Energy Derivatives, Trading & Risk Management

Tim J. Kramer

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I. Power Trading

OBJECTIVES OF THIS SECTION:

1. Understanding of the different types of power
2. Understanding of basic factors affecting demand (load).
3. Understanding of basic factors affecting supply (generation).
4. Understanding of financial products and trading hubs.
5. Familiarization of basic asset-based hedging strategies.
6. Integration of #'s 1 - 5 into basic hedging and risk management strategies.

TYPES OF POWER TRADED:

Power is a commodity, meaning that one unit of power is indistinguishable from another. In market activity, however, different types of power are referenced dependant on what time the power flows. The following will describe the different types of power traded.

On-Peak: On-peak power has two definitions – one for the East Coast (defined as everything except California) and one for the West Coast (California). East Coast weekday on-peak power is defined as the 16 hour block which occurs from hour ending (local prevailing time) 0700 to the hour ending 2200, Monday through Friday. "Hour Ending 0700" means that the power starts to flow, or be delivered, at precisely 6:00:00 A.M. and goes through till 9:59:59 P.M. ("Hour ending 22:00"). It is often referred to as "5 by 16", or 5 x 16, referencing the 5 days per week and 16 hours per day the power flows. Weekend on-peak power for the East Coast is defined as HE (Hour Ending) 0700 to HE 2200 for Saturday and Sunday. On-Peak power for the weekdays in the West Coast, often referred to as "Heavy Load" or 6 x 16, is for the hour ending (local prevailing time) 0700 to hour ending 2200. It is the same nomenclature as the East Coast except for the fact that the West Coast includes Saturday. Weekend on-peak power in the West Coast is defined as Sunday, HE 0700 to HE 2200.

Off-Peak: Off-peak power is also broken down into East and West Coast. Aside from the geographic distinction, off-peak has two distinctions – weekday and weekend. Weekday off-peak on the East Coast, also called "5 by 8", is defined as the eight hour block for the hours ending 2300 to the hour ending 0600, Monday through Friday (although it actually begins on Monday at 2300 and ends on a Saturday at 05:59:59). Weekend off-peak power for the East Coast is the 2 x 8 block, HE 2300 to HE 0600 for Saturday and Sunday. For the West Coast, weekday off-peak power (also called light loads) is for HE 2300 to HE 0600 Monday through Saturday. Weekend off-peak power is for Sunday, HE 2300 to HE 0600. The following chart summarizes the time blocks:

	Weekday On-Peak	Name	Weekday Off-Peak	Name	Weekend On-Peak	Name	Weekend Off-Peak	Name	Round the Clock
East	HE 0700 to HE 2200, M - F	5 x 16	HE 2300 to HE 0600, M – F	5 x 8	HE 0700 to HE 2200, Sat – Sun	2 x 16	HE 2300 to HE 0600, Sat – Sun	2 x 8	On-Peak + Off-Peak
West	HE 0700 to HE 2200, M - Sat	6 x 16 (Heavy Loads)	HE 2300 to HE 0600, M – Sat	6 x 8 (Light Loads)	HE 0700 to HE 2200, Sun only	1 x 16	HE 2300 to HE 0600, Sun only	1 x 8	On-Peak + Off-Peak

Note that the different nomenclatures can be confusing. Because electricity is a newly developing market, having only been partially deregulated in the United States since 1996, a wide cross-section of experience levels among the various professionals involved exists. Therefore, it is ALWAYS wise to verify specifically all terms involved in a transaction. To some people, off-peak may mean "5 x 8, 2 x 24" or the evening hours during the weekday (M – F) and every hour during the weekend (Sat – Sun). To others, off-peak may mean 7 x 8, or the evening hours Monday through Sunday. And to still others, it may mean just the Monday through Friday portion, 5 x 8. Again, it will save time and money to be specific during all transactions.

SuperPeak: "SuperPeak" is an unofficial term used to define the time period of highest demand during the peak hours. For the summer, the superpeak period is roughly from 12:00 P.M. to 18:00 P.M., when the air conditioning demand is the highest during the hottest part of the day. For the winter period, there are two "mini superpeaks" - from approximately 5:00 to 8:00 A.M. and then again from 5:00 to 8:00 P.M., matching the coldest parts of the day. The morning winter superpeak coincides with when residential and industrial buildings begin to heat up after being idle. The evening winter superpeak coincides again with the industrial and residential overlaps, as buildings remain heated for workers, while individuals return home to heat their previously idle homes, operate ovens and televisions, etc.

Shoulder Hours: Shoulder hours are on-peak hours during times of the normal workday when electricity demand is the lowest. In the summer, it is generally from 0700 to 1145 A.M. This is when the temperatures are moderate, and no cooling is needed yet. In the winter, it is the period from approximately 9:00 A.M. to 5:00 P.M. This is when buildings have already been heated, and the initial demand to take the temperature of a workspace from 50 degrees Fahrenheit to 70 degrees Fahrenheit during the morning is not nearly as great as it is to keep the building maintained at 70 degrees. Additionally, the sun provides external warming, helping to reduce demand during midday hours.

TYPES OF POWER DELIVERED:

Power is scheduled to be transmissioned several different ways. Depending on the type of transmission, power will be traded at different prices. Following are the different types of transmission.

Firm/Liquidated Damages: Firm/LD power is guaranteed to be there, no excuses. If for some reason the seller does not provide the power, (or if the buyer cannot take delivery of the power – a rare occurrence) then the seller must go out into the market and procure replacement power at his own expense. If nothing can be found, the original buyer may go out and procure the missing power, using economic responsibility (i.e. finding the cheapest replacement power available). The difference between the original contract price and the replacement price is billed back to the seller (hence "Liquidating Damages"). For instance, if Rice University decides to enter the power marketing business, and sells power "Firm/LD" to Duke Energy for $50.00/mWhr and for some reason cannot deliver this or any replacement power, Duke can search the open marketplace, buy its own replacement power for $1,000/mWhr, and bill Rice for the difference ($1,000 less the original contract price of $50.00). The "force majeur" clause could potentially be invoked, which translates as an "act of God". This means that the seller is not liable for any damages that occur due to forces beyond the scope of reasonable business practices. A tornado which wipes out a generating facility would constitute force majeur. A heat wave or miscalculation on the part of the seller would not.

Non-Firm: Non-firm power is just as the name states – it may or may not be at its destination. If the seller subsequently cannot provide the power for legitimate reasons, such as a generating unit malfunctions or the seller needs it to meet its own electricity demands, then the contract is null and void. Note that an inherent trust is involved – the seller will not invoke what is commonly referred to as "price majeur" – pulling back the power from the original buyer with the intent of selling it at a higher price, and also that the seller will do everything possible to deliver the power before it has to cut the scheduled flow. Since there is an inherent risk associated with buying Non-firm power (you run the risk of it not being delivered), it usually trades at a discount to Firm/LD. Utilities would prefer to sell Non-firm power since it provides them with the ability to cancel the sale if they underestimate power demands. However, the marketplace has very little, if any, appetite in for Non-firm power due to its unreliable nature.

System Firm (Unit Contingent): System-firm, or unit contingent power, is a cross between Firm/LD and Non-firm. It is power that is sold from a specific generating unit. As long as that unit is up and operating properly, the power must be delivered from the seller to the buyer, no exceptions. If the seller made a mistake in calculating available power but the designated unit is still functioning, the buyer must receive the electricity, and the seller must find another way to meet the original obligations. However, if the designated unit is, for whatever reason, unable to operate, then the seller is absolved of any and all responsibilities to deliver the power. System-firm power is more reliable than Non-firm, but less reliable than firm/LD. For this reason, it trades at a discount to Firm/LD, but at a premium to Non-firm. This is a popular vehicle with standard utilities, as selling system-firm power gives the utility some protection if the generator goes down, yet still provides a reasonable market price.

CINERGY SINGED: Tough Wholesale Market Burns Utility

August 25, 1999

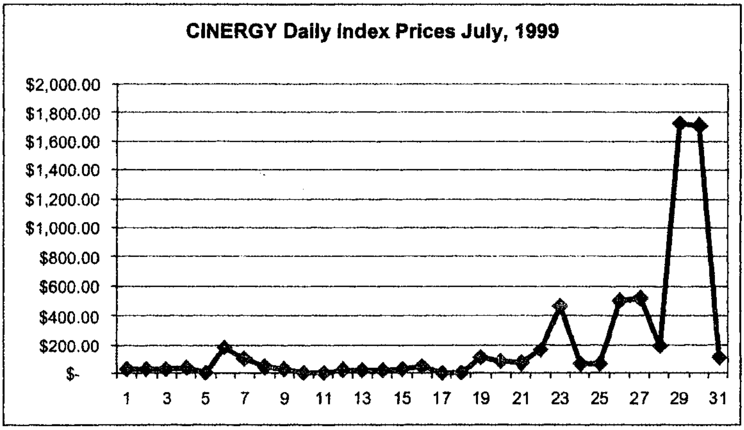
NEW YORK (Dow Jones) -- The Cinergy Corp. (CIN) traders buying and selling wholesale electricity on the afternoon of July 30 were taking a rough ride.

The Hottest Market

Imagine the Dow Jones industrial average soaring from 11,000 to 33,000. Or Microsoft Corp. stock falling from $80 to $10. In a single day. Electricity traders in the U.S. don't have to imagine; they've seen even bigger price movements this summer in what may be the world's most volatile market. Wild price swings for wholesale power didn't exist until 1996, when the federal government began deregulating sales between large producers and buyers. Before then, utilities had been protected by monopolies in their service areas and didn't compete, so they exchanged power at prices near cost. Deregulation allows power to be bought and sold on the wholesale market, under the theory that if utilities can buy and sell power freely, they won't need to build costly new power plants at customer expense. Competition was supposed to reduce and stabilize prices. That theory nearly melted down in June 1998, when a heat wave and a series of power plant shutdowns forced some Midwestern utilities to pay as much as $7,000 for a megawatt hour of electricity, which is enough juice to light 1,000 homes for an hour. Just days before, the same amount of power had been $50. Some electricity marketers and brokers went bankrupt. Cincinnati-based Cinergy Corp. spent $41 million to buy emergency energy, forcing it to take a charge against earnings. Left powerless by its supplier, Honda Motor Co. shut an Ohio assembly plant for a day. A heat wave that struck the Midwest the first weekend this past June brought back bad memories, as the cost of a megawatt hour in Ohio rose from $25.35 on Friday morning to $316.67 by Monday. But by week's end, prices cooled back down to $28.48. Another heat wave, in early July, produced an even smaller price spike. Could deregulation be working? This year will be a good test: a forecast by the East Central Area Reliability Council, a group of Midwestern utilities, predicts that this summer's peak consumption will be almost 3 percent higher than last year. Of course, there are winners, too, when temperatures and power prices soar. At Enron Corp., the nation's biggest power broker, 1998 third-quarter pretax income from wholesale energy operations was $104 million higher than a year earlier. Much of that jolt came from opportunistic electricity trading.

Mark Pittman, Josh P. Hamilton, and
Stacie Babula, with reporting by
Jonathan Berr

Bloomberg Magazine August, 1999



Load Growth: As business and residential areas expand, so too will demand for electricity. With an estimated 4% GDP for the United States (for calendar year 2000), more electricity will be needed to meet the forecasted increase in loads.

LOAD PROFILES:

As expected, load varies constantly. However, distinct patterns emerge during the different months of the year. These patterns vary by geographic location, but the general trend remains true - every month will have a morning peak and an evening peak. The morning peak occurs as people wake up, turn on their coffeepots, cook breakfast, take hot showers, dry their hair, etc. This occurs while the buildings where they work also begin to become active, as lights are turned on, photocopy machines and computers, temperature control units, etc.

The evening peaks occur for much of the same reasons. The industrial buildings are still operating at full capacity, while the residential units begin to gear up. As people come home, they repeat the routine by cooking dinner, watching television, surfing the net, etc.

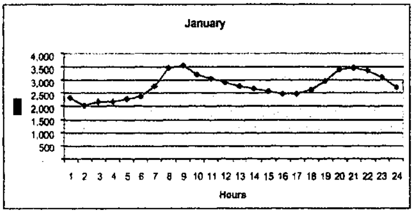
During the winter months (Jan-Feb) the morning peak is most pronounced, as heating demands are the primary driver. The other load factors (residential – cooking breakfast, showers, etc. and industrial – turning on equipment) still exist, but the primary driver for the morning winter peak is the heating demand from both residential and industrial buildings, as the morning is one of the coldest times of the day. During the summer months (Jul-Aug), the morning peak is almost unnoticeable, as there is no weather (temperature) related demands – buildings do not need to be heated or cooled during the summer mornings.

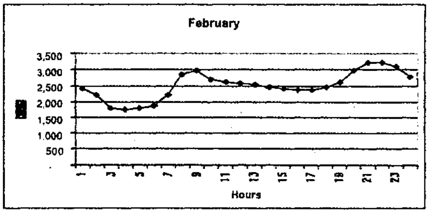
During the winter months, the evening peak is also very pronounced. The same scenario, where buildings are still operating at full capacity while individual homes begin to operate at full capacity again. In general, the evening peaks during the winter will meet or slightly exceed the morning peaks.

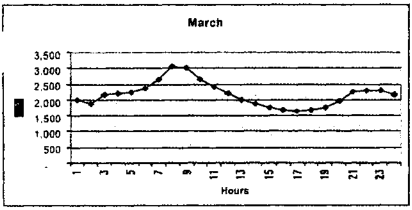
During the summer months, the evening peak is phenomenal, for lack of a better word. The air conditioning demand during a heat wave will obliterate any winter peak. Alternative sources of heating, such as gas, propane, wood, kerosene, etc. are available. However, there is only one way to cool off a building – electric air conditioning.

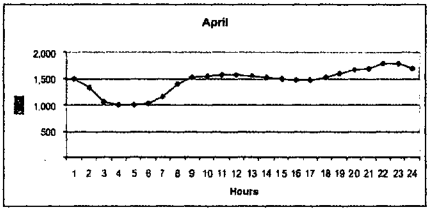
The shoulder months are a hybrid, or combination of the summer and winter. As you progress from winter to summer, the shape of the load curve transforms from a distinct morning and evening peak with an afternoon trough, to a flat line in the morning which ramps up strongly from noon until 5:00 P.M. As you progress back to the winter, the load curves again transform from a strong slope to a two-peaked shape.

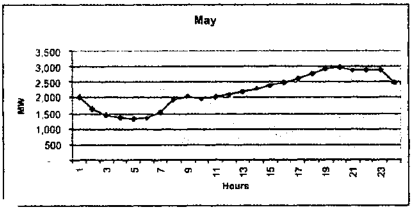
Profile of a Southeastern U.S. Load Center

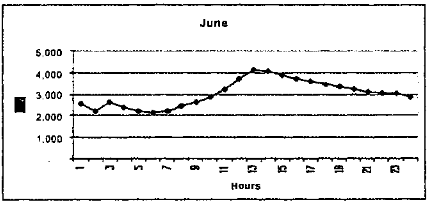




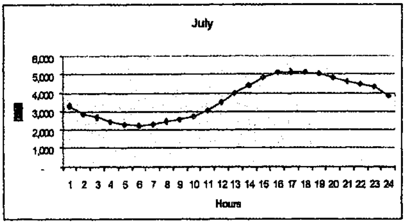


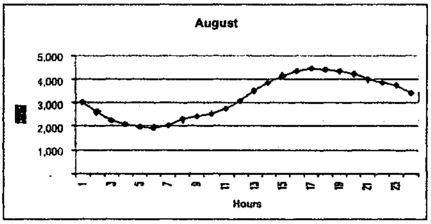


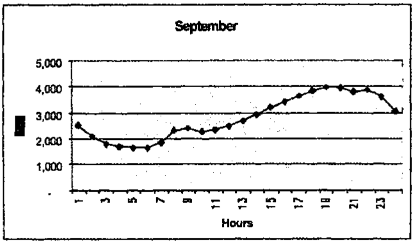


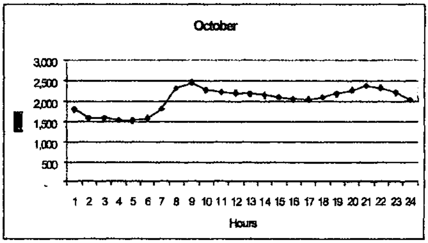


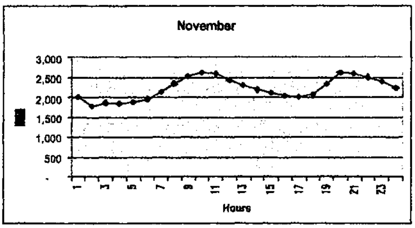
Profile of a Southeastern U.S. Load Center (Cont'd)

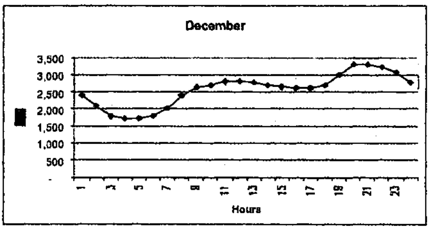












UNIT CHARACTERISTICS

Several types of units are used to generate electricity. Each unit has its own unique characteristics that must be factored into its operation. Aside from cost, flexibility in operation, start-up costs, maintenance schedules and reliability, more and more environmental factors need to be weighed.

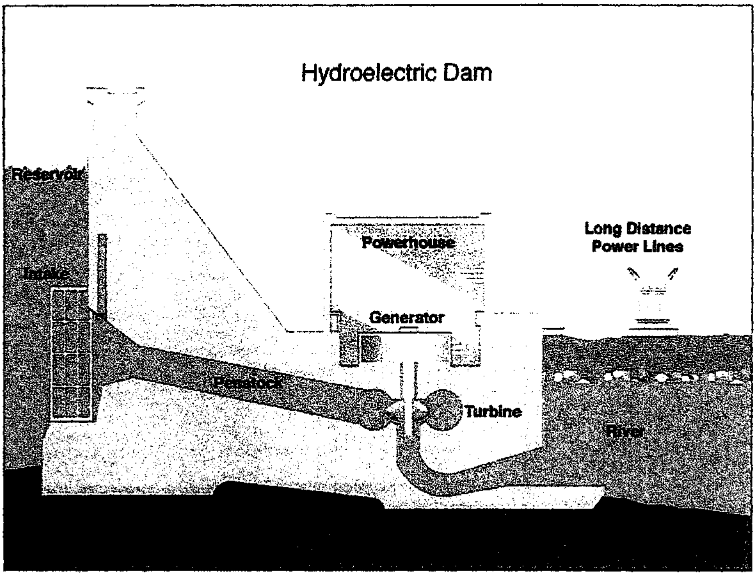
Coal Generation: Coal generators are simple – put pulverized coal into the firebox, burn it, produce steam, turn the turbine blades and produce electricity. There are very few difficulties in obtaining coal – it is readily available, easily transported by barge, rail or truck, and is in plentiful supply. Coal units are usually 700 mW's, have a minimum required output of 250 mW, and can vary the output in 50 mW blocks with ½ hour notice. Due to operating constraints, coal units usually require 72 hours notice before being placed online, must remain in operation for 72 hours, and require 72 hours notice to be taken offline. Once offline, they must remain down for 72 hours due to small preventative maintenance items. They are extremely reliable, and require scheduled extensive maintenance every 16 to 24 months. The noteworthy aspect of coal units is environmental. Burning coal produces sulfur dioxide (SO2) and nitrogen dioxide (NOX). Environmental regulations limit how much SO2 can be spewed, but additional "credits" can be purchased which allow the unit to pollute beyond the specified amount. The SO2 credits have varied in price during the last few years, from $80/ton to $225/ton, and could have a significant impact on cost effectiveness. NOX is not yet fully regulated. Regionally, these credits vary in price from $2,000/ton to $7,500/ton. Again, future consideration should be given to these costs.

Natural Gas-Fired Generation: Gas-fired generation comes in two basic types – simple or combined cycle, and gas turbine. Gas, used as the primary fuel, is cheap and readily available, but transportation is sometimes difficult. Scheduling gas to a generator depends on pipeline availability, which is sometimes difficult to procure. Simple or combined cycle gas generators are usually 750 mW, and can cycle as low as 100 mW. They have minimal start-up costs, are extremely reliable, and require very little preventive maintenance. The notification time to place online is generally 24 hours, must then remain online for 24 hours, and require 24-hour notification to take offline. Once down, they must remain idle for 24 hours. Gas turbine units (sometimes called "peakers" for their quick response) are generally 250 mW's. They can be placed online in a matter of minutes (simply by pushing a button), can cycle as low as 50 mW, and can be taken offline and placed online again with virtually no notification. The gas turbine units, because of their flexibility, are used to meet peak demands. They are not as heat-efficient and therefore not as cost effective as simple or combined cycle generators due to losing thermal efficiency through the combustion gases. Environmentally, burning gas produces CO2, which is not currently regulated, but is scheduled to be controlled by the year 2008, as per the Kyoto conference.

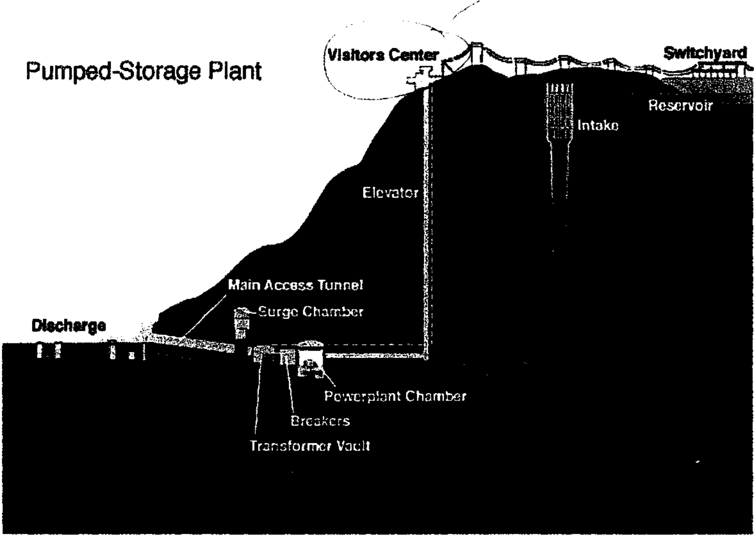
Nuclear Generators: Nuclear generators, although considered to be environmentally unfriendly, are the cheapest, cleanest and most efficient way to produce fuel. They produce between 1,000 – 2,000 mW's, and have zero operating flexibility. Once they are up and running, they must remain online and at full capacity until scheduled maintenance, which is usually every 16 to 24 months. They are extremely reliable, and have considerable infrastructure costs due to strict government regulations.

Oil-Fired Units: Generators which operate on oil are not common – most oil-fired generators are actually "dual-piped" in that they can operate on either natural gas or fuel oil. Availability of fuel oil is prevalent, as it can be piped, barged or trucked to the site. Operating characteristics are similar to those of coal units. The "72 Rule" usually applies – 72 hour notification to place online, minimum run time of 72 hours, 72 hour notification to take offline, and then a minimum down time of 72 hours. Because of cheap alternatives (coal and gas), oil-fired units are currently not popular. Older units still exist, and are used as backup or peaking units. When crude oil was recently trading as low as $11.00 a barrel, new gas units were being installed as dual operating units for both gas and fuel oil. Because of the inefficiency of the fuel and high burning temperatures inherent to fuel oil, these units are difficult to operate and expensive to maintain.

Hydro Units: Hydro units are water-powered turbine blades. The most common setup is an upper and a lower reservoir. Water is drained in a controlled manner from the upper to the lower reservoir, and it passes over turbine blades which turn, producing electricity. Once the water has collected in the lower reservoir, it must be pumped back up to the upper reservoir via an electric pump. The efficiency of these types of units is generally 75% – meaning that if water is drained out of the reservoir to produce 250 mW's for 4 hours (250 mW x 4 hours = 1,000 mWhrs), then 1,333 mWhrs will be needed to pump back the water to be used again (1,000 mWhrs/0.75 efficiency). The utility of this system is that a large discrepancy can exist between on-peak and off-peak power prices. If the 6-hour summer superpeak is trading for $500, and the off-peak is trading for $35, it would make economical sense to operate the unit. The specifics would be to produce the maximum output (say 250 mW) for the 6 hour super-peak, thus producing 250 mW's x 6 hours, or 1,500 mWhrs, at a market price of $500, for total revenue of $750,000. The cost to replace this water would be 1,500 mWhrs/0.75 efficiency, or 2,000 mWhrs, at a cost of pumping of $35, for a total debit of $70,000. The total income realized from operating this unit would be the $750,000 revenue from generation, less the $70,000 cost o pump, or $680,000. Situations this extreme do occur during the summer, but much less profitable scenarios exist all the time, and the market must be constantly monitored for such opportunities.



most important part of the operation



SUMMARY OF UNITS

UNIT	FUEL	EFFICIENCY	SIZE	MIN OUTPUT	COST PER mW	NOTICE ON	MIN ON	NOTICE OFF	MIN OFF
Coal	coal	Medium	750 mW	250 mW	$16 - $20	72 hrs	72 hrs	72 hrs	72 hrs
Gas CCGT	NatGas	Medium	750 mW	250 mW	$18 - $24	24 hrs	24 hrs	24 hrs	24 hrs
Gas Peaker	NatGas	Low	250 mW	50 mW	$30 - $60	30 min	30 min	30 min	30 min
Nuclear	Uranium	High	2,000 mW	2,000 mW	$6 - $12	N/A	N/A	N/A	N/A
Oil	Fuel Oil	Low	250 mW	50 mW	$50 - $100	48 hrs	24 hrs	24 hrs	48 hrs
Hydro	N/A	High	750 mW	250 mW	0.75 Efficiency	4 hrs	4 hrs	4 hrs	Pump Time

ASSET ALLOCATION:

Once an operating station has determined what the load forecast will be, the trick is to meet this obligation to serve power with the available resources at hand. Since electricity is a non-storable commodity, it is not possible to "turn on" all available resources, and to put into storage any power which is not used. The operating characteristics of the units must be optimized and allocated, along with purchasing and/or selling power in the open market, in order to balance generation with demand. Any excess generation that is created but not sold or used is "pushed" out into the grid system, and ZERO dollars are received for it. Any generation shortfalls that are not met (called "dragging") are "filled in" by the system operator at the cost of his most expensive unit plus a penalty fee. The trick again, is to optimize. Following are several steps taken to optimize power loads.

Generator Combination/Stack Optimization: The "Stack" is the available generation, listed in order of cost. When deciding how to allocate resources, cost, size and operating flexibility are the primary drivers. A sample of a "stack" is as follows:

UNIT	MIN	MAX	COST	STACK	MIN COST	MAX COST
Oil	50 mW	200 mW	$45	1750-1900 mW	$13.57	$16.05
Gas	50 mW	200 mW	$20	1550-1700 mW	$11.94	$12.65
Coal	250 mW	500 mW	$15	1250-1500 mW	$11.00	$11.67
Nuke	1000 mW	1000 mW	$10	1000 mW	$10.00	$10.00

Unit Commitment vs. Load Forecast: Once the operating characteristics of the stack are understood, the next step is to economically balance the units with the load forecast. This becomes an optimization problem. Again, the stated goal is to meet the scheduled load forecast with available resources as cheaply as possible – the bottom line is, "The Lights Must Stay On.". Too much power and you will "push" into the grid, and not receive any revenue for the excess generation. Not enough power, and you will be forced to buy at exorbitant prices. There are instances where it will cost money to keep a unit operating short-term, but in the long run, based on load forecasts, it will benefit the overall economics.

For example, assume a stack which consists of the following:

UNIT	COST	MIN OUTPUT	MAX OUTPUT	NOTIFICATION
#1	$15.00	500 mW	1500 mW	72 hours
#2	$45.00	500 mW	1000 mW	72 hours

And assume a simple load forecast of the following:

DAY:	MIN LOAD	MAX LOAD	COST USING UNIT #1 ONLY	COST USING #1 & #2
1	1000	1200	$15 X 1200	$15 X 700 + $45 X 500
2	1000	1300	$15 X 1300	$15 X 800 + $45 X 500
3	1000	1900	$15 X 1500 + ???	$15 X 1000 + $45 X 900
4	1000	1300	$15 X 1300	$15 X 800 + $45 X 500
5	1000	1800	$15 X 1500 + ???	$15 X 1000 + $45 X 800

Note that it is uneconomical to operate both units when examining days 1, 2 and 4 individually. However, with the 72-hour notification rule, both units must be operated for the entire 5-day period in order to maximize the overall economics. This is a simplified example, which becomes more difficult when the possibilities of buying and selling market power are introduced.

Using Own Resources vs. Market (going long/short vs. buying/selling in the open market): Electricity prices, on a short-term basis, are without question the most volatile commodity in the world.

The price of power in the marketplace will have a direct bearing on how generating units are used to meet forecasts. When market conditions permit, units can remain online when they are not needed to serve native load if the market price will support it. Conversely, additional units can be shut down when soft market prices make buying below unit costs a rational decision. Again, this is a simplified statement. The entire picture – next day as well as longer term weather forecasts – must be considered in conjunction with market prices and unit characteristics to meet load forecasts. Adding to the complication are the differences in prices between on- and off-peak power, and the efficiency ratings of any available hydro units. A specific example of how this process works, provided from an actual utility, is:

Exhibit A represents the data that a typical utility would require for next day planning purposes. The prescheduled markets at the various connection interfaces and an hourly forecast of next day load and pricing is shown.

Exhibit B represents a typical generation portfolio as analyzed on a day ahead basis. This exhibit shows the minimum and maximum capabilities of each unit along with the operating cost of the units. A load forecast is also presented for on-peak hours only in this example. The net long or short position can be analyzed with all of the units at their minimum and maximum capability. A column with a reserve margin (100MWs in this example) is included for planning purposes. No off-system purchases or sales have been included in this example. If the load forecast is correct for this utility, the net system will be short over the evening peak for the next day (HE18 – HE19) with no prescheduled purchases and with all of the units at their maximum capability. This short can be covered the following day in the hourly cash market, or prescheduled purchases can be made on a day ahead basis.

Exhibit C represents prescheduled purchases and sales that were made for our imaginary utility. In this particular example, net sales have been made. Power was purchased in one control area (SOCO), and wheeled to another control area (ESI) where it was sold. Additional sales were made into TVA and ESI as well. With the addition of these prescheduled sales, the utility is now even shorter over the middle part of the next day. The trader could have had the view that the next day hourly prices will not materialize and the net short in the afternoon will be covered for a lower amount than the revenue generated from the sixteen hour sale. The wheeling expense has been included in the prices for power that were outside of the utility's own control area.

Exhibit D represents the net revenue received from the prescheduled purchases and sales.

Exhibit E. In order to project profit and loss, the proper mix of generation, prescheduled purchases and prescheduled sales must be determined. The process of stacking the various pieces of the portfolio in order to determine how the net position will be covered is called balancing. As electricity can not be stored, the net of purchases and sales must balance to zero at the end of every hour. As prescheduled purchases and sales are fixed once committed to, the generation mix is assumed to serve the remaining position on a lowest to highest cost basis. The lowest cost unit is assumed to run as much as needed. If this is not enough generation for a particular hour, the next lowest cost unit is assumed to run. This procedure is continued for all units until each hour is balanced to zero. The net profit and loss can then be determined once the generation mix is forecasted. The physical capabilities of the unit as well as the unit cost are used in determining the proper generation mix.

Exhibit F represents the total predicted next day P&L.

Exhibit A

Next day planning for On-Peak hours only
Assume that wheels must be purchased if buying or selling into a control area other than the one you are located in - ignore losses
Assume purchases & sales are made in 50 MW blocks - enter as such on planning sheet
Assume no constraints on the amount of MWs that can be purchased or sold hourly

Location of load & units (control area)		ESI																
Time Frame		August																
Next day max temperature forecast		85 degrees F																
Next day load curve forecast	HE		7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
			1,928	2,314	2,430	2,430	2,649	2,940	3,293	3,622	3,948	4,145	4,311	4,484	4,484	4,259	4,004	3,804
Forecast Hourly Prices			20	20	25	30	40	55	60	75	90	110	125	140	125	89	35	25
(mid market ESI)	$ 66.50																	

		Bid	Offer
Next-day Prescheduled Market	TVA	$ 67.00	$ 70.00
(into products, 16 Hour	SOCO	$ 45.00	$ 50.00
schedules)	ESI	$ 65.00	$ 68.00
Wheel rates	TVA	$ 4.75	
	SOCO	$ 5.50	
	ESI	na	
Total import capability	TVA	100 MWs	
	SOCO	100 MWs	
	ESI	200 MWs	
Total export capability	TVA	200 MWs	
	SOCO	200 MWs	
	ESI	200 MWs	

Required:
1. Determine the appropriate amount and location of prescheduled sales and purchases - if any.
2. Forecast total next day P&L

* Long/Short w/ units at min & max (purch & sales included) **Exhibit B**

** Long/Short w/ units at max & reserve margin (purch & sales included)

GENERATION

DATE: 8/5/00

THURSDAY			$16.85		$22.50		$30.35		$35.75		$45.00		$69.76		Total System					
H.E.	$ 8.50	$ 9.15	**Coal 1**		**Coal 2**		**NG1**		**NG 2**		**NG 3**		**Oil**		**CAP**			*		**
C.T.	**Nuclear 1**	**Nuclear 2**	**MIN**	**MAX**	**MIN**	**MAX**	**MIN**	**MAX**	**MIN**	**MAX**	**MIN**	**MAX**	**MIN**	**MAX**	**MIN**	**MAX**	**LOAD**	**DWN**	**UP**	100
01	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
02	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
03	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
04	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
05	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
06	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
07	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	1,928	722	2,497	2,397
08	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	2,314	336	2,111	2,011
09	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	2,430	220	1,995	1,895
10	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	2,430	220	1,995	1,895
11	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	2,649	1	1,776	1,676
12	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	2,940	(290)	1,485	1,385
13	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	3,293	(643)	1,132	1,032
14	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	3,622	(972)	803	703
15	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	3,948	(1,298)	477	377
16	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	4,145	(1,435)	280	180
17	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	4,311	(1,661)	114	14
18	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	4,484	(1,834)	(59)	(159)
19	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	4,484	(1,834)	(59)	(159)
20	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	4,259	(1,609)	166	66
21	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	4,004	(1,354)	421	321
22	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725	3,804	(1,154)	621	521
23	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
24	1150	1200	400	1100	200	900	0	100	0	100	0	100	0	75	2950	4725		2,950	4,725	4,625
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)

(1) Max/Min output of Nuke 1 (no operating flexibility)
(2) Max/Min output of Nuke 2 (no operating flexibility)
(3) Min output of Coal 1
(4) Max output of Coal 1
(5) Min output of Coal 2
(6) Max output of Coal 2
(7) Min output of Natgas 1
(8) Max output of Natgas 1
(9) Min output of Natgas 2
(10) Max output of Natgas 2

(11) Min output of Natgas 3
(12) Max output of Natgas 3
(13) Min output of Oil Generator
(14) Max output of Oil Generator
(15) Minimum total output with all units on line (Nuke 1, Nuke 2, Coal 1, Coal 2). Natgas 1-3 & oil generation can remain off and have "instant start".
(16) Max total output with every available unit online & running at Max output

(17) Predicted demand or load forecast
(18) Shortfall () or excess in generation if Minimum capacity (#15) is used.
(19) Shortfall () or excess in generation if Maximum capacity (#16) is used.
(20) Same as #19 only with a reserve margin included in cell w7. This reserve margin is the amount of "cushion" one wishes to keep for load miscalculations, units outages, etc.

Exhibit C

DATE:	8/5/08																					
Thur	Location	SOCO	SOCO							TVA	TVA	TVA	TVA	ESI	ESI	ESI	ESI					
H.E.	Prices	$65.80	$65.80							$62.25	$62.25	$62.25	$62.25	$65.00	$65.00	$65.00	$65.00					
C.T.	LOAD	Purch 1	Purch 2	Purch 3	Purch 4	Purch 5	Purch 6	Purch 7	Purch 8	Sale 1	Sale 2	Sale 3	Sale 4	Sale 5	Sale 6	Sale 7	Sale 8					
01																						
02																						
03																						
04																						
05																						
06																						
07	1,928	[redacted]																				
08	2,314																					
09	2,430																					
10	2,430																					
11	2,649																					
12	2,940																					
13	3,288																					
14	3,622																					
15	3,946																					
16	4,145																					
17	4,311																					
18	4,484																					
19	4,484																					
20	4,259																					
21	4,004																					
22	3,804																					
23																						
24																						
	55,043	800	800	0	0	0	0	0	0	(800)	(800)	(800)	(800)	(800)	(800)	(800)	(800)	0	0	0	0	0
		(A)	(A)	(A)	(A)	(A)	(A)	(A)	(A)	(B)	(B)	(B)	(B)	(B)	(B)	(B)	(B)					

(A) Prescheduled purchases on a next day basis
(B) Prescheduled sales on a next day basis

Exhibit D

Forecasted P&L - On-Peak only
Off-system activity

H.E. C.T.	Purch 1	Purch 2	Purch 3	Purch 4	Purch 5	Purch 6	Purch 7	Purch 8	Sale 1	Sale 2	Sale 3	Sale 4	Sale 5	Sale 6	Sale 7	Sale 8	**Total**
01																	
02																	
03																	
04																	
05																	
06																	
07	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
08	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
09	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
10	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
11	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
12	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
13	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
14	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
15	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
16	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
17	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
18	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
19	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
20	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
21	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
22	(2,775)	(2,775)	0	0	0	0	0	0	3,113	3,113	3,113	3,113	3,250	3,250	3,250	3,250	19,900
23																	
24																	
	(44,400)	(44,400)	0	0	0	0	0	0	49,800	49,800	49,800	49,800	52,000	52,000	52,000	52,000	318,400

1. This worksheet is used to analyze & document off-system activity.
2. Any purchase or sales volumes are to be input in columns C through R/rows 13-28, the resulting P&L impact is calculated in columns C through R/rows 49-64.
3. Off system decisions should be made in light of the generation & load profile, arbitrage opportunities in the market place & the inherent risks in the overall position.
4. Net wheel charges from prices, enter positive price in appropriate blue shaded cells.
5. Physical interface limits must be observed.
6. Enter all volumes in 50MW blocks HE 7-22.
7. Enter purchase volumes as positive, enter sales volumes as negative

Exhibit E

Balancing

H.E. C.T.	Nuclear 1	Nuclear 2	Coal 1	Coal 2	NG1	NG 2	NG 3	Oil	Presched. Purchases	Presched. Sales	Hourly Buys/(sales)	Total	Diff to Load	H.E. C.T.	Forward Hourly Price Curve
01														01	
02														02	
03														03	
04														04	
05														05	
06														06	
07	1100	1200	1100	200					100	(400)	[illegible]	1928	(0)	07	20
08	1100	1200	1100	200					100	(400)	[illegible]	2314	(0)	08	20
09	1100	1200	1100	300					100	(400)	[illegible]	2430	0	09	25
10	1100	1200	1100	[illegible]					100	(400)	[illegible]	2430	0	10	30
11	1100	1200	1100	600	100	100			100	(400)	[illegible]	2649	0	11	40
12	1100	1200	1100	800	100	100	100		100	(400)	[illegible]	2940	0	12	55
13	1100	1200	1100	800	300	100	100	75	100	(400)	[illegible]	3293	0	13	60
14	1100	1200	1100	900	100	100	100	70	100	(400)	[illegible]	3622	0	14	75
15	1100	1200	1100	900	100	100	100	75	100	(400)	[illegible]	3948	0	15	90
16	1100	1200	1100	900	100	100	100	75	100	(400)	[illegible]	4145	(0)	16	110
17	1100	1200	1100	900	100	100	100	75	100	(400)	[illegible]	4311	(0)	17	125
18	1100	1200	1100	900	100	100	100	75	100	(400)	89	4484	0	18	140
19	1100	1200	1100	1000	400	100	100	75	100	(400)	89	4484	0	19	125
20	1100	1200	1100	900	100	100	100	75	100	(400)	[illegible]	4259	(0)	20	89
21	1100	1200	1100	900	100				100	(400)	[illegible]	4004	0	21	35
22	1100	1200	1100	900					100	(400)	[illegible]	3804	0	22	25
23														23	
24														24	
															$ 66.50

Notes:

1. Columns A through W give an overview of the generation & load profile of the system without off system purchases or sales.
2. After analyzing the net generation & load position, off-system decisions need to be made.
3. After all off-system decisions are made, the generating units need to be dispatched in order to estimate P&L. Place the amount of MWs each unit is expected to run in Columns Z through AD/rows 14-29 (the cells shaded blue).
4. Each unit should be dispatched in accordance with its physical operating limits and in light of the projected forward hourly market.
5. The difference to load (column AL) must be zero after all the units have been dispatched.
6. If a unit is not economical to dispatch in light of the forward hourly price curve (column AN), assume hourly purchases are made in order to balance column AL to zero.
7. If the physical capability of the unit is not sufficient to balance to zero, assume hourly purchases are made in order to balance.
8. If a unit is economical to run in light of the forward hourly price curve, but is not needed in order to serve load, assume the generation is sold in the hourly market (i.e. input hourly sales for excess generation in order to balance to zero).
9. Input hourly buys as positive and sales as negative.

Next Day P&L Forecast **Exhibit F**

Nuclear 1	Nuclear 2	Coal 1	Coal 2	NG1	NG 2	NG 3	Oil	Presched. Purchases	Presched. Sales	Hourly Buys/(sales)	Net costs before load
(9,775)	(10,980)	(18,535)	(4,500)	0	0	0	0	(5,550)	**25,450**	**28,440**	**4,550**
(9,775)	(10,980)	(18,535)	(4,500)	0	0	0	0	(5,550)	**25,450**	**20,720**	**(3,170)**
(9,775)	(10,980)	(18,535)	(20,250)	0	0	0	0	(5,550)	**25,450**	**40,500**	**860**
(9,775)	(10,980)	(18,535)	(20,250)	0	0	0	0	(5,550)	**25,450**	**48,600**	**8,980**
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	0	0	(5,550)	**25,450**	**64,040**	**17,790**
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	0	(5,550)	**25,450**	**77,550**	**26,800**
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	**67,920**	**12,689**
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	**60,225**	**4,994**
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	**42,930**	(12,301)
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	**30,800**	(24,431)
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	**14,250**	(40,981)
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	(8,260)	(63,491)
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	(7,375)	(62,606)
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	(3,575)	(4,500)	(4,481)	(5,550)	**25,450**	**14,774**	(40,457)
(9,775)	(10,980)	(18,535)	(20,250)	(3,035)	0	0	0	(5,550)	**25,450**	**5,110**	(37,565)
(9,775)	(10,980)	(18,535)	(20,250)	0	0	0	0	(5,550)	**25,450**	**6,150**	(33,490)
(156,400)	(175,680)	(296,560)	(292,500)	(33,385)	(35,750)	(40,500)	(35,850)	(88,800)	**407,200**	**506,374**	(241,851)

Unit cost		(1,066,625)
Prescheduled revenue/(cost)		318,400
Hourly revenue/(cost)		506,374
Revenue from Load @ $	30.00	1,651,304
Net projected P&L		**1,409,453**

This sheet is derived from other sheets, no inputs are required. It is assumed that load is served at $30/MW.

TRADING HUBS
Several established reference points, or "hubs" where electricity is commonly traded exist. These hubs came about as a way of standardizing the location and delivery points for ease of trading. The most common hubs, and their unique characteristics, are:

Northeast

PJM (Pennsylvania/Jersey/Maryland): PJM trades the standard 5x16 on-peak product, in a standard size of 50 mW. The unique characteristic of PJM is the "pool", or LMP (Locational Marginal Pricing). Members of PJM must "bid in" their resources to the pool at whatever cost they would like. Utilities that need power can then submit requests, on an hourly basis, to receive power at whatever the clearing price is for the pool. The maximum price allowed by the pool is $1,000 per hour – the "cap". In order to keep the process fair, utilities that have excess generation to sell are not allowed to collude, or "fix" prices. If any given utility "bids into the pool" at an exorbitant price, there is no guarantee that they will be competitive with the other utilities and hence no guarantee that they will sell power, thus leaving potential money on the table. Conversely, if a utility bids into the pool at an extremely low price, they may be short-changing the supply and demand balance, and again be leaving potential revenue on the table by not charging enough for their power. The lack of knowledge of what the other participants are doing is supposed to keep the process fair, and is to ensure that any and all utilities that need power will be able to procure it at a fair price. This is a very liquid point, and myriad trades take place on a next-day basis to as far out as 10-year strips. A struggling NYMEX contract also exists.

Bidding into the Power Pool

The most efficient management of a power asset involves a proactive effort to optimize profit through both the forward energy market and the ancillary services market. As you will read in the "Asset Development" chapter, there are several types of ancillary services, including regulation up, regulation down, spinning reserves, replacement reserve and real-time.

To demonstrate the value in ancillary services, assume we have a combined-cycle turbine that operates under the following constraints:

Unit Size (MW):	400
Heat Rate (MMBtu/MWh):	6.70
Fuel Cost ($/MMBtu):	2.10
Start-up Cost ($/MW):	30
Day Ahead Cost ($/MWh):	17.49
Marginal Cost:	15.07
Fixed O&M Cost ($kW-Yr):	18

Now assume that price forecasts for both the energy market and the ancillary services market are as follows:

Hour	Energy ($/MWh)	Regulation Up	Regulation Down	Spinning Reserve ($/MW)	Non-Spinning Reserve ($/MW)	Replacement Reserve ($/MW)	Real-Time Energy ($MWh)
1	16.19	10.31	6.88	3	2.19	0.00	9.87
2	15.73	15.44	10.29	2	0.57	0.00	10.98
3	14.57	15.94	10.63	0	1.01	0.00	12.02
4	13.55	14.73	9.82	0	0.63	0.00	10.55
5	13.57	6.34	4.23	0	0.21	0.00	9.45
6	15.56	15.34	10.22	3	0.73	0.00	8.67
7	17.58	16.45	10.96	4	0.45	0.00	13.25
8	22.03	7.22	4.81	5	2.03	0.00	12.56

9	28.01	6.01	4.00	5	4.01	1.00	25.34
10	28.68	4.10	2.73	6	4.68	2.03	28.03
11	30.76	4.29	2.86	8	4.76	2.01	27.22
12	30.83	4.85	3.24	8	4.83	2.68	27.78
13	30.15	6.28	4.19	8	4.15	2.76	22.33
14	28.2	6.05	4.04	10	4.09	2.83	22.00
15	27.57	9.28	6.19	10	4.47	2.15	22.76
16	27.23	11.53	7.69	12	4.22	2.09	18.13
17	27.01	11.85	7.90	12	4.75	2.47	18.15
18	27.00	9.98	6.65	10	4.63	2.22	20.16
19	24.12	8.81	5.88	10	4.69	2.75	24.75
20	23.62	9.38	6.25	11	4.63	2.63	24.82
21	24.06	12.95	8.64	7	4.59	2.59	24.00
22	22.15	17.49	11.66	5	4.15	2.15	23.16
23	17.73	14.84	9.89	5	2.73	2.03	18.90
24	16.54	9.92	6.62	2	0.54	0.00	18.35
Daily Avg. Price	**22.60**	**10.39**	**6.93**	**5.99**	**3.07**	**1.43**	**18.88**

The marginal cost the unit is $15.07. Note that the price of energy on the market is higher than $15.07 for 22 hours on this day, an operator could run the generator for the entire day to avoid additional start-up costs. In this scenario the operator, as a simple price-taker, is severely sub-optimizing potential earnings by not participating in the ancillary services market.

Now consider the possibility of this same unit participating in the regulation market. The day-ahead forward cost of the unit is $17.49/MWh, including one start-up. Suppose the operator anticipates the clearing price for regulation will be $6.50. The actual average, then, is $10.39. To equalize his profit from either market, he bids $24/MWh (=17.49+6.50) into the PX and now becomes a price taker in the regulation market as well. As a result, the generator will participate in the energy market for 11 hours for a profit of $10.65/MWh and in the regulation market for 13 hours for a profit of $12/MWh. Out of those 13 hours, the unit supplies 40MW (10%) of regulation for 4 hours and earns an additional $3.61/MWh.

	Energy ($/MWh)	**Regulation Up ($/MW)**	**Real-Time Energy ($/MWh)**
Bid Price ($/MWh)	24.00	0.00	17.00
Hours Exercised	11.00	13.00	4.00
Income ($MWh)	10.65	12.80	3.61

NEPOOL SYSTEM CLEARING REPORT

(www.iso-ne.com)

System Forecast					
Last Updated on: 09/13/1999 06:13:03 PM					
Today's Forecast			Tomorrow's Forecast		
Trading Interval	Forecasted Demand	Forecasted Energy Clearing Price	Trading Interval	Forecasted Demand	Forecasted Energy Clearing Price
Hour End	MWh	$/MWh	Hour End	MWh	$/MWh
1	10325	20.28	1	10900	22.25
2	9875	25	2	10275	21
3	9675	18.32	3	10000	19.61
4	9600	18.32	4	9850	17
5	9800	18.86	5	10000	18.33
6	10825	25	6	10900	20.31
7	12800	32.65	7	12650	31.11
8	14400	32.47	8	14300	30.99
9	15400	27.34	9	15300	31
10	16075	28.2	10	16000	31.81
11	16475	32	11	16500	32.63
12	16750	32.29	12	16825	31.82
13	16800	32.29	13	16950	32.62
14	16950	32.33	14	17150	32.45
15	17075	32.29	15	17175	32.77
16	17075	32.42	16	17150	32.72
17	17100	32.47	17	17050	32.5
18	16975	32.46	18	16775	31.82
19	16700	32.29	19	16275	29.88
20	16925	32.57	20	16525	31.14
21	16600	32.29	21	16400	30.99
22	15400	31.29	22	15250	22.25
23	13725	27.34	23	13525	17.9
24	12200	27.34	24	12000	16.47

NEPOOL (New England Power Pool): This pool trades just like the PJM pool. Also trades another type of "standard" product found only in NEPOOL – ICAP (Installed Capacity). ICAP is basically "the right to point to iron in the ground", an arcane rule in NEPOOL regarding reserve margin requirements (a rule which states that utilities must maintain an extra "reserve" or extra amount of power in order to meet any unforeseen emergencies). It is basically useless, but trades for $1.00 to $2.00 per mW in order to satisfy the rule. It allows utilities to say that they have installed capacity at a specific generator, even though they may or may not have the rights to the actual power produced. (No one said that this ever made sense!)

NYPOOL (New York Power Pool): Very similar to NEPOOL. No real "pool" exists yet. Standard blocks are for 25 mW, 5 X 16 on-peak. Even more illiquid than NEPOOL, if that is possible.

Mid-Continent

Cinergy (ECAR): Cinergy is the most liquid of all trading hubs. The standard product is 5 x 16 on-peak, 50 mW blocks, and trades take place from several thousand mW's on a next-day basis to several hundred on a term basis. It is also the most volatile area, and when press clippings reference energy prices, this is THE area to be cited.

Entergy (SPP): Identical in every respect to Cinergy, although it is slightly less liquid. This area is often "spread" against Cinergy (a spread is taking a long position in one region while taking a simultaneous offsetting short position in another area) in an attempt to capitalize on the price differentials between the two regions. More on spread trading later.

TVA - Tennessee Valley Authority (SERC): Again, identical to Cinergy and Entergy, although it is the least liquid of the three. It is also traded as a spread to Cinergy. While this used to be the premier hub when power was first deregulated, arcane rules and the fact that TVA was an uncooperative participant in the marketplace has caused this region to fall out of favor. Originally, only the 13 member utilities of the original Tennessee Valley Authority were allowed to sell, but not buy, power from TVA directly. TVA, however, retained the rights to buy and sell power with any utility of its choosing. This lopsided marketplace is the main reason for the liquidity differential between TVA, Cinergy and Entergy.

Texas (ERCOT): A very difficult place to operate. Although it trades the standard 50 mW 5 x 16 on-peak blocks, it may only trade 8 – 12 times per day on a next-day basis, and on a long-term basis, trades "by appointment only" (i.e. it trades so infrequently that it seems like market participants must make an appointment to get any business done). There are very few utilities which are located in this area, and they are not friendly towards outside participation. Additionally, it is next to impossible to transmit power from another region of the country into this region due to the lack of plentiful transmission lines. ERCOT has different types of "schedules" for power. They are:

Type A – A transaction where power delivered between a Buyer and a Seller that does not create a physical or financial obligation on either party to actually deliver or continue delivering once the transaction starts. The following terms and conditions apply:

(1) Can be interrupted by the Buyer or Seller for any reason.
(2) The Load Entity receiving the transaction shall carry or contract for spinning reserve service in the amount of the transaction.
(3) Shall not be placed in the Daily Operations Plans submitted to the ISO.

Type B – A transaction where power delivered from a utility's generation resource to its Native Load or between any other Buyers and Sellers creates both a physical and a financial obligation on each party to actually deliver and receive or continue delivering and receiving. The following terms and conditions apply:

(1) Cannot be interrupted by the transacting parties.
(2) Shall be placed in the Daily Operations Plans submitted to the Control Area and the ISO.

Type C – A Financially Firm Transaction where power delivered between a Buyer and Seller creates a financial obligation on each party to actually deliver and receive value. The following terms and conditions apply:

(1) Can be physically interrupted only by the Entity generating the power and energy, provided the Seller maintains a financial obligation to replace the physical delivery.
(2) Shall be placed in the Daily Operations Plans submitted to the Control Area and the ISO.
(3) Cannot be interrupted for economic reasons.

Type D – A transaction where power delivered between a Buyer and Seller obligates the Seller to deliver and the Buyer to receive, or the Seller to continue delivering and the Buyer receiving provided any specified generating unit contingencies do not occur. The following terms and conditions apply:

(1) Can be physically interrupted by the Providing Entity if any specified generating unit or units experience any specified contingencies which have been designated prior to the transaction.
(2) Shall be placed in the Daily Operations Plans including the resource designation and submitted to the Control Area and the ISO.
(3) Cannot be interrupted for economic reasons.

Type G – A transaction where power delivered between a Buyer and Seller, obligates the Buyer to receive and continue receiving. The Seller may interrupt the transaction without obligation with notice to Buyer under the following terms and conditions:
(1) Can be physically interrupted only by a deficit Load Entity designated prior to the transaction.
(2) Shall be placed in the Daily Operations Plans and submitted to the Control Area and the ISO.
(3) Cannot be interrupted for economic reasons.

West

The west has four major hubs. They are: Palo Verde, COB (California-Oregon Border), SP-15,and NP-15.

The West operates under the California PX, which is a "pool" system similar to what is found in the East. Power can be traded in the bilateral market (direct with counterparties), the OTC market (using brokers) or on electronic "matching" systems such as Bloomberg. If desired, power can also be traded on a next-day basis with the PX, or on an hourly basis with the PX. To trade on a next-day basis with the PX, the market participants submit their bids, offers and quantities, by hour, for the entire 24 hour next day period (unwanted hours are submitted as zero). The PX takes all of the bids and offers, and matches them up by allocating the sellers and buyers at each price level. The PX then notifies the buyers and sellers who have been paired up of the quantity, price and hours of their respective purchases and sales. The same process is repeated during the "day-of" market. Each hour, for the period two hours forward, participants submit bids, offers and quantities ONLY for the one hour period which commences in two hours (i.e. by 10:00, all bids and offers must be in for the power which will flow from 12:00 to 13:00).

Hourly Unconstrained Market Clearing Prices			
Day-Ahead market for delivery on: 10/26/99			
Total market volume (MWh) 549,070.5			
Hour	Price	Sum Supply	Sum Demand
1	34.756	19,233.80	19,233.80
2	34.0018	18,700.20	18,700.20
3	32.538	18,154.40	18,154.40
4	32.3496	18,116.20	18,116.20
5	34	18,915.70	18,915.70
6	40.395	20,808.90	20,808.90
7	44.5962	22,317.30	22,317.30
8	44.749	22,669.80	22,669.80
9	44.9684	23,411.80	23,411.80
10	48.1239	24,110.80	24,110.80
11	51.5979	24,437.30	24,437.30
12	54.7405	24,610.30	24,610.30
13	55.9947	24,824.60	24,824.60
14	57.8989	25,344.30	25,344.30
15	58.5823	25,395.00	25,395.00
16	59.7053	25,490.20	25,490.20
17	60.0062	25,521.30	25,521.30
18	54.8911	25,146.90	25,146.90
19	58.3699	25,382.10	25,382.10
20	59.9912	25,354.20	25,354.20
21	56.773	24,788.00	24,788.00
22	47.4504	23,184.30	23,184.30
23	40.9944	22,340.60	22,340.60
24	36.3284	20,812.50	20,812.50
Total		549,070.50	549,070.50

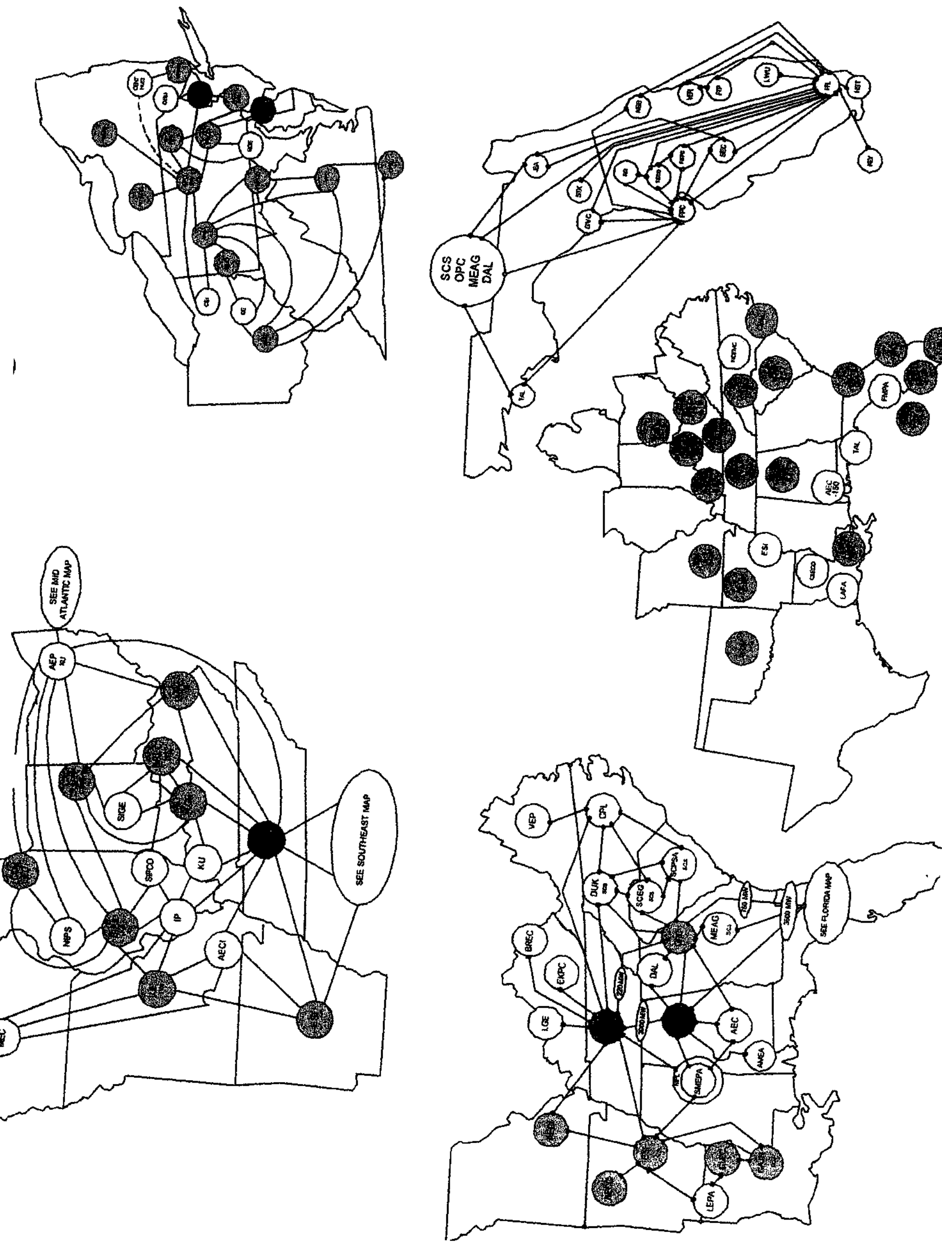
Hourly Unconstrained Market Clearing Prices					
Day-Of/Hour-Ahead Market Market for Delivery on: 10/11/1999					
Hour	Price	Incr Supply	Decr Demand	Dacr. Supply	Incr. Demand
1	26.8333	50	0	0	50
2	25.3805	50	0	0	50
3	25.3836	25	0	0	25
4	25.3803	50	0	0	50
5	25.3836	25	0	0	25
6	33.1333	25	0	0	25
7	30.5	25	0	0	25
8	30.0095	0	2.4	2.4	0
9	30.0098	0	0.8	0.8	0
10	30.0095	0	2.4	2.4	0
11	45.006	105	8	0	113
12	47.0001	165.6	11.4	0	177
13	49.7928	144.7	7.3	0	152
14	52.0069	324.4	8.6	0	333
15	76.1564	319.8	19.5	0	339.3
16	80.1844	276	24	0	300
17	96.3558	292.3	87.7	0	380
18	61.2824	237.8	12.2	0	250
19	59.671	225	7.2	0	232.3
20	67.8782	275.1	9.3	0	284.4
21	59.4706	200	9.9	0	209.9
22	34.8863	78.8	0	0	78.8
23	34.8851	63.9	0	0	63.9
24	34.8803	3.9	0	0	3.9
Total		2,962.30	210.8	5.6	3,167.40

Trades for Standard 16-Hour Daily Products

Delivery Point	Trading Volume Reported	All Peak Hours Volume	Number of Trades Reported	Volume Divisor
COB	925	14800	37	1.4
Mid-Columbia	550	8800	22	1.4
Palo-Verde	750	12000	30	1.4
ERCOT - B	250	4000	5	2.4
Com Ed	425	6800	9	2
Entergy	6450	103200	129	2.2
Cinergy	7300	116800	146	2.2
PJM	2650	42400	53	2.1
TVA	3400	54400	68	2.1

TRANSMISSION AND INTERFACES

The US is connected by a network of transmission lines that form a power grid. The purpose of this grid is to enable utilities to transmit power to different regions of the country. Theoretically, it is possible to generate an electron in Maine and send it to California. In reality, it is not possible to send a specific electron from one region to the next. When an electron is transmitted into the power grid, there is no way of knowing where that specific electron will end up. As long as the system balances (power generated equals power consumed), then no problems will occur. It is analogous to the Water Company putting a specific drop of water into the pipe system - the company cannot guarantee where that drop of water will go, but as long as every customer has H20 when needed, no problems occur. (Note that it is the fungibile nature of electrons or the inability to "brand" or discern one electron from another that makes electricity a commodity).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CPL
DUK
SCEG
SCPSA
MEAG
BREC
EKPC
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FMPA
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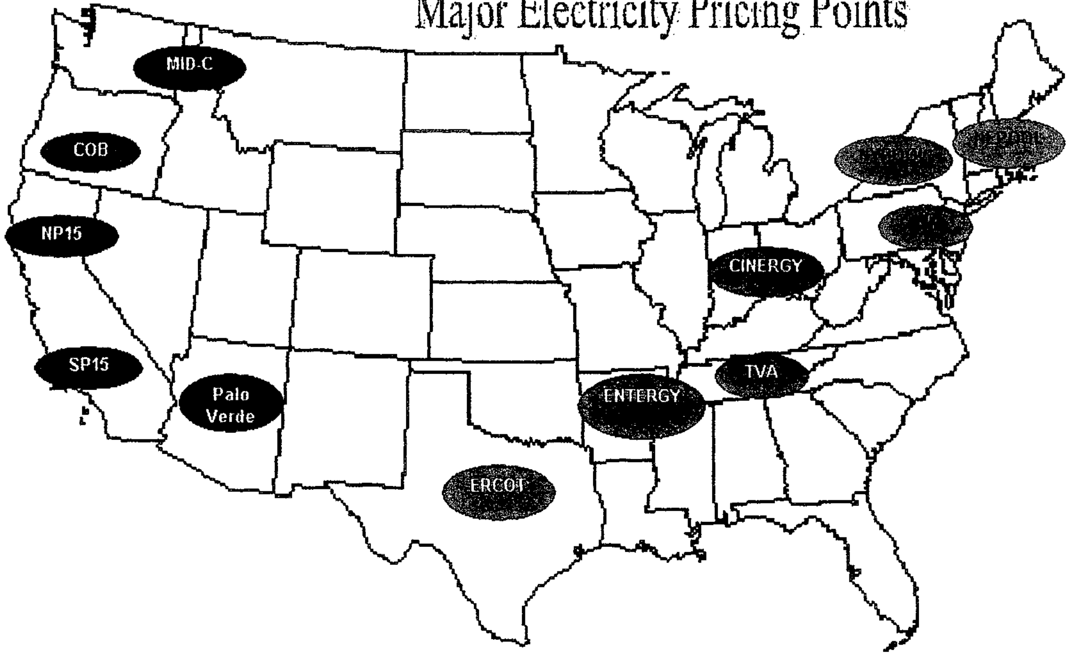
LAFA

Major Electricity Pricing Points



A. Wheeling: In reality, power is transmitted, or "wheeled" to various parts of the country every hour. If a utility can find power cheaper than it can generate from its own system, the utility will purchase that power and wheel it to serve load. It must pay a transmission fee, schedule the power (notify the sender, receiver, and everyone in the path of the intent), provide proper paperwork, and then confirm each one of these steps.
B. Interface Scheduling: The point on a trading hub where power is received and delivered is called an interface. In order to wheel power from Cinergy to Entergy, for instance, if the interface has room or if all available transmission has already been scheduled.
C. OASIS/NERC Tags: In order to see if transmission is available, you must log onto an internet system called OASIS (Open Access Same-Time Information System). This will list all available transmission, both firm and non-firm, for the interfaces in a given hub. Non-firm transmission is like non-firm power – the host utility can cancel, or "cut" it anytime they need the space to serve their own native load. Buyer Beware – cuts of firm transmission are not uncommon during the summer months. Firm transmission is like firm power – it is guaranteed unless an act of God disrupts it (lightning strike, etc.). If the desired transmission points are available, and the desired type (firm or non-firm), then a formal request is made on the OASIS system. Once the request is accepted, the appropriate paperwork must be completed. This is the NERC tag – a document which shows the generating source, any and all marketers which have bought and sold power on that path, and the ultimate destination point, or sink.

Entergy

New Transmission Request

Customer Information

Name
rtompkins

Company
LPM

Duns
877713156

Comments

Status Notification

E-Mail

http://

none

Seller Information

Company
EES - 062624212

Dates and Times

Start Date and Time
09/23/1999 00:00:00 CD

Stop Date and Time
09/24/1999 00:00:00 CD

Reference Numbers

Deal

Request

Sale

Posting

Service Information

Daily Firm-ATC

Capacity
18

Bid Price
$0.00

Preconfirmed

Path and POR/POD Information

POR
EES

POD
SOCO

Path Name
S/EES/EES-SOCO//

Source
EES

Sink
SOCO

Source (if -OTHER-)

Sink (if -OTHER-)

Ancillary Services

Service	Company	Link Type	Ref#	Capacity
SC	-NONE-	Future		
LC	-NONE-	Future		
RF	-NONE-	Future		
EI	-NONE-	Future		
SP	-NONE-	Future		
SU	-NONE-	Future		
RV	-NONE-	Future		

Interchange Transaction: 226D

Transaction Days

S	M	T	W	T	F	S
			Y			

Start Date 9/22/1999 Time Zone

End Date 9/22/1999 CD

Purchasing/Selling Entity (PSE)	LPM01
	LG&E Power Marketing
PSE Deal Reference #	
PSE Contact Name	LEM Coordinator
PSE Phone Number	(502) 627-4275
PSE 24 hr Phone Number	(502) 627-4275
PSE Fax	(502) 627-4177
PSE Email	ccordinators@lgeenergy.com
Source Generator Name	DUK
Source Phone	
Sending Control Area	DUK
	Duke Energy Corporation
Sending Control Area Phone	(704) 382-4413
Sending Control Area Fax	(704) 382-6938
Sending Control Area Email	duk@powemav.com
Load or Sink Entity	OPC
Receiving Control Area	SOCO
	Southern Company Services, Inc.
Receiving Control Area Phone	(205) 257-6302
Receiving Control Area Fax	(205) 257-5533
Receiving Control Area Email	InterchangePCC@weboasis.com
Remarks or Key Info	

Interchange Transaction ID No.

SCA	PSE	Unique #	Revision	RCA
DUK	LPM01	226D	000	SOCO

Energy Profile (at source) (Use Start/Stop time; NOT hour-ending) / Ramp Info

	Start	Stop	MW	MWH	Ramp Start	Ramp Duration
01	6:00	7:00	50	50		
02	7:00	8:00	50	50		
03	8:00	9:00	50	50		
04	9:00	10:00	50	50		
05	10:00	11:00	50	50		
06	11:00	12:00	50	50		
07	12:00	13:00	50	50		
08	13:00	14:00	50	50		
09	14:00	15:00	50	50		
10	15:00	16:00	50	50		
11	16:00	17:00	50	50		
12	17:00	18:00	50	50		
13	18:00	19:00	50	50		
14	19:00	20:00	50	50		
15	20:00	21:00	50	50		
16	21:00	22:00	50	50		
	Total:			800		

Loss Accounting

	TP	Start	Stop	Losses	MW @ POR	MW @ POD
01	TVA	6:00	22:00	2	50	48

Transaction Path

CA	TP	PSE	Path (POR/POD)	Product	OASIS #
DUK		DUKEBP	DUK/TVA	G; NonF	
DUK	DUK	DUKEBP	DUK/TVA	F-7	62889
TVA	TVA	LPM01	DUK/SCC	ND-3	486989
SOCO	GTC	LPM01	SCC/OPC	L; F-7	

TRADING TIME FRAMES

Power is a non-storable commodity, and therefore must be traded in discreet time frames - from next hour (a one-hour period) all the way out to a 10-year strip. The specifics of each are:

Hourly: Hourly power leaves no room for error. If you have it, you must either sell it or lower the output of the generator. If you need it, you must get it or "the lights go out". Trading hourly power usually starts at the top of the hour, and must be finalized, including tags and transmission, by the bottom of the hour in order to provide each hub's various control centers enough notification to make proper arrangements. For instance, if utility "A" needs to buy power for hour ending 0900 (the hour that starts at 08:00:01 and ends at 08:59:59), they will start to make calls at 0700. By 0720, they will have to make a decision as to which supplier to buy from. Between 0720 - 0730, they must complete all transmission requests, tags, etc., and notify all parties of their intent by 0730. From 0730 to 0800, the control area makes all necessary arrangements, and at the top of the hour, the power flows. (Repeat this process 23 more times a day). It is during this hourly process where power prices reach the egregious price of $10,000.

Next-Day: Next-day power begins trading at 7:00 A.M. the day before it is needed. All trading and associated paperwork must be completed by 1:00 P.M. in order to meet industry-implied deadlines. Note that no hard and fast rules exist as to when this must be done, but various utilities will be extremely unaccomodating if this time frame is not respected. Marketers with no available generation must purchase power in the day-ahead market to meet any sales obligations. Utilities that need power have the luxury of not buying in the daily market and instead, can take their chances for buying at better prices in the hourly market. Marketers that have power to sell must sell it in the daily market, because they do not have the luxury of simply backing down generation. Utilities that have power in excess of their scheduled load forecast can sell in the daily market, wait for potentially better prices in the hourly market, or simply reduce generator output during the actual day of flow if prices do not merit selling.

Next-Week: Power can trade for "blocks" of days, typical of which is an entire week. Marketers and utilities can look at weather forecasts and decide if they need to buy or sell a week's worth of power. Any sales or purchases that take place in the weekly market can be met by buying or selling in the next-day market, or if it is a utility with the luxury of generation, can be taken into the hourly market if so desired.

Monthly: The most common type of trading for marketers and speculators is monthly trading. Power typically trades in 50 mW blocks for all non-holiday weekdays during a month. Monthly trading can be closed out by offsetting weekly, daily or even hourly trades. Monthly trading is usually fairly liquid for a six to twelve month period.

Long-Term Trading: Occasionally (maybe once per week) a long-term deal will trade. These infrequent deals range from a full calendar year, up to a 10-year strip of power. Because of the notional value involved, credit issues with counterparties become important. Very little price discovery is available due to the lack of liquidity, and mark-to-market accounting becomes difficult.

Monday, August 16, 1999

Megawatt Daily Price Survey

The prices below are for power purchased in megawatt hours at the locations and regions listed in the far left. Except for weekends, the power purchased in these transactions was transmitted starting with yesterday's off-peak periods and continues today Information in the table includes financially firm, unit firm, system contingent and one-hour recallable transactions. Transactional data is gathered from utilities, marketers, coops, muncipals and government power agencies of all sizes. Some firm transactions may include capacity reservation charges. The first two columns of numbers indicate the most common price ranges, while the middle column is the volume-weighted average of all deals reported. The two columns on the far right are absolute low and high prices reported. Lack of boldface indicates insufficient data. for a price change. Trading practices differ across regions; for more information about Megawatt Daily. contact Financial Times Energy at 800-424-2908. Copyright 1999 by Financial Times Energy.

Delivery Date: 08/16/99

Delivery Point	Com Low	Com. High	Wtd Ave. INDEX PEAK	Abs Low	Abs. High
West					
COB	$28.00	$28.75	$28.45	$28.00	$29.50
Four C	$36.50	$36.75	$36.67	$36.50	$37.00
Mead. Nev.	$37.00	$37.50	$37.29	$36.50	$38.00
Mid-C	$22.50	$23.50	$23.08	$22.00	$24.00
NP15	$31.50	$31.75	$31.67	$31.00	$32.00
Palo Verde	$37.25	$38.00	$37.60	$37.00	$38.50
SP15	$32.00	$32.25	$32.21	$31.75	$32.25
Central					
ERCOT,econ.B	$240.00	$250.00	$246.23	$225.00	$260.00
Ameren	$199.50	$200.50	$200.00	$199.00	$201.00
Cilco/IP	—	—	—	—	—
Com Ed Border	$155.00	$160.00	$159.00	$150.00	$165.00
MAIN north	$90.00	$100.00	$96.86	$75.00	$100.00
MAPP	$38.50	$39.50	$39.00	$38.00	$40.00
Entergy, into	$270.00	$330.00	$300.94	$250.00	$375.00
SPP	$145.00	$200.00	$176.67	$130.00	$250.00
East					
Cinergy, into	$200.00	$275.00	$248.19	$170.00	$400.00

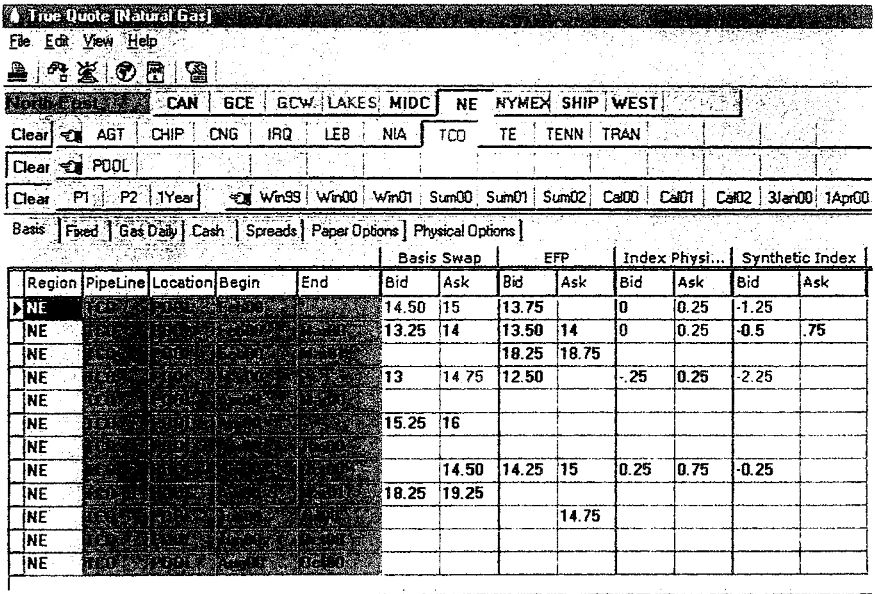
SOURCES OF LIQUIDITY

Power can be traded through a number of ways:

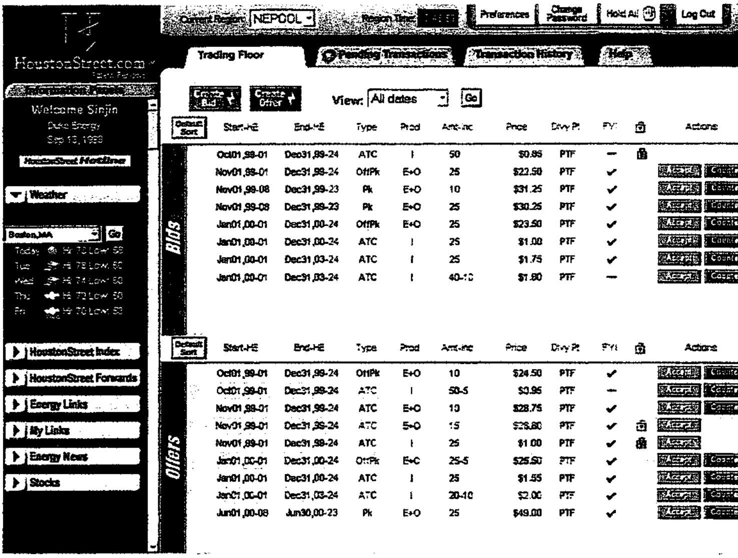
Broker: The brokered market deals in time frames from next day to 10 years. A broker is an intermediary that matches buyers and sellers – but they never take title of the power. They merely charge a fee for each transaction. The appeal of the brokered market is ease of use and anonymity. The identity of buyers and sellers is not revealed until a deal is actually closed.

Direct: The direct, or bilateral marketplace, involves companies contacting each other directly. Company "A" will call "B" and either show an offer (if they are a seller) or a bid (if they are a buyer). The other company may deal immediately on the price, counter with an improved offer or bid, or have no interest at all. The appeal of the direct market is developing business relationships, avoiding transaction costs (broker's fees), and the possibility of closing large volumes in a single transaction. The drawback can be that in showing a "side" of the market (bid or offer), the potential counterparty may know your intentions, try to "front-run" (buy or sell ahead of you at a better price) and it may be difficult to transact at a reasonable price.

Electronic: Several electronic systems have been developed, including Bloomberg and various Internet systems. These systems are merely electronic brokers. The buyers and sellers anonymously enter their bids and offers, or hit bids and lift offers to transact. Once a transaction is completed, the counterparties' names are revealed. The major advantage of this is pre-approved credit for counterparties and ease of use.



					Basis Swap		EFP		Index Physi...		Synthetic Index	
Region	PipeLine	Location	Begin	End	Bid	Ask	Bid	Ask	Bid	Ask	Bid	Ask
NE	[redacted]				14.50	15	13.75		0	0.25	-1.25	
NE	[redacted]				13.25	14	13.50	14	0	0.25	-0.5	.75
NE	[redacted]						18.25	18.75				
NE	[redacted]				13	14.75	12.50		-.25	0.25	-2.25	
NE	[redacted]											
NE	[redacted]				15.25	16						
NE	[redacted]											
NE	[redacted]					14.50	14.25	15	0.25	0.75	-0.25	
NE	[redacted]				18.25	19.25						
NE	[redacted]							14.75				
NE	[redacted]											
NE	[redacted]											



Several trading hubs which have contracts that are traded on an exchange. The east hubs are Cinergy, Entergy, TVA, COMED, and PJM. Each hub has contracts listed for 18 months. The prompt contract usually expires on the last Friday of the last week of the previous month (i.e. the month before actual flow). Each contract in the East is for 736 mW hours, delivered on-peak for 5 X 16 for the month. Although the actual volumes vary by month due to the number of on-peak days, each contract is good for approximately 2 mW, or it takes 25 contracts to make a standard 50 mW block for the month. The west, which has contracts for Palo Verde COB (California/Oregon border) only, is similar in all respects to the East with the exception of the fact that the traded product is for a 6 X 16 schedule. The liquidity of exchange-traded power contracts is horrible at best. As a reference, all hubs, east and west combined, average under 400 contracts per day, while the natural gas contract averages over 100,000 contracts per day.

Unless a contract is "closed out" (i.e. all purchases have corresponding sales and conversely, all sales have corresponding purchases) then at the end of the individual contract's life (expiry) the power must be physically delivered and received. Exchange for Physical's (EFP's) are a way to swap out exchange traded contracts for actual power. For example, assume you sell 50 mW of April Cinergy over the counter (OTC) for $22.00, and then to book a profit you buy 5 contracts at $21.75, 5 at $21.50, 5 at $21.25, 5 at $21.00, and 5 at $20.75. At the end of the month, the person to whom you sold the OTC power at $22.00 will want it delivered. Additionally, if arrangements are not made, then the 25 purchased contracts will have to be received. An EFP, which is done either through the exchange, can alleviate this problem. EFP's will allow you to swap the 25 contracts you purchased for the 50 mW you sold directly. In essence, you are exchanging the 50 mW block sale for a sale of 25 contracts. The 25 contracts you are now long via the EFP offset the five sales of 5 contracts. The 50 mW block sale OTC is offset by the 50 mW you are now long via the EFP. Bottom line is..... no delivery, no receipt.

OPTIONS

Options will be covered in depth in a different section. They will be briefly covered here only to point out the differences in time frames. Power options are unlike any other commodity options available. Since power is a non-storable commodity, options trade in discreet time frames. They are:

Superpeak: A superpeak call option is one where the buyer has the right to demand delivery of power for any 6-hour block of time, provided that 24 hours' notice is given. A superpeak call option for the month of July with a $50.00 strike means that on a day-ahead basis, the buyer can pick and choose the best hours (most expensive). Even though a 16 hour block of power may be trading for $40.00, the superpeak portion is most likely worth a great deal more. In order to cover the 6-hour short created by the option being called away, the seller usually must buy a 16 hour block, and then "dump" the shoulder hours. For example, assume the buyer calls away hours 1300 through 1800 on a $50.00 strike. The option seller, unable to find a similar option to cover the short, and unable to find someone willing to sell the peak hours only (since both are rare) must buy a 16 hour block for $45.00. It would seem like the option buyer exercised uneconomically, right? Wrong. The option seller, who purchased the 16 hour block, must sell hours 0700 to 1200 and 1900-2200 in the marketplace. The going rate for these "junk hours" (shoulder hours) will most likely be $20.00. So the option seller loses $11,000 on the transaction:

HE 0700 - 1200: ($20 sale - $45 purchase) x (50 mW) x 6 hours = -$7,500.00
HE 1300 - 1800: ($50 sale - $45 purchase) x (50 mW) x 6 hours = +$1,500.00
HE 1900 - 2200: ($20 sale - $45 purchase) x (50 mW) x 4 hours = -$5,000.00

Net Loss = -$11,000.

When you are short superpeak options, you are short gamma in the smallest of the most discreet time frames. The only way to fully hedge this position is to buy an offsetting peaking option. Any other alternative results in mismatched gamma, and is nearly impossible to hedge profitably.

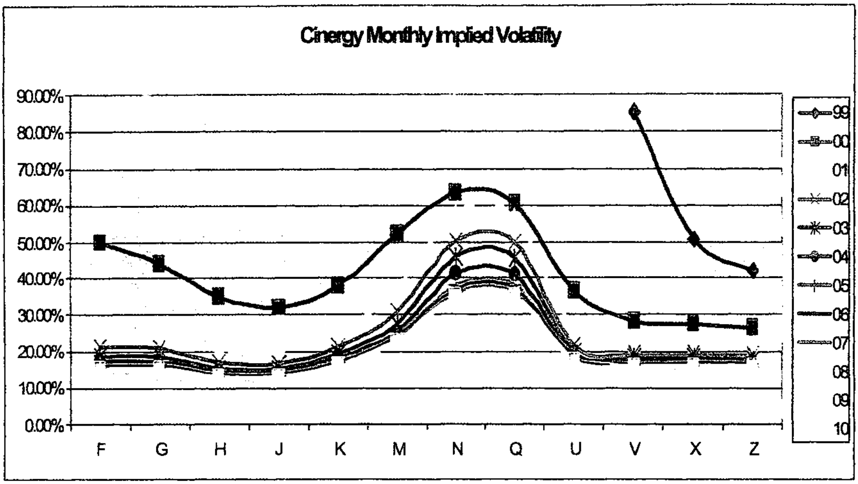
Next Day (Daily): Daily options are options that are purchased for a month, and allow the buyer to exercise with 24 hour notice. For example, the buyer of a $20.00 daily put option has the right to send power to the option seller every day with proper notification. Daily options are easier to hedge since power bought or sold in monthly or weekly time frames can be taken into the daily market. Daily options have a much cleaner match of the "Greeks" than peaking options.

