require the joint-venture's chief executive be a US citizen independent of either EdF or the combined Exelon-Constellation, that the right to remove the chief executive should alternate between the companies every two years, that EdF have the right to appoint the chief financial officer and that the size of the board be expanded by three.

"As EdF knows, the merger will not change their prior agreement with Constellation Energy Nuclear Group, nor will it in any way affect their ability to build new generating plants," Exelon spokesman Paul Elsberg said. He added that Exelon and Constellation do not need EdF's approval to proceed with the merger.

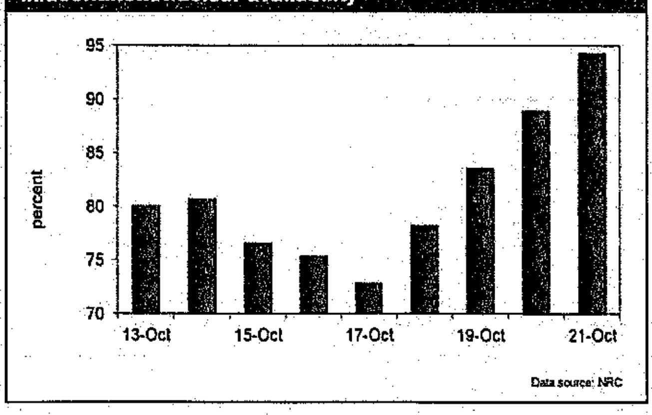
Exelon last week filed testimony from executives that it says "strengthens the companies' commitments related to the proposed merger," and "addresses BGE's ability to continue to provide safe and reliable service and operate in the public interest." The provisions include having BGE chief executive Kenneth DeFontes Jr. serve on Exelon's executive committee as well as corporate governance measures that "will ensure that BGE will remain locally managed and has the resources to provide safe and reliable power."

The company said some proposals, including one from the Maryland Energy Administration to require Exelon to increase its 25MW commitment to new renewable energy projects in the state, are "unnecessary, could harm BGE and its customers, or would adversely impact the terms of the transaction." It also said the Officer of People's Counsel suggestion of a three-year rate

US nuclear availability



Midcontinent nuclear availability



freeze "would jeopardize BGE's ability to make significant capital expenditures needed to maintain the reliability of the distribution system."

Exelon earlier this month agreed to restrict the sale of three coal-fired units to exclude eight power companies that already own 3pc or more of the overall PJM market. The companies also agreed to give 18 months written notice before retiring any generating unit and to limit the price on offers from gas units used during peak energy demand to PJM guidelines plus "the higher of 10pc of such costs or the applicable percentage of cost permitted under the PJM tariff to the extent a unit is a frequently mitigated unit, plus an adder not to exceed $1/MWH," according to terms of the letter that Joseph Bowring, the independent market monitor for PJM, sent to the Federal Energy Regulatory Commission and the Maryland Public Service Commission.

California mulls new RPS criteria

The California Energy Commission is moving toward incorporating the state's new 33pc by 2020 renewable portfolio standard (RPS) into the agency's renewable energy eligibility guidebook, with a draft released last week showing several changes to the criteria.

Some of the most significant changes in the guidebook will have to wait until the California Public Utilities Commission (PUC) revises its regulations on renewable energy certificate (REC) procurement, trading and enforcement to meet the stipulations in the law that established the 33pc RPS, SB 2X. But the CEC had to revise the guidebook at this time because its last revision was issued before the PUC decided to allow using tradable, unbundled RECs for compliance.

The commission stripped the language associated with the in-state delivery requirement. SB 2X eliminates the criteria that formerly required all renewable energy to be delivered into the state for it to be RPS-eligible.

The agency also needed to incorporate mandatory RPS levels for publicly owned utilities (POU), which had previously faced only voluntary targets. The commission will administer the POU requirements of the standard, but the Air Resources Board will impose any non-compliance penalties, while the PUC will continue to administer and enforce the RPS for retail utilities. The CEC guidebook sets compliance deadlines and monitoring and reporting requirements for POUs. It establishes an interim tracking system but POUs must complete their compliance reporting through the Western Renewable Energy Information Generation System by 2013.

The draft rulebook incorporates the feed-in tariff the PUC adopted this year. It stipulates that distributed generation facilities participating in retail utilities' net-metering programs retain all of the RECs associated with their generation, including any surplus power they sell to utilities rather than use onsite. The PUC's decision did not allow utilities to count the distributed generation from their net-metering customers to their RPS obligation, but the CEC says because tradable RECs can be used for compliance, utilities can procure and surrender RECs from distributed generation.

The draft would expand RPS eligibility to hydroelectric facilities larger than 30MW, so long as they operate as part of a water supply or conveyance system and are 40MW or less.

The draft guidebook revision also clarifies that while SB 2X has three-year compliance periods, utilities and POUs will be required to submit annual procurement reports to the CEC.

The CEC has determined that facilities can use up to 2pc of nonrenewable resources and still meet the RPS eligibility requirements. That de minimis level can be raised to 5pc if a facility meets several stipulations, including that the use of nonrenewable fuel will increase the renewable energy facility's generation "significantly" more than generation associated with using nonrenewable fuel.

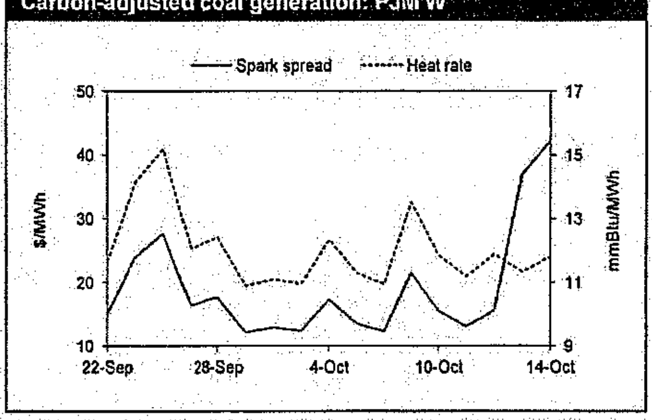
And for a facility to become eligible after repowering, the capital investment to revamp the facility must be at least 80pc of the total value of the repowered facility.

The CEC is holding a workshop on 21 October to discuss the draft. It has particularly asked for feedback on how to define "significantly" the measure of increased generation associated with a facility's use of nonrenewable fuel. It is also seeking input on whether the 80pc investment requirement is appropriate in terms of determining whether a repowered facility is considered "new" for eligibility requirements.

