January 2010

OTC Derivatives Reform:

Energy Sector Impacts

AGA American Gas Association

epsa Electric Power Supply Association
Advocating the **power** of competition

AXPC American Exploration & Production Council

ipaa America's Oil & Gas Producers

American Public Gas Association

National Rural Electric Cooperative Association
A Touchstone Energy® Cooperative

APPA American Public Power Association

NGSA Natural Gas Supply Association

AMERICA'S NATURAL GAS ALLIANCE

pjm

EEI Edison Electric Institute

OTC Derivatives Reform:

Energy Sector Impacts

Prepared by:

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American Exploration & Production Council
American Public Gas Association
American Public Power Association
America's Natural Gas Alliance
Edison Electric Institute
Electric Power Supply Association
Independent Petroleum Association of America
National Rural Electric Cooperative Association
Natural Gas Supply Association
PJM Interconnection LLC

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EXECUTIVE SUMMARY

The organizations below, representing the electric and natural gas industries and serving nearly all energy customers in the United States, support the goals of the Administration and Congress to improve transparency and reduce systemic risk in over-the-counter (OTC) derivatives markets. **As the Senate considers financial reform legislation, we believe it is essential that it preserve the ability of companies to access critical OTC energy derivatives products and markets.**

Energy commodities compose a small fraction – less than one percent – of the global OTC derivatives market, but our members rely on these products and markets to manage price risk and keep rates stable and affordable for retail consumers. Importantly, we would like to clarify that we represent only the listed energy sector organizations and not any financial or banking institutions. Our members' interests are focused on commercial risk management and well-functioning energy markets.

Specific examples from our organizations show that mandatory clearing or margining requirements could have many adverse and unintended consequences for legitimate end-users and the public:

- In 2009, an independent exploration and production company would have had $700 million less cash to invest in natural gas production, eliminating 240 wells in the Fayetteville shale and costing the community an economic loss of $1.9 billion and 1,500 fewer jobs (example 1).
- Rural electric cooperatives, which serve 18 million homes, farms, schools and businesses, may not be able to meet their systems' infrastructure investment needs and could be forced to borrow large sums at unaffordable rates (example 2).
- Publicly-owned electric utilities would lose access to an extremely important financing tool: tax-exempt financing for the prepayment of long-term natural gas and electricity supply contracts (example 3; see section on "Mandatory Clearing").
- A public gas utility would need to obtain a line of credit of at least $500 million and pass through borrowing costs that would effectively double the cost of interstate pipeline transportation and raise distribution rates more than 10 percent (example 4).
- A large electric power company could immediately face cost increases of 5 to 15 percent that would ultimately be passed on to customers (example 5).
- A regulated electric utility that provides transmission and distribution services would require $300 to $400 million in cash margin, directly jeopardizing its investments in efficiency, a "smart" grid and transmission for renewable power (example 6).
- Similarly, a regulated natural gas utility could require hundreds of millions of dollars in cash margin and may be forced to reduce or cease hedging, drastically increasing price volatility for its customers (example 7).
- Unable to secure transactions with liens on their power plants, U.S. wholesale electric power developers, including wind developers, may or may not be able to obtain credit facilities totaling $75 to $100 billion. In the current and foreseeable economic environment, such credit may simply not be available (example 8).

- A competitive electric power supplier would need to provide $1 to $2 billion in cash margin to its counterparties. This severe outcome would likely result in these companies NOT hedging or substantially reducing cash devoted to infrastructure development and existing facility upgrades (example 9).
- Might require a large natural gas producer to divert 25 percent or more of its capital budget away from its core exploration and production activities (example 10).
- Barring clarification in final law, overlapping regulation of organized electricity markets, such as Regional Transmission Organization (RTO) markets, could result in all electric utilities – investor-owned, public and cooperative – facing substantial additional costs in managing their use of the electric transmission system (example 11).

American Gas Association
American Exploration & Production Council
American Public Gas Association
American Public Power Association
America's Natural Gas Alliance
Edison Electric Institute
Electric Power Supply Association
Independent Petroleum Association of America
National Rural Electric Cooperative Association
Natural Gas Supply Association
PJM Interconnection LLC

1. INDEPENDENT OIL AND GAS PRODUCER

Source: Southwestern Energy Company, member of American Exploration & Production Council, America's Natural Gas Alliance and the Independent Petroleum Association of America

The Real Cost of Eliminating OTC Hedging

What would be the impact on Southwestern's operations in the Fayetteville shale had the Company been prevented from hedging 48% of its estimated 2009 production?

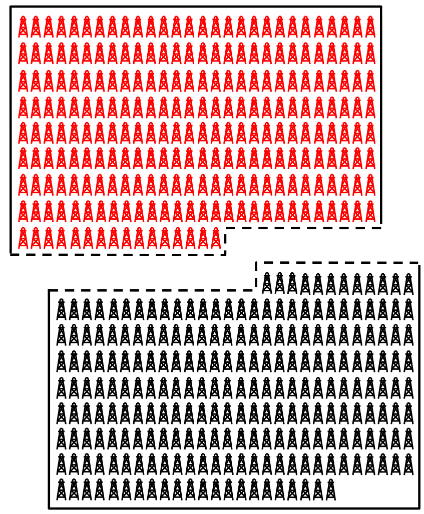
No hedges in place due to cash margin requirements.

↓

$700 million less cash available for investing.

↓

Elimination of 240 Fayetteville shale wells from our program.

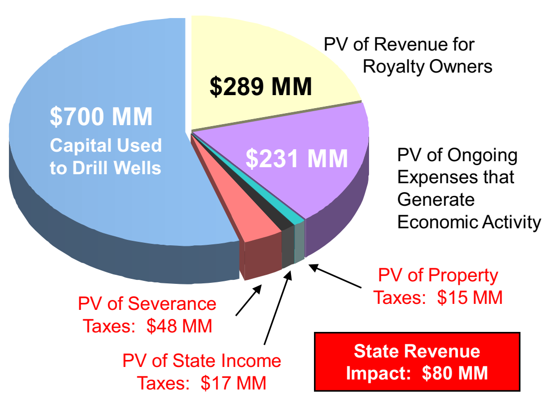


2009 Program = 470 operated wells

The Real Cost of Eliminating OTC Hedging

If Southwestern had been prevented from hedging 48% of its estimated 2009 production, what would the impact be?

Value Added: $600 MM



Total: $1,300 MM

The Real Cost of Eliminating OTC Hedging

Economic Impact

Direct Impact	$ 1,220 million
Indirect Impact	$ 561 million
State Tax Revenue Impact	$ 80 million
Total Impact	**$ 1,861 million**

Employment Impact

Oil and Gas Related Job Impact	1,000
Indirect / Induced Job Losses *	500
Total Impact	**1,500**

* Based on economic and employment multipliers published in the March 2008 study entitled "Projecting the Economic Impact of the Fayetteville shale Play for 2008-2012" by the Sam Walton College of Business Center for Business and Economic Research at the University of Arkansas.

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2. RURAL ELECTRIC COOPERATIVES

Source: National Rural Electric Cooperative Association

Testimony of the Honorable Glenn English, CEO
National Rural Electric Cooperative Association

Before the
United States Senate
Committee on Agriculture

November 18, 2009

It is an honor to appear before the Senate Agriculture Committee again, and I thank you for this opportunity to share rural electric co-ops' perspective on the issue of derivatives regulation.

As most of you know, the National Rural Electric Cooperative Association (NRECA) is the not-for-profit, national service organization representing nearly 930 not-for-profit, member-owned, rural electric cooperative systems, which serve 42 million customers in 47 states. I should also note that for the states represented by the Senators on this committee alone, NRECA has 21.6 million members and 494 electric co-ops. I know that this committee cares deeply about the fate of rural America, and before discussing derivatives, I want to thank you for your strong support of the idea that someone's standard of living should not be dictated by his or her zip code.