Monthly: Monthly options trade much more like typical exchange traded options. They usually expire a few days before the start of the month. Monthly options enable the buyer to deliver or receive power in a monthly block. Unlike dailies, which allow for notification every day of the month, monthly options allow for only one notification that commits each party for the entire month. Once a monthly option is exercised, it can be treated the same as a monthly purchase or sale – the power can be covered prior to the month, or covered intra-month by weekly, day ahead, etc.

Quarterly: There are two types of quarterly options – "one timers" (bullets) and "three timers". One timers allow for only one exercise for the entire 3 month period (hence the nickname bullet). Three timers allow for three individual exercises prior to each of the three months.

Calendar: Same as Quarterly – bullets and 12 individual strikes.

Since power can be traded in different time frames, daily and monthly options have separate, discrete volatility characteristics. As a reference, the volatilities of Cinergy for monthly and daily options are:


Cinergy Monthly Implied Volatility
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
F
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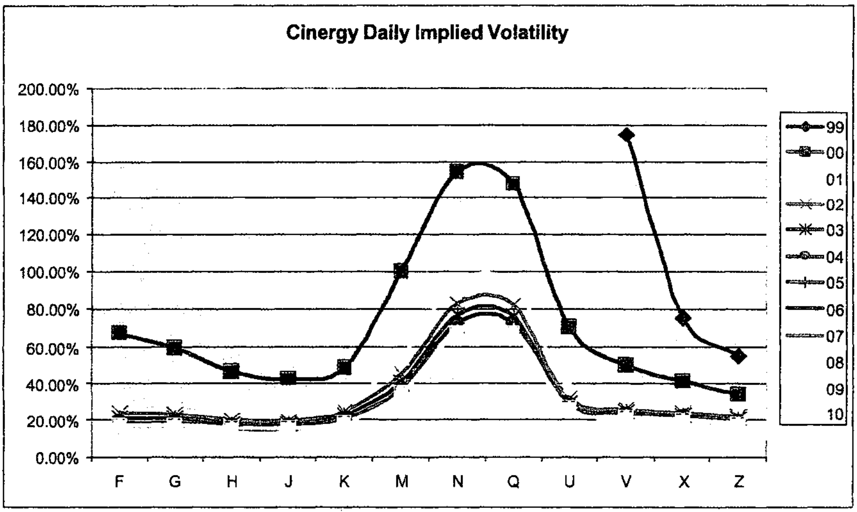
Cinergy Daily Implied Volatility
200.00%
180.00%
160.00%
140.00%
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
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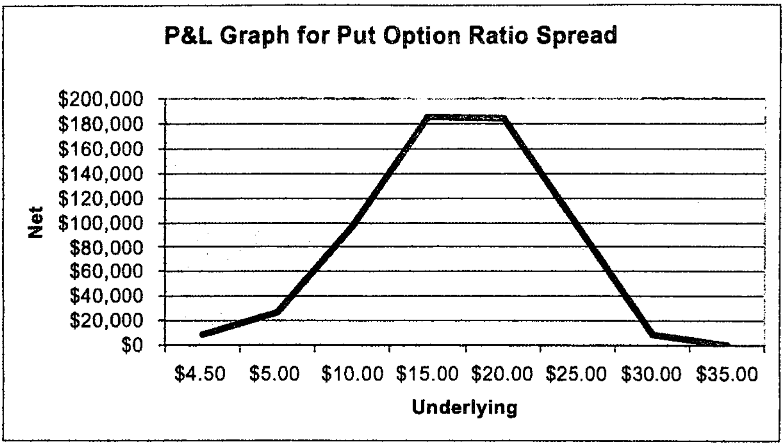
NEAT TRADING TRICKS:

Several basic trading and/or hedging techniques increase the probability of profit. While the list of available strategies is too numerous to mention and most people don't want to give away their best secrets, two of the better ones are:

Ratio Option Spreads
Assume the average cost of your generation (top of your "stack) costs $16.00. While canvassing the market for price discovery, you uncover the following two options – the Septemb er $35.00 monthly put is $3.25/$3.50, and the $20.00 put is trading $2.00/$2.25. The underlying is $38.00. You could buy one of the $35.00 puts for $3.50, and sell 2 of the $20.00 puts for $2.00. The purchase of the $35.00 put would cost you 1 x $3.50, or $3.50. The sale of the $20.00 puts would give you 2 x $2.00, or $4.00. Your net would be a $0.50 credit. This position remains profitable for you until the price of the underlying drops to $4.50 (which is considerably under your generation costs of $16.00). You would be glad to take power at $4.50 if your generation costs $16.00, and the price is so ridiculously low, it has an insignificant probability of occurring. The math is as follows

PUT STRIKE	VOLUME	PRICE	DEBIT/CREDIT	REVENUE
$35.00	+1	$3.50	-$3.50	(50 Mw) x ($3.50) x (22 peak days) x (16 peak hours) = -$61,600.00
$20.00	-2	$2.00	+$4.00	(50 mW) x ($4.00) x (22 peak days) x (16 peak hours) = +$70,400.00
NET:				+$8,800.00

UNDERLYING	+/- ON $35.00 p	+/- ON 2 $20.00 p	NET
>$35.00	-$61,600 + $0.00	+$70,400.00 - $0.00	+$8,800
$30.00	-$61,600 + $17,600	+$70,400 - $0.00	+$26,400
$25.00	-$61,600 + $88,000	+$70,400 - $0.00	+$96,800
$20.00	-$61,600 + $176,000	+$70,400 - $0.00	+$184,800
$15.00	-$61,600 + $352,000	+$70,400 - $176,000	+$184,000
$10.00	-$61,600 + $440,000	+$70,400 - $352,000	+$96,800
$5.00	-$61,600 + $528,000	+$70,400 - $528,000	+$8,800
$4.50	-$61,600 +$536,800	+$70,400 - $545,600	+/- $0.00



Q3 Cinergy Butterfly Spread
Historically, September produces price "surprises" to the upside. Because of this fact, October tends to rise in sympathy. Typically, November then lags, as people expect a normal month. December tends to stay "bid" in anticipation of a cold winter. Whether or not a cold winter materializes does not matter – as long as the market psychology anticipates the potential for price surprises to the upside in December, the December futures will stay bid.

In order to capitalize on this mentality, a safe play is the October/November/December "butterfly". This trade involves buying one October, selling two Novembers, and buying one December. The 1/2/1 ratio gives equal volume to the trade so that exposure on each part is matched.

Typically, this spread can be entered for a +$0.25 to +$0.50 premium. (Look at Aug 7, for example. Buying 1 CNV9 for $24.75, selling 2 CNX9 @ $25.75, and buying 1 CNZ9 for $26.40 will yield a premium, on a per-lot basis, of +$0.35 (receive 2 x $25.75 for Nov sold, pay 1 x $24.75 for Oct and pay 1 x $26.40 for Dec).

Historically, this spread rarely, if ever, trades at more than a $0.70 premium. So the risk on the trade is usually no more than -$0.35. This "fly" has a tendency to "blow out" to $0.75.

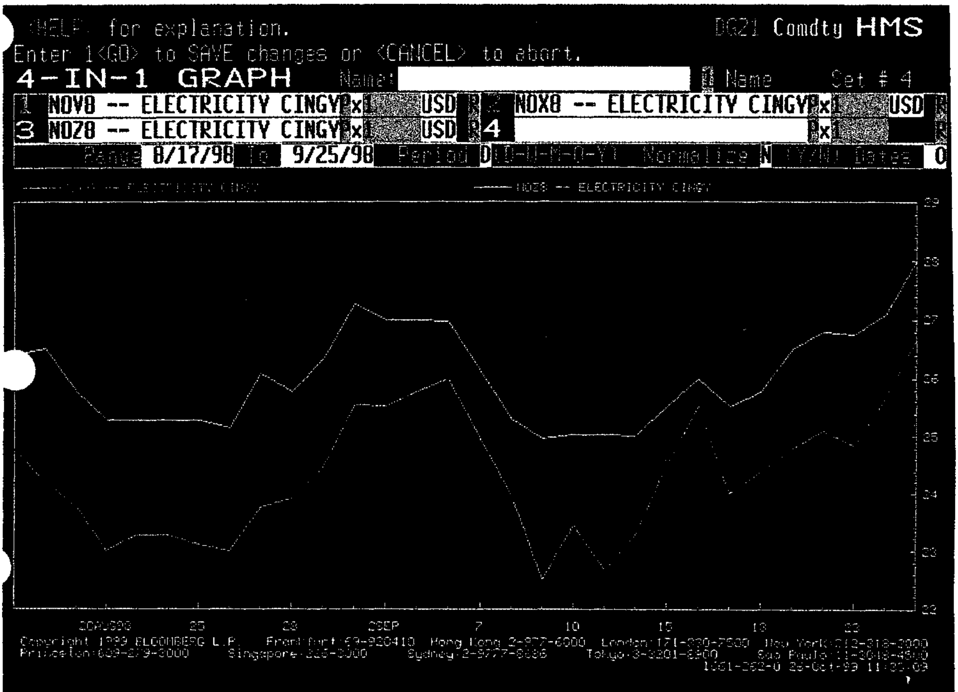
One way to exit this trade would be to keep it intact as a butterfly. Using Sep 15 as an example, you would sell 1 CNV9 @ $24.50, pay $24.63 for 2 CNX9, and sell 1 CNZ9 @ $25.50, and receive +$0.74. Not a bad risk/reward scenario – risking $0.35 to make roughly $1.00 ($0.30 credit on trade initiation + $0.74 to close out position).

Another way to exit this trade would be to treat it as two individual spreads – the Oct/Nov spread (in which you are long one Oct and short one Nov) and the Nov/Dec (short one Nov and long one Dec). If you choose, you can pick an opportune time to exit the Oct/Nov, and wait for a later time to exit the Nov/Dec (or vice versa).

As an example, the butterfly was entered on Sep 15 in the following way: Buying 1 CNV9 for $24.75, selling 2 CNX9 @ $25.75, and buying 1 CNZ9 for $26.40 will yield a premiumof +$0.35 per lot (receive 2 x $25.75 for Nov sold, pay 1 x $24.75 for Oct and pay 1 x $26.40 for Dec). On Sep 14, you can pay $23.85 for 1 CNX9, and sell 1 CNZ9 @ $25.00 (This nets you $1.15, less the $1.00 paid when the Nov/Dec leg of the fly was initiated, nets +$0.15). Then, on Sep 16, you can exit the Oct/Nov spread by selling 1 CNV9 @ $25.50 and paying $25.41 for 1 CNX9. (This nets $0.09 in addition to the $1.00 you received for initiating the Oct/Nov leg of the butterfly, for +$1.09). The total of the two "nets" results in "catching the fly" for $1.24.

A third way to exit the trade would be as individual legs. This involves more risk, as the other legs of the spread provide no inherent risk protection. However, on Sep 1, you could sell the 1 CNV9 @ $25.55 (+0.80), on Sep 8 buy back the short by paying $24.61 for 2 CNX9 (+$1.14), and on Sep 25 sell 1 CNZ9 @ $28.00 (+$1.60). The overall net is $3.54, or much higher than the butterfly or spread legs. Again, this involves much more risk.

Past performance is no guarantee of what will happen in the future. However, if seasonal "plays" continue to repeat, and if the trade makes sense and offers a low risk/reward scenario, it is worth a try. So long as the risk/reward is defined, and a "stop/loss" point is predetermined, the odds should be in your favor, and you will know where to get out if you are right, as well as where to exit if you are wrong.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Enter 1<GO> to SAVE changes or <CANCEL> to abort.
4-IN-1 GRAPH
Name
Set # 4
1 NOV8 -- ELECTRICITY CINGY Px1 USD
2 NOX8 -- ELECTRICITY CINGY Px1 USD
3 NOZ8 -- ELECTRICITY CINGY Px1 USD
4 Px1
Range 8/17/98 To 9/25/98 Period D (D-W-M-Q-Y) Normalize N (Y/N) Dates O
NOZ8 -- ELECTRICITY CINGY
29
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23
22
17AUG98
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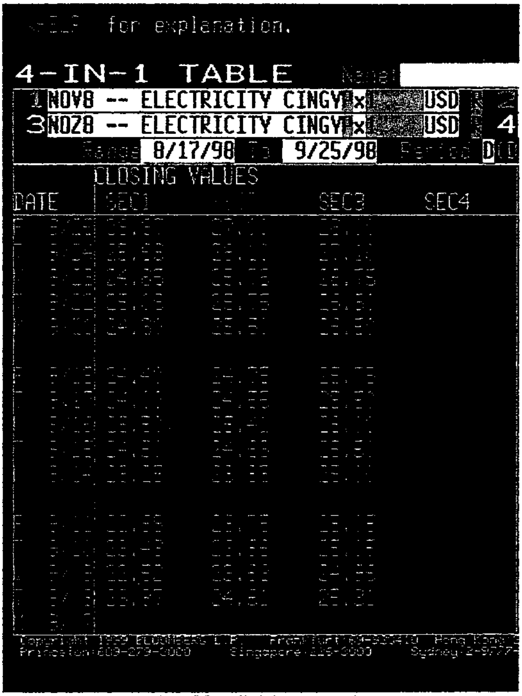

for explanation.
4-IN-1 TABLE
NOV8 -- ELECTRICITY CINGY
USD
NOZ8 -- ELECTRICITY CINGY
USD
8/17/98
9/25/98
CLOSING VALUES
DATE
SEC3
SEC4

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4-IN-1 TABLE Name:

1 NOV8 -- ELECTRICITY CINGY x1 USD 2

3 NOZ8 -- ELECTRICITY CINGY x1 USD 4

Range 8/17/98 To 9/25/98 Period D

DATE		CLOSING VALUES SEC1	SEC2	SEC3	SEC4
F	9/ 4	25.00	25.40	26.55	
T	9/ 3	25.75	26.35	27.00	
W	9/ 2	25.50	26.35	27.00	
T	9/ 1	25.55	26.50	27.25	
M	8/31	24.46	25.40	26.32	
F	8/28	23.90	24.85	25.75	
T	8/27	23.75	25.00	26.10	
W	8/26	23.00	24.[illegible]	25.15	
T	8/25	23.11	24.10	25.25	
M	8/24	23.25	24.80	25.25	
F	8/21	23.25	24.90	25.35	
T	8/20	23.00	24.10	25.35	
W	8/19	23.75	24.75	25.75	
T	8/18	24.20	25.00	26.50	
M	8/17	24.75	25.75	26.40	

SPARK SPREADS:

A spark spread is the difference in the power price between where the current market curve is, and what it would cost to buy gas and convert it to electricity at a set heat rate. As an example, assume the following:

Simple Spark Spread Example:

September Cinergy forward market price = $38.00/MWh
September Henry Hub natural gas price = $2.50/MMBtu

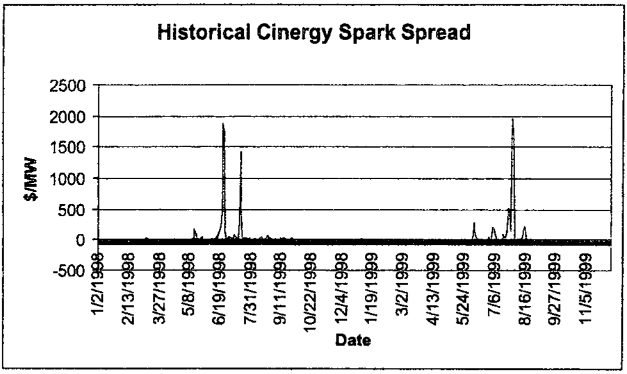
At a "10 heat rate" (10 mmBtu/MWHr), the cost of converting gas to power is:
($2.50 per MMBtu) x (10 MMBtu/MWHr) = $25.00 per MWh.

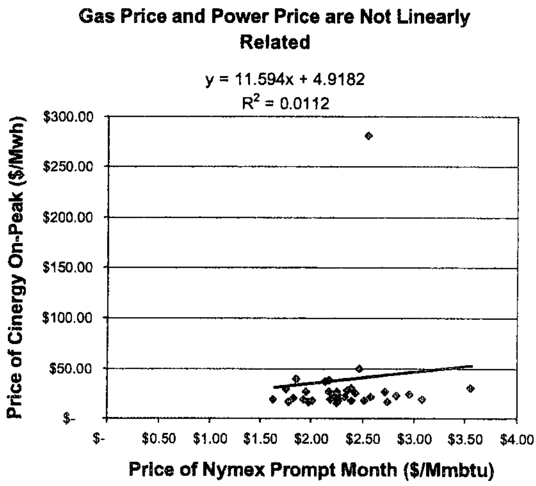
The difference, or "spark spread" is then $38.00 market cost minus $25.00 converted cost, or $13.00 per MWhr

The theory behind the spark spread is that as it widens, power plant operators have more incentive to buy gas and convert it to electricity. Over time, if the spread remains wide, it should attract "new build" if the returns on capital are sufficient. This means that if you could buy a generator, place it in operation, purchase gas, convert it to electricity and make a decent profit, then everybody would do it. Attracting numerous new participants into the market, who all would be buying gas and selling power, would cause the spark spread to collapse.

So a certain values of the spark spread will not attract new capital or yield a profit, and certain values exist where the spread will entice new participants into the market. Many speculators play this range by buying the spark spread when it narrows, and selling it as it widens. Speculators should be aware of two inherent problems with this:

1. Collapsing Spread: While no one would convert gas to power at a loss (negative spark spread), the spread may be "flat" and yield virtually no profit. This happens when the economics of a gas-fired power plant do not dominate the mix of generation. Coal units may be "on the margin" or at the top of the dispatch stack due to load requirements. Other supply/demand factors then predominate gas and power prices, and it is entirely possible to fluctuate around $18.00 for power, while gas may be $2.00, which would provide little if any opportunities for speculators to profit.
2. Exploding Spread: Theoretically the spread can widen indefinitely. If gas prices are between $2.00 to $3.00, and power prices get to $300 in the term (forward) market or $10,000 in the daily market, the spread is of course highly profitable. But it is not possible to build new generation overnight to capture this price differential. The inherent supply and demand balance for gas in relationship to power is "blown out the window". Any speculator trying to "pick a top" in the spark spread market must be aware of the huge risk potential.





Hedging Assets Using Spark Spreads:

Spark spreads provide a useful tool to hedge gas-fired generation. Within your company's hedging guidelines (addressed in a later chapter) you can

1. Lock in certain returns.
2. Provide price protection against adverse moves in power and/or gas.

3. Provide "scalping" opportunities by trading around hedges (i.e. buying back at attractive levels and resetting them at wider spread levels).
4. Allow for arbitrage opportunities:
   a. If the spark spread collapses, you can leave the initial hedges in place, take delivery of the gas and deliver the power that was pre-sold in order to book a profit.
   b. If the spread collapses, you can sell out the gas that was pre-purchased, buy back the power, and book a profit. This also lets you keep the opportunity to sell power in the hourly market if you think prices will be attractive.
   c. If the spread moves against you, the level at which the trade was initiated (bought gas/sold power) should have already produced an acceptable return, so there is no fear of covering the position at a loss. There is an opportunity cost foregone (the money left on the table by not being able to capture the spark at a higher rate by buying the cheaper gas and/or selling the higher-priced power) but as long as the hedging guidelines were followed, you won't have a problem.
   d. By selling the spark spread only, and not the "toll" (covered in the next section), you retain any ancillary services or additional benefits to owning the physical iron in the ground.

Spark Spread Contract Ratio Hedging:

In order to hedge using a spark spread, correct ratios of power to gas must be used. The calculation of how much gas to purchase against a set volume of power sold is as follows:

For a "7" heat rate:

(MW sold) x (hours sold) x (heat rate) = mmBtu's of gas to be purchased.

(50 MW) x (22 peak days in September) x (16 on-peak hours/day) x (7 heat rate) = 123,200 mmBtu's.
(123,200 mmBtu's)/(10,000 mmBtu's/NYMEX contract) = 12.32 contracts of gas.

The following table summarizes the correct hedge ratios for various heat rates using NYMEX power and gas contacts:

HEAT RATE	MW TO HEDGE	ON PEAK DAYS	HOURS/DAY	NYMEX GAS TO BUY	NYMEX POWER TO SELL	HEDGE RATIO Note that hedge ratios are approximate - estimations for ease of execution.
7	50	22	16	12 contracts	23 contracts	2:1
8	50	22	16	14 contracts	23 contracts	5:3
9	50	22	16	16 contracts	23 contracts	7:5
10	50	22	16	18 contracts	23 contracts	9:7
11	50	22	16	19 contracts	23 contracts	11:9
12	50	22	16	21 contracts	23 contracts	1:1

DIFFERENCES BETWEEN SPARK SPREADS AND TOLLING OPTIONS:

One area that causes confusion is the differences between a spark spread and a toll. As stated, spark spreads are simply buying gas and selling power in the correct ratio. "Tolling" refers to paying for natural gas, the physical act of putting natural gas into a generator, and then producing electricity.

With a spark spread, you are buying gas and selling power. With a toll, the costs are for the option premium for the toll and for the natural gas used to produce electricity.

Tolls are commonly sold in two ways – synthetically, or as an outright toll. An outright toll involves paying an option premium, usually in terms of $/kW month. This gives the buyer the right, but not the obligation, to "toll" gas (purchase his or her own gas, send it through the generator, and own the power output for sale in the marketplace or for use to meet load requirements). It also usually includes any ancillary or peripheral services that are associated with a generator. It is, for all practical purposes, the same thing as selling off a portion of a physical generator.

A synthetic toll involves paying an option premium for the right to purchase gas and have it converted into power. Unlike the outright toll, the synthetic toll does NOT involve the physical commodities. Rather than physically sending gas into a generator at a contracted heat rate and having to deal with the power output, the synthetic toll is usually settled at index. This means that a predetermined gas and power index are used to financially settle all synthetic tolling transactions. The benefits of a synthetic toll are that ancillaries are retained, ownership of the unit is retained, flexibility in terms of hourly versus daily arbitrage is kept, and scheduling problems that arise with multiple counterparties "tolling" on one unit are avoided.

An example of a toll is:

Definitions:

Delivered Fuel Price = the "Gas Daily" (GDD) - SoCal gas, large packages midpoint price plus $0.42 (represents LDC charge).
Variable O&M = $1.85 in 2000 escalated 3% annually.
Start Cost = $3,000 in 2000 escalated 3% annually.
Heat Rate = 10.0 MMBtu per MWh.

1. On 06June2000, Buyer notifies Seller, before 1200 Pacific prevailing time, that he will exercise his call for power for 07June2000 beginning at hour ending 0700 through hour ending 2200, for 100 MW.
2. Seller will deliver power to Buyer in the NP15 zone.
3. On 07June2000, Buyer and Seller "square up" accounts.
   Buyer will pay Seller the following for each MWh plus $3,000 for a start.
   (Assume that GDD - SoCal gas, large package, as printed on 07June2000, is $2.00.)

   (Delivered Fuel Price*10.0) + Variable O&M

   Example:
   GDD - SoCal, large pkgs. = $2.00

   Buyer pays:

GDD - SoCal	LDC	Total Gas:	Heat Rate:	Var. O&M =	$/MWh
$2.00	$0.42	$2.42	10.0	$1.85 =	$26.05

4. Buyer will pay Seller $26.05/MWh x 16 on-peak hours x 100 MW
   = $41,680.00 for the power
   + $3,000.00 start cost
   = $44,680.00 total cost for that particular day of exercise.

   Note: If Buyer decides to exercise on consecutive days for 24 hour periods, the start charge will be applied to the initial day only. If Buyer exercises on consecutive days for anything less than 24 hour periods, the $3,000.00 start charge applies to each day.

Summary of Toll Data

Assumptions: Heat Rate - 10.00 MMBtu/MWh
Var. O&M - $1.85/MWh - 3% annual escalation
Start Charge - $3,000 per start - 3% annual escalation
Forced Outage Rate - 0%

Year:		2000	2001	2002	2003	2004
<u>Capacity</u> (MW)		100	100	100	100	100
<u>Intrinsic</u> (000)						
Sales Rev.		12,353	11,601	12,326	12,301	13,237 (from dispatch model)
Var. O&M		8,320	7,485	8,052	7,822	8,494
Start Costs		495	467	442	531	540
Intrinsic Value		3,538	3,649	3,832	3,949	4,203 (sales less variable less start)
<u>Extrinsic</u> (000)						
Daily		307	352	404	757	738
Term		703	761	927	1,037	1,151
Total		4,548	4,762	5,163	5,742	6,093 (sum)
Discount	10.50%	1.000	0.905	0.819	0.741	0.671
NPV		4,548	4,310	4,228	4,256	4,087
Cumulative NPV			8,858	13,086	17,342	21,429
Individual Year Rate		**3.79**	**3.97**	**4.30**	**4.79**	**5.08**
Levelized Rate for 5 yrs.	**4.318**	5,181	4,689	4,243	3,840	3,475
			9,870	14,114	17,954	21,429

II. Natural Gas

OBJECTIVES OF THIS SECTION:

1. Understanding of basic physical aspects of gas from ground to wellhead.
2. Understanding of basic supply and demand fundamentals.
3. Understanding of basic trading instruments.
4. Familiarization of basic trading strategies.
5. Integration of #'s 1 – 4 into basic hedging and risk management strategies.

NATURAL GAS

During the 1980's the federal government began to deregulate the natural gas industry. Deregulation does not imply the government 'unregulated' the industry, or lifted all existing laws surrounding the operation and flow of natural gas. It merely signifies a reduction in the amount of restrictions placed upon the business. As laws were loosened and rewritten, natural gas as a traded market matured. This chapter will provide the basics of the natural gas market – from physical aspects to fundamental trading instruments and strategies.

OVERVIEW OF PHYSICAL GAS:

Natural gas is a fossil fuel comprised mainly of methane. It is a colorless, odorless, flammable substance formed by the decomposition of vegetable matter. It is found both onshore and offshore either by itself or with crude oil.

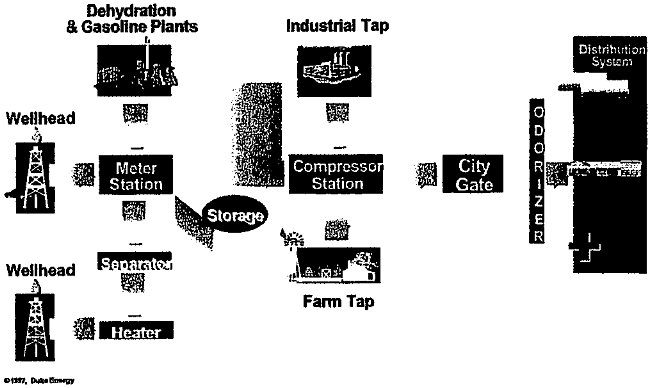
FINDING:
E&P (exploration and production companies) use a host of techniques to locate natural gas deposits in the earth, called finds, reservoirs, wells or deposits. Some of these practices include Seismic 3-D, in which a type of sonar is used to locate deposits; extrapolation techniques, where past finds are used to predict the location of future wells; and geological surveys, in which core samples are used to predict locations with increased probability.

EXTRACTING:
Once a deposit is discovered, gas is extracted and delivered to the end user. The reservoir of gas is directed into a wellhead, which collects and directs the flow of gas from the ground to the surface. Gas from various wellheads is then directed into a small-diameter pipe, which is part of a gathering system. The gathering system directs the gas flow to a processing plant. The purpose of the processing plant is to extract the natural gas in its purest form, and to separate any by-products for resale or disposal. Most often, the heavier hydrocarbon components are worth more when separated and sold as liquid products. The extracted natural gas liquid products (NGL's) have a premium market as feedstock for refineries and petrochemical plants. Specifics of NGL's will be covered in a later section.

		Pricing /1			Breakdown of Avg. MCF /2	
	Symbol	Example Avg Price	Gal/mmbtu	$/MMBtu	MMBtu	%
Natural Gas	NG or C1	$2.16 $/MMBtu	-	$2.16	1000	85%
Ethane	C2	20.8 ¢/gal	15.08	$3.13	53	5%
Propane	C3	32.7 ¢/gal	10.93	$3.57	49	4%
IButane	iC4	40.5 ¢/gal	10.04	$4.07	16	1%
Nbutane	nC4	38.2 ¢/gal	9.64	$3.68	31	3%
Ngasoline	C5s+	41.3 ¢/gal	8.70	$3.59	23	2%
					1173	100%

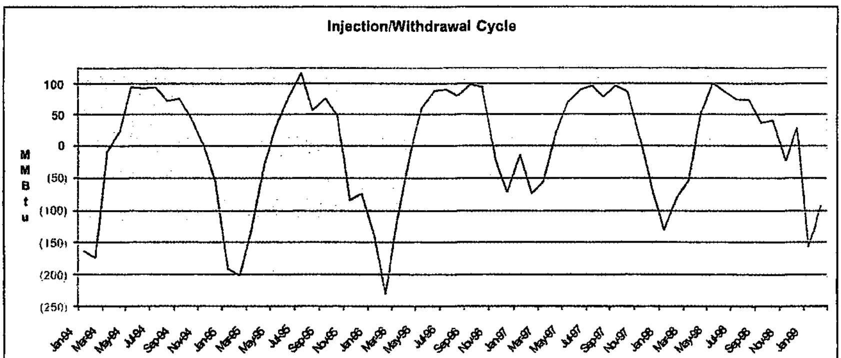
/1 Average of Apr-93 thru Mar-99 monthly prices
Bellevue for NGLS, NYMEX 3Day for gas.
/2 Btu contribution by component for 1 mcf with 2 gallons of NGLs per mcf
Assumes NGL mix as follows:

Ethane	40%
Propane	27%
Nbutane	15%
IButane	8%
Ngasoline	10%



GATHERING:
After natural gas has been extracted from the processing plant, it flows to the receipt point, which connects the plant to a pipeline interconnect, or mainline. Numerous receipt points, which connect each processing plant to a central mainline, exist for the major geographical regions. These specific pipelines are referred to by name as the various points and central deal locations when buying and selling gas.

STORING:
In addition to the normal flow from well to endpoint, storage facilities are located at various points along the pipelines. The storage facilities allow for natural gas to be injected or withdrawn, depending on supply and demand. Normal practice is to inject gas during the summer injection cycle (April to October) and withdraw during the winter withdrawal cycle (November to March). The withdrawal cycle corresponds to the increased demands for residential and industrial heating, whereas gas is injected into storage when demand is lower, with intent to build as much reserves as possible for the winter. Recently, utility usage during the summer, via gas-fired generators used to supply electricity for air conditioners and cooling demand, has created a situation where the late June through early August injection amounts are significantly below historical levels.



AMERICAN GAS ASSOCIATION WEEKLY STORAGE REPORT

	13-Aug	6-Aug	Week	Year	5 Year	% Full
Producing Region	725	724	+1	-55	+89	76%
Consuming East	1290	1247	+43	-123	-16	71%
Consuming West	387	280	+7	+36	+38	79%
Total	**2402**	**2251**	**+51**	**-142**	**+111**	**74%**

Storage facilities create an opportunity to optimize the market. An astute producer can monitor the spot and forward markets. Based on the cost of capital, cost of storage, fuel, insurance, etc. (carrying costs), producers can time when they will store gas versus when they will supply the gas. A storage facility creates an option; the producer is long a call option if gas is in storage, or long a put option if the storage facility is available but not full.

For example, an user needs to deliver 10,000 MMBtu/day for the month of November. The price of gas in November is $3.10. However, the end user can buy gas October 12-31 for only $3.00. The pipeline charges $0.02/MMBtu as an injection fee, and an $0.02/MMBtu withdrawal fee. Carrying costs are $0.05/MMBtu per month on the average daily balance. For simplicity sake, the fuel charges will be included in the injection and withdrawal rates. What profit, if any, will be made by buying gas in October, storing it, and withdrawing it in November?

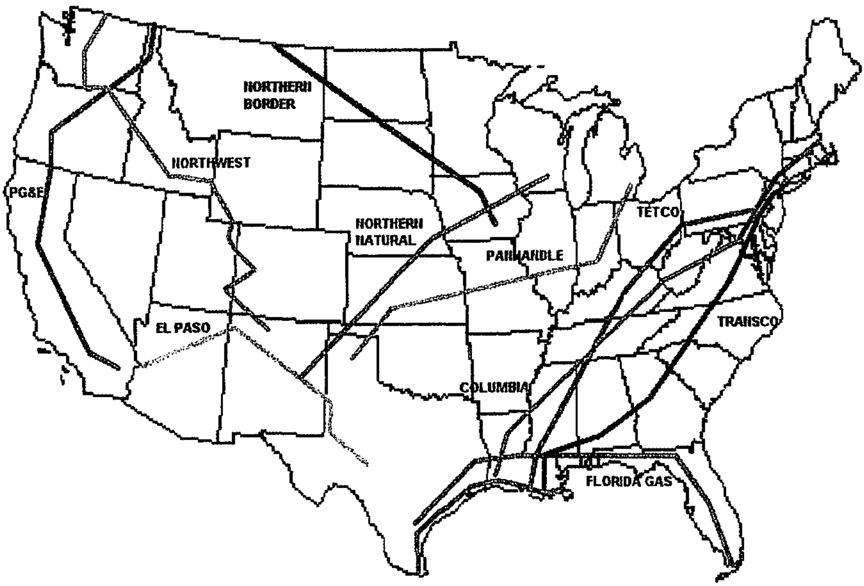
<u>October</u>		<u>November</u>	
Total Injection:	300,000	Total Withdrawal:	300,000
Injection rate:	<u>$ 0.02</u>	Withdrawal rate:	<u>$ 0.02</u>
Injection Fee:	6000	Withdrawal Fee:	6000
Avg Daily Balance	101,613	Avg Daily Balance	145,000
Carrying Charge	<u>$ 0.05</u>	Carrying Charge	<u>$ 0.05</u>
Carry Cost	5081	Carry Cost	7250

<u>Total Storage Costs</u>:	
Injection Fee	$ 6000
Withdrawal Fee	6000
Oct Carry Cost	5081
Nov Carry Cost	<u>7250</u>
Total:	24,331

$24,331 divided by 300,00 MMBtu yields a $0.0811 storage cost per MMBtu. The spread between the October and November prices is $0.10 (3.10-3.00). Thus, the total profit is $0.10 – 0.0811 x 300,000 MMBtu = $5669

TRANSPORTATION:

Physically moving gas from one region to another involves the process of nominating, confirming, scheduling, allocating and balancing. Nominating refers to when a party requests a pipeline to recognize and account for physical molecules of gas that will be transported from point "A" to point "B". If the request is in order and is accepted, the nomination is then confirmed, and the details are matched between counterparties to insure no errors. The pipeline schedules the physical gas to flow by notifying the operating personnel to expect a certain amount of gas to flow from the predesignated point to the receipt point for the specific day(s) and in the specified volume. Because numerous suppliers are connected to each major pipeline, gas designated from "A" to "B" may not actually be supplied by the original sender. All suppliers send gas into the pipelines, where the physical molecules flow from areas of high pressure to area of low pressure. Since gas is a commodity, all supplies are homogeneous. It does not matter if the gas from the original supplier arrives at the destination point or if gas from another supplier reaches the point. All that matters at the end of the day, supplies into the pipe match demands from the pipe. The act of coordinating the supply and demand is called allocating and balancing.



TRANSPORTATION TYPES:
Natural gas flow from producing regions (called access areas) to consuming regions (called market areas) via a grid of interstate and intrastate pipelines. Transportation along these pipelines can be done is several different ways. The two basic types of transportation are as follows:

Firm Transportation: Receives top priority, and cannot be interrupted under any circumstances unless a *force majeur* is declared (act of God).

Interruptible Transportation: Receives a low priority. This can be interrupted for various reasons, including overscheduling, natural disasters, emergency needs, or unscheduled maintenance.

Three major types of physical transactions are conducted – Firm Contracts, Baseload Contracts, and Swing Contracts. Firm contracts demand that the seller provide and the buyer accept the stated volume of natural gas at the specified location for the specific time. Should the buyer default, the seller will go into the marketplace, sell the unclaimed gas at the best possible price, and charge the difference between the contracted price and the market price to the buyer. Conversely, if the seller reneges, the buyer will go into the marketplace, purchase gas at the best available price, and charge the difference between market and contract back to the seller. Baseload contracts imply that the buyer and seller make a best-faith effort to honor all arrangements. Although the contract can be broken for any reason, it is a matter of personal and professional ethics to do everything reasonably possible to keep the other party whole. It is permissible under contract terms to break the contract because of more favorable market (price) conditions - loosely called *price majeur.* However, this type of action will virtually guarantee no one will deal with you in the future. Swing contracts are flexible arrangements that permit the volume of gas to vary as well as the term. These are sometimes desirable due to the added flexibility or because of a more favorable price.

Both swing and baseload contracts generally use interruptible transportation contracts, while firm contracts utilize firm transportation contracts.

SUPPLY AND DEMAND FACTORS:

BASIC DEMAND:
The demand for natural gas is affected by the weather. Extreme hot or cold conditions increase the need for cooling or heating. The strength of the economy is also a major factor. A strong economy will create the need for more gas as industrial demand increases. The following can segment the demand for natural gas: residential users, commercial users, industrials, and electric generation. Currently, demand growth for electric generation significantly exceeds the growth of other users and seems to be driving the forward market.

North American Gas Demand by Sector
(excludes fuel)

	Tcf				% of Total			
Year	Res/Com	Ind	Elec	Total	Res/Com	Ind	Elec	Total
1998	9.00	9.80	3.20	**22.00**	40.9%	44.5%	14.5%	100.0%
1999	9.06	9.95	3.32	**22.32**	40.6%	44.6%	14.9%	100.0%
2000	9.17	10.10	3.70	**22.96**	39.9%	44.0%	16.1%	100.0%

USERS:
The end users of natural gas are connected to various points along the ends of the many pipelines. LDC's (Local Distribution Companies) are distribution systems which supply gas to consumers in towns and cities. These public utilities service both residential and commercial end users. Industrial consumers use natural gas to directly or indirectly power machinery used in various manufacturing processes. Cogeneration companies use natural gas to produce electricity as well as capture "waste heat" for creating future energy. Additionally, peaking units, which are very similar to jet engines used in aircraft, burn natural gas as a direct product, using the combustion gases to produce electricity.

BASIC SUPPLY:
Price, availability, weather impact, transportation and substitution govern the supply side. Price will dictate storage versus supply, and also future capital expenditures. A high forward price curve will stimulate more E&P activity, where a low forward price curve may not support production, and could cause some suppliers to "shut in" production, or possibly go out of business. Weather, in the form of hurricane activity, can disrupt production and possibly supply. Transportation costs to the various hubs can dictate how much gas is made available to any one region. The costs of alternative fuels as well as the cost of the liquids (NGL's) may dictate processing plant activity. Specific supply/demand equations will be covered in a later lesson.

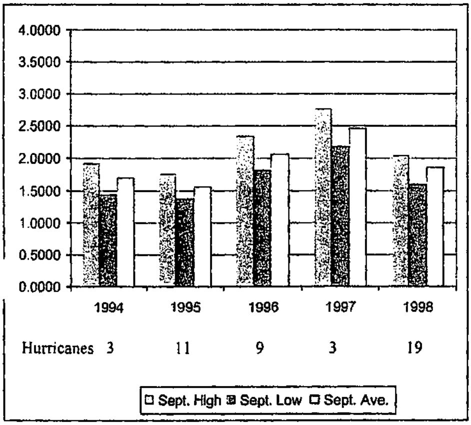
North American Supply
Supply Projections (Tcf)
(net of lease, pipeline, and plant fuel)

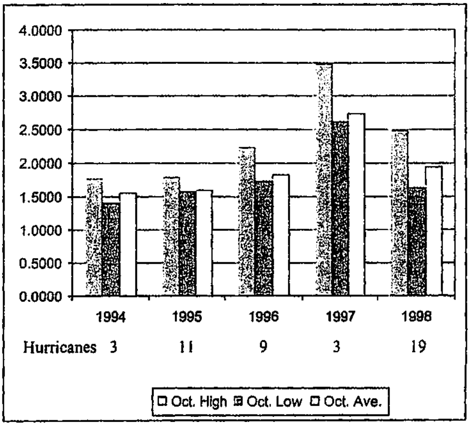
	1998	1999	2000
Appalachian Basin	0.53	0.55	0.57
East Gulf Onshore	0.18	0.18	0.19
North Central	0.32	0.36	0.40
Arkla-East Texas	1.16	1.19	1.21
South Louisiana Onshore	0.83	0.85	0.87
Texas Gulf Onshore	1.99	1.98	1.97
Williston Basin	0.10	0.10	0.10
Rockies	1.21	1.23	1.26
San Juan Basin	0.90	0.90	0.91
Overthrust Belt	0.11	0.11	0.12
Mid-Continent	2.71	2.69	2.66
Permian Basin	1.33	1.33	1.33
West Coast Onshore	0.26	0.25	0.23
Norphlet Gulf of Mexico	0.33	0.37	0.41
Gulf of Mexico Offshore	4.30	4.56	4.84
West Coast Offshore	0.06	0.06	0.06
Lower 48 Total	16.32	16.70	17.11
Alberta, Saskatchewan, Manitoba	4.47	4.58	4.68
British Columbia	0.70	0.69	0.68
Beaufort/Mackenzie/Northern Basin	n/a	n/a	n/a
Eastern Canada	0.18	0.19	0.20
Canada Total	5.35	5.46	5.56
North America Total (excl. Alaska)	**21.67**	**22.16**	**22.68**

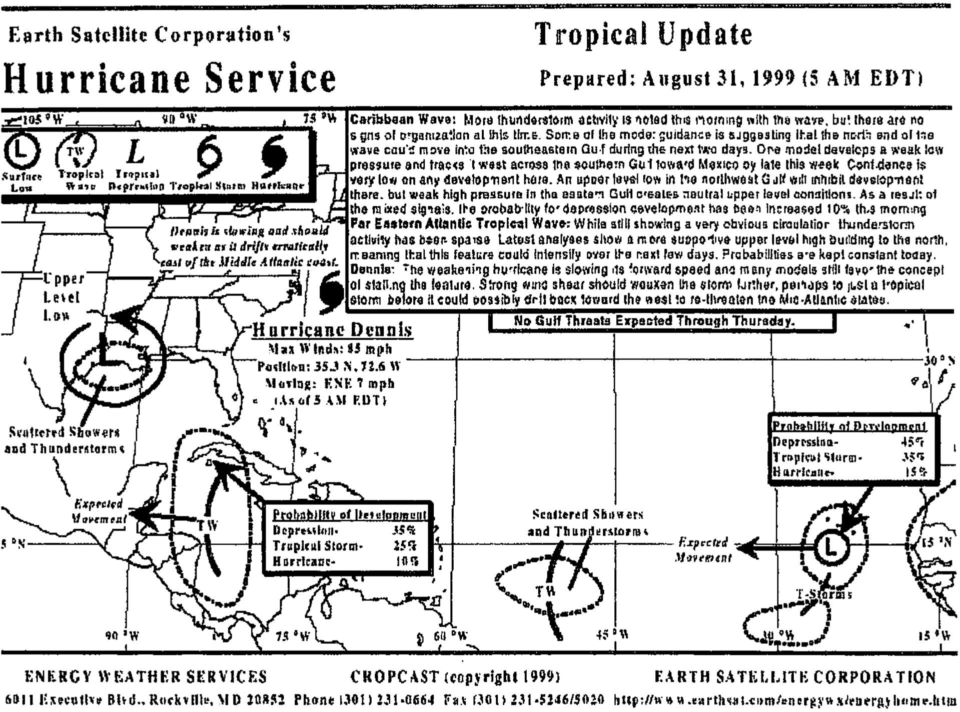
		Contract Month					
Year	Hurricanes	Sept. High	Sept. Low	Sept. Ave.	Oct. High	Oct. Low	Oct. Ave.
1994	3	1.9200	1.4500	1.7005	1.7700	1.3950	1.5514
1995	11	1.7550	1.3900	1.5572	1.7890	1.5710	1.5950
1996	9	2.3400	1.8200	2.0537	2.2400	1.7350	1.8356
1997	3	2.7600	2.1750	2.4556	3.4800	2.6200	2.7287
1998	19	2.0500	1.6100	1.8578	2.4800	1.6300	1.9483

Weather Source:
http://www.usatoday.com/weather/whurnum.htm
http://www.nhc.noaa.gov/1998archive.html

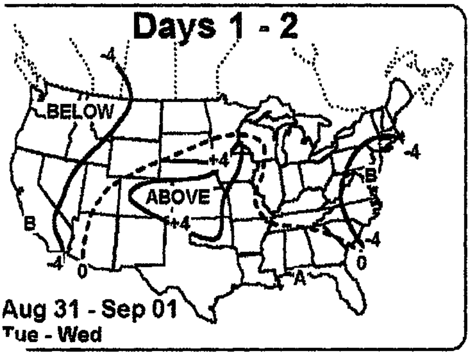
Price Source:
Prompt month price for month of Aug. and Sept.--Prophet

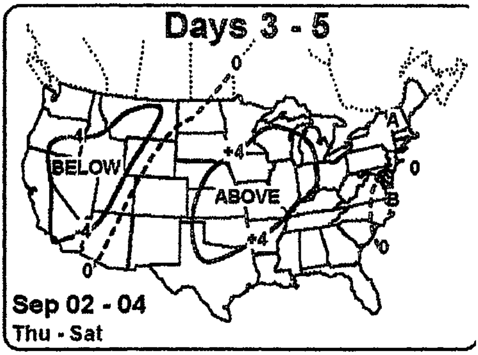






Natural Gas traders attach extreme importance to the weather and it's effects. Temperature differentials will signal a rally or decline in both the future and physical gas markets. Hurricane activity, as shown by the graphic above, also plays an important role. However, it should be noted from the preceding tables, it is not just the sheer number of hurricanes that may affect the prices of natural gas, but rather if the hurricane has the potential to develop in the Gulf of Mexico and disrupt production facilities.





VOLUME AND PRICING FORMAT:

BASIC TERMINOLOGY AND CALCULATIONS:

NYMEX:

1 contract equals 10,000 mmBtu for the period specified (i.e. buying 5 September NYMEX Natural Gas contracts is to purchase 5 x 10,000 MMBtu's, or 50,000 MMBtu's for the month of September.).

OTC (Over the Counter):

Specified in contracts per day (i.e. buying 2 a day of September is 2 x 30 days x 10,000 MMBtu's, or 600,000 MMBtu's delivered ratably during the month of September).

Volumetric Quotations:

Often times the trading of natural gas is specified in volumetric notation. The purchase of "20 million" is to buy 20,000 MMBtu's, or 2 NYMEX contract equivalents. This is also the volumetric equivalent of "20 million cubic feet per day", or again, 2 NYMEX contract equivalents.

Conversion Units:

CF	=	Cubic Foot
MCF	=	1000 CF
MMCF	=	1000 MCF
BCF	=	1000 MMCF
TCF	=	1000 BCF

Measured Units:

CF	=	1000 Btu (Standard Quality)		
MCF	=	MMBtu	=	Dth
MMCF	=	1000 Dth		
BCF	=	Million Dekatherm		

Thus:

100 NYMEX Natural Gas contracts = (100 contracts) x (10,000 MMBtu/contract) = 1,000,000 MMBtu's.

100 NYMEX Natural Gas Contracts = 1,000,000 MMBtu's (or 1,000,000,000 cubic feet) = 1 Bcf

Natural Gas Markets

PHYSICAL TRADING MARKETS:
Natural gas trades on a "next-day" and a "next-month" basis, as well as for specific individual tenures – someone is always willing to make a market for any time frame or any product – for a price. Physical deals done for "next-day" business are referred to as "cash" or "spot" transactions. The majority of physical natural gas trading takes place during bidweek. Bidweek is the last week of each month, and is used by marketers, LDCs, end users, etc. to fulfill any physical needs and set positions for the following month. Because of the number of players transacting business during this time, bidweek is always the most liquid time of the month to trade physical gas.

Physical trading can take place in several different ways. Electronic systems exist for some regional locations. Brokers, who never take title to the gas, anonymously match bids and offers of various buyers and sellers. Additionally, a bilateral market exists. Here buyers and sellers call other traders and marketers directly in an attempt to fulfill orders. The Internet is rapidly becoming a viable tool for buyers and sellers, as many brokerage firms are now making an effort to conduct business online. As with any transaction, counterparty credit risk must always be taken into account.

Following is an example of one broker company's market on Houston Ship Channel on the Internet:

As of Wednesday, 11/10/99, 05:20PM

Basis

		Term		Basis Swap		EFP	
Pipe	Location	Begin	End	Bid	Ask	Bid	Ask
SHIP		Dec99	Mar00	-6.5	-6		
SHIP		Dec99		-6.5	-6		
SHIP		Jan00		-8.5	-7.75		
SHIP		Feb00		-6.75	-6.25		
SHIP		Mar00		-4.75	-4		
SHIP		Apr00	Oct00	0.25	0.75		

FINANCIAL TRADING MARKETS:
Financial trading markets are considered to be the exchange-traded markets, over-the-counter (OTC) term markets, and specialized derivatives done through direct counterparties. The NYMEX market trades via contract months, with each contract good for 10,000 MMBtu's. The vast majority of contracts are "closed out" or liquidated before contract expiry, which is three business days prior to the actual month (i.e. the September 1999 contract would expire on Friday, August 27, 1999). Contracts not closed out can be taken into the physical market via a mechanism called "EFP's" – Exchange Futures for Physical (to be discussed later.) NYMEX contracts are listed for 18 months, and usually provide good liquidity for the first several

months. However, events such as days prior to holidays, extremely volatile conditions, or during contract expiry, the liquidity of the NYMEX market can become unreliable and spotty at best.

NYMEX Contract Equivalents

Avg. Daily Volume	00	01	02	03	04	05
OTC*	1,440	1,000	720	360	180	180
Direct*	3,600	2,880	2,160	1,000	1,000	1,000
NYMEX	13,092	1,732	363	N/A	N/A	N/A

*Estimates

Natural Gas Trading:

BASIS:

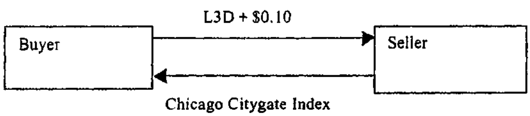
The NYMEX natural gas contract, if taken to delivery, is delivered to Sabine Pipeline Company's Henry Hub in Vermilion Parish, Louisiana. All other natural gas receipt points are traded at a differential to this point, which is called basis. Basis markets are traded OTC – through brokers and directly between users. Basis does not necessarily equate to the cost of transport from Henry Hub to the different trading points. Rather, basis is determined by supply and demand dynamics within a particular region.

Many market players trade basis. The hope is that the price level at Henry Hub and the desired delivery point (New York, for example) will not move in sync. A trader then can take advantage of these anomalies in the marketplace. The most influential factor in determining the price of gas at a particular point is the current and projected weather and temperature forecast. Some traders use historical spot prices to forecast what the future basis will be. It is possible to take the historical differences between the Henry Hub and New York and average these to predict what the future New York basis will be. Theoretically, the past spot prices of both Henry Hub and New York have the effects of regional weather embedded in them. Therefore, it is reasonable to assume the future weather patterns will repeat, giving a trader a good understanding of where future basis quotes will be for a given time frame.

BASIS SWAP:

Many traders use basis swaps to manage their basis risk. As with all general swaps, the buyer receives a floating payment and gives the seller a fixed price. However with a basis swap, the fixed payment is not entirely fixed – it is the average of the last three trading days of the futures contract (L3D) plus an agreed upon basis differential. The floating payment is an index number, usually determined by the first business day of the month.

For example, Company Buyer and Company Seller agree to transact Chicago Citygate basis for $0.10. Their trade would look as follows.



If L3D calculates to be $3.05, and the Chicago Citygate index is $3.17, the buyer makes payments as follows:

Pay:	$3.05	Receive:	$3.17
Pay:	.10		
	$3.15		$3.17

Profit: $0.02

INDEX:
Index, when referring to gas, is a weighted average of all trades for a particular region during a particular time frame. Several sources publish indices for major hubs on a regular basis; the most commonly used are *Gas Daily* to price daily flows, and *Inside Ferc* to price monthly flows of gas.

Following is an example of a published daily index for gas flows on a specific date, by pipeline:

Tuesday, August 31, 1999

Daily Price Survey

Listed in the left column are the midpoints of the daily ranges for the most common prices, paid in $/mmBtu of a typical volume of 5 thousand mmBtu. The middle column shows absolute low-high prices for transactions reported on the date at the top of the column; the third column shows that day's ranges for the most common prices. The prices are generally for gas flowing today, weekends are usually priced using data collected Friday. Ranges are for deals done before nomination deadlines. Boldface indicates the price range is based on data reported the previous day. Plain type indicates insufficient data to reconfirm or change the previous range. The common range is built around the volume weighted average and the midpoint is calculated for the common range. Data in this table is Copyright 1999 by FT Energy.

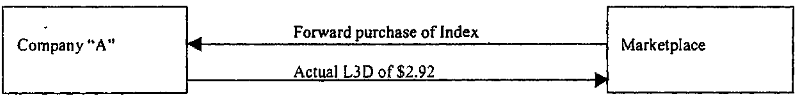
NATIONAL AVERAGE PRICE: $2.840

Trans. date	**8/30**	**8/30**	**8/30**
Flow date(s)	**8/31**	**8/31**	**8/31**
	Midpoint	**Absolute**	**Common**
Permian Basin Area			
El Paso	2.750	2.70-78	2.73-77
Northern (Mids 1-6)	2.750	2.73-77	2.74-76
Tex Intras, Waha area	2.805	2.77-84	2.79-82
Transwestern	2.700	2.66-73	2.68-72
East Texas-North Louisiana Area			
Carthage Hub tailgate	2.815	2.79-84	2.80-83
Koch (Zones 1&2)	2.700	2.69-71	2.69-71
Lone Star	2.750	2.74-76	2.74-76
MRT mainline	2.830	2.80-84	2.82-84
MRT west leg	2.805	2.80-82	2.80-81
NGPL TexOk (West)	2.780	2.76-80	2.77-79
NGPL TexOk (East)	2.780	2.73-82	2.76-80
Tennessee, 100 Leg	2.745	2.73-76	2.74-75
Texas Eastern (ETX)	2.780	2.74-82	2.76-80
Texas Gas (entire Z 1)	2.836	2.83-84	2.83-84
East-Houston-Katy			
Houston Ship Channel	2.865	2.84-90	2.85-88
Katy plant tailgate	2.845	2.81-87	2.83-86
Trunkline North	2.815	2.80-82	2.81-82
North-Texas Panhandle			
NGPL (Permian)	2.675	2.66-69	2.67-68
Northern (Mid 10)	2.615	2.59-64	2.60-63
Transwestern	2.700	2.65-73	2.68-72
South-Corpus Christi			
Agua Dulce hub	2.795	2.76-83	2.78-81
Florida Gas	2.800	2.77-85	2.78-82

The appeal of transacting at index is that it theoretically represents fair value for gas (i.e. where buyers and sellers are balanced). Additionally, it removes any "second-guessing" regarding buyers and sellers leaving money on the table (forgoing additional revenue) because each receives the established fair market value for gas. As an example, if Company A decides to sell gas forward at a fixed price of $1.95 in order to lock in profit margins, the company will look foolish in the eyes of management if the index price for that particular forward time period comes in at $2.75.

Index pricing also offers opportunities for speculation. If a company feels it has superior information or trading capabilities, it can sell fixed price gas forward at what is perceived to be a high rate, and purchase index gas to offset the sale. The desired goal is that the index price of gas will be determined to be a lower rate than the fixed price sale, creating a profit. The converse also holds, in that a company can buy fixed price gas while selling index, with the hope of the index gas price materializing higher than the original fixed price purchase.

INDEX TRADE:
Company "A" purchased fixed price gas on a forward basis for November at $3.25. The actual price of gas for November, as determined by the published index, was $2.75. The trader who made this decision is now less than enthusiastic about committing to fixed price gas, and wishes to merely match whatever price is determined to be "fair value" (index). The trader at "A" then purchases index gas for December. If the average of the last three days before expiry is $2.92, then "A's" purchase will match the published index.



NYMEX TRADE:
If Company "A" needs to purchase gas, an equivalent amount of NYMEX contracts can be bought on the exchange as a financial "hedge" or proxy for the needed gas. Hopefully, the change in the NYMEX contract price will match that of the physical gas needed, thereby offsetting any swings in P&L.

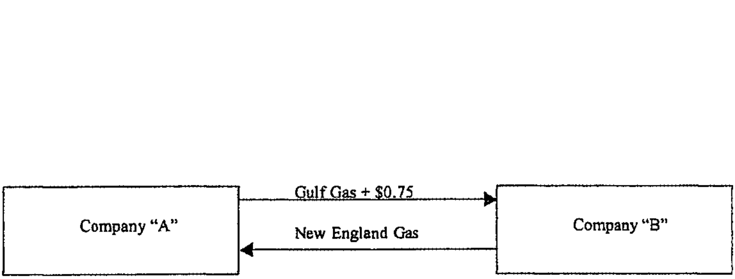
Example: Company "A" estimates it will need 20,000 MMBtu's of gas in June. "A" purchases 2 June NYMEX contracts (2 contracts x 10,000 MMBtu's/contract) for $2.39. Just before contract expiry, "A" sells the contracts back on the NYMEX for $2.35. The resulting P&L is:

(2 contracts) x (10,000 MMBtu's/contract) x ($2.35 - $2.39) = -$800.00.

Hopefully, this $800.00 loss is offset by an $800.00 gain at the location where "A" needs physical gas.

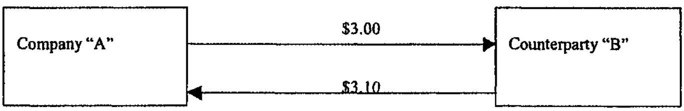
SWAPS:
A physical swap involves exchanging gas in one specific region for gas in a different region. For example, suppose a trader has an opportunity to sell gas in the Gulf next month at what is perceived to be a high price. After attempting to procure the gas, the trader finds only one supplier, who coincidentally happens to need gas in New England. The two agree to swap Gulf gas for New England gas (a price differential may be applied). Note the actual physical gas does flow and must be scheduled.

EXAMPLE OF SIMPLE PHYSICAL SWAP:
Assume that gas in the Gulf is $2.15, and gas in New England is $2.90. If Gulf gas is swapped for New England gas, the basis (differential) is included to make the transaction equal.



L3D:
As stated previously, "Last three days", or L3D, is defined as the simple arithmetic average of the last 3 settlement prices of a contract before it expires. If the April contract expires on March 24, then L3D is the average of the settlement prices which occurred during March 24, March 23 and March 22 provided no holidays or weekends occurred. L3D can be used as an important tool when utilizing OTC swaps to arbitrage the NYMEX market. A trader can buy L3D and sell the settle if the market seems to be rising, or sell L3D and buy the settlement in a declining market.

FUTURES SWAP (OTC):
Over the Counter (OTC) swaps are financial swaps which mirror the NYMEX contracts. The most notable exception is that if the OTC swap is not ""closed out" (offsetting transaction), then the difference between the original trade price and the settlement price for that month is paid between the two parties. Assume that Company "A" thinks the price of gas is going higher, but does not want to be bothered with any physical aspects of a gas transaction. Company "A" can purchase, through the OTC broker market, January gas at $3.00. "A" can then close out the transaction by completing an offsetting sale of January gas on the OTC broker market (hopefully at a higher price) or "A" can simply wait until expiry, and settle financially with Counterparty "B" based on L3D. If L3D turns out to be $3.10, and the trade was for 1/day, the transaction and P&L would be:



P&L Calculation: 1/day = (10,000 MMBtu's per day) x (31 days per month) = 310,000 MMBtu's.
(310,000 MMBtu's) x ($0.10) = $31,000.00

HEDGING A PHYSICAL TRADE WITH A FUTURES SWAP:
Assume that Company "A" sold physical gas at index + $0.05. "A" is now responsible for delivering the actual molecules of gas, and will receive a slight premium ($0.05) over index for their efforts. "A" must now buy the physical gas to cover this transaction. In order to procure the actual gas and to try and lock in a profit, "A" will now go into the marketplace, buy fixed price gas, and convert this fixed price purchase into a floating, or index purchase. This will match the exposure on the index sale, and hopefully lock in a profit. The steps for this transaction are:

1. "A" sells physical gas for Index + $0.05. "A" is now short the physical gas.

STEP #	RECEIVE	DELIVER
1.	I + ($0.05) payment	Physical gas

2. "A" buys the physical gas for a fixed price (assume $2.00). "A" is now "flat" physical gas (has both purchased and sold physical gas). "A" is still scheduled to receive index + $0.05 on the sale, but has

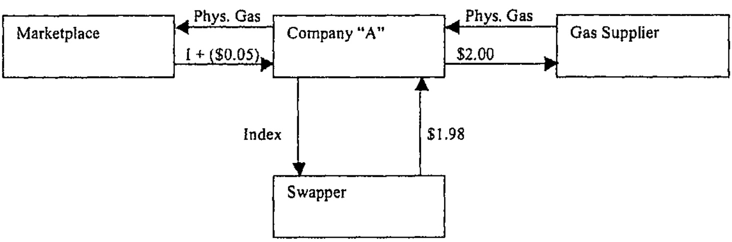
committed to pay $2.00 on the purchase. If index comes in higher than $1.95, ($2.00 purchase price minus the $0.05 index premium) then "A" will make money.

STEP	RECEIVE	DELIVER
1.	I + ($0.05) payment	Physical gas
2.	Physical gas	$2.00 payment
NET:	I + ($0.05)	$2.00

3. In order to lock in a profit, "A" wants to convert the index sale into a fixed price sale. To do this, "A" sells a financial swap to the marketplace and receives a fixed price (assume $1.98) and delivers payments at index (fixed for floating swap).

STEP	RECEIVE	DELIVER
1.	I + ($0.05) payment	Physical gas
2.	Physical gas	$2.00 payment
3.	$1.98	Index
NET:	$2.03 payment	$2.00 payment

4. A diagram of the transaction is as follows:



SWING SWAPS:
Swing swaps are another form of fixed for floating swaps. The only major difference is the index to be referenced. Normally, fixed for floating swaps reference L3D, however, swing swaps are for specific intramonth tenures. Swing swaps are financial (not physical) transactions utilized when a company wishes to convert an indexed price to a fixed price, or vice versa. The user will still need to go into the marketplace to procure physical molecules, if need be.

An example of this would be if Company "A" bought what it thought was enough gas to run its electrical generator for the month of July. During the last week of July, the 7-day weather forecast predicted record temperatures. "A's" load forecast showed that it would most likely need to buy additional gas for the time frame of July 21 to July 25 in order to operate its peaking units. "A" does not want to lock in prices today, because they feel that the weather has been "hyped" and that prices should come off. However, the possibility exists that prices may in fact continue to rise, so "A" decides the safest course of action is to buy in the needed gas at the daily indices. The swing swap for this time period is calculated as follows:

DATE:	HIGH	LOW	(H + L)/2
7/21	$2.05	$2.03	$2.04
7/22	$2.25	$2.15	$2.10
7/23	$3.05	$2.85	$2.95
7/24	$3.10	$2.40	$2.75
7/25	$2.35	$2.05	$2.20
			$2.4080

"A" would pay $2.408 for the gas it received during the period of 7/21 to 7/25.

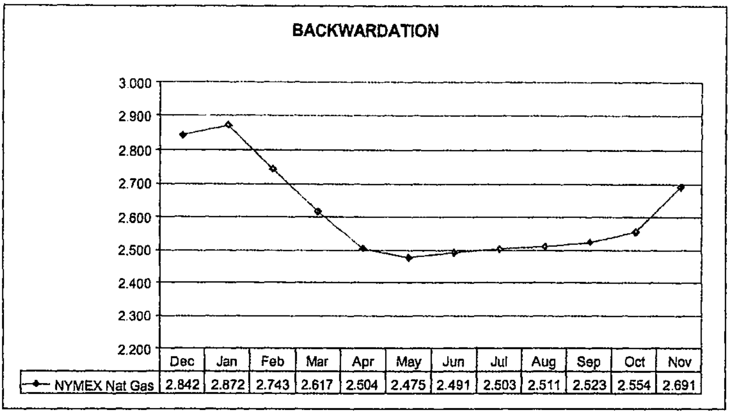
EXCHANGE FUTURES FOR PHYSICALS (EFP'S):
It is a commonly quoted statistic that 95% of all listed exchange contracts are "closed out" or offset. The remaining 5% are actually delivered or received. The mechanism to do this is called an EFP, or Exchange Futures for Physical (also called, in a shortened version that also matches the acronym, "Exchange for Physical"). Simply stated, EFP is an exchange of a futures position for a physical position in the cash market. EFP's are usually negotiated OTC (but can in some instances be negotiated on the exchange). They are always then "posted" on the exchange, so that the mechanics of delivery can be arranged. The specific steps are:
Buyer of an EFP (party wishing to trade a long futures contract position for physical gas):

1. Pays the EFP price to the seller. The EFP price is a negotiated price, and many times a basis is added if the buyer wishes to procure gas at a specific point other than the Henry Hub. Factors affecting the EFP price are: size, time of year, and number of parties on each side of the bid/offer spread. (If an inordinate amount of companies are long futures contracts and wish to take them to delivery in order to exchange them for physical gas, the counterparties will charge more money for this service, based on simple supply/demand).
2. Receive physical gas at the agreed upon delivery point.
3. Transfer the futures position into the account of the counterparty.

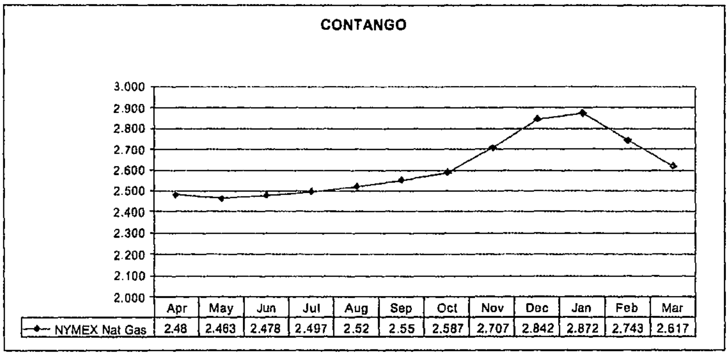
CAPACITY RELEASE:
Capacity release is also available for companies to trade. The cost for transporting gas is comprised of a fixed reservation charge, a variable commodity charge, fuel, and various surcharges. Company "A" can decide to buy capacity from Henry Hub to New York for a total cost of $0.55. If Henry Hub is trading at a fixed price of $2.20, and New York is trading at $2.80, Company "A" can use its capacity to obtain delivered gas at $2.75. Conversely, if the market drops, and Henry Hub and New York are trading at $2.05 and $2.50 respectively, Company "A" may opt not to use their capacity, and buy delivered gas at the market price of $2.50. However, most companies will separate their fixed and variable costs. If the variable cost of transporting gas from Henry Hub to New York is less than $.045 (2.50-2.05) Company "A" may still utilize their capacity, even though their total cost is not covered.

HEDGING CONCEPTS

GENERAL:
A myriad of trading and hedging strategies exist. It is impossible to present a laundry list or flow diagram to cover every possible situation. Techniques from fundamental analysis to technical analysis to neural nets are used every day in the industry. For every seller who thinks he has picked the top of the market, a buyer thinks it will go higher. Only time will tell which one is "right". "Right" being a relative term, because the market can go higher in the short-term, and lower in the longer-term. Rather than present detailed technical or fundamental analysis, the gas market has several unique situations to it.



	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
NYMEX Nat Gas	2.842	2.872	2.743	2.617	2.504	2.475	2.491	2.503	2.511	2.523	2.554	2.691



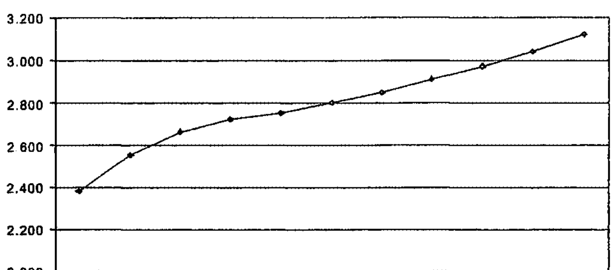
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
NYMEX Nat Gas	2.48	2.463	2.478	2.497	2.52	2.55	2.587	2.707	2.842	2.872	2.743	2.617

CURVE STRUCTURE:

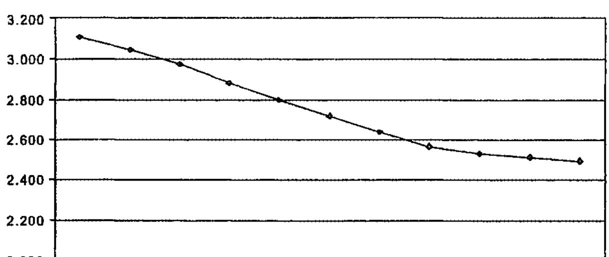
1. Short-Term Curve Structure (contango) - Looking at the NYMEX screen, the first 12 to 16 months of the natural gas curve has an inherent "shape" to it. When the prompt months are generally lower than the later months, the curve is said to be in contango. Contango curves are usually normal, and are explained by such factors as storage costs, time value of money, and present supply certainty versus future supply uncertainty. Seasonality is associated to the curve, as per the injection and withdrawal cycles. But when the seasonality is factored in, a general structure can be implied. If the contango is severe, this is considered to be a bearish factor, as present supply is weighing down front-end prices.

2. Short-Term Curve Structure (backwardation) – When factoring in seasonality, if the front end of the curve is generally higher than the back end of the curve, it is said to be in backwardation. Backwardation curves are not present in normal trading markets, and are indicative of bullish markets. The immediate supply is in question, and is bid higher to guarantee supply. Normal conditions are implied to be returning to the curve some time in the future.

3. Long-Term Curve Structure (backwardation and contango) – The shape of the long-term (for purposes of this discussion, long-term will mean calendar year prices) price curves are much more telling than short-term price curves. With long-term curves, the seasonality is removed from the equation, as the implied shapes of the individual months are already imbedded in the calendar year price. A backwardated long-term curve is extremely bullish, as it indicates significant supply/demand imbalances which are not expected to be resolved in the foreseeable future. Conversely, a long-term price curve in extreme contango is very bearish.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
NYMEX Nat Gas	2.384	2.550	2.663	2.720	2.750	2.800	2.853	2.913	2.975	3.045	3.120



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
NYMEX Nat Gas	3.109	3.045	2.976	2.875	2.795	2.715	2.635	2.564	2.532	2.511	2.493

4. Taking Advantage of Term Structures – Several techniques are effective for capitalizing on inherent differences in term structures. Two of the less commonly covered topics are spreads and butterflies.

Spreads: Spreads involve buying one month while simultaneously selling another month. The thought process behind this is to capture the inherent mismatch in what the price differential, or relationship, should be between the two. A common example would be the June vs. September spread. Spreads are "quoted" as the difference between the two prices, with the higher-priced month quoted first as the convention. It is possible to "leg" a spread, by buying the desired month and simultaneously selling the other month. It is more common, however, to receive a quote on the spread itself. Many floor traders specialize in spread trading, and will quote a tighter price than can be obtained via the legs. For example, if September '02 is trading $2.300/$2.310, and June '02 is $2.285/$2.295, then the proper quote, using the legs, is "Sep/June $0.005/$0.025." This is derived as the person who wants to buy the spread (buy Sep/sell June) must lift the $2.310 offer in September and hit the $2.285 bid in June, netting a payment of $0.025 (which is the same as lifting the $0.025 offer in the direct spread quote.). Conversely, the person willing to sell Sep/June would be hitting the $2.300 bid in Sep while lifting the $2.295 offer in June, for a difference of $0.005. A specialist trader might make an "inside quote" which is tighter that $0.005/$0.025 (for instance, $0.010/$0.020).

Buying the Spread

	Bid	Ask
Jun '02	2.285	2.295
Sep '02	2.300	2.310
Sep/Jun	0.005	0.025

Selling the Spread

	Bid	Ask
Jun '02	2.285	2.295
Sep '02	2.300	2.310
Sep/Jun	0.005	0.025

a. Butterflies: Butterflies are similar to outright spreads in that they involve a "mismatched perception in value" between months. Unlike outright spreads, which involve only two months (or years), butterflies involve 3 months (or years). The trade is to buy one amount of a particular month, sell twice that amount for the second month, and again buy the amount for the third month. (The same can be said for sell 1x of month A, buy 2x of month B, and sell 1x of month C). This trade can also be done for calendar years, "strips", or any other time frame involved. The idea behind the trade is that the price relationship between the three months is out of line. Putting on this trade is a relatively low-risk way to capitalize on what is perceived to be a temporary misalignment. The reasoning behind the 1/2/1 ratio of amounts bought/sold is to theoretically "hedge" the movements with equal amounts (i.e. the "delta" of the trade is neutral – that is, you are long and short an equal amount, which should minimize price exposure should the trade go against you.

Current

	Bid	Mid	Ask
2000	2.720	2.725	2.730
2001	2.620	2.625	2.630
2002	2.660	2.665	2.670
2003	2.700	2.705	2.710
2004	2.740	2.745	2.750

2000	2.720	2.725	2.730	(Sell 1x)
2001	2.620	2.625	2.630	(Buy 2x)
2002	2.660	2.665	2.670	(Sell 1x)

Projected

	Bid	Mid	Ask
2000	2.610	2.615	2.620
2001	2.650	2.655	2.660
2002	2.690	2.695	2.700
2003	2.730	2.735	2.740
2004	2.770	2.775	2.780

2000	2.610	2.615	2.620	(Buy 1x)
2001	2.650	2.655	2.660	(Sell 2x)
2002	2.690	2.695	2.700	(Buy 1x)

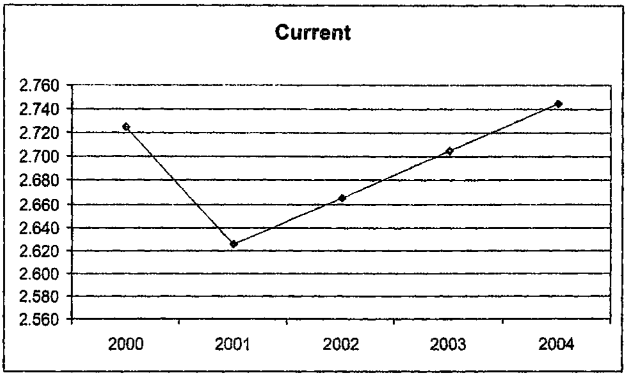
P&L

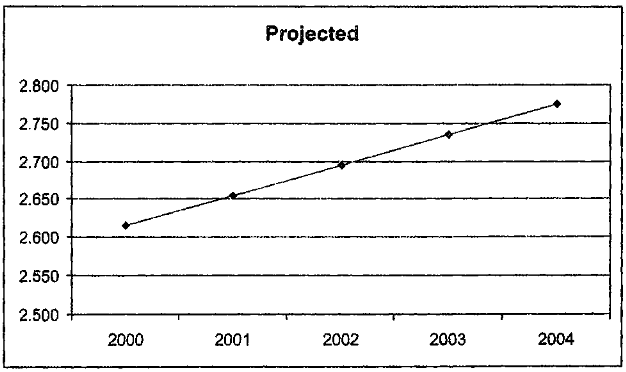
	Entry	Exit	+/-
2000	-1@2.72	+1@2.62	+0.10 on 1
2001	+2@2.63	-2@2.65	+0.02 on 2
2002	-1@2.66	+1@2.70	-0.04 on 1

+$0.10 x 1/Day x 30 Days/Month x 12 Months/Year x 10,000 MMBtu's = +$360,000
+$0.02 x 2/Day x 30 Days/Month x 12 Months/Year x 10,000 MMBtu's = +$144,000

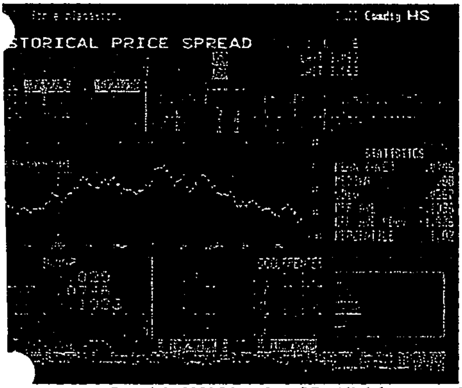
-\$0.04 x 1/Day x 30 Days/Month x 12 Months/Year x 10,000 MMBtu's = -\$144,000

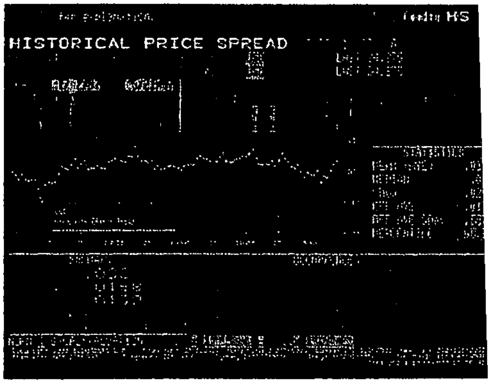
+\$360,000





5. Considerations: Traders should be aware of several "trading/hedging" considerations when entering into any type of spread trade (outright or butterfly). They are:
   a. Entry Strategy: You can enter into a spread via the individual legs, or by trading the spread as an outright. In order to enter in the most economical way, you should check where the individual legs of the desired spread are, as well as where the outright spread is. Sometimes it will make sense to just enter the position as an outright spread; other times, it may make sense to enter into one side first, then wait for the other leg to "come your way" (reach desired price).
   b. Historical Relationships: In order to decide if the chosen spread is worth entering, it is prudent to take a look at what the historical relationships of the spread have been. For instance, if the June/Sep spread typically trades between +$0.015 to +$0.10 (Sep premium), it would not make sense, under normal conditions, to enter the spread at a +$0.08 Sep premium. The risk/reward would historically be risking $0.065 ($0.080 entry point less the lower end of the trading range, $0.015) to historically make $0.020 (the upper historical end of the trading range, $0.100 less the entry price of $0.080). Although nobody can guarantee where prices will be or where they are going to go, you can put the odds significantly in your favor by dissecting where the spread relationships have historically been, and by selecting entry/exit points with sensible risk/reward profiles.


STORICAL PRICE SPREAD
HS


HISTORICAL PRICE SPREAD
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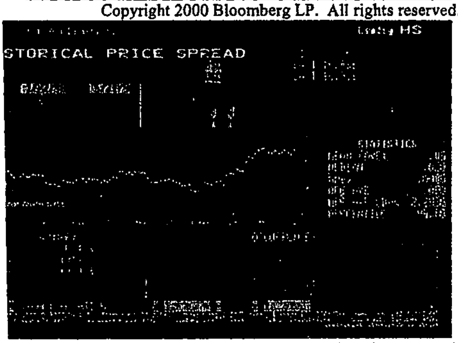
STORICAL PRICE SPREAD
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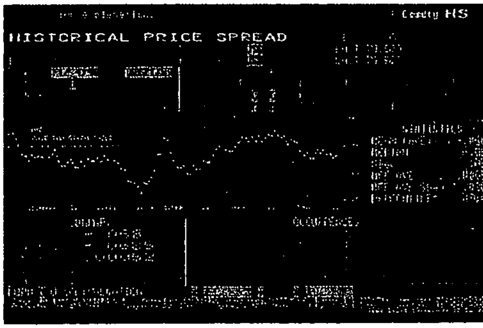
HISTORICAL PRICE SPREAD
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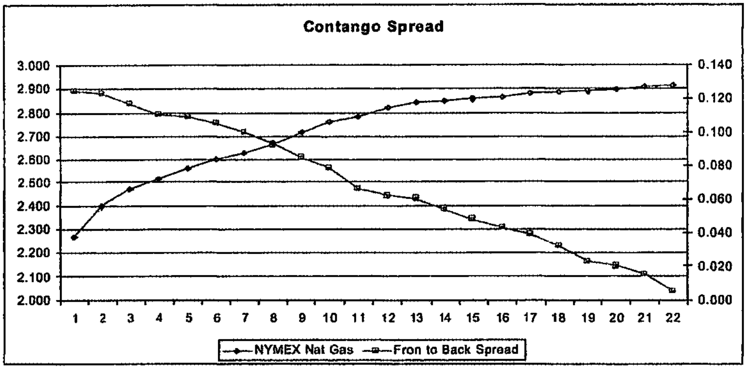
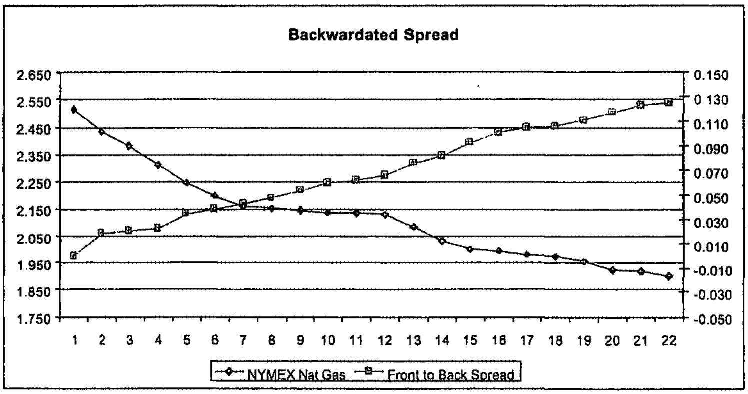
c. Bull vs. Bear Spread: Just as option spreads or outright positions have an inherent bull or bear bias to them, spreads in underlying commodities perform differently in different types of markets. For instance, if you have an extremely bullish view of the market, a spread in which you are long Dec/short Jan would make sense. Although you would expect Dec to trade at a discount to Jan under almost any condition (due to seasonal factors/heating demands, etc.), under a bullish market scenario, the spread would get significantly tighter, with Dec trading at a far less discount to Jan in a fast-rising market. Conversely, in a rapidly declining market, Dec would collapse much faster than Jan, because the uncertainty of future demand, weather, etc. would serve to keep Jan more supported than Dec. An examination of the bias of the spread, bull or bear, should also be conducted.





d. Spread "Delta": Just as an option has a delta (underlying equivalent position), so does a spread. By examining historical relationships, it is possible to determine how fast a spread will move up or down with respect o the underlying curve. By quantifying this delta, it is possible to put on a position without affecting materially what your overall exposure would be. As an example, assume you are long 2,000 lots of natural gas per month as a result of a production contract. If the curve is materially backwardated, with the Sep '01 trading at a $1.00 premium to the Sep '02, you may choose to enter an underlying backspread. If the historical data supports your view (i.e. the range historically is Sep '02 at a $0.75 premium to '01, and the widest it has ever been was $1.00 to the '01's), you can sell 2,000 lots of Sep '01 while simultaneously buying 2,000 lots of Sep '02. If the curve continues to steepen the backwardation (i.e. Sep '01 blows out Sep '02 by more than $1.00), you have sold off your Sep '01 production at what is hopefully a good rate, while capturing additional upside as Sep '02 rises, albeit at a slower rate. If the Sep '01 falls, Sep '02 should fall at a slower rate, and you can either buy back the spread (buy Sep '01/sell Sep '02 for a profit), or keep your Sep '01 spread sale outstanding while selling out the extra Sep '02 you bought, hopefully at a profit. Again, a historical examination of how the spread acts in a rising and a falling market will significantly put the odds in your favor. Quantifying how it acts will add a discipline to your approach.

Front-to-back Spreads

Definition

Front-to-Back Spreads refer to buying and selling contracts each having different time maturity along a forward curve. These spreads are also known as Horizontal Spreads, because quotes in paper publications (i.e. The Wall Street Journal) are listed by maturity dates from left to right.

Example:

- Buy some quantity of a January contract and sell some quantity of a February contract
- Sell some quantity of a March contract and buy some quantity of a June contract
- Buy some quantity of a Q1 strip and sell some quantity of a Q4 strip
- Sell some quantity of a 2000 strip and sell some quantity of a 2001 strip
- Buy some quantity of a December 2000 contract and sell some quantity of a December 2001 contract

Why Spreads

1. Speculation: A trader may have a view that the current spread value (Highest Valued contract – Lowest Valued contract) is either to high (wide) or to low (narrow). If the spread is viewed as to wide then the trader would sell the highest valued contract and buy the lowest valued contract. If the spread is viewed as to narrow then the opposite trade would take place.

   Example:

   Prompt Month (most current trading contract) is @ $2.75 and next month is trading @ $2.18. Spread is $0.57 (Highest $2.75 – Lowest $2.18), which is viewed by the trader as being to wide, therefore the trader would sell the spread (Sell Highest, Buy Lowest) and receive $0.57 for the sell.