The commission is also seeking stakeholder thoughts on the process of pre-certification and whether it should continue. The CEC says nearly 650 facilities have been pre-certified, many for five years or longer. Facilities cannot begin generating RECs until they have been certified by the CEC and pre-certification is designed to speed up the process of certification when the project is operating. A pre-certified facility can also boast the likelihood of its RPS eligibility based on the CEC's pre-approval. But the CEC is considering eliminating the pre-certification process for any facilities that are not fully developed and operational.

The agency is soliciting comment on the benefits of pre-certi-

Carbon-adjusted coal generation: PJM W



fication and if the process is continued, whether an expiration date should be set for the eligibility assurance.

RGGI fix may hinge on state laws

Seven of nine states in the Regional Greenhouse Gas Initiative (RGGI) can ratchet down on their part of the program's collective carbon cap administratively, according to an *Argus* analysis of each RGGI state's laws.

Expanding the program to cover imported electricity or other sectors of the economy would be a heavier lift, with four states legislatively specifying what entities could be covered under RGGI's cap-and-trade program.

Each RGGI state, except for New York, has passed laws enabling its regulators to create and participate in the regional CO_2 trading program. New York's regulators relied on a broad grant of authority under the state's clean air act to implement the program. Broadly, each enabling law recognized the 2005 memorandum of understanding between the RGGI states and directed their state's environmental regulators to implement the program outlined in the memorandum.

But New Hampshire and Maine, which both have Republican-controlled legislatures, specified their state's carbon emissions cap under RGGI in their enabling legislation, which means that the state's regulators would need the law amended before their portion of RGGI's cap can be lowered.

Republicans in New Hampshire's legislature spent most of the spring attempting to leave RGGI, but the Democratic governor vetoed the bill and the Senate fell short of a passing a measure to override the veto. During the floor debates on the RGGI repeal bill, Republican members of the state's House of Representatives bitterly attacked RGGI on philosophical grounds, making it unlikely that they will warmly receive legislation to improve the program.

While the majority of the states referred to the memorandum and left most of the details up to regulators, several legislatively enacted the terms of the memorandum, making it difficult or impossible for regulators in those states to make changes without asking the legislature to amend the enabling law. The legislation largely specifies which facilities may be covered by the rule and could limit the ability to extend the cap to include imported power or other economic sectors.

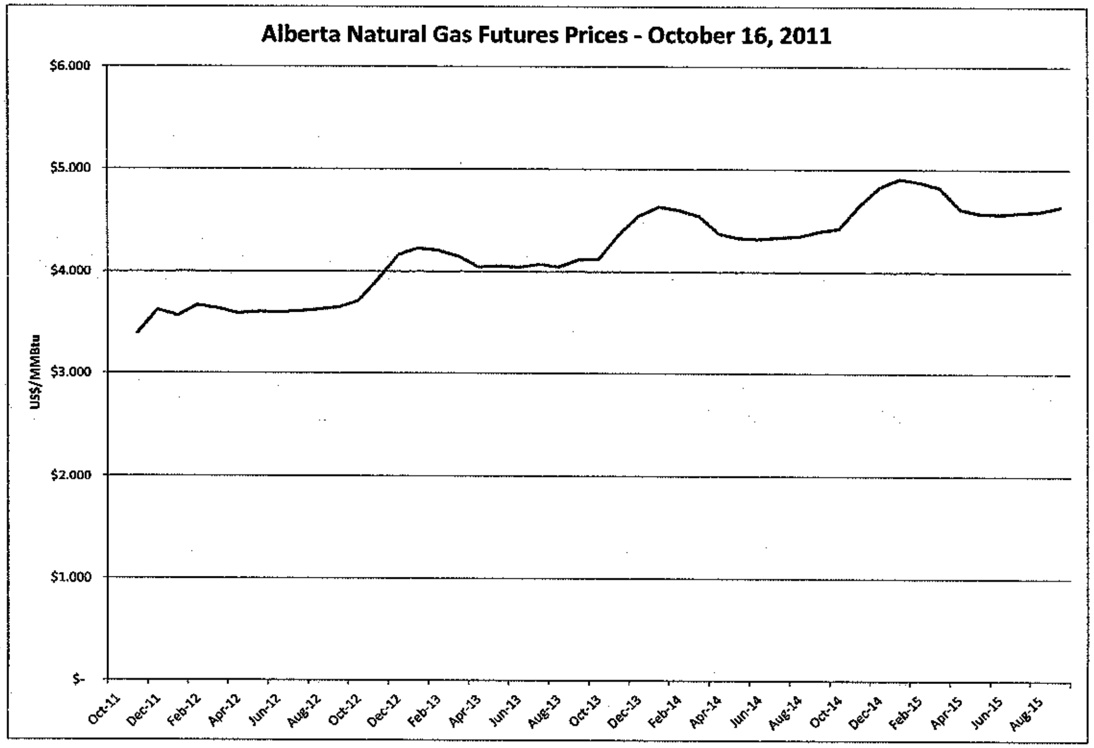
RGGI's emissions are far below the program's caps, which has left the CO_2 allowance market significantly oversupplied. RGGI CO_2 allowance prices have held very close to the program's price floor and the program has not led to any meaningful emissions reductions in the regulated sector. Any serious action to fix the program will require that the emissions cap is set at, or below, the program's current CO_2 emissions.

The RGGI-enabling laws in New Hampshire, Maine, Vermont and Massachusetts specified that the covered entities in RGGI are fossil fuel-fired electric units above 25MW. The RGGI states recently held a learning session on how to put electricity imports under the program's cap, which would likely require those states, which make up slightly more than a quarter of the program's emissions, to amend their enabling laws.

Exhibit SEL-05

Lands Energy Consulting
AECO Natural Gas Forward Prices (US$/MMBtu)
NorthWestern Energy

Mth-Year	NGX AECO LAST	
Oct-11		
Nov-11	$	3.390
Dec-11	$	3.625
Jan-12	$	3.565
Feb-12	$	3.670
Mar-12	$	3.638
Apr-12	$	3.590
May-12	$	3.605
Jun-12	$	3.600
Jul-12	$	3.610
Aug-12	$	3.630
Sep-12	$	3.650
Oct-12	$	3.713
Nov-12	$	3.928
Dec-12	$	4.168
Jan-13	$	4.233
Feb-13	$	4.210
Mar-13	$	4.155
Apr-13	$	4.053
May-13	$	4.058
Jun-13	$	4.050
Jul-13	$	4.078
Aug-13	$	4.053
Sep-13	$	4.125
Oct-13	$	4.130
Nov-13	$	4.365
Dec-13	$	4.548
Jan-14	$	4.635
Feb-14	$	4.603
Mar-14	$	4.548
Apr-14	$	4.375
May-14	$	4.333
Jun-14	$	4.325
Jul-14	$	4.340
Aug-14	$	4.353
Sep-14	$	4.398
Oct-14	$	4.430
Nov-14	$	4.652
Dec-14	$	4.826
Jan-15	$	4.908
Feb-15	$	4.876
Mar-15	$	4.821
Apr-15	$	4.618
May-15	$	4.576
Jun-15	$	4.568
Jul-15	$	4.583
Aug-15	$	4.596
Sep-15	$	4.641