NRECA estimates that cooperatives own and maintain 2.5 million miles or 42 percent of the nation's electric distribution lines covering three-quarters of the nation's landmass. Cooperatives serve approximately 18 million businesses, homes, farms, schools and other establishments in 2,500 of the nation's 3,141 counties. Cooperatives still average just seven customers per mile of electrical distribution line, by far the lowest density in the industry. These low population densities, the challenge of traversing vast, remote stretches of often rugged topography, and the increasing volatility in the electric marketplace pose a daily challenge to our mission: to provide a stable, reliable supply of affordable power to our members—including your constituents. That challenge is critical when you consider that the average household income in the service territories of most of our member co-ops lags the national average income by over 14%.

Madam Chairman, the issue of derivatives and how they should be regulated is something with which I have a bit of personal history going back twenty years when I was a Member of Congress on the House Agriculture Committee. Accordingly, I am grateful for your leadership in pursuing the reforms necessary to increase transparency and prevent manipulation in this marketplace. From the viewpoint of the rural electric cooperatives, the proposals to regulate the $600 trillion over-the-counter (OTC) derivatives market can be boiled down to a single, simple concern: affordability.

NRECA's electric cooperative members, primarily generation and transmission members need predictability in the purchase price for their inputs if they are to provide stable, affordable prices to their customers. Rural electric cooperatives use derivatives to keep costs down by reducing the risks associated with both volatile energy prices and financial transaction costs. It is important to understand that electric co-ops are engaged in activities that are pure hedging, or risk management. Our consumers expect us, on their behalf, to protect them against volatility in the energy markets that can jeopardize small businesses and adversely impact the family budget. The families and small businesses we serve do not have a professional energy manager. Electric co-ops perform that role for them and should be able to do so in an affordable way. We DO NOT use derivatives for other purposes.

Most of our hedges are bilateral trades on the OTC market. Many of these trades are made through a risk management provider called the Alliance for Cooperative Energy Services Power Marketing or ACES Power Marketing, which was founded a decade ago by many of the electric co-ops that still own this business today. If a derivatives counterparty does not pay up, there will be severe consequences for our members, so we are extremely careful about who we trade with and for how much, which is why ACES Power Marketing makes sure that the counterparty taking the other side of a hedge is financially strong and secure.

Though most of our trading involves natural gas, derivatives, specifically interest rate and currency swaps, are an important asset/liability management tool for cooperative lenders as well. Half of the electric cooperatives' finance needs are met by private cooperative lenders, including the National Rural Utilities Cooperative Finance Corporation (CFC), which uses derivatives to manage currency and interest rate risk, and thereby affords our electric cooperative borrowers more loan options. Again, these products are NOT used for investment but for risk management.

Even though the financial stakes are serious for us, rural electric co-ops are not large participants in the derivatives markets. In a market estimated to be $600 trillion dollars, our members represent a tiny fraction of the market and are simply looking for an affordable way to hedge. While our small size makes us insignificant to the larger market, it does mean that legislative changes which dramatically increase the cost of hedging or prevent us from hedging all-together will impose a real burden.

I want to remind you that we are NOT looking to hedge in an unregulated market. NRECA DOES want derivatives markets to be transparent and free of manipulation. The problem is that requiring all derivatives contracts to clear is just not affordable for most co-ops. That is because the margin we would have to provide would make hedging untenable for many of our members – we would have to come up with hundreds-of-millions of dollars in cash that we just do not have on hand.

In general, co-ops are capital constrained due to their non-profit status and other capital demands, such as building new generation and transmission infrastructure to meet load growth, installing equipment to comply with clean air standards, and maintaining fuel supply inventories. As member-owned cooperatives, we cannot go to the equity markets for additional resources. Maintaining 42% of the nation's electrical distribution lines requires considerable and continuous investment. A cash margin requirement associated with clearing our trades could compromise our ability to meet that infrastructure need.

Clearing also presents a significant potential predictability issue. In case of a catastrophic event, the marketplace could change dramatically in a very short timeframe. If a catastrophic event triggered market concern over fuel supplies, ratings could shift and the prices for contracts could swing dramatically, triggering a sizable margin call for a reason unrelated to the original trade. A co-op in that position would not have the cash reserves to cover the margin call, leaving only one, unattractive option –to borrow a large sum at unaffordable rates.

Rural electric cooperatives do trade on exchange (and thus have some trades cleared) when we can. Electric cooperatives customarily have a couple thousand trades at any given time on NYMEX, but due to the working margin requirements associated with clearing and the highly specialized nature of others, most of our trades are made on the OTC market. We would like to be able to trade our standardized contracts on an exchange or go through a clearinghouse, but many of our members just cannot afford it.

With affordability in mind, NRECA has closely examined the legislative proposals produced by the Department of the Treasury, the House Committee on Financial Services, the House Committee on Agriculture, and the Senate Committee on Banking Chairman Christopher Dodd (D-CT). With regard to the requirements that OTC derivative contracts clear, and that there be capital and margin requirements for derivatives contracts, there is recognition in the Treasury, House Financial Services, and House Agriculture proposals that trades made by hedgers should be treated differently. As requested by the Chairman, I have limited my remarks on these proposal to the specific issue of clearing and margin requirements, and I would gladly discuss other issues on request.

The Treasury proposal includes both a clearing requirement for standardized trades and separate capital and margin requirements for trades that are not cleared. Exceptions to these requirements are provided, but our co-ops would have difficulty meeting these requirements because the hedge exemption in the definition of major swap participant, which is key to the clearing and capital and margin requirement exemptions, is subject to being "an effective hedge under generally accepted accounting principles (GAAP)." This requirement is problematic because, for starters, the outcome of "GAAP hedge effectiveness" is often unknown at the inception of a derivative hedge when a co-op would have to decide whether or not it would fit in the hedge exemption. Meanwhile, as most of our trades are for natural gas, and are largely standardized, it's unlikely we would meet the clearing exemption standard that, "no derivatives clearing organization registered under the Act will accept the swap for clearing." NRECA has recommended changes to the Treasury proposal that would improve upon this hedge exemption (see Appendix).

In both the House Committee on Financial Services and the House Committee on Agriculture proposals, the definition of major swap participant is, like in the Treasury proposal, a critical test for determining an exemption to the clearing requirement, as well as additional capital and margin requirements. Neither bill utilizes the problematic GAAP standard for hedging, but both pieces of legislation specifically recognize that those, like NRECA, who are using swaps for legitimate hedging activities do not qualify as major swap participants. Importantly, not only would these bills allow co-ops to continue to hedge on the OTC market, but they would also permit us to trade with counterparties who may be major swap participants – this is critical to the continued existence of liquid and functioning OTC markets for us to trade in.

Finally, Senate Banking Committee Chairman Dodd recently introduced a discussion draft proposal that included new regulations for derivatives. Unfortunately, this draft, unlike the other proposals, does not specifically exclude hedgers from its major swap participant definition. Moreover, even if it did include a workable hedge exclusion from that definition we are troubled that, as we saw in the Treasury proposal, GAAP standards are once again problematically used to define hedging, while this draft's clearing exemption provides no certainty to our members because it requires the CFTC to first issue an order or rule granting deeming it "necessary or appropriate in the public interest" to exempt the swap transaction from clearing. Also adding to the uncertainty, the CFTC may grant a clearing exemption when one counterparty is not a swap dealer or major swap participant only if such party also does not meet the eligibility requirements of any dealers clearing organization for swaps. We simply must have more certainty for our members' legitimate hedge transactions.

Madam Chairman, we are looking for a legitimate, transparent, predictable, and affordable device with which to hedge. I know there are many ideas under consideration, but regardless of what specific solution is arrived at, I know that you and your committee are working hard to ensure these markets function effectively. The rural electric co-ops just hope that at the end of the day, there is a way for the little guy to affordably manage risk.

Thank you.