   One possible outcome:

Spread narrows (Prompt Month contract @ $2.50, Next Month Contract @ $2.22) to $0.28. The trader then buys back the spread (prompt month @ $2.50, sells the next month @ $2.22) thus gaining $0.29 on the trade.

2. Hedge: A specific long-term period commodity can be hedged using a financial instrument in a different time period. Why? The biggest reason is that long dated financial contracts are too thinly traded to support the size of the long-term commodity position.

Delta Hedge

A hedge ratio that is typically used is $hr = \rho_{a,b} \frac{\sigma_a}{\sigma_b}$ where "a" denotes time period 1 and "b" denotes time period 2. Let us look at an example using the above hedge ratio equation.

Example:

Given:

1. Contract "a" : January 1998 (monthly symbol F)
2. Contract "b": December 1998 (monthly symbol Z)
3. Standard Deviation of the absolute changes of Contract "a": .395019
4. Standard Deviation of the absolute changes of Contract "b": .217154
5. Correlation Coefficients of Contract "a" and Contract "b": .811221

Hedge_ratio = .811221 * (.395019 / .217154), Hedge_ratio = 1.47567

Interpretation:

Contract "a" will move more than contract "b", this is indicated by their respective volatility values. Therefore, in order to hedge the front contract with the back contract you would need more contracts in the back to correctly hedge the movements of the front contracts. In order to hedge back contracts you would need fewer contracts in the front to correctly hedge the movements of the back contracts. The correlation coefficient in the hedge equation can be loosely interpreted as how well the hedge ratio will perform. A big negative or positive correlation coefficient will be indicative of a good hedging strategy, while a correlation value close to zero is indicative of a poor hedging strategy.

Application:

For this example let us assume:

1) Current date is December 1, 1997
2) You are naturally long the December 1998 contract and want to hedge with selling the December, 1998 contract

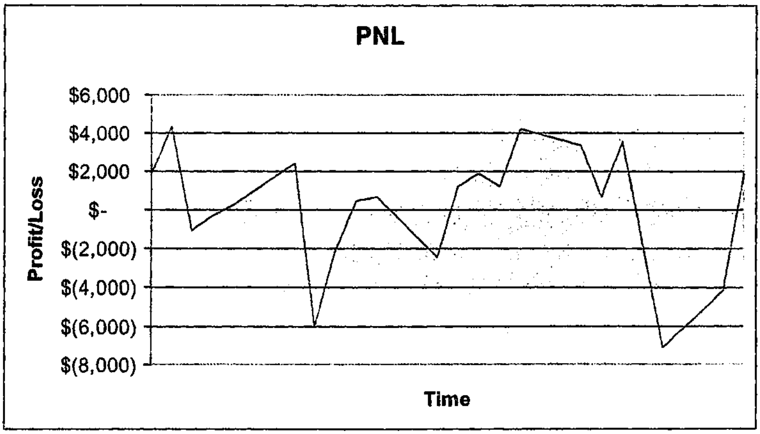
The question to ask is how much do you sell of the December 1998 contract in order to stay risk neutral?

Portfolio

1. Long 50 lots of the underlying commodity in December 1998.
2. Sell 50*(1/1.47567) or 33 contracts (rounded to the nearest contract) of January 1998 contracts (note: the hedge ratio is inverted to show the back-to-front ratio)
3. Each contract carries 1,000 brls/contract

What is the historical performance of this portfolio?

DATE	January	December	Jan Change	Dec Change	Jan PNL	Dec PNL	Tot PNL
01-Dec-97	$ 18.66	$ 19.40					
02-Dec-97	$ 18.76	$ 19.43	$ 0.10	$ 0.03	$ 3,300	$ (1,500)	$ 1,800
03-Dec-97	$ 18.80	$ 19.37	$ 0.04	$ (0.06)	$ 1,320	$ 3,000	$ 4,320
04-Dec-97	$ 18.60	$ 19.26	$ (0.20)	$ (0.11)	$ (6,600)	$ 5,500	$ (1,100)
05-Dec-97	$ 18.71	$ 19.34	$ 0.11	$ 0.08	$ 3,630	$ (4,000)	$ (370)
08-Dec-97	$ 18.84	$ 19.42	$ 0.13	$ 0.08	$ 4,290	$ (4,000)	$ 290
09-Dec-97	$ 18.67	$ 19.26	$ (0.17)	$ (0.16)	$ (5,610)	$ 8,000	$ 2,390
10-Dec-97	$ 18.14	$ 19.03	$ (0.53)	$ (0.23)	$ (17,490)	$ 11,500	$ (5,990)
11-Dec-97	$ 18.15	$ 19.08	$ 0.01	$ 0.05	$ 330	$ (2,500)	$ (2,170)
12-Dec-97	$ 18.21	$ 19.11	$ 0.06	$ 0.03	$ 1,980	$ (1,500)	$ 480
15-Dec-97	$ 18.17	$ 19.07	$ (0.04)	$ (0.04)	$ (1,320)	$ 2,000	$ 680
16-Dec-97	$ 18.17	$ 19.12	$ -	$ 0.05	$ -	$ (2,500)	$ (2,500)
17-Dec-97	$ 18.19	$ 19.11	$ 0.02	$ (0.01)	$ 660	$ 500	$ 1,160
18-Dec-97	$ 18.52	$ 19.29	$ 0.33	$ 0.18	$ 10,890	$ (9,000)	$ 1,890
19-Dec-97	$ 18.39	$ 19.18	$ (0.13)	$ (0.11)	$ (4,290)	$ 5,500	$ 1,210
22-Dec-97	$ 18.32	$ 19.05	$ (0.07)	$ (0.13)	$ (2,310)	$ 6,500	$ 4,190
23-Dec-97	$ 18.33	$ 18.99	$ 0.01	$ (0.06)	$ 330	$ 3,000	$ 3,330
24-Dec-97	$ 18.35	$ 18.99	$ 0.02	$ -	$ 660	$ -	$ 660
26-Dec-97	$ 18.20	$ 18.82	$ (0.15)	$ (0.17)	$ (4,950)	$ 8,500	$ 3,550
29-Dec-97	$ 17.62	$ 18.58	$ (0.58)	$ (0.24)	$ (19,140)	$ 12,000	$ (7,140)
30-Dec-97	$ 17.60	$ 18.65	$ (0.02)	$ 0.07	$ (660)	$ (3,500)	$ (4,160)
31-Dec-97	$ 17.64	$ 18.64	$ 0.04	$ (0.01)	$ 1,320	$ 500	$ 1,820
							$ 4,340



The perfect number of January contracts during this time period in order to have made the portfolio completely risk neutral were 37 contracts not the 33 contracts predicted from the hedge technique. However, this is just a snapshot of history and the 37 vs. 33 differential is well within statistical tolerances

e. Exit Strategy: A spread position allows for several exit strategies. They are:
   - ✓ Exit as an outright spread: This involves getting a quote for the spread and exiting the position via that quote.
   - ✓ Exiting via the legs: If a spread does not go your way, you always have the option of "dropping a leg". As an example, assume you sell July '01/Buy Aug '01 for a $0.02 credit (i.e. July is $2.430 and Aug is $2.410). If fundamental news comes out which is extremely bullish, and the July contracts go to a $0.10 premium over the August, (July $2.600 vs. August $2.500) you will have a mark to market loss of $0.080 ($0.020 entry point less the $0.100 current market). You always have the option of buying back just the July's, say at $2.600, and staying long the August. Your breakeven on the August will be $2.580 ($2.600 buyback price of the July's less the $0.020 credit received when the position was entered). If you choose to do this, you now have an outright long position, but if your view is that the market will continue to rise, you may be able to break even on the trade or even realize a profit. Be aware that if the market continues to fall off, you will realize an even greater loss than if you had just exited the spread immediately.
   - ✓ Exiting via multiple spreads: If you are in a butterfly (assume you are long 1 Cal '01, short 2 Cal '02's and long 1 Cal '03), you have several exit techniques:
     - ✓ Exit as a butterfly
     - ✓ Exit via the legs
     - ✓ Exit via the '01/'02 spread and via the '02/'03 spread (you can decompose the position as being long 1 Cal '01/Short 1 Cal '02, and as being short 1 Cal '02/long 1 Cal '03 – it is the same as the original 'fly).

MISCELLANEOUS

Obtaining large Quantities of Gas:

Production Payments and Pre-Pays

Volumetric Production Payments ("VPP") are acquisitions of real property interests in producing reserves. The purchaser of a VPP advances funds to a producer (or working interest owner) who in turn agrees to deliver a pre-determined volume of natural gas (or oil) over a pre-determined period of time. Effectively, this is a discounted fixed price purchase of natural gas. The producer's obligation to deliver is limited to production from specific properties. If those properties do not produce sufficient amounts to satisfy the VPP requirements, the producer is not obligated to deliver any other volumes. The purchaser of the VPP is taking the reservoir risk. The producer can benefit from several accounting and tax advantages using this structure. VPP's are "bankruptcy remote" under federal and most state bankruptcy laws.

Pre-Pays are similar to VPP's, with the exception that the recipient of the upfront dollar amount is obligated to deliver a pre-determined amount of natural gas over a pre-determined period of time, regardless of the source. The purchaser of the Pre-Pay is taking credit risk of the supplier, as opposed to reservoir risk in the VPP. A Pre-Pay is an executory contract and therefore is subject to bankruptcy laws.

Acquisitions

Acquisitions involves the purchase of natural gas reserves or the stock of companies which own natural gas reserves as a means to develop a "long" natural gas commodity price position. The acquiring company would have the responsibility to produce those purchased reserves.

Joint Ventures / LLP's

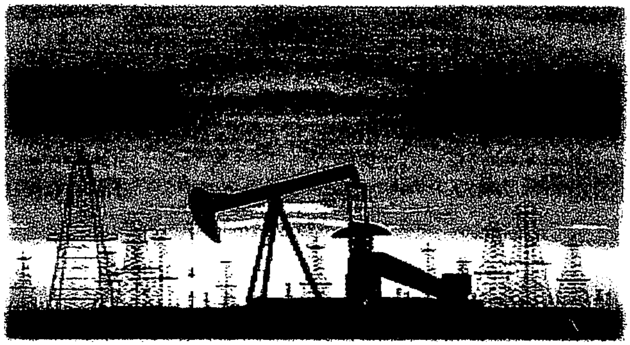
Joint Ventures and partnerships are structures that can be used to pursue acquisitions and allow for a sharing of risks and rewards with another party. Ideally, each party brings a specific level or area of expertise (e.g. reservoir analysis, production, marketing, risk management, etc.) which the joint venture/partnership can leverage from.

Structured Products / Origination

Origination is the process of developing and marketing structured products to customers. *Structured products* involve a variety of financial instruments and risk instruments that can be utilized to provide capital to producers or natural gas suppliers. Examples of financial instruments involve debt, leasing structures, preferred stock or even common stock. Since credit risk is preeminent within these structures, it is highly likely that some form of collateral or security will be attached to mitigate that credit risk. The use of fixed or index price gas purchase contracts can be used to mitigate credit risk, as well. Additionally, the use of risk instruments such as conversion rights, exchange rights or other forms of optionality can be embedded within the financial instrument which will achieve the ultimate goal of obtaining discounted fixed price natural gas. An example might be the purchase of a debt or preferred stock instrument (secured by an asset) which allows exchanging that instrument into a specific volume of natural gas in the future.

III. Petroleum Products

A. CRUDE OIL



Conceptually, the oil business appears straightforward: you look for the oil, you extract it, refine it, and get it to the customers. However, the simplicity is superficial. Large investments in time and money are required to find and extract oil and the logistics of transporting and storing it can be quite complex.

Though oil markets have been around for a while they are anything but stable. There are a wide variety of factors that affect the market: geology, economics, law, finance, technology, and environmental concerns are just a few. Each one of these factors can dramatically change the future of the energy market. For example, as early as the dramatic price jumps of the 1970s, the fundamental pricing environment for oil has undergone dramatic change towards a more open market. Furthermore, with NYMEX's introduction of its crude-oil futures contract, they provided a mechanism for price discovery, market information, and expectations, which increased the flexibility of buyer-supplier relationships, and allowed market participants to hedge against risks of market shocks.

Adding to the complexity of the crude-oil market are factors that do not exist in the stock market. Storage, for example, is a large driver of oil prices. The "storage limitation" problem contributes significantly to the volatility found in the market. To make things a bit trickier, the volatility is affected primarily in the "front end" of the term structure.

In this chapter, we will first look at the characteristics of the physical product, i.e., how it is extracted, etc. Second, we will take a look at the refining aspect of oil, i.e, the refining process. Third, we will take a look at the physical market for crude. The fourth topic is the forward curve. In essence, the curve is king—it is what we are ultimately concerned about, i.e., present and future prices. Key terminology that describes the shape of the curve will be defined and key determinants of the shape of the curve will be analyzed.

Fifth, supply and demand drivers of the oil market will be reviewed. Sixth, we will cover characteristics of the financial crude market—specifically, NYMEX's crude oil futures contract. Finally, we will take a look at international crude markets (alternative markets) and miscellaneous useful topics relating to crude.

PHYSICAL PRODUCT[1]

The first challenge is to locate new deposits of petroleum. Geological Formations are studied through:

- **Surface Methods** Sound waves, magnetic and gravity readings help locate promising formations under the earth. Radar is used to examine areas covered by forests or clouds.

- **Bore Holes** Deep holes are drilled so samples from underground layers can be studied.

Exploration becomes more difficult and costly all the time, because the most accessible reserves have already been found.

Oil companies are working to:

- **Develop Better Techniques** to find oil and estimate how much is there. Currently, satellites are being used to aid in exploration efforts.

- **Reach Remote, Hostile Environments**, such as deep oceans and arctic areas. Though they may hold untapped deposits, exploration in these areas is expensive, exhausting, and time-consuming.

- **Gain Access to Federal Lands**, which are promising. Oil companies are seeking to open up these lands for drilling. Sites include Alaska, continental U.S. and off our shores.

When searching for oil, the goal is to find a convergence of the geologic elements necessary to form an oil field. These elements include a source rock to generate hydrocarbons, a porous reservoir rock to hold them and a structural trap to prevent fluids and gas from leaking away. Traps tend to exist in predictable places - for example, along faults and folds caused by movement of the Earth's crust or near subsurface salt domes.

Finding these subterranean features requires a careful blend of science and art. For example, structural geology involves gathering and interpreting information from above ground to deduce what lies underground. Geologists obtain this information by examining exposed rocks or, when difficult terrain limits access, by examining images from satellites and radar.

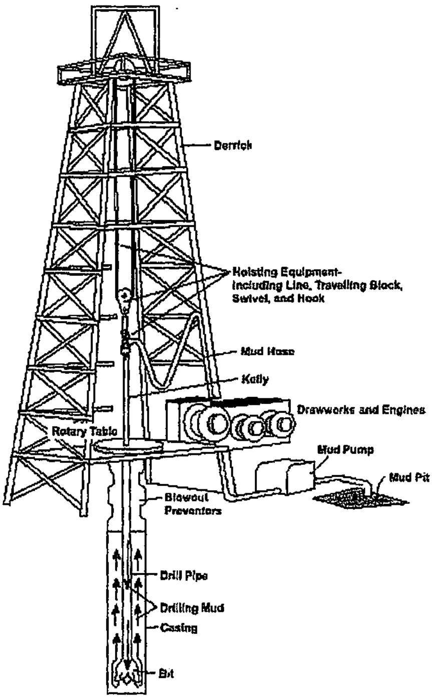
[1] Source: Energy Information Administration/U.S. Department of Energy.

Subtle changes within the Earth's magnetic and gravitational fields also may signal the presence of petroleum traps. To measure these changes, geophysicists use sensitive instruments called gravity meters or trail a magnetometer from a plane in an aerial survey.

Seismic surveying involves sending sound waves underground and measuring how long it takes subsurface rocks to reflect them back to the surface. These waves are made by pounding the earth with a truck-mounted vibrator or by exploding small charges on land or compressed air guns at sea. As the waves are reflected back, they're collected by listening devices called geophones and processed by computers. Earth scientists use the data to create three-dimensional models of underground rocks.

Although sight and sound are the senses most frequently used in prospecting, smell also can come into play. A sniffer is a sort of high-tech "nose" that can detect traces of gaseous hydrocarbons escaping from subsurface accumulations. Geologic and geophysical clues are enticing, but drilling -both on land and offshore - is the only way to confirm an oil or gas field's existence.

A Rotary Drilling System



Source: Energy Information Administration, Office of Oil and Gas.

This process requires:

- **Preparation of the Site**
  A construction crew must build roads, clear and level the site, and bring in materials and equipment for assembling the drilling rig.

- **Construction of the Rig**
  The drilling crew must set up the rig, lay out pipe and equipment, and prepare drilling "mud" (a special substance used during drilling to cool the drill bit, control pressure, etc.).

- **Drilling Through Earth**
  When drilling begins, a "blow-out preventer" (to close the pipe in an emergency) and a well casing (to prevent contamination of underground fresh water) are installed. At intervals, the drill pipe must be pulled up and the drill bit changed.

In the petroleum industry, the average U.S. wildcat well (an exploratory well drilled a mile or more from existing production) has a one in 10 chance of striking hydrocarbons. A rank wildcat well, drilled in an unproven, frontier area, stands a one in 40 chance. Thus, although today's prospectors have better tools than their ancient counterparts, good luck still is a factor in the search for petroleum.

Oil companies face special concerns when they attempt ocean drilling:

- **Deep-Water Technology:** Floating drilling platforms must be improved to withstand violent weather and corrosive seas.

- **Environmental Preservation:** The oil industry is improving methods of preventing and cleaning up oil spills.

When a petroleum reservoir is reached, drilling stops. Oil must then be recovered:

- **Installation of Pipes**
  and valves to control the flow of petroleum is always necessary. Oil is often under pressure from underground gas or water. This may force oil to the surface.

- **Release of Trapped Oil**
  may require special methods. If oil is trapped in rock or sand, water and sand (or acid) may be pumped in to open up channels and help release the oil.

- **Addition of a Pumping Unit**
  is required for most wells when natural pressure diminishes. Petroleum is pumped at a rate that won't deplete the well too quickly.

- **Separation of Elements**
  that come out of a well (gas, water, and sediments as well as oil) is the next step. Oil may be stored and later shipped to refineries; gas is delivered to pipelines.

Only about 1/4 of the oil in a reservoir can be recovered by natural flow and pumping.

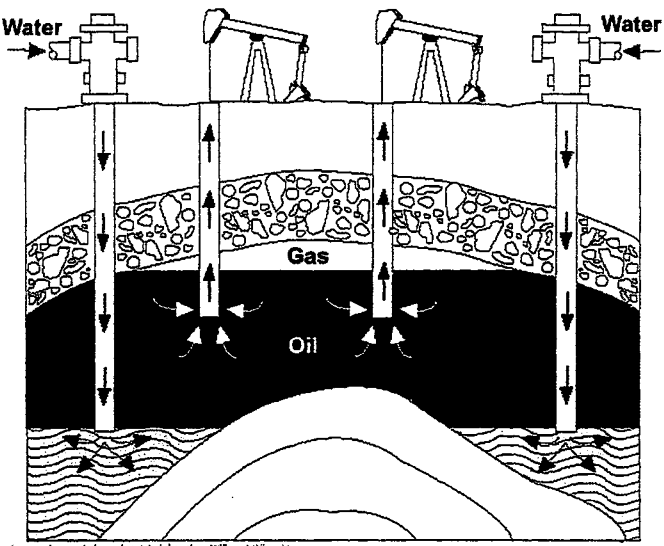
To get more oil out of a well, additional recovery methods are required. For example:

- **Water Flooding:** Water is pumped into the edges of a reservoir to force oil toward central wells.

- **Chemical Flooding:** oil companies are testing new chemicals that are more effective than water in binding themselves to oil and carrying it to the wells.

- **Heat Methods:** One method tries to thin oil for easier flow by heating it with injected steam or by burning some of it inside the well.

Secondary Recovery Using Water Injection to Supplement Drive



Source: Energy Information Administration, Office of Oil and Gas.

Drilling for oil and gas is a highly skilled operation, often carried out in remote or difficult terrain. If the find is promising and commercial conditions are right, a field will be developed and brought into production.

Wells are drilled with rotary drilling tools, which work on the same principle as the carpenter's brace and bit. The cutting tool is the drilling bit, which has tough metal or sometimes diamond teeth that can bore through the hardest rock. The bit is suspended on a drilling string consisting of lengths of pipe, which are added as the bit goes deeper. The bit is turned either by a rotary table on the drill floor or, increasingly, by a downhole motor.

In time, the bit gets worn and has to be replaced. The whole drilling string, sometimes weighing over 100 tons, must then be hauled to the surface and dismantled section by section as it emerges. The new bit is fitted and slowly lowered as the drill pipe sections are re-assembled. In a deep well, this operation - known as a "round trip" - can take up most of a twelve-hour shift. Until recently, the drilling crew carried it out manually. But automated drilling rigs, with mechanized pipe handling and computerized controls, are now being introduced to reduce drilling costs.

One of the essential supplies for the drilling crew is "mud", or drilling fluid. This is a special mixture of clay, various chemicals and water, which is constantly pumped down through the drill pipe and comes out through nozzles in the drilling bit.
The stream of mud returns upwards through the space between the drilling string and the borehole, carrying with it rock fragments cut away by the bit. At the top, the returned mud is sieved and then re-circulated through a pump.

The cuttings left on the sieve indicate the kind of rock the drill is passing through, and they may show traces of oil as the bit nears an oil-bearing formation. The drilling mud keeps the bit cool and prevents the escape of gas or oil when the bit enters an oil trap. The drilling rig is a substantial piece of equipment. So, access roads may have to be built before the start of drilling in remote areas. Nowadays, much smaller installations called *slimhole rigs* might be built to reduce transport costs.

The rate of drilling varies with the hardness of the rock. Sometimes, the bit may cut through as much as 60 meters an hour, but in a very hard layer progress may be as little as 0.3 meters an hour. Most oil wells are between 900 and 5000 meters deep, but wells as deep as seven or eight kilometers are sometimes drilled.

Wherever possible, wells are drilled vertically. But sometimes, especially offshore, wells have to be drilled which deviate from the vertical in order to reach a wide spread of targets from a single platform. This is known as *deviated drilling.*

Recent developments have made it possible to deviate from the vertical by as much as 90 degrees. Known as horizontal drilling, this technique can, in some instances, increase the productivity of a well. Special care is needed during drilling as the bit nears a formation containing oil and gas. The high pressure in an oil trap may force oil and gas up to the surface in a violent surge, as the drill breaks through the impermeable rock. Such *blow-outs* or *gushers* - common in the early days of the oil industry - pollute the environment, carry a high fire risk and waste hydrocarbons, so drilling technicians are now trained to prevent them.

The drilling supervisor in charge of drilling can anticipate the danger of a blow-out occurring when rock chippings from the well bottom show traces of oil, or when instruments on the derrick floor show rising pressures in the well. To avoid the blow-out, he can pump down heavier drilling mud to hold back the oil, or close special valves, known as *blow-out preventers*, fitted to the top of the well casing.

During drilling operations, valuable information about the field at various depths is collected by a procedure known as *logging*. Drill cuttings returned to the surface are examined for traces of hydrocarbons, as well as for their fossil content. *Wireline* logs examine the electrical, acoustic and radioactive properties of the rocks, giving clues as to the rock type, its porosity and how much fluid it contains.

Sometimes, rock specimens - known as *core samples* - are extracted for laboratory examination. The first well to be drilled in an area is known as an *exploration well*. If oil is discovered, *appraisal wells* are then drilled to establish the limits of the field. If the field is developed, some of these appraisal wells may be used as *production wells*. However, there are many factors to consider before a field is taken into production: how much oil does a reservoir contain and how much will it cost to extract (costs depend, among other things, on depth and how easily the oil flows to the surface)? how close is the field to potential markets? How many wells will be needed and where should they be located? What treatment facilities will be required?

Huge quantities of crude oil and refined products are moved and distributed all over the world every day.

- **Tankers**
  carry up to half a million tons of oil.
- **Trucks**
  can reach otherwise inaccessible areas with small loads of oils and gas.
- **Barges**
  use inland water to move oil cheaply from producers to consumers.
- **Pipelines**
  move oil long distances by pumping. This is the most economical way to move oil products.
- **Trains**
  and tank cars carry heavy, corrosive and temperature-sensitive products.
- **Destinations**
  include refineries, service stations, factories, airports, public utilities, etc.-wherever oil products are needed.

The most convenient way to move oil overland is to pump it through a pipeline. Pipeline networks criss-cross most continents.

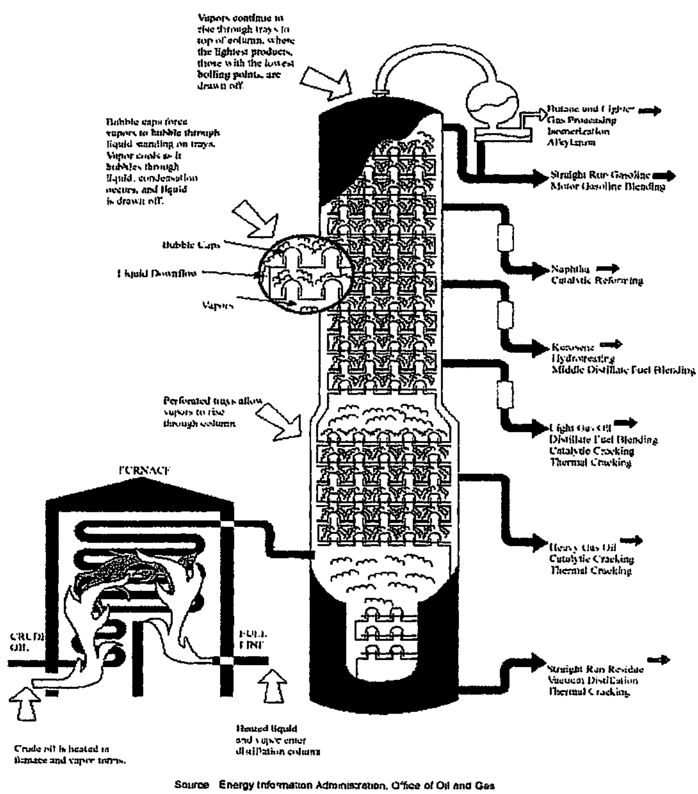
Crude oil pipelines are generally large in diameter (sometimes more than a meter) and pumping stations are built at regular intervals along the line to ensure that the oil is kept moving at around five kilometers an hour. Constructing a pipeline which may have to cross mountains, rivers or deserts is an immense engineering task, usually undertaken jointly by several companies who share the burden of the huge capital investment required.

As offshore production grows, more underwater pipelines are being constructed. These are laid from special pipe-laying barges on which the lengths of steel pipe are welded together before being laid on the seabed. With small diameter lines, the pipe may be unwound from a giant spool directly on to the seabed, thus avoiding the need for offshore welding. Lines transporting heavy oil may need to be insulated to ensure that the oil flows freely. Smaller pipelines are usually laid in a trench to protect them from damage by fishing gear. Where pipelines run underground, considerable excavation work has to be carried out when a new pipeline is laid. However, following construction, care is taken to ensure that the land is carefully reinstated: the landscape should look the same as before work started. A pipeline is checked regularly for corrosion or leaks using an 'intelligent pig' . This is a device fitted with sensors or recorders, which pick up any signs of corrosion or other defects as it is passed through the pipeline.

REFINING[2]

All refineries perform three basic steps: separation, conversion and treatment. Modern separation involves piping oil through hot furnaces. The resulting liquids and vapors are discharged into distillation towers, the tall, narrow columns that give refineries their distinctive skylines.

Crude Oil Distillation



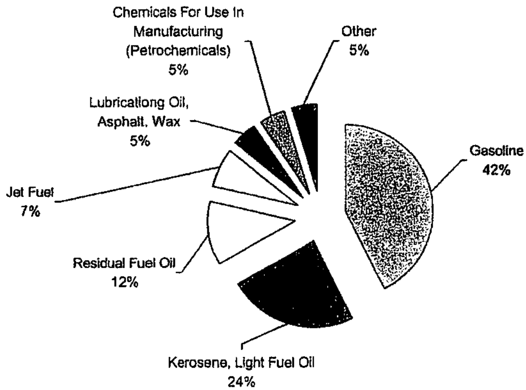
Source Energy Information Administration, Office of Oil and Gas

[2] Source: Energy Information Administration/U.S. Department of Energy.

Inside the towers, the liquids and vapors separate into components or fractions according to weight and boiling point. The lightest fractions, including gasoline and liquid petroleum gas (LPG), vaporize and rise to the top of the tower, where they condense back to liquids. Medium weight liquids, including kerosene and diesel oil distillates, stay in the middle. Heavier liquids, called gas oils, separate lower down, while the heaviest fractions with the highest boiling points settle at the bottom. These tarlike fractions, called residuum, are literally the "bottom of the barrel."

Today, some refineries can turn more than half of every 42-gallon barrel of crude oil into gasoline. That's a remarkable technological improvement from 70 years ago, when only 11 gallons of gasoline could be produced. How does this transformation take place? Essentially, refining breaks crude oil down into its various components, which then are selectively reconfigured into new products.

A Typical Barrel of Crude Yields A Variety of Products*



* The type of crude oil being processed determines the amount of each product obtained from each barrel.

The most widely used conversion method is called cracking because it uses heat and pressure to "crack" heavy hydrocarbon molecules into lighter ones. A cracking unit consists of one or more tall, thick-walled, bullet-shaped reactors and a network of furnaces, heat exchangers and other vessels.

Fluid catalytic cracking, or "cat cracking," is the basic gasoline-making process. Using intense heat (about 1,000 degrees Fahrenheit), low pressure and a powdered catalyst (a substance that accelerates chemical reactions), the cat cracker can convert most relatively heavy fractions into smaller gasoline molecules.

Hydrocracking applies the same principles but uses a different catalyst, slightly lower temperatures, much greater pressure and hydrogen to obtain chemical reactions.

Some refineries also have cokers, which use heat and moderate pressure to turn residuum into lighter products and a hard, coal-like substance that is used as an industrial fuel. Cokers are among the more peculiar-looking refinery structures. They resemble a series of giant drums with metal derricks on top.

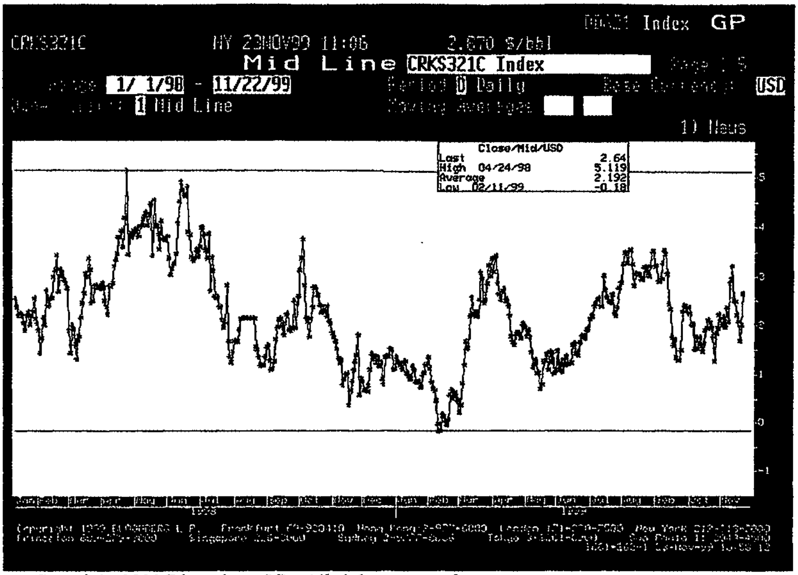
Cracking and coking are not the only forms of conversion. Other refinery processes, instead of splitting molecules, rearrange them to add value. Alkylation, for example, makes gasoline components by combining some of the gaseous byproducts of cracking. The process, which essentially is cracking in reverse, takes place in a series of large, horizontal vessels and tall, skinny towers that loom above other refinery structures. Reforming uses heat, moderate pressure and catalysts to turn naphtha, a light, relatively low-value fraction, into high-octane gasoline components.

Today, a major portion of refining involves blending, purifying, fine-tuning and otherwise improving products to meet customer specifications or government standards. Among the variables that determine the blend are octane level, vapor pressure ratings and special considerations, such as whether the gasoline will be used at high altitudes.

Refinery Economics play an important role in determining whether or not to process oil. The ultimate operating variable is, of course, the price of crude oil. Lately, benchmark crude prices have ranged from $15 to $27 a barrel. Crude oil quality is another key variable. Heavy, high-sulfur crudes can cost up to one-third less than lighter, better crudes.

One way of determining whether or not to crack the oil is by looking at the crack spread, i.e., the price differential between the price of crude and the price of the refined product.

Obviously, if the cost of crude is greater than the price you can get for the refined products, it does not make economic sense to crack the crude. Crack spreads have varied over a wide range historically. Below is a graph of a 3:2:1 crack spread. The 3:2:1 spread assumes that 3 barrels of crude oil are being refined into two barrels of gasoline and one barrel of heating oil. This is a common crack-spread benchmark.



Crack spreads are also referred to as "paper refineries." As you will notice from the 3:2:1 crack spread, what we are looking at is an inter-commodity spread. Because refineries purchase crude and sell refined products—which are usually in relatively fixed proportions— the prices of of the different commodities tend to move in parallel. As mentioned above, when prices of refined products are sufficiently greater thant crude prices, there will be buying pressure on crude prices which causes the crack spread to narrow and vice-versa. Often, spread trades will be implemented when the historical relationship gets out of line. However, the relationship between crude oil, heating oil, and gasoline is very complex. As a result, these types of trades should be executed with caution.

For example, if heating oil is at 73.68 cents/gallon, gasoline at 96.79 cents/gallon, and crude at 31.69 dollars/barrel, then buying the 321 crack is synonymous with (selling is exactly opposite):

1. selling 3 oil contracts,
2. buying 2 gasoline contracts, and
3. buying 1 heating oil contract.

So, we have:

+ 3 x 31.69 = 3000 barrels at 95.07 dollars
- 2 x 96.79 = 84000 gallons at 1.93 dollars/gallon = - 81.30 dollars/barrel
<u>- 1 x 73.68</u> = 84000 gallons .7368 dollars/gallon = - 30.95 dollars/barrel
- 17.18 dollars for 3000 barrels.

Since the crack spread contract trades in 1000 barrel lots, we divide by 3 to get 5.73 dollars/barrel. If the crack spread is different from this, there are arbitrage opportunities (ignoring transaction costs).

Because high-sulfur crudes require more processing, refineries that buy primarily cheap crudes incur more fixed expenses for equipment and labor. Processing high-sulfur crudes also requires greater expenditures for energy. In fact, energy accounts for roughly half the cost of running a refinery, which is the main reason some refineries ha ve cogeneration plants at most of its facilities. Cogeneration uses gases from refinery processing units to generate electricity and steam.

Refinery location is yet another variable. The closer a refinery is to both crude oil sources and a high demand market, the lower transportation costs are.

In the United States, the major refining areas are the Gulf Coast, US/Canadian Atlantic Coast, and the US Mid-Continent. Internationally, the Pacific Rim, Mediterranean area, and Northwest Europe are the major refining areas.

PHYSICAL MARKET

There are several key physical trading hubs in the world for crude oil. In some cases, the trading hubs are near the major refining centers that have been specified in the Refining section. Across the world, the principle trading regions are as follows:

Europe	United States	Canada	Asia	Middle East	Latin America
• North Sea • Mediterranean	• Mid-Continent (Cushing/ Midland) • USGC • West Coast	• Edmonton • Hardisty • Vancouver	• Singapore • Japan	• Persian Gulf	• Mexico • Venezuela • Argentina • Brazil

Below is a sample output of prices and spreads between some of the major locations and grades of crude oil.

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Hit 99<GO> to refresh news alerts.                    DG21 Index  W

15:30         GLOBAL SPOT CRUDE PRICES                  Page 1 / 11
Edits: 91<GO> Securities, 92<GO> Columns, 93<GO> Full edit; 94<GO> View News.
 SECURITY            | Time  |Current       SECURITY             | Time  |Current
 (US$/barrel)                               *Spreads*
 Benchmarks                                 Benchmarks
  3) Dated Brent      12:55   ↓  25.74       23)Dated Brent       12:56   ↓    .13
  4) WTI Cushing      13:08   ↑  27.37       24)WTI Cushing       13:08   ↓    .00
  5) Dubai Fateh      12:55   ↓  24.36       25)Dubai Fateh       12:55   ↑  -1.38
  6) Tapis             6:11   ↓  26.25       26)Tapis              6:11   ↓    .45
 U.S. Gulf Coast                            U.S. Gulf Coast
  8)Nymex WTI 1st Mo 11/24    s  26.87       28)WTI Cushing Roll  13:08   ↑    .50
  9) WTI Cushing      13:08   ↑  27.37       29)WTI Cushing       13:08   ↓    .00
 10) WTI Midland      13:08   ↑  27.42       30)WTI Midland       13:08   ↓    .05
 11) WTS Midland      13:08   ↓  25.31       31)WTS Midland       13:08   ↓  -2.06
 12) WTI Posting +    13:08   ↓   3.55       32)
 13) Koch-Prev Nymex  13:08   ↓  -2.69       33)
 14) Wyoming Sweet    13:08   ↑  27.17       34)Wyoming Sweet     13:08   ↓   -.20
 15) LLS St. James    13:08   ↑  26.92       35)LLS St. James     13:08   ↓   -.45
 16) HLS Empire       13:08   ↑  26.52       36)HLS Empire        13:08   ↓   -.85
 17) Mars Blend       13:08   ↓  24.36       37)Mars Blend        13:08   ↓  -3.01
 18) Eugene Island    13:08   ↓  25.94       38)Eugene Island     13:08   ↑  -1.43
 19) Bonito Sour      13:08   ↑  26.12       39)Bonito Sour       13:08   ↓  -1.25
 Tab for more info.                         40)
Copyright [illegible]
Princeton:609-279-3000   Singapore:226-3000   Sydney:2-9777-8686   Tokyo:3-3201-8900   Sao Paulo:11-3048-4500
                                                                     I661-262-1 24-Nov-99 15:29:22
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For any crude market to exist there needs to be trading liquidity. Additionally, there needs to be value associated with trading at a particular location. The value could be derived from price, location, etc. Because regional crudes are not necessarily sold to the local refiners, market conditions, values, and transportation rates will influence where the oil flows.

Pricing mechanisms in the market vary. For example, they can be based on a premium or discount to a benchmark crude spot price. WTI Cushing is a benchmark crude for the following reasons:

- sufficient supply and widely traded
- price transparency
- ease of entry and exit
- broad range of participants
- tight spreads.

Other types of pricing mechanisms include:

Fixed price deals in which an agreed price to conduct the transaction remains in effect for the life of the contract.

Floating price deals in which the price fluctuates with an index. This contract can be easily customized.

Variable price deals are like floating price deals that can also vary with respect to quality, location, and other terms.

Netback price deals consider the value of crude oil based upon the value of refined petroleum products derived from the crude, less any refining, transportation, finance or other costs. Each refinery's efficiency and product yield may be different, so each could have a different netback.

Trigger price is an option deal, which has a negotiated strike price.

Within the markets you have different participants with a variety of objectives. In broad terms, the market consists of two time horizons: spot and term. For the U.S. market, term can be considered anything greater than three months out for crude. Internationally, term is considered anything one year out or more.

Currently, the term market comprises approximately ten percent of transaction volume, but governs approximately fifty percent of the world's physical crude oil. On the other hand, the spot market comprises about half of the world's physical movements of crude oil but approximately ninety percent of the transaction volume!

In the U.S., the crude trading and scheduling (for pipeline transportation) deadline is 25^{th} of each month for the subsequent month of business. As a result, there may be high volatility around this period.

A company may wish to trade in physical crude for several reasons. For example, a major refinery might want to optimize their supply with respect to their demand or they might want to stockpile inventory in anticipation of a shortage. Other companies might be trading for a profit because they have superior market intelligence.

When trading for a profit there are a variety of strategies that can be used.

- Storage plays: The purchase of a specific grade of crude, paying a terminal an agreed upon storage fee with the anticipation that this specific grade of crude can be sold in the future at a net trading profit.
- Arbitrage plays: The term arbitrage is used loosely here. In actuality, this could be a spread play. This involves the simultaneous purchase and sale of two different grades of crude to profit from price differences.

- Outright position: This involves being either long or short in the physical market beyond the needs of business activity.

Most trading companies maintain an "Intelligence Record" of known turnaround schedules of local and international refineries. Turnaround schedules have a major impact on normal trading patterns and pricing.

There are several types of arbitrage relationships in the crude market. Among the most popular are:

- Locational
  The general idea behind locational arbitrage is to purchase oil where it is cheapest and sell it where it is highest. One must account for transportation costs when implementing this strategy. For example, if oil can be purchased for $23 a barrel at point A, and sold for $26 a barrel at point B where transportation from A to B is $3.5, then buying pressure will increase the price of A and selling pressure will decrease the price of B to the correct basis.

- Screen

Menu DG21h **Index** **ARB**

Reg. Unl. Gasoline Arbitrage Table (I)

15:05 Eastern 12/15/99

	Origin Price	Trans. Cost	Insur. & Fin.	Tax & Duty	Landed Price	Local Price	Diff.
Northwest Europe (91 RON) to U.S. East Coast (87 (R+M)/2 Conv.):							
$/ton	238.00	10.85	0.50	5.95	255.30	249.36	-5.94
1) cts/gal	66.67	3.04	0.14	1.68	71.51	69.85	-1.66
U.S. East Coast (87 (R+M)/2 Conv.) to Northwest Europe (91 RON):							
cts/gal	69.85	3.32	0.14	4.19	77.51	66.67	-10.84
2) $/ton	249.36	11.87	0.50	14.96	276.70	238.00	-38.70
West Mediterranean* to U.S. East Coast (87 (R+M)/2 Conv.):							
$/ton	246.00	12.38	0.50	5.95	264.83	249.36	-15.47
3) cts/gal	68.91	3.47	0.14	1.68	74.19	69.85	-4.34
U.S. East Coast (87 (R+M)/2 Conv.) to West Mediterranean*:							
cts/gal	69.85	3.32	0.14	4.19	77.51	68.91	-8.60
4) $/ton	249.36	11.87	0.50	14.96	276.70	246.00	-30.70

* Calculated on the basis of the differential between regular and 95 octane gasolines in Northwest Europe.

- Storage
  This sort of arbitrage is influenced by storage costs and is relevant primarily in contango markets. If the degree of contango in the market exceeds the carrying

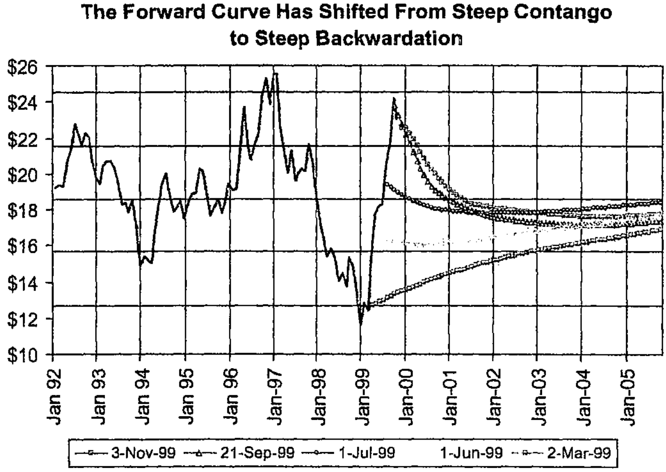
and financing costs of storage then there is a storage arbitrage opportunity. The procedure would be as follows:

1. Buy crude spot	3. Store Crude until delivery	5. Pay Storage
2. Sell crude forward	4. Deliver Crude at Forward Price	6. Keep Profit

The forward period chosen should be the one that takes full advantage of the contango market. This scenario leads one to expect that the level of contango will be limited by storage and financing costs. However, one must consider the varying storage and financing costs across market participants and the limited amount of storage capacity.

FORWARD CURVE

Price volatility has been a defining characteristic of the oil market as of late. As the chart below illustrates, the price of oil went from a little under $12 in January 1999 to nearly $26 as of November 1999.



The solid dark-blue line is the historical WTI average price. The various marked lines are the forward curve at different points in time. The forward curve, especially its shape, is a constant concern in the oil market. This section will introduce some terminology that describes the shape of the curve and some reasons that may contribute to that shape.

First, if you look at the green line dated March 2, 1999 you will see that the front part of the curve is lower than the back end. The front part of the curve refers to futures contracts that have their delivery close to the current date. For example, as of November 16, the front-most month on the futures curve is the NYMEX December crude contract. The upward-slope of the curve is what is normally expected for a price curve, i.e., as you move further out in time, the asset gets more expensive. This is a result of several factors, like the time value of money. People in the industry refer to this shaped curve as a curve that is in "contango."

In this scenario, the market is over-supplied with physical oil, and spot prices are lower than term prices. The producer faces difficulties when selling crude, but can sell futures at higher price. Strong contangos are often associated with poor short-term market supply conditions.

Referring back to the graph, as time moves forward the shape of the forward curve changes. Take the red line dated September 1, 1999, for example. The front end of the curve is much higher than the back end. This situation is termed "backwardation."

In this market scenario, spot prices are higher than term prices, and there is an added value for physical crude oil. Producers will therefore tend to sell immediately, and thus will act to undermine the backwardation spread (the difference in price between the front month and the back month).

There is also what is known as a "trendy" market. This can refer to either an increase in contango or an increase in backwardation. For example, starting with the pink curve dated June 1, 1999, the market has trended with respect to the backwardation, i.e., backwardation has steadily increased. The Holy Grail with respect to the forward curve is, of course, the anticipation of the shape of the curve and/or the reversal of the trend. Spread positions are implemented in order to capitalize in the changing term structure of the curve.

The forward curve is often confused as a price prediction. In other words, a market in backwardation would mean that the anticipated value of the spot price in the future is lower than the current one. Conversely, a market in contango would mean that the spot price in the future is expected to be higher than the current spot. However, that is not *necessarily* the case. There have been numerous studies that have shown the futures price is no better a predictor than the spot. Forecasting power and expectations should not be confused though. The shape of the market curve *does* convey market expectations. Another thing to be aware of regarding the forward curve is that prices on the curve can be locked in. So, though forward prices are not predicted prices, they are attainable prices.

So what determines the shape of the forward curve? A natural response would be supply and demand. Unfortunately, the answer is not that clear cut. Relating our analysis to basic valuation, the value of an asset today is equal to the present value of all future cash flows discounted at the appropriate rate less any carrying costs. For oil futures though, there is an added dimension, the convenience yield.

Convenience yield is the benefit that accrues to the holder of physical oil that is not attained with holding paper oil. Those who hold inventories of oil include refiners, distribution companies, and end consumers. These participants have a convenience yield because they need to have physical oil on-hand because it may be critical to their ongoing business. The astute can accurately infer that the size of the convenience yield will vary across participants. More specifically, it will vary according to the inventories of the various participants. In fact, inventories are a large component in determining the shape of the forward curve.

If we relate the concept of convenience yield back to the shape of the forward curve, a steeply backwardated market implies high convenience yields. Conversely, a market in contango implies a low convenience yield.

Convenience yield alone cannot explain the shape of the curve. As we discussed earlier, the forward curve gives information about the expectations of market participants. As a result, market perception has a significant influence on the shape of the curve. It is widely accepted in the oil industry that the price of oil, over a several year outlook, is mean reverting, i.e., it tends to fluctuate around a central, or mean, value. Taken in this perspective, the spot price can fluctuate around the mean quite erratically. However, the further-out months tend to be more stable around a mean value. The result is varying volatilities across the forward curve, i.e., the front part of the curve is more volatile than the back. This phenomenon is clearly demonstrated in Figure 1.

As we have seen, market participant's perception affects the forward curve. However, market participants themselves affect the curve as well. In other words, different types of participants, e.g., hedgers versus speculators, will buy and sell different parts of the curve—for different reasons. We can classify market participants into three broad groups: those who are naturally long oil, those who are naturally short oil, and speculators who are neither naturally long or short. The following table gives a few examples of those who are naturally long and short.

Long	Short
• "Upstream" operators Shell, Exxon, etc. • Producing countries (e.g., OPEC)	• Exploration companies Mobile, small E&P Companies • Refiners Shell, Exxon, etc.

Generally, we can say that the different classes of participants operate on two parts of the curve. The first part consists of maturities less than 18 months. This part of the curve is associated more with the physical market and to short-term expectations. The part of the curve that extends 18 months and beyond is usually associated with financial concerns. Participants on this part of the curve conduct long-term hedging operations and are motivated more by investment and project financing decisions, interest rates, inflation, etc. than short-term price fluctuations.

As we have seen, there is no easy explanation for the shape of the forward curve. However, that does not deter many from trying to model and predict the term structure. The models employ everything from technical analysis to fundamental analysis. Supply and demand are perhaps the cornerstone to any fundamental model. We will next discuss fundamental supply and demand drivers in the crude market.

SUPPLY DRIVERS

For the most part, the basic economics of supply and demand still dictate the price of oil. In the oil market, the most important supply factors are production and storage.

As we discussed earlier, storage has a very important impact on the shape of the forward curve. In Fact, volatility of oil is most affected by storage limitations. This phenomenon was seen most in the front part of the curve and is a major contributing factor to backwardation and convenience yield.

OPEC is, by far, the most significant supply factor. OPEC will frequently limit the supply of oil into the United States in order to increase prices. The only natural offsetting balance on OPEC's supply control is the incentive for OPEC member countries to cheat on their production quotas. OPEC production quotas and member compliance is constantly monitored.

1 DG21n Equity **OPCA**

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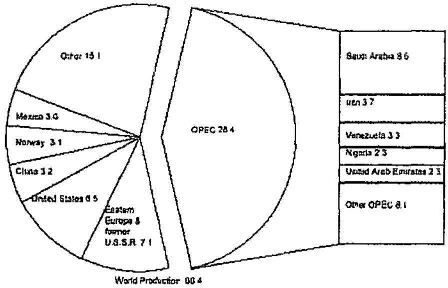
Bloomberg Estimated OPEC Crude Output

Est. Prod.('000 b/d) OPEC		Oct.	Sept.	% Comply	New Target	Pledged Cuts	Base-Line	Est. Cap+
Saudi Arabia	1)OPCRSAUD	7,600	7,590r	88%	7,438	1,310	8,748	10,800
Iran	2)OPCRIRAN	3,400	3,370r	93%	3,359	569	3,928	3,800
Iraq	3)OPCRIRAQ	2,780	2,840	---	---	---	1,688	2,750
Kuwait	4)OPCRKUWA	1,860	1,850	93%	1,836	369	2,205	2,650
U.A.E.	5)OPCRUAE	2,050	2,040r	87%	2,000	382	2,382	2,650
Qatar	6)OPCRQATR	630	610	65%	593	107	700	770
Mideast Total	7)OPCRMIDE	18,320	18,300r	---	---	---	19,651	23,420
Venezuela	8)OPCRVENZ	2,730	2,730	98%	2,720	650	3,370	3,400
Nigeria	9)OPCRNIGE	1,920	1,900	91%	1,885	373	2,258	2,230
Indonesia	10)OPCRINDN	1,310	1,300	36%	1,187	193	1,380	1,420
Libya	11)OPCRLIBY	1,320	1,300r	59%	1,227	226	1,453	1,560
Algeria	12)OPCRALGE	750	740	86%	731	137	868	930
Other OPEC Ttl	13)OPCROTHR	8,030	7,970r	82%	7.750	1,579	9,329	9,540
Total OPEC 11	14)OPCRTOTL	26,350	26,270r	---	---	---	28,980	33,140
Total ex. Iraq	15)OPCREXIQ	23,570	23,430r	86%	22,976	4,316	27,292	30,390
Neutral Zone #	16)OPCRNUZN	510	500	---	---	---	---	600

Baseline represents February 1998 production. Iraq is not sharing in cuts.
Production shared equally in Saudi Arabia and Kuwait quotas. r = revised
+ Capacity attainable within 30 days and sustainable for 90.

Below is a chart showing the sources of oil around the world. It is obvious that OPEC is a major supplier of oil.



Note: Totals may not equal sum of components due to independent rounding
Source: United States: Energy Information Administration. *Petroleum Supply Annual 1997*, DOE/EIA-0340(97)/1. Rest of world: Energy Information Administration. *International Energy Annual 1997*, DOE/EIA-0219(97)

DEMAND DRIVERS

Demand varies across participants. There is actually a broad base of consumers in the crude market so that no one force dominates demand as in the case of supply. Demand is the driver behind convenience yield and even seasonality. Backwardation is strongly related to demand. Certain market participants are willing to pay a premium to have physical inventory as opposed to future paper. For these participants, continual supply is crucial to their operations. Additionally, oil has strategic and political importance.

Since it cannot be produced or transported instantaneously, and since production centers are distant from refining and consuming centers, a shortage of supply can have a dramatic effect. This means that the elasticity of demand for the refined petroleum products is close to zero in the short term.

It is useful to monitor the long positions and short positions of hedgers and speculators. This can give you an idea of where the demand is coming from and the expectations of different market participants. An example of the data is below.

DG21n Equity **CFTC**

Crude Oil – NYME
Reportable Positions as of 11/2/1999
(Contracts of 1,000 barrels)

	Non-Commercial			Commercial		Total		NonReportable Positions	
	Long	Short	Sprding	Long	Short	Long	Short	Long	Short
Commitments	41,251	14,695	35,262	387,258	418,068	463,771	468,025	89,493	85,239
Changes from 10/26/1999 (Change in Open Interest: -16,120)	-12,144	2,903	3,262	-8,956	-31,215	-17,838	-25,050	1,718	8,930
Percent of Open Interest for each category of traders	7.5	2.7	6.4	70.0	75.6	83.8	84.6	16.2	15.4
Number of traders in each category	37	27	25	84	81	138	116		

Open Interest: 553,264 Total Traders: 173

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The Commodity Futures Trading Commission (CFTC) reports this data twice monthly. Open interest is the total number of outstanding positions at any given point in time. The non-commercial and commercial positions refer to a position used for hedging or risk management and those held as speculative trades, respectively. The number of contracts traded determines whether or not a position is reportable.

Up to this point, we have been speaking about the market in general terms. However, the most liquid oil market in the world is NYMEX. Next, we will take a look at the NYMEX crude-oil futures contract.

FINANCIAL CRUDE MARKET

Crude is the world's most actively traded commodity. It has only been over the past 20 years though that the oil markets have evolved into what we know them today. What has been consistent though, is that prices change.

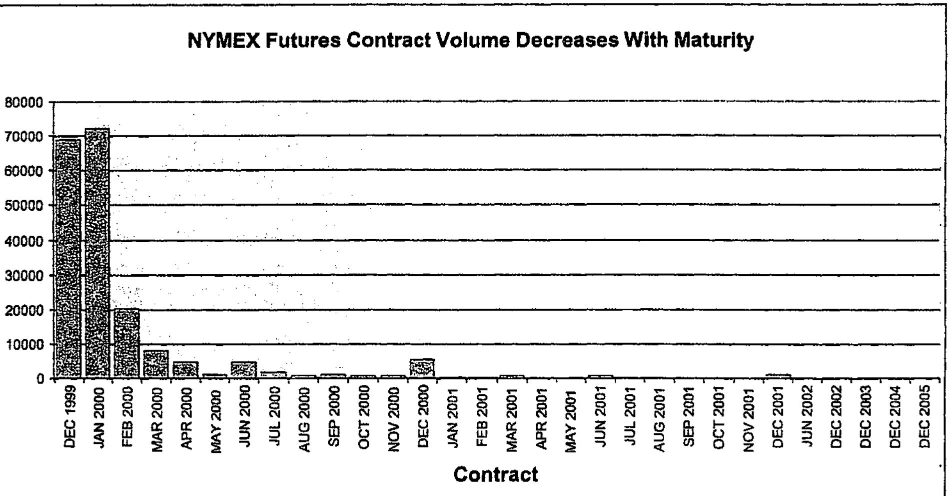
Fortunately, there is an active financial market where participants can hedge their price risk. The NYMEX crude contract is, by far, the most active. As a consequence, the NYMEX contract is the world's benchmark for oil trading.

When designing a standardized contract, a balance must be struck between flexibility and uniformity. The goal is to provide a useful tool for the widest audience. If the contract is too specific it becomes useless to the masses. Conversely, if it is too broad, the valuation becomes quite complex and participants are unsure of what they are buying.

The crude contract has several specifications that are presented below. For a description of the specification, visit the NYMEX web site at www.nymex.com.

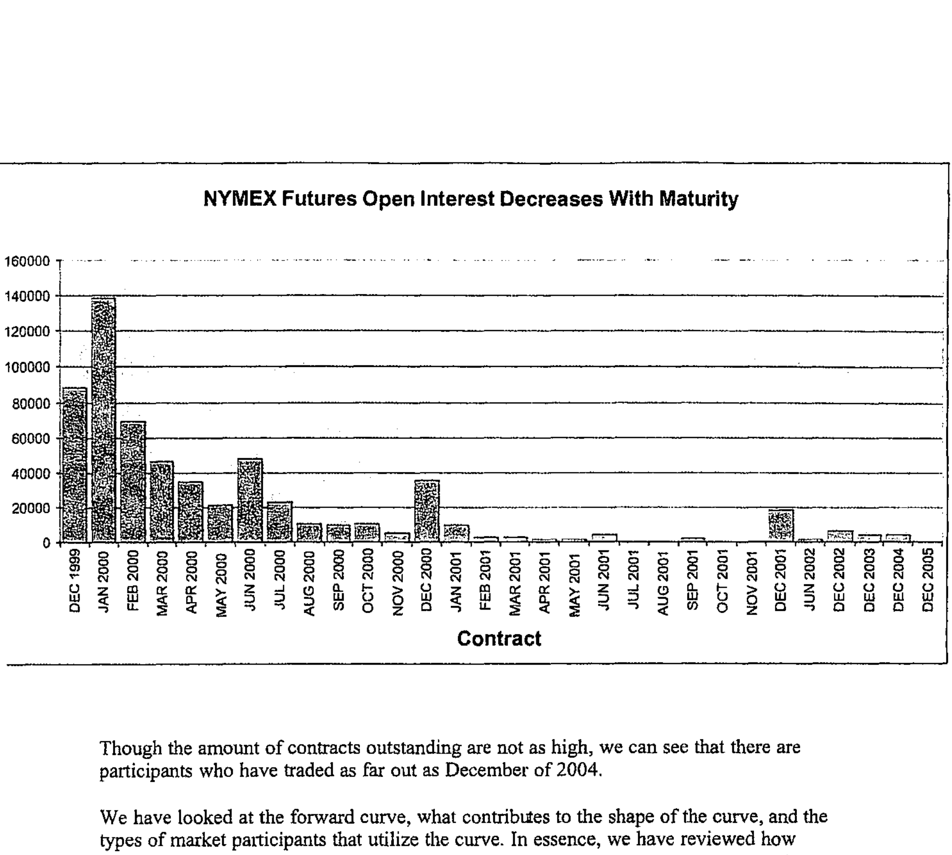
- Trading unit
- Trading Hours
- Trading Months
- Price Quotation
- Minimum Price Fluctuation
- Maximum Daily Price Fluctuation
- Last Trading Day
- Exercise of Options
- Delivery
- Delivery Period
- Alternate Delivery Procedure (ADP)
- Deliverable Grades
- Inspection
- Position Limits
- Margin Requirements
- Trading Symbols

NYMEX offers contracts that trade several years into the future. Below is a graph of the volumes of the contracts offered by NYMEX on November 15, 1999.



As one might expect, the volume is highest on the front part of the curve. However, there are contracts available as far as five years into the future. Intuitively, given what has been discussed about the parts of the curve different participants trade in, it makes sense that the longer-dated contracts will have less volume—hedgers do not trade as much.

Open interest, or total contracts outstanding, should give us an idea of the utilization of long-dated contracts. Below is a graph of open interest for November 15, 1999.



Though the amount of contracts outstanding are not as high, we can see that there are participants who have traded as far out as December of 2004.

We have looked at the forward curve, what contributes to the shape of the curve, and the types of market participants that utilize the curve. In essence, we have reviewed how prices at different maturities are determined—or at least impacted. We also covered basic supply and demand factors affecting oil prices. Finally, we briefly looked at the major market for crude, the NYMEX.

ALTERNATIVE MARKETS

We are constantly reminded that we operate in a global market place. The crude market is no different. There are many crude markets around the world.

There are over sixty different crude oils traded around the world. These crudes are valued differently for the following factors: 1) Quality of crude oil (heavy vs. light, sweet vs. sour), 2) transportation costs, 3) supply and demand and 4) events within the market place. By events within the market place I mean that if a refinery in Thailand has a serious fire and it declares force majeure, then it must resell its cargoes which it would have processed if it didn't go down.

The most volatile factor is supply and demand. Whether it is the OPEC nations reducing its supply of oil to the world market or regions demanding more oil and buying it away from its existing markets (an example would be Asian markets who are outbidding the European markets for West Africa oil), this can be a day-to-day dynamic. The most consistent factor affecting crude oil prices between basins is transportation costs. This represents the most consistent price differentiation.

The world has four very liquid markets for oil – West Texas Intermediate, Brent and Dubai crudes. West Texas Intermediate is priced typically at Cushing, Oklahoma and is the NYMEX trading point. Brent is the North Sea price for a number of different oils and is traded in London and around the world. Dubai is traded in Singapore and around the world.

A liquid market is one that is traded around the world against other markets and that futures contracts can be traded. There are many other crudes from Mexico, Columbia, Indonesia and FSU that are primarily sold under long-term contracts. These contracts are typically tied to indexes to prevent either party from getting hurt. They do not have futures markets at these points. Below is a listing of all the crudes that are available by country:

North Sea –
Brent
Forties
Flotta
Ekofisk
Oseberg
Statfjord

F S U -
Urals NEW
Urals Mediterranean
Siberian Light
Tengiz
Azeri Light
Friendship Czech
Friendship Germany

West Africa -
Bonny Light
Bonny Medium
Brass River
Forcados
Qua Iboe
Cabinda

Mediterranean -
Es Sider
Syrian Light
Iran Heavy Sidi Kerir
Iran Light Sidi Kerir
Suez Blend
Kirkuk

U.S./Canada -
WTI Midland
LLS St James
HLS Empire
Eugene Island
Mars Clovelly
Poseidon Houma
WTS Midland
Line 63
Alberta Edmonton
Bow River Hardisty

Mideast Gulf -
Dubai
Murban
Lower Zakum
Oman
Qatar Land
Qatar Marine

Asia-Pacific -
Minas
Duri
Cinta
Widuri
Arun
Attaka
Ardjuna
Belida
Bach Ho
Tapis
Gippsland

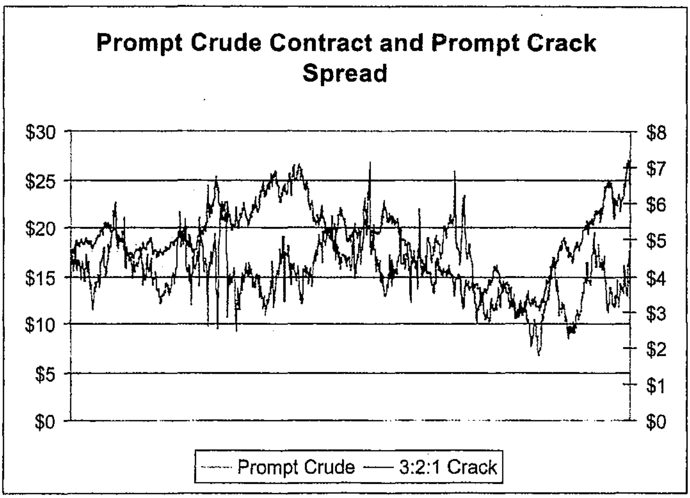
MISCELLANEOUS

It is common practice in the industry to use "asian" oil prices. The term asian in this context is derived from the derivatives market where asian connotes an average. For example, an asian option is an option whose payoff is a function of an average price of the underlying. In the crude market, the asian oil price is derived using multiple delivery months. For example, assume that we are in November. The prompt asian price would be the December asian and is calculated by taking two-thirds of the January futures close plus one-third of the February futures close. Numerically the calculation is:

On November 30:
January 1999 NYMEX oil futures = $24.59
February NYMEX oil futures=$23.95
December Asian = $24.59 * 2/3 + $23.95 * 1/3 = $24.38

As in any other market, information is critical when trying to understand the fundamentals. Two key sources of energy information are the Department of Energy and the American Petroleum Institute. Their website addresses are: www.eia.doe.gov and www.api.org, respectively. Both of these organizations issue extensive reports on the industry.

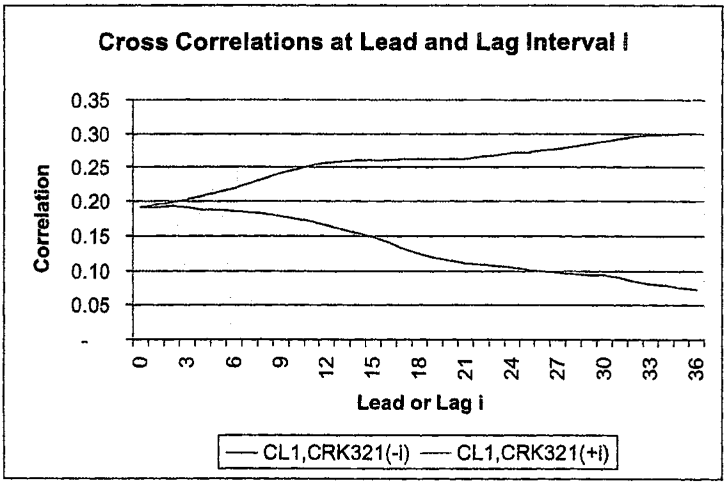
Crack spreads play an important role in the crude market. One might wonder if there is any knowledge about future prices contained in the spread. Below is a graph of the prompt crude price and the prompt 3:2:1 crack spread.



Simply looking at the graph above, one cannot make a clear determination of whether or not the crack is a good indicator. A better idea of the predictive power of the crack spread would be given by looking at the cross correlation for different leads and lags of the two assets. Below is a graph of correlations at different leads and lags. For example, the x-axis is labeled zero to thirty-six. The blue line shows the correlation between the crack spread and the lag of the number on the x-axis, say 12. A couple of things stand out in the graph:

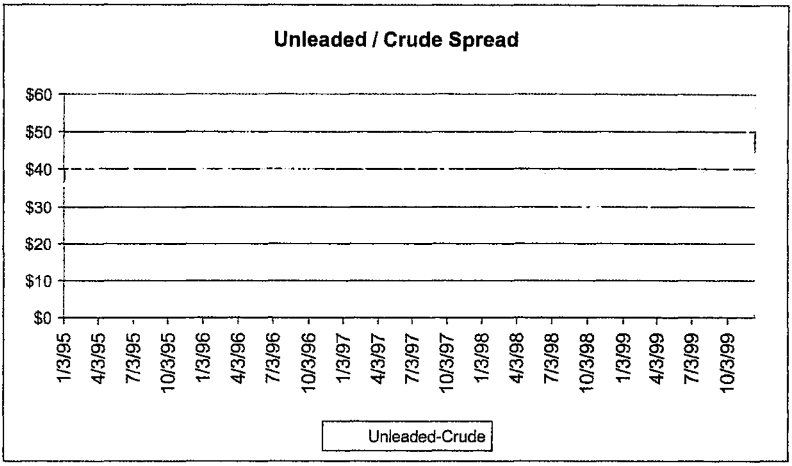
1. As the lead for the crack spread increases, the higher the correlation to crude.
2. The opposite is also true: the greater the lag of the crack, the lower the correlation to crude.

This would lead us to conclude that the current crude price is a better directional indicator for the future crack rather than the other way around, i.e., high crude prices today are associated (correlated) with high crack spreads in the future. This is a counter-intuitive result. After all, everything else equal, as crude prices rise, the crack tightens.



Spreads are a popular trade in any market and the petroleum market is no different. Below is the analysis of three spreads: Unleaded / Crude, Heating Oil / Crude, and Unleaded / Heating Oil.

One would expect that the unleaded / crude spread to be positive. Unleaded is a refined product and it wouldn't make much sense to make gasoline if there were no profit involved. From the graph below, we can see that the spread has varied over a wide range in just the past five years. However, a spread of about $40 seems to be most dominant.

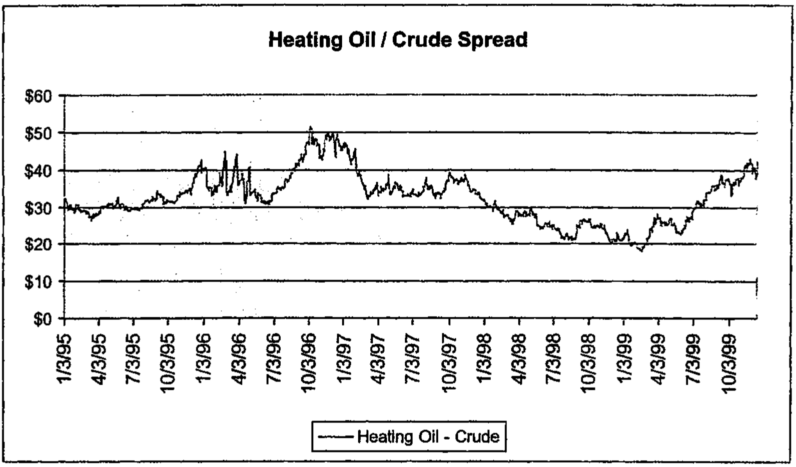


The calculation of the unleaded / crude spread is very similar to that of the crack spread--in fact this is a type of crack spread. For example, if gasoline is at $.9679 per gallon and crude is at $31.69 per barrel, the spread calculation is:

-$31.69 per barrel
+$.9679 x 42 = $40.65 per barrel
$8.96 (this spread is not divided by two because the unleaded / crude spread is quoted in comparable terms).

Heating oil is another refined product and, once again, we can expect this spread to be positive. Below is a graph of the spread over a period of about five years. Once again, we can see that the spread varied over a wide range. However, the average is closer to $30 rather than $40 as with the unleaded / crude spread, i.e., we would expect the unleaded / heating oil spread to be positive most of the time.

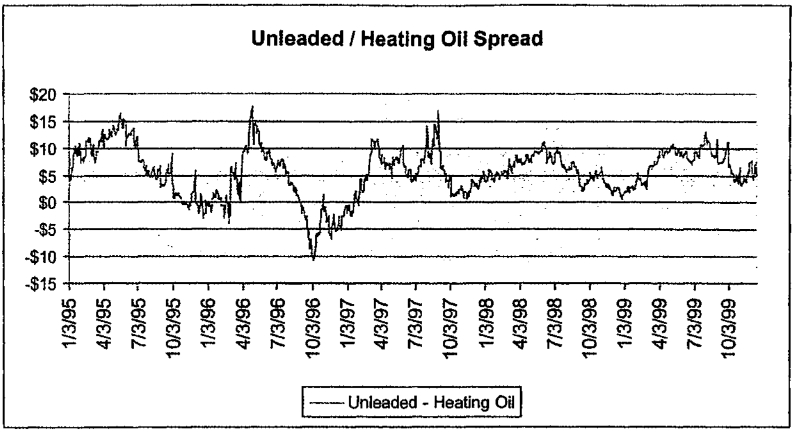
Notice too, that the two spreads tend to move together, i.e., they are highly correlated.



Again, the calculation is very similar. If heating oil is at $.7368 per gallon, and oil is at $31.69 per barrel, the spread is:

-$31.69
+$ .7368 x 42 = $30.95
-$ .744

It was hypothesized above that the unleaded / heating oil spread will be positive most of the time. The graph below indicates that this is the case. On average, the spread is around $5.54. However, we can see that, in the past five years, it has been as high as about $17.5 and as low as about -$10.00.


Unleaded / Heating Oil Spread
$20
$15
$10
$5
$0
-$5
-$10
-$15
1/3/95
4/3/95
7/3/95
10/3/95
1/3/96
4/3/96
7/3/96
10/3/96
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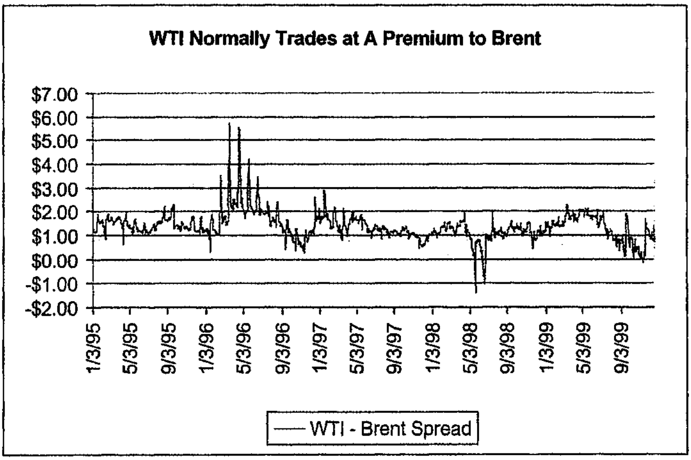
10/3/99
Unleaded - Heating Oil


WTI Normally Trades at A Premium to Brent
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
-$1.00
-$2.00
1/3/95
5/3/95
9/3/95
1/3/96
5/3/96
9/3/96
1/3/97
5/3/97
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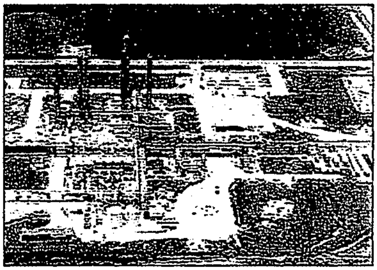
WTI - Brent Spread

B. Natural Gas Liquids



A fractionation plant located in Mont Belvieu, Texas, a major NGL pricing point.

The energy market in general, and the natural gas liquids market in particular, is filled with confusing and seemingly contradictory terminology for those unfamiliar to the industry. What follows is a brief introduction and explanation of some common industry terms relevant to the NGL[1] market.

Terminology

Hydrocarbon: Organic compound made up of carbon and hydrogen atoms. Heavier fossil fuels, such as coal, have a large ration of carbon to hydrogen, while natural gas (methane) is the lightest hydrocarbon, with one atom of carbon and four atoms of hydrogen ($CH4$). Natural gas liquids are heavier than methane but lighter than crude oil. Crude oil is a complex of many hydrocarbons.

Fractionation: The process of separating liquid hydrocarbons from natural gas into propane (C3), butane (C4), ethane (C2), and natural gasoline (C5+). Note: The "C#" refers to the number of carbon molecules in the NGL component. Also, natural gas is a term used loosely. There is a distinction though. Dry gas is natural gas without the liquids, i.e., gas after fractionation, wet gas is the gas prior to fractionation, and natural gasoline contains substantial quantities of pentane and heavier hydrocarbons and is extracted from "wet gas."

Frac Spread: This is the spread between the wet gas price and the individual liquids that can be extracted from the gas. Obviously, it takes money to extract the liquids so it would

[1] It is useful to know that NGLs and LPGs refer to the same thing and are used interchangeably in the industry. Usually, NGLs are referred to as LPGs outside of the U.S.

Menu DG21n Govt **FRAC**

Natural Gas Fractionation Spreads

Type number then <GO> for a graph of historical frac spreads.

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Spread Type	Graph	Ticker	Frac Spread ($/MMBtu)	Ethane	Propane	Iso-Butane	Normal Butane	Natural Gasoline
				----- Processing Plant Output (%) -----				
25% Ethane	1)	FRAC25ET	2.279	25.00%	37.50%	10.00%	15.00%	12.50%
30% Ethane	2)	FRAC30ET	2.235	30.00%	35.00%	9.40%	14.00%	11.60%
35% Ethane	3)	FRAC35ET	2.190	35.00%	32.50%	8.50%	13.00%	11.00%
40% Ethane	4)	FRAC40ET	2.147	40.00%	30.00%	8.00%	12.00%	10.00%
45% Ethane	5)	FRAC45ET	2.102	45.00%	27.50%	7.33%	11.00%	9.17%

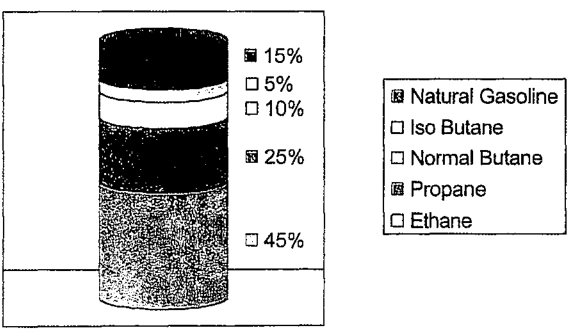
Price Basis: Frac spreads are based on current U.S. Gulf spot prices for natural gas at Henry Hub, La., and liquefied petroleum gas prices at Mont Belvi Texas. Natural Gas: $2.55/MMBtu; Ethane: 27.75 cts/gal; Propane: 43.75 cts/gal; Isobutane: 53.63 cts/gal; Normal Butane 54.13 cts/gal; Natural Gasoline: 57.75 cts/gal.

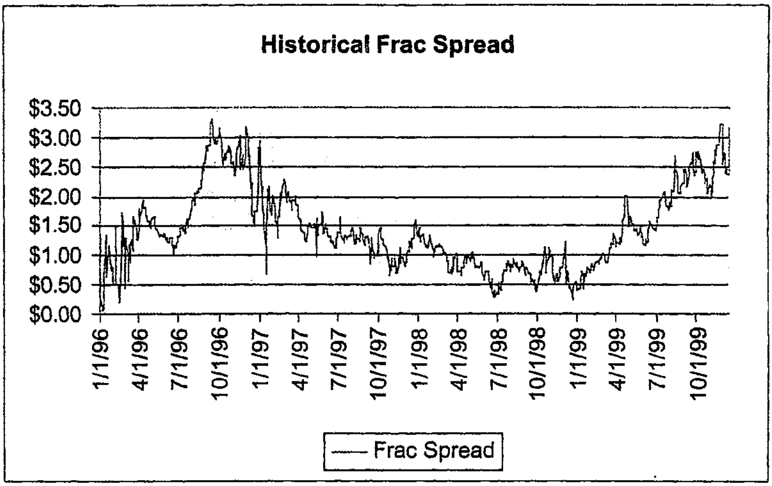
Conversion Factors: Ethane: 0.15; Propane: 0.108; Butanes: 0.101; Natural Gasoline: 0.09.

only make sense to do so if the margins are high enough, i.e., if frac spreads are high enough. An example of the output is as follows:

A frac spread is a weighted average of NGL prices less the price of natural gas and represents the theoretical profit of processing or "drying" natural gas into its constituent NGLs. Because ethane output is the most important consideration when fractionating natural gas, FRAC displays spreads for five different levels of ethane production. The percentages of the other NGLs are weighted accordingly.

A Typical NGL Mix Barrel From A Natural Gas Stream





Ultimately, a processor is concerned with the frac spread. He can hedge his exposure several ways. First, he can sell the frac itself on the market. As a result, the margin is locked in. If the spread tightens, i.e., falls, he will lose money in processing but will gain on his position. For example, referencing the Frac Spread chart presented earlier, the 45% ethane frac was selling for $2.10, i.e., the seller could lock in a margin of $2.10. Second, he can buy the gas and sell the refined product. This strategy locks in the spread as well. For example, again in reference to the display presented earlier, Gas could be purchased for $2.55/mmbtu and a barrel of NGLs could be sold for:

	Ethane	Propane	I-Butane	N-Butane	NG
¢/Gal.	27.75	43.75	53.63	54.13	57.75
Conversion	0.15	0.108	0.101	0.101	0.09
$/mmbtu	$ 4.16	$ 4.73	$ 5.42	$ 5.47	$ 5.20
Percentage	45%	28%	7%	11%	9%
Contribution	$ 1.87	$ 1.30	$ 0.40	$ 0.60	$ 0.48
$/mmbtu NGL Barrel	**$4.65**				

Obviously, selling the spread alone is more efficient since there is only one leg of the trade to worry about. However, taking a position in the two assets separately will set bounds on the price of the frac contract.

Net-Back Price: The effective wellhead price to the producer of natural gas, based on the downstream market price for the natural gas less the charges for delivering the natural gas to market.

Raw Mix: A liquid composition of all the NGL products. "Wet gas" comes in different grades, so to speak. A particular stream of natural gas will have a different composition of NGLs contained within. As a consequence, people will often refer to a raw mix of a particular stream of gas or composition that comes out of a particular processing plant. For example, one raw mix profile may be comprised of 40% ethane, 25% propane, 15% iso-butane, 5% normal-butane, and 15% natural gasoline.

Ethane Rejection: Plant recovery of all NGLs except for ethane, i.e., the ethane is left in the gas. Ethane rejection occurs when it is not profitable to extract the ethane from the gas stream, i.e., when the price of ethane is less than the price of gas plus extraction costs. For example, assume that ethane is trading for $4.00 per mmbtu and extraction costs are $0.15 per mmbtu for a total income of $3.85 per mmbtu. If gas can be sold for more than $3.85 per mmbtu, then it doesn't make sense to extract the ethane.

Feedstock: Natural gas, or NGLs, used as an essential component of a process for the production of a product, e.g., fertilizer, plastics, etc.

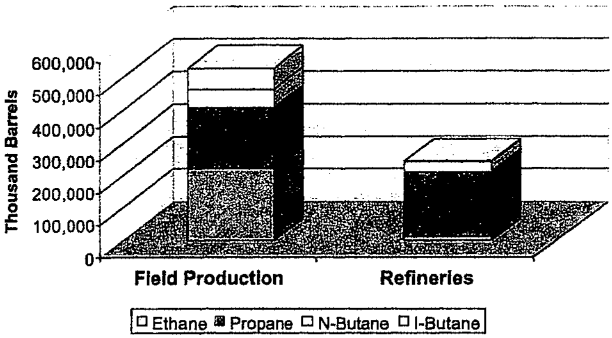
Liquefied Natural Gas: Distinct from NGLs, this is natural gas that has been super-cooled under pressure to –259 degrees F. It is almost pure methane.

Market Structure

Natural gas liquids include all hydrocarbons produced from natural gas (except methane) plus the C_2-C_4 hydrocarbon fractions isolated from petroleum refineries. However, its main components are Propane and Butane. The majority of total NGL production comes from natural gas processing with the balance coming from refineries.

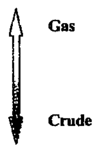
According to the Energy Information Administration, here is a breakdown of NGL components and their source, i.e., natural gas procession or refineries, in 1998.

Breakdown of NGLs by Source and Component



The five primary NGLs are:

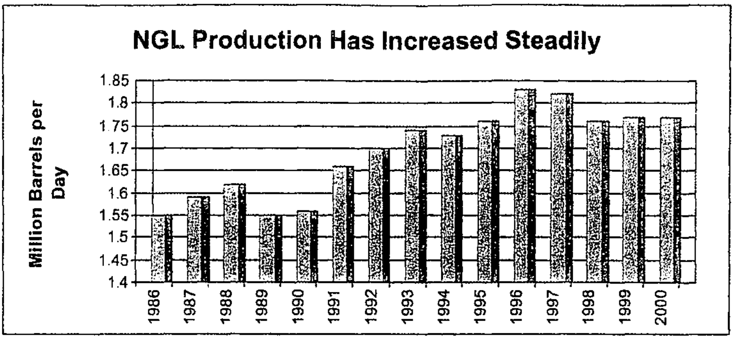
- Ethane (C2)
- Propane (C3)
- Iso-Butane (I-C4)
- Normal-Butane (N-C4)
- Natural Gasoline (C5)



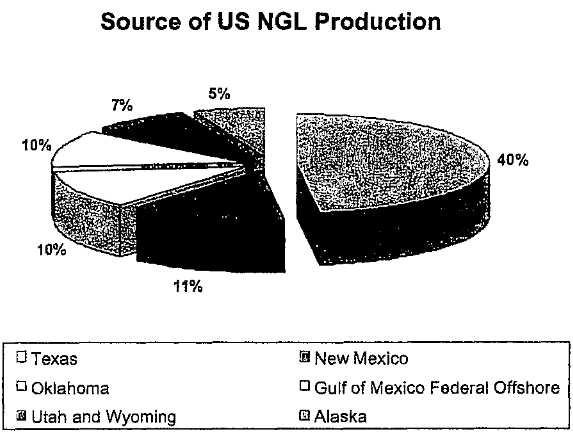
As noted earlier, the lighter the hydrocarbon, the more closely the NGL is related to natural gas. Conversely, the heavier the hydrocarbon, the more closely the NGL is related to crude.