LANDS ENERGY CONSULTING

GDP Implicit Price Deflator

DATA	INDEX	ANN BY Q	ANNUAL	YEAR		
2003 04	94.799					
2004 01	95.626					
2004 02	96.435					
2004 03	97.131					
2004 04	97.862					
2005 01	98.766	3.284%				
2005 02	99.438	3.114%				
2005 03	100.461	3.428%				
2005 04	101.309	3.522%	3.3%	2005		
2006 01	102.071	3.346%				
2006 02	102.973	3.555%				
2006 03	103.756	3.280%				
2006 04	104.218	2.871%	3.3%	2006		
2007 01	105.31	3.173%				
2007 02	106.008	2.947%				
2007 03	106.447	2.594%				
2007 04	107.069	2.736%	2.9%	2007		
2008 01	107.534	2.112%				
2008 02	108.069	1.944%				
2008 03	109.172	2.560%			3-YR AVE	
2008 04	109.300	2.084%	2.2%	2008	2.7668%	
2009 01	109.717	2.030%				
2009 02	109.594	1.411%				
2009 03	109.658	0.445%				
2009 04	109.943	0.588%	1.1%	2009		
2010 01	110.358	0.584%				
2010 02	110.793	1.094%				
2010 03	111.156	1.366%				
2010 04	111.644	1.547%	1.1%	2011		
2011 01	112.398	1.849%				
2011 02	113.118	2.099%				
2011 03	113.836	2.411%			3-YR AVE	6-YR AVE
2011 04			2.1%	2012	1.4620%	2.1144%

Exhibit SEU-07

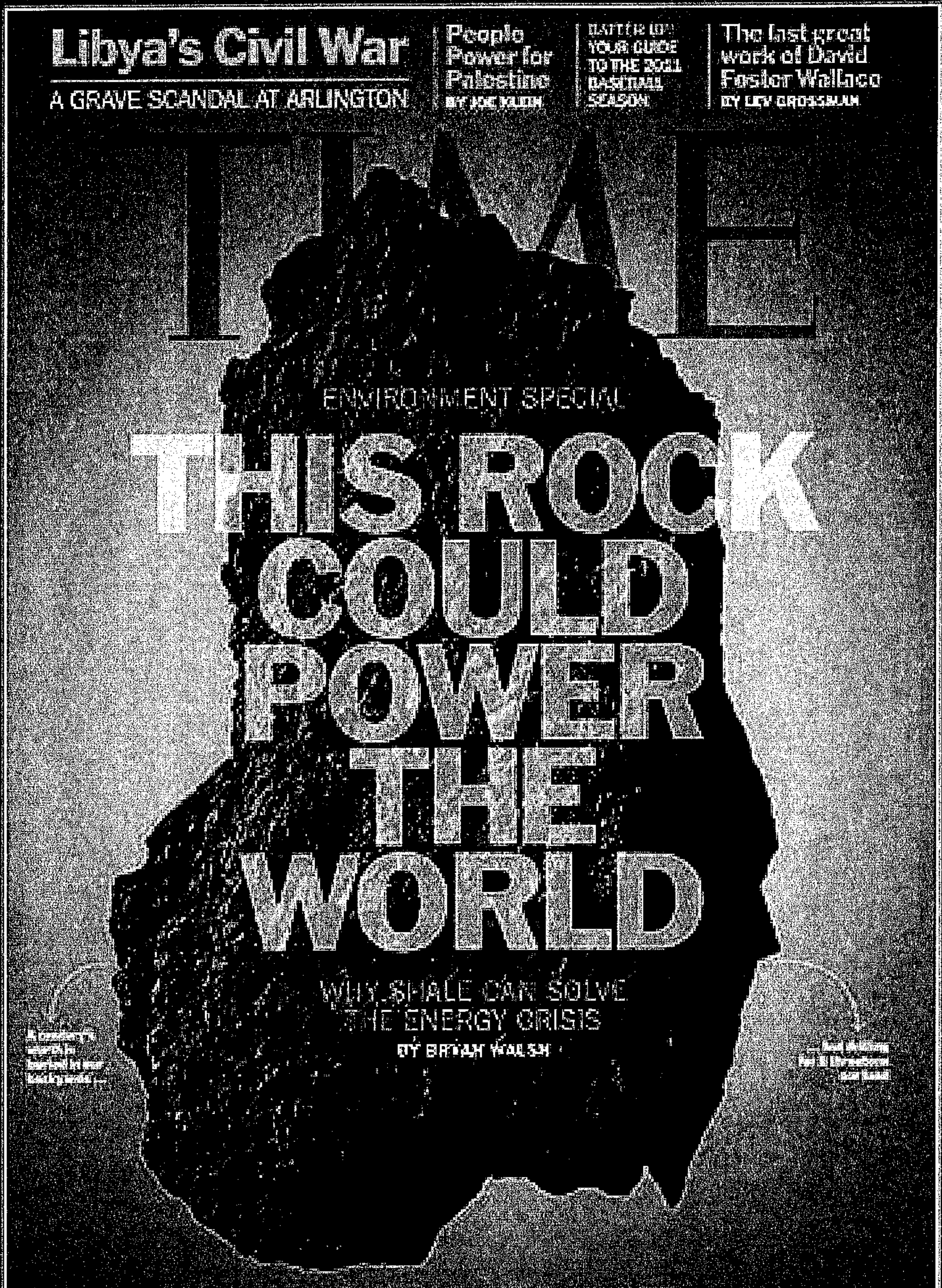


Exhibit SEL-07

TIME

Thursday, Mar. 31, 2011

Could Shale Gas Power the World?

By Bryan Walsh

For more than a decade, Bonnie Burnett and her husband Truman have owned a second home in the hilly farmland of Bradford County, in northeastern Pennsylvania. It was a getaway for the Burnetts (who live three hours to the south, in Stroudsburg), a place to take their grandchildren for a swim in the wooded pond that lies just a few steps from their front door. "It used to be heaven here," says Bonnie. "We were going to move here to live."