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3. PUBLICLY-OWNED ELECTRIC UTILITY

Source: American Public Power Association

Testimony of

PATRICK E. MCCULLAR
PRESIDENT AND CEO OF DELAWARE MUNICIPAL ELECTRIC CORPORATION
ON BEHALF OF
THE AMERICAN PUBLIC POWER ASSOCIATION (APPA)

For the

HOUSE ENERGY AND COMMERCE COMMITTEE'S SUBCOMMITTEE ON ENERGY AND ENVIRONMENT

Hearing on "Impacts of H.R. 3795, the Over-the-Counter Derivatives Market Act of 2009, on Energy Markets"

December 2, 2009

I appreciate the opportunity to provide the following testimony for the House Energy and Commerce Subcommittee on Energy and Environment's hearing on **"**Impacts of H.R. 3795, the Over-the-Counter Derivatives Markets Act of 2009, on Energy Markets."

I am Patrick McCullar, President and CEO of Delaware Municipal Electric Corporation (DEMEC). DEMEC is a public corporation constituted as a Joint Action Agency and a wholesale electric utility. DEMEC represents nine municipal electric distribution utilities located in the State of Delaware. DEMEC is a Load Serving Entity and a Generation Owner in the PJM Regional Transmission Organization serving 13 states and the District of Columbia. The continued goal and mission of DEMEC is to advance the principles of public power community ownership and provide competitive, reliable energy supply and services to our member's stakeholders and customers. DEMEC is able to accomplish its mission through active representation and participation in regional and federal arenas. DEMEC and its member municipal electric utilities have provided competitive, reliable electric service for decades, and will continue to provide the best service at the lowest possible cost for the ultimate benefit of the consumers and communities we serve.

Today I am testifying on behalf of the American Public Power Association. APPA represents the interests of more than 2,000 publicly-owned electric utility systems across the country, serving approximately 45 million Americans. APPA member utilities include state public power agencies and municipal electric utilities that serve some of the nation's largest cities. However, the vast majority of these publicly-owned electric utilities serve small and medium-sized communities in 49 states, all but Hawaii. In fact, 70 percent of our member systems serve communities with populations of 10,000 people or less.

Overall, public power systems' primary purpose is to provide reliable, efficient service to their local customers at the lowest possible cost, consistent with good environmental stewardship. Like hospitals, public schools, police and fire departments, and publicly-owned water and waste-water utilities, public power systems are locally created governmental institutions that address a basic community need: they operate on a not-for-profit basis to provide an essential public service, reliably and efficiently, at a reasonable price.

[Two sections removed from testimony for brevity**: "Support for Greater Transparency in Energy Markets" and "Regulation of Financial Transmission Rights"**]

Mandatory Clearing

Because of the volatility of energy markets, many public power systems use OTC derivatives to hedge the prices of natural gas and electricity that they obtain to serve their end-use customers. Because of their high credit ratings, ensured ratepayer revenue and substantial investment in utility infrastructure, many public power systems do not currently have to pledge liquid collateral for transactions below certain agreed upon dollar levels.

Some proposed legislation would require all OTC derivatives transactions to be cleared. This would require many public power systems to start posting margin for all of their OTC transactions, and require them to have collateral on hand to meet potential margin calls when required.

Requiring public power systems to comply with such requirements for all of their OTC transactions would be cost-prohibitive and would directly raise the price of electricity to their end-use consumers. Rates would increase because of the direct costs associated with clearing—this would include the cost of the required margin needed for each transaction, the cost of the margin the public power system would need to have on hand at any given time, and the increased borrowing costs incurred should the system still use the market to hedge. If a public power system chose not to continue using the OTC market to hedge its transactions because of the costs associated with these requirements, prices would still increase for consumers. This is because the public power system would be exposed to increased price volatility in electricity and natural gas markets, and, as non-profit entities, would have to pass unhedged price increases through to end-use consumers in its retail rates.

Some proposals would allow entities to meet clearing requirements using non-cash collateral. This option, however, generally is not viable for public power utilities. Many of these systems are prohibited by their constitutional documents and/or bond covenants from pledging their assets in such a manner. They would therefore be required to pledge non-cash collateral in the form of liquid assets. Public power utilities do not maintain the kind of liquid assets that would be required to support a transactional requirement.

But more important, mandatory clearing would effectively eliminate the current practice by some public power entities of using tax-exempt financing for the prepayment of long-term natural gas and electricity supply contracts, also known as "prepays." The Energy Policy Act of 2005 endorsed pre-pays by making some clarifications and creating a safe-haven for users of pre-pays should they have unforeseen circumstances such as the loss of a large customer. Since that time, pre-pays have been an extremely important financing tool for public power systems. These contracts allow public power systems to firm up natural gas and electric power supplies for up to 30 years into the future. One critical component of such prepay agreements is an OTC swap transaction that allows the public power system to pay a discounted rate below the prevailing spot market price for the commodity. The OTC derivatives used in prepays are "tear up" agreements; that is, they terminate at no cost in the event the prepay terminates. Due to the size and very long-term nature of a prepay, requiring clearing of a prepay swap would be so cost prohibitive that public power systems would no longer be able to use this important tool. This would increase the exposure of retail customers served by such public power systems to price volatility and, consequently, higher end-use customer costs.

APPA supports the clearing language in H.R. 3795 that provides an exemption from clearing for end-users. APPA opposes legislation that requires all OTC derivatives to be cleared, regardless of the nature of the end-user counter-party. Requiring public power systems to clear would pose significant financial hardships to them and the local governments that own them, without addressing any of the systemic problems that caused the financial crisis in which we now find ourselves. Derivatives end-users such as public power systems do not pose systemic risk to the market, as do bank-to-bank exchanges for the purposes of profit-making. Therefore, derivatives end-users should not be subject to the same type of regulation.

FTRs and buy/sell swaps offer effective risk hedging tools for the Delaware utilities because they face significant transmission cost risks related to insufficient transmission capacity and transmission congestion in the PJM footprint. The Delaware utilities must use these hedging tools to minimize the risk of unexpected price increases in the competitive energy markets and to assure reasonable prices to our end-use consumers. Without these hedging tools, Delaware public power utilities would be exposed to additional costs of as much as 5% of total delivery costs, or $5 million annually.

Continuing to allow energy end-users such as public power systems to use non-cleared, individually negotiated OTC transactions will be extremely important to our members in order to continue to offer the best electric rates possible to their customers.

*****

In conclusion, while APPA fully supports legislation to curb manipulation in the OTC derivatives market, we urge Congress to use caution when drafting legislation in this area to ensure it does not have an unintended, adverse effect on retail electric and natural gas customers. From APPA's perspective, a well drafted bill will include the provisions necessary to curb market manipulation while preserving FERC's primary jurisdiction over RTO/ISO markets, including the FTR markets, and preserving the ability of energy end-users to use non-cleared OTC swaps to hedge against energy price volatility.

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4. PUBLIC GAS UTILITY

Source: American Public Gas Association

MUNICIPAL GAS AUTHORITY OF GEORGIA

(770) 590-1000 ● 104 TownPark Drive ● Kennesaw, Georgia 30144 ● Fax# (770) 425-3372

Sent Via Facsimile (202) 225-3013 & Email

October 6, 2009

The Honorable Jim Marshall
U.S. House of Representatives
504 Cannon House Office Building
Washington, DC 20515

Re: Over-the-Counter Clearing

Dear Congressman Marshall:

I would like to follow-up on a meeting I had with Tim Nelson of your staff last Thursday on over-the-counter (OTC) clearing. In our meeting, I mentioned that the impact of mandatory clearing of OTC swaps on the Municipal Gas Authority of Georgia and our 76 Member Cities and their customers and communities would be to require initial capital of between $230 and $250 million and that the additional cost of this capital would be about $8 million per year passed through to our Members' consumers. I checked with our Risk Manager and based on our current hedge positions, the specific range is $163 million to $243 million. The following table shows how we developed this estimate:

Type of Hedging	Volumes Currently Hedged (MMBtu)	Contract Equivalent (Contract = 10,000 MMBtu)	Initial Margin Requirement at $5,000/Contract	Initial Margin Requirement at $7,500/Contract
Residential, Commercial & Industrial Load	38,883,000	3,888	$ 19,440,000	$ 29,160,000
Storage Gas	6,140,000	614	3,070,000	4,605,000
Long-Term Supplies*	278,374,000	27,837	139,187,000	208,780,000
Basis Swaps**	27,410,000	10,964	2,741,000	2,741,000
Total	350,807,000	43,303	$ 164,438,000	$ 245,286,000

* Long-term supplies include hedges associated with 15 and 20 year firm supply prepayments and acquisitions of natural gas reserves.