Since 1980, the number of natural gas processing plants in the world has increased steadily. The major gas-producing regions are the United States, Canada, the United Kingdom, Italy, Indonesia, Algeria and Saudi Arabia. North America is the largest NGL-consuming region.

Current NGL production continues to increase. Future production is expected to increase as well.

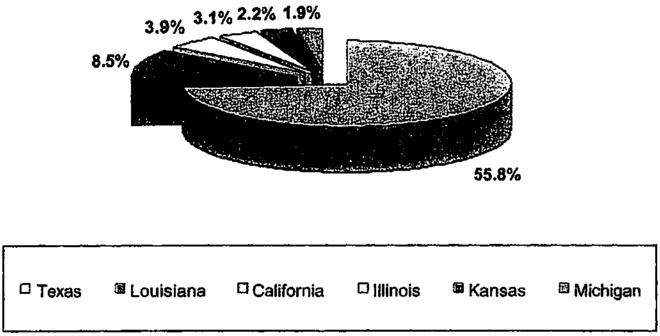


The top six domestic areas for proved reserves of natural gas plant liquids accounted for about 83 percent of the United State's natural gas plant liquids production:



Additionally, relatively few states account for the bulk of NGL sales. Texas is, by far, the largest purchasing state. The following chart shows the percent of total sales for the top 6 NGL purchasing states.

Texas Accounts for a Large Percentage of Total US NGL Purchases



Benefits of NGLs include transportability. NGLs can be moved around like a liquid, but burned like a gas. As a result, it can bring to users all the benefits of gas as a fuel without any costly infrastructure. Consumers in even the remotest areas can benefit, as can mobile users. Additionally, the absence of sulfur and the remarkably low production of NOx, air toxins, and particles produced during combustion make NGLs one of the world's most environmentally friendly sources of energy.

There are two main pricing points, or hubs, for natural gas. Mont Belvieu is located in Texas and Conway is located in Kansas. Most of the NGLs are priced off a basis from these two points.

Three primary uses for NGLs are:

- NGLs as a fuel
- NGLs as a motor fuel
- NGLs as chemical feedstock.

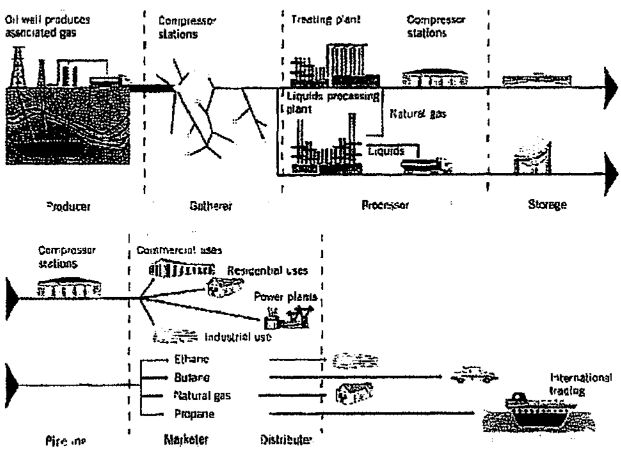
Here are some common feedstocks associated with their NGLs:

Ethane	Propane	Butane
• Paints	• rubbing alcohol	• synthetic rubbers
• camera film	• anti-freeze	• fibers
• synthetic rubber	• hydraulic fluids	• solvents
• plastics	• polyesters	
• vinegar	• detergents	

As mentioned above, the bulk of NGL production comes from natural gas processing with the remainder coming from refineries. Diagram 1 shows where NGL extraction and marketing fits into the oil and gas extraction and marketing process. Note that this is the base-case scenario. For example, the pressure required to liquefy ethane is so high that it is not currently feasible to import or export it overseas. Subtleties such as this make NGLs a very complex and interesting market.

Diagram 1

Natural gas business segmentation



Source: "Managing Energy Price Risk" 1st Edition, Risk Books 1995.

Processing Trends

There are a few primary gas-processing arrangements in the industry.

- Keep Whole contracts: the processor extracts the NGLs from the gas stream and replaces the equivalent Btu's to keep the total Btu content of the customer's gas stream the same, or "whole." The net effect of this type of contract is that the processor is net short gas. For example:

1. The processing plant has a customer that wants their gas processed, i.e., they want the NGLs extracted but don't want any of them.
2. The processor extracts the NGLs and effectively lowers the Btu content of the customer's gas stream.
3. As a consequence, the processor needs to purchase "dry gas" to replace the Btu content of the NGLs extracted. Hence, he is short gas and long NGLs.

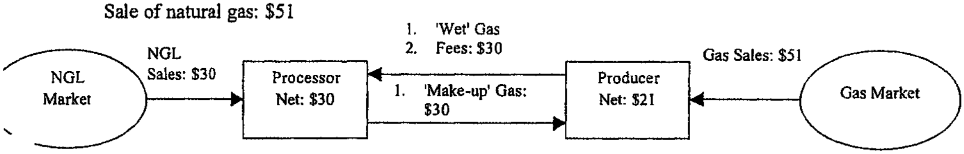
For example, assume that:

1. natural gas is selling for $2.55 per mmbtu
2. a barrel of NGLs is selling for $3.00 per mmbtu.
3. The customer doesn't like the margin so would rather have their 20 mmbtu's all in natural gas.

Then, the processor extracts the NGLs and lowers the mmbtu content of the customer's natural gas by say, 10 mmbtu's. The processor has to go out to the market to purchase the gas to replace what was lost for the NGLs which comes out to $30.

Processor P&L:
Extraction fee: $1.50 per mmbtu = $30
Purchase of natural gas: -$30
Sale of NGLs: $30

Customer P&L:
Extraction Fees: -$30
Sale of natural gas: $51



- Percent of Proceeds contracts: processor extracts the NGLs from the gas stream and keeps a percent of the gas to sell. A percent of the price received is paid back to the customer. Effectively, the processor is long gas and NGLs. For example,
  1. The processing plant has a customer the wants their gas processed, i.e., they want the NGLs extracted.
  2. The processor keeps a percentage of the gas.
  3. The processor markets the gas.
  4. The processor pays some of the proceeds back to the customer.

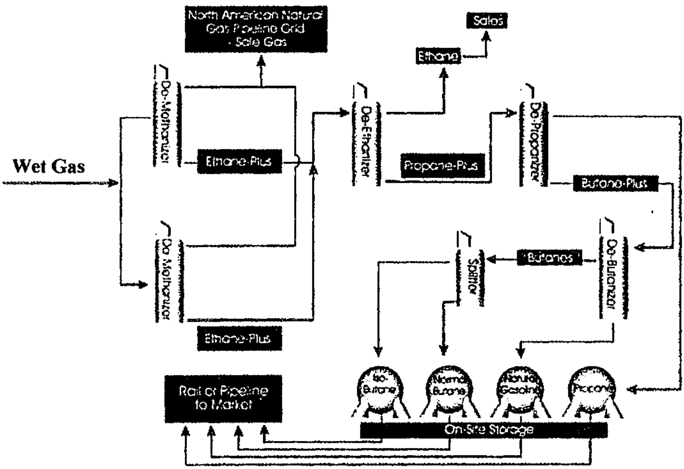
For example, the customer has 20 mmbtu's of wet gas to process. The processor keeps 5 mmbtu's for selling all of the gas and processing. The P&L would be as follows assuming 10 mmbtu's are NGLs and the other 10 are natural gas:

10 x \$2.55 = \$25.50
10 x \$3.00 = \$30.00

Total \$55.50 and the processor keeps 25% of the proceeds (5/20) = \$13.875.

- <u>Fee-based</u> contracts: the processor processes the gas for a fee. This arrangement keeps the processor neutral, i.e., no long or short positions.

Below is a diagram of how the processing takes place.



NGL Physical Markets

NGL markets are still in their infancy. However, they are expected to grow rapidly in the years to come. The following is a brief profile of some relevant fundamental factors affecting NGLs.

Transportation: NGLs are transported via pipelines. If the transportation is interrupted, NGL prices could spike upwards. A recent example is the Seminole NGL pipeline which experienced a brief outage and caused daily ethane prices to spike temporarily to as much as 43 cents per gallon in mid-August, 1999 – the average price in July, 1999 was around 28.8 cents.

Margins: Margin can be tracked with the frac spread. As long as the prices for NGLs exceed the price of gas plus processing fees, NGL production can be expected to continue.

Chemical Demand: NGLs are used as a chemical feedstock for a wide range of applications. Demand by chemical companies has a large impact on the prices of NGLs.

Price of Crude and Natural Gas: NGLs have a strong positive correlation to these two commodities. As will be shown later, when crude and natural gas prices rise, NGL prices tend to move with them. This relationship is very useful for a variety of applications, especially risk management.

Extraction costs: As the technology improves, the cost of extracting and cracking NGLs decreases. For example, cryogenic techniques, which employ extremely low temperatures to extract NGLs from natural gas, have increased the amounts of NGLs extracted for a particular stream of gas.

NGL Financial Markets and Risk Management

NGLs are, in general, very illiquid. At this time, propane is the only NGL that has a contract on NYMEX. Needless to say, the propane contract is very thinly traded. The contrast between a liquid market, such as crude, and NGLs, such as propane, is striking. Below is a table with the open interest and previous day's trading volume on September 15, 1999 for both crude and propane. N/A signifies that the contract was not available.

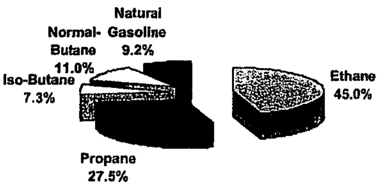
Contract	Open Int.-Oil	Open Int.-Propane	Previous day's tot. vol. -Oil	Previous day's tot. vol. -Propane
Oct-99	107962	270	94488	96
Nov-99	121083	392	87943	61
Dec-99	112095	813	28069	99
Jan-00	63264	452	11871	145
Feb-00	25974	218	3482	210
Mar-00	30257	146	2712	50
Apr-00	12579	30	1516	0
May-00	7985	135	1864	75
Jun-00	38717	100	3072	100
Jul-00	12750	0	443	0
Aug-00	5053	0	48	0
Sep-00	7557	0	76	0
Oct-00	5832	0	120	0
Nov-00	2662	n/a	111	n/a
Dec-00	34903	n/a	1585	n/a
Jan-01	4906	n/a	0	n/a
Feb-01	793	n/a	0	n/a
Mar-01	1367	n/a	0	n/a
Apr-01	239	n/a	0	n/a
May-01	243	n/a	0	n/a
Jun-01	4747	n/a	0	n/a
Jul-01	38	n/a	0	n/a
Aug-01	53	n/a	0	n/a
Sep-01	2302	n/a	0	n/a
Oct-01	27	n/a	0	n/a
Nov-01	0	n/a	0	n/a
Dec-01	14578	n/a	151	n/a
Jun-02	770	n/a	45	n/a

It is apparent from the table that the crude market has liquidity in the current and far-out months. Equally apparent, is the illiquidity of the propane market. In fact, the crude contract for nearly 2 years out has nearly 3 times as many contracts outstanding than the prompt propane contract! Needless to say that the other NGLs such as ethane and butane have even more illiquid markets.

For a company that has a large NGL exposure, illiquid markets can be very inconvenient at best. However, there are still ways to mitigate the risk.

It was mentioned earlier that NGLs have a positive correlation to both crude and gas. This makes perfect sense given that NGLs are composed of components that resemble gas (ethane, propane) and crude (butane, natural gasoline). But how do we quantify this?

First, let's compose a barrel of NGLs, i.e., assume a particular NGL composition so that we can model just one variable. Referring back to the Bloomberg caption, we will use the last composition:



Next, we want to take a look at the relationship between our NGL barrel, crude, and natural gas. The NGL barrel data series is priced off of Mont Belvieu starting in January of 1994. Crude[1] and gas prices are taken from the NYMEX futures prices.

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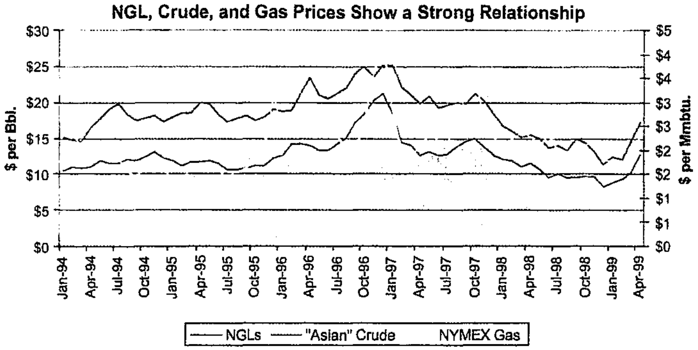
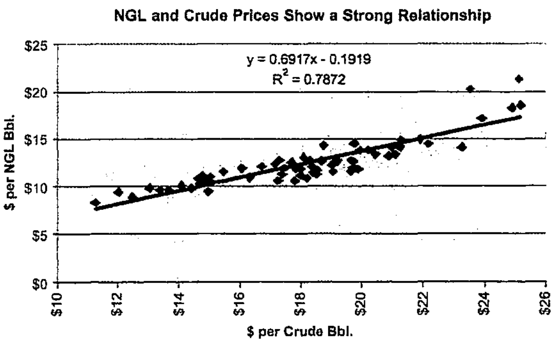
[1] It is common in the industry to talk about the "Asian" price of crude. The Asian price is calculated as 2/3 * "prompt" NYMEX contract + 1/3 * "next" NYMEX contract. For example, if we are in August, the prompt NYMEX contract would be September and the next NYMEX contract would be October. The reason this is done has to do with deliverability of the underlying physical. Also, the final 3-day average of the NYMEX gas price is used, as is common in the industry.

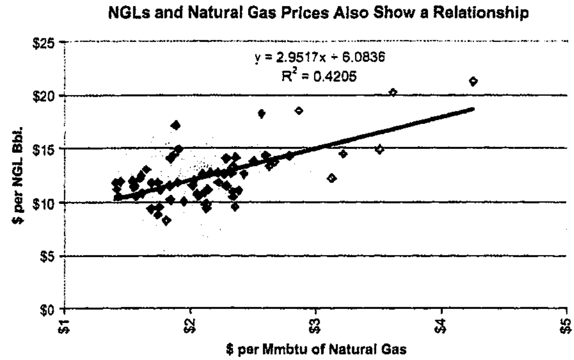


There are a number of ways we can proceed from here. Remember that the goal is to manage the risk of an NGL position using crude and gas.

Regression analysis is useful in quantifying relationships between several variables. Once we have quantified the relationship between crude, natural gas, and NGL prices[1], we can proceed to hedging the risk of the underlying asset, NGLs. But first, let's look at the relationships separately.



[1] It is common practice, when modeling prices, to use price changes rather than levels. This is because of stationarity issues. However, it is widely accepted in the industry that crude is mean-reverting, which mitigates those concerns over long-term price modeling. For hedging over short-time frames, using changes is better but comes with higher transaction costs. For more information on stationarity, consult an introductory time series or econometric textbook.



The equations on the charts tell us that the price of an NGL barrel is equivalent to about .7 times the price of an oil barrel less, .2. Or, the price of an NGL barrel is equivalent to about 3 times the price of an mmbtu of natural gas plus 6 dollars. Additionally, we see that the price of oil explains about 79 percent of the variability in the price of NGLs and that the price of natural gas explains about 42 percent. However, oil and gas also have some relationship between them. So what is the effect of oil and gas on NGLs independent of each other? To find that out, we use multiple regression.

Regression Statistics	
R Square	0.8303
Standard Error	1.0555

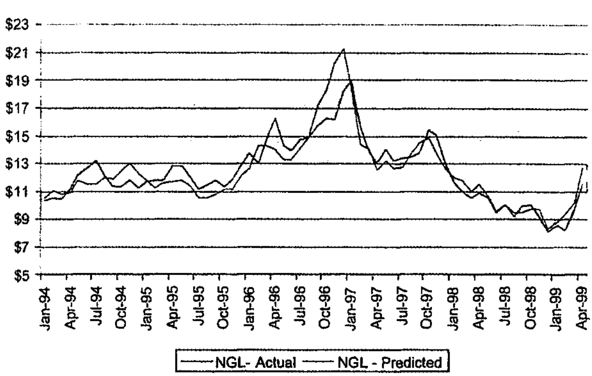
	Coefficients	Standard Error	t Stat
Intercept	(1.07)	0.7938	(1.3496)
"Asian" Crude	0.62	0.0452	13.6519
Natural Gas	1.04	0.2642	3.9402

Both of the t-stats for the coefficients allow us to reject the null hypothesis that they are equivalent to zero, i.e., that they are not significant. We can also see that the percent of NGL price movement explained – i.e., the R Square – has increased, leading us to believe that using both oil and gas is better than using either one alone.

According to the multiple regression analysis, the price of a barrel of NGLs is equivalent to .62 the price of a barrel of oil plus 1.04 times the price of an mmbtu of natural gas less a constant of 1.07 (which is statistically insignificant). For example, if crude were $20 per barrel and natural gas were $2.55 per mmbtu then the predicted price of a barrel of NGLs would be: .62 x $20 + 1.04 x $2.55 - $1.07 = $13.98.

Now that we have this relationship, it would be a good idea to compare the predicted values of our model versus the actual prices.

NGL Predicted Prices are Close to Actual Prices



So, now we have a relationship to use to cover our NGL price exposure. We can use NYMEX oil and natural gas futures contracts. However, there is also risk associated with using related commodities to hedge. Often, the term used for the risk in cross-commodity hedging is referred to as basis risk. In the energy industry, though, basis has a meaning of its own and the term correlative risk is often used instead. In fact, correlative risk is more descriptive of the type of risk that is encountered when using different commodities to hedge. What you are assuming when putting on a cross-commodity hedge is that the relationship between the commodities will stay the same. This is definitely not the case! However, in the long-term, the relationship between NGLs, crude, and natural gas has been fairly steady.

A different approach can be taken to hedge NGL price exposure using crude and natural gas. If we look at a portfolio of NGLs, crude, and natural gas, what would be the quantities of crude and natural gas that minimize the variance of the portfolio?

Let:
w = vector of weights of each asset in the portfolio
S = variance-covariance matrix of the assets in the portfolio

Then the variance of the portfolio is equal to w S w'. For the three-asset case this comes out to be,

variance of portfolio = $w1^2 s_1^2 + w2^2 + w3^2 \; s_3^2 + 2 \; w1w2 s_{21} + w1w3 s_{31} + w2w3 s_{32}$

where w_i is the weight of asset i, and $\sigma_{j,k}$ is the covariance between asset j and k. We want to minimize this with respect to w_2 and w_3 where w_2 and w_3 are crude and natural gas, respectively.

Variance - Covariance Matrix			
	NGL	"Asian" Crude	Natural Gas
NGL	6.36	7.24	0.78
"Asian" Crude	7.24	10.46	0.75
Natural Gas	0.78	0.75	0.31

NGL weight	Crude weight	Natural gas weight
1	w_2	w_3

Minimizing with respect to w2 and w3 we get:

w_2 = -0.61740423
w_3 = -1.041158834.

That is, we should short .62 barrels of oil and 1.04 mmbtu's of natural gas. The observant will note that these are the same ratios that we got with the multiple regression analysis—a comforting result. So, if NYMEX oil futures are on 1000 barrel lots, NYMEX gas futures are on 10,000 mmbtu, and we are hedging 10,000 barrels of NGLs, we would want 10,000 x .62 = 6200 barrels of oil (or 6 contracts) and 1.04 x 10,000 = 10,400 mmbtu's of natural gas (or 10 contracts).

Conclusion

In this chapter, we have reviewed the definition of natural gas liquids, their chemical properties, fundamental drivers, and hedging strategies using related commodities. It is important to state, once again, in closing that a cross-commodity hedge also has risk. Correlative risk is the risk that arises from the changing relationship between commodities. This risk, too, can be modeled and dealt with separately. However, that is beyond the scope of this lesson. The NGL market is growing steadily. Hopefully, with this growth, a more liquid market will develop and better hedging instruments will become available.

IV. Energy Options

.INTRODUCTION:

This chapter assumes that the reader is already familiar with basic option theory – plain vanilla calls, puts and the profit and loss diagrams associated with each. If not, before progressing any further, the following textbooks are strongly recommended:

1. Options: A Personal Seminar, by The New York Institute of Finance
2. Options as a Strategic Investment, by Lawrence G. McMillan
3. Option Pricing and Investment Strategies, by Richard Bookstaber
4. Option Volatility and Pricing, by Sheldon Natenberg.

Additionally, this chapter will NOT cover options pricing theory or any advanced math other than basic algebra. Although there are dozens of different ways to price options and to calculate such things as volatility and "greeks", this can be achieved with many inexpensive software programs that are commercially available. Also, if you are long 1,000 $25.00 call options on February Crude Oil while the price is dropping in $0.25 increments due to OPEC news, no amount of high-tech software will be able to get you out of that predicament. In this instance, you need to know a few general rules of thumb, which can be calculated in your head so that you can act immediately to stop the bleeding. Total command of the situation, with simple math that will "get you in the ballpark" as compared to complicated calculus which takes valuable time to compute, can mean the difference between salvaging a bad position or getting totally wiped out. This section is designed to teach you how to trade options. For more specific information on pricing of options and options theory, there is an addendum to this chapter which covers this material in greater detail.

From a trading perspective, an introduction to any options course must start with basic terminology that is applicable across all Options and Derivatives analyses. These basic definitions are generally the same across all markets, regardless if the underlying is bonds, stocks, currencies, or commodities. Nonetheless, an expert derivative trader in one market may lack the skills to effectively trade options in other markets. Essentially, it is essential to understand the basics of generic options trading and the methods behind the valuations, but it is equally important to understand the intricacies of the particular options and underlying market being traded.

OPTION BUILDING BLOCKS:

Basic Option Types:

There are two basic types of options from which all other options, exotics and combinations are developed. They are Call Options and Put Options.

A call option gives the person who owns it the right, but not the obligation, to purchase the underlying commodity at the predetermined price (strike price) during a specific time interval (time to expiration). The person who sold this call option has the obligation to deliver the underlying commodity if it is called away by the owner of the option.

A put option gives the owner the right, but not the obligation, to sell the underlying commodity at the predetermined price (strike price) during a specific time interval (time to expiration). The person who sold this put option has the obligation to deliver the underlying commodity if it is "put" to him by the owner.

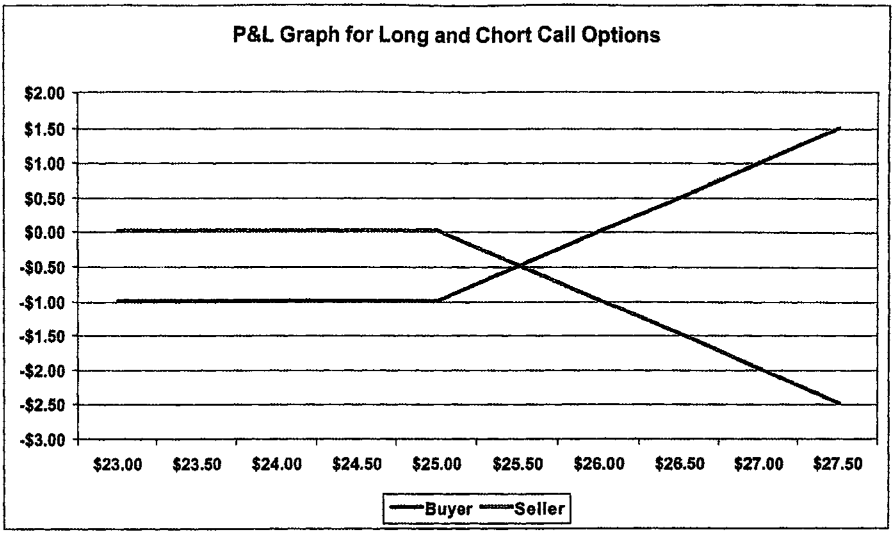
Observe the underlying P&L's of call and put options:

1. Assume that a $25.00 call option on June crude oil can be purchased for $1.00. The associated profit and loss for this option will be:
   BUYER SELLER

UNDERLYING	PROFIT	Less Premium Paid	P&L		PROFIT	Plus Premium Paid	P&L
23.00	0.00	-1.00	-1.00		0.00	1.00	1.00
23.50	0.00	-1.00	-1.00		0.00	1.00	1.00
24.00	0.00	-1.00	-1.00		0.00	1.00	1.00
24.50	0.00	-1.00	-1.00		0.00	1.00	1.00
25.00	0.00	-1.00	-1.00		0.00	1.00	1.00
25.50	0.50	-1.00	-0.50		-0.50	1.00	0.50
26.00	1.00	-1.00	0.00		-1.00	1.00	0.00
26.50	1.50	-1.00	+0.50		-1.50	1.00	-0.50
27.00	2.00	-1.00	+1.00		-2.00	1.00	-1.00
27.50	2.50	-1.00	+1.50		-2.50	1.00	-1.50

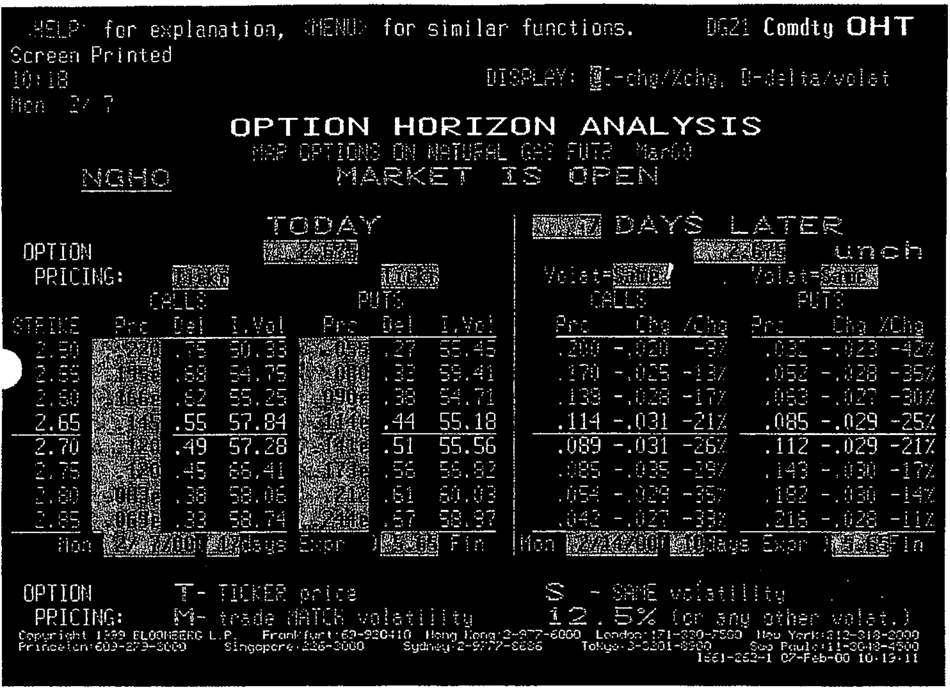
In this example, the person who buys the call option will only exercise it if the price of June crude oil is above $25.00. That is, the person who owns the $25.00 option will only "call away" or exercise his right but not obligation, to purchase crude oil at $25.00 if it is profitable to do so. If crude is trading for $23.00, it makes no economic sense to take delivery at $25.00. You could simply buy it in the market for $23.00, which is cheaper than exercising the $25.00 call option. The $1.00 premium paid for the option is "spent money" that is not taken into consideration when exercising the option. If crude is trading for $24.75, it STILL makes no sense to exercise the option, even though $1.00 in premium was paid. Since the $1.00 premium cannot be recouped, it still makes economic sense to purchase the commodity in the market at a cheaper price ($24.75) than to demand delivery at a higher price (the $25.00 strike). The breakeven price for the buyer is $26.00. At $26.00, the buyer gets to purchase crude oil by exercising the option at $25.00, has made a $1.00 profit ($26.00 market price less the $25.00 strike price) which nets out against the $1.00 premium paid to break even.

The person who sold the option gets to keep the $1.00 premium regardless of where the underlying commodity is trading. As long as prices are below $25.00, the seller (writer) of this option is fine. As prices start to climb above $25.00, the seller will have to go into the marketplace and purchase the underlying commodity to deliver. Regardless of how high prices get, the seller is contractually obligated to deliver crude oil to the buyer (holder) of the option at $25.00. The breakeven price for the seller of the option is $26.00. At $26.00, the seller of the option loses $1.00 (buys it at the market price of $26.00 but delivers it at the strike price of $25.00) which nets out against the $1.00 premium received for breakeven.



There are 5 basic underlying features to be discussed for any generic option. They are:

1. Strike Price: Strike price (or exercise price) is the price at which the underlying commodity will be delivered, if exercised.
2. Underlying Commodity Price: This is where the commodity on which options are being traded is currently priced.
3. Time to Expiration: The amount of time that remains until the life of the option has expired. Once an option has expired, it can no longer be exercised.
4. Interest Rates: The current risk-free market interest rate. Interest rates are less important for valuing commodity derivatives than they are for stock and bond options
5. Volatility: The amount of fluctuation the underlying commodity exhibits over time, usually measured in an annualized form. There are two main volatilities that traders frequently discuss: Historical volatility and implied volatility. Historical volatility is calculated using historical data, while implied volatility is what the market prices of options are "implying" what volatility will be in the future.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OPTION HORIZON ANALYSIS

NAP OPTIONS ON NATURAL GAS FUT2 Mar00

NGHO MARKET IS OPEN

TODAY | [illegible] DAYS LATER

OPTION PRICING: [illegible] [illegible] | [illegible] unch | Volat=[illegible] Volat=[illegible]

	CALLS			PUTS			CALLS			PUTS		
STRIKE	Prc	Del	I.Vol	Prc	Del	I.Vol	Prc	Chg	%Chg	Prc	Chg	%Chg
2.50	[illegible]	.75	50.33	[illegible]	.27	55.45	.200	-.020	-9%	.032	-.023	-42%
2.55	[illegible]	.68	54.75	[illegible]	.32	59.41	.170	-.025	-13%	.052	-.028	-35%
2.60	[illegible]	.62	55.25	[illegible]	.38	54.71	.139	-.028	-17%	.063	-.027	-30%
2.65	[illegible]	.55	57.84	[illegible]	.44	55.18	.114	-.031	-21%	.085	-.029	-25%
2.70	[illegible]	.49	57.28	[illegible]	.51	55.56	.089	-.031	-26%	.112	-.029	-21%
2.75	[illegible]	.45	66.41	[illegible]	.56	56.92	.085	-.035	-29%	.143	-.030	-17%
2.80	[illegible]	.38	58.06	[illegible]	.61	60.03	.054	-.029	-35%	.182	-.030	-14%
2.85	[illegible]	.33	58.74	[illegible]	.67	58.97	.042	-.027	-39%	.216	-.028	-11%

Mon [illegible] ([illegible] days Expr) [illegible] Fin | Mon [illegible] ([illegible] days Expr) [illegible] Fin

OPTION PRICING: T- TICKER price M- trade MATCH volatility S - SAME volatility 12.5% (or any other volat.)

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WHO TRADES ENERGY OPTIONS:

Hedgers: the hedgers include any market participant who wishes to reduce risk to energy prices. These include producers of energy who are at risk when prices drop and consumers of energy who are at risk when prices rise. They will buy or sell options to offset that risk. Utilities who produce power and consume natural gas need to hedge both those risks. Hedgers often trade buy using naked options such as buying puts or selling calls or both (collars) to protect against directional moves.

Speculators: Speculators include market participants who are using trades to profit from the various movements of the energy prices. These include hedge funds, banks, and some energy marketing companies. Speculators will buy naked options for directional plays which give them limited downside (cost of premium) and unlimited upside. Speculators will also bet on the direction of volatility by buying and selling straddles and strangles.

Arbitrageurs: Arbitrageurs include individuals who profit from inefficiencies of the market. These include market-making locals on the floor of the Futures and Options Exchanges (NYMEX), banks, and some energy marketing companies. Market makers will show bids and offers on every option and option spread accumulating complex positions that need micro-management. Traders will use derivative risk analysis to manage these portfolios. The main tools they use to gauge risk are often referred to as "Greeks".

TRADING DEFINITIONS OF GREEKS

DELTA:

Delta is traditionally defined as:

$$\frac{\Delta \text{ price of the option}}{\Delta \text{ price of the underlying}}$$

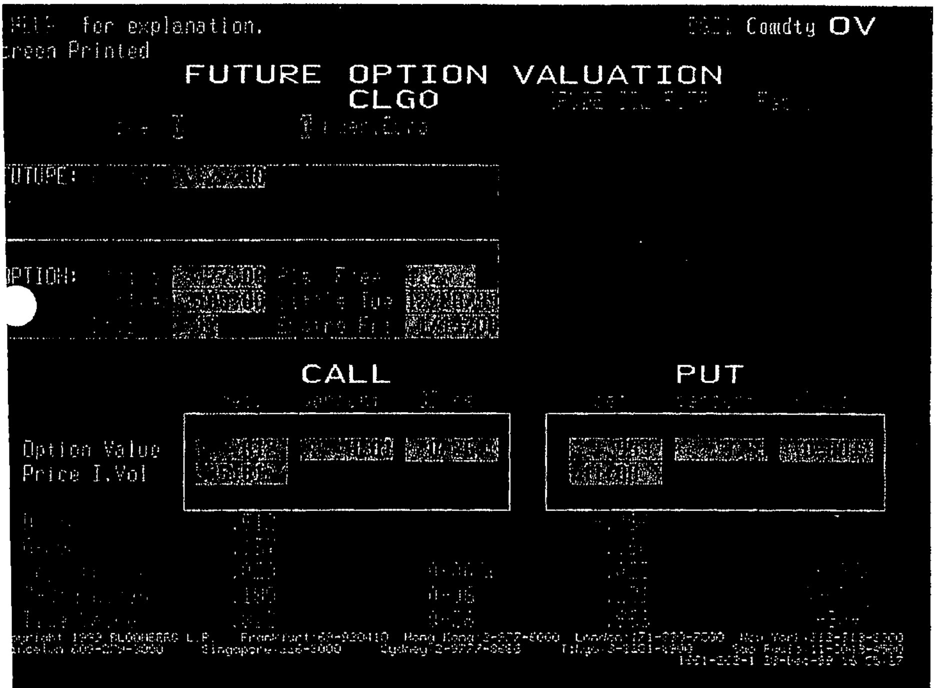
This is also the first derivative of the infamous Black-Scholes Equation. This mathematical definition is useful, but from a pure trading standpoint, we need to know quickly what effect an option and an underlying price change will have on our overall portfolio. To this extent, we must look at other definitions.

Additionally, delta can be defined as the amount of an underlying commodity that needs to be bought or sold in order to have a "price neutral" overall position. The delta of an option will ALWAYS be between -1.00 and 1.00. (Another rule of thumb to keep in mind is that the delta of an at-the-money option is always approximately equal to 0.50,; deep in-the-money options have a delta of approximately 1.00, and deep out-of-the money options have a delta of approximately 0). Taken as a percentage, it is multiplied by the number of options contracts to give the amount of the underlying that must be bought or sold in order to eliminate any P&L changes in the overall portfolio.

Delta can also be thought of as the probability of an option finishing "in the money". Simply put, prices of underlying contracts can do three things: go up, go down, or stay the same. Remembering that an at-the-money option has a delta of 0.50, this means that the option has a 50% chance of finishing in-the-money. An out-of-the-money option that has a delta of 0.33 has a one-third chance of finishing in-the-money.

These definitions should be simple to comprehend, but to actually grasp the concept of delta, we will walk through an example of putting on an option position, watching the underlying, and seeing how it affects the price of the option and how maintaining a "delta neutral" position insulates us from price movements.

Above is a six-month chart of crude oil. Assume that crude is currently trading \$27.00, and you wish to buy 100 of the \$27.00 (at-the-money) call option. You wish to remain "delta neutral", so you also will be putting on a hedge for your option in the underlying crude oil commodity. The valuation of the \$27.00 call option and the associated greeks are:



The $27.00 call option would cost you:

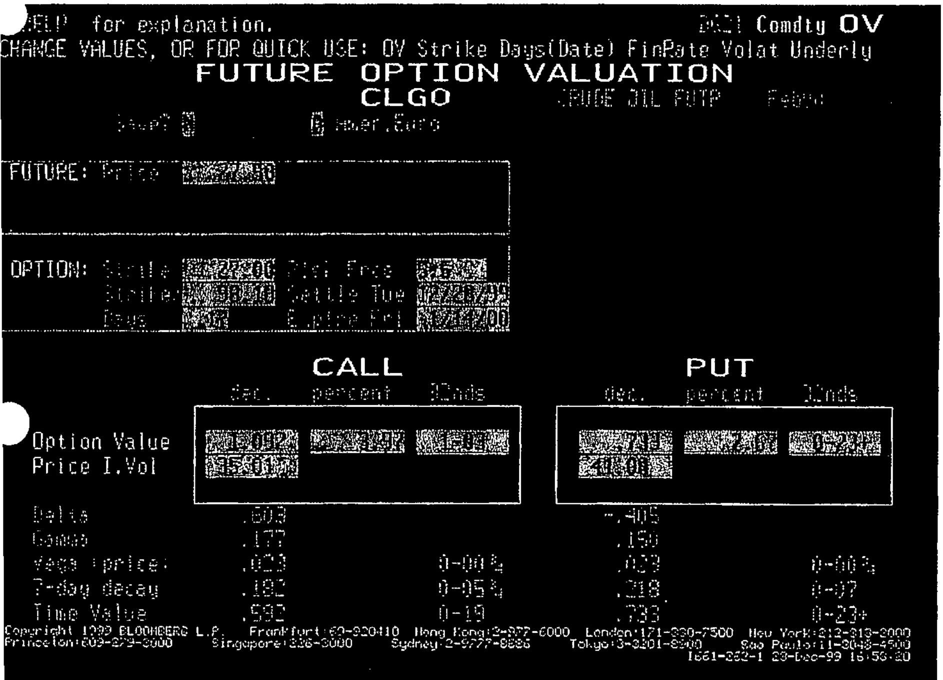
$0.812 per contract x 100 contracts x 1,000 barrels of crude oil per contract = $81,200.00 for the entire call option position. In order to remain delta neutral, we must sell enough of the underlying in order o cover our price exposure. This is calculated as:

100 call option contracts x 0.512 delta = 51 contracts (round off to the nearest contract). For illustrative purposes, we will assume that we can sell the required delta position at $27.00.

We now have a delta neutral position on, which consists of long 100 $27.00 call options and short 51 underlying crude oil contracts. A tabular summary, which will be useful for tracking changes of our overall position, is:

Underlying	Option Premium	Delta	Gamma	Total Option Value	Change in Option Value from $27.00 ATM	Underlying Sold	P&L on Underlying sold
$27.00	$81,200	0.51	0.187	$81,200	0	51	0

Now, let's see if we truly are neutral by examining if price and only price moves from $27.00 to $27.50. (In a real world environment, implied volatility and time to expiry would also be changing. For illustrative purposes only, all other variables except underlying price are held constant. Additionally, other factors such as interest rates, margin and variation are also ignored in order to focus on the delta effects).



Underlying	Option Premium	Delta	Gamma	Total Option Value	Change in Option Value from $27.00 ATM	Underlying Sold	P&L on Underlying sold
$27.00	0.8120	0.51	0.187	$81,200	0	51	-$25,500
27.50	1.092	0.603	0.177	$109,200	+$28,000	9	0

Here's how the calculations are done. The initial price paid for the option ($0.812, or $81,200) stays the same. The original 51 lots sold at $27.00 as the initial delta hedge stay in place – you've already sold them, and they are gone.

When the price of the underlying moves up to $27.50, the option is then worth $109,200 (the $1.092,000 premium times 100 contracts times 1,000 barrels per lot). Therefore, the option has gained $28,000 (the original valuation at $27.00 of $81,200 is now worth $109,200 at $27.50).

However, the hedge has lost money. The 51 lots sold at $27.00 have lost ($27.00 - $27.50) x 51 contracts for a delta hedge at $27.00 times 1,000 barrels per contract = $25,500.

Therefore, the hedge has accomplished what we wanted it to do. It has offset the gain in value of the option. In a delta neutral position, the gain or loss in the option premium should be exactly offset by the loss or gain in the underlying as a delta hedge.

The next logical question is why the option gain is not EXACTLY equal to the hedge loss. The reason is that the delta for the option is precise for one and only one price. At $27.00, the delta of the option is exactly 0.512. As prices move up, the delta gets greater. This is illustrated by the fact that the delta of the option at $27.50 is now 0.603. This means that you should have already been selling contracts every few cents as prices moved up in order to stay perfectly neutral. As prices moved from $27.00 to $27.50, you should have been selling an extra 9 lots (the difference between the 51 original delta at $27.00 and the 60 delta at $27.50).

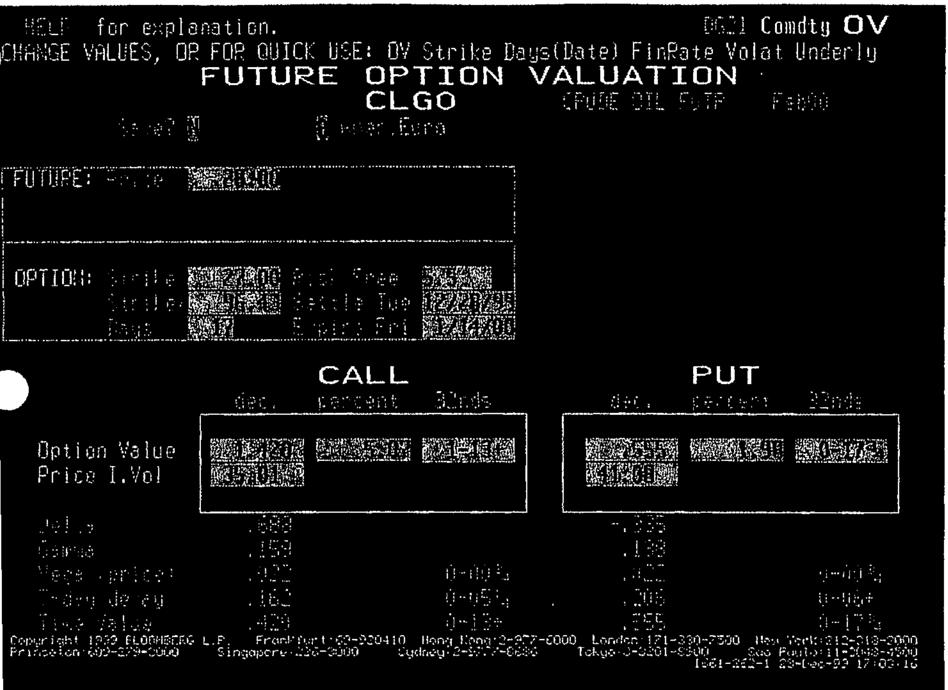
An approximate way to account for this difference is to say that as prices moved from $27.00 to $27.50, we were selling 9 lots. Factor in to the P&L that 9 lots were sold at an average of $27.25 ($27.50 - $27.00), and you have an additional loss on a perfectly neutral position of 9 lots x 1,000 barrels per lot x ($27.25 average sale price - $27.50 current market price) = $2,250. Add this to the original calculated loss of $25,500, and we are very close to being price neutral as compared to the $28,000 option premium gain.

The exact formula for the difference in the $28,000 gain in the option premium versus the $25,500 loss in the underlying delta hedge is:

Price Change = $[(\Delta) + ½(\Gamma^2)]$

But for purposes of trading, making quick decisions, and figuring out in your head what is happening to your portfolio, using the raw delta or the raw delta and the average sales method will work fine. Sophisticated options trading software and options portfolio software will give you more precise and faster calculations if needed.

Following through with the same example, we will now examine a move up to $28.00.



Underlying	Option Premium	Delta	Gamma	Total Option Value	Change in Option Value from $27.00 ATM	Underlying Sold	P&L on Underlying sold
$27.00	0.8120	0.51	0.187	$81,200	0	51	-$51,000
$27.50	1.092	0.603	0.177	$109,200	+$28,000	9	-$6,750
$28.00	1.420	0.688	0.159	$142,000	+$60,800	9	0

To reinforce the concepts one more time, we will walk through the basic math.

From $27.00 to $28.00, the option premium moved up from $0.812 to $1.420, for a gain of $60.800 (100 options x 1,000 barrels per contract x $1.420 - $0.812). The hedge lost approximately $57.750 (the original 51 lot delta hedge lost $1.00 times 1,000 barrels for $51,000. The delta hedge adjustment of 9 lots laid out in the marketplace at an average of $27.25 less the current market of $28.00 x 1,000 barrels per contract gives an additional loss of $6,750)

Again, the numbers are not exact due to the technique of using algebraic approximations instead of precise mathematical equations. When quickness counts, close is good enough.

This is a simple, brief yet accurate example of how a trader or a portfolio manager would think of option delta's. It is:

- When I put on an options position, what must I buy or sell to be hedged?
- What is the option going to act like in terms of underlying contracts?
- What happens to my option price as the underlying moves up or down?
- What adjustments must I make to my underlying position to remain neutral as prices move?

OPTION GAMMA

Gamma is traditionally defined as the second derivative of the Black-Scholes equation, or:

$$\Gamma = \frac{\text{Change in delta}}{\text{Change in underlying}}$$

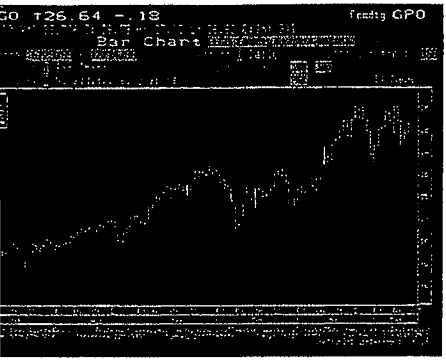
Expressed in simple terms, gamma is how quickly your delta will change. When trying to maintain a delta neutral position, it is the gamma that will tell you how much you need to adjust your underlying sales and/or purchases in order to remain insulated from price movements.

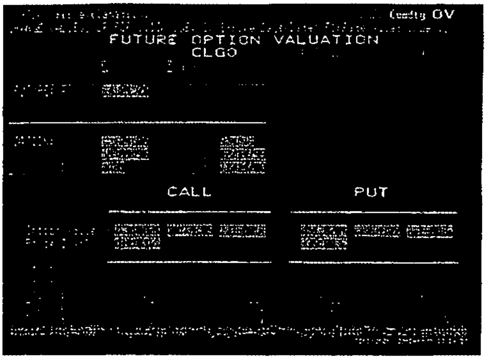
"Scalping gamma" is a technique that you will hear about, and if correctly performed can be profitable. It involves putting on an options position, and trading in and out of the underlying (buying and selling). If you are long the original options position, (call or put), the option will provide protection against loss on the underlying. If you are short the original option position, the underlying will provide you protection against loss on the underlying.

Gamma scalping involves the basic principle of mean reversion – that volatility will revert back to some mean or average value over a certain period. If it is possible to have perfect knowledge, then the implied volatility of an option, after the time period of that option has expired, will exactly match the price movements for that period. This means that the person who buys an option, which of course involves paying a premium for it, will exactly make up the money spent on that premium (no more or no less) by scalping gamma. The volatility expected (implied) is realized, and the option was perfectly priced. The person who sold this "perfectly priced" option will receive premium. This money received will be lost by the seller in scalping gamma (trying to stay neutral by selling in a falling market and buying in a rising market). The seller, just like the buyer, will break even on "perfectly priced" options.

Using the principle of mean reversion and the point that perfectly priced options are when implied volatility is actually realized, the logical question is "Wonderful, but how can I make money?" To demonstrate this, we will take a look at 10 trading days and demonstrate gamma scalping to see what happens.

Going back to the crude oil example, we will purchase 1,000 $24.75 call options that expire on February.

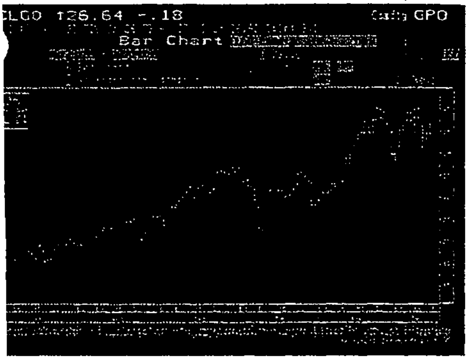


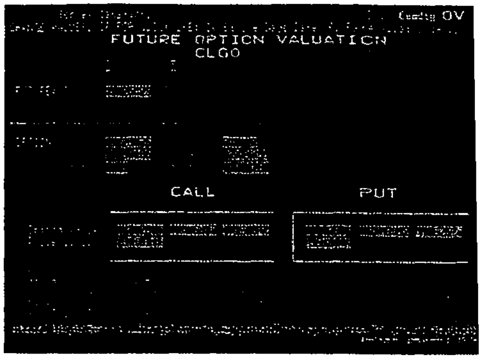


Date[1]	Close[2]	Premium[3]	Option Value[4]	Option P&L[5]	Delta[6]	Gamma[7]	Underlying Trade[8]	Underlying P&L[9]
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	0

1. Assumption is that the options were purchased at the opening on 14Dec99.
2. Assume that the opening price of $24.75 for the call options is ATM, since the difference from the opening price of $24.76 is immateria l.
3. Premium is calculated using the Black model from Bloomberg analytics. Any commercially available software package should yield similar results.
4. Option value is calculated as 1,000 $24.75 Feb '00 call options x 1,000 contracts per option x $1.002 per option premium.
5. Since the option was just purchased (on the opening), there is no P&L yet.
6. See #3.
7. See #3
8. In order to be delta neutral at the start of this trade, you must simultaneously sell 517 Feb contracts (1,000 call option position x 0.517 delta).
9. It is assumed that the underlying delta hedge was "crossed" (sold at the same price as the strike -- $24.75) which was AM at the time of initiation. Since no price movement has yet occurred, there is no P&L change.

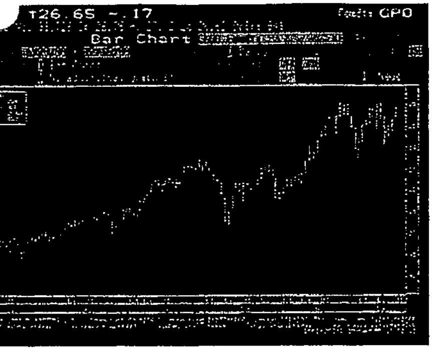
Now that the position of long 1,000 Feb '00 $24.75 call options and the associated delta hedge has been established, we will walk through ten days of gamma scalping. For ease of illustration, we will assume that all scalps (position adjustments due to gamma) are done on the market close and incur no slippage).

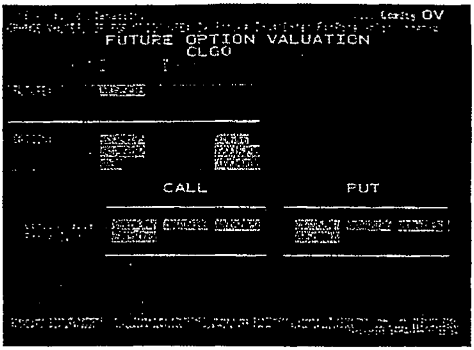




Date	Close	Premium	Option Value	Option P&L[1]	Delta	Gamma	Underlying Trade[2]	Underlying P&L[3]
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-279,180
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	0
Total				296,000			-597	-279,000

1. Option P&L is calculated as the difference between the initial payment and the current market value. Current market value is calculated as 1,000 Feb '00 call options x 1,000 barrels per contract x option premium.
2. Underlying trade is determined as the amount of underlying February contracts to be sold in order to be neutral. With 517 contracts sold of the open, and a delta on the close of 597, an additional 80 contracts must be sold in order to remain neutral.
3. Each successive trade will be individually marked to market. The initial delta hedge of selling 517 contracts at $24.75 is now valued at –279,180. (517 contracts sold on the open x 1,000 barrels per contract x $24.75 – closing price of $25.29).

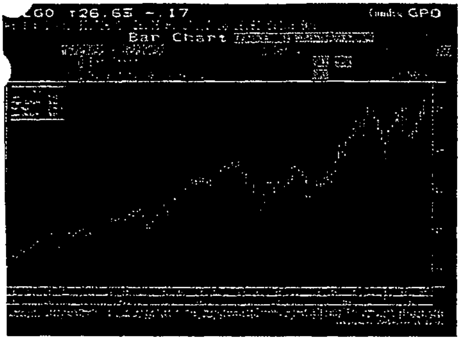


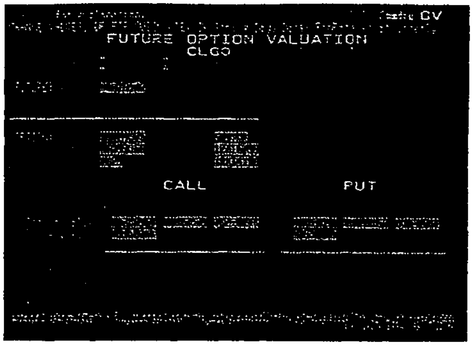


Date	Close	Premium	Option Value	Option P&L[1]	Delta	Gamma	Underlying Trade[2]	Underlying P&L[3]
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-558,360
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-43,200
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	0
Total				632,000			-671	-601,560

1. Option P&L calculation remains the same. It is marked to market each day using the options calculation, and then compared to the previous day's value to obtain a P&L. Note that the P&L change from 14Dec99 to 15Dec99 is +$336,000 ($1,634,000 - $1,298,000). Also note that the *sum* of the P&L changes to date (+$632,000) is equal to the P&L change for the entire term at this time (from the 14Dec99 initiation of the trade to the close of 15Dec99).
2. In order to be hedged on the close of 15Dec99, we must be short 617 contracts (1,000 options x 0.617 delta as of 15Dec99). We are already short 517 from trade initiation, and an additional short of 80 from the close of 14Dec00, making a total short of 597. In order to get to the hedged short position of 671, sell an additional 74 lots.
3. Each individual trade will be marked to market. A quick summary of marking individual trades to market is:

Date	Transaction	Price	Reval	P&L
Initiated	Sold 517	24.75	25.83	-558,360
14Dec99	Sold 80	25.29	25.83	-43,000
15Dec99	Sold 74	25.83	25.83	0
Total				





Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-863,390
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-90,400
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-43,660
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	0
Total				1,044,000			-718	-997,450

At this point, the trader has several possible scenarios. He can:

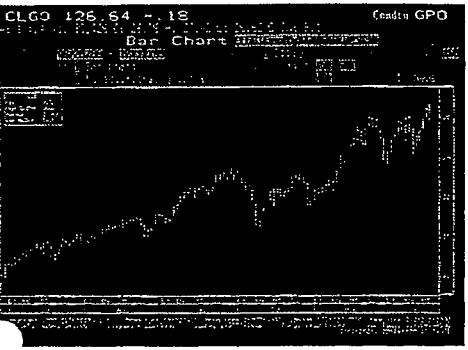
1. Maintain his current position, and continue to scalp the underlying.
2. Close out the entire position by selling out the long call options for $1,044,000 and buying back the underlying short position for -997,450. The resulting net profit of +$46,550 is decent for 3 days of trading (averaged over a 250 day trading year, this results in an individual P&L of almost $4 million).
3. Close out a partial position. The trader can sell out a portion of the call options (say 500) and buy back a pro-rata portion of the underlying hedge (50% of 718 shorts = 359). This would book about half of the current profits on the trade. Under normal circumstances, if the trader carefully remains delta neutral, he should at worst break even on the remaining days and keep this profit.
4. "Take a view" and assume that prices have broken out of a range to the upside. In this case, he could buy back some or all o f the underlying hedges sold in anticipation of prices going higher. He could then reset his sales at a better price level. Note that if some of the underlying is bought back, it is the same as remaining in the original long 1,000 call position *and* going naked long the underlying. For example:

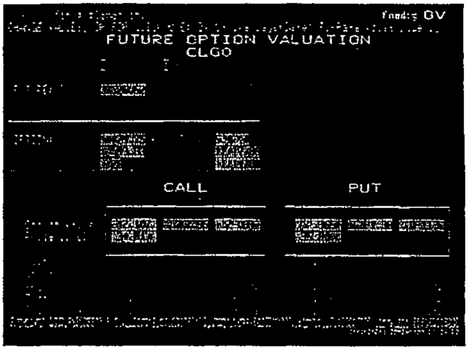
Hedged Position =	+ 1,000 $24.75 call options	and	-718 underlying
"Take a View" =	+ 1,000 $24.75 call options	and	-500 underlying.

   This "Take a View" position will act just like the Hedged Position plus being long 218 underlying (718 desired hedge short less the 218 bought back).

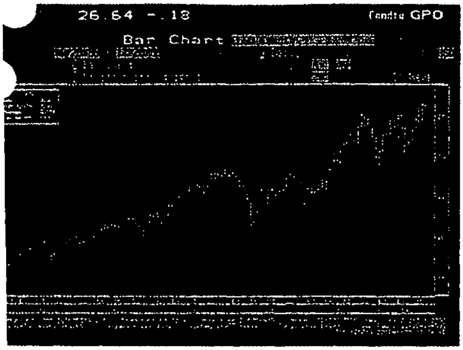
5. "Take a view" and sell out some or all of the call options, and stay short the underlying in anticipation of prices falling off dramatically.

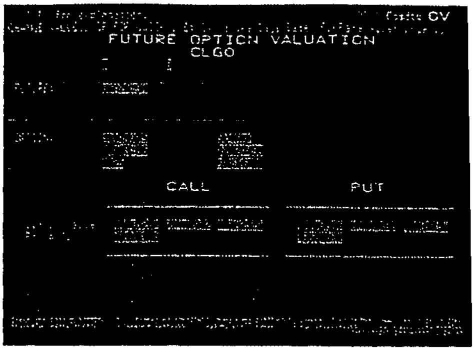
At this point it is up to the individual discretion of the trader. If he thinks volatility is high, he may wish to sell out partial positions. If he thinks prices will continue to go up, he may buy back partial shorts. If he thinks prices will go down, he may stay short the underlying and sell out some or all of the underlying. Or, if he thinks volatility is still cheap or just wishes to remain in a hedged trade, he may continue to do what he has been doing. In order to illustrate further, we will continue with the example.





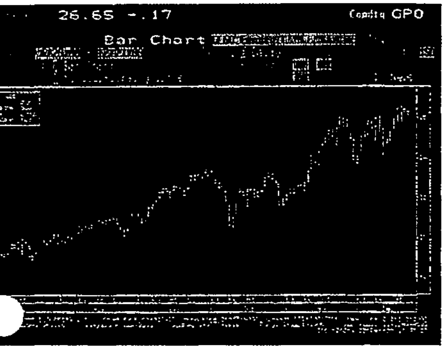
Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-915,090
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-98,400
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-51,060
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	-7,700
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	0
Total				1,105,000			-765	-1,072,250

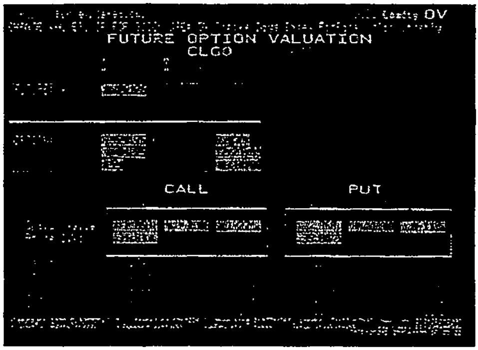




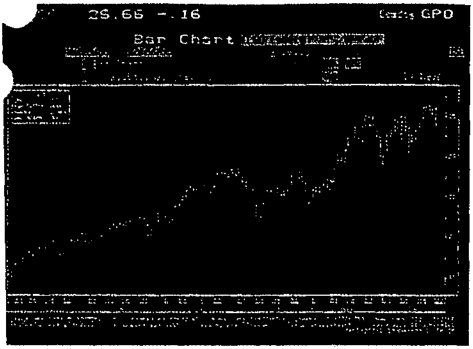
Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-822,030
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-84,000
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-37,740
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	6,160
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	3060
20Dec99	26.34	1.928	1,928,000	-179,000	0.753	0.124	12	0
Total				926,000			-753	-934,550

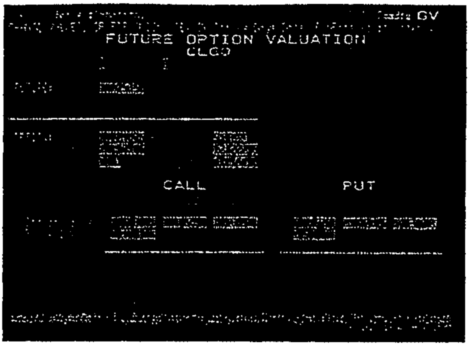
Notice now that as prices come off, we are losing money on a mark to market basis on our options position but gaining money on the contracts that we sold short as a hedge. This particular trade is shaping up to be less volatile than anticipated. The time period chosen was close to a holiday which is typically more volatile than other periods due to lack of liquidity, people being on vacation, traders marking and closing their books for year end. Additionally, crude oil is typically more volatile during this time period due to the influences of weather, which is extremely volatile. However, this trade is not yet shaping up to be extremely volatile.



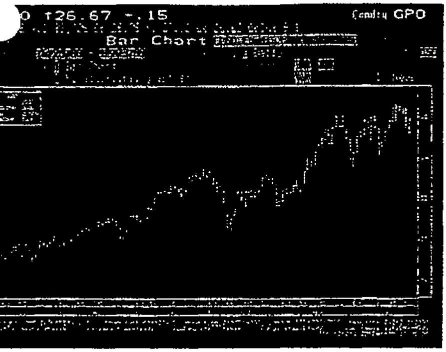


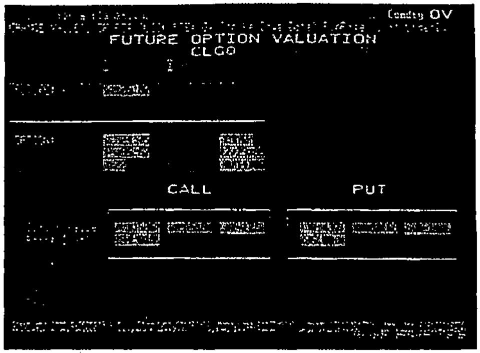
Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-780,670
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-77,600
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-31,820
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	12,320
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	4,420
20Dec99	26.34	1.928	1,928,000	-179,000	0.753	0.124	12	-960
21Dec99	26.26	1.853	1,853,000	-75,000	0.746	0.129	7	0
Total				851,000			-746	-874,310



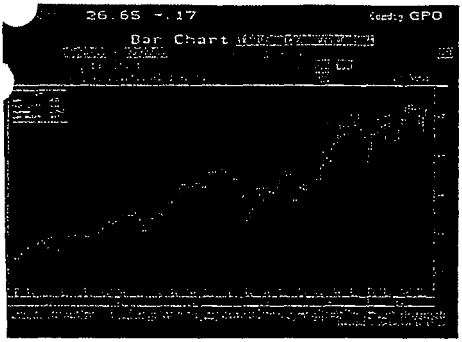


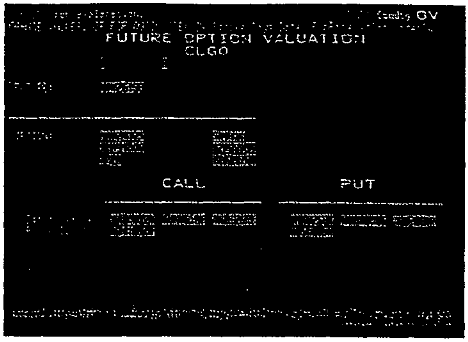
Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-357,750
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-16,800
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	24,420
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	70,840
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	17,340
20Dec99	26.34	1.928	1,928,000	-179,000	0.753	0.124	12	-10,080
21Dec99	26.26	1.853	1,853,000	-75,000	0.746	0.129	7	-5,320
22dec99	25.50	1.300	1,300,000	-553,000	0.637	0.158	109	0
Total				298,800			-637	-307,350



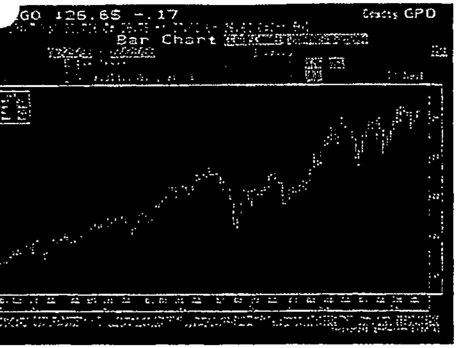


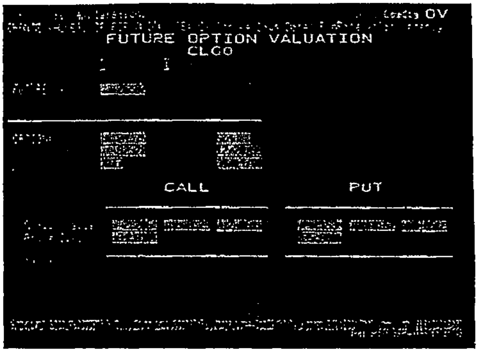
Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-579,040
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-46,400
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-2960
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	42,350
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	11,050
20Dec99	26.34	1.928	1,928,000	-179,000	0.753	0.124	12	-5,640
21Dec99	26.26	1.853	1,853,000	-75,000	0.746	0.129	7	-2,730
22dec99	25.50	1.300	1,300,000	-553,000	0.637	0.158	109	40,330
23Dec99	25.87	1.531	1,531,000	231,000	0.699	0.153	-62	0
Total				529,000			-699	-543,040





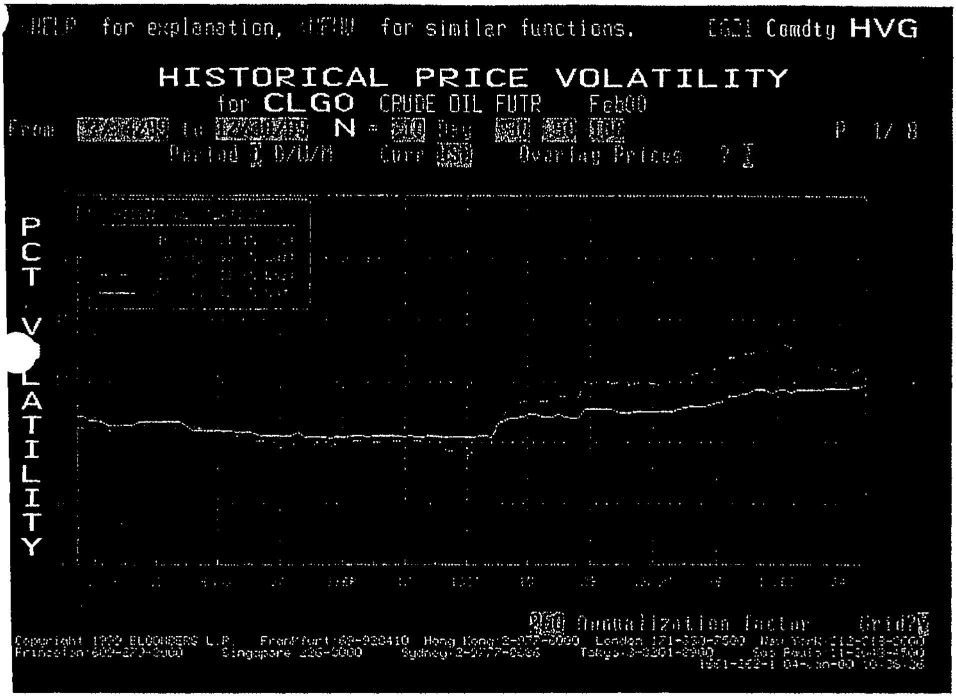
Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-816,860
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-83,200
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-37,000
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	6,930
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	3,230
20Dec99	26.34	1.928	1,928,000	-179,000	0.753	0.124	12	-120
21Dec99	26.26	1.853	1,853,000	-75,000	0.746	0.129	7	490
22dec99	25.50	1.300	1,300,000	-553,000	0.637	0.158	109	90,470
23Dec99	25.87	1.531	1,531,000	231,000	0.699	0.153	-62	-28,520
27Dec99	26.33	1.814	1,814,000	283,000	0.784	0.139	-85	0
Total				812,000			-784	-864,580





Date	Close	Premium	Option Value	Option P&L	Delta	Gamma	Underlying Trade	Underlying P&L
Initiated	24.76	1.002	1,002,000	0	0.517	0.152	-517	-1,070,190
14Dec99	25.29	1.298	1,298,000	296,000	0.597	0.143	-80	-122,400
15Dec99	25.83	1.634	1,634,000	336,000	0.671	0.132	-74	-73,260
16Dec99	26.42	2.046	2,046,000	412,000	0.718	01666	-77	-30,800
17Dec99	26.52	2.107	2,107,000	61,000	0.765	0.114	-17	-5,100
20Dec99	26.34	1.928	1,928,000	-179,000	0.753	0.124	12	5760
21Dec99	26.26	1.853	1,853,000	-75,000	0.746	0.129	7	3920
22dec99	25.50	1.300	1,300,000	-553,000	0.637	0.158	109	143,880
23Dec99	25.87	1.531	1,531,000	231,000	0.699	0.153	-62	-58,900
27Dec99	26.33	1.814	1,814,000	283,000	0.784	0.139	-85	-41,650
28Dec99	26.82	2.206	2,206,000	392,000	0.851	0.112	-67	0
Total				1,204,000			-851	-1,248,740

Notice that after the end of ten trading days, the buyer/hedger of the call options is losing money (+$1,204,000 on the option less -$1,248,740 on the underlying hedges) while the seller of the options, performing exactly the same hedging program, would have gained the equal and opposite amount that the buyer lost ($44,740). This indicates that when volatility was purchased, it was expensive. Again, if volatility is "cheap", then the individual who scalps gamma will make more money on hedges than is spent on option premium. If volatility is expensive, then the seller will lose less money scalping negative gamma then he received by selling the options.



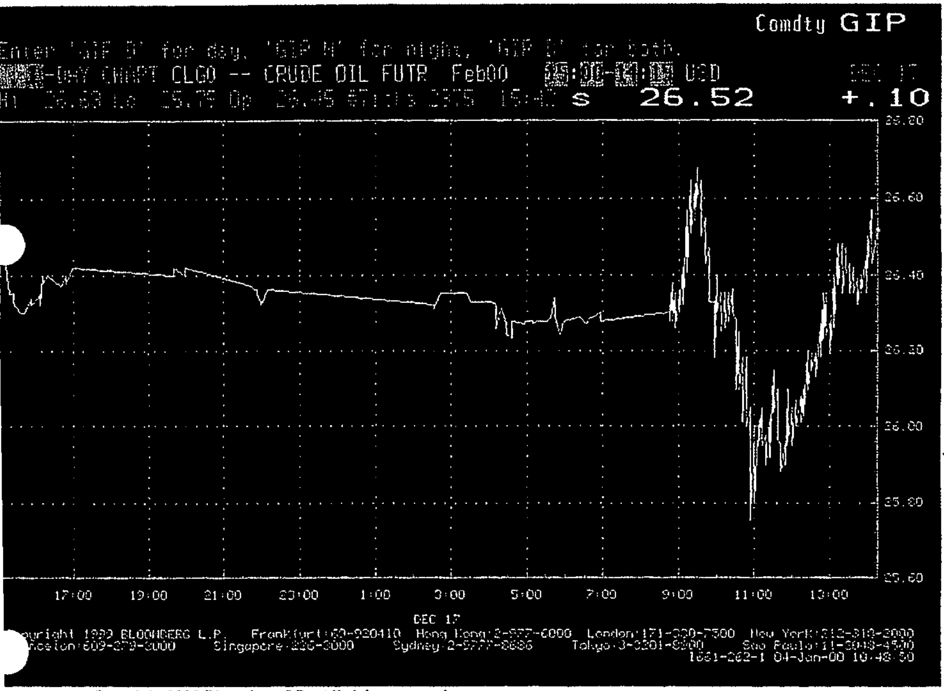
An additional factor comes into play – it is possible to perform "multiple scalps" intraday. Specifically, if crude oil would move violently up and down several times in the same day, we can buy every time it hits the bottom of the range and sell every time it gets near the top of the range.

For example, 17 Dec 99 was a particularly volatile day. The trader who is "on his game" would start the day with an "order board" telling him where he wants to be a buyer and where he'd like to sell based on maintaining a dynamic neutral overall position. Using again a simple Black equation, the order board for this day would look like:

PRICE	ORDER
26.60	-773
26.50	-764
26.42	-751
26.40	-749
26.30	-735
26.20	-722
26.10	-710

26.00	-699
25.90	-687
25.80	-672

Here's what actually happened that day:



Here's the intraday transactions that would have occurred, and the resulting P&L:

Hedge Level	Trade Amount	Trade Price	MTM P&L
-751	-33	26.42	-3300
-764	-13	26.50	-260
-773	-9	26.60	720
-764	9	26.50	180
-749	15	26.40	1800
-735	14	26.30	3080
-722	13	26.20	4160
-735	-13	26.30	-2860

-749	-14	26.40	-1680
-735	14	26.30	3080
-722	13	26.20	4160
-710	12	26.10	5040
-699	11	26.00	5720
-710	-11	26.10	-4620
-699	11	26.00	5720
-687	12	25.90	7440
-672	15	25.80	10800
-687	-15	25.90	-9300
-672	15	25.80	10800
-687	-15	25.90	-9300
-699	-12	26.00	-6240
-687	12	25.90	7440
-699	-12	26.00	-6240
-710	11	26.10	-4620
-699	11	26.00	5720
-687	12	25.90	7440
-699	-12	26.00	-6240
-710	-11	26.10	-4620
-722	-12	26.20	-3840
-735	-13	26.30	-2860
-722	13	26.20	4160
-735	-13	26.30	-2860
-749	-14	26.40	-1680
-764	-15	26.50	-300
Total:	**-46**		**16640**

As compared to the "end-of-day" trading example, we would have made +$16,000 as compared to the intraday scalping example. This is just another way to make money. Once again, in extremely volatile markets you can take advantage of these price movements by dynamically hedging options positions. In slowly trending or stagnant markets, the option buyer will find it difficult to make money.

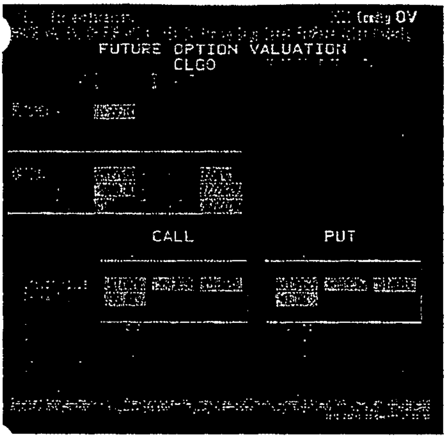
THETA

Theta is defined as:

Change in option Value
One-day change in time to expiration

Options prices decline as expiration approaches. The rate of decline is more rapid towards the end of he option's life than at the beginning (more time for it to finish in the money). This rate of decay is not linear. It is related to the square root of the time remaining. For example, all other factors being equal, a 3 month option loses value at twice the rate of a 9 month option (since the square root of 9 = 3), and a 2 month option loses value at twice the rate of a 4 month option (square root of 4 = 2).

This principle of decay is why writing options is popular. Premium can be collected, and this money "banks" itself at the rate of theta each day. The buyer of the options has the opposite problem on his hands. This is why a popular technique for options buyers is a "time stop". Time stops are trade exit points based on theta. Traders who buy pure options (and do not delta hedge or trade volatility) will decide a certain date to exit the options position. This date is somewhat based on the time decay curve for that particular option. Since theta kicks into high gear as the option draws towards expiry, the trader will pick a point where he does not want to bleed out any more money, and will sell out the long option position.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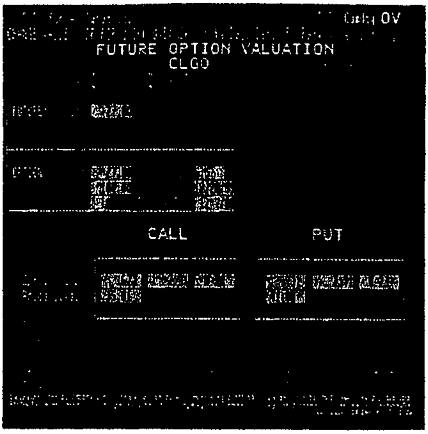
CLGO
CALL
PUT


OV
FUTURE OPTION VALUATION
CLGO
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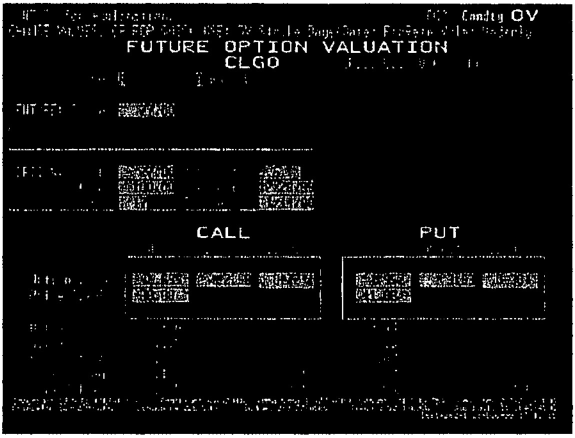
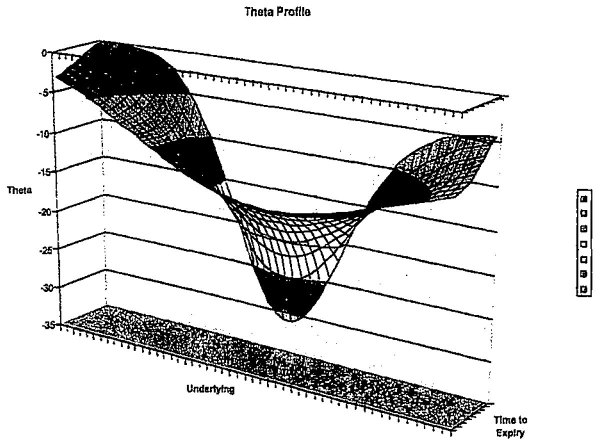
PUT


OV
FUTURE OPTION VALUATION
CLGO
CALL
PUT

Expiry	Remaining	Und.	Premium	Vol	Delta	Gamma	Vega	T	T-7
1/27/00	30	27.00	1.760	35.01	0.516	0.141	0.031		0.133
1/14/00	17	27.00	0.0.695	35.01	0.510	0.219	0.023		0.161
1/7/00	10	27.00	0.623	35.01	0.510	0.244	0.018		0.281



A simple example of applying theta to an option premium:
Given:

- Long ATM 2.5 Call
- 35% Volatility
- 9.5% Interest Rates
- Days to maturity @ 73 days

Theta is -. 49833; therefore, a 10 day passage of time would reduce the option value by $.02 (10/255 * -. 49833).

General remarks regarding theta:

1. Theta has the greatest impact on option value erosion when the option stays at-the-money. With no price movement, the "asset" purchased (option) merely wastes away. The maximum time value an option has is obtained at-the-money, while deep out of the money and deep in the money have less theta erosion.
2. Theta is a greek that cannot be hedged, however you can combine other options in order to create strategies that will minimize theta erosion. (see next example)
3. "Gamma Scalping" requires you to pay for the long gamma through theta, remember: "you pay for getting long gamma." The buyer of an option is purchasing volatility – no volatility means no price movement, and no chance to scalp gamma, which results in a wasting asset.

Getting Paid Gamma (Calendar Call Spread)

This is a simple example to illustrate the notion of getting paid gamma. The option strategy is as follows:

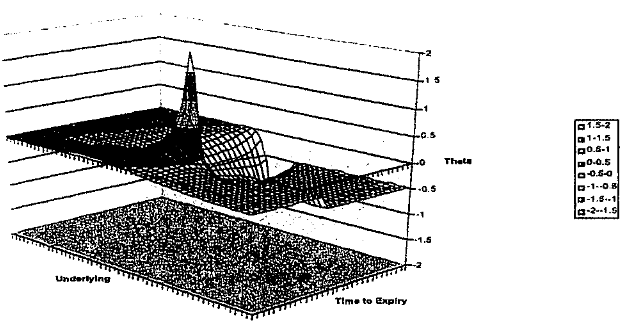
- Long ATM 2.5 Call
- 35% Volatility
- 9.5% Interest Rates
- Days to maturity @ 67 days

- Short ATM 2.5 Call
- 20% Volatility
- 9.5% Interest Rates
- Days to maturity @ 159 days

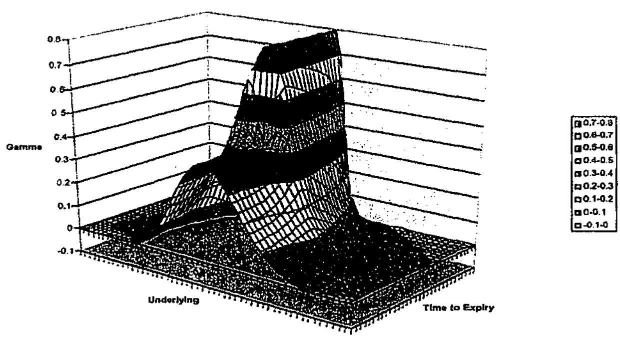
Gamma at inception: .389001
Theta at inception: -. 01556, theta is negative but negligible, and will become positive with the passage of time.

This is a simple example that illustrates getting paid gamma, the major assumption in this example is that the near contract trades and the distant contract is trading flat, which is not an invalid assumption to make.

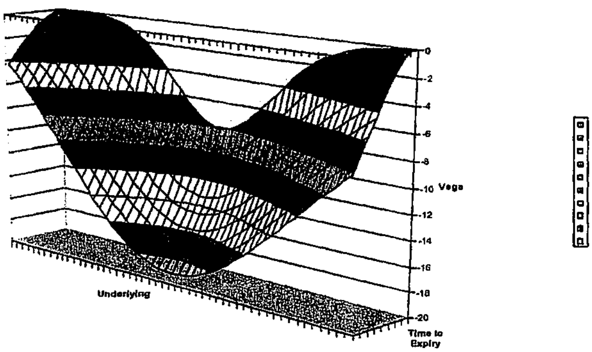
Theta Profile



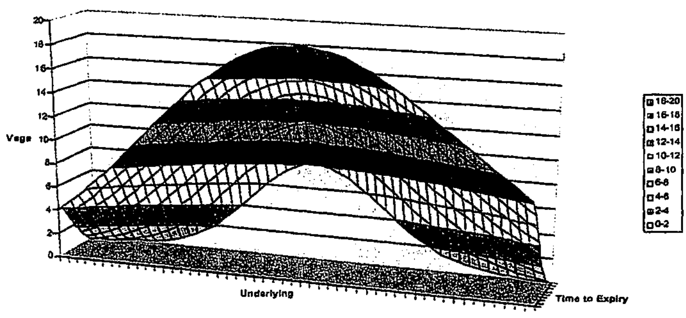
Gamma Profile



Short Vega Profile



Long Vega Profile



Vega is:

V = E Option Value/ E Volatility.

This number can be derived from the Black-Scholes Differential Equation as the partial derivative of the equation with respect to volatility, and is stated in percentage terms. The easiest way to understand vega from a trader's perspective is to work though a straddle (long a call and long a put at the same strike). Generically, it is:

I. Long Straddle
- Buy an ATM k1 Call
- Buy an ATM k2 Put
  Where k1=k2

II. Short Straddle
- Sell an ATM k1 Call
- Sell an ATM k2 Put
  Where k1=k2

Given:
- Long an ATM 2.5 Call/Put
- 35% Volatility
- 9.5% Interest Rates
- Days to maturity @ 73 days

Vega is .891024; therefore, a small % change in volatility, (assume 1%), will increase the option value by roughly $ .01 (.01*. 891024). **Remember**: When dealing with changes in greeks, those changes have to be considered small. Why is the straddle an energy volatility trader's option strategy of choice? Basically, at-the-money straddles are delta neutral. In this example the delta is .05112 (-. 47444 long put, .525563 long call), therefore the straddle has greater exposure to vega and rho. The type of market traded determines which greek receives the greatest emphasisIn the energy markets, moves in volatility will have greater option value impact than interest rates. Straddles like any other option strategy engineered to neutralize specific greeks will be greek neutral only for a short period of time. Straddles can also be utilized to take advantage of the underlying commodity making a substantial upward or downward move, i.e. prior to some economic report being released to the public. A specific trading example using a greek book to track PNL of a natural gas straddle position is:

Given:

Trade Date	Expiry	Strike	Price	Implied Vol	Interest Rates
1/10/00	3/28/00	2.500	2.500	0.35	0.095
1/15/00	3/28/00	2.500	2.485	0.32	0.095
1/20/00	3/28/00	2.500	2.450	0.33	0.095
1/25/00	3/28/00	2.500	2.550	0.45	0.095
1/30/00	3/28/00	2.500	2.560	0.47	0.095
2/4/00	3/28/00	2.500	2.510	0.48	0.095

Option Value/ Greek Table

Shows a hypothetical gas straddle position going forward in time.