The Burnetts say their plans changed when a natural gas drilling operation on an adjacent property started less than 400 ft. (122 m) from their house. It was one of thousands of wells that have been drilled in Pennsylvania as part of a booming natural gas rush. In June 2009, when the Burnetts were home in Stroudsburg, tens of thousands of gallons of drilling water that had been stored on the well pad spilled, leaking downhill and into the Burnetts' trees and pond. Truman says that spill ruined a 50-ft. (15 m) swath of forest and affected their water. The pond seems lifeless, and the bass and perch that the Burnetts once fished with their grandchildren are gone. Even after the accident, the well is still running. The Burnetts can hear the hum of a gas compressor running 24 hours a day. "Did it ruin my life?" asks a tearful Bonnie. "I'd have to say yes." (See pictures of the effects of global warming.)

Dave DeCristo of nearby Canton, Pa., can see wells from his home too, but that's where any similarity with the Burnetts ends. DeCristo moved to this rural community to work as a plumber before he launched a gas station and a fuel-support outfit. He did well, but his businesses really took off in 2008, when drilling companies eager for the region's natural gas began setting up shop, and he's added dozens of employees. In addition, DeCristo — like other landowners around the region —has sold a gas company the right to drill on his land. There's a well not far from his front door. "I could never dream I was going to be able to grow this big," he says. "I've been a blessed person because of this."

Until recently, natural gas was the forgotten stepsister of fuels. It provides about a quarter of U.S. electricity and heats over 60 million American homes, but it's always been limited — more expensive than dirty coal, dirtier than nuclear or renewables. Much of Europe depends on gas for heating and some electricity — but the bulk of the supply comes from Russia, which hasn't hesitated to use energy as a form of political blackmail. The fuels of the future were going to be solar, wind and nuclear. "The history of natural gas in the U.S. has been a roller-coaster ride," says Tony Meggs, a co-chair of a 2010 Massachusetts Institute of Technology gas study. "It's been up and down and up and down." (See the world's top 10 environmental disasters.)

Natural gas is up now — way up — and it's changing how we think about energy throughout the world. If its boosters are to be believed, gas will change geopolitics, trimming the power of states in the troubled Middle East by reducing the demand for their oil; save the lives of thousands of people who would otherwise die from mining coal or breathing its filthy residue; and make it a little easier to handle the challenges of climate change — all thanks to vast new onshore deposits of what is called shale gas. Using new drilling methods pioneered by a Texas wildcatter, companies have been able to tap enormous quantities of gas from shale, leading to rock-bottom prices for natural gas even as oil soars. In a single year, the usually sober U.S. Energy Information Administration more than doubled its estimates of recoverable domestic shale-gas resources to 827 trillion cu. ft. (23 trillion cu m), more than 34 times the amount of gas the U.S. uses in a year. Together with supplies from conventional gas sources, the U.S. may now have enough gas to last a century at current consumption rates. (By comparison, the U.S. has less than nine years of oil reserves.)

Watch TIME's video "Oil Spill Anxiety on the Bayou."

See the top 20 green tech ideas.

Nor is the U.S. alone. Britain, India, China and countries in Eastern Europe have potential shale plays as well, while Australia, having invested in huge infrastructure projects, has started sending fleets of ships with liquefied natural gas around the world.

Over all this loom three factors: booming demand for energy as nations such as China and India industrialize; the accident at the Fukushima nuclear plant in Japan, which has dimmed prospects for a renaissance of nuclear power; and the turmoil in the oil-rich Middle East. Taken together, they have opened space for gas as a relatively clean, relatively cheap fuel that can help fill the world's needs during the transition to a truly green economy. (As important as renewable energy is, it will likely take years for green power to shoulder the electricity load.) Although gas isn't used for transport, boosters like Texas tycoon T. Boone Pickens think if heavy-duty vehicles were fueled with natural gas, the U.S. would be able to cut imports of oil. U.S. utilities worried about meeting regulations on carbon and air pollution are switching from dirty coal to gas as a power source. In a speech on March 30, President Barack Obama hailed natural gas as part of the solution to reducing America's oil addiction. "The potential for natural gas is enormous," he said.

They Weren't Ready for This

But there's a catch. As shale-gas drilling has ramped up, it's been met with a growing environmental backlash. There are complaints about spills and air pollution from closely clustered wells and fears of wastewater contamination from the hydraulic fracturing process — also known as fracking — that is used to tap shale-gas resources. In the U.S., the gas industry is exempt from many federal regulations, leaving most oversight to state governments that have sometimes been hard-pressed to keep up with the rapid growth of drilling. The investigative news site ProPublica has found over 1,000 reports of water contamination near drilling sites. New York State — spurred by fears about the possible impact of the industry on New York City's watershed — has put hydraulic fracturing on hold for further study, while some members of Congress are looking to tighten regulation of drilling. "We were not ready for this," says John Quigley, former head of Pennsylvania's department of conservation and natural resources. "We weren't ready for the technology or the scale or the pace." (See America's natural gas boom.)

And that's what makes this new energy revolution — because that's what it is — so complex. The richest shale-gas play and potentially the second biggest natural gas field in the world is called the Marcellus, and its heart runs straight through parts of Pennsylvania and New York. This drilling isn't taking place in the Gulf of Mexico, the Saudi deserts or lightly populated western Canada. It's happening right in the backyard of the U.S. Northeast, a densely populated place accustomed to consuming fossil fuels, not producing them. But if the global appetite for gas and oil keeps growing, rural Pennsylvania won't be the last unlikely place we'll drill. Because for all our fears of running out of oil, we should be able to find more than enough fuel to keep the global economy humming — provided we're willing to drill in deeper, darker, more dangerous or more crowded places. The Arctic, the ultra-deep ocean off Brazil and New York City's watershed all could go under the drill as we enter what the writer Michael Klare has called the Era of Extreme Energy. The power will keep flowing — but with environmental and even social costs we can't yet predict. (See "Down and Dirty.")

It wasn't news to fossil-fuel experts that the Marcellus Shale — a 400 million-year-old narrow band of black rock that lies thousands of feet deep — could contain gas. Shallow natural gas wells have been drilled in the Northeast for decades. But shale like that of the Marcellus is made up of deep, hard rock, and it does not surrender its gas easily. Shale wasn't worth the trouble — until a veteran wildcatter named George Mitchell began experimenting with the Barnett Shale in Texas in the 1980s. Mitchell found that a mix of horizontal well drilling and hydraulic fracturing — more on that later — could allow him to pry gas from the shale. "It was lore in the gas industry that you would hurt a well by putting water down it," says Terry Engelder, a geoscientist at Penn State University. "These guys discovered that the more water they used, the better."

See pictures of critters caught in the Gulf oil spill.