** Basis swaps assume a contract equivalent of 2,500 MMBtu per contract.

Natural Gas

The Honorable Jim Marshall
Page Two

You will see in the above table that we have looked at two different estimates for the initial capital requirement -- $5,000 per contract and $7,500 per contract. The initial capital requirement for a NYMEX contract (10,000 MMBtu) is currently $4,000 per contract. However, NYMEX adjusts this capital requirement based on the overall price of natural gas and volatility. When natural gas prices hit their peak last year, the initial capital requirement was over $10,000.

As you know, in addition to the initial capital requirement, the clearing exchanges can and do require additional capital contributions based on daily mark-to-market calculations which account for fluctuations in the price of natural gas. For this reason, we would have to obtain a line of credit substantially larger than the initial capital requirement range of $163 million to $243 million to be prepared to cover capital calls resulting from a change in natural gas prices. Assuming an overall line of $500 million for our hedging activity (which may be too little) with $200 million funded for the initial capital requirement, the added borrowing costs for our organization could easily exceed $10 million per year (based on the average interest rates of the past 5 years).

When spread over our Members annual volumes, this added borrowing costs amounts to approximately 25 cents on every MMBtu delivered. This cost increase is the equivalent of doubling the cost of interstate pipeline transportation per MMBtu or raising distribution rates over 10 percent. And as we noted to Tim Nelson, this substantial increase in cost to the consumer comes without any benefit.

Again, we appreciate the opportunity to share our concerns with you. If you have any questions, please give me a call.

Sincerely,

Arthur C. Corbin
President & CEO

Cc: Tim Nelson, Legislative Assistant
Dave Schryver, American Public Gas Association

Point of Contact:

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5. LARGE ELECTRIC POWER COMPANY

Source: Member company of Edison Electric Institute and Electric Power Supply Association

EDISON ELECTRIC INSTITUTE

epsa®
Electric Power Supply Association
Advocating the ***power*** *of competition*

Hedging Costs Example: Large Electric Power Company

January 2010

What are the costs of an over-the-counter transaction?

The costs vary by transaction. In an over-the-counter (OTC) transaction, the costs are typically far less than the cost of trading on an exchange, particularly for creditworthy companies. If a company has a strong credit rating it enables its counterparties to extend to it some amount of unsecured credit. A company can also use standby letters of credit or cross-commodity netting through master netting arrangements to provide collateral or minimize a counterparty's exposure to it. Other companies sometimes offer liens on assets to enable hedging transactions. All of these measures can yield the same level of payment security at a much lower cost than the cost of posting margin on an exchange for a comparable exchange-traded product.

Consider the following example. Assume that in 2009 an electric power supplier wanted to enter into a fixed price power supply agreement with a utility for 300 megawatts of power in 2012 to hedge against the price volatility in the short term or spot market for power and lock in its income stream. Assume further that the market price the supplier gets from the utility is $50 per megawatt hour. At the power supplier's current credit rating, it is typically extended an unsecured line of credit of about $20 million. Under this hypothetical, $25 million is required to secure this transaction. Given the power supplier's unsecured line of credit, it would only have to post $5 million at the time of the deal's execution. If, however, the power supplier also trades natural gas with the counterparty, and does so under the same agreement, and the natural gas positions are worth $7.5 million, then the net exposure of the counterparty to the power supplier would be less than the $20 million line of credit - $25 million in security requirements minus $7.5 million value of the natural gas position - or $17.5 million. The end result would be that the power supplier would not have to post any margin or incur the cost associated with tying up cash for this purpose.

In contrast, as is demonstrated in the example below in response to the next question, doing the same transaction on an exchange through a futures contract or through a bilateral transaction that clears on an exchange, would necessarily cost the power supplier millions of dollars in up front collateral, even though at the time of the trade, the position creates no exposure for the exchange.

How much does it cost to conduct business on exchange versus off-exchange?

The primary cost of conducting business on an exchange, as compared to off-exchange, is the substantial margin requirements mandated for clearing or trading futures contracts on exchanges. Typically an exchange will require an initial margin in the range of five to fifteen percent of the total notional value of the transaction (the total quantity times the price). If a transaction were required to be cleared on an exchange, the exchange would determine the market value of the position on a daily basis. If the position becomes more valuable (from the exchange's perspective) because market prices have changed since the date of the transaction, the exchange will require the posting of additional "variation" cash margin. In addition to these margin costs, parties trading on an exchange also incur additional costs associated with establishing a credit facility, such as a loan or letter of credit, for the transaction and the interest costs of the required margin.

The following hypothetical transaction attempts to provide a more specific sense of the costs of transacting business on an exchange. Assume that in 2009 an electric power supplier seeks to enter into a fixed price power supply agreement with a utility for 300 megawatts of power in 2012 to hedge against the price volatility in the short term or spot market for power and lock in its income stream. Transacting such a deal on an exchange would be costly because the credit line required to do business on the exchange is substantial. The power supplier would first have to meet a 5% initial margin for its hedges on the exchange. Assuming a $50 per megawatt-hour market price, the power supplier would have to put up $6.6 million dollars of initial margin and would have to set aside another $66 million dollars for potential variation margin. Assuming the power supplier has a BBB credit rating, the interest expense on the $6.6 million would be around 5% annually. The power supplier would thus incur over $1 million in interest expense on the initial margin. The supplier would also incur another $1.1 million in expense to set up a credit facility for the $72.6 million needed to meet the margin requirement for the deal. These two expenses would add over $0.80 per megawatt hour in transaction costs. More importantly, if prices fell after the utility entered into the hedge, the margin requirements would increase as would the interest expense. If prices moved down 50% during 2009, an additional $8 M in interest expense would be incurred through 2012, adding $3.10 per megawatt hour to the cost of providing the power. So the power supplier ultimately faces a potential of $3.95 per megawatt hour, or roughly $10 million, in interest expenses to hedge the deal, which represents an 8% increase in power costs. In the normal course of business those costs will be passed along to the utility and its customers.

How much more could electricity cost if companies could only hedge on regulated markets with stricter margin and capital requirements?

It is very possible that a requirement that virtually all trading activity occur on organized exchanges, either through clearing or futures contracts, could increase the power prices charged to utilities and other customers by anywhere from 5% to 15%.

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6. REGULATED TRANSMISSION & DISTRIBUTION UTILITY

Source: Edison Electric Institute

EEI EDISON ELECTRIC INSTITUTE

Hedging Costs Example: Electric T&D

January 2010

Introduction

This paper provides a detailed example of how the mandatory use of exchange-cleared transactions would increase energy costs and reduce regulated electric utilities' capacity to invest in energy efficiency, a "smart" grid and transmission lines, such as those needed for wind power.

The example described herein compares (1) using unsecured credit, as is commonly negotiated by energy producers and users when hedging with over-the-counter (OTC) derivatives transactions (the "OTC Hedges") and (2) the costs and impacts of exchange cleared hedges, where all credit must be secured by cash collateral (the "Exchange Cleared Hedges").

Common Assumptions

We make several common assumptions in both scenarios.

A regulated transmission and distribution (T&D) electric utility typically enters into cash-settled derivatives to hedge to the cost of power it expects to buy for and deliver to its customers. Such hedges reduce the price volatility electricity customers would experience without the hedges.

For this example we will assume the utility buys a cash-settled fixed electricity swap[1] for one calendar year as a hedge. The term is 100 megawatts (MW), on-peak, at a contract price of $80/MWh. The swap will settle at a local zonal hub. On the day of transaction (execution date) the contract (or fixed) price is near or at the market price and thus the Fair Market Value – also known as the "marked-to-market" value – of the transaction is zero (or some nominal amount).