Trade Date	Option	Delta	Gamma	Vega	Theta

	Value				
1/10/00	0.315907	0.064477	0.795278	0.9190938	-0.737649707
1/15/00	0.279256	0.023536	0.797537	0.8863239	-0.687981418
1/20/00	0.278878	-0.0563	0.795898	0.8416495	-0.70604977
1/25/00	0.372053	0.15805	0.782179	0.8286484	-1.08252219
1/30/00	0.37496	0.174334	0.778762	0.7947169	-1.181432003
2/4/00	0.360154	0.090191	0.792782	0.7582612	-1.240273693

Changes Matrix

Changes				
Trade Date	Option Value	Underlying	Volatility	Time
1/15/00	-0.03665	-0.015	-0.03	5
1/20/00	-0.00038	-0.035	0.01	5
1/25/00	0.093174	0.1	0.12	5
1/30/00	0.002908	0.01	0.02	5
2/4/00	-0.01481	-0.05	0.01	5

Greek PNL Approximation Matrix (Greek Book)

Trade Date	Delta ($)	Gamma ($)	Vega ($)	Theta ($)
1/15/00	-0.00097	8.94688E-05	-0.02757	-0.014464
1/20/00	-0.00082	0.000488492	0.008863	-0.01349
1/25/00	-0.00563	0.003979488	0.100998	-0.013844
1/30/00	0.00158	3.9109E-05	0.016573	-0.021226
2/4/00	-0.00872	0.000973453	0.007947	-0.023165

The greek PNL Approximation matrix is designed to demonstrate that the option strategy (straddle) has the greatest PNL impact from the changes in volatility and theta. Note that the greeks will give an approximate PNL value, because the example illustrates relatively large changes for the greek book.

Be aware that you are fighting theta with this type of strategy, and on the same note remember that you can loose theta (or gain if you short the straddle) over weekends.

The greatest impact on the overall PNL for this position comes from changes in volatility. So at this point it should become evident that you can trade volatility the same as any other tradable commodity, and take directional outlooks on the underlying volatility the same as you would take directional plays on the underlying itself.

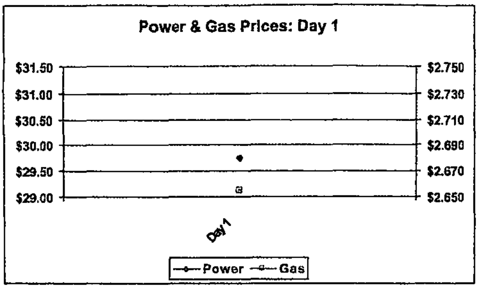
The above example greatly simplifies what a "pure" volatility trader would do on a daily basis. The true options (volatility) trader would have on myriad positions at different strikes, time frames and amounts. This results in a highly complex set of aggregate greeks, with an equally complex set of changes and P&L ramifications every day. Commercially available option software is indispensable in tracking, graphing and reporting multiple option positions.

Dual Variable Options:

A gas-fired generator is an example of a *dual variable option.* The asset owner has the choice to buy gas, run it through the generator, produce electricity, and then sell the resulting power at market.

The owner is subjected to P&L swings based on price moves (as is the buyer of any standard option). In the case of the dual variable option, the buyer is subjected to relative price changes between gas and electricity.

As the relationship between gas and power prices moves closer (compresses), the option has less value, and as it widens, the option has more intrinsic value. This price movement again creates opportunities to make money. As is the case with a standard call option and the chance to scalp gamma, the dual variable option creates the potential to scalp gamma - in this instance, from two commodities.



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.655
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$28.45
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.226
Delta1 (Power)	0.618
Delta2 (Gas)	0.494
Gamma1 (Power)	0.041
Gamma2 (Gas)	0.045

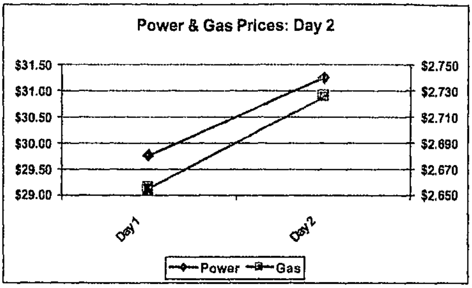
Date	Close Power[1]	Option Prem.[2]	Option Value[3]	Option P&L[4]	Power Delta[5]	Power Gamma[6]	Power Und. Trade[7]	Power P&L[8]
7-Jan-00	$29.75	$4.226	$1,487,515	$0	0.618	0.041	-618	$0.00

Date	Close Gas	Option Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
7-Jan-00	$2.655	$4.226	$1,487,515	$0	0.494	0.045	+174	$0.00

Assume that you have bought 1000MW capacity on a gas-fired power.

1. Assume that the option is ATM with opening prices of $29.75 for power and $2.655 for gas.
2. The option premium is calculated using a standard Black equation for dual variable options.
3. The option value is calculated as 1 Jun '00 spread option x 1000MW x 352 peak hours x $4.226 per option premium.
4. Since the option was just purchased on the open, there is no P&L yet.
5. See #3.
6. See #3.
7. In order to be delta neutral at the start of this trade, you must simultaneously sell 618 MW of power (0.618 power delta x 1000MW capacity) and buy 173 natural gas contracts (0.494 gas delta x 352,000 total MWhs capacity x 10.0 heat rate / 10,000 MMBtu per contract).
8. Since no price movement has yet occurred, there is no P&L change.

Now that the position of long 1 Jun '00 spread option and the associated delta hedge has been established, we will walk though ten days of gamma scalping. Just as in the crude oil gamma scalping section, we will assume that all transactions are done on the market close and therefore do not incur slippage.

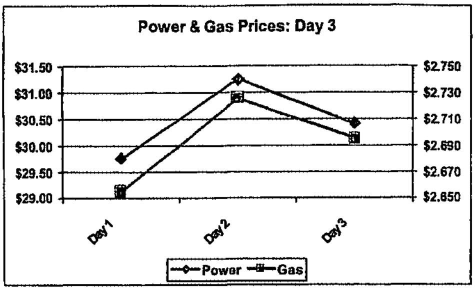


Market Gas ($/MMBtu)	[redacted]
Gas Basis ($/MMBtu)	[redacted]
Burner Tip ($/MMBtu)	$2.725
Avg. Heat Rate (MMBtu/MWh)	[redacted]
Non-Fuel Var. O&M ($/MWh)	[redacted]
Total Production Cost ($/MWh)	$29.15
Market Power ($/MWh)	[redacted]
Discount Rate	[redacted]
NG/Power Correlation	[redacted]
Days until Expiration	[redacted]
Gas Volatility	[redacted]
Power Volatility	[redacted]
Monthly Premium Value	4.793
Delta1 (Power)	0.648
Delta2 (Gas)	0.526
Gamma1 (Power)	0.038
Gamma2 (Gas)	0.044

Date	Close Power	Toll Prem.	Option Value	Option P&L[1]	Power Delta	Power Gamma	Pwr Und.[2] Trade	Power P&L[3]
07-Jan-00	$29.75	$4.226	$1,487,515	$0	0.618	0.041	-618	-$325,776.00
08-Jan-00	$31.75	$4.793	$1,687,053	$199,538	0.648	0.038	-30	$0.00
Total				**$199,538**			**-648**	**-$325,776.00**

Date	Close Gas	Toll Prem.	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$121,100.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	$0.00
Total				**$199,538**			**+185**	**$121,100.00**

1. Option P&L is calculated as the difference between the initial payment and the current market value. Current market value for the option is calculated as 1000MW x 352 peak hours x option premium.
2. The underlying trades of power and gas, which are used for delta hedges, are determined as the amount of underlying power and gas to be sold or bought in order to remain delta neutral.
3. Each successive trade will be individually marked to market. The initial delta hedge of selling 618MW of power at $29.75 is now valued at -$325,776.00 (618MW x 352 peak hours x ($29.75 - $31.75 closing price)). The initial delta hedge of buying 173 gas contracts at $2.655 is now valued at $121,100.00 (174 contracts x 10,000MMBtu per contract x ($2.655 - $2.725 closing price)).

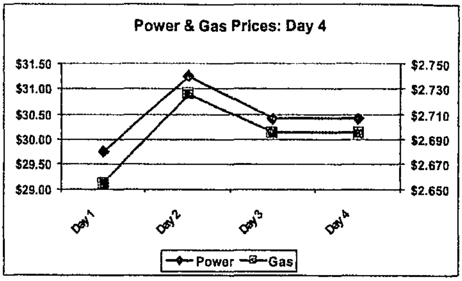


Market Gas ($/MMBtu)	[redacted]
Gas Basis ($/MMBtu)	[redacted]
Burner Tip ($/MMBtu)	$2.695
Avg. Heat Rate (MMBtu/MWh)	[redacted]
Non-Fuel Var. O&M ($/MWh)	[redacted]
Total Production Cost ($/MWh)	$28.85
Market Power ($/MWh)	[redacted]
Discount Rate	[redacted]
NG/Power Correlation	[redacted]
Days until Expiration	[redacted]
Gas Volatility	[redacted]
Power Volatility	[redacted]
Monthly Premium Value	4.403
Delta1 (Power)	0.627
Delta2 (Gas)	0.504
Gamma1 (Power)	0.040
Gamma2 (Gas)	0.044

Date	Close Power	Toll Premium	Option Value	Option P&L[1]	Power Delta	Power Gamma	Power Und.[2] Trade	Power P&L[3]
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$141,169.60
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$8,931.12
09-Jan-00	$30.40	4.403	$1,549,773	-$137279	0.627	0.040	+21	$0.00
Total				**$62,258**			**-627**	**-$132,238.48**

Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$69,200.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	-$3,300.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	$0.00
Total				**$62,258**			**+178**	**$65,900.00**

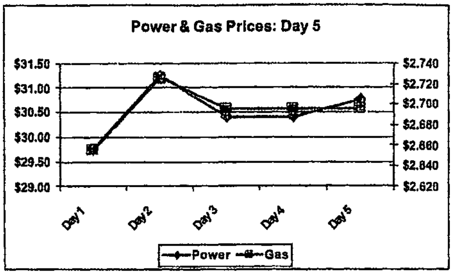
1. Option P&L calculation remains the same. It is marked to market each day using the option value calculation, and then compared to the previous day's value to obtain a P&L. For example, the P&L change from 07-Jan-00 to 08-Jan-00 is +$199,538 ($1,687,053-$1,487,515). The sum of the P&L changes to date (+$62,258) is equal to the P&L change for the entire term at this time (from the 07-Jan-00 initiation of the trade to close on 09-Jan-00).
2. In order to be perfectly delta hedged on the close of 09-Jan-00, we must be short 627MW of power (1000MW of capacity x 0.627 delta as of 09-Jan-00) and long 178 contracts of gas (0.504 gas delta x 352,000 total MWh x 10.0 heat rate / 10,000MMBtu per contract). We are already short 618MW from trade initiation, and short an additional 30MW from the close on 08-Jan-00, making a total short of 648MW. In order to get to a short power hedged position of 627MW we must buy back 21MW. On the gas side, we are already long 174 contracts from the trade initiation, and long an additional 11 contracts from the close on 08-Jan-00, making a total long gas position of 185 contracts. In order to obtain the perfectly delta hedged gas position of short 178 contracts, we must buy back 8 contracts (to simplify this transactional process, numbers have been rounded and therefore account for the apparent miscalculation of 185 – 8 = 178).
3. Each individual underlying trade for both power and gas will be marked to market.



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.695
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$28.85
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.391
Delta1 (Power)	0.627
Delta2 (Gas)	0.505
Gamma1 (Power)	0.040
Gamma2 (Gas)	0.044

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$141,169.60
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$8,931.12
09-Jan-00	$30.40	4.403	$1,549,773	-$137,279	0.627	0.040	+21	$0.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
Total:				**$58,116**			**-627**	**-$132,238.48**

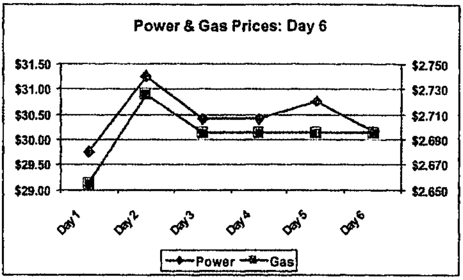
Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$69,200.00
08-Jan-00	$2.725	4.793	$1,687,053	199,538	0.526	0.044	+11	-$3,300.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	$0.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
Total:				**$58,116**			**+178**	**$65,900.00**



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.695
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$28.85
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.596
Delta1 (Power)	0.641
Delta2 (Gas)	0.520
Gamma1 (Power)	0.039
Gamma2 (Gas)	0.044

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$217,184.00
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$5,253.60
09-Jan-00	$30.40	4.403	$1,549,773	-$137,279	0.627	0.040	+21	$2,464.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
11-Jan-00	$30.75	4.596	$1,617,806	$72,175	0.641	0.039	-14	$0.00
Total:				$130,291				-$209,466.40

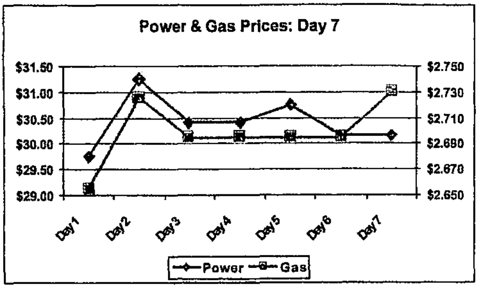
Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$69,200.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	-$3,300.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	$0.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
11-Jan-00	$2.695	4.596	$1,617,806	$72,175	0.520	0.044	+5	$0.00
Total:				$130,291			+183	$65,900.00



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.695
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$28.85
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.215
Delta1 (Power)	0.617
Delta2 (Gas)	0.495
Gamma1 (Power)	0.041
Gamma2 (Gas)	0.045

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$86,873.60
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$11,557.92
09-Jan-00	$30.40	4.403	$1,549,773	-$137,279	0.627	0.040	+21	-$1,760.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
11-Jan-00	$30.75	4.596	$1,617,806	$72,175	0.641	0.039	-14	$2,745.60
12-Jan-00	$30.15	4.215	$1,483,795	-$134,010	0.617	0.041	+24	$0.00
Total:				**-$3,719**			**-617**	**-$74,330.08**

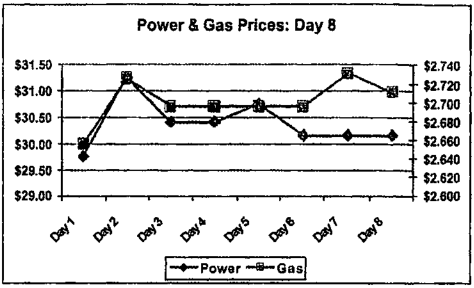
Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$69,200.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	-$3,300.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	$0.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
11-Jan-00	$2.695	4.596	$1,617,806	$72,175	0.520	0.044	+5	$0.00
12-Jan-00	$2.695	4.215	$1,483,795	-$134,010	0.495	0.045	-9	$0.00
Total:				**-$3,719**				**$65,900.00**



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.730
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$29.20
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.036
Delta1 (Power)	0.602
Delta2 (Gas)	0.480
Gamma1 (Power)	0.042
Gamma2 (Gas)	0.044

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$86,873.60
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$11,557.92
09-Jan-00	$30.40	4.403	$1,549,773	-$137,279	0.627	0.040	+21	-$1,760.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
11-Jan-00	$30.75	4.596	$1,617,806	$72,175	0.641	0.039	-14	$2,745.60
12-Jan-00	$30.15	4.215	$1,483,795	-$134,010	0.617	0.041	+24	$0.00
13-Jan-00	$30.15	4.036	$1,420,838	-$62,956	0.602	0.042	+15	$0.00
Total:				**-$66,676**			**-602**	**-$74,330.08**

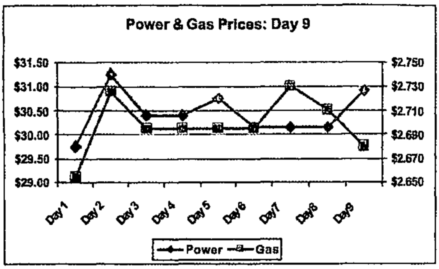
Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$129,750.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	$550.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	-$2,450.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
11-Jan-00	$2.695	4.596	$1,617,806	$72,175	0.520	0.044	+5	$1,750.00
12-Jan-00	$2.695	4.215	$1,483,795	-$134,010	0.495	0.045	-9	-$2,800.00
13-Jan-00	$2.730	4.036	$1,420,838	-$62,956	0.480	0.044	-5	$0.00
Total:				**-$66,676**			**+169**	**$126,800.00**



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.710
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$29.00
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.119
Delta1 (Power)	0.610
Delta2 (Gas)	0.489
Gamma1 (Power)	0.041
Gamma2 (Gas)	0.045

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$86,873.60
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$11,557.92
09-Jan-00	$30.40	4.403	$1,549,773	-$137,279	0.627	0.040	+21	-$1,760.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
11-Jan-00	$30.75	4.596	$1,617,806	$72,175	0.641	0.039	-14	$2,745.60
12-Jan-00	$30.15	4.215	$1,483,795	-$134,010	0.617	0.041	+24	$0.00
13-Jan-00	$30.15	4.036	$1,420,838	-$62,956	0.602	0.042	+15	$0.00
14-Jan-00	$30.15	4.119	$1,449,935	$29,097	0.610	0.041	-9	$0.00
Total:				**-$66,676**			**-610**	**-$74,330.08**

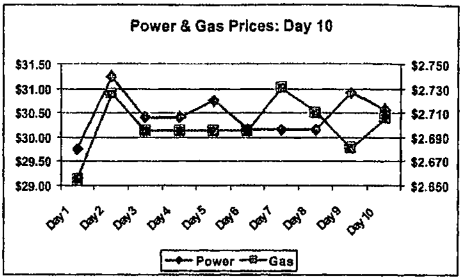
Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$95,150.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	-$1,650.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	-$1,050.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
11-Jan-00	$2.695	4.596	$1,617,806	$72,175	0.520	0.044	+5	$750.00
12-Jan-00	$2.695	4.215	$1,483,795	-$134,010	0.495	0.045	-9	-$1,200.00
13-Jan-00	$2.730	4.036	$1,420,838	-$62,956	0.480	0.044	-5	$1,000.00
14-Jan-00	$2.710	4.119	$1,449,935	$29,097	0.489	0.045	+3	$0.00
Total:				**-$66,676**			**+172**	**$93,000.00**



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.680
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$28.70
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.721
Delta1 (Power)	0.653
Delta2 (Gas)	0.535
Gamma1 (Power)	0.039
Gamma2 (Gas)	0.045

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$249,761.60
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$3,677.52
09-Jan-00	$30.40	4.4030	$1,549,773	-$137,279	0.627	0.040	+21	$3,520.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
11-Jan-00	$30.75	4.596	$1,617,806	$72,175	0.641	0.039	-14	-$686.40
12-Jan-00	$30.15	4.215	$1,483,795	-$134,010	0.617	0.041	+24	$6,336.00
13-Jan-00	$30.15	4.036	$1,420,838	-$62,956	0.602	0.042	+15	$3,960.00
14-Jan-00	$30.15	4.119	$1,449,935	$29,097	0.610	0.041	-9	-$2,112.00
15-Jan-00	$30.90	4.721	$1,661,796	$211,860	0.653	0.039	-43	$0.00
Total:				**$174,280**			**-653**	**-$235,066.48**

Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$43,250.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	-$4,950.00
09-Jan-00	$2.695	4.4030	$1,549,773	-$137,279	0.504	0.044	-8	$1,050.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
11-Jan-00	$2.695	4.596	$1,617,806	$72,175	0.520	0.044	+5	-$750.00
12-Jan-00	$2.695	4.215	$1,483,795	-$134,010	0.495	0.045	-9	$1,200.00
13-Jan-00	$2.730	4.036	$1,420,838	-$62,956	0.480	0.044	-5	$2,500.00
14-Jan-00	$2.710	4.119	$1,449,935	$29,097	0.489	0.045	+3	-$900.00
15-Jan-00	$2.680	4.721	$1,661,796	$211,860	0.535	0.045	+16	$0.00
Total:				**$174,280**			**+188**	**$41,400.00**



Market Gas ($/MMBtu)	[illegible]
Gas Basis ($/MMBtu)	[illegible]
Burner Tip ($/MMBtu)	$2.705
Avg. Heat Rate (MMBtu/MWh)	[illegible]
Non-Fuel Var. O&M ($/MWh)	[illegible]
Total Production Cost ($/MWh)	$28.95
Market Power ($/MWh)	[illegible]
Discount Rate	[illegible]
NG/Power Correlation	[illegible]
Days until Expiration	[illegible]
Gas Volatility	[illegible]
Power Volatility	[illegible]
Monthly Premium Value	4.362
Delta1 (Power)	0.629
Delta2 (Gas)	0.510
Gamma1 (Power)	0.041
Gamma2 (Gas)	0.045

Date	Close Power	Toll Premium	Option Value	Option P&L	Power Delta	Power Gamma	Power Und. Trade	Power P&L
07-Jan-00	$29.75	4.226	$1,487,515	$0	0.618	0.041	-618	-$173,747.20
08-Jan-00	$31.25	4.793	$1,687,053	$199,538	0.648	0.038	-30	$7,355.04
09-Jan-00	$30.40	4.403	$1,549,773	-$137,279	0.627	0.040	+21	$1,056.00
10-Jan-00	$30.40	4.391	$1,545,631	-$4,142	0.627	0.040	0	$0.00
11-Jan-00	$30.75	4.596	$1,617,806	$72,175	0.641	0.039	-14	$915.20
12-Jan-00	$30.15	4.215	$1,483,795	-$134,010	0.617	0.041	+24	$3,379.20
13-Jan-00	$30.15	4.036	$1,420,838	-$62,956	0.602	0.042	+15	$2,112.00
14-Jan-00	$30.15	4.119	$1,449,935	$29,097	0.610	0.041	-9	-$1,126.40
15-Jan-00	$30.90	4.721	$1,661,796	$211,860	0.653	0.039	-43	$5,297.60
16-Jan-00	$30.55	4.362	$1,535,333	-$126,462	0.629	0.041	+24	$0.00
Total:				$47,818			-629	-$154,758.56

Date	Close Gas	Toll Premium	Option Value	Option P&L	Gas Delta	Gas Gamma	Gas Und. Trade	Gas P&L
07-Jan-00	$2.655	4.226	$1,487,515	$0	0.494	0.045	+174	$96,500.00
08-Jan-00	$2.725	4.793	$1,687,053	$199,538	0.526	0.044	+11	-$2,200.00
09-Jan-00	$2.695	4.403	$1,549,773	-$137,279	0.504	0.044	-8	-$700.00
10-Jan-00	$2.695	4.391	$1,545,631	-$4,142	0.505	0.044	0	$0.00
11-Jan-00	$2.695	4.596	$1,617,806	$72,175	0.520	0.044	+5	$500.00
12-Jan-00	$2.695	4.215	$1,483,795	-$134,010	0.495	0.045	-9	-$800.00
13-Jan-00	$2.730	4.036	$1,420,838	-$62,956	0.480	0.044	-5	$1,250.00
14-Jan-00	$2.710	4.119	$1,449,935	$29,097	0.489	0.045	+3	-$150.00
15-Jan-00	$2.680	4.721	$1,661,796	$211,860	0.535	0.045	+16	$4,000.00
16-Jan-00	$2.705	4.362	$1,535,333	-$126,462	0.510	0.045	-9	$0.00
Total:				$47,818			+179	$88,400.00

This series of trades is only a snapshot of 10 days within the six-month life of the option. The overall P&L for the option and delta hedges is -$18,540.56 (+$47,818 option P&L + $88,400.00 gas P&L - $154,758.56 power P&L). One factor that could account for the negative overall P&L is price correlation. If the two variables in a spread option are too closely correlated then the spread between the two variables remains constant as prices move together. When the spread remains constant, then the two options essentially become just one option, leaving nothing to optimize. Another factor which can contribute to a negative P&L is high volatility. If the option is purchased when the volatility is, then gamma scalping becomes much more difficult. Lastly, it should be noted here that a spread option on 1000MW of power is a large position. Ten days does not provide an accurate picture of what can happen during the life of such a long-term investment.

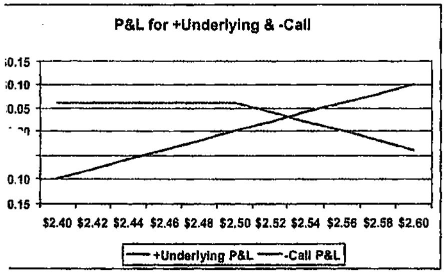
SYNTHETICS

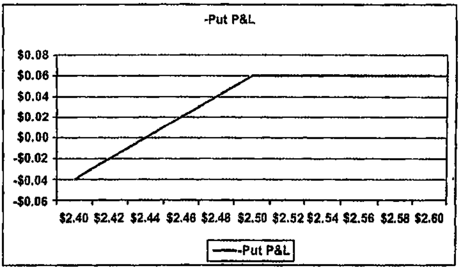
Synthetics involve using puts, calls, and underlying commodities in varying combinations in order to produce a "new" position.

The first basic example of a synthetic is a covered call. This involves buying the underlying and selling a call for an equal amount of contracts.

Assume that June NatGas is trading $2.50 (mid-market), and the $2.50 call option is trading $0.06 (mid) and the $2.50 put is trading $0.06. Buying the underlying and selling the call will result in a position that yields the exact same profile as selling the $2.50 put. If prices go up, you get to keep the premium received for selling the call option, but the buyer of the call option will exercise it, taking away any of your additional upside potential. If prices go down, you can keep the premium you received from selling the call option, but you will lose money being long the underlying. This is the same risk/reward profile as being short the put option. The P&L's are:

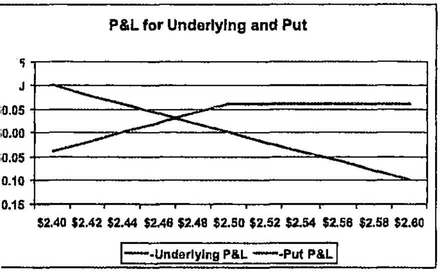
Price	+Und.P&L	- $2.50 Call P&L for $0.06	Net P&L		Sell $2.50 Put P&L for $0.06	
2.40	-0.10	+0.06	-0.04		-0.04	
2.42	-0.08	+0.06	-0.02		-0.02	
2.44	-0.06	+0.06	0.00		0.00	
2.46	-0.04	+0.06	+0.02		+0.02	
2.48	-0.02	+0.06	+0.04		+0.04	
2.50	0.00	+0.06	+0.06		+0.06	
2.52	+0.02	+0.04	+0.06		+0.06	
2.54	+0.04	+0.02	+0.06		+0.06	
2.56	+0.06	0.00	+0.06		+0.06	
2.58	+0.08	-0.02	+0.06		+0.06	
2.60	+0.10	-0.04	+0.06		+0.06	

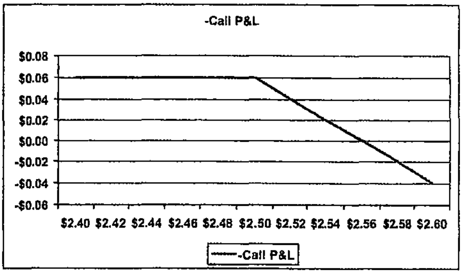




Another example is a covered put. This would be selling the underlying and selling the put option in an equal amount. Selling the put option allows you to collect premium, while taking away any profit potential should prices fall (the person to whom you sold the put in order to receive the premium will exercise the put in a falling market, thus filling in your short underlying position). Should prices rise, you have no protection. This is the same profile as writing a call option.

Price	-Und.P&L	- $2.50 Put P&L for $0.06	Net P&L		Sell $2.50 Call P&L for $0.06	
2.40	+0.10	-0.04	+0.06		+0.06	
2.42	+0.08	-0.02	+0.06		+0.06	
2.44	+0.06	+0.00	+0.06		+0.06	
2.46	+0.04	+0.02	+0.06		+0.06	
2.48	+0.02	+0.04	+0.06		+0.06	
2.50	0.00	+0.06	+006		+0.06	
2.52	-0.02	+0.06	+0.04		+0.04	
2.54	-0.04	+0.06	+0.02		+0.02	
2.56	-0.06	+0.06	0.00		+0.00	
2.58	-0.08	+0.06	-0.02		-0.02	
2.60	-0.10	+0.06	-0.04		-0.04	



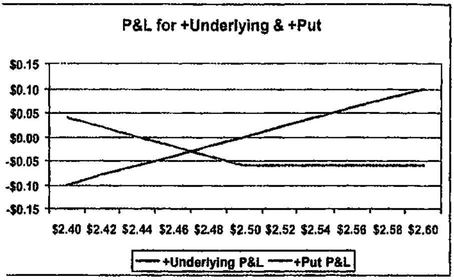


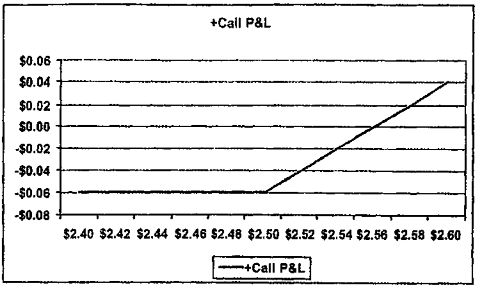
If we can synthetically go short call and put options through a combination of underlying and other option positions, then we should also be able to go long call and put options synthetically. A synthetic long call option position would be:

Synthetic Long Call = Long Underlying + Long Put

If prices go up, you will make money on the long underlying position (less the premium you paid for buying the put). If prices go down, you will be able to exercise the put option to sell out the long underlying position. The only money you will be out is the premium paid for the put plus or minus any difference between the strike of the put and the underlying. The associated P&L's are:

Price	+Und.P&L	+ $2.50 Put P&L for $0.06	Net P&L		Buy $2.50 Call P&L for $0.06	
2.40	-0.10	+0.04	-0.06		-0.06	
2.42	-0.08	+0.02	-0.06		-0.06	
2.44	-0.06	0.00	-0.06		-0.06	
2.46	-0.04	-0.02	-0.06		-0.06	
2.48	-0.02	-0.04	-0.06		-0.06	
2.50	0.00	-0.06	-0.06		-0.06	
2.52	+0.02	-0.06	-0.04		-0.04	
2.54	+0.04	-0.06	-0.02		-0.02	
2.56	+0.06	-0.06	0.00		0.00	
2.58	+0.08	-0.06	+0.02		+0.02	
2.60	+0.10	-0.06	+0.04		+0.04	



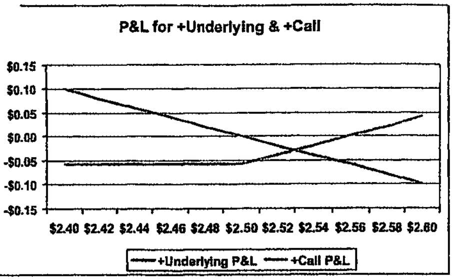


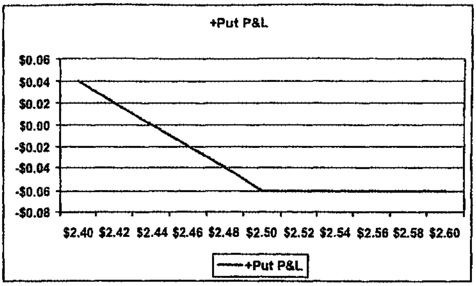
It should be just as easy to construct a synthetic long put position. Selling the underlying and buying a call option in equal amounts do this. Should prices rise, you will exercise the call option purchased to protect against the short underlying position. If prices fall, you will make money on the short underlying position (less the premium paid for the call option protection). This will give you the same profile as being long a put option.

Long Synthetic Put Option = Short Underlying + Long Call Option.

The chart looks like this:

Price	-Und.P&L	+ $2.50 Call P&L for $0.06	Net P&L		Buy $2.50 Put P&L for $0.06	
2.40	+0.10	-0.06	+0.04		+0.04	
2.42	+0.08	-0.06	+0.02		+0.02	
2.44	+0.06	-0.06	0.00		0.00	
2.46	+0.04	-0.06	-0.02		-0.02	
2.48	+0.02	-0.06	-0.04		-0.04	
2.50	0.00	-0.06	-0.06		-0.06	
2.52	-0.02	-0.04	-0.06		-0.06	
2.54	-0.04	-0.02	-0.06		-0.06	
2.56	-0.06	0.00	-0.06		-0.06	
2.58	-0.08	+0.02	-0.06		-0.06	
2.60	-0.10	+0.04	-0.06		-0.06	



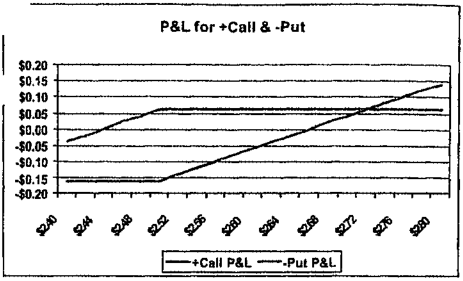


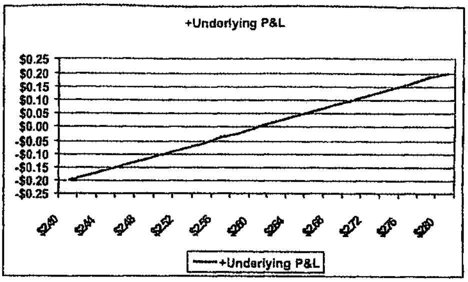
Since it is possible to construct long and short synthetic call and put options positions, the next logical step (and thankfully the last in synthetics!) is to construct synthetic long and short underlying positions.

To construct a synthetic long position, you would buy a call option and sell a put option. The easiest example of this is to do it at the same strike. This acts just like an underlying long position because as prices move up from the strike, you would exercise the call because it is in the money. As prices move down and away from the strike, the person who purchased your put option would exercise it against you, and put the underlying to you at a price higher than the market. Again, if this is done for the same strike, and the premium paid for the call option is the same as the premium received for the put option, then the resulting synthetic position acts exactly like being long the underlying.

A slight variation of this is if the premiums paid and received are not equal. This will "adjust" the price where you are long. Continuing with the previous example, if June NatGas is now trading up to $2.60 (mid-market), and the $2.50 call is $0.16 and the $2.50 put is $0.06 (mid-market), then the P&L profile is:

Price	+ $2.50 Call P&L for $0.16	-$2.50 Put P&L for $0.06	Net P&L		Long underlying @ $2.60*	
2.40	-0.16	-0.04	-0.20		-0.20	
2.42	-0.16	-0.02	-0.18		-0.18	
2.44	-0.16	0.00	-0.16		-0.16	
2.46	-0.16	+0.02	-0.14		-0.14	
2.48	-0.16	+0.04	-0.12		-0.12	
2.50	-0.16	+0.06	-0.10		-0.10	
2.52	-0.14	+0.06	-0.08		-0.08	
2.54	-0.12	+0.06	-0.06		-0.06	
2.56	-0.10	+0.06	-0.04		-0.04	
2.58	-0.08	+0.06	-0.02		-0.02	
2.60	-0.06	+0.06	0.00		0.00	
2.62	-0.04	+0.06	+0.02		+0.02	
2.64	-0.02	+0.06	+0.04		+0.04	
2.66	0.00	+0.06	+0.06		+0.06	
2.68	+0.02	+0.06	+0.08		+0.08	
2.70	+0.04	+0.06	+0.10		+0.10	
2.72	+0.06	+0.06	+0.12		+0.12	
2.74	+0.08	+0.06	+0.14		+0.14	
2.76	+0.10	+0.06	+0.16		+0.16	
2.78	+0.12	+0.06	+0.18		+0.18	
2.80	+0.14	+0.06	+0.20		+0.20	



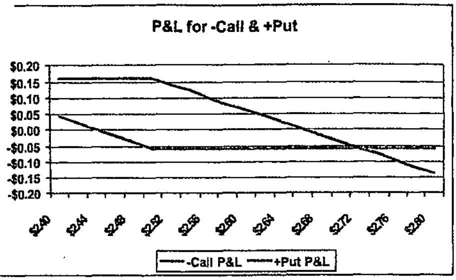


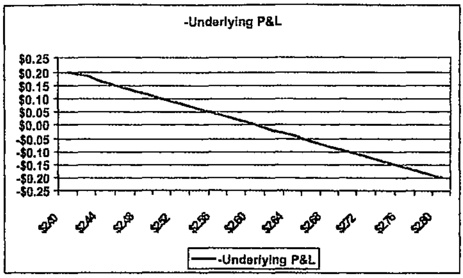
This position acts like you are long the underlying at $2.60 instead of where the strikes are ($2.50) because of the difference in premium. You received $0.06 for the put option sold, yet paid out $0.16 for the call option purchased, netting out –$0.10 in premiums. This $0.10 that was spent on the total options positions must be used to adjust upwards the price of the synthetic underlying which you are now long. The underlying will have to move up an additional $0.10 to overcome the net premium spent before this position becomes profitable.

This makes sense. The market will normally not allow you to get long at $2.50 when the underlying is trading for $2.60. If that were possible (and yes, sometimes it is!), then you will have uncovered a true arbitrage position (more on this later).

To construct a synthetic short position, we will again continue with the previous example. June NatGas has moved up to $2.60. The $2.50 calls are trading for $0.16, and the puts are still $0.06. To become synthetically short, you will need to purchase the put option while selling the call option. If prices move up, you will be in some pain, as the owner of the call option you sold will choose to exercise it. Should prices move down, you will be making money, as you can choose to exercise your put. This will give the same profile as being short the underlying. The chart is:

Price	-$2.50 Call P&L for $0.16	+$2.50 Put P&L for $0.06	Net P&L		Long underlying @ $2.60*	
2.40	+0.16	+0.04	+0.20		+0.20	
2.42	+0.16	+0.02	+0.18		+0.18	
2.44	+0.16	0.00	+0.16		+0.16	
2.46	+0.16	-0.02	+0.14		+0.14	
2.48	+0.16	-0.04	+0.12		+0.12	
2.50	+0.16	-0.06	+0.10		+0.10	
2.52	+0.14	-0.06	+0.08		+0.08	
2.54	+0.12	-0.06	+0.06		+0.06	
2.56	+0.10	-0.06	+0.04		+0.04	
2.58	+0.08	-0.06	+0.02		+0.02	
2.60	+0.06	-0.06	0.00		0.00	
2.62	+0.04	-0.06	-0.02		-0.02	
2.64	+0.02	-0.06	-0.04		-0.04	
2.66	0.00	-0.06	-0.06		-0.06	
2.68	-0.02	-0.06	-0.08		-0.08	
2.70	-0.04	-0.06	-0.10		-0.10	
2.72	-0.06	-0.06	-0.12		-0.12	
2.74	-0.08	-0.06	-0.14		-0.14	
2.76	-0.10	-0.06	-0.16		-0.16	
2.78	-0.12	-0.06	-0.18		-0.18	
2.80	-0.14	-0.06	-0.20		-0.20	





This position acts as if you were short the underlying at $2.60 rather than where the strikes are ($2.50). This is because you received a net premium of $0.10 ($0.16 for selling the call less $0.06 paid for buying the put). This additional $0.10 gives you profit above the strike, which is the same as being short at a higher level (in this case $2.60).

A summary of the basic synthetic positions is:

Initiated Trades	Synthetic Position
Long underlying + short call	Short put (covered call)
Short underlying + short put	Short call (covered put)
Long underlying + long put	Long call
Short underlying + long call	Long put
Long call + short put	Long underlying
Short call + long put	Short underlying

An easy way to think about synthetics and to help alleviate any confusion is to focus on the option premium. Is the premium being paid or received in the synthetic position? If you are paying premium, then you are synthetically going long an option (since paying an outright premium is done to take an outright long option position). Conversely, if you are receiving premium, then you must be synthetically selling an option (since receiving an outright premium is done to take an outright short option position).

To illustrate a quick thought process to determine what an overall synthetic position is illustrated by:

1. Buy the underlying for $2.50.
2. Sell the $2.50 call for $0.06.

Thought Process:

A. Bought underlying: prices go up = good; prices go down = bad
B. Sold call: Received premium, so synthetic option position must be short an option.
C. Prices go up = make money long on underlying, lose money on call for a net "wash" of breakeven, but get to keep the premium.
D. Prices go down = lose money on long underlying, short call is worthless, get to keep premium.
E. Net = prices go up, keep premium; prices go down, lose money less premium

Therefore, Position acts like being short a put option.

USES FOR SYNTHETICS

Why bother putting on synthetic options positions? It would seem that if a trader wanted an outright options position, then the easiest thing to do would be to simply go out and buy or sell the desired option. Several reasons exist for focusing time and effort on synthetics. They are:

1. Liquidity. It may not always be possible to enter a market and buy or sell the desired options. Perhaps the options market makers do not have a particular "axe" (desire to take a trade) in the desired option. The chosen market itself could be illiquid (for instance, call options in the power market are more frequently traded by utilities because of the inherent fear or need to be confident about securing electricity). Or the desired strike does not exist. For whatever reason, synthetics are a valuable tool if liquidity is absent.
2. Cheaper Alternatives: For the following example, assume that June Cinergy is trading $60.50/$61.00. Additionally, the $60.00 call is quoted by your favorite broker as $5.50/$6.00, and the $60.00 put is also quoted as $5.50/$6.00. If you want to get long the $60.00 put, you could easily lift the $6.00 offer. But there is a cheaper way to get long this option. If you hit the bid on the underlying for $60.50, and buy the $60.00 call by lifting the $6.00 offer, you have synthetically purchased the desired $60.00 put option. But what is the price for this? By selling the underlying for $0.50 greater than the $60.00 strike of the put, you have "added" $0.50 to your breakeven, which can just as easily be subtracted from the $6.00 premium paid for the protection of the call option. Therefore, your synthetic long put position was initiated for $5.50, which is the bid side of the actual put market, and saves money fro m just lifting the offer.
3. Deep "In-The-Money" Options Do Not Trade. Using the same example above where June Cinergy is trading $60.50/$61.00, there may be plenty of quotes for put options below the strike, but not many calls. This is because options market-makers usually quote puts and calls which are at the money
4. True Position Dissection: Assume you are a utility and have excess power to sell in June (same example again). Your view of the market is that prices have probably "topped out" and may be due for a pullback. You are thinking about selling some call options to take in extra premium - is this a good idea? Consider this - if the market has indeed "topped out", would you sell puts here? The answer is probably no. If you would sell puts in a falling market, although you would collect the premium, chances are that the buyer of the put would exercise the option and "put" the power to you at a higher price in a falling market. Well...if you think selling puts in this instance is a bad idea, then selling calls against your natural long position (covered calls) is the same as writing puts. This is another valuable reason for understanding synthetics. It allows you to look at positions and combinations of positions with a more complete knowledge of how it affects the overall portfolio.
5. Deal Pricing Strategies ("Back of the Envelope Calculations): June Cinergy is still trading $60.00. An originator wants to sell one of his customers a $20.00 call option. What's it worth? To determine this, you could check around for the exact same thing - a $20.00 call option. Chances are, since it is so deep in the money, you won't find one. Alternatively, you could find a $20.00 put, run it through an options calculator to determine what the implied volatility is, and then use this implied volatility to price the $20.00 call. You could also use put/call parity to figure this out (more about put/call parity later). Or, you can dissect this into synthetic positions and get a close approximation for what the option should be worth. Assuming that power will most likely not trade below $15.00 (based on historicals) and that the cost of your generation is roughly $15.00 (probably another reason why you think it won't trade lower), you now have established a starting point. The $20.00 call has $40.00 of intrinsic value ($60.00 market price less the $20.00 strike). You can think of this deep in the money call as a put. Yes, a put option. Since it is deep in the money, the buyer will exercise it a majority of the time. The only time the buyer will not exercise it is if prices drop off dramatically and it is not in the money. So, in effect, the buyer will be "putting" the power to you when prices are below $20.00. And since prices (in your opinion) cannot get below $15.00, the correct way to value the $20.00 call is to take the $40.00 intrinsic and add to it whatever you think the $20.00/$15.00 "put spread" is worth to you. If that is $1.75 (a rough approximation of 1/3 the difference in strikes), then the $20.00 call option is worth $40.00 (intrinsic) + $1.75 ($20.00/$15.00 put spread), or $41.75.
6. Market Direction: Knowing where things should trade synthetically, and then comparing these prices to actual market quotes, will tell you where the market is trying to go. If the synthetic calls are computed to be $5.50/$6.00, and the outright market is quoted as $5.85/$6.00, then you know that

buyers of call options, or volatility, are active. It may even be someone tipping their hand as to the perceived direction of the underlying.

7. Arbitrage: There are numerous ways to synthetically create a position while simultaneously closing it out with the underlying for an instantaneous profit. These arbitrage situations exist frequently, and if you are paying attention, it is free money. This will be the next topic of discussion.

OPTION ARBITRAGE

The first step in trying to arbitrage options is to understand the put/call parity concept. It is:

Option Strike +Call Premium = Underlying + Put Premium

For example, if June Cinergy is still trading $61.00, and the $60.00 call is $5.75, then the $60.00 put should be worth:

($60.00) + ($5.75) = ($61.00) + (Put Premium)
= $4.75 for the $60.00 strike put.

If the market is quoting this put as a higher premium, say $5.00, then it is overpriced. You should synthetically go long the put (sell the underlying and buy the call), and sell the overpriced outright put to lock in a profit. If you did that, here's what the results would be:

Price53 .25	-Und.P&L	+ $60 Call P&L for $5.75	Net P&L		Sell $60 Put P&L for $5.00	Arbitrage Profit	
53.50	+7.50	-5.75	+1.75		-1.50	+0.25	
53.75	+7.25	-5.75	+1.50		-1.25	+0.25	
54.00	+7.00	-5.75	+1.25		-1.00	+0.25	
54.25	+6.75	-5.75	+1.00		-0.75	+0.25	
54.50	+6.50	-5.75	+0.75		-0.50	+0.25	
54.75	+6.25	-5.75	+0.50		-0.25	+0.25	
55.00	+6.00	-5.75	+0.25		+0.00	+0.25	
55.25	+5.75	-5.75	0.00		+0.25	+0.25	
55.50	+5.50	-5.75	-0.25		+0.50	+0.25	
55.75	+5.25	-5.75	-0.50		+0.75	+0.25	
56.00	+5.00	-5.75	-0.75		+1.00	+0.25	
56.25	+4.75	-5.75	-1.00		+1.25	+0.25	
56.50	+4.50	-5.75	-1.25		+1.50	+0.25	
56.75	+4.25	-5.75	-1.50		+1.75	+0.25	
57.00	+4.00	-5.75	-1.75		+2.00	+0.25	
57.25	+3.75	-5.75	-2.00		+2.25	+0.25	
57.50	+3.50	-5.75	-2.25		+2.50	+0.25	
57.75	+3.25	-5.75	-2.50		+2.75	+0.25	
58.00	+3.00	-5.75	-2.75		+3.00	+0.25	
58.25	+2.75	-5.75	-3.00		+3.25	+0.25	
58.50	+2.50	-5.75	-3.25		+3.50	+0.25	
58.75	+2.25	-5.75	-3.50		+3.75	+0.25	
59.00	+2.00	-5.75	-3.75		+4.00	+0.25	
59.25	+1.75	-5.75	-4.00		+4.25	+0.25	
59.50	+1.50	-5.75	-4.25		+4.50	+0.25	
59.75	+1.25	-5.75	-4.50		+4.75	+0.25	
60.00	+1.00	-5.75	-4.75		+5.00	+0.25	
60.25	+0.75	-5.50	-4.75		+5.00	+0.25	
60.50	+0.50	-5.25	-4.75		+5.00	+0.25	

60.75	+0.25	-5.00	-4.75		+5.00	+0.25	
61.00	0.00	-4.75	-4.75		+5.00	+0.25	
61.25	-0.25	-4.50	-4.75		+5.00	+0.25	
61.50	-0.50	-4.25	-4.75		+5.00	+0.25	
61.75	-0.75	-4.00	-4.75		+5.00	+0.25	
62.00	-1.00	-3.75	-4.75		+5.00	+0.25	
62.25	-1.25	-3.50	-4.75		+5.00	+0.25	
62.50	-1.50	-3.25	-4.75		+5.00	+0.25	

Looks like a guaranteed $0.25 under any circumstances. And this is exactly what the put/call parity equation said it should be.

Using the put/call parity to determine the proper price for options based on the prices of other options, combined with knowledge of synthetics, can be used to scour the marketplace for potential arbitrage opportunities. Note that it does not matter what any sophisticated options pricing model says should be fair value - all that matters is where the options are trading in the marketplace, and where you can synthetically lock up your profits. With this in mind, we shall examine some of the more standard option arbitrage situations.

Conversions and Reversals:

A conversion is simultaneously buying the underlying, selling the call and buying the put for a profit. It can be viewed as synthetically going short the put (buying the underlying and selling the call) and then buying the outright put back at a cheaper rate. Or, it can be viewed as buying a cheap synthetic call (buying the underlying and buying the put) and then selling out the more expensive outright call for a profit. And finally, it can be viewed as going synthetically short at a higher rate (selling the call and buying the put) and then buying back the cheaper outright underlying. Any way you choose to do it does not matter. This is because all three legs must be done simultaneously in order to lock in the profit. The worksheet for the software is:

CONVERSIONS

(buy underlying; sell call, buy put)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call:	S	1.00	$30.00	$ 4.00	$ 4.25	$4.00
Put:	B	1.00	30.00	$ 3.50	$ 3.75	($3.75)
D/C:						$0.25
Synthetic Short @:						$30.25
Conversion P&L:						$0.50

REVERSALS

(sell underlying; buy call, sell put)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call:	B	1.00	30.00	$ 4.00	$ 4.25	($4.25)
Put:	S	1.00	30.00	$ 3.50	$ 3.75	$3.50
D/C:						($0.75)
Synthetic Long @:						$30.75
Reversal P&L:						($1.25)

UNDERLYING:

BID:	ASK:
$29.50	$29.75

A reversal is the same thing as a conversion, but in the opposite direction. You sell the underlying, buy the call and sell the put simultaneously for a profit. You are either:

a. Synthetically going long the cheap put (selling the underlying and buying the call) and then selling out the more expensive outright put for a profit, or
b. Synthetically going short the expensive call (selling the underlying and selling the put) and then buying back the cheaper outright call, or

c. Synthetically going long at a cheap level (buy buying the call and selling the put) and then selling out the more expensive outright underlying position.

Any way you look at it, as long as the trades are done simultaneously, there is a profit.

BOXES

Boxes are a bit more complicated than conversions and reversals, but they act the same way. There are two techniques for "boxing up" options:

a. By going synthetically long at one set of strikes while simultaneously going short at another set of strikes, or
b. By putting on a series of options spreads at different strikes that will net out for a profit.

The box for going synthetically long and short is as follows:

CONVERSION ONE:
(sell oall, buy put)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call:	S	1.00	30.00	$ 4.00	$ 5.00	$4.00
Put:	B	1.00	30.00	$ 7.50	$ 8.00	($8.00)
D/C:						($4.00)
Synthetic Short @:						$26.00
Conversion P&L:						($2.75)

REVERSAL ONE:
(buy oall, sell put)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call:	B	1.00	35.00	$ 2.50	$ 3.00	($3.00)
Put:	S	1.00	35.00	$ 9.00	$ 10.00	$9.00
D/C:						$6.00
Synthetic Long @:						$29.00
Reversal P&L:						($0.50)

Box P&L:
($3.00)

UNDERLYING:

BID:		ASK:
$ 28.50		$ 28.75

The box for spreads is as follows:

Long Box Spread:

(long bull call spread/long bear put spread)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call 1:	B	1.00	25.00	$ 3.00	$ 5.00	($5.00)
Call 2:	S	1.00	30.00	$ 2.00	$ 3.00	$2.00
D/C:						($3.00)
Put 1:	B	1.00	30.00	$ 4.00	$ 5.00	($5.00)
Put 2:	S	1.00	25.00	$ 2.00	$ 3.00	$2.00
D/C:						($3.00)
Synthetic Long @:						$28.00
Synthetic Short @:						$27.00
Net P&L:						($1.00)

Short Box Spread:

(short bull call spread/short bear put spread)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call 1:	S	1.00	25.00	$ 3.00	$ 5.00	$3.00
Call 2:	B	1.00	30.00	$ 2.00	$ 3.00	($3.00)
D/C:						$0.00
Put 1:	S	1.00	30.00	$ 4.00	$ 5.00	$4.00
Put 2:	B	1.00	25.00	$ 2.00	$ 3.00	($3.00)
D/C:						$1.00
Synthetic Long @:						$29.00
Synthetic Short @:						$25.00
Net P&L:						($4.00)

UNDERLYING:

BID:	ASK:
$ 20.50	$ 20.75

SYNTHETICS

As previously covered, synthetics involve replicating a position with other options and an underlying position. A useful tool to have is a worksheet that allows you to input the underlying price along with a series of call and put options at different strikes. This will allow you to search for possible arbitrage situations.

SYNTHETIC PUTS

Long Put = Short underlying + long call
Short Put = Long underlying + short call

	Strike:	Bid:	Ask:
Call 1:	300.00	$5.00	$ 5.00
Call 2:	75.00	$4.50	$ 5.35
Call 3:	100.00	$2.50	$ 4.50
Call 4:	55.00	$0.75	$ 1.00
Call 5:	60.00	$0.50	$ 0.75

	Strike:	Prem:
Long Put 1 @:	$300.00	$ 280.20
Long Put 2 @:	$ 75.00	$ 55.55
Long Put 3 @:	$100.00	$ 79.70
Long Put 4 @:	$ 55.00	$ 31.20
Long Put 5 @:	$ 60.00	$ 35.95
Short Put 1 @:	$300.00	$ 279.90
Short Put 2 @:	$ 75.00	$ 54.40
Short Put 3 @:	$100.00	$ 77.40
Short Put 4 @:	$ 55.00	$ 30.65
Short Put 5 @:	$ 60.00	$ 35.40

UNDERLYING:

BID:		ASK:
$24.80		$25.10

SYNTHETIC CALLS

Long Call = Long underlying + long put
Short Call = Short underlying + short put

	Strike:	Bid:	Ask:
Put 1:	24.00	$ 1.10	$ 1.20
Put 2:	45.00	$ 21.00	$ 21.50
Put 3:	50.00	$ 24.50	$ 25.00
Put 4:	55.00	$ 28.50	$ 29.00
Put 5:	60.00	$ 32.25	$ 32.75

	Strike:	Prem:
Long Call 1 @:	$ 24.00	$ 2.30
Long Call 2 @:	$ 45.00	$ 1.60
Long Call 3 @	$ 50.00	$ 0.10
Long Call 4 @	$ 55.00	$ (0.90)
Long Call 5 @:	$ 60.00	$ (2.15)
Short Call 1 @:	$ 24.00	$ 1.90
Short Call 2 @:	$ 45.00	$ 0.80
Short Call 3 @:	$ 50.00	$ (0.70)
Short Call 4 @:	$ 55.00	$ (1.70)
Short Call 5 @:	$ 60.00	$ (2.95)

SYNTHETIC STRADDLES

Going long a straddle involves buying a call and put at the same strike, while going short a straddle is selling a call and a put at the same strike. Due to volatility skew, most traders get a quote of the at-the-money straddles to input into their various volatility models for further calculations. This is where you will be searching for money. If the quotes received do not match up with what you can replicate synthetically, then a profit opportunity exists. Synthetic straddles can be replicated by:

a. Long Synthetic Straddle = Buy 2 puts and buy 1 underlying. One of the puts purchased will cross off with the underlying to make a long call position. Combined with the other long put, and you have long call/long put at the same strike (your synthetic straddle).
b. Long Synthetic Straddle = Buy 2 calls and sell 1 underlying. One of the calls purchased will cross off with the underlying to make a long put position. Match this with the other call not yet crossed and you have another long straddle.
c. Short Synthetic Straddle = Sell 2 puts and sell 1 underlying. Again, one of the puts sold crosses off against the underlying to make a short call position. Combine this with the other short put not yet "used" to make a short straddle.
d. Short Synthetic Straddle = Sell 2 calls and buy 1 underlying. Pair one short call with the long underlying. This covered call equals being short a put, which with the other short put makes you short the straddle.

LONG SYNTHETIC STRADDLE

(buy 2 puts; buy 1 underlying)
(=long call/long put same strike)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Put 1:	B	2.00	28.50	$ 3.25	$ 3.50	($7.00)
Put 2:	B	2.00	30.00	$ 4.25	$ 4.50	($9.00)
Put 3:	B	2.00	31.00	$ 5.25	$ 5.50	($11.00)
Put 4:	B	2.00	32.00	$ 6.25	$ 6.50	($13.00)
Straddle 1:			28.50			(7.75)
Straddle 2:			30.00			(8.25)
Straddle 3:			31.00			(9.25)
Straddle 4:			32.00			(10.25)

LONG SYNTHETIC STRADDLE

(buy 2 calls; sell 1 underlying)
(=long put/long call same strike)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call 1:	B	2.00	29.00	$ 3.25	$ 4.00	($8.00)
Call 2:	B	2.00	30.00	$ 3.00	$ 3.25	($6.50)
Call 3:	B	2.00	31.00	$ 2.75	$ 3.00	($6.00)
Call 4:	B	2.00	32.00	$ 2.50	$ 2.75	($5.50)
Straddle 1:			29.00			(8.00)
Straddle 2:			30.00			(7.50)
Straddle 3:			31.00			(8.00)
Straddle 4:			32.00			(8.50)

UNDERLYING:

BID:		ASK:
$ 29.00		$ 29.25

SHORT SYNTHETIC STRADDLE

(sell 2 puts; sell 1 underlying)
(=short call/short put same strike)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Put 1:	S	2.00	28.50	$ 3.25	$ 3.50	$6.50
Put 2:	S	2.00	30.00	$ 4.25	$ 4.50	$8.50
Put 3:	S	2.00	31.00	$ 5.25	$ 5.50	$10.50
Put 4:	S	2.00	32.00	$ 6.25	$ 6.50	$12.50
Straddle 1:			28.50			7.00
Straddle 2:			30.00			7.50
Straddle 3:			31.00			8.50
Straddle 4:			32.00			9.50

SHORT SYNTHETIC STRADDLE

(sell 2 calls; buy 1 underlying)
(=short put/short call same strike)

	B/S	Qty:	Strike:	Bid:	Ask:	Prem:
Call 1:	S	2.00	29.00	$ 3.25	$ 4.00	$6.50
Call 2:	S	2.00	25.00	$ 6.25	$ 6.50	$12.50
Call 3:	S	2.00	31.00	$ 2.75	$ 3.00	$5.50
Call 4:	S	2.00	32.00	$ 2.50	$ 2.75	$5.00
Straddle 1:			29.00			6.25
Straddle 2:			25.00			8.25
Straddle 3:			31.00			7.25
Straddle 4:			32.00			7.75

UNDERLYING:

BID:		ASK:
$ 29.00		$ 29.25

OPTIONS TRADING STRATEGIES

There are countless combinations of options and underlying positions. The best way to express some of the more popular combinations are by the standard P&L graphs. Using this tool, you can easily see which risk profile fits your view of the market, and put on a position accordingly.

Some of the more popular options trades are:

Long Call	Buy 1 100 call
Short Call	Sell 1 100 call
Long Put	Buy 1 100 put
Short Put	Sell 1 100 put
Long Straddle	Buy 1 100 call Buy 1 100 put
Short Straddle	Sell 1 100 call Sell 1 100 put
Bull Spread	Buy 1 95 call Sell 1 95 put
Bear Spread	Buy 1 105 put Sell 1 95 put
Bull Fence	Buy 1 105 call Sell 1 95 put
Long Call Ratio Spread	Short 1 100 call Long 2 105 calls
Short Call Ratio Spread	Long 1 100 call Short 2 105 calls
Bear Cartwheel	Long 1 100 call Short 2 105 calls Short 1 100 put Long 2 95 puts
Long Butterfly	Long 1 95 call Short 2 100 calls Long 1 105 call

Where:
Underlying price = 100
Days to Expiry = 30
Implied volatility = 15
Interest Rate = 10
1 Standard Deviation = 5.7
2 Standard Deviations = 11.4

For the following P&L graphs, assume that:

$ = dollar payoff at expiration (solid line) and at 30 days (light line).
Δ = Delta
Γ = gamma
Θ = theta

K = Vega (vega is not actually a greek letter. It is used since it is a pneumonic for volatility. The actual greek letter used to represent volatility is Kappa).

PIN RISK

Pin Risk is what occurs when the strike price of an option on expiry is exactly the same as the underlying price of the commodity. For example, assume the September Natural gas $2.00 call option expires on 22 August. At 3:09 Eastern Prevailing Time (EPT) on 22 August, (the NYMEX market closes at 4:10 EPT) the underlying is trading exactly at $2.00. The holder of the $2.00 call option is not in the money nor out of the money – he is at the money. Conversely, the seller of the option is also neither in nor out of the money, but at the money. With exactly one minute left to go in trading, the holder of the call option must decide if it is worthwhile to exercise. If he wants the position, he will exercise – it is the same to him as buying the underlying in the marketplace. However, he may or may not have wanted the underlying position. His real motivation may have been to trade the options, not the underlying, and with expiry one minute away, must make a choice. That is, to exercise into the underlying, which may or may not be profitable, or to let the option expire and do nothing, and risk not getting long the underlying at an attractive price.

The seller has the real dilemma – buy the underlying in anticipation of it getting called away,and risk not getting called, which results in holding an underlying position which is not wanted. Or, not buy the underlying, get called away, and then be naked short the underlying.

VOLATILITY SKEW (SMILE):

If you were to plot the volatilities of a strip of options, the graph would most likely show that the further out of the money options have higher implied volatilities. This is called the skew, or smile. One of the greatest challenges in managing a portfolio of options is to accurately value the volatility skew. Since commodity price movements have fatter tails than the lognormal distribution of the Black-Scholes formula would predict, traders will price out of the money options with different implied volatilities than at the money options. This skew can be positive or negative, and continually changes over time. Volatility skew should be used when pricing options. However, difficulties arise when valuing portfolios using different volatilities associated with skew. Sometimes simple is better.

UNIQUE CHARACTERISTICS OF ENERGY OPTIONS

<u>Crude Oil</u>
Crude Oil options have been around have been around the longest of all energy options and are certainly the most liquid. The majority of options traded on Crude are monthly expiry on the New York Mercantile Exchange and the International Petroleum Exchange. These options exploded in popularity during the Gulf War in 1990-91 when uncertainty in future price caused implied volatilities to trade close to 200%.

Additionally, large volumes of OTC (over-the-counter) Asian options trade on Crude Oil. These options are financially settled against the arithmetic average of a stated month's future daily price settlements or other index daily price settlements. These Asian options are more appealing hedges for end users because average prices may follow their cash-flow exposures more closely and create a better hedge than options on a monthly future contracts. Furthermore, traders need not concern themselves with liquidating future contracts after options expiration. Lastly, Asian options have lower premiums than plain vanilla monthly options.

Because of the liquidity of the Crude Oil market, it presents an excellent opportunity for option market makers. The challenge for these traders is the competition of a surplus of market makers and the continuous change in the volatility skew. The majority of the time the Crude out-of-the-money calls and puts will trade with a slightly higher implied volatility than the at-the-money options (Table 15). However, depending on the types of players influencing the market, this relationship can change. During times of low volatility, and consolidation, strikes that are slightly out-of-the-money will often trade with a lower implied volatility than the at-the-moneys. If producers dominate the option market, calls will trade at a volatility discount while put will be a premium.

The seasonality of Crude Oil will also affect the options market. Low storage levels before winter can cause uncertainty and entice consumers to hedge their bets by purchasing calls (increasing volatility and upside skew) in fear of a cold winter with high heating demand. Additionally, the same scenario holds true during spring driving season when gasoline demand increases.

Natural Gas

Natural Gas Options on the NYMEX were first introduced in 1992, but did not become a very liquid market until 1996. The NYMEX options are american-style monthly options on futures that are deliverable at the Henry Hub in Louisiana. The last few years have shown in incredible growth explosion, particularly in the NYMEX look-a-likes options. The look-a-likes are OTC options that are financially settled against the penultimate NYMEX future settlement date.

Options on swap strips will also trade from time to time in the OTC market. These Swaptions will usually expire just prior to the first month included in the swap. For example, a calendar 2001 Nymex $2.40 call swaption gives the purchaser the right to buy a Calendar 2001 swap at $2.40 on December 24, 2000. These swaptions trade with a considerably lower implied volatility than monthly options. This is because averaging prices of monthly contracts together will reduce volatility.

Additionally, many pipeline or location options other than Henry Hub are traded in the OTC market. The most common location options to trade are San Juan (southwest), Rockies (west), Sumas (northwest), MidContinent, Transco Zone 6 (Northeast) and Gulf Coast. All these hubs have basis markets with respect to the Henry Hub. The monthly options on these pipes are finacially settled against their bid week settlement price. Furthermore, options on the basis spreads are sometimes traded in the OTC market.

Finally, daily index options on all the locations are occasionally traded. These options are more appealing to hedgers who are usually measured against index. Their exotic theoretical nature creates problems for market makers. First, the strike price for the daily index calls or puts is not determined until the monthly index is set after bid week. Next, once the index and strike is determined, the holder owns a strip of options each expiring one day after the next, financially settled against a published daily index. Since no experienced trader would rely on the any option model with one day before expiration, it creates a valuation problem. This is the main reason why the bid/ask spread is wide enough for the traders to take the unknown risks. Although most of traded daily options have floating strikes and are financially settled, there are occasionally some with fixed strikes and physical settlement.

The seasonality of Natural Gas is quite profound largely affecting the options market. Trading Natural Gas can be thought of as trading two separate commodities. The April-October summer period is the lower volatility, fill the storage commodity; the November-March winter period is the higher demand, more volatile commodity. A colder than normal winter can cause supply shortages which will make the market spike higher. This every year concern causes winter future prices and implied volatilities to trade higher than the summers.

The volatilty skew in Natural Gas monthly option market is always changing is trades differently in the winter and summer months. In the winter months, the out-of-the-money call skew is extremely high particularly for strikes above the $3.00 level. The main reason for this is that if the market does trade above the $3.00 range it becomes extremely uncertain and volatile. When this happened in 1996, implied volatilities traded over 100%. On the other hand, out-of-the money puts usually trade with equal or less of an implied volatility than the at-the-money options, particularly if they are around the $2.00 level. The reason for this is that when prices fall it's because the supply shock potential is going away. Additionally, the Natural Gas option market is dominated by speculators and market makers, not hedgers. The summer volatility skew is much flatter. (Table16 and Table 17)

Power

Electricity Options have been around since utilities and end-users started entering into power purchasing contracts. However, the hidden optionality on volume, location, etc. found in these agreements has not been financially acknowledged and traded until recent years. The NYMEX introduced the first electricity futures and options contracts in 1996 on the COB and Palo Verde hubs. Soon to follow was the OTC traded NYNEX look-a-likes imitating the Natural Gas market. In 1998 and 1999, the NYMEX added the Cinergy, Entergy and PJM contracts. None of these financial markets have exploded with growth as of yet; nonetheless, with new players such as Banks, Foreign Utilities, Hedge Funds and demand side hedgers entering into the market, growth is inevitable.

The majority of options traded in the past couple of years have been physically settled monthly and daily options. These contracts trade in 50 MW (5X16 Heavy Load) blocks in the East and 25 MW (6X16 Heavy Load) blocks in the West. The daily physical options have a fixed strike price, unlike Natural Gas, and trade with much higher implied volatilities due to the frequent extreme price moves in the last couple of years. Many generators take advantage of these high premiums by selling calls against their excess generation.

Additionally, some financially settled daily options are traded in the OTC market. These options are settled against an index such as the Dow Jones Daily Price Index or against the daily PX price in California. These provide a much cleaner way to hedge and speculate risk avoiding the hassles of daily exercises and scheduling. The future success in the growth of the business will be led by financial contracts such as these as they break down barriers of entry such as infrastructure needs and overprotective letters of credit.

Also, options on monthly strips of power trade in the OTC market. These products are a bit different than the Natural Gas swaptions because they are exercisable into actual physical power contracts, not just a financial swap. The main strips quoted are quarters and calender years.ers.

The volatility skew in monthly power options is yet to be established. For now, the reader can assume it is somewhat flat. However, daily out-of-the money call options do trade with much higher implied volatilities than the at-the-moneys due to the frequent supply shocks that can send daily prices to almost any price. The out-of-the-money puts will vary throughout the year.

Although the electricity forward market trades with a correlation to daily prices, this phenomenon is more a result of market psychology than fundamentals. In other words, the astute trader may take advantage of this reality, however, he should respect that each monthly contract can behave like a separate commodity. In general, trading electricity is quite different than any other commodity. The lack of storage and frequent supply shocks creates a very volatile, unpredictable and risky environment. Traditional financial risk management theory often fails. This unique atmosphere will eventually lead to huge growth in options trading. Hedgers will need to use them for insurance and earnings volatility reduction purposes. Additionally, Speculators can use options to put on low risk directional bets. However, until the market has sufficient liquidity, market makers need to be extra cautious and respect this unique animal. More than any other commodity, the successful electricity market maker needs to have a good feel for the direction of the market due to the inability to hedge his risk in an illiquid market.

Numerical Derivative Pricing Models

Any derivative pricing process is contingent upon how the underlying price can change over time; therefore, it is worth the effort required to examine a few methods that will model price movement dynamics.

The objective of all the numerical models is to give a solution to a stochastic difference equation (sde) given specific boundary conditions (payoff formulas, discussed later). A stochastic differential equation is an equation that tries to model how a random process (stochastic), in this case prices, changes through time. Only the very basic concepts will be covered and not the mathematical rigor required in normal a stochastic calculus course. There a couple of baseline assumptions to all stochastic price models. These assumptions are as follows:

1. Prices behave as a *Markov Process*. Simply stated, the last observed price contains the only relevant piece of information for predicting future price values.
2. Price behavior is considered to be a *Wiener Process*. This is also mathematically the same as Brownian motion as it relates to particle physics. Brownian motion governs the small changes in a stochastic variable over time. A Wiener process is the random drawing from a standard normal distribution adjusted by the square root of the change in time.

All the derivative models will be illustrated using the following two very well known stochastic differential equation models, the first is a simple cash flow model and the second is a simple stock (non-dividend paying) model. (**Note:** I use the non-dividend paying stock model in order to help simplify and easily tie together the different pricing models. Also, commodity prices are more difficult to model)

Cash Flow Model: dx = a dt + b dz

dx is the change in the cash flow (x).
a is the drift term, the expected trend/growth of the cash flow
dt is the change in time, stated as a ratio of time step divided by the total number of time steps. ex. Time step is one day and there are 255 days in a year, thus the ratio is 1/255 or .00392. Another example: You are interested in every price changes every five days, then 5/255 or .01961
b is the volatility of the cash flow, or how much it varies over time
dz is the Weiner process.

Note: This model allows for negative values, which financially means that a company must borrow funds to remain viable.

Stock Model: dx = a(x, t) dt + b(x, t) dz

dx is the change in the stock value (x).
a is the drift term, the expected trend/growth of the stock price, which is a function of the current stock value and time.
dt is the change in time, stated as a ratio of time step divided by the total number of time steps. ex. Time step is one day and there are 255 days in a year, thus the ratio is 1/255
b is the volatility of the stock price, which is a function of the current stock value and time.
dz is the weiner process.

Monte Carlo Simulation

Monte Carlo simulation in the context of pricing options is the process of generating random price changes over time, these changes are mathematically modeled by a stochastic differential equation (SDE).

A differential equation is simply an equation that mathematically models changes in a process. A stochastic variable is a variable that randomly changes over time. Thus, a stochastic differential equation is an equation that mathematically models random changes over time. An example of a stochastic pricing model was given early in the introduction. The fundamental idea is to generate all possible prices that may occur in the market place, thus creating a probability distribution. Then you can use different pay out functions to determine an option's pay out at a specific point in time (the classical pay out function for a call is Max(Price-Strike,0) and for the put is Max(Strike-Price,0)). The average of all the possible payoffs is the option's premium.

Once the stochastic differential equation has been developed this method is the simplest and most flexible model to develop for pricing derivatives. The draw back is that it can be computationally expensive in terms of CPU and calculation time.

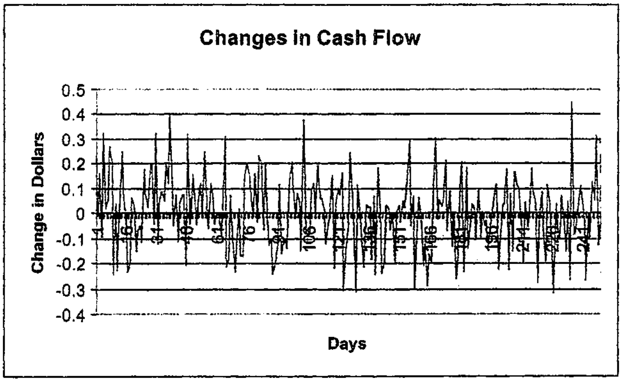
The two models are outlined below in excel. The stock model will be utilized to price both a put and call option.

"Excel Recipe":

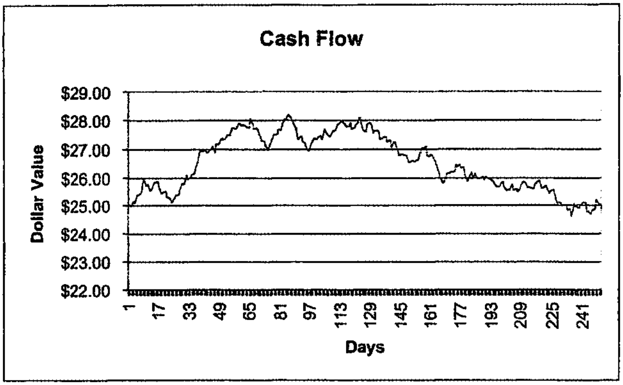
Cash Flow Model:

The SDE is dx = a dt + b dz

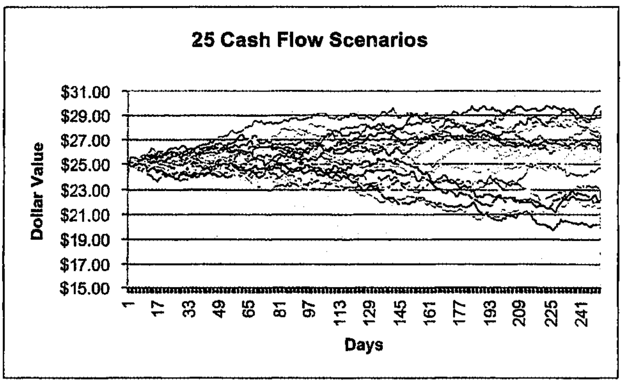
1. In cell b3 enter the last observed cash flow value, enter $25 (could represent different size denominations).
2. In cell b4 enter the expected trend of the cash flow, enter .15
3. In cell b5 enter the volatility of the cash flow, enter 2.5
4. In cell b6 enter the change in time, enter 1/255
5. In cell c8 enter the following formula
   $B$4*$B$6+$B$5*$B$6^0.5*NORMINV(RAND(),0,1)
6. Copy this down to c256. You should have a set of values that will give you something very similar to the following graph.



7. In cell c258 enter b3
8. In cell c259 enter c258 + c8
9. Copy down to c508
10. You should now have a graph that closely resembles the following graph.



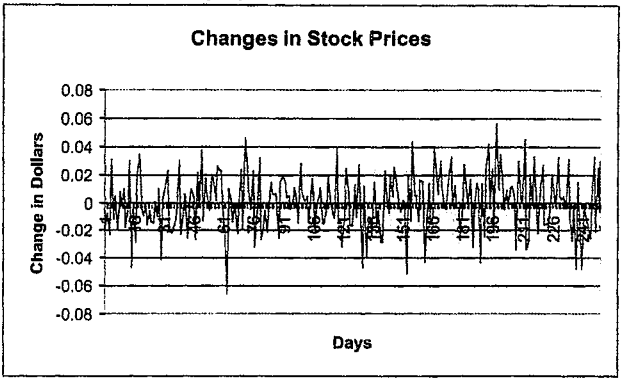
11. In order to turn this into a true Monte Carlo Simulation create several paths by copying cells c8:c508 to the right, copying into the next 24 columns to the right. You should then have a graph that shows 25 different possible paths that cash flow can move over a period of one year.



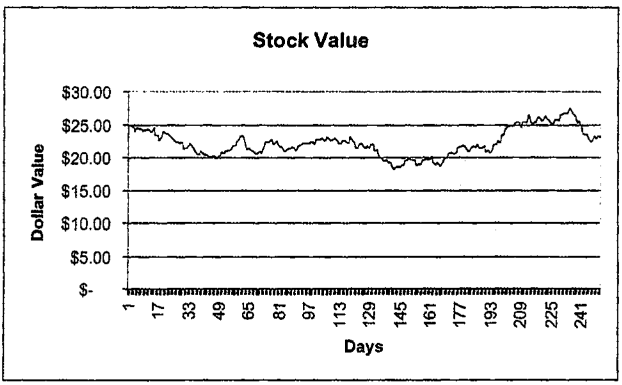
Stock Model:

The SDE is dx = (a - b^2/2) dt + b dz

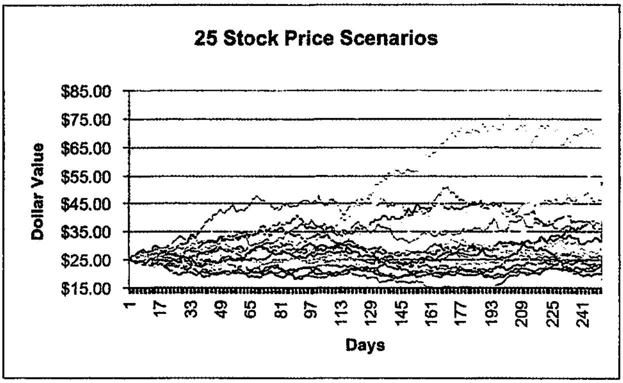
1. In cell b3 enter the last observed cash flow value, enter $25
2. In cell b4 enter the expected growth rate of the cash flow, enter .15
3. In cell b5 enter the volatility of the cash flow, enter .35
4. In cell b6 enter the change in time, enter 1/255
5. In cell c8 enter the following formula
   ($B$4 - $B$5^2/2)*$B$6+$B$5*$B$6^0.5*NORMINV(RAND(),0,1)
6. Copy this down to c256. You should have a set of values that will give you something very similar to the following graph.



12. In cell c258 enter b3
13. In cell c259 enter c258 * exp(c8), note the subtle difference between the two models. Cash Flow is based on absolute changes, and Stock is based on log changes.
14. Copy down to c508
15. You should now have a graph that closely resembles the following graph.



16. In order to turn this into a true Monte Carlo Simulation create several paths by copying cells c8:c508 to the right, copy into 24 columns to the right. You should then have a graph that shows 25 different possible paths that cash flow can move over a period of one year
17. You are now ready to price a contingent (derivative) claim using these randomly generated prices in the next section



Pricing Options:

Call: Payoff Function is Max (Stock Price - Strike, 0)

1. In cell b7 enter the strike, enter 25 (at-the-money)
2. In cell b510 enter MAX(C508-$B$7,0)
3. Copy over to AA510
4. In cell C512 enter AVERAGE(C510:AA510)
5. Call premium is approx. $5.50 (Note: Do not forget to NPV this value!)

Put: Payoff Function is Max (Strike - Stock Price, 0)

1. In cell b7 enter the strike, enter 25 (at-the-money)
2. In cell b510 enter MAX($B$7-C508,0)
3. Copy over to AA510
4. In cell C512 enter AVERAGE(C510:AA510)
5. Put premium is approx. $2.00 (Note: Put-Call parity states that the call and the put have to be valued the same when the option is at-the-money, however in this example don't forget the growth rate.)

Remember: In order to insure convergence of the option value (derivative) you need to simulate a minimum of 10,000 scenarios.

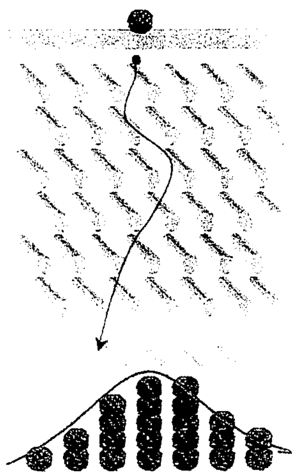
Remarks:

Only the last price generated by each scenario was used to price the option, which is reflective of the European style option. The European option expiry is at the end of the contract term, therefore the payoff of the option only occurs at expiry. Contrast this with an American option which can be exercised at anytime that the underlying is above (call)/below (put) the strike.

There are a lot of different stochastic models to use in trying to price options (ex. commodities are best modeled through a mean-reversion stochastic model), but this example will give you the basic knowledge building blocks to price options.

Binomial Tree (Lattice Tree)

This methodology tries to solve the price movement (stochastic differential equation) through implicit statistical measures of the underlying price distribution, where as in the previous Monte Carlo method the price movement distribution was explicitly calculated. The basic premise is that prices can only move either up or down given a very small change in time. Given the price movement distribution, a move up has a probability of occurrence p and a move down has a probability of occurrence $1-p$. (Note: p is a risk-adjusted probability and comes from the theory of arb itrage and is considered not to be the true probabilities). Simulating the number of possible up and down scenarios going forward in time will generate a binomial distribution, and the binomial distribution discretely approaches the continuous normal distribution. The simulation of up and down movements going forward in time is classically represented in the marble and peg board game. The game is where you drop a marble down a board filled with evenly spaced pegs staggered at each row, so that the marble either bounces to the right or to the left and will eventually come to rest in evenly spaced bins at the bottom. When several marbles have been allowed to transverse the board and collect into the various bins the classical gaussian bell-shaped curve starts to emerge.



This method is very flexible and actually allows pricing of some exotic options where the Monte Carlo methodology fails to do so.

'**u** = Exp(b dt^.5) , u is the up move, b is the volatility of the underlying price movement, dt is the change in time

d = 1/u, d is the move down, u is the move up

p = (Exp(mu dt) - d)/(u - d), p is the probability of an up move, mu is the growth rate, u and d defined as before.

Lets walk through an example in excel. In this example we should get exact same outcomes, unlike the previous Monte Carlo example where the outcomes where random.

1. In cell B4 enter .15, the growth rate
2. In cell B5 enter .35, the volatility
3. In cell B6 enter .2, the change in time (I want to create a 5 nodal lattice tree; thus 255/5 = 51 51/255 = .2
4. In cell B7 enter 25, the initial stock value
5. In cell D4 enter EXP($B$5*$B$6^0.5)
6. In cell D5 enter 1/D4
7. In cell F4 enter (EXP($B$4*$B$6)-D5)/(D4-D5)
8. In cell F5 enter 1-F4
9. The Lattice setup is:

				=D4*E11	=MAX($B$7-F10,0)
			=D12*D4	=G10*$F$4+$F$5*G12	
		=D4*C13	=F4*F11+F5*F13	=E11*D5	=MAX($B$7-F12,0)
	=D4*B14	=F4*E12+F5*E14	=D12*D5	=F4*G12+F5*G14	
B14	=F4*D13+F5*D15	=D5*C13	=F4*F13+F5*F15	=E13*D5	=MAX($B$7-F14,0)
	=D5*B14	=F4*E14+F5*E16	=D14*D5	=F4*G14+F5*G16	
		=D5*C15	=F4*F15+F5*F17	=E15*D5	=MAX($B$7-F16,0)
			=D16*D5	=F4*G16+F5*G18	
				=E17*D5	=MAX($B$7-F18,0)

Put Valuation

				46.75751	0
			39.98283	0	
		34.18973	0	34.18973	0
	29.23599	0.580895	29.23599	0	
25	[illegible]	25	1.313754	25	0
	21.37776	3.204232	21.37776	2.971192	
		18.28034	5.589264	18.28034	6.719657
			15.63171	8.892233	
				13.36684	11.63316

Call Valuation

				46.75751	21.75751
			39.98283	16.20049	
		34.18973	11.30391	34.18973	9.189731
	29.23599	7.570167	29.23599	5.126361	
25	4.929262	25	2.859668	25	0
	21.37776	1.595225	21.37776	0	
		18.28034	0	18.28034	0
			15.63171	0	
				13.36684	0

Black-Scholes Model

The Black-Scholes option-pricing model is a closed-form solution to the Stock Model. What does this mean? The numerical solutions demonstrated so far involve an iterative process, which explicitly calculates a price distribution, and a derivative value based upon that distribution; while a closed-form solution utilizes an implied distribution to derive a derivative value with no iterative calculations. How the Black-Scholes solution was derived is beyond the scope of this discussion.