Watch TIME's video "America Wants In on China's Clean-Energy Biz."

Engelder should know; he played a key role in the discovery of the Marcellus Shale. At the beginning of the last decade, a Texas-based company called Range Resources began experimenting on Marcellus wells in western Pennsylvania. The company had little more than expensive holes to show for it until it began tweaking Mitchell's method. By August 2007, Range had a winner, even as Engelder, a gas-shale expert, began to realize just how huge the Marcellus play could be. During a December 2007 conference call with investors, Engelder estimated the recoverable amount of natural gas in the Marcellus at 50 trillion cu. ft. (1.4 trillion cu m). Estimates now range up to 10 times as high, which would provide the energy equivalent of 86 billion barrels of oil. "I remember thinking, Merry Christmas, America," Engelder says now. "It was absolutely an amazing thing."

The agents of drilling companies had already begun moving into Marcellus territory, snapping up gas leases. That's not unusual in Pennsylvania — most farmers and other large landholders have leased the gas rights to their land for decades, often for little more than a few dollars an acre (0.4 hectare). But not much actual drilling was ever done. (Landholders are paid an up-front bonus per acre for a lease, plus some percentage of the value of any produced gas as a royalty.) When word got out that the Marcellus was for real, the price for leases skyrocketed — rising to $5,000 an acre by the summer of 2008, according to Engelder — and dozens of gas companies jostled for territory. Once land was leased, the drilling rigs arrived, clustering in rural areas of southwestern and northeastern Pennsylvania. More than 2,400 Marcellus wells were drilled from 2006 to the end of 2010 in the state, and some 300 were drilled before March 10 of this year. "It's like a treadmill. Companies have to keep drilling wells and adding new ones to their inventory," says Tim Considine, an energy economist at the University of Wyoming. "That's a lot of activity that adds up." (Talking clean energy with America's greenest executive.)

Considine co-authored an industry-sponsored study in early 2010 that estimated that Marcellus drilling would create or support 88,000 jobs that year and more than 100,000 in 2011, plus billions of dollars in economic value for the state. Those numbers are debatable, but it's impossible to miss the buzz of economic activity in drilling regions. Relatively few of those jobs directly involve drilling and fracking —most of that work goes to roughnecks with Texas or Oklahoma license plates on their pickups — but there are work and wages for local truck drivers, subcontractors, waiters and bartenders. Rural Bradford County has long been one of Pennsylvania's poorer areas, but last year the county led the state in job creation. Gregg Murrelle manages the Riverstone Inn and Comfort Inn in Towanda, the Bradford County seat, and his hotels are fully booked for weeks on end, full of gas workers on 14-day stints. He's building another unit, and he estimates he's hired an additional 20 employees since the drillers moved in, with another 15 to 20 needed for the new hotel. "It's just been wonderful that these businesses have come into the area," says Murrelle, who has leased the land around his properties for drilling. "We're not being impacted by the recession at all."

For a state that is billions of dollars in debt, it's hard to resist the economic potential of drilling, drilling and more drilling — not that many politicians are trying. A just-released Penn State study found that sales-tax revenues from Pennsylvania counties with at least 150 Marcellus wells experienced an 11.36% increase from 2007 to 2010, while counties without wells experienced sharp declines. New Republican governor Tom Corbett — who has received hundreds of thousands of dollars in contributions from the gas industry over his career — sees the Marcellus as the key to Pennsylvania's economic rebirth, and he's already begun removing some limits on drilling. "The Marcellus is a resource, a source of potential wealth, the foundation of a new economy," said Corbett last month in his maiden budget address. "Let's make Pennsylvania the Texas of the natural gas boom." (Watch breakthroughs at the Energy Summit.)

Which, as some very unhappy Pennsylvanians see it, is exactly the problem.

The Flowback

It wasn't the fact that the gas company used the family driveway to bring hundreds of trucks to the well being drilled on their property that annoyed the Johnsons so much. Nor was it that the multi-acre well pad was just a few hundred feet from their back door, even though the Johnsons had leased hundreds of acres on their dairy farm outside Wellsboro. But when their cows last summer ended up drinking from a suspected leak in a drilling wastewater pond —slurping up water contaminated with the radioactive element strontium — that was too much. You don't mess with a farmer's livestock, and dozens of the Johnsons' cows had to be kept in quarantine. "We wished the gas company had never come around here," says 75-year-old Don Johnson, who has lived in the area his entire life. "They affected the water, and without water you can't farm here and you can't live here."

See pictures of the Gulf oil spill.

See "Fear and Loathing in the Oil Market."

It's water that's at the heart of the environmental impact of shale-gas drilling. To understand why, you need to understand how horizontal well drilling and hydraulic fracturing work. The name isn't accidental —as much as 5 million gal. (19 million L) of water is used in a typical hydraulically fractured (or hydrofracked) well in the Marcellus. First a drilling rig will dig a vertical hole several thousand feet deep, gradually bending until the concrete-encased well reaches the shale layer. After burrowing horizontally for as much as a mile (1.6 km), the drillers lower a perforating gun down to the end of the well. That gun fires off explosions underground that pierce the concrete and open up microfractures in the shale. The drillers then shoot millions of gallons of highly pressurized water, mixed with sand and small amounts of additives known as fracking chemicals, down the well, widening the shale fractures. Natural pressure forces the liquids back up the well, producing what's known as flowback, and the gas rushes from the fractures into the pipe. The grains of sand included in the fracking fluid keep the shale cracks open — like stents in a clogged blood vessel — while the well produces gas for years, along with a steadily decreasing amount of wastewater from deep inside the shale.

Many environmental activists worry that fracking fluid could somehow contaminate nearby groundwater. Even though fracking chemicals make up only perhaps 0.5% of the overall drilling fluid, in a 5 million–gal. (19 million L) job, that would still amount to some 25,000 gal. (95,000 L). It's not always clear what those chemicals are, because the industry isn't required to release the precise makeup of its fracking formulas — and drilling-service companies like Halliburton have been reluctant to reveal the information. (It's not for nothing that a provision in the 2005 energy bill that prevents the Environmental Protection Agency from regulating hydraulic fracturing has been nicknamed the Halliburton loophole.) Gas companies compare fracking additives to household chemicals, but some environmentalists and scientists believe the formulas can contain toxic ingredients. When the fracking fluid mixes with the shale, it may also become contaminated with radioactivity —the Marcellus is slightly radioactive — while growing increasingly brackish. "You bring everything the fluid encounters down there back to the surface along with the gas," Michel Boufadel, an environmental engineer at Temple University, told TIME last year. (See "Building a Country By Switching On the Lights.")