We assume the market price declines $10/MWh the day after execution of the hedge. As a result of this market price movement, there is there is mark-to-market value of approximately -$4.1 million[2]. We will assume for simplicity that the market price remains $70/MWh through settlement of the transaction.

1. OTC Hedges

In the OTC Hedge example, the two counterparties have negotiated and given each other $20 million in unsecured credit; this means that neither party needs to post collateral as long as the mark-to-market does not exceed $20 million. If one counterparty winds up with an exposure in excess of this credit line, then that counterparty would need to secure the exposure in excess of $20 million. Continuing with the example above, the -$4.1 million mark-to-market will not require additional collateral since it is below the $20 million credit line.

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1 Fixed electricity swap: a cash-settled derivative in which one party pays a fixed (negotiated) price while the other pays a floating (market) price.

2 100 MW x 1 year x 4,096 on-peak hrs/yr x -$10/MWh = -$4.1 million.

State-regulated electric utilities often negotiate contracts that do not require any collateralization unless the utility defaults on the contract. Counterparties accept such unsecured credit for several reasons, the most important of which is that the state-regulated utility has a higher probability of performance over time compared to purely unregulated power companies.

2. Exchange Cleared Hedges

If all energy derivatives had to be exchange cleared, the utility would need a bank credit facility to ensure it could provide ("post") cash collateral to cover the exchange's exposure as the price of electricity and hence the value of the contract changed.

There are three major costs to a utility using Exchange Cleared Hedges:

1) The cost of posting initial margin (required as a deposit to do business on an exchange)
2) The cost of posting variable margin (collateral required by the exchange as its exposure to the utility varies)
3) Costs to the utility for establishing a credit facility large enough to meet its largest cash margin requirement

For this example, we will ignore the credit facility cost[3]. Additionally, it is not uncommon for a utility to use a clearing broker for Exchanged Cleared Hedges. We will assume the transaction goes through a clearing broker and we will, for simplicity, ignore all fees associated with the clearing broker.

Initial margin is calculated by the exchange, and that cost is passed on to the clearing broker. The clearing broker may add an additional fee to the initial margin based on factors not required by the exchange (e.g., the utility's creditworthiness), which we will ignore. Assuming a typical initial margin of $1,650 per exchange contract and assuming one contract is 400 MWh, initial margin equals approximately $1.7 million. This results in an **initial margin cost of $85,000**[4] assuming a borrowing cost of 5%.

While a percentage of initial margin may be posted by Letter of Credit (LOC) or some other non-cash form of collateral, variation margin must be posted in cash. Additionally, clearing account fees may be added on top of initial and variable margin. Since we are ignoring all costs associated with the clearing broker, it is reasonable and conservative to assume the entire initial margin is posted in cash. The variation margin, based on the above example, is $4.1 million. Unlike the OTC Hedge, where no collateral is required to be posted, the utility must post 100% in cash collateral whenever its contract is "out of the money" and the exchange has credit exposure. Using the borrowing cost of 5%, the **expected variation margin cost is $205,000.**[5]

The combination of these costs results in Exchanged Cleared Hedges having a total cost of at least $290,000 and creates an incremental cost of $290,000 over OTC Hedges. The clearing requirement also requires the utility to assume $5.8 million in debt to finance the collateral, whereas the bilateral agreement required no such commitment. It is important to note that, since wholesale power developers and competitive electric suppliers (i.e., power plant owners) would also pay more to hedge their future sales,

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[3] This conservative approach assumes the utility has already established a credit facility that is used for multiple purposes and would be sufficiently large to meet its cash margin requirements during stressful (volatile) market conditions.
[4] Initial margin cost = ((100 MW x 4,096 hrs)/400 MWh) x $1,650 x 5%
[5] Variation margin cost = $4.1 million x 5%

customers would pay twice: once through higher costs at wholesale, and again through higher costs at the retail (utility) level.[6]

Customer and T&D Infrastructure Impact

Electric utilities often hedge far greater volumes than the one-year 100 MW contract described above. For a utility to hedge 3,000 MW of load, equivalent to several large power plants, a $10/MWh drop in market price, as described under our common assumptions, would result in P/L of approximately -$123 million[7]. Under OTC Hedges, very little collateral would be required to be posted – even for this larger volume – because the utility would contract with multiple counterparties, with the portfolio of contracts providing credit lines sufficient to absorb any out-of-the-money exposure. However, if the utility were required to use Exchange Cleared Hedges, an initial margin of approximately $51 million and variable margin of approximately $123 would be required. The annual cost to post the above total of $174 million in cash would be $9 million based on our assumed 5% borrowing cost. Again, these costs would be over and above the costs experienced by the electricity supplier (i.e., power plant owner).

If the utility maintains a significant hedging portfolio that extends over several years, the cash required and borrowing costs could be two or more times higher. **This would equate to $300 to $400 million in capital, for a single T&D utility, devoted to non-productive Exchange Cleared Hedges that could otherwise be allocated to jobs-producing investments in energy efficiency programs, a technologically advanced distribution grid, and new transmission lines, such as for wind and other renewable sources of power.** Furthermore, there are additional negative consequences that could result:

- Credit ratings agencies would reevaluate T&D utilities' liquidity risk (i.e., the risk that they would not have enough liquidity on hand to meet short-term company needs) and could downgrade their short- and/or long-term credit ratings, raising borrowing costs and ultimately customer rates (over and above the costs calculated in this paper and the higher costs at wholesale).
- T&D utilities, after weighing the negative effects of diverting capital from investment needs to exchange margin, could choose to invest and forgo hedging. This would lead directly to more volatile customer rates.

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6 For an example of these costs, please see "EEI Hedging Costs Example: Electric Generation."

7 3,000 MW x 1 year x 4,096 on-peak hrs/yr x -$10/MWh = -$123 million.

7. REGULATED NATURAL GAS UTILITY

Source: American Gas Association

AGA American Gas Association

NATURAL GAS UTILITY

Example of Cost Impact of Mandating All Hedging To Be Conducted on an Exchange or Through a Clearing House

This purpose of this document is to explain why natural gas utilities (utilities) hedge in today's market and discuss the negative repercussions of mandating that all hedging transactions be conducted on an exchange or through a clearing house.

Utilities hedge not to outguess the market, but for the sole purpose of reducing price volatility for their customers—volatility that is caused by today's fluctuating commodity market. Utilities pass the financial results of their hedging plan, whether positive or negative, to their customers subject to prudence review.

Utilities can hedge via two distinct markets. They can implement their hedging strategy via an exchange or through the OTC market.

Hedging through an exchange requires utilities to provide margin, initially as they establish their hedge position, and incrementally if the market moves against their position. Initial margin requirements on the New York Mercantile Exchange (NYMEX) during the past three years have ranged from approximately $3,250 to $11,750 per contract and are currently $5,000. A contract is for 10,000 MMbtu. If a utility had projected sales of 100 Bcf and hedged 60 percent of its projected sales by purchasing futures, it would have to post an initial margin requirement of $30,000,000 for one year's worth of hedges at today's initial margin requirement (60,000,000/10,000 X $5,000).

If the utility established its hedges at an average of $8 per contract and the market dropped to an average of $4 per contract, the utility would have to provide an additional margin requirement of $240,000,000 for that year's hedges, assuming the initial margin requirement remained unchanged (60,000,000 X $4). If the utility hedges for a period of three years in the future and the market moved against its established position by an equivalent dollar amount, the margin requirement via the NYMEX would be three times as much, or $810,000,000. Margin requirements for the period hedged are due immediately as the market moves, while the utility can only collect the cost or pass on the benefit of hedging to its customers when the customer burns its gas.