I will go through the steps involved in pricing an option using the Black-Scholes solution in excel. The variables are as follows:

'd1 = ln (s / x) + (r + sigma^2 / 2)* (T-t) / sigma*(T-t)^.5
d2 = ln (s / x) + (r - sigma^2 / 2)* (T-t) / sigma*(T-t)^.5 or d2 = d1 - sigma (T-t)^.5

call = s N(d1) - x Exp(-r (T-t)) N(d2)
put =x Exp(-r (T-t)) N(-d2) - s N(-d1)

Where, ln is the natural log function,
s is the current stock value,
x is the strike value
r is the risk-free interest rate
sigma is the stock's volatility
(T-t) is the time till expiry (percentage of a year)
N is the standard normal cumulative probability density function
Exp is the exponential function

1. In cell B3 enter .35, sigma
2. In cell B4 enter 25, current stock value
3. In cell B5 enter 25, strike value
4. In cell B6 enter .07, risk-free rate
5. In cell B7 enter 1, (T-t) 255/255 = 1
6. In cell D3 enter, (LN(B4/B5)+(B6+B3^2/2)*(B7))/(B3*B7^0.5)
7. In cell D4 enter, D3-B3*B7^0.5
8. In cell D5 enter, NORMDIST(D3,0,1,TRUE)
9. In cell D6 enter, NORMDIST(D4,0,1,TRUE)
10. In cell D7 enter, NORMDIST(-D3,0,1,TRUE)
11. In cell D8 enter, NORMDIST(-D4,0,1,TRUE)
12. In cell F3 enter, B4*D5-B5*EXP(-B6*B7)*D6 (Call Value)
13. In cell F4 enter, B5*EXP(-B6*B7)*D8-B4*D7 (Put Value)

The call value is $4.26 and the put value is $2.58

Black's Model (Options on Futures Model)

The Black-Scholes Model is based on stock prices or in commodity lingo spot prices. Black's model is a model that is used in pricing derivatives on future prices, therefore is well suited to price commodity based derivatives. The main difference between the two models is that risk-free interest rates as well as cost-of-carry are imbedded in the futures price (future prices are derivative contracts on spot prices), therefore the model doesn't need to adjust the underlying to account for those two variables.

I will go through the steps involved in pricing an option using the Black's solution in excel. The variables are as follows:

'd1 = ln (f / x) + (sigma^2 / 2)* (T-t) / sigma*(T-t)^.5
d2 = ln (f / x) - (sigma^2 / 2)* (T-t) / sigma*(T-t)^.5 or d2 = d1 - sigma (T-t)^.5

call = [f N(d1) - x N(d2)] Exp (-r (T-t))

put = [x N(-d2) - f N(-d1)] Exp(-r (T-t))

Where, ln is the natural log function,
f is the current stock value,
x is the strike value
r is the risk-free interest rate
sigma is the future's volatility
(T-t) is the time till expiry (percentage of a year)
N is the standard normal cumulative probability density function
Exp is the exponential function

1. In cell B3 enter .35, sigma
2. In cell B4 enter 25, current future value
3. In cell B5 enter 25, strike value
4. In cell B6 enter .07, risk-free rate
5. In cell B7 enter 1, (T-t) 255/255 = 1
6. In cell D3 enter, (LN(B4/B5)+B3^2/2)*(B7))/(B3*B7^0.5)
7. In cell D4 enter, D3-B3*B7^0.5
8. In cell D5 enter, NORMDIST(D3,0,1,TRUE)
9. In cell D6 enter, NORMDIST(D4,0,1,TRUE)
10. In cell D7 enter, NORMDIST(-D3,0,1,TRUE)
11. In cell D8 enter, NORMDIST(-D4,0,1,TRUE)
12. In cell F3 enter, (B4*D5-B5*D6)*EXP(-B6*B7) (Call Value)
13. In cell F4 enter, (B5*D8-B4*D7)*EXP(-B6*B7) (Put Value)

The call value is $3.23 and the put value is $3.23

Volatility

Volatility is a term that is used just as often as prices, however a lot more misunderstanding is associated with volatility than there is associated with prices. What is volatility? Volatility is the standard deviation of the log returns converted into annualized terms. Volatility is spoken of in two varieties, historical and implied.

Note: Trading lingo for volatility is vols.

Historical

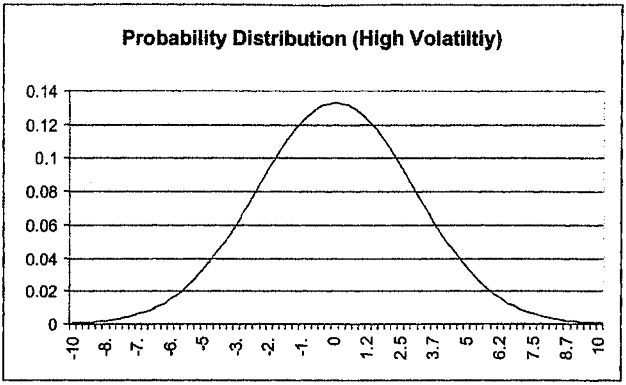
Historical volatility represents how log price returns have historically moved around the historical average price return.

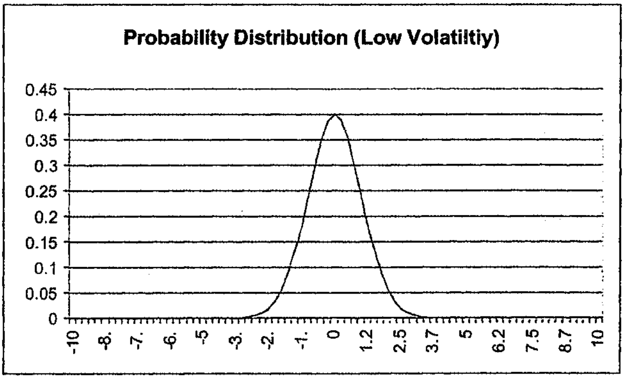
Determining volatility from historical prices:

1. Calculate price returns. Price returns are calculated by taking the natural log of today's price divided by the prior price (log(t - 1/ t)). (t represents a single period of time)
2. Calculate the expected value of the price returns. Average(price returns)
3. Calculate for each return its squared distance from the average price return. (price return[j] - average price return) ^ 2
4. Calculate the standard deviation. Sum (Step #3)/(Total number of returns - 1)
5. Calculate the volatility. Standard deviation in Step #4 * (Number of Trading days in a Year) ^.5

Date	Price	1. Returns	2. Average	3. (avg-xi)^2	4. STD	5. Volatility
1/1/99	1.875					
1/4/99	1.875	0		3.619E-06		
1/5/99	2.1	0.113329		1.328E-02		
1/6/99	2.04	-0.028988		7.336E-04		
1/7/99	2.035	-0.002454		3.042E-07		
1/8/99	1.895	-0.071277		4.813E-03		
1/11/99	1.875	-0.01061		7.583E-05		
1/12/99	1.82	-0.029772		7.767E-04		
1/13/99	1.82	0		3.619E-06		
1/14/99	1.865	0.024425		6.931E-04		
1/15/99	1.78	-0.046648		2.002E-03		
1/18/99	1.795	0.008392		1.060E-04		
1/19/99	1.795	0		3.619E-06		
1/20/99	1.77	-0.014025		1.470E-04		
1/21/99	1.8	0.016807		3.500E-04		
1/22/99	1.845	0.024693		7.073E-04		
1/25/99	1.81	-0.019152		2.976E-04		
1/26/99	1.75	-0.033711		1.012E-03		
1/27/99	1.72	-0.017291		2.368E-04		
1/28/99	1.75	0.017291		3.684E-04		
1/29/99	1.805	0.030945		1.079E-03		
			-0.0019		0.001405	0.02243

High volatility is relative only to low volatility. In other words volatility is only considered high whenever a low has been established and/or visa versa. What impact does volatility have on the shape of distributions? High volatility will lower the number of occurrences at the mean and increase the number of occurrences away from the mean, and low volatility will increase the number of occurrences around the mean and will decrease the number of occurrences away from the mean. The demonstrative graphs are as follows:





Implied Volatility

Implied volatility is the volatility that the markets are currently using to price and trade derivatives, and you will use implied volatility in all derivative models. How does one calculate implied volatility? Using the Blacks Model that you previously created and an ATM straddle quote from the market you can calculate implied volatility as follows:

1. Split the ATM straddle quote in half. (straddles you recall are +/- ATM call, +/- ATM put) Let us assume the quote was $ 6.460, thus $6.460/2 = $3.23
2. In cell F10 enter the straddle quote, enter 3.23
3. In cell F12 enter =F10-F8
4. Open solver and enter F12 as target, select value of 0, by changing cell B3, and Click Solve
5. The volatility solved for is your implied volatility, which in this case solver returned an implied volatility number of .349. (Close to the .35 original)

V. Fundamental Analysis

Fundamental Analysis of U.S. Electricity Markets

Introduction

Power price forecasting methods are rapidly changing. The modeling effort performed by an investor-owned utility and delivered to its state regulatory agency has less value as a tool to be used in today's wholesale markets. Methodologies such as "integrated resource planning" do not adequately address the capacity requirements and inherent risks faced by today's electricity suppliers. Moreover, fundamental operating information, once openly shared by utilities, is becoming increasingly difficult to obtain. This section discusses the analytic methods and data available to examine power markets. It covers the evolution of the models to coincide with deregulation of the sector, approaches used today, and how to verify the results against known or expected behavior by the participants.

The primary purpose of fundamental modeling should not be the production of a point forecast. While liquidity issues pervade, there are both short term and medium term prices available from brokers and counterparties. In addition, long term power prices can be quickly developed as a function of new unit costs given assumptions on fuel, capital costs, interest rates, etc. Instead of point price projections, power price modeling can be used for the following purposes:

- Development of a "company-bias" case,
- To determine which elements are key drivers of price movements,
- To produce alternative scenarios or sensitivity-study cases,
- To establish a common framework for the study of the inter-relationships between all energy commodities (power, gas, coal, and oil), and
- To develop a better understanding between the physical market for power (spot trading on an hourly basis) and financial products available.

The most common purpose of power modeling is the preparation of the "company bias" or "company base-case". In this instance, a set of analytics are laid upon the company's best estimate of future growth and cost changes in order to produce a view for comparison against the market. For example, model prices that are higher than the current market would suggest a long position or a favorable outlook for investment. Likewise, model prices that are lower than the current market suggest a short position strategy, or perhaps asset divestiture. The company case can be developed by an internal staff of analysts or through the use of outside consultants. In the latter instance, the company can purchase an "off-the-shelf" forecast (periodic offerings are available from PIRA, CERA, Foster Associates, ICF/Kaiser, HESI, as well as others) or customized to incorporate special knowledge known by the company, specific assumptions, or to address individual needs.

Perhaps the most useful purpose of power modeling is to identify the key drivers of price movement. For example, which has a bigger impact, a $0.10 change in the cost of fuel or a 1% change in the cost of capital? Will next summer demand push prices above the $100/mwh level? $200? $10,000? In addition, the model can be used to construct alternative scenarios or publish sensitivity studies where the point projection is less important than the magnitude of the change relative to the differences in the underlying assumptions.

More recently, power models have been linked to natural gas models. In general, future power plant is expected to be dominated by gas-fired generating resources. This includes both combined-cycle for baseload and intermediate duty and simple cycle gas turbines for peaking duty. The magnitude and location of the new generating facilities has a significant impact on the cost of gas. This includes both wellhead prices (say rising to the cost of new offshore development) as well as transportation infrastructure costs (e.g., the cost of new pipelines to serve the midwest). Likewise, gas price movements impact spark spreads, and thus the timing, magnitude, and success of new power plant ventures. Moreover, commodity price movements in coal and oil, interest rates, and other factors impact power prices. Models can be used to study the inter-relationships within the context of specific business decisions.

Models can also be used to help understand the hourly movement in the price curve. Power is traded in firm blocks which occur over the "on-peak" period (say 7 a.m. to 10 p.m. Mon-Fri). However, physical power is sold on the market in hourly increments as market participants maintain sufficient deliveries to meet ongoing changes in demand. Often the shape of the hourly curve is significant; the four superpeak hours may sell for over $100 while the other twelve of the onpeak period may sell for only $20. This has consequences for owners of assets with an underlying cost of production between the two prices. The "shape" of the hourly price curve typically dictates the number of hours the plant operates, the number of starts (with an underlying cost), and the additional value a more flexible resource contributes. While the model may not produce a forecast that exactly matches the current market, it can help portray hourly differences and the magnitude and length of the superpeak relative to shoulder hours.

Characteristics of the Power Market

Wholesale electric power price levels result from owners' ability to recover fixed and variable operating costs given various demand levels. At times where supply far exceeds demand, say at 4:00 AM, generators are fortunate to recover short run marginal cost (SRMC). Conversely, at times of high demand, say at 5:00 PM on the hottest day of the summer, prices spike to high levels that cover all variable operating costs plus allow a significant contribution to fixed and capital recovery costs. The unique aspects of the supply-demand equilibrium in the power sector include:

- Electricity is not storable; the supply-demand balance is performed instantaneously,
- Transmission limitations cause price disconnects between regions
- Operating constraints and energy limitations on certain resources inhibit the ability of the generating facilities to respond to changes in demand
- Arbitrage opportunities exist on power-fuel (say gas or oil), fuel-fuel (dual fired facilities) and wholesale output-ancillary service output

Forward markets exist in electricity from a real-time (minute to minute) basis, on out to calender years,e.g., annual basis, several years out. The basic measure is \$/mwh and the smallest form traded is on an hourly basis. Prices vary from region to region because transmission is not provided free and is sometimes not available, thus preventing a nationwide price convergence. There are three separate operating regions in the U.S.; the Eastern grid, which reaches as far west as Oklahoma, Kansas and the Dakotas; the Western grid, which encompasses the states west of those above; and Ercot, which includes most of the state of Texas. The only connections between these large regions are through High Voltage DC lines, which significantly limit transfers of power. In the Eastern grid, the major trading hubs (operating regions) are: Cinergy (ECAR), ComEd (MAIN), TVA (SERC), Entergy, PJM, NYPool and Nepool. In the West, the major hubs are Mid Columbia, COB, PV, NP15 (Northern California) and SP15 (So. Calif.).

Relative to other energy commodities, power prices exhibit extreme volatility. This is particularly true in the summer when peak demand closes in on the existing capacity surplus. During these times, the system becomes stressed and the market participants take full advantage by bidding up the price of power plant output. For example, on a mild summer weekday, prices may average about \$30 (enough to cover the operating costs of all resources operating). On a hot day by contrast, daily prices can spike to over \$1000/mwh. In ECAR during summer 99, hourly prices rose as high as \$12,000/mwh. Understanding why, when, where, and how often this happens is critical to the success of the modeling effort.

Prices are defined as "energy only" on a firm LD (short for liquidating damages) basis. This means that physical energy deliveries are guaranteed; if the seller fails to perform, then it is liable for additional costs incurred by the buyer to secure alternate supply. The price does not include "capacity rights" that might be required for retail energy suppliers in certain markets. Capacity is discussed in greater detail subsequently.

In addition to electricity energy markets, power generators have opportunities to supplement their revenue through the provision of ancillary services. These include spinning and operating reserves, regulation, reactive power (voltage), energy imbalance service, and scheduling, system control and dispatch services. Each of these items help keep the real time system in proper balance. Some plants, by their fortuitous location on the grid, as well as their operating cost and engineering characteristics, are better able to take advantage of these opportunities.

Evolution of Modeling Procedures

The electricity sector has been a major beneficiary of Operations Research and financial engineering techniques. Linear and Dynamic Programming have long been used to optimize both the daily operation of generating resources and capacity expansion decisions. Option pricing models developed by Black and Black-Scholes have been used determine the value of the electric output, given the volatility in the power and underlying fuel market. More recently, the mean-reverting, or non-log normal probability distribution of power prices has been studied using Monte Carlo simulation techniques.

Prior to deregulation of the wholesale markets, power price modeling was geared toward producing a "least cost" solution. Utilities operated a franchise; they constructed power plants to serve electric demand for a given service territory. The utilities constructed sufficient generating capacity to be virtually certain that demand would never be interrupted. Then, the generating portfolio was optimized to the specific hourly demand profile subject to the utility's ability to trade marginal amounts of energy with its neighbors.

The least cost electric dispatch model (also known as the "Production Costing" model) produces an estimate of power plant operation given the supply portfolio and associated demand curve. There are two types of production costing models; the chronological and the load duration curve approach. The latter ranks the various hours over the study period (year, month, week) from highest to lowest, then estimates plant operation by dispatching each resource in order, from cheapest to most expensive. A corresponding "price duration" curve is output, e.g., the model reports how often prices are above a certain level or how often a specific plant is at the margin. Load duration curve models are helpful for estimating plant output and fuel budgeting, but are of limited value in forecasting prices over specific hours.

Chronological pricing models portray how the portfolio of power plants operate on an hour by hour basis. The models explicitly consider plant startup costs, generation and transmission constraints, plant output flexibility, changes in demand, operating reserve requirements and other physical limitations. Their drawback is their inability to fully consider the impact of unplanned outages by the resources. However, this can be addressed through Monte Carlo–type approaches. Chronological models report plant output, marginal, and average hourly costs for the optimal operation of the supply stack to meet the hourly demand forecast for the study period.

However, Production Costing models only address variable operating costs. Fixed expenses, such as labor, supplies, rent, insurance, and capital investment costs are not explicitly considered. The fixed component accounts for between one-third and one-half of total operating costs. Thus a method is needed to estimate future fixed costs and how they are recovered in wholesale power markets.

A number of approaches to modeling fixed costs have been suggested. Two will be described here. The first is the cost-recovery approach (also referred as the "finance approach"). The model begins with an assumption of total fixed costs that will be recovered in the future. For example, at a supply-demand equalibrium, prices converge to long run marginal cost, i.e., the cost of most economic new entrant. At times of capacity surplus, prices will be somewhat less than new unit cost, and at times of capacity deficiency, prices rise above new unit cost. Once the fixed cost element is determined, an allocation procedure is needed. This can be accomplished using historical price volatility, or, more commonly, some form of bidding-based approach. In this case, the production costing model is used with varying price inputs; during mild weather or competitive days, the bid price for the plant reverts to variable cost only. On more extreme demand days, the bid price is increased to include a portion of fixed costs. The model then performs a simulation using bid prices; under-recovery forces a new simulation using higher bid prices while over-recovery forces a simulation using reduced bid prices.

A second approach (often referred as the "structural approach") is to examine historical price volatility in greater detail and use this as the basis both for the allocation of fixed costs as well as the magnitude of fixed cost recovery. In this instance, two models are employed. The production costing model examines the energy component, and a second simulation model is employed to determine the magnitude of the fixed (capacity) related addition to wholesale power prices. The second model is a combination of demand profiles, supply stack availability profiles, and transmission path constraints. It examines historical prices as a function of these components, and then performs a Monte Carlo simulation of future operating conditions in order to arrive at forecasted prices. More recently, production costing models have been adapted to derive the energy component as the result of bidding against ancillary service markets. For example, a supplier with a $15/mwh variable cost that can recover $10 of profit in the ancillary market (by providing regulation, operating reserves, etc) will bid $25/mwh or more into the energy market.

Both approaches have advantages and drawbacks. The finance approach is reasonable from a long-term perspective, but is not necessarily valid for any given year. Moreover, bidding logic works only when the modeler has full access to the physical traders and can anticipate the reaction to future conditions. The Monte Carlo approach requires accurate historical information on generating plant and transmission path availability; these are often not available to the desired degree.

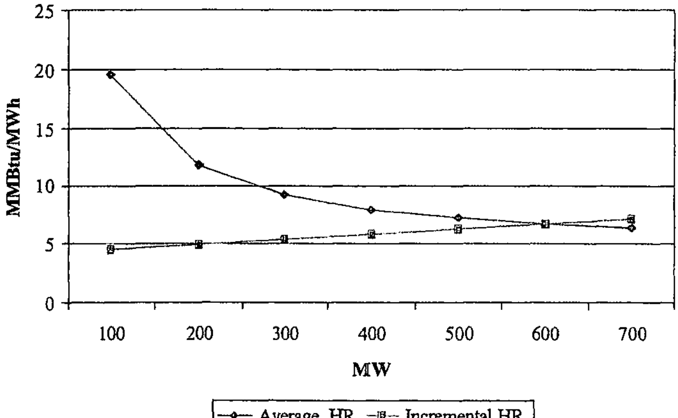
Underlying Cost of Energy

Operating Economics

Supply Stack. Generating facilities can be referred to as the supply stack. This designation sorts the various plants in a merit order by increasing marginal operating cost. First in line are hydro stations, which utilize a "free" fuel source. Next in line are nuclear stations. While the total operating cost of a nuclear station might be relatively high, most of these costs are fixed (sunk), thus the marginal cost of additional output is lower than most other generating facilites. Next in line is typically coal-fired generation. Coal fuel supplies are relatively cheaper than, say, gas or oil, which are the next type in the supply stack. At the end of the stack are the most expensive gas or oil units. Some supply stacks include pumped (hydro) storage facilities and non-dispatchible power projects, which typically utilize renewable fuel sources. Examples are wind, solar, biomass and geothermal stations. Supply stacks can also include "behind the fence" generating resources. The most common example is co-generation. This is where an industrial facility (say a paper factory or chemical processing plant) constructs a power plant that utilizes the excess steam produced for the industrial process. The power facility produces electricity in excess of the industrial demand and thus the remainder is sold into the local grid. Co-generation facilities typically operate at very high utilization factors and are priced so as to be high in the supply stack or dispatch order.

Thermal, i.e., powered by other energy fuels such as nuclear, coal, natural gas or oil, power stations operate under a typical production curve function. Thermal plants have a designated thermal efficiency, which is expressed as a heat rate function in MMBtu/Mwh. Total (variable) cost that results from providing energy from a thermal plant is fuel cost (price of fuel x average heat rate of the facility) plus variable operating expenses (e.g. labor, materials and supplies that vary with the level of plant output). The graph below illustrates the production function (i.e. heat rate) for a typical thermal power station.

Figure 3: Heat Rate Example



As is typical with thermal engines, average heat rate decreases (or thermal efficiency increases) as the level of plant output is increased. For example, at minimum operating levels, the plant operates at its least efficient level, while at maximum output the plant operates at or near its most efficient heat rate. The table below illustrates the relationship between heat rate and cost of output

Output	Average Heat Rate	Total Heat	Incremental Heat Rate	Fuel Cost	Avg. Cost	Incr. Cost
100 MW	19.525	1952.50		1.00	$19.52	
700 MW	6.297	4407.90	7.172	1.00	$ 6.30	$7.17

Given the above cost and heat rate characteristics, the resource generates at an average cost of $ 6.30/mwh (at max output) and has an incremental cost of $7.17/mwh. These might equate to a bid price to turn the resource on and then to increase real-time output once the unit is up and operating. Of course this example only covers the fuel portion; variable operating & maintenance costs (V O&M) add from $1/mwh to $5/mwh. [Annual fixed and capital recovery costs are covered in a later section.]

Power plants are dispatched to meet demand in a number of fashions. In one instance, an investor-owned-utility will pool its own resources to meet retail load, while buying and selling with its neighbors when surpluses/shortfalls occur. The pool resources are stacked in order of increasing variable cost so that a "least cost" dispatch results. When neighboring prices are lower than internal plant costs, the plants are turned down or shut off to take advantage of the market. Likewise, when demand falls short of the combined output of the committed (or available) resources, the utility offers its surplus to its neighbors. These trades are in the form of bilateral contracts and are made for time periods starting on an hourly basis and working on up to annual deals. A more formal pooling mechanism exists in certain areas where neighboring utilities offer their resources into one centrally dispatched pool. Members then purchase back from the pool on an hourly basis to meet their own demand levels. The pool thus acts as a central clearinghouse for energy transactions. Merchant plants and industrial generating facilities have the option of joining the pool or entering into bilateral contracts for its output.

Dispatch economics must account for a number of complexities over and above plant variable costs in a supply stack. These include:

- Startup costs
- Ramping, must-run, and other Operating Constraints
- Spinning and other Operating Reserves
- Energy limited resources

Startup Costs. Certain costs are incurred to start electric generating resources. For example, distillate fuel oil is used to initiate turbine operation until the boiler is hot enough to produce the necessary steam. Often, specific labor costs are designated with the startup procedure. In addition, starting and stopping a thermal resource results in wear & tear; the resulting maintenance costs might then be allocated back on a per start basis. When the latter is included, the cost per start might increase on the order of $10,000 per start. There are several types of plant starts: hot starts, warm starts and cold starts. These refer to the length of time the unit has been offline. Cold starts are the most expensive due to the time necessary to get the boiler up and running at a level to produce minimum output of electricity. In each case, there are economic decisions made in the dispatch that match plant startup costs against the costs of continued operation during times when market prices are below operating cost.

Ramping and Must-run constraints. Most plants are not capable of instantaneously raising and lowering output to exactly match real-time changes in demand. Ramp rates refer to the speed at which plant output level can change (say 6 MW/minute). This constraint is factored into the dispatch and might result in additional or more flexible resources being committed to serve the demand. Must run resources occur for two reasons. The first is due to plant construction; the plant may have overwhelming startup costs or be incapable of shutting down and then be reliable for service in the near future. Another type of must-run facility occurs due to demand; the plant may be strategically located near a demand center (say a city) such that other resources in the region cannot effectively move their output to the load and thus forcing the must-run plant into operation. In the latter case, the resource may be uneconomic but nonetheless included in the dispatch.

Spinning and Operating Reserves. In order to meet instantaneous demand changes and allow for the possibility of one or more resources incurring an unexpected outage, the dispatchers will commit more resources than necessary to simply meet load. The amount extra will be subject to ramping and startup constraints (say so much @ 30 second response time, so much at 1 minute, so much at 10 minutes, etc).

Energy limited resources. This typically refers to hydro plants but also can involve other generation types. There are three types of hydro facilities. First, "run-of-river" plants provide energy in fixed quantities over hours based on the river flows which vary seasonally. There is no flexibility in scheduling or varying output levels. Second, "peak-shaving" or "storage" hydro allows the dispatcher to vary hourly production levels subject to a maximum storage capability (the size of the dam) and to river flows over the course of the seasons. Third, "pumped-storage" hydro is a peak-offpeak arbitrage machine. Water is physically pumped from a lower dam to a higher dam during low priced hours and then allowed to spill during high priced hours. The plant's output will be based on its efficiency factor and the daily peak/off-peak price differential. Another type of energy limited plant are the non dispatchibles. These include solar, wind, trash burners, and geothermal resources.

Fuel Cost Considerations

Thermal power stations are fueled by either nuclear (rods), coal, natural gas, or oil (#6 residual, #2 heating oil, distillate or jet fuel). The characteristics of each are discussed in turn below:

Nuclear. The fuel cost of nuclear stations is typically fixed under a long term contract. Variable costs are kept low so that the plant will be economic to operate at maximum loading whenever possible. Of course, total operating costs may be quite high, resulting in stranded cost issues. There is very little flexibility with these units or optionality that could be captured in the commodity markets.

Coal. The cost of fuel in Coal-fired power stations is based on the underlying commodity price and transportation expenses. Often, there are significant contractual issues working in the equation. The most basic scenario is a min-mouth plant; this is where the plant is located directly next to the fuel source. Coal is mined for exclusive purposes of supplying fuel to the power generator. In this case, there is a long term contract for the fuel. Moreover, the fuel is sold on a take-or-pay basis. This means the plant guarantees the mine owner revenues on an agreed upon tonnage level. Then, the plant operates at a capacity factor that ensures the tonnage obligation is met. The next scenario is quite the opposite; the power plant purchases coal from spot markets (often from great distances away) and then arranges for transportation to the facility. Transportation costs often exceed the underlying price of the commodity. In this scenario, the net fuel costs are often somewhat higher, but in this case the generator is under no obligation to purchase fuel or operate the plant. A third, and perhaps most likely, scenario exists where the fuel is purchased both via contract and spot markets.

The dispatch price is based on spot costs, not (contractually) sunk costs, and optionality exists once the take-or-pay obligation is satisfied. Also, emissions plays a role in the operation of coal-fired facilities. Plants are constrained by their NOX, SO2, and Carbon Monoxide (CO) output. Several years ago, investor owned utilities were issued "Emissions Credits" by the FERC. The purpose of the credits was to limit total nationwide pollution by these resources. If a utility could replace coal-fired generation with other forms of supply (or demand side management programs), then the utility could sell their surplus emissions credits to other utilities. Over time, the credits would be phased out, as all plant owners met their emissions target through replacement and/or scrubbers on existing coal generation.

Natural Gas. Currently, gas-fired generating plant accounts for less than 15% of the total power resources in the U.S. However, gas is on the margin significantly more often; usually most of the on-peak hours in many trading regions. Moreover, gas-fired generation accounts for virtually all new construction. Gas-fired Combined-cycle technology is cheaper (based on fixed plus variable costs) than conventional steam plants fired by coal or nuclear power. Gas-fired gas turbines used for peaking needs are typically more economic than those using oil (distillate) fuel. The cost considerations for gas plants are similar to those for coal; there is a contract vs spot price consideration, and there is a commodity and transportation component. Less likely is a long term fuel contract that locks in a fixed price of gas over the life of the generating asset. Gas contracts are more linked to monthly and daily swings in the commodity market. Contracts are necessary more to guarantee supply rather than price. Also, the price includes a location basis that encompasses transportation costs from the wellhead to the plant site. The fuel agreement will also include a balancing component, which allows the plant to vary usage, both from an hour to hour standpoint (for example, the plant reduces output during low priced hours overnight) as well as seasonally.

Oil. There are actually two types of oil-fired generating resources. First are conventional steam (baseload) plants that utilize #6 residual fuel oil. The fuel has the texture of paving tar, e.g., it is less refined. The fuel price is less expensive than other oil products; over the years the cost of resid-fired generation has been comparable to coal or gas-fired steam plant. Second, gas turbine peaker plants can use distillate fuel. These facilities typically have high heat rates and more expensive fuel costs but are cheaper to install. They are commonly constructed for reliability purposes or to meet a small demand in an isolated locality. In some cases, the peaking facilities are duel-fueled, e.g., capable of burning either natural gas or distillate fuel, subject to cost and emissions considerations.

Operating Cost Considerations

In addition to fuel, generating facilities have a number of other operating costs. These include labor, materials, outside services, rents, and depreciation. Total fixed costs are split between the fixed and variable components for purposes of arriving at the correct dispatch price. This is not a simple exercise, as many cost components vary with output but only to a partial degree. For example, annual maintenance costs might be higher if the unit operates for more hours during the year. Conversely, maintenance might be cheaper if the resource were left on longer rather than started and stopped frequently. Another example is sunk costs associated with a fuel contract; including take-or-pay or other high contract expenses as a variable component in the dispatch price might significantly alter plant operation. At worst, the plant is shut down and the must-take provisions are executed. Plant operators will attempt to properly allocate operating costs to the most appropriate category; by level of output, by number of starts, or as an annual fixed expense. The operators will attempt to optimize plant earnings subject to competitive forces in the market.

Underlying Cost of Capacity

The Economics of Recovering Fixed Costs

Almost half of the total cost to operate an electric generating resource is fixed. In addition to fuel and variable operating costs, the plant owner must recover fixed expenses, capital recovery, taxes and profit. The amount of fixed costs depends on plant type and plant age. Baseload resources, constructed to operate continuously with low variable costs typically have a higher fixed component. Nuclear, coal-fired steam, and hydro facilities are included here. Conversely, intermediate and peaking resources have a higher variable but cheaper construction cost.

In the days pre-deregulation; electric utilities were given a mandate to develop a portfolio of resources that optimized costs associated with serving native load customers in a reliable manner. Moreover, utilities were directed to diversify fuel needs, reduce reliance on oil products, encourage the development of renewable forms of generation (such as solar, wind and biomass), and meet a certain level of supply needs through conservation and demand management programs. As a result, today's supply portfolio includes substantial fixed costs that would not be recoverable in an efficient market. These are referred to as stranded costs.

Today, retail suppliers are expected to maintain sufficient capacity reserves to be virtually certain to "keep the lights on". This is known as their obligation to supply. Many states have a minimum reserve margin standard. This is at least 15% and in some cases it is as high as 24%.

Plant owners recover fixed costs in a number of ways. The most common method today is through retail tariffs. However, as deregulation continues and utilities unbundle (disaggregate part of their generation-transmission-distribution supply chain) costs, fixed costs associated with generation must be recovered in wholesale power markets. The wholesale market currently offers three ways to recover fixed costs. They vary by region. The first method is through bilateral contract. The buyer agrees to pay the seller a payment based on the amount of energy delivered at a pre-selected time. For example, the seller delivers 100 MW of power continuously over a month (round-the-clock) at an energy price of $20/mwh and a capacity charge of $5kw/month. Total costs under this agreement amount to $20 x 744 hrs/month x 100 mwh/hr + $5 x 100,000 kw = $1.988 Million. Another example is a unit contingent contract expected to deliver 100 MW during all on-peak hours at a 90% availability for similar capacity and energy price terms. In this case, the expected costs are $20 x 21 weekdays x 16 hrs x 100 MW x .90 + $500,000 = $1.105 Million. Bilateral contracts exist because buyers expect fixed costs to be passed through in the daily spot market(s). The two ways fixed costs are captured directly in wholesale commodity markets are discussed in turn below.

The second method is the "ICAP" market. In certain regions of the country (namely New York and the New England states), electricity capacity is traded as a distinct commodity product. ICAP is traded in KW/Month terms. Thus a supplier serving a 100 MW load at a 60% load factor over the year will contract for roughly 525,600 mwh in the energy market and 120 MW of ICAP. This product has the most value during months of high demand, typically July and August. The Jan-Feb winter period also has some value, particularly when extreme weather conditions apply.

Most states in the U.S. do not have a separate and distinct market for electricity capacity. In the third case, fixed costs are recovered in the energy markets. This requires that plant operators bid prices for wholesale transactions that recover operating costs plus some or all fixed costs. Their ability to receive prices above operating cost is a reflection of the supply-demand balance that exist during the time in question. For example, during an extremely low demand period, say at 4:00 a.m. on a mild weather day, there should be excess generating supply and correspondingly weak price levels. This is due both to the surplus of supplies and to the engineering constraints that exist for many baseload power stations. High startup costs and the inability of power stations to reduce output levels cause induce the operators to be "price takers". In hourly markets such as the California pool or the New England pool, it is not uncommon for prices to drop to levels below the short run marginal cost of the cheapest thermal power station. Prices can drop to zero on occasion. At the other extreme, during extremely high demand periods, say at 5:00 on the hottest day of the summer, there are fewer supply alternatives and correspondingly high prices. At its most extreme, monopoly-type price spikes occur. Last summer in the midwest, hourly prices exceeded $12,000/mwh. The variable operating cost of the most expensive plant running at that time was about $100/mwh.

Supply-Demand Balance

The suppliers in the regulated electric utility industry had to maintain sufficient generating reserves in order to satisfy its franchise obligation to supply. To aid in this effort, investor-owned-utilities created the NERC (North American Electricity Reliability Counsel). NERC and its sub regions performed an independent assessment of generating needs and provided guidance to its members as to minimum and optimal reserve targets. It used a variety of measures; the most common two were reserve margin (capacity surplus/peak demand) and "Loss of Load Probability" or LOLP. The latter measure was intended to take into account the number and various sizes and operating availability of power plants in the region. For example, a region with lots of large nuclear stations with high historical outage characteristics would have a higher LOLP than would another region with the same level of capacity reserves but consist of many smaller plants with better availability statistics. To illustrate, the midwest region of ECAR might get by with a 15% reserve margin while the island of Oahu might reqiure as much as a 50% reserve margin in order to attain a similar LOLP measure. In general, NERC advocated that investor owned utilities carry a 20% reserve margin or a 1 day in 10 years (.0274%) loss of load probability. Historically, utility companies were eager to comply with this requirement since it resulted in investment programs for generation and thus company growth. Over the past ten-fifteen years, state regulatory agencies have been more reluctant to encourage new utility generation (for a variety of reasons). As a result, capacity surpluses that existed in the past are down to minimal levels in most areas of the country today.

The following table illustrates the supply-demand balance that exists in the U.S. as of November 1999. The Demand side of the equation is developed by:

- Identifying and aggregating utility load by region
- Adjusting the non-coincident utility peaks to a regional coincident peak
- Subtracting load management and interruptible demand, to get
- Net regional peak demand

Local peak demand in a region does not occur simultaneously. As a result, an adjustment from non-coincident peak (NCP) to coincident peak (CP) is performed. This correction is on the order of a 1-3% reduction. Load management programs include residential water heater cutoff switches, commercial a/c cutoffs, and other mechanisms where the local power supplier has the capability to reduce demand for a short period of time (say up to

U.S. Electricity Supply Demand Balance

	2000	2001	2002	2003	2004	2005	2006	2007	2008
Annual Summer Peak Demand									
New York - West	9,694	9,805	9,907	10,035	10,120	10.208	10,287	10,376	10,461
New York - East	19,538	19,762	19,967	20,225	20.397	20,575	20,733	20,912	21,084
NEPOOL	21,990	22,455	22,929	23,323	23,778	24,222	24,778	25,218	25,655
PJM	47,612	48,444	49,237	50,033	50.863	51,725	52,575	53,443	54,292
ECAR	92,678	94,435	96,269	97,937	99,180	101,576	103,066	104,361	106,397
MAIN	45,109	45,792	46,392	47,113	47,947	48,813	49,605	50,275	51,113
VACAR	50,469	52,920	54,091	55,188	56,183	57,003	57,890	58,686	59,562
TVA	26,214	26,823	27,516	28,278	29,115	29,985	30,881	31,823	32,820
Southern Co	38,886	40,130	41,241	42,346	43,410	44,553	45,741	46,823	47,892
Florida	33,532	36,091	36,967	37,817	38,641	39,587	40,402	41,302	42,239
Entegry	24,180	25,331	25,857	26,315	26,926	27,368	28,073	29,212	29,826
ERCOT	49,891	51,928	53,346	54,544	55,856	57,356	58,742	60,189	61,992
SPP Central	19.430	20,064	20,483	20,979	21,303	21,781	22,009	22,489	22,996
SPP North	15,385	15,804	16,143	16,486	16,846	17,186	17,588	18,037	18,438
MAPP - US	28,775	29,423	29,952	30,480	30,954	31,497	32,038	32,626	33,114
Net Internal Demand	523,383	539,207	550,297	561,099	571,519	583,435	594,408	605,772	617,881
Available Resources									
New York - West	15,108	15,108	15,108	15,858	15,858	15,858	15,858	15,858	15,858
New York - East	20,733	20,733	20,733	22,563	22,563	22,563	22,563	22,563	22,563
NEPOOL	24,357	25,927	26,298	27,608	27,108	27,108	27,108	27,108	27,108
PJM	57,331	56,712	58,162	59,512	57,282	57,282	57,282	57,282	57,282
ECAR	106.474	109,659	112,716	112,716	112,716	112,716	112,716	111,954	111,954
MAIN	53,426	54,094	55,278	55,278	55,278	54,348	53,576	53,576	53,576
VACAR	57,252	59,672	60,152	60,152	60,152	60,152	60,152	60,152	60.152
TVA	31,275	32,865	33,385	33,385	33,385	33,385	33,385	33,385	33,385
Southern Co	45,152	46,382	47,552	47,552	47,552	47,552	47,552	47,552	47,552
Florida	38,825	41,340	43,603	43,603	43,603	43,603	43,603	43,603	43,603
Entegry	30,739	31,239	32,419	32,419	31,483	31,483	31,483	31,483	31,483
ERCOT	60,666	63,966	67,766	68,116	68,116	67,558	67,558	67,558	67,558
SPP Central	24,256	24,766	26,656	26,956	26,956	26,956	26,956	26,956	26,956
SPP North	16,477	16,727	16,977	16,977	16,977	16,977	16,977	16,977	16,977
MAPP - US	32,654	33,191	33,191	33,356	33,356	33,356	33,521	33,521	33,521
Net Internal Capacity	614,725	632,381	649,996	656,051	652,385	650,897	650,290	649,528	649,528
Reserve Capacity	91,342	93,174	99,699	94,952	80,866	67,462	55,882	43,756	31,647
Eastern Grid Reserve Margin	17.5%	17.3%	18.1%	16.9%	14.1%	11.6%	9.4%	7.2%	5.1%
Western Grid Peak Demand	124,995	127,150	129,590	132,098	134,655	137,231	140,030	142,772	145,572
Western Grid Capacity	155,248	158,726	161,137	165,634	165,882	165,882	165,882	165,882	165,882
Reserve Capacity	30,253	31,576	31,547	33,536	31,227	28,651	25,852	23,110	20,310
Western Grid Reserve Margin	24.2%	24.8%	24.3%	25.4%	23.2%	20.9%	18.5%	16.2%	14.0%

several hours) in exchange for a rate reduction to the customer. Interruptible load is a more large-scale program where, say, an entire industrial site agrees to allow the power supplier to cutoff the electricity (again for up to several hours) in exchange for a rate reduction. The interruptible component of a power supplier's customer demand can be significant. It reaches as high as 8% of total demand in some regions. It is also considered somewhat controversial as many of the programs were initiated as pseudo-rate reductions to select industrials where the possibility of an actual supply interruption was remote. The figures in the chart below reflect demand after all interruptible load is taken out; re-including this component as actual demand would lower capacity reserves and the reserve margin.

The supply component is developed by:

- Identifying and aggregating utility owned generation resources
- Adding "behind the fence" capacity, i.e., co-generation
- Adding the value of expected new generating projects (a subset of those announced that will successfully complete development)
- Subtracting plant retirements
- Balancing regional supplies from expected movements across the transmission grid, in order to arrive at
- Net regional capacity

The first observation one would make after viewing the above chart is that the Eastern grid is fast becoming "short" while the Western grid maintains adequate reserves over more of the years reported. In fact, the East, particularly the midwest regions (Ecar, Main, Serc and Entergy), have needs for new resources not yet started in development. Other areas in the east (Nypool and Nepool) either have sufficient reserves now or announced new projects that indicate an excess supply situation for the foreseeable future. The West, while appearing long, is more the result of large hydro reserves in the Pacific Northwest. Other areas in the West, namely California and Arizona, have needs for new generation within the next two-three years. Power prices currently reflect these perceptions.

Cost of Capacity

The capacity component, economic rent, or shortage costs, that exist in the forward market for electricity is the result of the aggregation of daily supply-demand balances. The factors that influence this are:

- Daily weather conditions, for its impact on demand
- The accuracy of the demand forecast
- Plant availability in the region
- Outages on key supply facilities
- The level of congestion on transmission
- The trading positions of key members in the market

Under a perfectly balanced system, prices would be expected to converge at long run marginal cost. This can be viewed as the sum of fuel and other variable O&M, plus the annual fixed operating and capital recovery costs. In the perfect world, suppliers construct the optimal amount of new capacity as well as the optimal portfolio of baseload, intermediate and peaking facilities. The amount and portfolio mix would be based on existing plant retirements, load growth, and the (net) amount and type of generation that flows into the region.

Using the above table as an example, power suppliers would begin to develop projects that would begin commercial operation in about the year 2004 so that the reserve margin increased to a level above 15%. If sited in Ecar, the plant is probably a peaking facility, to complement the existing portfolio of predominately coal and other baseload resources. If sited in Ercot or Entergy, the plant is more likely a combined cycle gas plant that would take advantage of superior heat rates and cheap gas supplies.

The annual costs that result from a long run marginal cost perspective, can be computed using dispatch and cash flow models. The former is used to determine annual output, fuel and variable operating costs of the existing and new generation mix. The latter is used to compute annual costs of the optimal plant addition. Then the annual costs can be defined on a per mwh basis to arrive at the expected future power price.

However, the above type analysis fails to consider two important questions:

1. How should fixed costs be allocated? And
2. How large is the fixed cost component under less than perfect balance?

Historical evidence (there is often only a short period to consider, e.g. less than 2 years in many cases) suggests that the shortage component can only be captured during periods where the capacity surplus is minimal. For example, over 80% of annual shortage costs have been historically recovered in the July-August on-peak period. Other times include the rare day where load is abnormally high, or an outage occurs on a key generating or transmission resource. Overall, shortage costs observed in the hourly markets occur mainly in the top 500 hours (about 5%). A number of modeling approaches have been utilized to address the sharpness of the power price curve, including mean reversion models, Monte Carlo simulation, and statistical methods. To date, there is no universally accepted approach, which is largely the result of lack of hard data with which to construct a model.

There are a number of ways to construct a model of shortage costs. In any case, the following information will aid in decision making and forecasting:

1. Annual Reserve Margin may help dictate the response of the forward curve to new plant development. For example, the Nepool curve over the past year (18 months ago contango, then backwardation as a result of the plethora of new project announcements, then more flat as more and more of the announced facilities abandoned development) present evidence of the relationship between reserve margin and prices.

2. The development of a functional form of the relationship between daily prices, temperature, load and significant plant outages would be a more robust analysis. Load and temperature data is available as far back as twenty years. Price data is available but in many instances for only a few months back. Outage data is the hardest to acquire. Often, outages of large units are publicized, but information for the majority of units is privately maintained. The "Rampup" database provides hourly generation data; this indicates when plants are operating but does not provide a reason (economic or outage) why the plant is not online.

3. Historical price volatility data can be compared to daily demand and load volatility to further strengthen the functional relationships.

4. A mapping of significant generating assets, e.g., those closely connected to major load sites may help determine when outages of specific resources are more highly correlated to price spikes.

5. California, Nepool, and the England&Wales pool provide historical spot prices on an hourly basis and thus might be used to further develop the relationship between prices, the supply-demand balance, fuel prices, transmission constraints and other factors.

The North American Fundamental Power Model

As discussed earlier, there are several approaches the modeler can take in developing a power forecasting model. The outline below provides a broad categorization of the data required.

Outline

Regional Breakdown
- NERC regions and/or Trading Hubs
- California Breakout (NP15, ZP26, SP15)
- Canadian Imports
- Regulatory Environment (for example: ISO or RTO)

Demand Module
- Historical hourly load shapes (available from FERC Form 714)
- Annual Peak and Energy Forecast (developed internally or available from EIA Form 411)

Energy Supply Module
- Regional Generating Resources
  - Capacity (summer & winter rating: available from RDI Powerdat)
  - Minimum output rating (RDI)
  - Estimate of unplanned outages and scheduled maintenance
    - (historical data available from RDI and RampUp database)
  - Heat Rate Data (available from EIA Form 860 or derived from RPA Stack Emission Database)
  - Hydro Unit data (periodic water flow, reservoir size, capacity, efficiency)
  - Location
  - Ramping flexibility (RDI)
- Fuel Cost Information (delivered to plant)
  - Forecast of spot prices (gas, coal, nuclear, oil, distillate)
  - Location basis
  - Applicable LDC charges

Transmission Path Module
- Contracted inter-regional power flows

Excess capability to move power from region to region (available from regional transmission studies that comprise FERC Form 715)

Capacity Module
- Annual view of supply-demand balance by region
  - Expected new entrants and retirements by year
  - Peak demand forecast, interruptible load, demand mgt. programs
  - Import & Export capability
  - Projected Reserve Margin
- Historical recovery of capital costs, i.e., the difference between spot prices and Short run marginal cost
  - Historical daily spot prices
  - Historical daily peak demand
  - Historical plant availability
  - Historical daily spot fuel costs
  - Historical daily ancillary service prices
  - Historical daily transmission outages and/or constraints
- Historical price volatility
  - Daily
  - Monthly
  - Correlation between power and underlying fuel prices
- New Entrant Capital Cost Estimates
  - By plant type (combined cycle, peaker)
  - Construction costs
  - Annual fixed expenses (labor, rents, property taxes, etc)

Given that the above information has or can be collected the steps in creating the power model would include:

1.) Develop regional supply-demand tables for each year of the study period. The tables would identify peak load, net peak (less interruptibles and load mgt.), existing capacity in the region, new entrants and retirements.
2.) Refine the supply-demand tables to account for inter-regional transfer capability of energy. For example, the modeler would identify the amount of power that could flow from the Southeast (SERC region) to the Midwest when economically advantageous.
3.) Construct a database to represent the supply stack. This includes plant operating characteristics and specific underlying fuel price estimates.
4.) Employ a production costing model to develop hourly short run marginal energy costs based on the supply-demand framework established above.
5.) Identify capital recovery costs required to attract new entrants. This entails a cash flow model with an assumption of the return requirement of the participants.
6.) Develop a method to allocate capital recovery costs to select hours based on historical performance.
7.) Identify the hourly differences in regional prices; adjust prices for convergence based on historical arbitrage.

8.) Examine the prices produced by the model for inconsistencies or mis-interpretations.
9.) Once the base case has been developed, repeat the above steps for alternative scenarios or sensitivity studies.

Checking the Model

The following below are questions the modeler might ask to check the validity of the model:

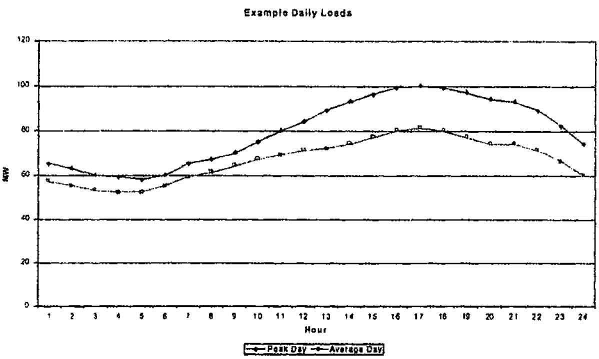
1.) Is the model consistent with historical, i.e., known, or expected results? In general, the model should produce market prices similar to recent experience after accounting for major changes such as fuel costs, new units, retirements, and major plant outages.
2.) Are the historical off-peak prices and on-peak prices during shoulder months consistent with short run marginal cost produced by the model? Large variations between market and model during these hours suggest significant data errors.
3.) Are the power price differentials between regions consistent with the market? If not, are there significant changes in the fundamental makeup to suggest a price flip?
4.) Is the number of hours in the model where prices are marked up for capacity consistent with the market? Is the daily and monthly price volatility consistent with historical results, after accounting for fundamental changes?
5.) Is the capacity markup consistent with historical evidence? The model should be able to provide a probability distribution of daily price as a function of surplus demand in the region. The model should be able to demonstrate the conditions needed to exist to achieve prices >$100, >$500, >$1000?
6.) Does the model respond appropriately to alternative scenarios and sensitivity studies?

An Illustrated Example

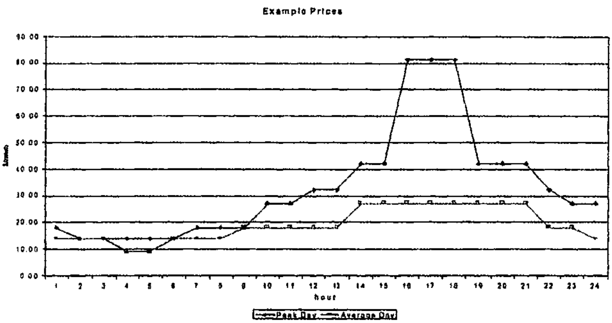
Assume a simple regional power system as characterized by the table below. The plant group column might represent a single plant or several plants of similar cost and availability. The variable cost column represents the sum of fuel cost x heat rate + variable O&M. To simplify matters, we assume the plant cost is the same for all levels of output (e.g., heat rate is constant).

Next, assume we must forecast the power price over two days given by the load curves pictured below:

Plant	Size (MW)	Var. Cost ($/mwh)	Avail. (%)	Net Avail. (MW)
1	52	9.00	0.90	46.80
2	11	14.00	0.92	10.12
3	10	18.00	0.90	9.00
4	9	27.00	0.95	8.55
5	8	32.00	0.95	7.60
6	7	42.00	0.85	5.95
7	3	81.00	0.88	2.64
8	20	200.00	0.99	19.80
	120.00			110.46

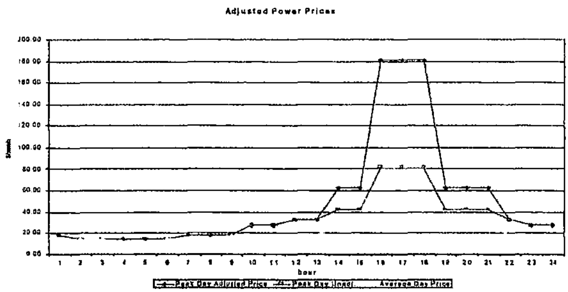


A simple stacking of the plants against the hourly loads would result in prices as shown below:



The above graphs and table raise a number of issues. First, it is apparent that plant group 1, generating at a cost of $9/mwh, recovers cost each hour and contributes to fixed expenses and profit in all but two hours. During the peak day plant 1 earns:

($81-$9) = $72/mwh x 52 MW x 3 hrs = $11,232. The earnings during these three hours plus the others during the year may but likely will not be sufficient to recover all fixed expenses (labor, rents, supplies, etc.) plus contribute profit to clear the company's hurdle rate. The financial model would then compute the required premium needed to fully recover costs and earn sufficient return on investment. Historical data in the form of hourly prices (available in California, PJM and NePool) and daily spot price volatility would likely suggest that fixed cost premiums would not occur during the "average" day when load is well below the total available capacity and the marginal energy cost stays below $30. More likely, the fixed cost premium would occur during the top priced hours of the year; thus the financial model in this example would attach a price premium to the six hours of the peak day. Further, the allocation would be higher in the top three hours than the next tier. For example, the $81 price might spike to $181, while the $42 price might spike to only $62. The financial model would work in a manner so as to develop hourly prices that closely mirror historical price shape and volatility as well as target earnings for the generators.



The next issue raised by the example is plant availability. The above price curve only applies when all the plants are available to meet demand. "On average" the plant list of 120 MW with the availability rates listed above appear sufficient to meet a daily peak of 100 MW. However, on days where load rises above 100 MW, say on extremely hot summer days, there is an increasing probability that the above plants will not be sufficient. Moreover, it is likely that some units (albeit a small percentage) will not be available due to some unforeseen plant breakdown. The net effect is that instead of plant group 7 (with an $81 cost) being at the margin, the system is forced to operate plant group 8 with much higher cost. In fact, the system may be forced to purchase high priced power from outside the region or shed demand (blackout). The Monte Carlo approach would be to simulate daily demand conditions subject to potential weather variations. Then the model simulates plant availability and matches up supply and demand conditions. Based on historical prices, supply and demand conditions, the Monte Carlo approach assigns price premiums that have been observed in the past. For example, a 1% capacity surplus might result in a very high premium (say >$1000/mwh) while a 10% instantaneous capacity surplus results in no premium. Once the relationship is determined, the prices in each simulation are determined and given a probability of occurance.

<u>Suggested Reading</u>

Stoll, Harry G., <u>Least Cost Electric Utility Planning</u>, John Wiley & Sons, Inc., ISBN 0-471-63614-2

Fundamental Analysis of Natural Gas Modeling

Outline:

1. Introduction

2. Supply Issues

- Existing Supply Resources
- Supply Costs
- Analyzing Supply Deliverability

3. Demand Considerations

- Gas Demand Constants
- Gas Demand Usage by Sector (chart)
- Core and Non-Core Markets and Fuel Switching
- Natural Gas Prices Relative to Oil Prices (graph)
- GDP projections and their potential affect on gas demand (graph)
- Power generation growth and environmental issues

4. The Pipeline Network

- Overview of the existing pipeline network
- Pipeline Regional Capacities, Average Flows, and Usage Rates (chart)
- Recent Pipeline Variable Operating Costs to East North Central Markets (chart)
- Proposed New Pipelines (table)
- Historical Pipeline additions and costs

5. Storage Issues

- Storage and Gas Demand
- Storage Costs and Gas Prices
- Summer demand spikes and gas

6. The Fundamental Gas Model

- A Simplified Natural Gas Model (map/network diagram)
- Steps to creating a simple gas model
- Checking the Model

Introduction

The natural gas business has evolved dramatically over the past few decades from a highly regulated industry to an increasingly unregulated industry today. The advent of the deregulated natural gas industry has resulted in a number of new business opportunities within the industry. At one time, local distribution companies purchased substantially all of their gas supplies directly from the interstate gas pipeline companies. Today, these same local distribution companies (LDCs) are much more likely to purchase their gas supplies from gas marketers. In addition, many of these same LDCs have negotiated deals with various marketers under which the marketers manage the LDCs' gas supply requirements and gas transportation and storage contracts.

If today's industry players expect to realize the full benefits from industry deregulation, they must have a thorough understanding of the fundamentals of the industry, the fundamentals that drive the gas pricing mechanism. This paper discusses the fundamentals that drive prices within the natural gas industry and focuses on natural gas modeling tips and techniques.

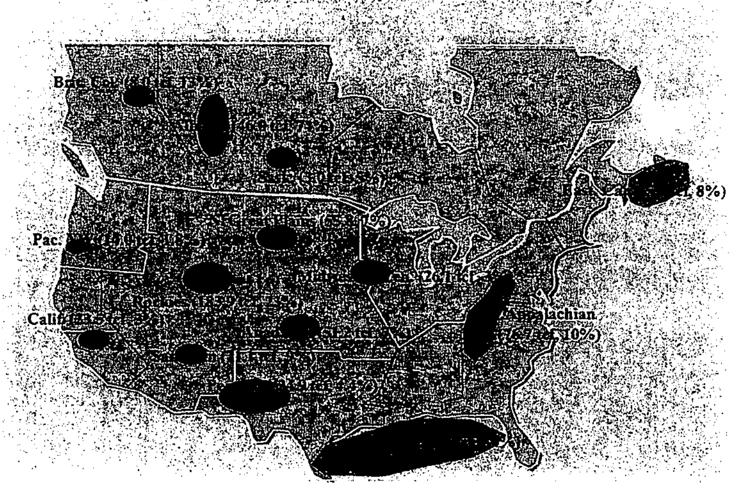
Supply Issues

Existing Supply Resources

North American natural gas supply sources include gas from both conventional oil and gas reservoirs or non-conventional sources, such as coalbed methane, tight sands, and shale seam formations and LNG shipments. Currently, approximately 75% of the proved reserves in the United States are from conventional sources, most of which are in the Gulf Coast, Anadarko, and Permian supply regions.

The following map shows the major supply basins in North America with the Proved and Potential Reserves for each basin and the percentage of the total reserves for each basin (for each country):

North American Supply Basins
(Proved/Potential Reserves, % of total U.S/Canada)



Most of the unconventional resource formations are located in the San Juan, Rocky Mountain, and Appalachian regions. LNG receipt points in the United States include terminals at Cove Point, Maryland; Lake Charles, Louisiana; Boston, Massachusetts; and Elba Island, Georgia. In Canada, the vast majority of the gas resources are located in the Western Canadian Sedimentary Basin in Alberta and neighboring British Columbia and Saskatchewan. The gas modeler must include all of these existing gas supply sources in the model network

Supply Costs

Projecting supply costs is one of the most critical factors in gas modeling. Natural gas producers are faced with a multitude of supply costs in extracting their gas reserves and delivering these reserves to the pipelines. These costs include the following:

- Exploration costs which include acquisition of unproved acreage, geological and geophysical seismic costs, and drilling and equipping costs;
- Development costs which include acquisition of proved acreage, lease equipment, and additional support drilling and equipping costs; and
- Production (lifting) costs which include taxes, compression charges, processing charges, gathering charges, and fuel losses.

Supply costs will fluctuate based upon the level of reserves (hence deliverability) replacement and the level of drilling required to meet anticipated gas demand levels. The following table shows a breakdown of total exploration and development costs in the United States from 1991 through 1997:

		1991	1992	1993	1994	1995	1996	1997
Exploration Costs (million $)		(1)						
U. S. Onshore	2,160	1,593	1,371	1,491	1,644	1,644	3,394	
U. S. Offshore	2,109	1,082	1,415	1,897	1,866	2,827	3,598	
Canada		661	336	403	573	493	355	310

Development Costs								
U. S. Onshore	7,430	5,703	5,843	6,324	6,051	6,087	9,807	
U. S. Offshore	2,506	1,936	2,303	2,876	2,873	3,892	5,229	
Canada		1,070	770	1,156	1,262	1,406	1,210	1,688
Total U. S. Expl. & Devl.	14,205	10,314	10,932	12,588	12,434	14,450	22,028	
Total Can. Expl & Devl.	1,731	1,106	1,559	1,835	1,899	1,565	1,998	

(1) Source: Energy Information Administration, Form EIA-28

Production costs, primarily gathering and processing costs, have averaged $0.30- $0..33 cents/Mcf onshore and $0.25/Mcf offshore during this same time period

Analyzing Supply Deliverability

Because natural gas is a depletable resource, the gas modeler must continuously monitor the depletion of the gas supply regions. Each region has a different reserves to production (R/P) ratio depending upon the dynamics of the reservoirs within the region. The modeler incorporates this R/P ratio in his forecast of the future gas supply deliverability for each region. The following chart (2) shows typical R/P ratios for various conventional resource basins during 1994:

Supply Region	Proved Reserves 12/31/93 (Bcf)	1994 Prod. (Bcf)	R/P Ratio
Anadarko	24105	2563	9.4
Appalachia	236	4	53.7
California-Onshore	2876	253	11.4
California-Offshore	1737	58	29.9
Gulf-Offshore	27296	4942	5.5
Gulf-West Onshore	17542	3070	5.7
North Central	993	59	16.9
Northern Great Plains	2585	201	12.8
Permian	14343	1791	8.0
Rockies	4897	489	10.0

(2) Source: California Energy Commission's "Natural Gas Market Outlook", June, 1998.

Another factor that the gas modeler must consider in his deliverability projections and costs are the current rig and well counts. Has there been sufficient drilling activity to replace declining reserves? The following chart demonstrates how the relationship between rig counts and gas well completions per rig often varies and how that relationship has changed over the last few years:

(Total United States)

		1993	1994	1995	1996	1997	1998
Gas Rigs		365	426	385	464	566	554
Gas Well Completions/Rig		29.4	25.0	25.2	21.6	20.2	18.5
Total Production Bcf/d	49.99	51.38	50.53	52.98	53.86	53.07	

The table above demonstrates that, from 1993 to 1998, the rig count increase averaged 8.7% per year, but the gas well completions per rig over that same time period actually declined over 9% per year. Also, the average annual production increase from 1993 through 1998 has been approximately 1.2% per year. Contrast this 1.2% production increase figure with an average projected demand increase of 2.5% per year from 1999 forward!

Finally, the modeler must also incorporate into the model all new supply resource basins.

The modeler must determine if sufficient gas reserves and deliverability are (economically) available to meet the market's gas demand projections. How many rigs will be needed to generate the supply necessary to meet the gas demand, subject to the modeler's interpretation of the gas deliverability curve? Is there a sufficient level of inventory of rigs to meet this demand? Have there been, or do we anticipate, any technological advances that may lower the drilling costs in the future? Does history tell us anything about the correlation between technological advances and lowered drilling costs?

Demand Considerations

Gas Demand Constants

There are a few constants that the gas modeler can depend upon in analyzing gas demand. First, gas demand tends to be seasonal in nature. Colder temperatures, for example, generally correlate to increased demand in the residential and commercial sectors. However, cold temperatures do not tend to have as large an influence on the industrial and power generation sectors. Observing historical regional trends is a good way for the gas modeler to initially allocate demand for each month among the various sectors. The Energy Information Administration's "Natural Gas Monthly" publication is a good data source for this purpose. The following table shows a typical percentage distribution of gas demand usage by month for two different regions of the United States:

	Florida:			***New England:***		
	Res/Comm	Ind.	Elec.	Res/Comm	Ind.	Elec.
Jan	17%	8%	6%	18%	9%	1%
Feb	15%	7%	5%	18%	8%	1%
Mar	11%	8%	7%	15%	9%	6%
Apr	8%	8%	7%	9%	7%	10%
May	6%	7%	10%	5%	8%	11%
Jun	5%	8%	9%	4%	8%	13%
Jul	5%	8%	10%	3%	8%	14%
Aug	4%	9%	11%	3%	8%	15%
Sep	5%	8%	10%	3%	8%	9%
Oct	5%	9%	8%	5%	9%	11%
Nov	7%	9%	9%	7%	9%	5%
Dec	12%	10%	8%	11%	8%	3%

Notice the relatively flat industrial loads in the table above and the Summerspikes in the electric load.

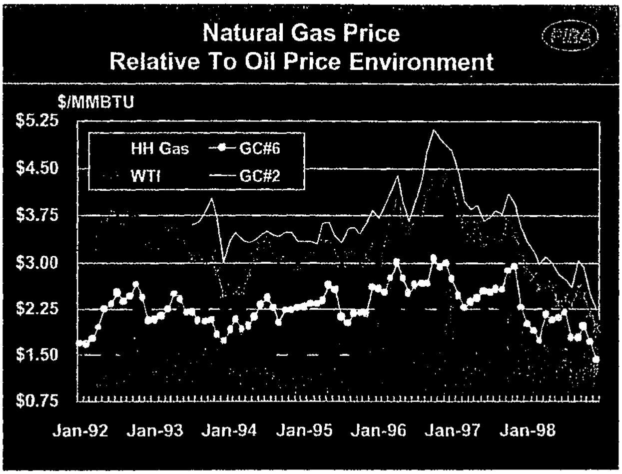
The gas modeler must be aware of the distinction between core and non-core markets. In general, core markets are defined as those markets which do not have fuel-switching capabilities whereas non-core markets have the ability to readily switch to a competing fuel, such as No. 2 fuel oil or coal. Core markets include the residential and commercial sectors and a percentage of the industrial and electric generation sectors. The percentage of the industrial and electric generation sectors with competing fuel capability varies from region to region, so the gas modeler must determine what percentage of each market is core vs. noncore and at what price the consumer will switch fuels. The Federal Energy Regulatory Commission's Form 423, an annual report of the different types of fuel purchased by each utility, is one tool used to help determine this volume allocation. The gas modeler must monitor the gas prices vs. fuel oil prices closely in order to project the competitive fuel-switching price, as this price is a critical input in any gas model. The following conversion factors can be used to convert daily, monthly, or annual fuel usage in gallons to an equivalent Mcf of gas at a 1030 Btu:

Propane:	11.245	(91,600 Btu/gallon)
No. 2 oil:	7.410	(139,000 Btu/gallon)
No. 6 oil:	6.960	(148,000 Btu/gallon)

In the example above, if you use 100,000 gallons per year of No. 6 oil, the equivalent number of Mcf is 100,000 divided by 6.960 or 14,368 Mcf per year. The following is a price equivalency table for gas (at a 1030 Btu), propane, No. 2 oil, and No. 6 oil :

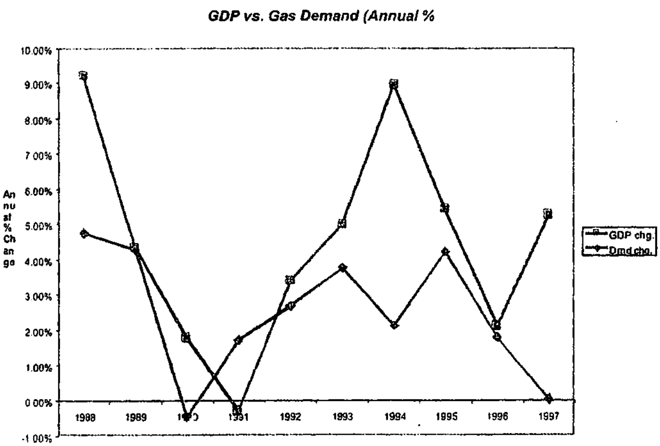
Nat. Gas $/MMBtu	Nat. Gas $/Mcf	#2 Oil $/gal	#6 Oil $/gal	Propane $/gal
$1.80	$ 1.85	$0.250	$0.266	$0.165
$1.85	$ 1.91	$0.257	$0.274	$0.169
$1.90	$ 1.96	$0.264	$0.281	$0.174
$1.95	$ 2.01	$0.271	$0.289	$0.179
$2.00	$ 2.06	$0.278	$0.296	$0.183
$2.05	$ 2.11	$0.285	$0.303	$0.188
$2.10	$ 2.16	$0.292	$0.311	$0.192
$2.15	$ 2.21	$0.299	$0.318	$0.197
$2.20	$ 2.27	$0.306	$0.326	$0.202
$2.25	$ 2.32	$0.313	$0.333	$0.206
$2.30	$ 2.37	$0.320	$0.340	$0.211
$2.35	$ 2.42	$0.327	$0.348	$0.215
$2.40	$ 2.47	$0.334	$0.355	$0.220
$2.45	$ 2.52	$0.341	$0.363	$0.224
$2.50	$ 2.58	$0.347	$0.370	$0.229
$2.55	$ 2.63	$0.354	$0.377	$0.234
$2.60	$ 2.68	$0.361	$0.385	$0.238
$2.65	$ 2.73	$0.368	$0.392	$0.243
$2.70	$ 2.78	$0.375	$0.400	$0.247
$2.75	$ 2.83	$0.382	$0.407	$0.252
$2.80	$ 2.88	$0.389	$0.414	$0.256
$2.85	$ 2.94	$0.396	$0.422	$0.261
$2.90	$ 2.99	$0.403	$0.429	$0.266
$2.95	$ 3.04	$0.410	$0.437	$0.270
$3.00	$ 3.09	$0.417	$0.444	$0.275
$3.05	$ 3.14	$0.424	$0.451	$0.279
$3.10	$ 3.19	$0.431	$0.459	$0.284
$3.15	$ 3.24	$0.438	$0.466	$0.289
$3.20	$ 3.30	$0.445	$0.474	$0.293
$3.25	$ 3.35	$0.452	$0.481	$0.298
$3.30	$ 3.40	$0.459	$0.488	$0.302
$3.35	$ 3.45	$0.466	$0.496	$0.307
$3.40	$ 3.50	$0.473	$0.503	$0.311
$3.45	$ 3.55	$0.480	$0.511	$0.316
$3.50	$ 3.61	$0.486	$0.518	$0.321

There exists a rather high correlation factor between the prices for Fuel Oil #6 and WTI crude oil. This correlation factor can be used in conjunction with the crude oil futures prices to project the competitive fuel price for the model. The following table from PIRA shows the correlation between natural gas prices relative to various oil prices from 1992-1998:



Changes in Gas Demand

There are a number of reasons why gas demand may fluctuate other than a consumer switching to a cheaper



fuel. A strong GDP, for example, translates into an increase in gas demand, particularly in the industrial sector. The graph below depicts the relationship between changes in the GDP (annually) and changes in gas demand from 1988-1997.

Another recent development that will have a continuing affect on gas demand projections is the rapid growth in gas-fired power generation units. In its September 13, 1999 issue *Gas Daily* reports that between 80,000 MW and 165,000 MW of new generating capacity is proposed for development. *Gas Daily* believes that, realistically, about 40,000 MW of this capacity may be constructed resulting in additional gas demand of perhaps 7 bcf/d.

Gas demand may also fluctuate due to new environmental treaties or laws. The Kyoto Treaty calls for a 5% reduction in greenhouse gas emissions by the period 2008-2012 from their level in 1990. If implemented by the United States and Canada, this treaty could potentially result in a huge reduction in energy consumption and higher energy prices. Also, Federal clean-air mandates calling for lower NOX and SOX emissions may result in increased consumption of natural gas.

There are a number of different gas demand forecasts currently floating around the gas industry. In separate studies conducted recently, PIRA projects a 27 tcf U. S. demand market by 2010 and EIA forecasts a 30 tcf U. S. demand market by 2011. The gas modeler's job is to analyze these forecasts and to arrive at a demand forecast that is consistent with his company's interpretation of the future market for natural gas.

The Pipeline Network

The natural gas pipeline network in North America consists of a complex labyrinth of lines connecting gas supply sources to demand centers and other pipelines. There are more than 85 U. S. interstate pipeline systems operating approximately 200,000 miles of transmission lines. In addition, there are 11 major Canadian lines, the largest of which is TransCanada PipeLines which transports gas from Alberta to Quebec.

Capacities and Usage Rates

The gas modeler's first task in analyzing the pipeline network is to model the existing interregional pipeline capacities. The following data, extracted from a recent publication by the Energy Information Administration entitled "Deliverability on the Interstate Natural Gas Pipeline System", is a good starting point for this task. This table summarizes the pipeline capacities from region to region and the average flows and usage rates across the regions as of 1996:

Table: Pipeline Regional Capacities, Average Flows, and Usage Rates

Sending Region	Receiving Region	Capacity	Avg. Flow	Usage Rate (1)
Canada	Central	1.563	1.542	99
	Midwest	3.049	2.581	85
	Northeast	2.393	1.834	77
	Western	3.786	3.275	87
Total from Canada		10.791	9.233	86
Mexico	Southwest	.350	.037	11
Total from Mexico		.350	.037	11

Central	Canada	.066	.004	4
	Midwest	9.879	7.714	78
	Southwest	2.114	1.267	70
	Western	1.194	.713	95
Total from Central		13.253	9.698	78
Midwest	Canada	2.543	1.626	68
	Central	2.354	1.564	94
	Northeast	4.887	4.220	86
Total from Midwest		9.784	7.41	83
Northeast	Midwest	2.038	.910	45
	Southeast	.520	.015	60
Total from Northeast		2.558	.925	45
Southeast	Midwest	9.821	8.020	82
	Northeast	5.149	4.431	86
	Southwest	.405	.060	86
Total from Southeast		15.375	10.300	83
Southwest	Central	8.609	4.993	60
	Mexico	.844	.083	10
	Southeast	20.846	16.063	77
	Western	5.351	2.415	45
Total from Southwest		35.650	23.555	66
Western	Central	.298	.004	0
	Mexico	.045	.009	21
Total from Western		.343	.013	29
Grand Total		88.0	63.4	72

(1) Usage rates shown may not equal the average flow divided by the capacity because in some cases no throughput was reported at known border crossings, so this capacity was not included in the usage rate computation.

Transport Costs

In order to more accurately capture the transport cost differentials among the pipelines, the gas modeler will need to further sub-allocate the data in the above table to the 85 interstate systems in the United States and 11 Canadian systems. Most of the pipeline rate data can be found on the individual pipeline bulletin boards on the internet or from numerous industry publications and databases. The following chart summarizes recent variable operating costs for various pipelines serving the East North Central region:

Recent Pipeline Variable Operating Costs to

East North Central Markets

Pipeline	VOC	Fuel %	*Total VOC*

N. Border (16,13)	$	0.290	2.90%	$	0.348
NGPL (16,6)	$	0.001	2.12%	$	0.043
NGPL (IA-IL)	$	0.002	1.81%	$	0.038
NB (Ventura-Joliet)	$	0.150	1.30%	$	0.176
ANR (Midcont-Chi)	$	0.047	5.24%	$	0.152
NGPL (LA-Chi)	$	0.011	3.26%	$	0.076
NGPL (Carth-Tuscola)	$	0.009	3.80%	$	0.085
ANR (Gulf-Mich)	$	0.046	5.33%	$	0.153
Trunkline (LA-Tuscola)	$	0.015	2.65%	$	0.068
Trunkline (Tuscola-Chi)	$	0.006	0.96%	$	0.025
Trunkline (Tuscola-Ohio)	$	0.006	0.96%	$	0.025
Great Lakes	$	0.017	3.01%	$	0.077
TxGas (Carth-Leb)	$	0.036	3.50%	$	0.106
TxGas (Monroe-Leb)	$	0.045	4.58%	$	0.136

<u>New Pipelines</u>

A critical factor in modeling natural gas pipeline fundamentals is forecasting which pipelines will actually be constructed. The following chart summarizes the recently announced and proposed pipelines.

Region	**Project Name**	**Project Type**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**Incre. Cap. (Bcf/d)**
			Expected InService Month:							
W. Can.	Southern Crossing (BC)	New Pipe			11					0.30
W. Can.	TCPL 1999 facilities			11						0.10
E. Can.	Millenium West Pipeline	New Pipe			11					0.70
E. Can.	Lake Erie Crossing	New Pipe			11					0.70
E. Can.	Maritimes & N.E.	New Pipe		11						0.53
E. Can.	TGM Exp. (Supply PNGTS)	Extension		2						0.18
Northeast (Cross Border)	Millennium Pipeline	New Pipe			11					0.70
Northeast (Cross Border)	Maritimes & N.E.	New Pipe		11						0.44
Northeast (Cross Border)	Portland Nat. Gas Trans.	New Pipe		2						0.18
'ortheast (Interregional)	ANR Supply Link	Expansion			11					
ortheast (Interregional)	Independence	New Pipe			11					0.90
Northeast (Interregional)	Transco Market Link Expan.	Expansion			11					
Northeast (Interregional)	Spectrum	Cap. Turnback			xxxx x					0.03
Northeast (Interregional)	Eastern Express Project 2000	Exp./Ext.			11					0.17
Northeast (Interregional)	Iroquois (NY-Vermont lat.)	Lateral				11				0.23
Northeast (Interregional)	Hub Pipeline (Algonquin)	Extension			11					0.60
Midwest US	Alliance Pipeline	New Pipe			10					1.33
Midwest US	Northern Border: 1998	Exp./Ext.	12							0.70
Midwest US	Northern Border: 2000	Extension			xxxx x					0.06
Midwest US	Vector Pipeline (to	New Pipe			10					1.00

	Millen.)								
Midwest US	TriState Pipeline (to Millen.)	New & Exp.		11					0.50
Midwest US	Viking Voyageur								0.00
Midwest US (Intraregional)	Illinois-Wisconsin	New Pipe			11				0.65
Midwest US (Intraregional)	ANR System Expansion	Expansion		11					0.20
Midwest US (Intraregional)	ANR System Expansion	Expansion			11				
Midwest US (Intraregional)	Guardian Pipeline	New Pipe		11					0.75
Midwest US (Intraregional)	Horizon Pipeline	New Pipe			Fall				0.63
S. Central/S. Atl. (Carolina)	Palemetto Interstate Pipe.	New Pipe				4 (Ph 1)	4 (Ph 2)	4 (Ph 3)	0.20
S. Central/S. Atl. (Carolina)	Carolinas Pipeline Project	Exp./Ext.					1st Qtr		
S. Central/S. Atl. (Carolina)	Sundance Expansion	Expansion				4			
S. Central/S. Atl. (Other)	SouthCoast Expansion	Expansion		11					
Central/S. Atl. (Other)	East Tennessee Nat. Gas	Expansion		11					
S. Central/S. Atl. (Other)	Volunteer Pipeline	New Pipe			11				0.03
S. Central/S. Atl. (Florida)	Florida Gas - Phase IV Exp.	Expansion			5				0.27
S. Central/S. Atl. (Florida)	Florida Gas - Phase V Exp.	Expansion			12				
S. Central/S. Atl. (Florida)	Gulf Stream Pipeline	New Pipe				6			
S. Central/S. Atl. (Florida)	Buccaneer	New Pipe				4			
S. Central/S. Atl. (Florida)	Sawgrass	New Pipe				11			1.00
Western/Mountain	Coastal	New Pipe							
Western/Mountain	Southern Trails Pipeline	Conversion/Ext.				1st Qtr.			0.12
Western/Mountain	TransColorado Gas Trans.	New Pipe	2						0.20
Western/Mountain	Ruby Pipeline	New Pipe			Fall				0.25
Western/Mountain	Kern River Expansion	Expansion		12					0.30
								Total	**13.93**

As the table demonstrates, a number of competing regional pipeline projects are often announced. For example, there are currently three major pipeline projects plus an existing pipeline capacity expansion project (in two phases) proposed for the Florida market. The Florida market demand is not predicted to be sufficient to warrant the construction of this much new capacity. The gas modeler's job is to determine which pipeline(s) will actually be constructed or, at the very least, how much new capacity will actually be built in the area based upon the projected demand. Historically, in cases where none of the pipelines has a competitive advantage in the market place, the competing projects have often pooled their resources and shared the market by building jointly owned lines.

Historical Pipeline Additions

The gas modeler would benefit from studying historical additions to the pipeline network and the cost of these additions. This analysis, along with an understanding of the existing regional basis differentials and regional capacity usage factors, provides a guide for assessing whether or not the proposed pipelines can economically compete with the existing pipelines in the region.

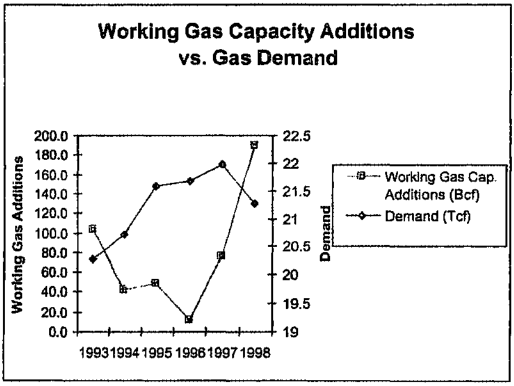
Storage Issues

One of the major advantages natural gas has over other alternative energy sources is that it can be stored. The benefits of gas storage to the natural gas industry are two fold in that it provides for a mitigating affect on both gas demand and gas prices.

Storage and Gas Demand

The United States currently has over 400 storage fields with a working gas capacity of over 3,200 bcf. The American Gas Association allocates each storage facility to one of three geographic location categories: the Producing Region has a working gas capacity of approximately 949 bcf and includes Texas, Oklahoma, Kansas, New Mexico, Louisiana, Arkansas, Mississippi, and Alabama; the West Consuming Region includes the states west of the Mississippi River and has a working gas capacity of 490 bcf; and the Eastern Consuming Region has a working gas capacity of over 1,800 bcf and includes the states east of the Mississippi River. In Canada, the storage fields in Alberta, Saskatchewan, British Columbia have a combined working gas capacity of approximately 275 bcf and the storage fields in Ontario and Quebec have a combined working gas capacity of 226 bcf.

Gas demand is forecasted to increase rather dramatically by the year 2004. One of the tasks of the gas modeler is to project gas storage additions. One might expect a correlation between increased gas demand and increased gas storage, and this relationship can be seen be studying historical data. The following chart demonstrates how gas storage has increased over the years in relation to increasing gas demand.



The current (lower) rate of increase in storage level additions in relation to storage demand has prompted some concern in the market place. This situation perhaps may be alleviated by the recent upsurge in gas prices, but the gas modeler must be aware of this current shortfall in storage and somehow factor it into the model's assumptions. Studying historical storage additions in relation to gas demand may help provide some insight into how the market will react should storage fail to keep up with gas demand.

Storage and Gas Prices

The other major benefit to gas storage is the affect it has on gas prices. Without gas storage, the consumer would pay dramatically higher prices during the Winter months as overall demand increases and pipeline capacities are stretched to their limit. Consuming region storage, in particular, alleviates this situation by reducing the amount of long-haul gas transportation required during the Winter.

Of course storage isn't free, so the gas modeler must include storage injection and withdrawal costs and fuel losses in the model. There are a number of industry databases and regulatory sources such as tariff filings where this data can be readily obtained.

Summer Demand Spikes

One of the beauties of gas storage is that traditionally storage injections and withdrawals have followed a rather consistent, logical pattern. Storage withdrawals peak during January when (an industry average) of approximately % of the working gas available is withdrawn. A typical annual withdrawal/injection schedule for a storage site having a working gas capacity of 4 bcf/d would most likely look something like the following table (these figures are the working gas available at the beginning of the month):

(Bcf/d):	WGA	Monthly Change
Jan	2.72	(.72)
Feb	2.00	(.47)
Mar	1.52	(.41)
Apr	1.12	.07
May	1.19	.38
Jun	1.57	.41
Jul	1.98	.43
Aug	2.41	.39
Sep	2.81	.41
Oct	3.22	.19
Nov	3.40	(.16)
Dec	3.24	(.52)

One of the challenges in the future to the gas modeler will be projecting the affect that Summer demand spikes due to gas used for power generation may have on storage. If Summer demand increases are as much as anticipated, one would expect the above storage schedule to be altered somewhat.

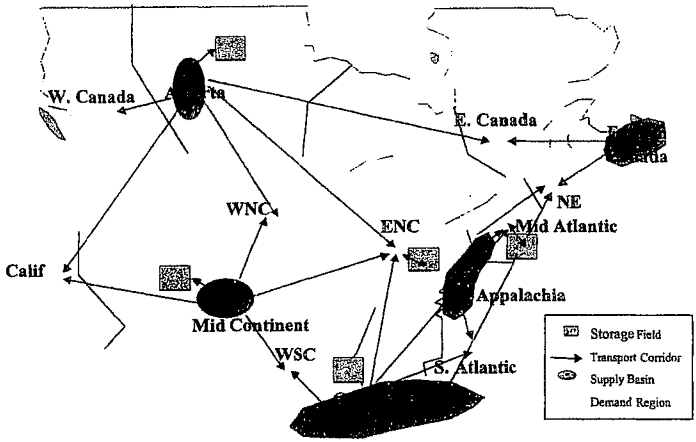
The Gas Model

When all of the above parameters are clearly identified, the gas modeler is ready to construct the model. One of the essential keys to any successful gas forecasting model is the logic behind the model's optimization algorithm. A gas model algorithm must consider all of the following factors. A successful model will mimic the market place, i.e., it will reach an equilibrium point between supply and demand, it will dispatch gas on a least-cost basis to consumers, it will properly allocate the gas between core and non-core markets based upon the alternative fuel price input by the user, it will dispatch storage logically.