The chance that fracking fluid could directly escape through the deep fractures created by the process and contaminate groundwater appears remote. The Marcellus Shale is separated from aquifers by thousands of feet of rock, much of it impermeable, and the gas industry argues that there has never been a proven case of water contamination through hydraulic fracturing. "I don't think it's scientifically plausible to suggest that could happen," says Don Siegel, a hydrogeologist at Syracuse University. In a 2009 study, the Ground Water Protection Council, a consortium that includes industry and state regulators, reported that the chance of aquifer contamination was extremely low, echoing the results of a 2004 EPA review of hydraulic fracturing. But that EPA report has been criticized, and the science is open enough that the agency is beginning a comprehensive new study of the relationship between hydraulic fracturing and drinking water.

Of greater concern is what may be happening closer to the surface. Wells need to be properly cemented to prevent any gas or fluid from escaping before it's collected. Cementing is one of the trickiest parts of drilling — a bad cement job helped lead to the Deepwater Horizon blowout last year — and it can and does fail over time. That seems to be what happened in the northeastern Pennsylvania town of Dimock, where the state government has said poor cementing around well casings by the drilling company Cabot allowed methane to contaminate the water wells of 19 families. Methane isn't dangerous to drink, but in high enough concentrations it can cause water to burn and even explode — which is exactly what happened to one Dimock family's well in 2009. (Cabot has denied that it caused the methane contamination, which the company claimed was naturally occurring, but it did offer the affected residents compensation.) "We were never forewarned about this risk," says Craig Sautner, one of 14 affected Dimock residents still suing Cabot. "I worry that this took years off our lives."

Beyond well problems, there's the threat of spills like those that struck the Burnetts and the Johnsons. The gas industry says such accidents are rare. "We drill 35,000 wells a year, and 95% are fractured," says Lee Fuller, executive director of Energy in Depth, a gas trade group. "We need to put this in a context that reflects all the successes as well as the failures." Still, in 2010 the Pennsylvania department of environmental protection issued 1,218 violations, out of 1,944 inspected Marcellus wells, for offenses ranging from littering to spills on drill sites. Wells have blown out, and explosions from methane contamination have destroyed homes. Shale-gas drilling is an industrial process, and the more wells that are drilled, the more often something will go wrong — and in a populated state like Pennsylvania, those accidents will be felt. (See "The Greening of the American Brain.")

Even if everything goes right, hydraulic fracturing can produce over 1 million gal. (3.8 million L) of toxic, briny wastewater over the lifetime of an individual well. In western states like Texas, companies can store the wastewater in deep underground control wells, but Pennsylvania's geology makes that difficult. As a result, drillers have had to ship much of their wastewater to municipal treatment plants —and as a recent New York *Times* investigation showed, those plants are often incapable of screening all drilling-waste contaminants. Although Pennsylvania has begun to tighten treatment regulations and gas companies are recycling increasing amounts of wastewater — reusing it in additional frack jobs — the problem is still one of the biggest challenges in drilling. "There are only a few thousand wells now, but there will be far more," says Anthony Ingraffea, a structural engineer at Cornell University. "What will life be like when there are 100,000 wells here?"

See if environmentalism has lost its spiritual core.

After an oil calamity, is it time for natural gas?

That's the fear of many Pennsylvania residents. It's not just the worries about what might be happening to their water; it's also what they know is happening to their communities. Trucks crowd country roads, ferrying drilling fluid and equipment to and from wells. Jobs are up, but some businesses have suffered as employees have fled for higher-paying jobs in the gas industry. As rig workers have snapped up every available room in tiny towns, rents have skyrocketed, punishing low-income families who don't own their homes. Those who had moved to the area for a quiet Pennsylvania — and those who've valued that peace for generations — feel betrayed. "I think it's been a good thing overall," says John Sullivan, a commissioner for Bradford County. "But I just wish we could keep the economic benefit and minimize everything else."

The Cleaner Fuel

Good luck with that. Make no mistake: in a post-Fukushima world, the U.S. will use this gas. It's important to cast the environmental controversies surrounding shale drilling against the backdrop of the fossil fuel that, if all goes well, gas should help displace: coal. From mountaintop-removal mining to its impact on climate change, cheap coal is toxic to the human race. Thousands die in coal mines annually around the world; in the U.S. alone, air pollution from coal combustion leads to thousands of premature deaths a year. Natural gas power plants, by contrast, emit far fewer air pollutants. Natural gas's benefit over coal when it comes to climate change is less clear-cut, but it's there, and gas can also coexist with renewable energy, providing inexpensive backup for wind and solar. "Natural gas could be crucial to integrating renewables into the power grid," says Ralph Cavanagh, a co-director of the Natural Resources Defense Council's energy program. (See 12 people to blame for the Gulf oil spill.)

Still, Cavanagh has a warning: "Industry can blow this if it doesn't meet the public's environmental expectations." Those expectations will almost certainly include tougher regulations. In the U.S., that can be done, starting at the federal level, by giving the EPA the power to do a life-cycle analysis of hydraulic fracturing, looking at the cumulative impact of wide-scale drilling on water supplies. Representative Maurice Hinchey of New York and Senator Robert Casey Jr. of Pennsylvania have submitted commonsense pieces of legislation that would require industry to disclose the identities of chemicals used in fracking jobs. The bulk of the oversight may still be done by states, but governors will need to take care that drilling doesn't outpace regulators, as happened in Pennsylvania. The best gas players can keep improving their rates of recycling wastewater — Chesapeake Energy says it has a 100% recycling rate — while making use of new technologies like those offered by the Utah-based firm Purestream, which can evaporate and clean wastewater at the wellhead. Areas like the New York City watershed that are too valuable should be kept off-limits. "The gas is out there, and it can be accessed," says Dean Oskvig, president and CEO of Black & Veatch's energy business. "But we do need to solve the environmental issues surrounding that extraction." (See pictures of the world's most polluted places.)

If that can be done right, shale gas really could change the way we use energy for the better. But even if it does, the industry will still fundamentally remake parts of the U.S., and of the world, in ways we won't always like. But that's the price of extreme energy, and it's one we'll continue to pay until we can curb our hunger for fossil fuels or find a cheap, reliable and clean alternative to them.