Hedging utilizing OTC instruments requires no initial margin requirement and no incremental hedging margin up to an established credit amount that is normally defined by the utility's and counterparty's credit rating. OTC hedges that don't exceed their credit limits are settled at expiration. The expiration of hedges coincides with the anticipated usage of the utilities' customers. If the utility spreads its OTC hedges over various creditworthy counterparties, the need to provide incremental margin for adverse market movement is greatly reduced or eliminated. This greatly reduces the need to establish credit facilities whose cost would be passed on to the ratepayer, whether they are needed or not. Utilities that are forced to clear all OTC trades via an exchange may be forced either to alter their hedging plans by utilizing hedging instruments that don't require margin (the purchase of calls only), or shorten their hedging horizon to lessen their margin requirements, or cease hedging altogether.

The main objective of Congress in requiring all OTC trades be cleared is the financial security of hedges. Subject to prudence review, utilities will pass on the cost or gain of their hedges to their customers as their hedges expire and their customers consume their gas. Most utilities hedge primarily for their sales customers, which are mostly residential and commercial customers who have no readily available alternative energy supply. Utilities typically hedge only a portion of their projected sales, which protects the utility from lower unanticipated usage due to weather, or from customer migration to alternative sources of energy. Thus, there is no risk to recover prudently incurred hedging costs from the customer. Because utilities pass on the cost of their prudently incurred hedges and have the financial power of their customers behind them, utilities should be exempt from clearing their OTC hedges on an exchange, and save the unneeded cost of providing margin for their customers.

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8. WHOLESALE POWER DEVELOPER (GENERATOR)

Source: Edison Electric Institute

EEI EDISON ELECTRIC INSTITUTE

Hedging Costs Example: Electric Generation

November 2009

Introduction

This paper provides a detailed example of how the mandatory use of exchange-cleared transactions would increase substantially the costs incurred by wholesale suppliers and, more importantly, retail consumers of electricity.

The costs described herein compare the costs of (1) using assets as collateral, as is commonly done in over-the-counter (OTC) derivatives markets (the "First Lien Hedges") and (2) the costs of exchange cleared hedges, where cash is used as collateral (the "Exchange Cleared Hedges"). **While the level of price assurance is the same under both scenarios, mandatory clearing results in nearly four times the cost at the wholesale level, or nearly $10 million per year in additional transaction costs at a single large power plant**[1].

Common Assumptions

We make several common assumptions in both scenarios.

An energy company owns a 1,000 megawatt (MW) power plant and expects to produce 7.5 terawatt-hours of electricity per year. The company "hedges," or agrees to sell, 100% of this production for the next three years. Because the financial markets for natural gas are more active than those for electricity, and because the prices of electricity and natural gas are closely related, the company "sells forward" (i.e., sells for deferred delivery) an amount of natural gas equivalent to its electricity production. The market heat rate[2] is 8.0, which translates 7.5 terawatt-hours of electricity into 60 Bcf of gas[3], and the market price of natural gas for delivery in 2010, 2011 and 2012 is $7 per MMBtu. At this quantity and price, the energy company will be selling gas with a notional value of $1.260 billion[4].

Given the volatility of natural gas prices, the energy company can expect that between now and 2013, the price at which it sold will be below market prices ("out of the money") 50% of the time. During this time, the buyer (or counterparty) will have exposure to (i.e., credit risk associated with) the energy company. Across the three years, this exposure could be expected to average $120 million, commonly known as "expected potential exposure" ("EPE"). However, at its peak the exposure will reach a maximum of $365 million, also known as "maximum potential exposure" ("MPE").

EPE and MPE are used in determining the credit costs of either First Lien Hedges or Exchange Cleared Hedges. We also assume that the energy company has a "BB" credit rating, which is a proxy for the company's overall creditworthiness and also affects costs in both cases.

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1 The analysis would vary based on the particular company's business model. For example, some energy companies with high (e.g., BBB) credit ratings can obtain unsecured credit from OTC counterparties and avoid the cost of a First Lien Hedge.

2 Heat rate refers to a power plant's efficiency in converting fuel to electricity.

3 7.5 TWh x 1,000,000 MWh/TWh x 8.0 MMBtu/MWh / 1 Bcf/1,000,000 MMBtu = 60 Bcf.

4 60 Bcf x 3 years x 1,000,000 MMBtu/1 Bcf x $7/MMBtu = $1.260 billion.

1. First Lien Hedges

In a First Lien Hedge, the counterparty to the energy company secures its exposure by taking a lien in assets of the energy company. A key benefit of a First Lien Hedge is that as the counterparty's exposure to the energy company increases, so does the value of the energy company's assets that provide the collateral[5]. This is commonly referred to as taking "right way risk."

When entering into a First Lien Hedge with an energy company, a counterparty understands that it is providing credit and charges the energy company for this service. Typically, this charge is based on the energy company's credit rating and the counterparty's expected potential exposure.

Using our common assumptions, the average expected credit exposure for a counterparty to the energy company is $120 million. If the counterparty estimates that 50% of this exposure would be offset by right way risk, and using a cost of credit for the "BB" energy company of 5%, the counterparty would charge the energy company by reducing the price it pays by $0.05/MMBtu[6], for a **total cost of First Lien Hedges of $9 million**.

2. Exchange Cleared Hedges

If all energy derivatives had to be exchange cleared and energy companies could not use their assets as collateral, the energy company would need a bank credit facility to ensure it could provide ("post") cash collateral to cover the exchange's exposure as the price of gas and hence the value of the contract changed.

There are three major costs to an energy company using Exchange Cleared Hedges:

1) Initial margin (required as a deposit to do business on an exchange)
2) Variable margin (collateral required by the exchange as its exposure to the energy company varies)
3) Costs to an energy company for establishing a credit facility large enough to meet MPE, or its largest cash margin requirement

Using our common assumptions, a credit facility of $365 million would be needed for Exchange Cleared Hedges and would cost 5% drawn and 1.5% undrawn[7].

Assuming a typical initial margin of $5,000 per exchange contract, initial margin would equal $90 million, $60 million and $30 million in years 1, 2 and 3, respectively. This results in average postings of $60 million per year and an **initial margin cost of $9 million**[8].

Average variation margin is based on the EPE of $120 million. Unlike the First Lien Hedges where 50% of the counterparty's credit exposure is covered by right way risk, the energy company must post 100% in cash

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5 For example, if the market price of gas increases and the energy company expects to owe (rather than receive) money on its hedge, it is also true that revenues (price x volumes) from the company's future production, and hence its creditworthiness, have increased.

6 ($120 million/year x 3 years x 5% = $18 million) x 50% not covered by right way risk = $9 million; ($9 million/180 Bcf) x 1 Bcf/1,000,000 MMBtu = $0.05/MMBtu.

7 Size of credit facility = maximum potential exposure = $365 million; assumed rates based on "BB" credit rating.

8 1 Bcf = 100 contracts; Year 1 = 18,000 contracts outstanding * $5,000 = $90 million draw on the facility; Year 2 = 12,000 x 5,000 = $60 million draw on the facility; Year 3 = 6,000 x 5,000 = $30 million draw on the facility; average draw of $60 million x 3 years x 5% = $9 million.

collateral whenever its contract is "out of the money" and the exchange has credit exposure. Using the drawn cost of 5% and a three year term, the **expected variation margin cost is $18 million**.[9]

The undrawn portion of the facility is the third component of cost. Based on a $365 million credit facility and the average draws from initial and variation margin of $180 million combined, the **cost for the $185 million undrawn portion would be $8 million**[10].

The combination of all these costs results in Exchanged Cleared Hedges having a total cost equal to $35 million[11] and creates an incremental cost of $26 million over First Lien Hedges[12], for the operations of a single large power plant over a three-year period.

Consumer and Credit Market Impact

Based on the calculations described herein, the increase to wholesale suppliers would be $1.16 per megawatt hour[13], which would increase costs to retail consumers by at least $15-17 per year based on average consumption of 14,000 kilowatt hours per year. The actual cost to consumers would be higher after accounting for the wholesaler's margin requirements and any hedging by the consumer's retail provider, whose costs could also be expected to increase. Furthermore, the wholesaler's and consumer's costs would be higher in markets with a higher heat rate (i.e., with less-efficient generating plants) and if natural gas prices were more than $7 per MMBtu. We believe these additional costs and/or increases would easily translate into **a total increase in costs to consumers of approximately $30-50 per year**.