Steps to Creating a Simple Gas Model

A simple gas model of North America might look something like the following diagram. It is recommended that the modeler create a mapped network such as that displayed in this example. This network diagram permits the modeler to more readily identify the relationships among the supply basins, demand centers, storage fields, and pipeline links.

A Simplified Natural Gas Model



To create such a model, the modeler should proceed in the following fashion (refer to the sources and techniques outlined in this paper to complete each of the following steps):

- Step 1: identify and diagram the storage basins for the model. In the sample model, we have identified and diagrammed five major supply basins – Mid Continent, Gulf Coast, Appalachia, Alberta, and Eastern Canada.
- Step 2: create a production profile (deliverability schedule) for the available supply for each basin for the model period.
- Step 3: assign supply costs to each supply basin for the model period.
- Step 4: identify and diagram the demand regions for the model. In the sample model, we have identified nine major demand regions – California, West North Central (WNC), East North Central (ENC), Western Canada, Eastern Canada, West South Central (WSC), South Atlantic, Mid Atlantic, and Northeast. Further subdivide the demand regions into core and non-core markets.
- Step 5: identify and diagram the storage fields. In the sample model, we have identified five major storage areas in the Mid Continent, Gulf Coast, ENC, Mid Atlantic, and Alberta regions. Three of these storage fields are linked to supply basins and two fields are linked to demand regions.
- Step 6: develop a storage plan for each storage field reflecting changes in the working gas available in storage from one time period to the next.
- Step 7. identify and diagram all pipeline links from region to region within the model.
- Step 8: assign capacity values, transportation rates, and fuel losses to each pipeline link.
- Step 9: input a node for the competitive fuel price, that price at which the non-core markets will switch to a competitive fuel.
- Step 10: link all the demand, supply, transport, storage, and competitive fuel nodes to formthe network. Note that in the sample model the storage nodes are bi-directional, representing injections into and withdrawals from storage.

After the model network has been created and all the data has been input into the model, the modeler is ready to let the model algorithm calculate the equilibrium price for supply and demand, i.e., the point at which, for each node, the supply and demand curves cross. This solution to this equilibrium algorithm must include all the variables that were identified in the above steps to creating a simple model - the supply deliverability schedule, the supply cost, the demand forecast subdivided into core and non-core markets, injections into and withdrawals from storage, the pipeline capacities from region to region, pipeline transport rates, pipeline losses, and the competitive fuel price.

- Checking the Model

How does one know that a natural gas model is working properly? How can one test the results? The following are some questions the modeler might ask to check the validity of the model:

- 1.) First of all, the model results should be relatively consistent with historical results. A good test of any model is to compare its results to history. By inputting known parameters from recent history, the model user can compare model results to history. If the results are significantly different, the model user should carefully review each input. If the network has been constructed properly (i.e., supply, demand, transport, and storage nodes are linked logically), The user should also be aware, however, that some of the differences in results most likely are due to market"perception" drivers or market "reaction" drivers, such as concerns over a hurricane in the gulf disrupting supplies or forecasts of an unusually cold or warm winter.
- 2.) The model should dispatch storage logically. Storage modeling presents a challenge since dispatching storage optimally does not always coincide with market dispatching. Often, the market refrains from withdrawing storage in December, even when December might be exceptionally cold and logic would dictate that the storage be withdrawn, since the market perceives the storage may be needed during January or February. For that reason, it is recommended that the model user have the ability to input a storage plan that overrides the model's storage optimization algorithm. - Another check on storage might be to review the August storage levels. Are they less than the other Summer months because of the increase in power generation gas usage?
- 3.) The allocation process should dispatch gas to consumers on a least-cost basis. The user should be able to "eyeball" this. Check the supply costs and transport costs feeding into each allocation node and confirm that the model is "least-cost" allocating.
- 4.) The model should reach a logical equilibrium price between supply and demand. This is another check that can be verified mainly by comparing results to history. If results seem unreasonable, begin the reconciliation process by checking the supply inputs. If supply looks reasonable, proceed to the demand levels, then the transport inputs, and finally the storage inputs.
- 5.) Do the model results clearly indicate market inefficiencies. Model price "blowouts" should be clearly visible in the results whenever capacity constraints occur or demand and supply are clearly unequal. The model will bump up against the alternative fuel price or the choke price. Also, another example, storage inefficiencies should be evident whenever storage working gas available capacity is inconsistent with increases in demand
- 6.) Change some of the model parameters. Does the model respond favorably to changing assumptions? When the model parameters are changed, subtle changes are reflected in basis spreads among the regions. It is much more uncommon for large regional basis swings to occur, unless parameters are changed rather dramatically . Identifying these changes requires that the model user have a through understanding of the North American gas market network.
- 7.) Do the model's price results reflect the seasonal changes in gas demand. Where there is more storage readily available, the prices will be more level; where less is available, the prices should spike more. Do the prices reflect the increased demand for gas usage in power generation during August, for example?

Fundamental Analysis of Crude Oil Markets

Basis Differentials in the World Crude Oil Markets:
There are over sixty different crude oils traded around the world. These crudes are valued differently for the following factors: 1) Quality of crude oil (heavy vs light, sweet vs sour), 2) transportation costs, 3) supply and demand and 4) events within the market place. By events within the market place I mean that if a refinery in Thailand has a serious fire and it declares force majeure, then it must resell its cargoes which it would have processed if it didn't go down.

The most volatile factor is supply and demand. Whether it is the OPEC nations reducing its supply of oil to the world market or regions demanding more oil and buying it away from its existing markets (an example would be Asian markets who are outbidding the European markets for West Africa oil), this can be a day-to-day dynamic. The most consistent factor affecting crude oil prices between basins is transportation costs. This represents the most consistent price differentiation.

The world has four very liquid markets for oil – West Texas Intermediate, Brent and Dubai crudes. West Texas Intermediate is priced typically at Cushing, Oklahoma and is the NYMEX trading point. Brent is the North Sea price for a number of different oils and is traded in London and around the world. Dubai is traded in Singapore and around the world.

A liquid market is one that is traded around the world against other markets and that futures contracts can be traded. There are many other crudes from Mexico, Columbia, Indonesia and FSU that are primarily sold under long-term contracts. These contracts are typically tied to indexes to prevent either party from getting hurt. They do not have futures markets at these points. Below is a listing of all the crudes that are available by country:

North Sea –	F S U -	West Africa -
Brent	Urals NEW	Bonny Light
Forties	Urals Mediterranean	Bonny Medium
Flotta	Siberian Light	Brass River
Ekofisk	Tengiz	Forcados
Oseberg	Azeri Light	Qua Iboe
Statfjord	Friendship Czech	Cabinda
	Friendship Germany	

Mediterranean -	U.S./Canada -	Mideast Gulf -
Es Sider	WTI Midland	Dubai
Syrian Light	LLS St James	Murban
Iran Heavy Sidi Kerir	HLS Empire	Lower Zakum
Iran Light Sidi Kerir	Eugene Island	Oman
Suez Blend	Mars Clovelly	Qatar Land
Kirkuk	Poseidon Houma	Qatar Marine
	WTS Midland	

Asia-Pacific -	Line 63	
Minas		Alberta Edmonton
Duri		Bow River Hardisty
Cinta		
Widuri		
Arun		
Attaka		
Ardjuna		
Belida		
Bach Ho		
Tapis		
Gippsland		
Jabiru		
Cossack		
Kutubu		
NW Shelf		

VI. Asset Development

SITE DEVELOPMENT

Introduction

Once a region has been targeted due to its attractive market economics and the type and size of the generation facility have been chosen, locating a site for project development comes down, on a simplistic level, to "x marks the spot". The convergence of resources critical for the operation of the plant -- land, water, fuel supply and access to the transmission grid – will dictate the best opportunities for site location. While the close proximity, availability and relative cost of resources are key considerations, a multitude of other issues can influence a siting decision. Other issues include, but are not limited to, the existence of a favorable regulatory environment, positive community reception and the potential for tax abatement. The competitive advantage in generation development generally goes to the first-mover and it is, therefore, critical to be one step ahead of the competition. It is not uncommon to find other developers poking around in the same area, which quickly leads to higher prices due to the perception of constrained resources.

Land

The first step in project development, once a target area has been defined, is to find a tract of land for the future site. This task can be supported with the assistance of a local realtor to identify parcels of land available for lease or purchase. A typical land purchase arrangement involves the developer securing an option agreement. The seller provides an option to purchase the land within a designated time for a predetermined price. The acreage needed is driven by the size of the project. For example, a 500 MW combined-cycle generation facility will typically need less than 100 acres; 20-30 acres required for the actual footprint of the plant while the remaining acreage serves as a buffer to local residents from visual and auditory impacts. Other siting considerations include adequacy of road access to the site and availability of rail lines nearby to facilitate the delivery of heavy equipment.

It is also important for the developer to identify potential annexation, zoning and taxing issues. The first question to ask is simple: is the site located within existing city limits? In some states – Texas, for example -- counties are not granted the right to control land use; i.e., establish zoning regulations. Therefore, if the identified tract of land is within a county and not within city limits, no zoning regulations of noise levels, building heights, etc. exist. If a tract of land is annexed as "agricultural" within a city, however, it will have to be re-zoned appropriately for development – for example, as "industrial" – before construction can begin.

Depending on local state and city regulations, which vary widely, municipalities may be able to annex and zone property against the developer's will. In most situations, a city will work with the developer to annex property encompassing the proposed project in order to obtain property tax revenue (See "Negotiating Property Tax"). It is possible, however, to negotiate a "non-annexation" agreement with a city to remain outside city limits for a term of years. As a cautionary note, a non-annexation arrangement is typically coupled with a payment in lieu of taxes to the city. This arrangement does not preclude other cities from annexing the site. Bottom line: it is absolutely essential to have a good handle on local regulations and establish positive community relations during the beginning of a project.

Water Supply

Early in the process of site selection, the developer must evaluate and rank all potential sources of water supply. The type and size of a project will dictate the water supply requirements. For example, a 500 MW combined-cycle gas-fired generation facility may require up to 5 million cubic gallons of water per day (mgd) while a 640 MW single-cycle gas-fired generation facility or "peaker" may require as little as half a million gallons a day – a tenth as much! For a combined-cycle plant, water is used primarily for non-consumptive cooling processes. Only a small fraction of the plant's requirements involve consumptive, or potable water.

Common water sources include surface water from nearby lakes or streams, wastewater effluent, and groundwater. Sources are evaluated on the basis of quantity, quality, availability, location, permit requirements, reliability, and relative cost. Community considerations may come in to play, particularly if other users may preempt the plant's use and restrict water supply during drought conditions. Combining multiple water supply sources and planning for on-site storage can provide flexibility and reliability solutions to ensure adequate backup water supply. Without water, the plant simply cannot run. In the event of an inadequate water supply, as a last resort it is possible to employ a process known as evaporative cooling which does not require water for operation. The tradeoff for evaporative cooling is high capital and operating and maintenance (O&M) expenditures.

Although most of a plant's water supply evaporates during the cooling process, about ¼ (assuming four cycles of flow through the system) will remain as discharge or "blowdown". The concentration of constituents of the blowdown, on the other hand, will be four times higher than original levels. Discharge options include transference to a local river or stream, returning the discharge stream to a wastewater treatment plant, removal through deep well injection, or zero discharge. Each option has varied costs and permitting requirements as well differing levels of public opposition.

Transmission Access

Transmission access – FERC Orders 888/889 – provided the impetus for opening transmission systems to non-discriminatory use, leading to opportunities for new market participants including merchant power plants. In evaluating transmission needs it is important to understand the interconnecting entity's Open Access Transmission Tariff (OATT). Any entity that manages transmission service, be it a regional utility or an Independent System Operator (ISO) must have an OATT filed with the FERC. The

OATT will outline the entity's process for evaluating the impact of new generation and the process to interconnect to transmission system or grid.

It is important to note that no "cookie cutter" approach to securing transmission service exists. Regional operating areas, Independent System Operators and Transco's will have a degree of variance as to how new generation is integrated and studied for system planning and operations. Each operating areas timing, costs and other applicable issues are addressed in the OATT.

After reviewing the OATT and obtaining a thorough understanding of the process, a reservation for transmission service may be necessary to be submitted. A Transmission Service Request on OASIS (Open Access Same Time Information System) and the Interconnecting Utilities Open Access Tariff will define the timing for results requests transmission service. Transmission Service Requests in association with new generation will necessitate a System Impact Study to study the impact on the bulk power system and available transmission service. Results from the System Impact study can take from 60 to 90 days. Again, the timing and process will be outlined in the Interconnecting Utilities OATT. Operating areas Available Transmission Capacity to another Operating area is posted on its OASIS page.

Most likely a generating facility will be either a peaking facility, selling its electric power during periods of peak electricity demand, or a base load facility, which fulfils the base load demand of a region. The type of facility and the amount of risk the project is willing to carry will determine the type of service requested. The two major types of service are:

i) Firm – Available for terms ranging from one day to a year. All Long-Term Firm service will have equal reservation priority with Native Load Customers and Network Customers. Firm service has a higher priority than non-firm. Annual Firm is the last service to be cut during a time of transmission shortage. A premium is paid for the reliability of Annual Firm service.
ii) Non-firm – Available for terms ranging from one hour to one month. Non-Firm service is made available from transmission capability in excess of the amount needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking long-term and short-term Firm. Service is of lower priority during times and may be cut during times of transmission shortage or to fulfill a firm contract.

Rates for transmission service will vary from Operating area to Operating area. Once again the OATT needs to be referenced for the specific rates. Rates will also be posted on the OASIS web site.

Gas Supply and Transportation

Securing a cost-effective and reliable fuel supply source is another critical project development element. The commodity component is the largest operating cost for a natural gas-fired generation facility. The developer should investigate existing sources of supply and identify transportation availability and constraints on nearby underground gas pipelines. The developer will negotiate fuel supply and transportation agreements that establish volume, price and term requirements.

In evaluating fuel supply needs, the developer will need to take the daily operations of the plant into consideration – will the plant's volume requirements change significantly from day to day or will they remain relatively constant? Differing contract terms can provide for flexibility and balancing of a plant's fuel supply.

Another key variable is the evaluation of "firm" versus "non-firm" supply and transportation. In cases of constrained resources, priority will be allocated to holders of "firm" gas transportation service. The benefit of firm supply is reliability; the tradeoff is higher cost. If a developer elects to forgo firm supply and obtains non-firm or interruptible service, the risks of supply interruption and the impact on plant operations must be evaluated.

Environmental Permitting

In order to commence construction activity, a developer must receive a PSD (prevention of significant deterioration) air permit or "permit to construct" from the local regulatory agency. The regulatory basis for the air permitting process lies in the Clean Air Act (CAA) that was originally passed in 1970 but has undergone significant amendment – most recently in 1990. The CAA set national ambient air quality standards for major air pollutants and required states to develop implementation plans to implement and maintain these standards. Processes and standards vary significantly from state to state and depending on whether the plant will be sited in an "attainment" or "non-attainment" area. If the plant will be located in an attainment area the developer must summarize the Best Available Control Technology (BACT) in the air permit application. If the plant is in a non-attainment area the air permit application will have to demonstrate the plant's emissions controls meet the Lowest Achievable Emission Rates (LAER). Meeting strict non-attainment area standards are possible, but require additional equipment which increases capital investment and ongoing operation and maintenance costs.

In Texas, the air permit application is submitted to the Texas Natural Resource Conservation Commission (TNRCC) and proceeds as follows: a permit engineer will be assigned to the project and the environmental completeness of the project will be evaluated. After technical review by a permit engineer and if no further information is required to supplement the application, a draft air permit will be issued by the agency. The developer can issue comments to the draft and begin negotiation of permit conditions. Following the negotiation period, public notice period will proceed, typically for 30 calendar days. If significant public opposition exists, a public hearing may be held which may delay the process by several months. Upon completion of the public notice and review period, final permit conditions will be defined and issued through a final air permit.

While the PSD permit is the most critical permit obtained for the development project, it is one among a long list that can vary significantly with locality and site conditions. Typical state and federal permits include, but are not limited to,

(1) National Pollutant Discharge Elimination System (NPDES) permit for storm water runoff filed 180 days prior to startup of a new facility with the EPA;
(2) acid rain permit filed up to two years in advance of operation;
(3) wastewater discharge permit; and
(4) opinions from the state's historical preservation office and the U.S. Fish and Wildlife Service stating that the planned project's activities are not expected to result in adverse cultural resource or endangered species impacts.

Additional city, state and federal permits may be required if construction is expected within an existing floodplain or if wetlands will be impacted. A developer must also comply with, or seek a variance from, municipal and county ordinances ranging from noise levels to building heights.

Property Tax Negotiation

Power plant projects involve multi-million dollar investments by the developer and provide local communities with significant property tax streams. Due to the economic impact of property taxes, it is critical to ascertain the project's future tax bill early in the development process. For a $200 MM project located in north Texas, for example, the combined city, county and school taxes can exceed $3 MM a year with half of the tax revenue dedicated to the school district.

After establishing the taxing entities (city, county, school, local hospital district or community college, etc.), next evaluate the potential for tax abatement. To encourage development and the creation of jobs, cities and counties often provide tax incentives to companies for locating within their jurisdictions. State regulations, however, may restrict tax abatement in term or amount. In Texas, for example, legislation passed in 1993 works to penalize a school district that provides abatement by restricting the district's state funding. Initial research may include obtaining a copy of the entity's tax abatement guidelines and inquiring whether tax abatement has been granted in the past.

A necessary step in the pursuit of local tax abatement for the site developer is to identify local legal, real estate and community support sources. During this process, determine early the community's key decision-makers and establish issues that are important to the local community. A receptive local government and solid working relationships with the city and county are critical to the success of a development project.

Equipment Procurement Contract Negotiation

The Engineering, Procurement and Construction (EPC) contract is an agreement between the project developer and the engineering/construction company who is building the power plant. For a merchant power project, the value ofthe EPC contract typically accounts for 80-90% of the developer's overall capital investment. Therefore, it is imperative the risks be allocated to the parties with the best chance of mitigating to maximize the odds for the project's ultimate success.

If only one agreement between the project developer and a single EPC contractor, exists, the contract is typically arranged so the EPC contractor agrees to complete the entire project on a fixed-price basis. This is also known as a Lump Sum Turnkey Key (LS TK) contract. In this contract, the EPC contractor assumes all of the risk for cost overruns resulting from either its specific work or the work of subcontractors and vendors. In this sense, the EPC contractor is providing a full wrap guarantee. Thus, the EPC contractor would also be the beneficiary if the contract was either overestimated or favorably executed.

The project developer should only enter into such an agreement if there is reasonable assurance the contractor has estimated the project's cost accurately and the contractor can and will pay any damages or cost overruns without negatively impacting the project's ultimate success. In this case, the EPC contractor is in the best position to handle the risk of cost uncertainties. For taking this risk, the EPC contractor is paid a fixed fee that generally is negotiated to 5-15% of the EPC contract's value. Additional variable or "incentive fees" may be negotiated into the contract should the contractor performance result in improved project economics, i.e. higher plant output, schedule improvement, and higher plant operating efficiency. Similarly, the EPC contract is typically arranged so the negative fees or "liquidated damages" (LDs) are paid by the EPC contractor to the project developer should the contractor's performance result in decreased project economics.

An alternative approach may be for the project developer to negotiate a cost-reimbursable agreement with the EPC contractor and share in the risk of cost uncertainties. In this instance, the parties will typically negotiate a lower fixed fee (3-10%) for the EPC contractor, and cost overruns or underruns are either shared or picked up by the project developer. As with the LSTK contract, variable fees and LDs can be negotiated as part of the cost reimbursable contract.

In some instances, the project developer may chose to have multiple contracts with different engineering and/or construction companies. For instance, the developer may find a particular engineering/construction company is very strong at the design of the facilities civil work (site preparation, foundations, support steel, buildings) but does not have the necessary skill or experience in the mechanical systems (piped water/steam systems and equipment installation). Or, perhaps the engineering company can take the full risk for the facility's design but is not an experience constructor in the particular region where the site is to be built. In these examples, the project developer assumes some of the risk for the overall project necessary to manage multiple contracts and sort through interface disputes.

Regardless of which approach is chosen, the EPC contract(s) should cover a specific scope of work, under specific conditions, and should stipulate compliance with codes, laws and environmental regulations as of the date of contract signing. Pushing the contractor beyond this point tends to unbalance the risk/reward equation. Project contingencies are meant to cover changes in the law, changed project requirements, and the like. Remember, putting these risks on the EPC contractor may move the deal outside his comfort zone, and the project developer could pay dearly for that in the end.

As insurance, the project developer may also chose to hire an independent engineering consultant ("owner's engineer") to oversee the execution of the EPC contract. In that instance, the consultant should participate during contract negotiations so the terms and features are understood and agreeable to all parties.

At the time of this writing, the merchant generation market is on its initial upswing in the U.S., and this has caused a shortage for qualified EPC contractors and available equipment. Since the lead time on the most popular equipment is being pushed several years out, some project developers have chosen to standardize their project designs and order equipment well in advance of identifying specific project sites. For instance, if a project developer plans to install a certain number of projects in the next five years, he may have to order and begin paying for equipment a year or two prior to the need date. Otherwise, he may have to settle for inferior quality equipment or equipment with less operating experience. If the equipment is ordered and bought by the project developer prior to negotiating the EPC contract, the project developer can still have the EPC contractor take over control of the equipment and manage the equipment procurement for a specific project.

Operation and Maintenance Contract Negotiation

One of the decisions a developer needs to make relatively early in the process of creating a power generation business is whether he will or will not directly employ the staff which will operate and maintain the power plant.

This decision is directly related to the developer's vision of the type of company that he intends to create. Will the company be a developer, owner and operator of power plants; a developer and owner of power plants, but not an operator; or simply a developer of facilities, neither owning nor operating his project, but intending to sell all or a controlling equity stake in his project to another investor?

Another one of the key elements in this decision is whether the developer wishes to shift certain risks of operation and maintenance to a third party. In the case where the developer elects to directly employ the operating staff, the developer, in effect, has elected to retain the risks inherent in the operation and maintenance of the facility. Conversely, in the case where the developer elects to contract the operations and maintenance of the facility to a third party, the developer has the opportunity to shift certain risks from himself to this third party operator. Key decision-making criteria in this election revolve around:

a) The developer's vision for his business.
b) What operations and maintenance risks a third party is capable of controlling.
c) The benefits reaped by the developer through the use of a large, operation and maintenance contractor)

In order to justify the added administrative burden of bringing in a third party to operate and maintain a plant, the developer must have a clear vision of which risks he desires to shift to a third party operator. In addition, he must have a clear vision of which risks a third party operator is willing to accept, at what price and under what conditions.

Typical provisions of an operations and maintenance contract include:

a) a description of the relationship of the owner, operator and subcontractors;
b) a detailed list of operator responsibilities;
c) a list of the owner's responsibilities;
d) a description of the payments to be made for the operating services, including both base and incentive fees;
e) term of the agreement and the circumstances under which the agreement may be terminated;
f) indemnity and limitation of liability provisions;
g) warranties;
h) representations of the owner and operator;
i) force majeure;
j) a description of the insurance to be provided by the operator; and
k) other miscellaneous provisions typical of contracts of this type.

It is not uncommon for developers, many of whom have no experience in the day-to-day operation and maintenance of facilities, to downplay the importance of the operation and maintenance of the facility. In the evolving merchant marketplace, this approach is almost a certain guarantee of disaster.

Typical O&M Expenses ($000)	**Yr. 1**
Fixed Cost Estimate:	
Staffing	2,000
G&A Expense	200
Office/Computer Equip & Supplies	30
Laboratory/Maintenance Tools & Equip	20
Professional/Technical Consultants/Agents	200
O&M Contractor Insurances	50
General & Facilities Maintenance	25
Spare Parts	100
Consumables	10

Site Maintenance/Security	50
Rolling Stock Maintenance Fuel	10
Communications	25
Staff Training/Licensing	50
Required Inspections	50
Travel Expenses	50
O&M Contractor Office Facilities	100
Water Contract	500
Incentive Fee - O&M	125
Fixed Fee - O&M	500
Total Fixed Cost	4,095

Variable Cost Estimate:

Overhauls/Inspections	1,300
Overhaul Parts	2,300
Catalyst	200
Equipment Rental	100
Chemicals (Water Treatment)	400
Consumables	50
Ammonia	400
Major Equip Repair/Replacement	250
Utilities	240
Maintenance - Contractor Support	200
Unplanned Maintenance	350
Other Unplanned	50
Total Variable Cost	5,840

Not Included:

Property Taxes
Insurance
Fuel & Fuel Transportation Charges
Transmission Fees
Power Marketing Fees

Development Costs

During the early stages of development, before dirt is turned on the site, expenses will pile up fast. Expenditures vary by location and by project, but a typical budget may shape up as follows for 6-9 months of development activity:

engineering	$300,000
environmental permits & surveys	$500,000
G&A	$ 50,000
land and water options	$250,000
legal / consulting / local PR	$100,000
transmission	$ 25,000

The bulk of the early project expenditure is getting the site ready to submit the all-critical PSD air permit application. Before the developer can submit the application, the stack location must be defined to support air impact modeling. To pinpoint the stack location, the development team must involve engineering to lock down a site layout. To lock down a site layout, the engineering team must have access to the site for survey work, which necessitates securing a land option early in the development process. (See "Development Timeline")

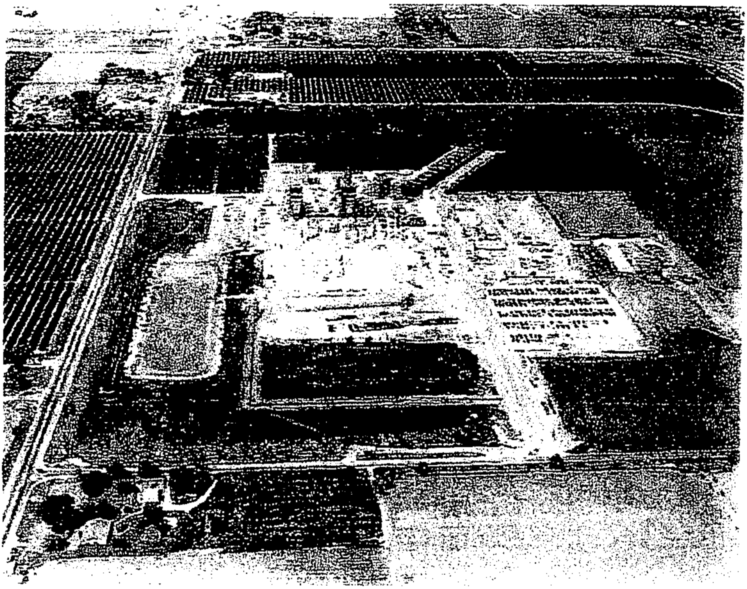
The majority of the plant's investment coincides with the purchase of the major equipment items – gas turbines, steam turbine and heat steam recovery generators (HRSGs) – and the associated costs of construction. The equipment purchase and EPC (equipment procurement and construction) expenses can bring the total price tag of a project to well over $200 million for a 500 MW combined-cycle facility.

Development Timeline

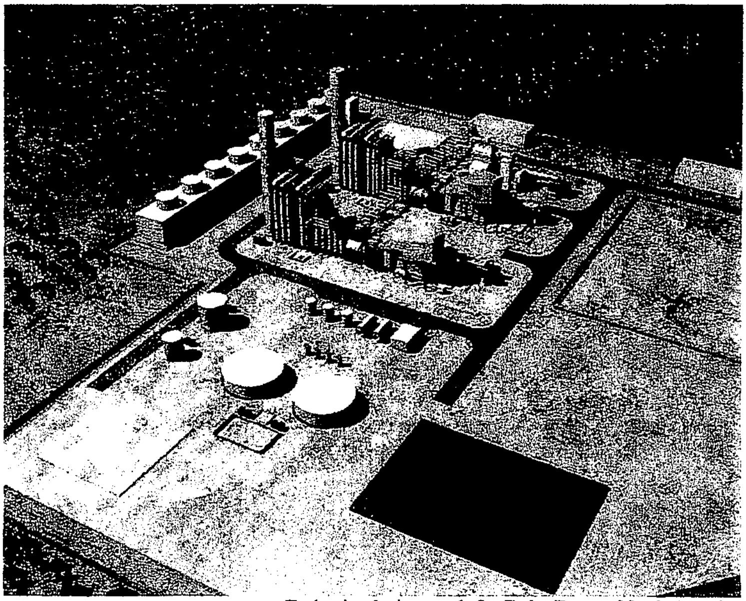
In order to begin construction, the developer must receive a final PSD air permit from the local regulatory agency. Timelines vary from state to state between the time of submittal of the air permit application and the reception of the final permit. Working backwards from the receipt of a final air permit and the ability to commence construction, the development timeline will shape up as follows (assume that construction begins, for simplicity, on the first of the year), allowing for variations between states and regulatory bodies:

Receipt of final air permit / construction begins	Jan 1
Receipt of draft air permit and public notice period	Nov – Dec 31
Regulatory agency reviews air permit application	June – Nov
Submit air permit to local regulatory agency	June
Site layout design / air modeling	April – June
Site surveywork	March
Secure land option	February

Construction periods vary based on the size of the project, weather conditions in the area and with experience levels of contractors. Another time-critical early development item is securing transmission access. Depending on NERC region, it is necessary to file an interconnection request as early as possible to ensure access to the transmission grid. Load studies will be conducted by the regulatory body or local transmission provider to determine if transmission upgrades are necessary – which may or may not be the responsibility of the developer. Research of the local transmission rules and permitting requirements are critical early development steps.



Duke Energy Hidalgo, L.P.
Edinburg, Texas
September 1999



Early site design work for Duke Energy North America
prepared by Duke / Flour Daniel

Sample Construction Costs for North East U.S. (MM$)

Combined Cycle	MW	524
207FA	EPC	$379
	Other	$93
	Total	$472
	EPC 5/98	$379
	Increase	$0
	EPC Cost	$198.8
Other Costs:		
Substation & Switchyard		$6.0
Transmission Upgrades		$0.0
Gas Line & Rail		$10.0
Water Supply		$1.0
Land Cost & Site Remediation		$3.0
Spare Parts & Inventories		$3.0
Sales Tax	6%	$8.3
Permitting		$2.0
Legal & Consultants		$2.5
Development Fees		$0.5
Project Management		$1.5
Start-Up Fuel & Supplies		$1.5
O&M Mobilization		$2.5
Contingency	3%	$7.1
Total Other Costs		$49.0
Total Costs:		
Combined Cycle		$247.7

ECONOMIC EVALUATION

WHAT ARE ANCILLARY SERVICES?

Ancillary services are needed to support the transmission of electric energy across a single utility's transmission network or a region-wide grid. These services range from actions necessary to effect the transaction to services that ensure transaction completion while maintaining the integrity of the transmission grid. Under the old regulatory and market paradigms, ancillary services were bundled with transmission service. Transmission customers were somewhat oblivious to their exact nature and cost. Under new and developing wholesale electricity markets, ancillary services are being unbundled from transmission service, prioritized and exposed to market-based pricing like energy. Ancillary services currently cost U.S. electricity consumers about $12 billion a year, roughly $4/Mwh[1].

While the ancillary service markets continue to evolve and develop, their beginning can be traced back to the Federal Energy Regulatory Commission's (FERC) landmark Order 888. In issuing Order 888 in April 1996, FERC essentially opened the transmission systems of the nations publicly owned utilities to competition. By requiring public utilities to file a single pro forma tariff for transmission service, FERC ensured all transmission customers comparable access to the nation's grid. Included in these pro forma tariffs for the first time were provisions for ancillary services. Specifically, FERC approved six ancillary services as described below. The first two are services that must be obtained from the transmission provider to provide basic transmission service because the local control area can only provide these services. The remaining four are subject to competition from multiple suppliers, but transmission providers are required to offer them to transmission customers that serve load within the transmission provider's control area. Finally, FERC did not preclude the offering of other services to facilitate transactions. FERC's six ancillary services are:

- Scheduling, System Control and Dispatch — Transmission provider must provide and transmission customer must procure this product which facilitates the scheduling and coordination of transactions while maintaining system reliability.
- Reactive Supply and Voltage Control — Transmission provider must provide and transmission customer must procure this product which injects or absorbs reactive power to maintain transmission-system voltages within required ranges.
- Regulation and Frequency Response — Transmission provider must offer to provide or it may be purchased from third parties or self supplied. This product regulates the moment-to-moment variations in load within a control area and can be referred to as "load following" or "automatic generation control".
- Energy Imbalance — Transmission provider must offer to provide or it may be purchased from third parties or self supplied. This product supplies any hourly mismatch between a transmission customer's actual and scheduled transaction including over-generation.

[1] Making Bulk Power Systems Work In a Competitive Electric Industry: The Importance of Ancillary Services, Edison Electric Institute, December 1997.

- Operating Reserve - Spinning Reserve — Transmission provider must offer to provide or it may be purchased from third parties or self supplied. This product has the ability to immediately respond to a generation outage because back-up generation is online, synchronized and can fully available within 10 minutes.
- Operating Reserve - Supplemental Reserve — Transmission provider must offer to provide or it may be purchased from third parties or self supplied. This product also responds to a generator outage but usually within a 30 to 60 minute time frame. It may or may not be online and synchronous and may include interruptible load.

WHERE ARE THE ANCILLARY SERVICE MARKETS TODAY?

The good news is that the ancillary service markets are evolving, as more Regional Transmission Organizations (e.g. ISO) become operational and experienced. The California ISO, ISO-New England and the PJM Interconnection are three examples of where regional ancillary service markets are in various stages of development and operation. The bad news is that their development continues to lag behind the competitive energy markets. In fact the ancillary markets continue to receive considerable scrutiny and remain heavily regulated and immature. Price caps in California and price revisions in ISO-New England demonstrate that these markets are not yet workably competitive. This results from lack of market liquidity, flawed market rules and software and perverse incentives. For example, the California ISO is required to purchase ancillary services at "least cost", which encourages the ISO to use other market rules (e.g. reliability must-run) to secure these products at lower prices rather than letting the market set the price. California also uses price caps to manage the ancillary service markets, while ISO-New England will revise the market clearing price for ancillary services until its market rules and software are revised. However, there is hope. ISO-New England is making its revisions now and California is looking to do away with price caps in the near future. In the end, we should have workably competitive ancillary service markets that operate in close coordination with the energy markets.

HOW ARE THESE ANCILLARY MARKETS WORKING?

First, put aside all differences between the regional market structures. Not only do ISOs have different rules for access, pricing, and congestion, but the ancillary service markets are quite unique in terms of their operation, bidding process and settlement. For example, ISO-New England and PJM have required capacity markets as part of the ancillary service market - California does not. These ISO have also sub-divided some of FERC's ancillary services, with FERC approval, to create separate product markets. However, looking across all the ancillary service markets and recent FERC orders, several common trends are emerging:

- Bidding — Information submitted by the market participant (e.g. scheduling coordinator) indicating the bid price, quantity and technical parameters at which it will supply various ancillary services. While the schedule must be coordinated through the ISO, the ISO or separate exchange may establish a market for these products.

- Pricing — The market-clearing price for a specific ancillary service as determined by the bid prices stacked from low to high until a sufficient quantity is achieved as determined by the ISO or exchange. In general, the pricing for automatic generation control and 10 minute spinning reserve is the lost opportunity cost of not participating in the energy market plus the market clearing price for that service. Prices for other reserve services (e.g. non-spinning, capacity) are settled at the market-clearing price for those services as determined by the bids. Energy imbalance is settled at the energy market-clearing price. Absent market flaws, market-based pricing for these products will be permitted.
- Fulfillment — Ancillary services have degrees of importance to the ISO. For example, automatic generation control is more important than 10 minute spinning reserve. 10 minute spinning reserve is more valuable than 10-minute non-spinning, etc. In order to discourage market power in any of the product markets, the ancillary service markets are filled according to their priority. Excess bids in say 10 minute spinning reserve will be used to fill the 10-minute non-spinning reserve market before bids for 10-minute non-spinning reserve are considered. To discourage withholding, market participants may be required to bid all excess capacity into the ancillary service markets as well.

In closing, ancillary service markets will continue to evolve and change. Understanding their unique structure and relationship to the competitive energy markets is key for any market participant.

Project Development
Expenses
The economic evaluation of a project is not complete until all sources of expenses have been identified and calculated. During the development stage, make sure to communicate with taxing authorities, fuel providers, transmission owners, local government and internal divisions to determine what charges the project will be liable for and what expenses qualify for abatement. The following expenses represent typical costs associated with power plant development but remember it only takes one unknown expense to derail a once viable project.

Franchise Taxes
Companies are charged franchise taxes for having the right to do business in that state. The tax is assessed at the state level and it varies from state to state. The state's department of commerce or tax commission will have information regarding applicable taxes and computational procedures. Generally, the tax is computed based on the net worth of the company. For instance, Texas charges a franchise tax on either 4.5% of a companies net income or a 0.25% of their taxable capital.

Another expense to be cognizant of when evaluating sites, is franchise fees. Franchise fees are charged for utilizing public right of way. While a potential site may occupy private property, natural gas, transmission, or water lines will more than likely use public right of way at one point or another. Therefore, the franchise fee is considered a payment for the use of that right-of-way. The fee is charged either by the county or city and is typically based on a percentage of the total commodity purchase or sales if a plant is making direct retail sales. Speak with city and county representatives to determine if franchise fee's are an issue.

For example, a city may charge a franchise fee of 2% on the total delivered cost of natural gas to a power plant because the natural gas lines for the plant cross city right-of-way. If a power plant consumes 85,000 MMBtu/d at a delivered price of $2.50/MMBtu, the franchise fee will be $4,250.00 per day. These charges are extremely excessive considering the amount of public right-of-way utilized by a facility so attempt to negotiate the fee with the proper authority whenever possible.

Fuel
The purpose of a power plant, simply put, is to convert fuel into power. We take a resource like natural gas or coal and change it into electricity that we can access from any household outlet. Fuel is the raw material of power plants, and understandably it is typically the largest expense. (The obvious exception is hydroelectric power, but we won't consider water as fuel in this section.) If a developer can understand and effectively manage fuel issues the project is much more likely to succeed, and if a particularly advantageous fuel price can be negotiated a project is more likely to have a competitive advantage over its competitors. Fuel flexibility may also provide a project with a distinct competitive advantage over other projects that do not have this flexibility, and it can allow a project to benefit from competition between fuel suppliers. For example; a developer might site a natural gas fired plant near several gas pipelines or gas

storage areas, or a developer might configure a plant to burn either fuel oil or natural gas. In regions where fuel prices are especially volatile a clever fuel strategy can allow a project to hedge against fuel price spikes by allowing the project operator to use the lowest priced fuel alternative

Fuel Taxes

Fuel tax is a special tax on fuels such as natural gas, fuel oil, or diesel. It is assessed at the state level and may vary between states. However, a number of states provide fuel tax exemptions for fuel used in a manufacturing process. To verify its applicability, check with the department of commerce or state tax commission for more specific information.

Operations & Maintenance

Operations and Maintenance (O&M) expenses are the day to day operating expenses that the project incurs when generating power and the periodic maintenance and repairs performed to keep the equipment functioning reliably. Operating expenses are typically items such as lube oil, potable water, office supplies, and plant staff salaries. Maintenance expenses include repairs done when the equipment has broken, or periodic overhauls done to ensure that it will continue to operate for the life of the project.

These maintenance overhauls or inspections are like periodic oil changes done on an automobile. They improve immediate efficiency--usually decreasing the heat rate slightly, they can find and repair problems before a break-down occurs, and they allow aging components to be replaced or refurbished. Most plants have a maintenance schedule for each of the prime movers--the engine, turbine, or similar machine that drives the electric generator for the power plant, and careful adherence to that schedule can protect and increase availability and reliability. O&M is a large expense item for a project. The General Electric recommended major overhaul for their frame 7 combustion turbine takes 28 days and can cost upwards of $3million.

O&M Costs include a fixed and variable component, with most O&M being variable. Utilities and salaries are fixed, but most maintenance items, including major overhauls vary according to how the plant is run. The maintenance schedule mentioned above is driven by the hours the machinery operates, or the number of times it is started and stopped.

Variable O&M costs including fuel are the determining factors of whether a merchant plant will run or sit idle. When the market price for electricity is greater than variable O&M and fuel costs, the merchant plant will run. The amount by which the market price exceeds variable O&M and fuel is the amount of revenues that can go toward covering fixed cost. The power producers in a given area with the lowest variable O&M and fuel costs will be the first to run and last to stop as market prices rise and fall. In the advantageous situation where a particular project has lower relative O&M and fuel costs in a given electricity market, that project will be able to apply more revenue toward paying off capital.

Property Taxes

Property tax is a tax on the market value or current value of the facility. The county assessor will assess the plant and assign a value to it. This value will then be used to calculate the property tax. The tax usually represents taxes collected for the county, city, schools, roads, bridges, and emergency services. The rates vary widely so refer to the local county clerk's office for the specific property tax components and methodology for calculating.

The following is a general demonstration on calculating property tax.

Market Value of Power Plant	**$200,000,000.00**
Property Tax	
County	0.37 %
City	0.58 %
School	1.57 %
Roads & Bridges	0.11 %
Other	0.00%
Total Property Tax	**2.16%**
Total Tax	**$4,320,000.00**

Gross Receipts Tax

Variable O&M costs along with fuel are the determining factors of whether a merchant plant will run or sit idle. When the market price for electricity is greater than variable O&M and fuel costs, the merchant plant will run. The amount by which the market price exceeds variable O&M and fuel is the amount of revenues that can go toward paying fixed cost. The power producers in a given area with the lowest variable O&M and fuel costs, will be the first to run and last to stop as market prices rise and fall. In the advantageous situation where a particular project has lower relative O&M and fuel costs in a given electricity market, that project will be able to apply more revenue toward paying off capital.

Administrative and General expenses

Administrative and general expenses generally include overhead, consulting support, employee expenses, hiring, recruiting, relocation, professional/certification fees, and other miscellaneous charges.

Insurance

There are several types of insurance that the developer needs to understand and estimate: Operating insurance includes property insurance, automobile liability insurance, workers compensation insurance, and other liability insurance.

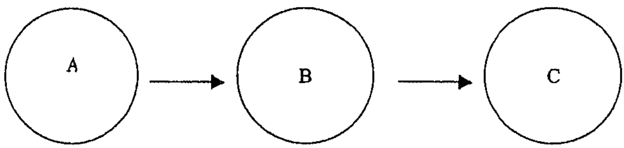
Additionally title insurance typically insures the full estimated capital cost of the plant. The cost of this insurance will vary widely state to state. The developer will need to contact specialist familiar with state insurance markets to provide estimates or quotes on the costs of this insurance.

Transmission Wheeling

Wheeling expenses are primarily transportation charges on the energy being transferred within a specific transmission system or it is a charge for transferring the energy from one transmission system to another system. The local utility, control area or regional transmission organization will have tariffs outlining the charges. The most common fees associated with charges for Firm Energy Transmission Services include:

<u>Administrative Customer Fee</u> - basically a reservation fee for firm service.
<u>Line Loss Capacity Charge</u> - payment for the fixed-investment related costs in supplying transmission capacity.
<u>Line Loss Energy Charge</u> - payment for power that is lost as it is wheeled across transmission lines.
<u>Off-Cost Generation</u> - an allocated cost assessed on users of transmission facilities to compensate for generating activity undertaken to control power flows across transmission interfaces.
<u>Reactive Power Charge</u> - a charge based on the transmission, production and energy costs associated with the supply of reactive power.

Wheeling Service
Wheeling has generally been defined as the movement of electricity from one utility's system to another over the transmission facilities of intervening systems. For example, consider the following diagram in which utility control area A sells energy to utility control area C across utility control area B.



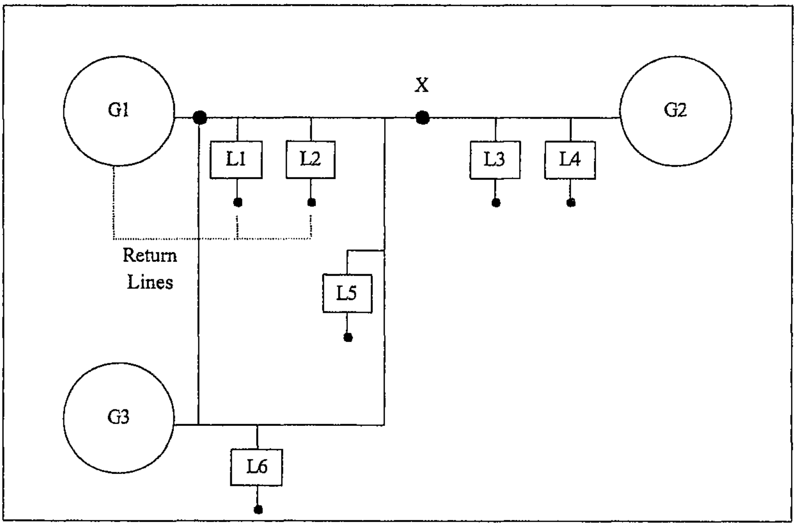
However, wheeling also occurs within a single utility's control area and within broad regional transmission markets. Each of the three is discussed below.

Wheeling Across
Using the example from above, this transaction type is what most people consider to be wheeling from a traditional perspective. Here, the wheeling service allows a utility to transfer its energy to another utility through an intermediate utility system. In this example, utility A arranges for the transmission service of energy (e.g. firm, non-firm) across utility B to utility C. Physical interconnections between the utility control areas support the transfer of energy. Under most circumstances Utility B delivers the exact amount of energy it received from utility A. If transmission losses occur, the wheeling utility is compensated via payment-in-kind, or the source utility (A) agrees to the inclusion of additional energy costs to balance the losses. This is in addition to the wheeling charge (e.g. $/megawatt hour "Mwh") that generally reflects the embedded cost of the bulk power transmission system of the transmitting utility. Keep in mind that

wheeling charges can vary from customer-to-customer depending upon the customer's load, usage and service characteristics.

Wheeling Within

The wheeling of energy also occurs within a single utility control area. For example, utility control area A must wheel power from its multiple generation plants to its load, both of which are in the control area. The example below demonstrates how multiple generators (G) serve various loads (L). Unlike wheeling across, where transmission customers must request either firm or non-firm transmission service, here the utility control area uses network service to support its transaction. Network service combines both the generation and transmission function to support the least-cost delivery of energy within a utility control area. So-called transmission dependent utilities (municipal and cooperatives utilities) located in utility control are A, may also be eligible for network service as well. For example, a municipal utility may have "pockets" of load in utility control area A, but only a single generation source to serve all or part of its load. Network service gives that municipal the ability to meets its load demand without having to schedule multiple firm or non-firm transmission paths within that utility control area. Municipals obtaining network service pay a separate transmission service fee, while control area utility customers pay a bundled rate for generation, transmission and distribution under the traditional regulatory paradigm.



Wheeling in Regional Transmission Organizations (RTOs)

RTOs represent a relatively new market concept for the electric power industry. In short, RTOs are a collection of utility control areas that have placed the operation of their bulk power network under the control of an independent entity. Using our original example, utility control areas A, B and C would combine in a single RTO. While RTOs have many benefits including ensuring non-discriminatory transmission access and creating broad regional markets, one primary benefit is the elimination of transmission rate pancaking. For example, an independent generator located in utility control area A that wanted to sell power to utility control area C would pay only a single wheeling charge to move its energy, if an RTO existed. Without the RTO, the generator would have had to pay A and B separate and pancaked wheeling charges. The wheeling charge is either a single system wide average or a single zonal rate that reflects the cost of transmission where the energy is ultimately delivered. For example, if energy were delivered to zone C under an RTO, C's zonal rate of $3/Mwh would apply. If the rate were a system average, it may be greater than or less than C's zonal rate, depending upon the rates for zone A and B. Wheeling-through an RTO is a similar process to the first case discussed, while wheeling-in an RTO may be either network transmission service or point-to-point (e.g. specific point of receipt to specific point of delivery).

Contract Path versus Actual Flow

The wheeling of power outside network service involves the designation of specific points of receipt and specific points of delivery on the bulk power system. For example, a wholesale power marketer must designate the specific bus at which it will receive the energy from a generator and must designate the specific bus at which it intends to deliver the energy for resale. To complete its transaction, the marketer must reserve transmission. This is known as the contract path. Unfortunately, electricity follows the path of least resistance rather than a predetermined route causing the actual flow to be quite different from the contract path. This is often referred to as loop-flow and it impacts the operation and reliability of the bulk power system significantly. Consider the following real-world example, a 1,000 MW contract sale between Ontario Hydro and the New York Power Pool. The contract between the two entities schedules the power to flow across a specific interface between the two systems, but in actuality, none of the power flows across that interface. Instead, 500 MW takes a more northerly route across another interface while the remaining 500 goes through Michigan, Ohio, West Virginia, Virginia, Maryland and Pennsylvania before reaching the New York system. Utility control areas in those states and regions must internalize this loop flow with their other transactions, but receive no financial benefit. Only the utility transmission owner over whose wires the energy was scheduled to flow receives revenues from the transaction. In fact, loop flow may prevent some utilities from completing their scheduled transactions and therefore reduce its revenues. From a reliability perspective, the impacts of loop flow can severely strain the security of the system because the affected party might be unaware of whose transactions are causing the problem. The industry continues to seek better solutions to solve these problems such as "tagging" (e.g. identifying transaction parties) and regional transmission organizations offer a more coordinated approach toward efficient grid management.

Congestion

Congestion on the bulk transmission system can occur from a number of events including loop flow, transmission or generator outage or over-subscription of the available transmission capacity (ATC) to accommodate wheeling. Congestion is also a function of the transmission system configuration and location of generation on the system. While congestion can occur at any point on the transmission system, most of today's congestion points have been identified. Regardless of the cause, congestion results in the transmission systems inability to move a desired number of MWs across a specific interface. For example, constrained interface(s) in PJM (Pennsylvania, New Jersey, Maryland ISO) at times prevent the flow of lower cost energy located in western PJM to eastern PJM. The result is that higher cost resources in eastern PJM must be dispatched to meet demand. Congestion can also interrupt wholesale wheeling transactions. Depending upon the type of service (e.g. firm, non-firm) congestion across an interface will require transmission line loading relief that prescribes the curtailment of transactions. For example, wheeling transactions using non-firm service would be curtailed first, followed by firm transactions if necessary, based on length of duration. Under the old regulatory and market paradigm, congestion costs or the costs associated with the redipatch of more expensive generation, were uplifted and spread across all market participants on a pro rata basis. However, under the new emerging market structures, different congestion management methodologies are being considered. While the congestion management procedures reflect the market design (e.g. nodal, zonal), two common principles have emerged. The first is the principle of "cost causation". Parties who cause congestion are responsible for paying congestion-related costs. The second principle relates to the purchase of a property right. These may be financial rights, operational rights or both. In essence, the purchaser of these rights insulate themselves from congestion related costs. Depending upon the specific market structure, they may be either auctioned or allocated. Trading in a secondary market is also envisioned. To date, these rights are still mostly conceptual, but California just held its first "fixed transmission right" auction.

State & Federal Income Taxes

Federal and State income taxes are considered fixed costs for evaluation purposes. The state income taxes generally range from 5% to 8% and the federal tax rate is equal to 35%. State taxes are deductible for federal tax computations therefore, the overall tax rate is usually near 40%. The following is an example of how to compute Mississippi's overall tax rate.

Mississippi State tax rate	=	0.05	
Federal tax rate	=	0.35 x (1-0.05)	=0.3325
Total tax rate	=	0.05 + 0.3325	=0.3825 or 38.25%

Depreciation is another fixed cost to be aware of when evaluating a project. The two most commonly referred to depreciation schedules are the alternative depreciation system (ADS) and the modified accelerated cost recovery system (MACRS). The ADS uses a straight-line recovery method which depreciates a constant percentage of the original investment over the property life. MACRS is the preferred schedule to follow because it allows for a shorter recovery period. Under MACRS, the 200% (double) declining balance method is used for 3, 5, 7, and 10 year recovery periods. While, the 150% declining balance method is used for 15 and 20 year periods. The following tables represent the various MACRS schedules.

TAX LIFE OF ASSET IN YEARS

Year of Life	3	5	7	10	15	20
1	33.33 %	20.00 %	14.29 %	10.00 %	5.00 %	3.750 %
2	44.45	32.00	24.49	18.00	9.50	7.219
3	14.81	19.20	17.49	14.40	8.55	6.677
4	7.41	11.52	12.49	11.52	7.70	6.177
5		11.52	8.93	9.22	6.93	5.713
6		5.76	8.92	7.37	6.23	5.285
7			8.93	6.55	5.90	4.888
8			4.46	6.55	5.90	4.522
9				6.56	5.91	4.462
10				6.55	5.90	4.461
11				3.28	5.91	4.462
12					5.90	4.461
13					5.91	4.462
14					5.90	4.461
15					5.91	4.462
16					2.95	4.461
17						4.462
18						4.461
19						4.462
20						4.461
21						2.231

VALUATION METHODOLOGIES

Internal rate of return and net present value are traditional capital investment analysis tools which are still used today to evaluate merchant plant investment opportunities. Annual cash flow models are commonly used to project economic performance over the economic life of the long-lived asset. The largest portion of value is associated with the valuation of the spark-spread option.

A power plant can generally be viewed as a spread option between power and gas markets. A spread option can be evaluated using standard option pricing techniques. The advantage of using standard option pricing techniques is that all inputs can be gathered from the market and a true market valuation can be obtained. The disadvantages of using the standard option pricing techniques involve the standard product used in power markets and the divergence of physical options from financial options.

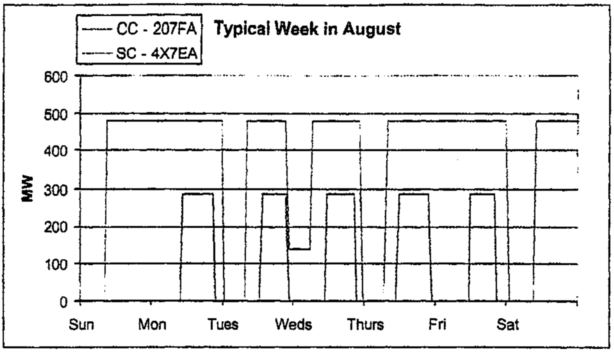
The standard product in power markets is a 5x16 product in eastern power markets and a 6x16 product in western power markets. A 5x16 product represents power delivered Monday through Friday from 7 A.M. to 11 P.M. A 6x16 product represents power delivered Monday through Saturday from 7 A.M. to 11 P.M.

These products are referred to as on-peak products. The remaining hours are referred to as off-peak. These products were created to increase liquidity in power trading. However, physical power is traded as an hourly product. Units that run fewer hours than the standard product have a tendency to be undervalued using standard option pricing techniques.

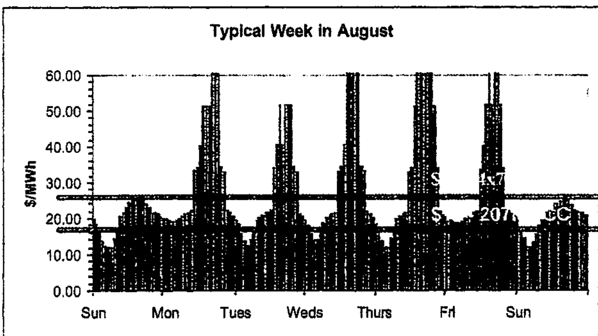
Unlike a financial option, a physical power plant cannot be exercised whenever it is in the money or not exercised when it is out of the money. A physical power plant cannot go instantaneously from maximum capacity to minimum capacity. A power plant is limited by its ramp-up and ramp-down rates. A power plant will also be limited to a minimum number of hours it must be on-line and off-line in order to synchronize with the power grid and to minimize thermal stress that can damage the unit. There are also associated start-up and shut-down costs with power plants. All of these parameters can be evaluated using economic dispatch.

Economic dispatch was originally developed by the utility industry to minimize the cost associated with serving load. Economic dispatch is a linear program that has the objective function of meeting load at minimum cost constrained by the operating constraints associated with each power plant. In evaluating a power plant in competitive wholesale power markets, the objective function is changed to maximizing profitability in an hourly power market. The most important input is the hourly power price.

As stated earlier, hourly power is not traded forward. An hourly forward curve is developed by fitting forward market prices to historical hourly prices. An example of economic dispatch for a simple cycle and combined cycle gas plant is displayed below



	Fuel Cost		Heat Rate		Variable O&M		Variable Cost	Start-up Cost
CC	**$2.20/MMBtu**	**x**	**6,902 Btu/kWh**	+	**$2.60/MWh**	=	**$18/MWh**	**$2,000**
SC	$2.20/MMBtu	x	12,056 Btu/kWh	+	$0.00/MWh	=	$26/MWh	$18,000



Although neither methodology is perfect for calculating a power plant's embedded spark spread option, standard option pricing techniques and economic dispatch give valuable insights into the future profitability and operation of power plants. Both should be used.

To illustrate a typical merchant power plant's annual results, the table below is a simplistic example:

Key Assumptions	
Energy Price	$29.54
Capacity Price	10.48
Total $ MWh	$40.02
Delivered Fuel Price $MMBtu	$2.75
Heat Rate Btu/kWh	6,900
Per $ MWh	$18.98
Assumed (contractual) Operating Hours	7,500
Nominal Plant Capacity	500 MW
Plant Cost (mm)	$225
Depreciable Life (yrs)	30

Financial Results	($000 Omitted)
Sales Revenue	$150,075
Fuel Cost	71,175
Spark Spread	78,900
Variable O&M (@$2.60 MWh)	9,750
Fixed O&M	3,000
Insurance	150
Property Taxes	4,200
G&A	800
EBITD	61,000
Depreciation	7,500
EBIT	53,500
Cash Taxes (from taxable Income calculation)	15,800
After-Tax Free Cash Flow	$37,700

Calculations

1. $40.02 x 7,500 x 500 = $150,075
2. $18.98 x 7,500 x 500 = $71,175
3. $2.60 x 7,500 x 500 = $9,750
4. No calculation, amount assumed for illustration
5. $225,000,000/30 year life

Technology Section

This section describes in general terms the "energy conversion" technology prevalent in the industry today for converting natural gas fuel into electricity for the U.S. market. The primary component in this conversion process is the combustion turbine, which is most often seen in the aircraft industry and the engine used to power jet airliners. This technology has been around since the early 1900s, and throughout the years a strong synergy has existed between the aircraft engine advances and the advances in "land-based" power generation turbines.

In its simplest form, the combustion turbine burns natural gas and converts the energy into electricity. Physically, the natural gas fuel enters into the combustion turbine-generator, is burned, and the hot exhaust gas stream that results turns the turbine and electrical generator before exiting through an exhaust stack. This is the basis of the "simple-cycle" or "peaking unit". However, a vast amount of energy is lost through the exhaust stream, as the gas exiting the stack is still very hot and therefore wasted into the atmosphere. The "combined-cycle" converts some of this wasted energy by boiling water into steam using the exhaust stream as its heating source. This boiling process takes place in a component called the Heat Recovery Steam Generator (HRSG).

Steam leaving the HRSG is routed into a conventional steam turbine-generator as found in coal and oil-fired boiler plants and nuclear power plants. The energy contained in the steam is used to power a turbine and electrical generator, separate from the combustion turbine and generator, to create additional electricity output.

Combustion turbines are more sensitive to outside air conditions than conventional boiler-based power generating plants. Such factors as air temperature, density, and humidity can have a significant affect on the ability of the combustion turbine to convert natural gas energy into electricity. Although this section will not go into detail on this aspect, it is worth noting as the project developer tries to match marketplace needs with technology capabilities.

However, the project developer has tools at his disposal for enhancing the performance of combustion turbines when the atmospheric conditions of a particular location are not ideal. This section will discuss a couple of these enhancement features, namely "duct firing" and "inlet cooling", and provide a general discussion on their applications.

Several manufacturers supply combustion turbines for power generation, but the primary vendors are General Electric, Siemens/Westinghouse, and ABB. The purpose here is to compare the relative "frame" sizes of turbines used in the industry and provide an overview of the predominate configurations for meeting the needs of today's merchant generation marketplace. It is not the purpose of this writing to compare the relative merits of different suppliers, but where specific performance parameters are provided in describing a particular frame size, the standard equipment provided by General Electric is referenced. Other suppliers supply equipment with comparable performance, and it should not be inferred that the author is biased toward a single manufacturer.

Turbine	Heat Rate	Typical Installation Cost	Output	Startup Cost
8x7 E sc	12,000	$380/kW	640 mW	$16,000/st
2x17 F cc	6,800	$500/kW	510 mW	$2,000/st $1,000/hr
LM6000 sc	9,500	$500/kW	50 mW	$0

Combined-Cycle

The concept of "Combined-Cycle" is the combining of combustion turbine- generated energy with steam turbine-generated energy. The simple-cycle configuration used in peaking units (see Section 3b) is combined with a steam cycle to increase the amount of fuel energy that can be converted into electrical energy.

The advantages of a combined-cycle configuration are very simple: more energy contained in the natural gas fuel is converted to electricity. The combined-cycle unit is said to be more efficient than the simple-cycle unit, in that regard. However, there are drawbacks as the combined-cycle plants are typically more expensive, require longer to construct, and take longer to start than simple-cycle peaking units. Therefore, the project developer will typically apply combined-cycle units in markets where the need is for base load generation such that the plants operate around the clock, and not in markets which would require frequent starts and stops.

Thermal efficiencies of combined-cycle plants have increased steadily since the first gas turbine was used to generate electricity in the United States in 1949. Advances in gas turbine performance resulting primarily from higher firing temperatures have led combined-cycle efficiency improvements. Current plants are operating at net thermal efficiencies of greater than 55 percent; in other words, 55 percent of the energy contained in the fuel is converted into electricity. This compares to simple-cycle units that operate at net thermal efficiencies of 35 percent.

Combined-cycle units are designed to compete in base-load markets where there is an assurance the units will be economically dispatched most days of the year. The more efficient the unit is, the less fuel is consumed and therefore the operating costs are minimized. However, the tradeoff for lower efficiency units is typically higher capital costs. Therefore, the project developer must balance the capital and operating costs of the particular technology with that technology's performance characteristics in order to meet the needs of the marketplace.

The following sections describe the standard combustion turbine "frame" sizes found in the power generation industry today for combined-cycle power plants.

Frame E

The Frame E combustion turbine is time-tested, performance-proven, and capable of heavy-duty applications. Frame E (and the advanced Frame EA) units are acknowledged as the industry standard for reliability and availability in medium-size applications, and have been available to the marketplace for nearly twenty years. The primary application of the Frame E unit is for simple-cycle generation, although these turbines have been used in combined-cycle designs.

The Frame E turbine produces approximately 85 megawatts (MW) of electricity in simple-cycle with a firing temperature of 2000 degrees Fahrenheit (°F). Typically, two Frame E combustion turbines are paired together with one 85 MW steam turbine-generator, as such creating an industry standard "2-on-1" combined-cycle configuration generating a total of 255 MW of electricity. The efficiency of this configuration is approximately 40-45 percent.

Frame F

The Frame F combustion turbines are a bit larger than the Frame E units and fire the natural gas at a higher temperature (2400 °F), thereby raising the electrical generation capabilities. Having first been introduced in the U.S. in 1986, Frame F (and the advanced Frame FA) units are acknowledged as the industry standard for larger combined-cycle power plants, although a few projects have been completed using Frame F units in simple-cycle.

The Frame F turbine produces approximately 170 MW of electricity in simple-cycle. As with the Frame E combined-cycle plants, Frame F combustion turbines are also paired together with a single steam turbine-generator, albeit a much larger unit at 170 MW. The 2-on-1 Frame F combined-cycle plant can therefore produce approximately 510 MW of electricity. The efficiency of this configuration is approximately 48-50 percent.

Frames G and H

The Frame G and Frame H combustion turbines are newer and larger combustion turbines designed as the next generation for larger combined-cycle power plants. These larger units are not designed for use in peaker applications.

These larger turbines produce approximately 250 MW of electricity and having firing temperatures of 2600 °F. Typically, these turbines are arranged in a single shaft 1-on-1 combined-cycle configuration to produce approximately 400 MW of electricity. The efficiency of this configuration is approximately 60 percent.

Duct Firing

The term "duct firing" refers to the burning of natural gas downstream of the combustion turbine in the HRSG, increasing the amount of steam produced for higher electrical output. This is very similar to the burning of gas in conventional power plant boilers, supplementing the amount of available heat found in the combustion turbine exhaust stream.

Typically, the industry has used duct firing in "cogeneration" applications (see section 3.a.v below) in order to meet the required steam loads, but several power project developers are now "firing" the HRSG in order to increase the power output for their combined-cycle plants. For example, the standard 2-on-1 Frame F combined-cycle produces approximately 510 MW with no duct firing (or "unfired"). With duct firing, the power output of the same configuration can be increased to as much as 610 MW based on prudent economical and reliable considerations.

Inlet Cooling

Since the combustion turbine uses outside or "ambient" air in order to sustain the combustion process, the turbine's performance is changed by anything that affects the mass flow of the air intake to the compressor section of the turbine. If the ambient air becomes denser, the turbine's performance increases, as measured by parameters such as electrical output, efficiency, heat consumption, and exhaust flow.

Ambient air density is increased as its temperature is decreased. Quite simply, cold air weighs more than warm air. Additionally, air density decreases at higher altitudes as anyone who has climbed mountains can attest. It follows logic, therefore, that project developers would strive to site new merchant power plants at the lowest possible site elevations and the coldest climates possible in order to achieve a competitive advantage.

Unfortunately, the developer's options are limited in certain regions of the country where a market may exist but the ambient air conditions are not ideal. However, several manufacturers provide equipment that can be applied to the inlets of combustion turbines so that the inlet air temperature can be lowered and unit performance can be increased. Lowering the compressor inlet temperature can be accomplished by installing an evaporative cooler or inlet chiller in the ductwork just upstream of the compressor

In the evaporative cooler, moisture is evaporated into the inlet air either by spraying water over a surface media or by spraying a fine mist directly in the inlet of the turbine, this latter technology known as "inlet fogging". Evaporation, or the process of converting liquid water to a vapor state, requires energy. This energy is drawn from the air stream, the result being cooler, more humid air. Capital and operating costs are very low for evaporative coolers compared to chillers, but the amount of performance is limited by the amount of moisture the inlet air can absorb. Thus, the biggest gains from evaporative cooling are realized in hot, low-humidity climates, and conversely the performance increases are minimal in high-humidity climates. Recent advances in the design of inlet fogging systems have made it possible to increase the relative humidity of the inlet air to greater than 100%, thereby offering an economic performance enhancing device even in areas of high humidity. Typically, evaporative coolers are proven to be economically viable on peaker units.

Chillers, in essence large air conditioning units and unlike evaporative coolers, are not limited by ambient air conditions as the desired air temperature can be achieved by increasing the capacity of the chilling device. Installing chillers is typically an economic alternative to evaporative coolers for base-load combined-cycle projects. The inlet air is chilled in a refrigeration cycle in which the refrigerant (such as Ammonia) is compressed and condensed to reject heat form the inlet air stream. While lowering the inlet air results in higher electrical output, the chilling temperatures are typically limited to about 45°F, below which icing in the compressor inlet can cause problems. Inlet air chillers are typically cost-effective to increasing the turbine's output in the 10-20% range.

Peaking Units

Project developers may find a market where the base-load needs are already met by low-cost nuclear or coal-fired power facilities, and it may not be cost-effective to compete with a new, state-of-the-art combined-cycle project. However, such markets may find themselves in need of short-term peaking capacity during the summer or winter peak load periods. Peaking units are typically low-cost alternatives that can be started and shutdown frequently on those days when the demand for electricity is greater than the available generation capacity. Obviously, the lower the cost to produce electricity the more often the unit will be dispatched, and therefore the goal of project developers when considering peaking unit technology is to minimize the capital and fixed operating costs of the project. Since the payback period is limited to only those days when the load demand is high, the developer is not as concerned with efficiency and "variable" operating costs as in a base-load market.

The term simple-cycle refers to a combustion turbine and generator where the inlet air and fuel mixture is burned to turn the turbine-generator and exhausted through a stack in a "simple" and low-cost configuration. Larger and more complex combustion turbines, such as the Frame G and Frame H units, are not designed for frequent starts and stops and therefore not considered for peaking unit applications. The typical units used for peaking applications are the Frame E and LM6000 turbines, although there may be certain markets where the Frame F unit is considered. In order to distinguish which technology to apply in a particular market, the project developer must be able to approximate the number of hours the unit will be dispatched and the number of starts the unit will be subjected to. These parameters affect the maintenance cycles and economic impacts to the units.

Frame E

The Frame E was previously described as the industry standard for reliability and availability in medium-size applications, and has been available to the marketplace for nearly twenty years. The primary application of the Frame E unit is for simple-cycle generation, although as previously mentioned the Frame E has been used in combined-cycle. The project developer will use the Frame E turbine when the marketplace calls for a medium number of operating hours (750 to 2000 hours per year) and number of unit starts (100 to 300 starts per year). The Frame E unit is widely considered the most popular peaking unit because of its flexibility to meeting most peaking markets.

The Frame E turbine produces approximately 85 megawatts (MW) of electricity in simple-cycle at a thermal efficiency of approximately 30 percent.

Frame F

The Frame F combustion turbines are a bit larger than the Frame E units and fire the natural gas at a higher temperature (2400 °F), thereby raising the electrical generation capabilities. Frame F machines are acknowledged today as the industry standard for larger combined-cycle power plants, although a few projects have been completed using Frame F units in simple-cycle when the number of starts can be kept low (typically less than 100 starts per year).

The Frame F turbine produces approximately 170 MW of electricity in simple-cycle with a thermal efficiency of approximately 35 percent.

LM6000

The LM6000 was introduced in the U.S. in 1989 as an aeroderivative industrial gas turbine. The term "aeroderivative" refers to a ground-based gas turbine that is derived from a large jet turbine used in the aircraft industry. The LM6000 is one of the largest and most efficient aeroderivative units available, with a rated output of 40 MW and a thermal efficiency of 40 percent.

Adaptation of aircraft engines for industrial, utility and marine propulsion applications has long been accepted as a means of assuring power plants with high efficiency and ease of maintenance. Because of their heritage, aeroderivative turbines typically require less space and supporting structure than Frame E and Frame F units. These features also equate to reduced plant construction time and adaptability to meet unique site or application dictated requirements.

The project developer will typically chose the LM6000 when he needs to a minimal amount of new peaking generation quickly and when the number of starts per year are high (greater than 300 per year).

Inlet Cooling

As previously described, inlet cooling can be applied to a combustion turbine in order to enhance the unit's performance. For peaking unit applications, the capital and fixed operating costs must be minimized. Therefore, evaporative cooling technologies are typically proven to be economical alternatives to be provided either by the turbine manufacturer or as an add-on supplied by a third-party vendor. The high costs of chiller units typically prevents their applications on peaker units.

A description of inlet cooler fundamentals was provided in Section 3.a.v. Two types of evaporative coolers are used to increase peaker unit performance – conventional evaporative cooling systems and inlet fogging devices. The conventional coolers use a wetted honeycomb-like medium to maximize the evaporative surface area and cooling potential. This medium material is typically a foot or so thick and covers the entire inlet duct area. These systems have been successfully applied to peaker units for several years, but they do have drawbacks. The media causes a pressure drop in the inlet air duct, installation often requires substantial ducting modifications, and the amount of cooling can be fairly small in humid climates. However, in climates with high temperatures and low humidity, the conventional evaporative cooler can be a very economical alternative and most turbine manufacturers offer these as options. On a hot and dry day, the evaporative cooler may increase the turbine output by 10-15%.

The inlet fogging system is a newer technology that is just now reaching acceptance by the turbine manufacturers and a performance enhancement option, but has been shown to be an effective alternative to conventional evaporative cooling in high-humidity climates. Because a fine water mist is sprayed directly into the compressor inlet, manufacturers have been wary of the impact this technology could have on the turbine's reliability. Large droplets of water reaching the compressor could do serious damage, and long-term the vendor's had concerns that introducing air at humidities greater than 100% could increase the unit's degradation. However, several systems have been designed and are now available to the project developer that have been proven to not have a negative impact on the turbine's reliability, and turbine manufacturers may be offering these systems as options in the near future. Output of a peaker unit may be increased by as much as 20% using an inlet fogging system.

Cogeneration

As previously mentioned, the term cogeneration refers to the production of electricity and another byproduct, typically steam, for industrial or commercial applications. This section describes the typical electricity/steam cogeneration power plant found in many industrial manufacturing processes. Also discussed is the role of cogeneration in the new merchant generation marketplace.

Large industrial facilities have the need for many utilities required to manufacture their product – electricity, steam, air, hydrogen, etc. If the amount of required utility is large, the design of the industrial plant includes in-house generation of the particular product. Many industrials have their own steam generating boilers as part of their plant, and some industries that use a large amount of electricity take a portion of their generated steam to drive a steam turbine-generator to create their own electricity in-house. Generating electricity and another by-product stream, in this example steam, is called "cogeneration".

The design of in-house electric and steam generating facilities was typically limited to meeting the amount of internal consumption because of the limited market for excess generation. However, in 1978, U.S. Congress created the PURPA act allowing cogenerators to sell excess electricity generated to the local utility. The act required the utility pay for this electricity at the price it would have cost the utility to generate its own power (also referred to as the utility's "avoided cost"). Since 1978, hundreds of cogeneration plants were built by project developers to sell electricity to local utilities and augment the cost to producing this electricity by also selling steam and other by-products to local industry. Often, these facilities were called PURPA facilities or "qualifying facilities" because they had to meet certain PURPA criteria in order to qualify for the guaranteed electricity sales contract with the local utility. Fundamentally, the steam/electricity requirements of the industrial host dictate when the cogeneration plant runs and the scheduling of maintenance outages.

Merchant generators, on the other hand, do not typically have power-sales contracts with the local utility for the majority of their electricity, but they may choose to design a cogeneration merchant plant and sell a by-product such as steam to a nearby industrial facility. In essence, the project developer over-sizes the HRSG to generate excess steam for sale as a by-product. A portion of the cogeneration plant's electrical output may be sold to the industry in addition to the amount available to the merchant market. The one drawback is the fact that the industrial's steam/electricity requirements must still dictate when the merchant-cogeneration plant operates and when maintenance outages are scheduled, and the resulting operation may not be ideally matched with the needs of the merchant marketplace.

Different "Tweaks" to Turbines (Cost Per Turbine)

Modification	Installed Cost ($MM)	Increased Output (MW)	Turbine Configuration	Comments
Inlet Cooling	1-6	0-25	SC, CC	Results dependent on ambient air conditions (temperature, humidity) where installed Performance and cost vary significantly with technology type Technology chosen may require high quality (de-mineralized) water
Duct Firing	2-10	2-50	CC Only	Limited by firing temperature Requires excess steam turbine / generator capacity over basic designs May add significantly (up to 1mm gallons/day) to cooling water requirements

Project Finance

There are two main characteristics generally associated with project financing: 1) Non-recourse; and 2) Off-balance-sheet. A third is not as common but equally, if not more important; off-credit.

The term non-recourse means the lender only has rights to the cash flows generated by the specific project that is being financed. Off-balance-sheet means that the debt obligation of the project does not appear as a liability on the parent company's balance sheet and does not affect the traditional book value calculation of the debt-equity ratio. In general, since a project financing is non-recourse and off-balance-sheet it does not affect the credit rating of the parent company. This is referred to as off-credit. However, rating agencies are aware of the added debt burden and will generally incorporate a certain percentage of it into their calculations. Non-recourse financing gives the parent company an option to default on the project debt without exposing its balance sheet to the lender. Unfortunately options rarely come for free and the value of this imbedded option will be charged to the project in the form of higher interest rates and more extensive covenants. For example, many lenders will require that a project company pay cash every year into a major maintenance reserve fund for major repairs on the power plant.

In addition to the obvious advantages mentioned above, project financing reduces short term cash requirements and enables value-added deals to be completed with limited equity. Project finance allows companies to leverage investments at rates that are usually considerably less expensive than their weighted average cost of capital and project hurdle rates. The debt is typically paid down over many years, as many as 30 for some power plants. Typically lenders will also allow companies to delay principal payments for up to five years. A longer pay down and delay in principal payments will usually result in an increase in both the net present value (NPV) and internal rate of return (IRR) of the project. The following example illustrates how leverage can increase returns for a power plant.

Example I: The example shows a 20 year payback stream on an initial investment of $250. The unleveraged IRR of the project is calculated at the top to be 11.06% and the NPV at 10% is $16.08. At the bottom we introduce project financed debt for 60% of the plant costs or $150. The debt is issued at an 8% interest rate and since the 8% is less than the 10% hurdle rate, the NPV of the project goes up with the leverage. Use of the less expensive funds which have a five year principal delay and a 15 year payback, increases the IRR to 21.12%. The IRR is now referred to as a leveraged IRR. Delaying the principal payback brings more of the earlier, and therefor more essential, cashflows to the bottom line of the project company.

Example II: The example is identical to Example I with two exceptions; the principal payback period has been shortened to 10 years from 15, and there is no longer a delay on the principal payback. As mentioned above, the result of this change is a decrease in both the NPV and IRR of the project to $45.68 and 15.22% respectively.

The interest rate and payback terms associated with project level debt for a power plant can vary based on many different factors. First, banks are very interested in knowing how certain the cash flows are. Financing for a purely merchant plant will be much more difficult to obtain and be much more expensive than for a plant that has much of its output sold under long-term power purchase agreements. The more certain the cash flows the less expensive the debt. Take-or-pay and/or full requirements contracts on steam and power can command some of the lowest cost financing, especially when backed by an investment grade company. Second, the greater the percentage of equity the project company is willing to invest, the less expensive the debt. Banks, as well as any other lender, feel more comfortable when the project company "puts its money where its mouth is." Last, cost of project level debt will be highly dependent on the project's debt coverage ratio (DCR).

When power companies decide to build merchant power plants they are relying heavily on their view of future prices for power in and around the chosen region. This is also referred to as their view of the forward price curve for power or their forward deck. Similarly, lending institutions will develop their own forward deck to analyze the potential profitability of a plant. Developing an accurate price curve can be very difficult and requires considerable expertise, which leads to outsourcing this task. Banks will often use consultants to handle this and other tasks. Consultants will also get involved in modeling the operational parameters of a plant. Companies such as R.W. Beck and RDI have both operational and market expertise. Banks will sometimes rely heavily on the opinion of consultants when deciding the credit risk of a power project.

Project financing of a power plant can be a long and arduous task, but if done properly can be beneficial to both the project company and the lender. A value-adding deal with project financing is better than no deal at all.

EXAMPLE I

		Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
unleveraged	Project annual cashflows	-$250.0	$31.3	$37.5	$37.5	$31.3	$31.3	$31.3	$31.3	$25.0	$18.8	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3
	principal paid		$0.0	$0.0	$0.0	$0.0	$0.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0	-$10.0
	cumulative principal paid		$0.0	$0.0	$0.0	$0.0	$0.0	-$10.0	-$20.0	-$30.0	-$40.0	-$50.0	-$60.0	-$70.0	-$80.0	-$90.0	-$100.0	-$110.0	-$120.0	-$130.0	-$140.0	-$150.0
	principal outstanding		-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$140.0	-$130.0	-$120.0	-$110.0	-$100.0	-$90.0	-$80.0	-$70.0	-$60.0	-$50.0	-$40.0	-$30.0	-$20.0	-$10.0	$0.0
	interest expense		-$12.0	-$12.0	-$12.0	-$12.0	-$12.0	-$11.2	-$10.4	-$9.6	-$8.8	-$8.0	-$7.2	-$6.4	-$5.6	-$4.8	-$4.0	-$3.2	-$2.4	-$1.6	-$0.8	$0.0
	after tax interest expense		-$7.8	-$7.8	-$7.8	-$7.8	-$7.8	-$7.3	-$6.8	-$6.2	-$5.7	-$5.2	-$4.7	-$4.2	-$3.6	-$3.1	-$2.6	-$2.1	-$1.6	-$1.0	-$0.5	$0.0
leveraged	Project annual cashflows	-$100.0	$23.5	$29.7	$29.7	$23.5	$23.5	$14.0	$14.5	$8.8	$3.0	$16.1	$16.6	$17.1	$17.6	$18.1	$18.7	$19.2	$19.7	$20.2	$20.7	$21.3

Unleveraged:

npv@10 $16.08
irr 11.86%

Leveraged:

npv@10 $63.16
irr 21.12%

Debt/Equity Split

equity	-100	40%
debt	-150	60%

Debt Characteristics

interest	8%	
term	15	Years
tax rate	35%	

EXAMPLE II

			Year 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
unleveraged	Project annual cashflows	-$250.0	$31.3	$37.5	$37.5	$31.3	$31.3	$31.3	$31.3	$25.0	$18.8	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3
	principal paid		-$15.0	-$15.0	-$15.0	-$15.0	-$15.0	-$15.0	-$15.0	-$15.0	-$15.0	-$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	cumulative principal paid		-$15.0	-$30.0	-$45.0	-$60.0	-$75.0	-$90.0	-$105.0	-$120.0	-$135.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0	-$150.0
	principal outstanding		-$135.0	-$120.0	-$105.0	-$90.0	-$75.0	-$60.0	-$45.0	-$30.0	-$15.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	interest expense		-$10.8	-$9.6	-$8.4	-$7.2	-$6.0	-$4.8	-$3.6	-$2.4	-$1.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	after tax interest expense		-$7.0	-$6.2	-$5.5	-$4.7	-$3.9	-$3.1	-$2.3	-$1.6	-$0.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
leveraged	Project annual cashflows	-$100.0	$9.2	$16.3	$17.0	$11.6	$12.4	$13.1	$13.9	$8.4	$3.0	$16.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3	$31.3

unleveraged
npv@10% $16.08
irr 11.06%

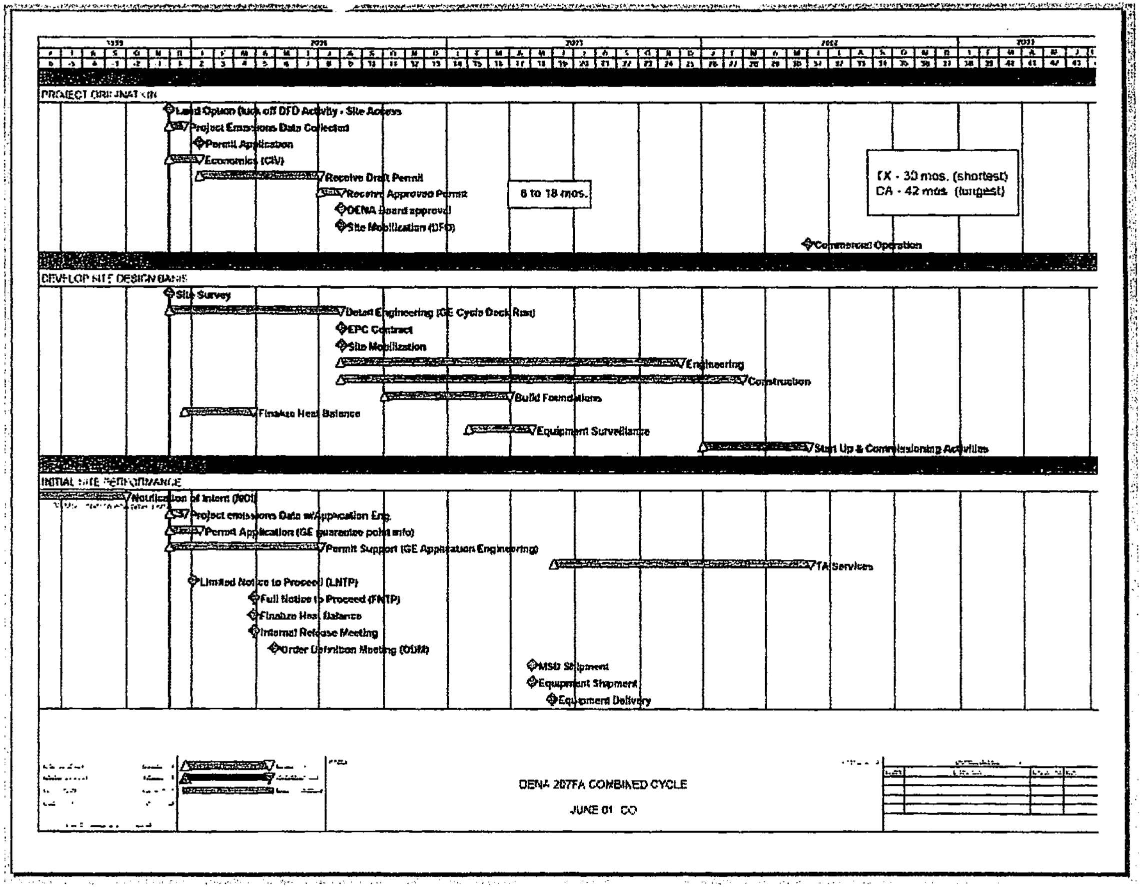
leveraged
npv@10% $45.68
irr 15.22%

Debt/Equity Split

equity	-100	40%
debt	-150	60%

Debt Characteristics

interest	8%	
term	10	Years
tax rate	35%	


PROJECT ORIGINATION
Land Option (kick off DFD Activity - Site Access
Project Emissions Data Collected
Permit Application
Economics (CIV)
Receive Draft Permit
Receive Approved Permit
DENA Board approval
Site Mobilization (DFD)
8 to 18 mos.
FX - 30 mos. (shortest)
CA - 42 mos. (longest)
Commercial Operation
DEVELOP SITE DESIGN BASIS
Site Survey
Detail Engineering (GE Cycle Deck Run)
EPC Contract
Site Mobilization
Engineering
Construction
Build Foundations
Finalize Heat Balance
Equipment Surveillance
Start Up & Commissioning Activities
INITIAL SITE PERFORMANCE
Notification of Intent (NOI)
Project emissions Data w/Application Eng.
Permit Application (GE guarantee point info)
Permit Support (GE Application Engineering)
TA Services
Limited Notice to Proceed (LNTP)
Full Notice to Proceed (FNTP)
Finalize Heat Balance
Internal Release Meeting
Order Definition Meeting (ODM)
MSD Shipment
Equipment Shipment
Equipment Delivery
DENA 207FA COMBINED CYCLE
JUNE 01 CO

VII. Emerging Markets

Weather

Overview

Weather is an inescapable part of everyone's life. It is explained on the news every evening, seemingly only to be contradicted every morning when people leave their homes. In these inconsistencies, weather has emerged as a tradable commodity. Many industries are effected by weather and have significant risk exposure due to specific weather conditions. Ski resorts have revenue risk if mild winter months cause a decrease in snowfall. The agriculture industry experiences risk if it is hot and dry in the summer or rainy and cold during planting season. Gas pipelines have transportation risk if the winter is unseasonably warm or the summer too cool. Likewise, utilities have much of the same seasonable risk as gas pipelines do. All these industries can hedge portions of their risk by trading weather.