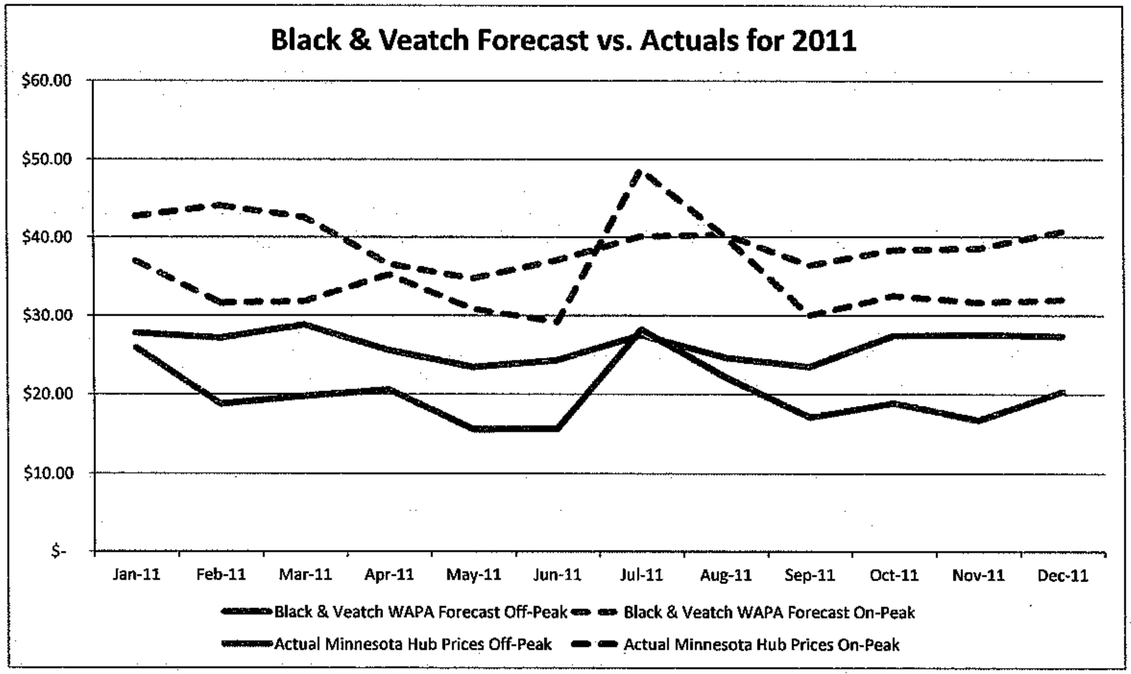
For some people, though, the price may simply be too high. Cindy Copp's family had lived in northeastern Pennsylvania's Tioga County for five generations, and after selling her home in town recently, she'd planned to open an organic farm. But as the quiet 50-year-old learned more about what drilling might do to the land — and as the gas boom made her hometown unrecognizable — she surrendered. "I tried to start my community, but the community is fractured," she says, her eyes welling. "I don't see a future here."

Instead, Copp is moving to a rural commune near Hudson, N.Y. There's no shale-gas drilling there — yet.

Find this article at:
http://www.time.com/time/magazine/article/0,9171,2062456,00.html

Black & Veatch 2011 Forecast compared to Actuals

	TOD/Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Annual
Black & Veatch WAPA Forecast	Off-Peak	$ 27.75	$ 27.12	$ 28.82	$ 25.59	$ 23.45	$ 24.31	$ 27.52	$ 24.63	$ 23.48	$ 27.43	$ 27.57	$ 27.38	$ 26.26
	On-Peak	$ 42.70	$ 44.09	$ 42.58	$ 36.61	$ 34.76	$ 37.07	$ 40.10	$ 40.35	$ 36.41	$ 38.36	$ 38.53	$ 40.68	$ 39.35
Actual Minnesota Hub Prices	Off-Peak	$ 25.84	$ 18.74	$ 19.76	$ 20.54	$ 15.55	$ 15.63	$ 28.14	$ 22.13	$ 17.07	$ 18.88	$ 16.70	$ 20.31	$ 20.14
	On-Peak	$ 36.95	$ 31.61	$ 31.83	$ 35.23	$ 30.85	$ 29.12	$ 48.61	$ 40.02	$ 29.99	$ 32.51	$ 31.68	$ 32.01	$ 34.53
WAPA - B&V	Off-Peak	$ (1.92)	$ (8.38)	$ (9.06)	$ (5.05)	$ (7.89)	$ (8.67)	$ 0.62	$ (2.50)	$ (6.41)	$ (8.55)	$ (10.87)	$ (7.07)	$ (6.11)
	On-Peak	$ (5.75)	$ (12.48)	$ (10.75)	$ (1.39)	$ (3.91)	$ (7.95)	$ 8.52	$ (0.33)	$ (6.42)	$ (5.86)	$ (6.85)	$ (8.67)	$ (4.82)



The Black & Veatch forcast for 2011 was higher than actual prices in all months of 2011 other than July. On a year average basis, their On-Peak forecast was 14% higher than actual and the Off-Peak forecast was 30% higher than actual