Mandatory clearing would also cause an incremental capital drain on both the power industry and the financial system. We estimate that current and planned electric plants with a total capacity of at least 200,000-300,000 megawatts would require **$75-100 billion in credit facilities** to meet exchange margin requirements. These are plants owned or planned by wholesale developers and marketers of electric power, including wind developers, all of which use the OTC market to hedge their cash flows. Mandatory clearing would thus **reduce capital available for new generation and transmission projects, as well as to other industries and for consumer uses** (e.g., the automobile industry, small businesses, student loans).

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9 $120 million/year x 3 years x 5% = $18 million.
10 Undrawn facility = $365 – $60 – $120 million = $185 million x 3 years x 1.5% = $8.33 million.
11 Total cost of Exchange Cleared Hedges = $9 + 18 + 8 million = $35 million.
12 Net incremental cost = $35 million costs for Exchanged Cleared Hedges - $9 million costs for First Lien Hedges = $26 million.
13 $26 million / 3 years / 7.5TWh/year = $1.16/MWh increased cost to wholesale suppliers.

9. COMPETITIVE ELECTRIC POWER SUPPLIER

Source: Electric Power Supply Association

Electric Power Supply Association
Advocating the **power** of competition

10,000 MW 2010 Baseload Generation Hedge

Based on Current Pricing Environment

Peak	Off-Peak	Total	
10,000	10,000	10,000	MW to hedge per year
4096	4664	8760	hours per year
40,960,000	46,640,000	87,600,000	mwh per year
$ 116,506,000	$ 140,112,000	$ 256,618,000	Initial margin
$ 481,280,000	$ 224,338,400	$ 705,618,400	Potential variation margin
$ 597,786,000	$ 364,450,400	$ 962,236,400	Total Margin
		$ 115,468,368	Cost of Margin at 12% Cost of Capital
		$ 1.32	Per MWH cost

Based on Summer 2008 Pricing Environment

Peak	Off-Peak	Total	
10,000	10,000	10,000	MW to hedge per year
4096	4664	8760	hours per year
40,960,000	46,640,000	87,600,000	mwh per year
$ 302,720,000	$ 230,073,600	$ 532,793,600	Initial margin
$ 860,160,000	$ 419,760,000	$ 1,279,920,000	Potential variation margin
$ 1,162,880,000	$ 649,833,600	$ 1,812,713,600	Total Margin
		$ 217,525,632	Cost of Margin at 12% Cost of Capital
		$ 2.48	Per MWH cost

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10. LARGE NATURAL GAS PRODUCER

Source: Natural Gas Supply Association

NGSA
Natural Gas Supply Association

Pending Derivatives Legislation

Impact on the Oil & Natural Gas Industry

Introduction

The near collapse of the financial system in 2008-2009 has stimulated significant analysis and debate as to the root causes of the crisis and what actions can be taken to prevent this from recurring in the future. Explosive growth of the securitization market coupled with coincident growth in the over-the-counter credit default markets and a series of other dynamics led to an unstable system. As the housing market entered a downturn, it appeared to trigger a rapid devaluation of assets which in turn caused devastating effects on liquidity throughout the system. In response to this crisis, Legislators have initiated a series of actions aimed at greater transparency, higher collateral requirements and an improved regulatory and oversight framework. Many of the proposals appear to specifically target the CDS market but in the process have unfortunately expanded to encompass all derivatives, all commodities and all exchanges. Furthermore, the proposals tend to focus on the derivative risk-management tools (credit default, interest rate, foreign exchange, and commodity swaps, futures, options, etc.) rather than the root problems associated with securitized asset valuation and orderly functioning and oversight of that specific market. One fear is that by encompassing all derivatives into one category it may inadvertently burden the oil & gas industry with very high costs taking a large amount of productive capacity out of the economy.

Use of Financial Derivatives

For example, a typical, large independent oil & natural gas exploration and production company regularly deals with volatility in oil & natural gas exploration. Such companies regularly make extensive use of financial derivatives with the discrete purpose of ensuring a stable cash flow from which they can consistently fund their capital program to find and bring much needed energy resources to market. Although they may make use of exchange-traded instruments, many of their financial transactions are concluded over-the-counter (OTC) under bilateral credit agreements. These frequently use the OTC markets for efficiency and economic reasons and allows the companies to: 1) customize the instrument specifically to operations; 2) reduce the need for cash by permitting more flexibility in the types of collateral leading to a more efficient use of capital and greater liquidity; 3) provide credit exposure diversification; and 4) have the ability to modify credit arrangements depending on a variety of factors during the term of a trade.

In order to stabilize cash flow from physical operations, companies can require the use of derivatives in a future tenor, for a specific location, of a specific quality, with both flow variability and pricing features that are specifically relevant to individual asset basins they plan to develop. For example, suppose a company wants to assure the cash flow expected from a particular basin in 2011. It could trade today the outright price portion (referenced to Henry Hub in Louisiana) on the New York Mercantile Exchange. However it would only be able to transact in discrete, individual months (January, February, March, etc) rather than as one calendar strip. If the company were to try to execute this transaction for a period that far in the future, the liquidity of individual months becomes thin and the company would run the risk that it would only be able to trade some of the months but maybe not all of them at once. Additionally, there is no exchange-traded basis to account for the fact that production may be in a region where the price can be significantly different than it is at Henry Hub. Thus, the company would run the very real risk of being unable to fully secure price management objectives which could hinder its development plans for those assets. Alternatively, in today's environment a company can turn to counterparties who have purposefully established large transaction pools, or books, from which they are willing to take in numerous transactions from buyers and sellers, in varying tenors, locations, and commodities allowing companies a very efficient means to shift risks without having to devote the resources to maintain such a large transaction deal stream on its own.

Value of Bilateral Arrangements

Many financial transactions are executed OTC under bilateral credit terms generally governed by the widely accepted International Swap Dealers Association (ISDA) master agreement. Bilateral credit terms are an important feature in that there is a mutual recognition and valuation of each counterparty's creditworthiness and financial wherewithal. Should there be an adverse market move against a company's financial positions, there will be an offsetting positive effect on its physical assets which lowers the company's overall credit risk to its counterparty. Hence, the company generally is able to initiate a financial transaction under an open line of credit. Of course, if there is a significant market move over time, there is a possibility that one of the two counterparties will ultimately need to collateralize the transaction in some form. However, there is recognition in the credit valuation process that the financial instrument will settle in a time and method that is consistent with future physical cash flows and thus that threshold can be set higher than can be set by a central clearinghouse. The risk-management model used by a clearinghouse involves an analysis of historical volatility of a particular standardized instrument which is then used to assess the size of default expected based on a given participant's open financial position which could be mutualized and absorbed across all members. The model is better suited for purely financial participants not necessarily commercial participants with physical assets. The difference in collateralizing cleared transactions versus conducting business bilaterally is significant for commercial participants. For example, if all OTC commodity derivative positions were moved to a clearinghouse it might require a company to divert 25 percent or more of its capital budget away from its core exploration and production activities.

Diversification of Business Partners

In order to manage bilateral credit risk, companies typically continuously review the financial health of their counterparties and also intentionally maintain a diverse set of trading partners to ensure that no one default would be firm-threatening. A large company may have a portfolio of over 25 counterparties with whom it has financial transactions in place. This allows them to successfully navigate through numerous financial crises including the downfall of the merchant energy traders like Enron in the early 2000s and more recently the bankruptcy of SemGroup and Lehman with no adverse effect to its operations. If a company had to focus its transactions in one, or even a few, central clearinghouses it would have a highly concentrated credit exposure, undermine the company's ability to manage this exposure, and inhibit its ability to commit to long-term projects.