Comparison to Black & Veatch Price Forecast

	LANDS ENERGY FORECAST				BLACK & VEATCH FORECAST					
	NO CARBON		WITH CARBON		Black and Veatch			Difference		Oak Tree
	HLH PRICE	LLH PRICE	HLH PRICE	LLH PRICE	On-Peak	Off-Peak	Average	On-Peak	Off-Peak	Offer Price
2011					$ 39.35	$ 26.26	$ 32.48			
2012	$ 32.32	$ 20.03	$ 32.32	$ 20.03	$ 39.64	$ 26.46	$ 32.73	$ (7.32)	$ (6.43)	$ 54.40
2013	$ 35.41	$ 22.04	$ 35.41	$ 22.04	$ 43.78	$ 28.46	$ 35.76	$ (8.37)	$ (6.42)	$ 55.76
2014	$ 38.01	$ 23.20	$ 38.01	$ 23.20	$ 50.06	$ 32.46	$ 40.85	$ (12.05)	$ (9.26)	$ 57.15
2015	$ 39.85	$ 24.33	$ 42.35	$ 25.88	$ 54.40	$ 36.18	$ 44.86	$ (12.06)	$ (10.29)	$ 58.58
2016	$ 40.95	$ 25.00	$ 43.45	$ 26.52	$ 67.59	$ 53.58	$ 60.26	$ (24.14)	$ (27.06)	$ 60.05
2017	$ 42.08	$ 25.69	$ 44.58	$ 27.21	$ 71.05	$ 55.99	$ 63.14	$ (26.47)	$ (28.78)	$ 61.55
2018	$ 43.24	$ 26.40	$ 45.74	$ 27.92	$ 74.52	$ 58.17	$ 65.98	$ (28.78)	$ (30.25)	$ 63.09
2019	$ 44.43	$ 27.13	$ 46.93	$ 28.65	$ 76.31	$ 59.75	$ 67.65	$ (29.38)	$ (31.10)	$ 64.66
2020	$ 45.66	$ 27.88	$ 50.65	$ 30.92	$ 75.39	$ 59.91	$ 67.29	$ (24.74)	$ (28.99)	$ 66.28
2021	$ 46.92	$ 28.64	$ 51.91	$ 31.69	$ 77.24	$ 61.94	$ 69.23	$ (25.33)	$ (30.25)	$ 67.94
2022	$ 48.21	$ 29.43	$ 53.20	$ 32.48	$ 78.48	$ 63.60	$ 70.68	$ (25.27)	$ (31.13)	$ 69.64
2023	$ 49.54	$ 30.25	$ 54.53	$ 33.29	$ 80.65	$ 65.43	$ 72.67	$ (26.12)	$ (32.14)	$ 71.38
2024	$ 50.90	$ 31.08	$ 55.90	$ 34.12	$ 81.50	$ 66.79	$ 73.82	$ (25.61)	$ (32.67)	$ 73.16
2025	$ 52.31	$ 31.94	$ 59.80	$ 36.50	$ 83.37	$ 68.37	$ 75.50	$ (23.57)	$ (31.87)	$ 74.99
2026	$ 53.75	$ 32.82	$ 61.24	$ 37.38	$ 85.72	$ 70.74	$ 77.87	$ (24.48)	$ (33.36)	$ 76.87
2027	$ 55.23	$ 33.72	$ 62.72	$ 38.29	$ 88.08	$ 73.10	$ 80.23	$ (25.36)	$ (34.82)	$ 78.79
2028	$ 56.75	$ 34.65	$ 64.25	$ 39.22	$ 90.44	$ 75.47	$ 82.60	$ (26.19)	$ (36.25)	$ 80.76
2029	$ 58.32	$ 35.61	$ 65.81	$ 40.17	$ 92.79	$ 77.83	$ 84.96	$ (26.98)	$ (37.66)	$ 82.78
2030	$ 59.93	$ 36.59	$ 67.42	$ 41.15	$ 95.15	$ 80.20	$ 87.33	$ (27.73)	$ (39.04)	$ 84.85
2031	$ 61.58	$ 37.60	$ 69.07	$ 42.16	$ 97.97	$ 82.98	$ 90.13	$ (28.90)	$ (40.82)	$ 86.97
2032					$ 100.79	$ 85.77	$ 92.93			
2033					$ 103.60	$ 88.55	$ 95.74			
2034					$ 106.42	$ 91.34	$ 98.54			
2035					$ 109.24	$ 94.12	$ 101.34			
Levelized for 2012-2031	$44.10	$26.99	$47.40	$29.01	$67.88	$52.44	$59.80			$65.10
Levelized for 2012-2015							$38.13			$56.33

Exhibit SEL-09

Comparison of Price Forecasts for HLH

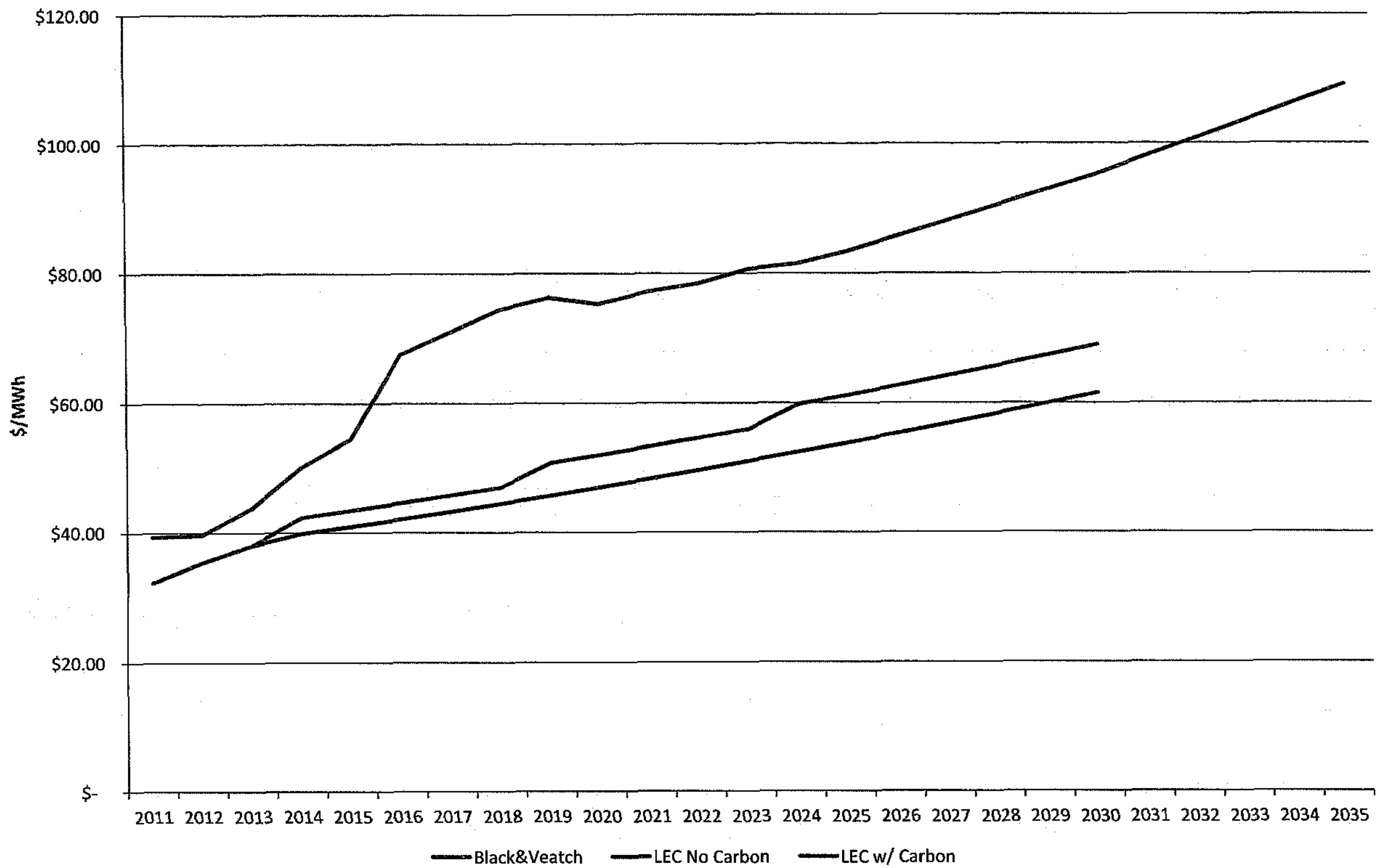


Exhibit SEL-09