Clearinghouse operations have an excellent track-record having navigated through numerous default events over the years. However, if you review the safeguards in place at the New York Mercantile Exchange (NYMEX) for example, you will see that they require clearing member firms to have minimum working capital of only $5MM and contribute to a guaranty fund of only $2MM (maximum) each. The current size of the guaranty fund is $150MM and they have an additional $100MM default insurance policy. CME group appears to have higher capital reserve requirements upwards of $7 billion whereas the Intercontinental Exchange seems comparable to NYMEX. These may sound like substantial funds and it has indeed enabled the clearinghouse model to perform flawlessly for years. However, it is also true they have had nowhere near the volume and size of financial transactions being envisioned in the proposed legislation which has money flow on the order of several hundred trillion dollars not hundreds of millions.

It is not at all obvious that should all financial transactions be forced through a central clearinghouse, where firms essentially turn over their credit management functions to the clearinghouse, in the wake of a systemic crises where many major financial institutions are on the brink of default, that the clearinghouses would be any better off to withstand this type of stress. In fact, it's very possible the situation may have been worse due to the opaqueness of who has what exposure. Of course the clearinghouses could be required to significantly increase their working capital, but this would again seem an inefficient use of capital which could be put to better use elsewhere in the economy. As tumultuous as the financial crisis was, and as exposed as the financial system was to the downturn in securitized assets, a majority of the other OTC markets did function well allowing companies to manage risks efficiently and successfully.

Pending Legislation

When looking at legislation to improve the functioning of the financial sector, it appears that legislative proposals to-date treat all derivatives the same. However, there are fundamental differences between the securitized asset markets and commodities. One of the key advantages in the commodity markets is the existence of an efficient, transparent, price discovery process. Commodity futures markets such as those for energy, grain, or livestock, for example, have a physically deliverable component that continuously adjusts the price at which buyers and sellers mutually agree is the proper market clearing price at any point in time. This price, by definition, occurs at the nexus of fundamentally balanced supply and demand; and of course this is a continuously moving point.

Should the financial markets deviate substantially from the underlying physical markets for any length of time, it opens up the opportunity to arbitrage between the two markets which has the effect of bringing them back into alignment. For example, should the financial market trade artificially higher than the true physical market, then one could short the financial market at a premium, purchase the physical commodity at a discount and make delivery at expiration of the financial contract thus capturing arbitrage profits. A healthy, efficient market will rapidly move back into equilibrium as arbitragers quickly push the price back where it is justified by the physical fundamentals. This dynamic works equally well should the financial market trade at a significant discount to the true physical value. Having a liquid, efficiently functioning, physically deliverable feature to the futures markets achieves a fair, transparent, clearing price and serves to keep the financial and physical markets closely aligned.

Contrast how the energy markets function, characterized by this physical deliverability, to the securitized asset markets where complex and opaque models were used to derive 'fair-value' for these assets. When the market realized how horribly mis-priced these assets were it caused a ripple effect to roll through the derivatives markets associated with these assets. There was no opportunity for a more orderly readjustment between an underlying physical market and corresponding derivative financial instruments as exists in other commodity markets. As additional regulation is considered, serious consideration should be given to bifurcating the securitized asset markets from the physical commodity markets so as not to unduly burden a whole segment of the industry that is functioning transparently and efficiently.

Summary

In summary, it is important to support efforts that improve liquidity and transparency and that ensure that fair market clearing prices are able to be efficiently established. The draft legislation presented to-date, however, would have detrimental effects to our industry, including significantly higher transaction costs, loss of market liquidity, increased volatility, and increased credit risk. Specific legislative recommendations include the following:

- Consolidating oversight for all financial commodity instruments under the CFTC and all securities and securities-based assets (including CDS) under the SEC, while encouraging close coordination between the two agencies;
- Specific position limits should continue to be maintained on physical commodity futures contracts, and those limits should decrease appropriately as expiry approaches. The exchanges, like NYMEX, have a vested interest in establishing position limits that ensure orderly functioning of their respective markets, and they are in the best position to recommend position limits to ensure this continues. However, it would seem the CFTC should have ultimate regulatory oversight and approval authority to ensure consistent methodologies and outcomes occur across all market segments;
- Bifurcate securitized asset derivatives markets from physically deliverable commodity markets. Markets characterized by highly transparent price setting mechanisms (e.g. energy markets) can utilize a trade reporting/repository model for improved regulatory oversight. Where asset clearing prices are more opaque (e.g. securitized assets and CDS), utilize a clearinghouse model to improve the level of collateralization of the trades and oversight capabilities;
- Continue to allow commodity market participants the ability to efficiently trade OTC bilaterally and negotiate appropriate collateral terms directly with their counterparties that account for their entire asset portfolio, not simply one side of a financial transaction.

These recommendations are designed to balance improved transparency and oversight without damaging the ability to efficiently and cost-effectively bring new oil & natural gas supplies to consumers in the future.

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11. REGIONAL TRANSMISSION ORGANIZATION

Source: PJM Interconnection L.L.C.

Regional Transmission Organization

PJM Interconnection L.L.C. ("PJM") is the Regional Transmission Organization ("RTO") serving a 13-state region including the District of Columbia. As the RTO in a region serving a population of 51 million, PJM is responsible for the real time operation of the bulk power electric transmission grid to ensure that the grid reliably balances the supply and demand for electricity on a minute by minute basis, 365 days a year. In order to maintain this critical balance, PJM uses market mechanisms on a day-ahead and real-time basis, to match competitive offers for the generation of electricity with the corresponding demand for electricity at any given time. In addition, PJM ensures that load serving entities are able to meet their service obligations to their customers by allocating rights to the use of the transmission system ("FTRs") based on historic purchases by those same load serving entities. Every aspect of PJM's markets and grid operations is regulated by the Federal Energy Regulatory Commission ("FERC") pursuant to the Federal Power Act.

Certain provisions of the pending legislation, when coupled with ambiguity about whether FTRs are subject to the CFTC's jurisdiction under the Commodity Exchange Act (in addition to their clearly being regulated by the FERC under the Federal Power Act), could substantially impact the costs to load serving entities of managing their use of the transmission system.

CFTC has not identified to date, where additional duplicative or even conflicting regulation by the CFTC would provide significant benefit in the provision of this regulated product to electricity users. Moreover, a review of CFTC regulations raises substantial questions about their potential negative impact on both the cost and efficiency of today's markets for FTRs. Specifically, should RTOs be required to register as "Derivatives Clearing Organizations" under the Commodity Exchange Act, RTOs and the large and small utilities that depend on them, would face the following requirements:

- The RTO would have to raise sufficient financial resources to manage and maintain clearing functions. Today, RTOs do not have guarantee funds, intermediate default structures or other tiers of financial security. In order to conform to CFTC core principles, RTOs would need to establish these costly additional layers of protection without a clear corresponding level of benefit to consumers. To date, RTO members have agreed to share in their default risk which, by definition, is limited to the markets within the RTO itself. The markets are protected from undercapitalized participants through FERC-approved credit policies tailored to each of the RTO markets;
- The RTO would have to establish admission and eligibility standards that differ from those approved by the FERC] for those doing business within the RTO markets. Users of PJM markets range from very large utilities to very small municipal systems as well as industrial and commercial customers. As required by the Federal Power Act, FERC's regulation to date has been designed to ensure nondiscriminatory access to these markets by all players, big and small. A requirement that PJM impose new financial eligibility standards beyond its present credit requirements will flow directly through to the bottom line of these market participants and make access to RTO markets more difficult and costly for small players such as small utilities, renewable resource developers and end use customers;
- CFTC principles would require the RTO to impose margin requirements on market participants. These margin requirements would flow through as increased costs to electricity consumers without a clear and corresponding benefit;

PJM believes that an extension of the CFTC's regulatory authority to RTO markets would be of questionable benefit because the RTO markets are already subject to extensive FERC oversight. In short, unlike the drivers for other aspects of financial reform legislation, there is no "regulatory gap" in the regulation of RTO products and services that requires Congressional action. Rather, traditional CFTC regulation would be a poor fit and would open the door to duplicative and potentially inconsistent regulation by two federal regulators over a single product.

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