Degree Day

Weather products can be indexed on rainfall, snow pack, or hurricanes. Most weather products, however, are bought or sold in degree days, which is based on temperature. A degree day is the difference between a day's average temperature and a baseline value, typically 65° F. This baseline generally represents a comfortable temperature, notwithstanding the regional sensitivities to temperatures. (Someone in Lansing, Michigan may find 65° balmy, while people in Brownsville, Texas may find 65° too cool). Degree days come in two types; a heating degree day (HDD) and a cooling degree day (CDD). A HDD is used principally November through March and a CDD is used from April through October.

Daily HDD are calculated as follows:

$$\text{Daily } HDD = 65° - (High + Low)/2$$

Daily CDD are calculated as follows:

$$\text{Daily } CDD = (High + Low)/2 - 65°$$

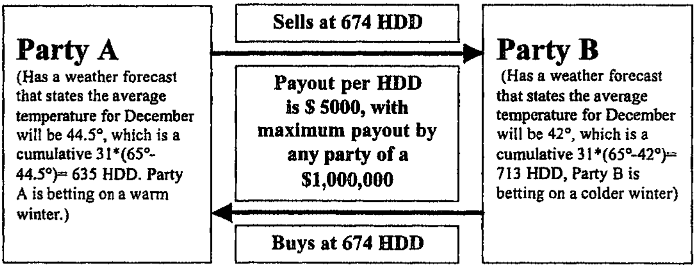
The high and low in the above equations are the maximum and minimum temperatures for a 24 hr (midnight till midnight) period. Every observable day will carry either a HDD or a CDD value. The cumulative observed HDD or CDD for a specified period, usually a month, will represent an index that can be tracked similar to any other type of index (OEX, SPX, etc). Thus, to obtain a monthly HDD/CDD, the average monthly temperature is simply subtracted or added from 65°, and multiplied by the number of days in the month.

Weather Products - OTC

Weather products behave somewhat differently than typical commodity options. Since the underlying (a HDD/CDD) cannot actually be bought, (you cannot take physical delivery of a HDD/CDD, as opposed to energy, or agriculture commodities) All weather commodities are financially settled. Additionally, because weather cannot be manipulated, no single market player has any real ability to corner the marketplace. With good data, all parties are on equal footing. Most weather products are traded on temperature, with the value of a HDD/CDD typically set at $5000. Some exotic products set on snowfall, rainfall, river flow or wind can also be structured.

Swaps

The simplest weather product thus far is a HDD/CDD swap. This product allows two parties to agree upon a fair index value, called the swap rate or the swap strike, that represents the expected future index value. The maximum payout for any weather swap is $1,000,000. The following is an example:



Using a simple average, the swap rate of the deal is determined to be 674 HDD.

$$(635 + 713) / 2 = 674 \text{ HDD}$$

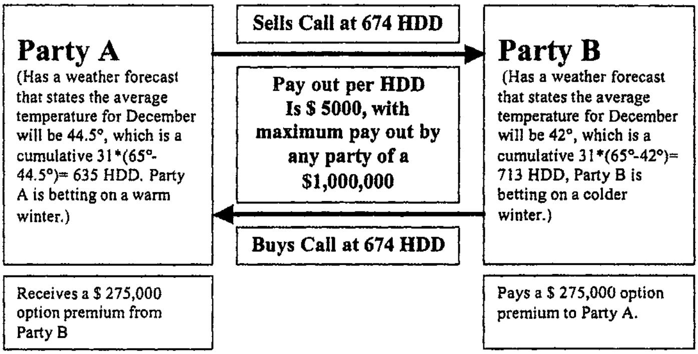
The seller of a swap will have to pay if the actual HDD/CDD value is below the swap rate. The buyer pays if the settled value is above the swap rate. Neither party pays the other party a fee to enter into the swap.

Scenario 1:
December's average temperature turned out to be 40°; colder than what Party A had forecasted. The cumulative HDD for December is then 31*(65°-40°) = 775 HDD. Party A pays party B: (775-674)*$5000 = $505,000.00.

Scenario 2:
December's average temperature turned out to be 48°, warmer than what Party B had forecasted. The cumulative HDD for December is then 31*(65°-48°) = 527 HDD. Party B pays party A: (674-527)*$5000 = $735,000.00.

Options

Unlike other financial products, weather option pricing is not derived by standard Black Scholes equations. Statistical and mathematical models are continuously being developed to optimize option pricing. The behavior of puts and calls, however, is standard. Market players will purchase calls if they think HDD/CDD will be higher than a specific strike price, and will purchase puts if HDD/CDD is estimated to be below the strike price. An example follows:



Using a simple average, the strike price of the option is determined to be 674 HDD.

(635 + 713) / 2 = 674 HDD

Scenario 1:

December's average temperature turned out to be 40°, colder than what Party A had forecasted. The cumulative HDD for December is then 31*(65°-40°) = 775 HDD. Since 775 is greater than the strike of 674, the call is exercised. Party A pays party B: (775-674)*$5,000 = $505,000.00.

Net for Party A is $ 275,000.00 - $ 505,000.00 = -$ 230,000.00

Net for Party B is -$ 275,000.00 + $ 505,000.00 = $ 230,000.00

Scenario 2:

December's average temperature turned out to be 48°, warmer than what Party B had forecasted. The cumulative HDD for December is then 31*(65°-48°) 527 HDD. Since 527 is less than the strike of 674, the call expires worthless. The only money that exchange hands is the option premium.

Net for Party A is $ 275,000.00 - 0 = $ 275,000.00

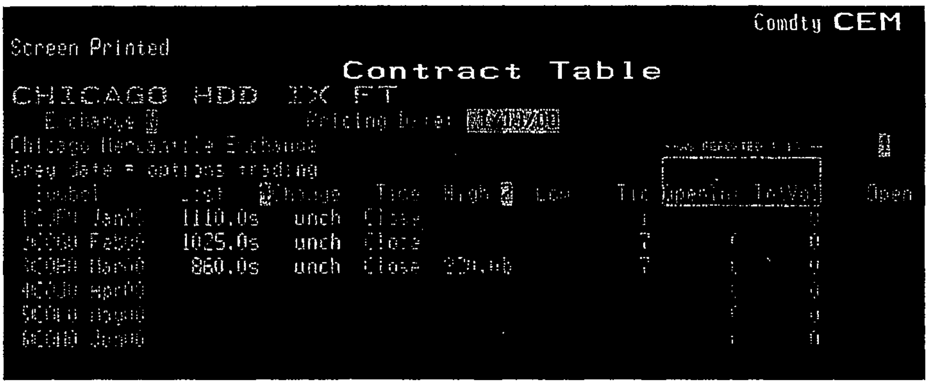
Net for Party B is -$ 275,000.00 + 0 = -$ 275,000.00

Weather Bonds

The most advanced structured weather product publicly available is the weather bond. These issuers of bonds will pay the buyer an interest rate dependent on temperature performance at various specified regions across the nation. Enron and Koch are the only companies to offer weather bonds thus far.

Weather Products - Exchange

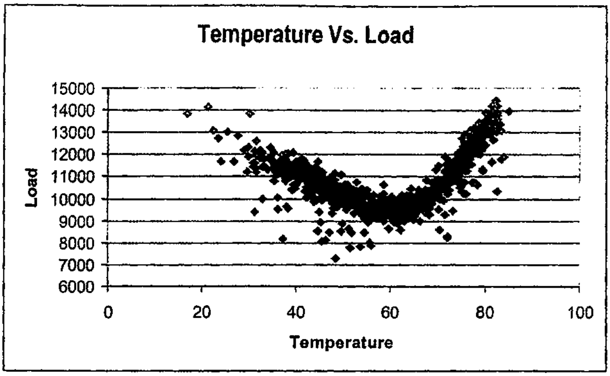
Futures and options are traded on the Chicago Mercantile Exchange (CME) and are similar to over-the-counter (OTC) products with the usual difference being that OTC allows more contractual flexibility, while the CME offers liquidity. The weather future contracts and the options on those contracts have not traded long enough to measure the probability of continued existence.

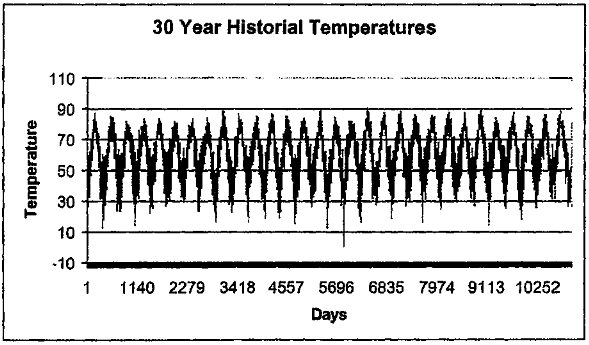


Weather Derivatives - An Advanced Example

Most power utilities have weather exposure in their revenue streams. For example, if winter is extremely cold, the residential and commercial sectors will demand a great amount of electricity to run furnaces and space heaters. This electric demand decreases dramatically if the winter is warm. The swing in demand related to temperature extremes creates what is called volumetric risk. Volumetric risk is the risk incurred by a fluctuating demand for a product, whether the product is electricity, gas, or ski lift tickets. Fluctuating demand will create swings in revenue streams, which can impact operating performance. In order to reduce revenue swing volatility, weather derivatives can be is used as a hedge. In this example, electricity demand is shown to effectively forecast the variance in revenues for a regulated power utility.

As shown, a strong correlation exists between temperature and load (electricity demand).





Risk managers can use statistical analysis to transform the monthly-expected temperature and its standard deviation into a monthly-expected revenue and monthly-expected revenue standard deviation. Ultimately, a rate base can be developed to forecast revenue volatility based on temperatures

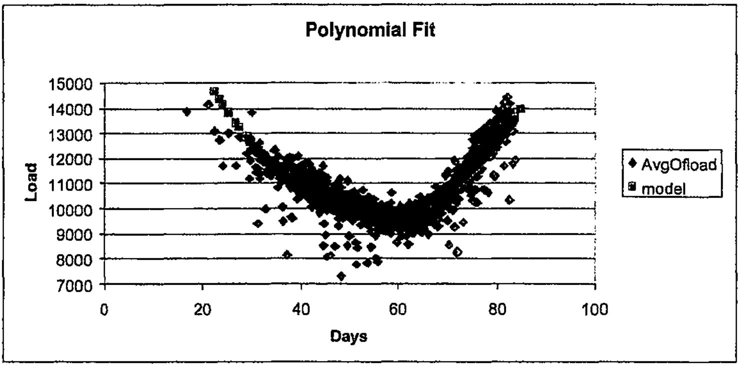
30-years Statistics are used to determine the monthly-expected temperature.

Month	Expected temp	StdDev Temp	Expected CDD*	Expected HDD*
Jan	40.09	11.33	0.0376	24.94
Feb	43.74	11.74	0.149	21.38
Mar	51.52	11.80	0.72	14.20
Apr	60.51	10.93	2.48	6.97
May	68.12	9.37	5.50	2.38
Jun	75.20	8.13	10.54	0.33
Jul	78.76	7.54	13.78	0.02083
Aug	77.09	7.19	12.15	0.0562
Sep	71.47	8.59	7.62	1.14
Oct	60.82	10.11	2.28	6.45

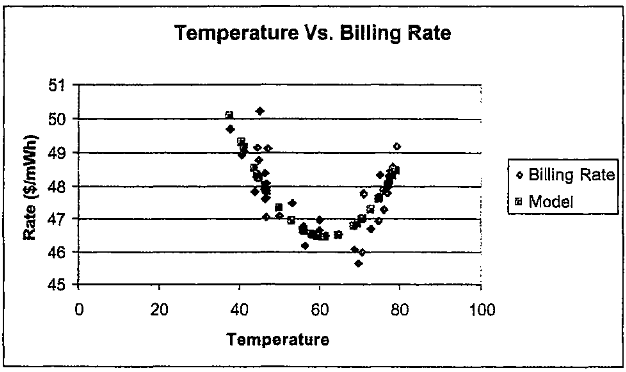
Nov	51.32	11.03	0.50	14.18
Dec	43.74	11.22	0.11	21.37

* To get cumulative HDD/CDD multiple by the appropriate number of days in the month.

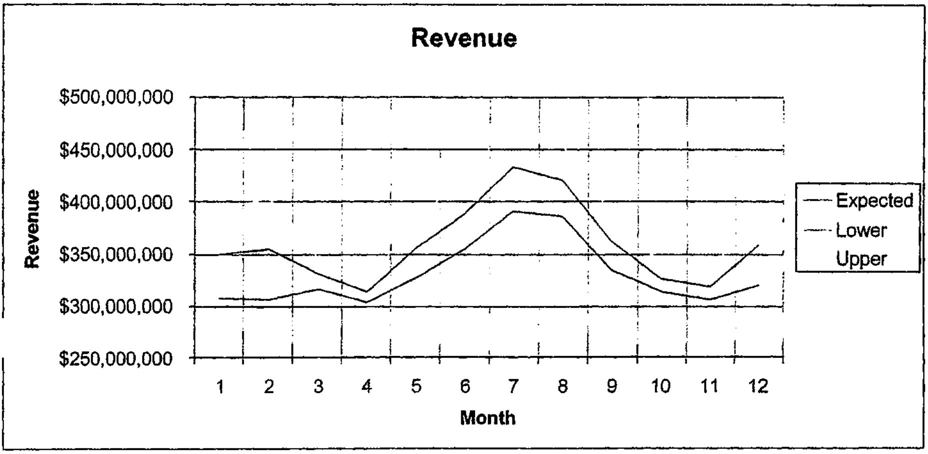
A polynomial equation is used to transform expected temperature into load. This equation has an R^2 of 0.725307.



The next polynomial equation uses temperature to fit a rate base. The R^2 of this equation is 0.657156.



The risk analysis results, shown in the following chart, display a higher revenue risk in the winter than the summer, which may be counterintuitive for many people. Regulated



power assets have base rates set to various customer sectors, and therefore carry no market risk. However, the unregulated power assets have not only volumetric risk but also market risk, which is extremely high during summer months.

The mathematical details of this example can be found in Appendix A.

MTM of Weather Sensitive Assets.

Quadratic polynomials that approximate load and rate given normally distributed temperature.

Expected Value of a 2^nd degree polynomial (C1 x^2 + C2 x + C3), where x is a normally distributed variable.

See below for Expected value of x^2

$ev = c1\left(\mu_{temp}{}^2 + \sigma_{temp}{}^2\right) + c2\,\mu_{temp} + c3$

$c3 + c2\,\mu_{temp} + c1\,(\mu_{temp}^2 + \sigma_{temp}^2)$

Variance of a polynomial.

$variance = Expand[((c1\,x^2 + c2\,x + c3) - ev)^2]$

$$c2^2\,x^2 + 2\,c1\,c2\,x^3 + c1^2\,x^4 - 2\,c2^2\,x\,\mu_{temp} - 2\,c1\,c2\,x^2\,\mu_{temp} + c2^2\,\mu_{temp}^2 - 2\,c1\,c2\,x\,\mu_{temp}^2 - 2\,c1^2\,x^2\,\mu_{temp}^2 + 2\,c1\,c2\,\mu_{temp}^3 + c1^2\,\mu_{temp}^4 - 2\,c1\,c2\,x\,\sigma_{temp}^2 - 2\,c1^2\,x^2\,\sigma_{temp}^2 + 2\,c1\,c2\,\mu_{temp}\,\sigma_{temp}^2 + 2\,c1^2\,\mu_{temp}^2\,\sigma_{temp}^2 + c1^2\,\sigma_{temp}^4$$

Moments of a normally distributed variable.

$psi = Exp[\mu_{temp}\,t + .5\,\sigma_{temp}{}^2\,t^2]$

$e^{t\,\mu_{temp} + 0.5\,t^2\,\sigma_{temp}^2}$

Expected value of x

$m1 = D[psi, \{t, 1\}]\ /.\ t \to 0$

μ_{temp}

Expected value of x^2

$m2 = D[psi, \{t, 2\}]\ /.\ t \to 0$

$\mu_{temp}^2 + 1.\,\sigma_{temp}^2$

Expected value of x^3

$m3 = D[psi, \{t, 3\}]\ /.\ t \to 0$

$\mu_{temp}^3 + 3.\,\mu_{temp}\,\sigma_{temp}^2$

Expected value of x^4

$m4 = D[psi, \{t, 4\}]\ /.\ t \to 0$

$\mu_{temp}^4 + 6.\,\mu_{temp}^2\,\sigma_{temp}^2 + 3.\,\sigma_{temp}^4$

Now substitute for each expected value of x^y from above into the variance formula.

$polyvariance = Simplify[variance\ /.\ \{x \to m1, x^2 \to m2, x^3 \to m3, x^4 \to m4\}]$

$\sigma_{temp}^2\,(1.\,c2^2 + 4.\,c1\,c2\,\mu_{temp} + 4.\,c1^2\,\mu_{temp}^2 + 2.\,c1^2\,\sigma_{temp}^2)$

*Expected Value of Load(temp)*Rate(temp), where*

Load(temp) and Rate(temp) are quadratic polynomials.

Find the expected value for (x y).

$\mathbf{Cov_{load,rate} = Expand[(x - \mu_{load})\ (y - \mu_{rate})]}$

$x\,y - y\,\mu_{load} - x\,\mu_{rate} + \mu_{load}\,\mu_{rate}$

$\mathbf{Cov_{load,rate} =}$

$\mathbf{Simplify[x\,y - y\,\mu_{load} - x\,\mu_{rate} + \mu_{load}\,\mu_{rate}\ /.}$

$\mathbf{\{x \to \mu_{load},\ y \to \mu_{rate},\ x\,y \to x\,y\}]}$

$x\,y - \mu_{load}\,\mu_{rate}$

Now solve for expected value of (x y).

$\mathbf{Exy := Covxy + \mu_{load}\,\mu_{rate}}$

$Covxy + \mu_{load}\,\mu_{rate}$

It is well known that $Cov_{x,y} = \rho_{x,y} * \sigma_x * \sigma_y$,

and we can assume that $\rho_{x,y} = 1$, thus :

$\mathbf{Exy = \sigma_{load}\,\sigma_{rate} + \mu_{load}\,\mu_{rate}}$

$\mu_{load}\,\mu_{rate} + \sigma_{load}\,\sigma_{rate}$

*Variance of Load(temp)*Rate(temp) [Revenue].*

Find the expected value of $x^2\,y^2$

Find Variance of x^2

$\mathbf{Expand[(a^2 - (\mu_{load}{}^2 + \sigma_{load}{}^2))\,\hat{}\,2]}$

$a^4 - 2\,a^2\,\mu_{load}^2 + \mu_{load}^4 - 2\,a^2\,\sigma_{load}^2 + 2\,\mu_{load}^2\,\sigma_{load}^2 + \sigma_{load}^4$

$\mathbf{varx2 =}$

$\mathbf{Simplify[}$

$\mathbf{(a^4 - 2\,a^2\,\mu_{load}^2 + \mu_{load}^4 + 2\,a^2\,\sigma_{load}^2 - 2\,\mu_{load}^2\,\sigma_{load}^2 +}$

$\mathbf{\sigma_{load}^4)\ /.\ a^2 \to (\mu_{load}{}^2 + \sigma_{load}{}^2)]}$

$a^4 - \mu_{load}^4 - 2\,\mu_{load}^2\,\sigma_{load}^2 + 3\,\sigma_{load}^4$

$\mathbf{varx2 =}$

$\mathbf{Simplify[}$

$\mathbf{varx2\ /.\ \{a^4 \to \mu_{load}{}^4 + 6\,\mu_{load}{}^2\,\sigma_{load}{}^2 + 3\,\sigma_{load}{}^4\}]}$

$4\,\mu_{load}^2\,\sigma_{load}^2 + 6\,\sigma_{load}^4$

This is based on Exy function above.

$\mathbf{Ex2y2 =}$

$\mathbf{Simplify[}$

$\mathbf{(4\,\mu_{load}^2\,\sigma_{load}^2 + 6\,\sigma_{load}^4)^{.5}\,(4\,\mu_{rate}^2\,\sigma_{rate}^2 + 6\,\sigma_{rate}^4)^{.5} +}$

$\mathbf{(\mu_{load}{}^2 + \sigma_{load}{}^2)\,(\mu_{rate}{}^2 + \sigma_{rate}{}^2)]}$

$(\mu_{load}^2 + \sigma_{load}^2)\ (\mu_{rate}^2 + \sigma_{rate}^2) +$

$(4\,\mu_{load}^2\,\sigma_{load}^2 + 6\,\sigma_{load}^4)^{0.5}\ (4\,\mu_{rate}^2\,\sigma_{rate}^2 + 6\,\sigma_{rate}^4)^{0.5}$

$\mathbf{varxy =}$

$\mathbf{Expand[(load\ rate - (\mu_{load}\,\mu_{rate} + \sigma_{load}\,\sigma_{rate}))^2]}$

$load^2\,rate^2 - 2\,load\,rate\,\mu_{load}\,\mu_{rate} +$

$\mu_{load}^2\,\mu_{rate}^2 - 2\,load\,rate\,\sigma_{load}\,\sigma_{rate} +$

$2\,\mu_{load}\,\mu_{rate}\,\sigma_{load}\,\sigma_{rate} + \sigma_{load}^2\,\sigma_{rate}^2$

varxy =
Simplify[
$$\left(\mathbf{load}^2\,\mathbf{rate}^2 - 2\,\mathbf{load}\,\mathbf{rate}\,\mu_{load}\,\mu_{rate} + \mu_{load}^2\,\mu_{rate}^2 - 2\,\mathbf{load}\,\mathbf{rate}\,\sigma_{load}\,\sigma_{rate} + 2\,\mu_{load}\,\mu_{rate}\,\sigma_{load}\,\sigma_{rate} + \sigma_{load}^2\,\sigma_{rate}^2\right)\ /.$$
$$\left\{\left(\mathbf{load}^2\,\mathbf{rate}^2\right) \rightarrow \mathbf{Ex2y2},\ (\mathbf{load}\,\mathbf{rate}) \rightarrow (\mu_{load}\,\mu_{rate} + \sigma_{load}\,\sigma_{rate})\right\}]$$

$$\mu_{rate}^2\,\sigma_{load}^2 - 2\,\mu_{load}\,\mu_{rate}\,\sigma_{load}\,\sigma_{rate} + \mu_{load}^2\,\sigma_{rate}^2 + (4\,\mu_{load}^2\,\sigma_{load}^2 + 6\,\sigma_{load}^4)^{0.5}\,(4\,\mu_{rate}^2\,\sigma_{rate}^2 + 6\,\sigma_{rate}^4)^{0.5}$$

Converted by *Mathematica* January 11, 2000

Coal - Ground to Power

Outline of Chapter

1. What is Coal
2. Mining
3. Purchasing
4. Transportation
5. Power Plants

Overview of Coal

Coal is a black to brownish-black combustible matter formed from non-aerated decomposition of plant matter under pressure over millions of years. The plant matter predominately came from prehistoric peat swamps. There are four major classifications for coal (ranked from oldest to youngest): 1) Anthracite 2) Bituminous 3) Subbituminous and 4) Lignite. The differences among the four coal types will be discussed in the Purchasing Section.

Demand for coal

After the 1973-74 Arab oil embargo, the United States had to start thinking about alternate energy sources. The natural energy commodity of choice is coal due to its low cost and ease of mining. The production of coal has increased steadily since the oil embargo occurred. Factors that may positively effect coal demand are: normal weather patterns, a decrease in exports, high natural gas and oil prices, and hydroelectric generation falling off. Factors that negatively effect coal demand are: warmer than normal winters, reduced consumer willingness to carry large coal inventories, and diminishing electric demand.

Currently, the US is the second largest net exporter of coal behind Australia, and the second leading producer behind China. However, the US has the largest recoverable coal reserves in the world, allowing it to control worldwide coal pricing. Coal reserves are defined as follows:

Total Resources - Coal deposits that are both discovered and yet to be discovered, but considered probably existing. Total Resources = 3.968 trillion short tons.

Identified Resources - Coal deposits that have supportive geological evidence and the coal can be ranked and quantified. Identified Resources = 1.731 trillion short tons.

Demonstrated Reserve - Coal that can be extracted given today's technology. This coal meets minimum physical and chemical composition criteria in order to be useful if mined. Demonstrated Reserve = 826.17 billion short tons.

Recoverable Reserves - Demonstrated Reserves that can be economically mined, extraction rate is 60%. Recoverable Reserves = 495.7 billion short tons.

Mining

Where is the coal?

Five main coal regions exist in the United States, Northern and Central Appalachian Basin, Gulf Coast Plain, Illinois Basin, Colorado Plateau, and Powder River Basin/Northern Great Plains. Various coal types are found throughout all regions, however Lignite tends to be more prevalent in the western regions, and Anthracite is only found in the Appalachian regions.

Coal Extraction Methodologies

The coal industry employs either one of two methods to extract coal from the ground, surface mining or underground mining. Which mining technique used depends greatly on the depth of the coal, deposit size, and deposit quality and quantity. Coal residing more than 200 feet underground will be mined through underground mining techniques.

Surface or strip mining is the removal of soil until the coal seam is exposed. Strip mining can be categorized into five groups: 1) Area - surface depth of the coal is constant and the land is considered level. 2) Contour - surface depth of coal is constant and follows the contour of the land. 3) Open pit - surface depth is above 200 feet and coal seam is deep. 4) Mountain Top - the coal seam lies close to the apex of a hill or mountain. 5) Auger - Boring of holes into the coal seam to remove the coal. Land reclamation laws are extremely strict on strip mining operations. Currently laws are being established that will make mountain top mining illegal.

Underground mining bores an entry point to the depth of a underground coal seam. Mine entry points can be one or more of the following types, sloped - a diagonal duct, shaft - a vertical duct, or drift - a horizontal duct or full horizontal coal seam exposure. Two main techniques exist for the physical recovery of the coal from an underground mine. Room-and-pillar is the process of leaving large portions of the coal seam intact in the form of pillars. These pillars then act as ceiling support for the prevention of cave-ins. The room-and-pillar techniques allow a coal extraction rate of only 50% to 60%. Longwall mining is the process of removing coal from a seam along its entire width. This process does not leave any coal support pillars. Rather, moveable hydraulic pillars maintain ceiling support close to a long wall panel and will allow for controllable cave-ins in excavated sites. Longwall mining will have an extraction rate of about 80%.

Coal Preparation

Coal preparation allows the mining company to better deliver a desirable product to their customers. The preparation of coal can be as simple as guaranteeing a specific coal topsize, the largest allowable piece of coal, through the use of giant shifters to more sophisticated preparation techniques. Advanced coal preparations are used to classify and ensure the ash content, sulfur content, and heating value content of the coal meet the customer's needs. These classifications follow the ASTM (American Society of Testing and Materials, URL: www.astm.com) guidelines. Cleaning technologies include water-based gravity separators, heavy-media-based gravity separators, and techniques that utilize the surface properties of coal.

Purchasing

Coal Testing

Coal is tested for the following qualities: 1) Moisture, 2) Grindability, 3) Heating value, and 4) Impurities, which includes ash content, ash type, sulfur, and trace elements.

Moisture is either inherited or surface. Surface moisture can be decreased by applying heat to evaporate the moisture. Inherited moisture is chemically bound to the physical coal and tends not to be removed for economical reasons. High moisture content lowers the heating value of the coal. Not only does high moisture content impact the heating value of coal, it can also become difficult to physically handle, plugging boiler chutes and bins.

Grindability is the measure of the coal's hardness, strength and fracture index. Grindability is considered to be the amount of energy required in making the coal useful, both from the perspective of the mining process and boiler requirements. Coal hardness is most often described by the HGI, Hardgrove Grindability Index. A high index value indicates the coal requires less energy/effort to transform it into a workable form, a lower index value indicates more energy is needed to transform the coal.

Heating Value is the single most important parameter to understand. It is the prevailing component that drives the price of coal. Higher heating valued coals are worth more than lower heating valued coal. Heating value is measured in British thermal units (Btu) per one pound of coal (Btu/lb.). Heating value is also used in determining the SO2 emissions potential. Emissions are measured in pounds of SO2 per unit of heating value.

Impurities enter coal during the initial formation of the peat swamps, the first stage in coal formation. The most important impurities are: ash, sulfur, and trace elements. Ash is the result of the transformation of various minerals in a combustionable environment. Ash comes in two forms. Bottom ash falls to the bottom of a boiler and needs to be disposed of, and fly ash, which is trapped in through the use of a filtration system in the exhaust stack of the boiler. Fly ash can be used as filler in cement, and road tar, where bottom ash has no practical use. Sulfur will be discussed in the Emissions section. Trace elements are measured in parts per million (PPM). The most hazardous trace element to date is mercury, which is extremely detrimental to fish and wildlife

A Simple Coal Rank Table

Class	Heat Content		Sulfur Content		Grindability	
	Low	High				
Anthracite	13000		Low		High	
Bituminous	10500	14000	Low	Medium	Medium	High
Subbituminous	8300	11500	Low	Medium	Low	Medium
Lignite	6300	8300	Low	High	High*	

*Lignite has a high moisture content which may require a lot of extra energy to make the coal useful.

Coal Price Structure

Coal currently trades in two types of environments, spot and long-term contractual agreements. Spot is currently considered to be any coal purchase that is deliverable with in an 11-month window. Coal is currently going through major trade restructuring, due to deregulation occurring in the power industry. Deregulation is forcing everyone to operate at more efficient levels, which would include coal procurement procedures.

Transportation

Coal is primary transported by rail and barge. Occasionally, coal will travel by tractor-and-trailer. The primary measurement for coal transportation is a short ton, which is 2000 lbs.

Power Plants

Emissions

Outline of Chapter

1. Pollutants
2. EPA Sanctions
3. Sanction Compliance Options
4. Allowances

Pollutants

EPA Sanctions

Sanction Compliance Options

Allowances

VIII. Risk Management

1. Understand the various sources of risk.
2. Understand the thought process involved in deciding when and how to hedge.
3. Understand the various tools and techniques available for hedging.
4. Understand the limitations and inherent problems with hedging in each individual market.
5. Understand how to formulate an overall hedging strategy for commodity price exposure.

SOURCES OF PORTFOLIO POSITIONS

A. Asset Developers

Asset developers are the individuals who choose to invest capital in physical plants. It can be in many different forms, a sampling of which is:

1). A generator (providing a spark spread position)

2). A processing plant (providing equivalent NGL positions in crude oil and natural gas, positions in NGL's outright, and/or natural gas "Keep-Whole" positions)

3). Natural Gas Storage Facilities (providing inherent options and gas positions)

4). Natural Gas or NGL Fields/Finds (providing outright positions)

Whatever the form, asset developers will be the major source of commodity risk positions. Traders are, in effect, "chipping around for nickels". The notional value associated risk and P&L contributions that trading provides pale in comparison to what the asset developers bring to the table. Trading organizations, while expected to contribute to the bottom line, are more valuable for price discovery and as a source of hedging and liquidity for asset developers. As an example of the financial differences, here is a comparison of an aggressive trading position versus a conservative asset position:

POSITION	VOLUME	FUEL CONTRACTS	+/- $0.10 GAS CURVE	+/- $5.00 POWER CURVE
Trader: Long 50 mW of Calendar Year	211,200 mWHrs (assuming 22 peak days/month)	None	N/A	$1,056,000.00/yr.
Developer: Purchase one 500 mW CCGT	2,112,000 mWHrs (assuming 22 peak days/month)	4 Contracts/Day	$1,460,000.00/yr.	$10,560,000.00/yr.
NGL Plant	100 MMCF/Day	3 Contracts/Day	$1,095,000.00/yr.	N/A
Pipeline Capacity	4 BCF/Day	400 Contracts/Day	$146,000,000.00/yr.	N/A

A one-year calendar position for a trader constitutes significant size and risk (risk parameters and measurements will be covered later). A single 500 mW generator for an asset developer is merely one small portion of an overall portfolio. It should be clear as to which group is in the more prominent role.

B. Originators:

Like asset developers, Originators will bring significant positions into the Risk Management book. The positions are typically complex. During the infancy of deregulation, where price discovery and the sophistication of the players was not yet highly developed, simple deals such as buying and selling power and/or gas were prevalent. Now, with the advent of multiple brokers and electronic trading systems, competing on pure price alone for simple commodities is a losing proposition. Every market participant knows where the bid and offer is on any given liquid commodity, and in order to entice counterparties to enter into deals, the price must be better than what they could find in the broker or bilateral market. This results in "giving away market share", which is rarely, if ever, a wise move in the energy markets.

Giving away market share on the promise of future deals or on the premise of attaining market share (participants are ranked by industry trade newsletters) will not pay dividends. It usually takes the form of selling to the customer below the bid or buying from the customer above the offer with the hope that in the future, more deals of bigger size and with bigger profit potential will come your way. This just does not happen. One of two possible outcomes will occur, neither of which is positive. The first is that the counterparty which you just "gave away money" (sold below the bid or bought from him above the offer) will expect similar treatment in the future. You run the risk of "conditioning" the counterparty to expect sweetheart deals and free money. The other possible outcome is that the customer merely becomes price sensitive, and will deal with whomever offers the best deal, which the next time around, may or may not be you.

For these reasons, deals that are originated now contain multiple "moving parts". This could include coal, SO2, NOX, power, gas, transmission, weather derivatives, crude and or NGL's. Typically, the goal is to find a "mismatched perception in value" (the new buzz phrase). A Counterparty may be long coal, and willing to unload a sizable amount below the bid. Conversely, you may be long power, and be willing to unload a significant quantity below the bid. A deal in which the Counterparty gives you coal in exchange for an equivalent BTU amount of power (synthetic coal tolling agreement) may be successful. You may be valuing the coal on the offer side and the power on the bid side, while your Counterparty will be doing just the opposite. This allows both parties to achieve what they think is a fair deal.

It is these "moving parts" that will place commodity and price risk into the Risk Management book.

ASSIGNING/TRANSFERRING RISK

Once the Asset Developers or the Origination Team completes a transaction, the corresponding commodity position and financial risk must be managed immediately. This can be initiated in one of three ways – individually within the business units, Intracompany transfer, or Agent Status.

A. Managing Positions within the Business Units (Individual Trading Units):

Some corporations choose to have separate trading units within each business unit. For instance, the Asset Developers, Originators, and trading arm all have their individual trading desks for commodity price exposure. Each individual group is treated as a stand-alone, separate entity. Reporting, risk measurements, performance and compensation issues are all handled by each individual business unit.

PRO's:
1. Eliminates the need for intracompany price transfers of commodity and price risk.
2. Provides direct source of price discovery and market intelligence (direct trading arm of business unit is constantly in the marketplace and provides direct feedback of who is doing what, and how prices are trending, etc.
3. Eliminates need to re-transfer positions and associated hedges if the assets are divested. For instance, assume 10 years' worth of power is sold and gas is bought to hedge the spark spread of a generating asset. If the asset is then sold, there is no need to re-transfer the hedges to another business unit. The Asset Development group knows what hedges are in place, and either includes the hedges as part of the asset sale (the power sale contracts and the gas purchase contracts travel with the asset sale) or removes the hedges within their own trading unit.

CON's:
1. Time and effort involved in intracompany transfer. The transferring business unit and the trading or risk management business units must agree upon prices, volatility, correlations, heat rates, and all other associated assumptions.
2. The hedges must "travel twice". Any associated hedges will most likely be transferred at the bid or offer, and then be transferred back (if the asset is sold) at the offer or bid. Paying away the bid/ask spread makes this unprofitable.
3. Cost. Each business unit must establish its own trading personnel, back office, mid office, accounting and other functions. The cost of these redundancies can be prohibitive.
4. Self-Arbitrage. While the Asset Development or Origination team may be selling a commodity to hedge length by hitting a bid, another trading arm may be lifting an offer in the same commodity, thus making the overall corporation pay away the bid/ask spread.

5. Marketplace Confusion. Direct counterparties, customers and brokers will not know which arm to deal with.
6. Reporting. This creates several different reports and possibly several different reporting formats for management to digest, creating further confusion and inefficient operations.

B. IntraCompany Transfer (Using existing company trading arm—centralized trading):

Intracompany transfers involve moving the position from the books of the business unit that did the original deal to the books of the business unit that trades or manages the risk. Some corporations choose to have their originators and asset developers transfer all positions to the trading arm. The trading arm has two functions - speculate on fixed-price, and provide liquidity for the originators and developers when they need to transfer positions.

PRO's:
1. Do not need to bear the cost of carrying multiple business unit trading arms.
2. Allows Originators/Developers to focus on "writing tickets" (closing deals) and building relationships with customers, and not have to worry about being involved in-depth with the trading markets.
3. Cost effective—less duplication of infrastructure.

CON's:
1. Extra layers of personnel to overcome when communicating price discovery and market intelligence.
2. Time and money spent on intracompany book transfers.
3. Bias of trading arm to "fade" business units. If the trading arm is negotiating a transfer with the originators/developers, there is a natural tendency to want to "buy" (receive) the position well below the bid or to "sell" (deliver) the position well above the offer. Several sources of negotiation, such as liquidity, slippage, execution costs and price will be friction points.
   - ✓ Liquidity: Whether or not the market is a liquid, well-traded hub, firm transportation/transmission versus non-firm or interruptible, reliability of transmission, etc. The business unit will tend to downplay these factors, while the trading arm will try and use them as a significant extra cost.
   - ✓ Slippage: If a market is "tight" (close bid/ask price), the trading arm will negotiate a much wider bid/ask, depending on the size of the position to be transferred. The saying "Size Matters" is appropriate here.
   - ✓ Execution Costs: Brokerage fees, back-office personnel, contract administration, etc. The trading arm would like additional compensation for the use of their resources, while the business units will claim that this is a "sunk cost" which the trading arm has already incurred.
   - ✓ Price: Many power trading hubs and natural gas basis points are extremely illiquid past 16 months. A long-term deal (>2 years) will have little, if any, price discovery. The long-term price curve will be a major point of contention, as will volatility.
4. Tendency of trading arm to "front-run" business units. If the trading arm is aware that a business unit will be transferring a large position in the near future, there is a natural bias for the trading arm to Front-run. Front-running involves buying or selling ahead of the transfer, in an attempt to run the price up or down before the transaction occurs. For instance, if the originators have a customer who is willing to buy 1,000 mW for a ten year strip, the trading arm, anticipating the transfer of this position into their books, will go out and buy as much 10-year power as possible. This will make the overall transfer price higher, and make the original front-running positions profitable. The trading arm can "lean" on the anticipated transfer, in that if prices do not go up, or tend to fall off, they can always rely on the originated deal as a bid (protection to the downside.)

As an example of the difficulties in negotiating a transfer for a 10-year, 1,000 mW block of power that the origination group wishes to sell to a customer (the origination group must close the sale with the customer, then buy the power from the trading arm). The customer wants the power delivered into COMED, a non-liquid trading point which is one "wheel" away from Cinergy, a liquid point:

	MARKET	NEGOTIATED TRANSFER
Price	$33.00/$34.00	$34.00 (must "lift offer"; no real term market)
Liquidity Premium	N/A	$5.00 (cost of firm transmission plus covers risk of being "cut")
Slippage	N/A	$6.80 (20% size slippage)
Execution	N/A	$2.00 (arbitrary cost assignment)
Total	$33.50 (assume mid-market)	$45.80

It is clearly evident that most deals with customers will be difficult, if not impossible to close under these conditions. If the customer is aware that the term market is $33.00/$34.00, they will argue for buying the power closer to the bid side of the market ($33.00). If the originators are forced to show a price of $45.80 to the customer (so that the origination group does not lose money in the transfer to the trading arm), there is little hope of getting a deal done. The notional difference in price between $45.80 and $33.00 on a 10-year, 1,000 mW on-peak deal is (22 on peak days/month x 12 months * 16 peak hours * 10 years * 1,000 mW * ($45.80-$33.00)) = $540,672,000.00. NOBODY is going to give that to you!

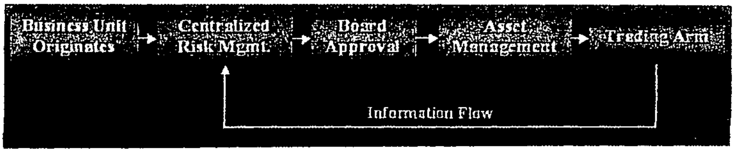
The trading group usually does not care if the deal gets closed. Most trader would rather not worry about large positions, instead choosing to scalp in and out of the market on a rapid, small-scale (small position) method. Not finding a way past this problem and not closing deals of this type is a significant detriment to all involved. Both groups need to see this "customer flow" in order to gain market intelligence and know what is taking place in the industry. The knowledge that customers are large term buyers can help both the trading group and the origination arm position themselves to take advantage of this trend. The trading arm can initiate speculative positions from the long side in anticipation of massive buy interest. The originators can structure products geared towards power purchasers. But by consistently showing non-competitive prices, customers will label your company as unresponsive and stop communicating their interests. This lack of information will severely hamper the overall competitive stance in the marketplace.

C. Centralized Risk Management Group:

Centralized risk management is the paradigm that the industry is in the process of developing. It involves ONE GROUP that is responsible for the overall commodity and price risk of the ENTIRE CORPORATION. The typical breakdown is by commodity and/or by time frame.

The commodity breakdown is as the name describes – each commodity (power, gas, crude, NGL's, etc.) is an independent division of one group. The positions and risk metrics of the group are reported in aggregate, and decisions on trading, hedging and risk management are made with the entire portfolio position taken into consideration.

The time frame breakdown is similar to the commodity breakdown, with the exception of the division of responsibilities within time frames. Most of the volume of trades, liquidity and volatility takes place on the "screen" (so called because exchange-traded contracts can easily be viewed on a computer monitor screen). The skills and interest level in quickly scalping, trading and speculating the front months (the first 16 months of most exchange-traded contracts are liquid enough to be listed on the "screen) is quite different from that of the longer-dated commodity exposure. To certain companies, it makes sense to have a group which focuses on the front months, and a group which is responsible for everything that is longer-dated with respect to risk management.



For centralized risk management, the factors are:

PRO's:
1. Eliminates intracompany arbitrage. By managing the individual positions as one large aggregate position, it is much easier for the Risk Manager to know precisely what all positions are, as well as the overall exposure in each commodity book. By proactively managing these positions, when he sets strategy for the group, he can reduce or eliminate traders buying and selling the same commodity at the same time.
2. Communication: With a central risk management, trading and hedging point, every business unit in the organization knows precisely where to go for pricing, market intelligence, execution and reporting.
3. Ease of Reporting: Instead of dealing with myriad reports from different commodities, traders, business units and time frames, the overall exposure of the company is cleanly reported in one concise format.
4. Self-Hedging: Various business units or traders may initiate positions in the overall book which naturally offset each other. An example would be a long position in NGL's, and a long spark spread position. This could be broken down into a correlative long position in crude and natural gas (NGL long), and a short gas/long power position (spark spread). Combining commodity exposures would result in merely a long power position, as the NGL length can be used to offset the short gas position in the spark spread. Although this is a basic example, when multiple commodities, volatilities, and time frames are combined and reported, the process as a whole becomes much clearer for the risk manager.
5. Eliminates redundancy: No need to duplicate any mid or back office functions.
6. Transfer Pricing: When properly designed, centralized risk management eliminates the need for complex transfer pricing rules. More on this later.

CON's:
1. Overlapping Responsibilities: There is natural overlapping that occurs in any group, such as time frames, commodites with correlated positions, hubs, regions, etc. One centralized group, if not properly and actively managed, will develop internal friction based on these overlaps (turf wars). An example of this would be if a company acquired an NGL processing plant, which creates a position in Ethane, Propane, and Butane. However, these are not extremely liquid commodities, and the exposure can be correlated to a crude oil and natural gas position. So the NGL traders and the crude oil trading goup will both want the asset and the subsequent responsibility for the position in their respective books. Clear lines of responsibility mut be established.
2. Cumbersome
   - ✓ Reports: The initial gathering and assimilating of reports can be unbearable. A data entry error in one region can ripple through the entire combined report, and take hours to solve. For instance, assume a trader accidentally keys in a long-term power price as "$3.50" instead of the real price of "$33.50". The positions for power will be wrong (options create delta positions based on price) the P&L for the group will be wrong, and any spreads based on this region will be wrong

(basis spreads or spark spreads). Additionally, valuation of generating assets will be incorrect. Unless the reporting system is extremely user-friendly, chasing down the source of this simple mistake can be time consuming.

- ✓ Change: Making changes to the system or structure of a centralized group is like trying to turn around an aircraft carrier – it takes time and the general consensus of company's upper management. Upper level management does not like surprises, and wants to be involved in the decision process of how the group is structured, the types of reports shown, risk limits – basically everything. Getting this type of consensus approval can be painful.

3. Risk Limits (one trader affects another): If "Trader A" has a strong market conviction and puts on a massive commodity position accordingly, he may use up all of the risk capital for the given group (max out the Value at Risk or Position Limits). This may preclude "Trader B" from placing a similar position on the books, because the overall group exposure limits have been reached. What one trader does should not affect what another wants to do. When a group, such as traders, are compensated directly on their performance, this problem will occur frequently if not addressed.
4. Transfer Pricing: When improperly designed, centralized risk management actually exacerbates the normal problems associated with centralized risk management. More on this later.

The New York Times
Sunday, June 27, 1999

Firing Up An Idea Machine

Enron Is Encouraging The Entrepreneurs Within

By Agis Salpukas

Houston – Two words sum up the management philosophy at the Enron Corporation, according to its president, Jeffrey K. Skilling: loose and tight.

"We are loose on everything related to creativity," said Mr. Skilling, who came here in 1990 to help transform Enron from a regulated natural-gas pipeline company into the energy industry's most free-wheeling cowboy.

"We like to have smart people try new things," said Mr. Skilling, 45. While other energy companies collect engineers, Enron has hired hundreds of M.B.A.'s in recent years from top universities—about 150 this year alone—and even the occasional liberal-arts major just out of college. "We stick them in the organization and tell them to figure something out," he said.

So where does "tight" figure in? With intense controls, imposed whenever Enron signs a long-term contract to deliver a commodity, like natural gas—a $600 million computer system tracks the company's financial exposures—or when it comes time to evaluate those smart people's performance.

"Risk-taking, anytime, is managed centrally," Mr. Skillling explained.

In less than a decade, lassoing loose and tight into a single strategy, Enron has emerged from its unlikely perch in the utility industry as a model for the new American workplace—every bit as much as the Silicon Valley start-ups that usually come to mind when the subject is entrepreneurship or innovation.

In the process, the company has opened huge new profit centers: by building power plants and pipelines in Asia, Europe, Latin America and the United States; trading natural gas and electricity in wholesale markets at home and overseas, and applying its financial expertise to create hedging instruments for the energy industry and other commodity businesses.

Its stock, meanwhile, has sharply outperformed the Standard & Poor's 500 through the 90's—a time when its old peers in the gas business have badly lagged behind the market.

New management approaches abound: Walls have fallen within its 57-story headquarters tower, the better to promote cross-pollinating conversations. Through internships and mentor programs, seasoned executives help even the lowest-ranking employees find an interest—and then challenge them to start a new business for the company.

Mr. Skilling says he does not care how people dress when they come to work, or whether expense accounts are filed on time. Or even if, after an all-out effort, a venture fails—like Enron's heavily publicized push two years ago to become the nation's leading retail marketer of electricity, as states like California opened the power business to competition. The executive who led that effort is now in charge of spending perhaps eight times as much to sell long-term power contracts to big companies.

"If you try new things," Mr Skilling said, "some will work, some won't"

What is it like to work in such an environment? To hear employees tell their stories, it's a tight-rope walk—exhilarating, if sometimes scary.

Moving Up, 46 Floors

Two hours with David W. Cox is as exhausting as a full day with someone else. Near 6 feet tall, Mr. Cox, 36, is a blur of motion on a 45^{th}-story trading floor, where he oversees a staff of 30 as a vice president.

Their business is one that Mr. Cox invented: writing swaps contracts that allow big consumers like newspapers publishers to hedge against the fluctuations in the price of paper.

Enron wrote $4 billion of the contracts in 1998. And Mr. Cox, who started the 90's working in the basement as a $5-an-hour graphics clerk, sounds amazed that he is ending the decade heading one of the company's fastest-growing new enterprises.

For Mr. Cox, the door to entrepreneurship was opened directly by Mr. Skilling. Then a newcomer himself to Enron, Mr. Skilling, a former consultant at McKinsey & Company, was building the company's wholesale trading of natural gas, and Mr. Cox was helping to prepare materials for his presentations.

Mr. Skilling, he said, was constantly challenging employees to find ways to take advantage of the turmoil that impending deregulation had unleashed in the gas industry. "He made us feel that there was nothing that we could not do," Mr. Cox recalled.

After three years, he persuaded Mr. Skilling to find an outside concern to handle Enron's graphics needs—and then left to join, and eventually buy, that small company that absorbed the work. About 25 Enron employees went with him.

The business grew quickly. Mr. Cox was soon also supplying graphics for Conseco, the insurer, and Sprint, the long-distance telephone company, offering long-term contracts for the service at a fixed-price that included the cost of paper.

In 1995, though, paper prices surged, doubling because of high-demand and tight manufacturing capacity. Put on the spot, Mr. Cox tried to freeze his paper costs, but was rebuffed by every producer or broker.

Sensing an opening, he got in touch with big paper consumers. Historically, those buyers had simply ridden the up-and-down cycles of paper prices: When costs were low, publishers, for example, would build up big supplies, but that piled expensive inventory costs on their books. And when prices shrank, they often had to absorb quick price increases.

Mr. Cox's idea was to package financial deals that wold guarantee paper users predictable prices—if not the lowest prices—for the long term. Publishers would sign long-term contracts with a financial partner. If the price they paid to their supplier was higher than the contracted price, the partner would make up the difference; if the price was lower, the publisher would pay the difference to its partner in the hedge. The deals would be very much like those Enron was making with users of natural gas and other commodities.

Eventually, he convinced the Times Mirror Company and Media News Group, both publishers of big city newspapers, that the concept had merit. Next, he called his mentor, Mr. Skilling, who quickly embraced the idea as a logical extension of Enron's financial deal-making. He invited Mr. Cox to return to Enron to set up the business. The $5-an-hour clerk would become a vice-president with a six-figure salary.

Over time, paper users have warmed to the concept. The value of the contracts rose twentyfold last year, to $4 billion, representing about 1 percent of the global paper market. Mr. Cox expects the contracts' value to quadruple over the next two years.

Mr. Cox attributes his entrepreneurial instincts to being, literally, a survivor. As a 19-year-old crewman on an oil industry supply boat that broke up in 20 minutes during a storm east of New Bedford, Mass., he learned a crucial lesson. "It was a life-defining moment," Mr. Cox said. "I realized that life was so precious"—and that most anything was in reach if he tried hard enough.

Looking For Change

Lynda R. Clemmons was not a classic hire for an energy company. She had been a history and French major at Southern Methodist University in Dallas and then spent an unhappy year after graduation concluding that investment banking was not to her liking.

But she had hedged her bets a bit in college, by minoring in business. And she wanted to work for a company in the middle of major change. So, at 22, she joined Enron—where, she said, her bosses seemed to have faith that she could beat her own path.

Based on her previous experience, she started out working as an analyst in mergers and acquisitions. But Ms. Clemmons—who recently began riding motorcycles (though only after taking a safety course)—found that she was more attracted to the breakneck world of natural gas and electricity trading on the 31st floor of Enron's headquarters.

After transferring to work with the traders, she grew fascinated with the market for emissions credits, in which power companies that pollute less than they are allowed sell pollution rights to dirtier utilities.

As her new job put her in contact with executives of coal-fired utilities, Ms. Clemmons learned that they had another need: a hedge against the vagaries of weather that confound energy producers. During heat waves, for example, utilities either must restart—at great cost—their moth-balled generating units or buy power in wholesale markets where prices have spiked.

"They had been fantasizing about some kind of product to protect them against the weather for many years," Ms. Clemmons explained, sipping hot tea at a Starbucks stand in the headquarters lobby. Enron had been pondering the problem, too, she said, but "no one had put the case together before."

So Ms. Clemmons did, setting up a one-woman enterprise within Enron Capital and Trade, the company's financial unit, to develop a contract that essentially would let utilities buy insurance against the weather.

Initially, she approached Enron's trading, legal and credit departments for help on specifics, and checked in once a day with a supervisor. "I didn't have somebody holding my hand saying, 'O.K., this is how it's done,'" she said.

As the venture blossomed, she was able to get people assigned from other company areas to work for her. "You create your own network," Ms. Clemmons explained. But with the added support came stricter controls, like having to complete a daily profit-and-loss statement. "It becomes very clear very quickly if you are losing a lot of money," she said.

The most difficult part of the project, she said, may been overcoming the skepticism of older, male executives in the utility industry, many of whom already considered Enron a threat to their business because of deregulation. And even more of whom were taken aback by her youth when she showed up with her charts and graphs.

"But you're younger than my daughter. Why should I listen to you?" Ms. Clemmons, now 29, recalled being asked more than once.

Nevertheless, her persistence and cool, matter-of-fact manner eventually won their confidence. With the first transactions lined up, Mr. Skilling took the new business to Enron's board for approval.

In two years, Ms. Clemmos and her staff, which now numbers 13, have sold about $1 billion in weather hedges. Essentially, she has created a new industry; companies like Koch industries, the Southern Company, and Utilicorp United compete with Enron for utilities' business.

Ms. Clemmons, meanwhile, is in demand as a speaker to explain her new field. She recently was a chairwoman of a conference on risk management that drew 500 participants.

And she is just getting started. She figures that American companies with big exposure to weather-related risks have more than $1 trillion in yearly revenues; utility deregulation and the weather extremes driven by the El Nino phenomenon can only spur demand.

"We've only scratched the surface," Ms. Clemmons said.

Spreading The Word

The business that Thomas D. Gros is building for Enron remains untested. But his entire career seems to have been aimed at the opportunity.

He studied aerospace engineering, worked as an analyst for the Central Intelligence Agency, earned an M.B.A. and set up a natural gas trading operation—competing against Enron—for British Petroleum. He also did a stint on Wall Street with Chemical Bank.

But Mr. Gros—wiry, precise and impatient—quit that job in 1996. "I could not impact directly the bottom line of the firm," he said.

So he took a job at Enron, in charge of marketing commodity trading services to big industrial customers. And as he set up an office for the operation in mid-town Manhattan, he stumbled upon his entrepreneurial opening.

To connect his team's computers to those at Enron's headquarters in Texas, he ordered an expensive T1 telecommunications line. But it provided far more capacity than the office needed.

The trader in Mr. Gros saw the potential for profit in the spare bandwidth. "I wanted to see if there was a way to sell it to get some value for it," he said.

He quickly realized that he was not alone; many other companies were locked into contracts that wasted telecommunications capacity. Enron itself had built excess capacity into its internal fiber optic network. And had acquired even more with its purchase of Portland General Electric, an Oregon utility, in 1997.

He floated the idea within the company, drawing the interest of traders and other employees. "When people here see an opportunity, they want to participate," he said. "We do not ask permission to spread the word. We just do it."

He was able to spend freely on travel to sell the concept; when he needed larger sums--$50,000 in start-up expenses, for example—his boss was able to authorize the outlay.

"There wasn't any budget, per se," Mr. Gros said.

Last year, the company approved his plan to start a bandwidth exchange and to trade Enron's own account. His title is now vice president for global bandwidth trading.

Mr. Gros hopes to have his new marketplace in operation by year-end. But there is much to sort out, from the ground rules of trading to the technology to support it. And there is competition: At least three companies are already operating bandwidth exchanges, though Mr. Gros says the others focus on voice communications while Enron will offer a spectrum of communications capacity.

For now, Mr. Gros is using Enron's excess capacity to keep his growing team connected. A video link, for example, ties staff members Houston to colleagues in New York, maximizing what he calls informal collisions. "The really creative ideas," Mr. Gros said, "don't come on a schedule."

A FINAL NOTE ABOUT TRANSFER PRICING:

From start to finish, the process by which a deal is completed and then hedged by centralized risk management should be:

1. Contact with Customer: The customer tells the originator or asset developer where their interests are.
2. Originator/Developer obtains pricing from the centralized risk management group. This includes any variables such as volatility, prices, heat rates, correlations, etc. IT IS IN THE BEST INTERESTS OF THE RISK MANAGEMENT GROUP TO SHOW <u>COMPETITIVE</u> PRICING. Without competitive pricing, the company will never close any deals, originate any risk, or manage any assets. With no new positions on the books, the centralized risk management group is effectively eliminating their own jobs. Without assets to optimize, the risk management group becomes exclusively a speculative trading shop. There is little, if any appetite in the industry for pure speculative trading (based on such newsworthy blowups as PCA, LG&E Columbia,

Cinergy, etc.). Additionally, without competitive pricing, the risk management group will not receive valuable market intelligence which will help them optimize their positions.

3. Final price shown to customer.
4. Deal is closed.
5. Deal is given to the centralized risk management group AT THE PRICES ORIGINALLY USED. Simply put, the centralized risk management group stands behind/honors any prices shown to originators/asset developers. The risk management group is then free to hedge and optimize as they choose.
6. Centralized risk management group hedges commodity price exposure.

The key to this process is the understanding that the risk management should WANT as many positions as possible. This allows for geographic diversity (portfolio theory) natural hedging, "crossing" positions (sometimes deals will be on the buy side, other times on the sell side) from "inventory", and a valuable amount of deal flow and market intelligence. For example, if the originators and asset developers bring a massive amount of deals to be priced, all of which are buyers, the risk management group will know to go and purchase the commodity ahead of time in the bilateral or direct marketplace. If the developers/originators "win" the deal, the commodity will already be in inventory. If not, another company will be in the marketplace trying o buy from you what you have already purchased at a lower price.

MEASURING RISK

In order to measure the amount of risk in a portfolio, three things are needed: you must know your position, the volatilities of the commodities involved, and the current price of the commodities. Although this sounds like an easy task, it is by no means a simple assignment. The intricacies are as follows:

A. Know Your Position:

This is the first rule of trading, hedging and speculating. KNOW YOUR POSITION! Without this, you will be whipsawed in the marketplace like a rag doll. Are you short or long? If you do not know, you will not know how to react when prices move up or down. You will not know what risk you have on the books. And you will not be able to provide accurate management reports. Simply put, the first thing you should do when you walk in the door every morning is verify your position.

1. Outright Position: The outright position consists of all buys and sells for a particular underlying commodity. This is the first step towards getting your arms around what you have in your book. There will be multiple commodities, with many buys and sells in every imaginable time frame. Learn (read this as "memorize") every aggregate position for every commodity and for every time frame. A sample outright power position report is:

	Peak Days	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MTM P&L															
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]
Net Position	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]															
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]									
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]									
Net Position	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]															
[illegible]	[illegible]	[illegible]	[illegible]	0	0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	0	1	0	0	0	0	0	0	0	0	1	1	1	1	1
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			[illegible]	[illegible]	[illegible]	[illegible]
Net Position	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
DELTA OFFPEAK															
[illegible]	[illegible]	1	0	7,300	[illegible]	[illegible]									
[illegible]	[illegible]	1	0	0	0	0	[illegible]	[illegible]	[illegible]	0	1	1	[illegible]	[illegible]	[illegible]
[illegible]	0	1	0	0	0	0									
Net Position	[illegible]	1	0	7,300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	1	1	[illegible]	[illegible]	[illegible]
GREEKS															
Theta (per day)	[illegible]	422	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	1	1	1	1	1
RHO (per [illegible])	[illegible]	[illegible]	31	[illegible]	[illegible]	[illegible]	0	0	0	0	1	1	1	1	1
Vega (per [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	371	[illegible]	0	0	0	0	1	1	1	1	1
Gamma ([illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0	0	0	0	1	1	1	1	1
[illegible]															
[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

2. Greek-Adjusted Position: Options will change the overall outright position of your book. Once you put on an option position, whether it is buying or selling or puts or calls or whatever, IT DOES NOT MATTER! Once the option position is in your book, you now have a delta and a gamma to manage with respect to your outright position. On a very simple basis, assume only the following is in your portfolio:
   a. Long 100 contracts of August NYMEX natural gas.
   b. Sold 100 August NYMEX natural gas call options, strike = $2.25.
   c. Current market price for August NYMEX natural gas is $2.25 (option is at the money)
   d. Delta for the August NYMEX natural gas option is +/-0.50 (at the money options have a delta of approximately 50%).
   e. Gamma for this option is +/-0.10 (for a $0.10 move).

   Your position is:

Current Market	$2.25
Underlying	+100
Call Option Delta	-50
Net	+50

You should treat your position as being long 50 lots, NOT as being long 100 lots and being short a call option. You also need to keep in mind synthetics, as this position could be decomposed as being short the $2.25 put ("covered call = put"). You also need to keep in mind the gamma of the position. If prices move up by $0.10, you will be long only 40 lots, as the gamma eats away at your overall length. And if prices fall $0.10, you will be long 60 lots, as the gamma adds to your length.

You can continue to manage this position based on the overall underlying commodity with respect to your gamma and delta. You should know what rising and falling prices will do to your net. With this understanding, you can then position yourself the way you want to be in the marketplace. You can formulate a game plan for all possible outcomes, and try to control your exposure and optimize your risk. If this was the only thing you did to treat your combined options and underlying positions, you would be fine.

However, it does benefit to keep in mind the synthetics. this position can be broken down into the covered call. Should market conditions warrant such a strategy, you can buy back the synthetic put you have sold. This will leave you with a net overall flat position. If you buy the put, as prices move up, the length you lose from the call will offset what you gain in length from the put (just the opposite happens in a falling market). Illustrated, it looks like this:

Current Market	$2.25
Underlying	+100
Call Option	-50
Put Option	-50
Net	0

Current Market	$2.75
Underlying	+100
Call Option	-80
Put Option	-20
Net	0

Current Market	$2.00
Underlying	+100
Call Option	-30
Put Option	-70
Net	0

The bottom line is to know how your greeks will affect your overall position. Constantly monitor your options with respect to the underlying to determine if any synthetics exist intentionally or unintentionally in your portfolio. Then manage your overall delta while looking for other options opportunities. Note: See above Position Report Summary for example of Greeeks.

3. Correlated Positions:

There will be several commodities in your portfolio that cannot be hedged or reported via traditional methods. The most common group for this is NGL's. There is no forward long-term market for any NGL products, no price or volatility curves, and very little trading done. For these reasons, NGL's are usually broken down into equivalent crude oil and natural gas positions.

The problems occur when viewing the aggregate NGL positions over the entire time frame. The difficulties arise when trying to determine at what point positions should be reported as the outright NGL's, and at what point they should be reported as correlated equivalents. Typically, the breakdown occurs at the time frame where the liquidity dries up. This is usually around the 6-month point. Positions inside of 6 months are usually reported as the actual NGL's (propane, butane, etc.) and longer than 6 months are reported as the crude and natural gas equivalents.

Again, you must keep in mind what both positions are – the NGL and the correlated equivalents. This will allow for hedging the position where the liquidity is the greatest (crude and gas) while searching for any long-term hedging possibilities in the true NGL market.

1999-02 Hedges Against NGL Exposure
1/21/99

Production Months

			Jan-99	Feb-99	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99	99 TOTAL
POSITION															
C2	Ethane Frwd Sales (C2 Frac)											-	-	-	
NG	NG Swaps (for C2 Frac)											0	0	0	-
	PIPELINE CALLS	Nominal	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(315)	(3,780)
		Delta	-	-	-	-	-	-	-	-	-	-	-	-	-
	PIPELINE SWAPS (C3 Hedge)		(450)	(450)	(450)										(1,350)
	PIPELINE SWAPS (PTR Hedge)					75	75	75	75	75	75	75	75	75	675
OIL	CALLS	Nominal	(400)	(500)	(800)	(1,000)	(1,000)	(1,000)	(200)	(200)	(200)	(200)	(200)	(200)	(5,800)
		Delta	-	-	-	-	-	-	-	-	-	-	-	-	-
	PUTS	Nominal							200	200	200	200	200	200	1,200
		Delta							-	-	-	-	-	-	-
	Front-to-Back SWAPS							-	-	-	-	-	-	-	-
	Asian Swaps								(966)	(997)	(1,364)	(1,647)	(1,226)	(1,485)	(7,685)
MTM															
	ETHANE FRAC HEDGE						$523	($98)	($256)	($1,025)	$322	($508)	($3)	($129)	($1,159)
	PIPELINE CALLS		$415	$415	$415	$415	$415	$415	$75	($255)	$98	($432)	$415	$415	$2,806
	PIPELINE SWAPS		$1,522	$1,278	$689	($57)	$152	$238	$329	$758	$114	$318	$973	$433	$6,248
	OIL CALLS		$266	$316	$235	($2,020)	($2,489)	($2,638)	($1,510)	($1,750)	($2,252)	($1,647)	($2,056)	($2,330)	($17,838)
	OIL PUTS								($84)	($84)	($84)	($84)	($84)	($84)	($504)
	OIL FRONT-TO-BACK							$5,258	$4,325	$0	$0	$0	$0	$0	$9,583
	OIL ASIAN SWAPS								($2,163)	($3,835)	($8,957)	($2,156)	($8,536)	($6,516)	($32,229)
	Closed Futures		$4	$25	-	$5	$19								$43
		Total	$2,207	$2,024	$1,539	($1,658)	($1,380)	$3,195	$707	($6,251)	($10,759)	($4,510)	($9,706)	($8,512)	($33,103)
			Settled	Settled	Settled	Settled	Settled	Settled	Settled	Settled	Settled	Settled			

4. Summary Reporting:

Summary reporting is an effort to combine ALL commodity exposure into a concise format. Consideration must be given to such areas as overall mmBtu exposure, regional exposure, "units" reported (NYMEX equivalent contracts or other underlying basis). Additionally, the correlation between each and every commodity must be considered (i.e. is a long crude oil/short natural gas position "hedged" or flat? Is a short power position in ERCOT offset by a long NGL position in Dallas?). Typical summary reports are:

A. Master Summary Report;

The Master Report will list the overall exposure of the Risk Management group. It is generally broken down by individual, broad commodity groups (gas, power and crude only), although occasionally, it will be by mmBtu's. The purpose of this report is to provide management with an overall feel for the exposure of the book. It is designed so that an appreciation for the affect of commodity price movements can be quickly determined without having to ask the individual traders. If crude oil rises 10% in one day, this report should be able to be used as a guideline for the overall P&L effect on the portfolio.

Energy Positions Report 26-Jan-00 13:56

	Total Positions through 2005						Price Changes	Changes in Value of Current Position Due To Price Change ($MM)					
	Gas Trans	Trans Capacity	Petrol Products	Power Gen	Trading & Mktg	Total	5 Yr Avg Price Change	Gas Trans	Trans Capacity	Petrol Products	Power Gen	Trading & Mktg	Total
[illegible]													
Crude	(1.78)	0.00	(16.39)	0.00	0.66	(17.51)	0.679	($8)	$1	($37)	$2	$2	($42)
	(1.79)	0.00	(16.39)	0.00	0.68	(17.51)		($8)	$1	($37)	$2	$2	($42)
[illegible]													
Canada - West	0.00	(8.26)	0.00	0.00	0.43	(8.14)	0.088	$0	$0	$0	$0	$0	$0
Gulf Coast	(108.33)	(0.22)	(4.76)	8.41	28.13	(69.95)	0.088	($11)	$0	$0	$2	$6	($3)
Mid Continent	0.00	0.00	(19.23)	(2.99)	(7.55)	(27.45)	0.088	$0	$0	($4)	$0	$0	($4)
Mid West	26.23	4.56	0.00	(8.26)	3.01	26.83	0.088	$5	$0	$0	($5)	($3)	($3)
North East	88.89	8.22	0.00	(14.75)	(15.26)	64.11	0.076	$9	$0	$0	($2)	($2)	$5
Texas	(16.52)	0.00	(5.29)	(1.55)	(10.85)	(26.21)	0.089	($3)	$0	($3)	$0	($4)	($10)
West	0.00	0.00	(6.71)	(36.75)	3.14	(42.12)	0.090	$0	$0	$0	($3)	$0	($3)
	(0.73)	4.31	(34.99)	(55.89)	6.05	(81.93)		$0	$0	($7)	($9)	($3)	($19)
[illegible]													
Ethane	9.25	0.00	79.22	0.00	0.00	81.56	0.009	$8	$0	$51	$0	$0	$59
Gasolines & Other	4.18	0.00	45.25	0.00	0.00	46.56	0.016	$6	$0	$31	$0	$0	$36
Isobutane	1.84	0.00	18.49	0.00	0.00	21.85	0.016	$4	$0	$19	$0	$0	$23
Normal Butane	1.84	0.00	19.63	0.00	0.00	24.91	0.016	$4	$0	$16	$0	$0	$20
Propane	3.55	0.00	30.59	0.00	0.00	32.44	0.016	$8	$0	$55	$0	$61	$124
	20.26	0.00	187.18	0.00	0.00	206.32		$29	$0	$172	$0	$61	$262
[illegible]													
ECAR	0.00	0.00	0.00	6.83	(3.14)	5.49	(0.403)	$0	$0	$0	($6)	($2)	($8)
ERCOT	0.00	0.00	0.00	3.91	(2.97)	2.93	0.681	$0	$0	$0	$10	$0	$10
MAAC	0.00	0.00	0.00	0.00	2.05	4.05	0.651	$0	$0	$0	$0	($2)	($2)
MAIN	0.00	0.00	0.00	5.75	0.00	7.76	(0.293)	$0	$0	$0	($3)	$0	($3)
NPCC	0.00	0.00	0.00	9.73	(23.26)	(16.43)	1.056	$0	$0	$0	$21	$0	$21
SERC	0.00	0.00	0.00	0.00	(2.43)	(4.43)	(0.016)	$0	$0	$0	$0	$0	$0
SPP-S	0.00	0.00	0.00	18.19	(2.40)	17.79	0.046	$0	$0	$0	$5	$0	$5
WSCC	0.00	0.00	0.00	44.35	4.39	50.74	1.338	$0	$0	$0	$63	$4	$67
	0.00	0.00	0.00	87.56	(37.76)	67.83		$0	$0	$0	$90	$0	$90
												Total Value Change:	$288

B. Individual Commodity Summary Report:

These reports are designed to show overall exposure broken down by specific commodities. Typically, it is given as Power (East and West), Natural Gas (Financial and Basis), NGL's (short-term), and Crude/NGL Equivalents. This is to provide a deeper understanding of where the risk resides within the company. For instance, while a Master Report may show overall electricity to be flat, it may, in actuality, consist of a long West Power position and a short East Power position. Since there is no transmission between these two points, and they trade as two discrete "animals", a flat power position report is misleading. There is a very strong possibility of power prices converging or diverging in these two regions. The same holds true for gas basis positions, as well as crude versus the actual NGL's.

Crude/NG/NGL Positions Report 26-Jan-00 14:23

	Total Positions through 2005						Estimated Current Market Levels ($ per BBL)						Value Change (in $MM) since
	2000	2001	2002	2003	2004	2005	2000	2001	2002	2003	2004	2005	26-Jan-00
[illegible]													
Crude	1.45	2.10	2.10	2.10	2.10	2.10							
Hedges	(27.39)	(3.25)	(0.25)	0.00	0.00	0.00							
Net	(25.94)	(1.15)	1.85	2.10	2.10	2.10	25.06	20.42	18.97	18.41	18.16	18.11	(55.43)
												Subtotal:	(55.43)
[illegible]													
Gulf Coast	(0.75)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	(0.75)	(0.60)	(0.60)	(0.60)	(0.60)	(0.60)	2.64	2.56	2.57	2.61	2.66	2.72	(0.45)
Mid-Continent	(5.23)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	(5.23)	(2.12)	(2.12)	(2.12)	(2.12)	(2.12)	2.44	2.45	2.45	2.48	2.53	2.58	[illegible]
Texas	(2.65)	(1.57)	(1.57)	(1.57)	(1.57)	(1.57)							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	(2.65)	(1.57)	(1.57)	(1.57)	(1.57)	(1.57)	$2.54	$2.56	$2.56	$2.60	$2.65	$2.71	[illegible]
West	(0.36)	(0.45)	(1.36)	(1.12)	(0.65)	(0.42)							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	(0.36)	(0.45)	(1.36)	(1.12)	(0.65)	(0.42)	2.34	2.36	2.37	2.40	2.45	2.50	(0.22)
												Subtotal:	($6.26)
[illegible]													
Ethane	15.52	18.23	18.23	18.23	18.23	18.23							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	15.52	18.23	18.23	18.23	18.23	18.23	0.29	0.26	0.25	0.24	0.24	0.26	66.64
Gasolines & Other	3.10	3.57	3.57	3.57	3.57	3.57							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	3.10	3.57	3.57	3.57	3.57	3.57	0.56	0.47	0.44	0.43	0.43	0.43	30.25
Isobutane	2.95	3.49	3.49	3.49	3.49	3.49							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	2.95	3.49	3.49	3.49	3.49	3.49	0.55	0.46	0.43	0.42	0.41	0.41	18.25
Normal Butane	4.58	5.11	5.11	5.11	5.11	5.11							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	4.58	5.11	5.11	5.11	5.11	5.11	0.62	0.44	0.41	0.40	0.40	0.40	12.26
Propane	12.26	13.85	13.85	13.85	13.85	13.85							
Hedges	0.00	0.00	0.00	0.00	0.00	0.00							
Net	12.26	13.85	13.85	13.85	13.85	13.85	0.46	0.39	0.36	0.35	0.35	0.35	69.71
												Subtotal:	197.10
												Grand Total:	136.41

C. Specific Reports;

Specific reports are what the individual traders for each commodity can use to verify their positions. They will list each individual hub for each individual commodity. Aside from looking at a laundry list of every trade done to date, this is the best way to assess the overall specific positions.

Crude Positions Report 26-Jan-00 14:23

12/29/99	59424304	23.25	NYMEX OIL CUSHIN MONTH AVERAGE	May 1, 2000	July 1, 2000	SWAPS	May 31, 2000	MONTHLY AVG	CRUDE OIL	-200,000.00	$36,950.00
12/29/99	59424304	23.25	NYMEX OIL CUSHIN MONTH AVERAGE	May 1, 2000	July 1, 2000	SWAPS	June 30, 2000	MONTHLY AVG	CRUDE OIL	-200,000.00	$101,430.00
12/29/98	59424304	23.25	NYMEX OIL CUSHIN MONTH AVERAGE	May 1, 2000	July 1, 2000	SWAPS	July 31, 2000	MONTHLY AVG	CRUDE OIL	-200,000.00	$171,526.00

B. PRICE:

The next important step in measuring risk is to know price. Once you know your position, you must know where current prices are, as they will have an effect on positions (options positions delta's change with price). Additionally, price is used to help evaluate risk in terms of historical standard deviations, and other risk metrics that will be covered later. And of course, if your job is to be a risk manager, you should know at all times where price is so that you can have an intuitive feel for real-time P&L, probable direction for where prices are headed, and input into pricing meetings for originators and developers.

1. Liquid price Curves: Easy. Just take whatever data source is used (Bloomberg, Reuters, Prophet, CQG, etc.) and capture the settlement price of the exchange-traded contracts. There is not much to dispute. If any prices in a liquidly traded market get too far out of line with

perception, the players will quickly take advantage of it, and re-align fair value. The current level of activity in the marketplace justifies using the following:

COMMODITY	EXCHANGE-TRADED LIQUIDITY	OTC-TRADED LIQUIDITY
Power	6 months	12 months
Natural Gas	18 months	2 – 3 years (traded) 10 years (quoted)
Crude Oil	18 months	2 – 3 years (traded) 10 years (quoted)
Propane	3 months	6 – 9 months
Heating Oil	6 months	9 – 12 months
Gasoline	6 months	9 – 12 months

2. Illiquid Price Curves: (NOTE: Due to the liquid nature of crude and gas, and the highly illiquid nature of long-term power, these sections will deal almost exclusively with power. You should be able to find solid long-term price curves in crude and gas that you can trade on, but this is a rare occurrence in power)

This is where you earn your paycheck. The question is what to do where there is not a well-defined, liquidly traded market. You will be providing input for pricing deals, and EXPECTED TO HONOR THOSE PRICES even though no real market exists. Additionally, you must mark your positions to market every night based on your determination of where long-term prices are. If you are too far off, you will eventually get tagged with a massive P&L swing on a mark-to-market basis. A few tricks for helping derive long-term price curves in illiquid markets are:

a. Calendar Rolls: Calendar rolls are quoted as a spread between years. For instance, if you heard the following for natural gas: "The '00/'01 spread is one bid at three", it would mean that someone is willing to buy 2001 and sell 2000 and pay $0.01, or to buy 2000 and sell 2001 and receive $0.03.

Roll	Bid	Ask
2000/2001	$0.01	$0.03
Action:	Buy 2001	Buy 2000
	Sell 2000	Sell 2001

So why is that important? If you know the shape of the 2000 curve (monthly quotes), and the '00/'01 calendar roll, you can apply the same "shaping" to the year 2001 individual months to develop a more comprehensive price curve. Any additional calendar rolls you can uncover in the marketplace will help you further develop your own long-term price curves.

On-Peak Cal 2000 Palo Verde Power

Month	Hours	Bid	Mid	Ask
Jan-00	400	29.00	29.25	29.50
Feb-00	400	27.50	27.75	28.00
Mar-00	432	26.00	26.25	26.50
Apr-00	400	26.25	26.50	26.75
May-00	416	27.75	28.00	28.25
Jun-00	416	34.40	34.65	34.90
Jul-00	400	53.25	53.50	53.75
Aug-00	432	62.75	63.00	63.25
Sep-00	400	51.40	51.65	51.90
Oct-00	416	32.00	32.25	32.50
Nov-00	400	30.00	30.25	30.50
Dec-00	400	31.00	31.25	31.50
Cal '00	4912	36.01	36.26	36.51

00/01 Roll:	0.30/0.50

On-Peak Cal 2001 Palo Verde Power

Month	Hours	Bid	Mid	Ask
Jan-01	416	29.55	29.80	30.05
Feb-01	384	27.95	28.20	28.45
Mar-01	432	26.35	26.60	26.85
Apr-01	400	26.60	26.85	27.10
May-01	416	28.20	28.45	28.70
Jun-01	416	34.95	35.20	35.45
Jul-01	400	53.80	54.05	54.30
Aug-01	432	63.30	63.55	63.80
Sep-01	384	51.85	52.10	52.35
Oct-01	432	32.35	32.60	32.85
Nov-01	400	30.35	30.60	30.85
Dec-01	400	31.35	31.60	31.85
Cal '01	4912	36.39	36.64	36.89

In the above example using power, the calendar 2000/2001 roll is $0.30 bid at $0.50 offer. This computes to a $0.40 mid-market roll. A simplified way to apply this roll to the 2001 monthly curve would be to add $0.40 to each month. However, a more realistic monthly shape would allow the summers to "grow" more rapidly than the winter months, which in turn would be higher than the shoulder months. Thus, notice that the summer month roll is $0.55, while the shoulder month roll is $0.35.

If you can't find too many calendar rolls, then you will have to make some assumptions based on whatever limited data is available. Again, using natural gas as an example, if you have the following rolls quoted in the market:

2000/2001 = $0.010/$0.030
2001/2002 = $0.020/$0.040
2002/2003 = $0.030/$0.050
2003/2004 = $0.035/$0.055
2004/2005 = $0.040/$0.060

You can make some natural assumptions regarding the outer years. The degree of contango starts to taper off. And as the time frame becomes longer, the "cost of carry" on an NPV basis becomes less of an impact. So a strong argument could be made for keeping the calendar rolls $0.040/$0.050 for the remainder of any terms. Absent any other information equally strong case can be made for "tapering off" the calendar rolls (flattening the contango). At this point, you don't know - but neither does anybody else!! If there are no market quotes, as long as you can apply sound logic, your guess is as good as anybody else's. The trick will be to validate it.

b. "Fitting Strips":

This technique is used when you have decent short-term quotes and sporadic long-term quotes. The short-term quotes give you the "shape" or seasonality of the commodity, and then this is used as a model to be applied to the long-term quote. For example, assume you receive the following quotes:

Cal '00/'01	$0.30/$0.50
Cal '01/'02	$0.25/$0.35
Cal '01-'05 Strip	$36.75/$37.25

On-Peak Palo Verde Power

Month	Hours	Bid	Mid	Ask
Jan-00	400	29.00	29.25	29.50
Feb-00	400	27.50	27.75	28.00
Mar-00	432	26.00	26.25	26.50
Apr-00	400	26.25	26.50	26.75
May-00	416	27.75	28.00	28.25
Jun-00	416	34.40	34.65	34.90
Jul-00	400	53.25	53.50	53.75
Aug-00	432	62.75	63.00	63.25
Sep-00	400	51.40	51.65	51.90
Oct-00	418	32.00	32.25	32.50
Nov-00	400	30.00	30.25	30.50
Dec-00	400	31.00	31.25	31.50
Cal '00	4912	36.01	36.26	36.51
Month	Hours	Bid	Mid	Ask
Jan-01	416	29.55	29.80	30.05
Feb-01	384	27.95	28.20	28.45
Mar-01	432	26.35	26.60	26.85
Apr-01	400	26.60	26.85	27.10
May-01	416	28.20	28.45	28.70
Jun-01	416	34.95	35.20	35.45
Jul-01	400	53.80	54.05	54.30
Aug-01	432	63.30	63.55	63.80
Sep-01	384	51.85	52.10	52.35
Oct-01	432	32.35	32.60	32.85
Nov-01	400	30.35	30.60	30.85
Dec-01	400	31.35	31.60	31.85
Cal '01	4912	36.39	36.64	36.89
Month	Hours	Bid	Mid	Ask
Jan-02	416	29.90	30.15	30.40
Feb-02	384	28.20	28.45	28.70
Mar-02	418	26.50	26.75	27.00
Apr-02	416	26.75	27.00	27.25
May-02	418	28.45	28.70	28.95
Jun-02	400	35.30	35.55	35.80
Jul-02	416	54.15	54.40	54.65
Aug-02	432	63.65	63.90	64.15
Sep-02	384	52.20	52.45	52.70
Oct-02	432	32.50	32.75	33.00
Nov-02	400	30.50	30.75	31.00
Dec-02	400	31.50	31.75	32.00
Cal '02	4912	36.70	36.95	37.20

Month	Hours	Bid	Mid	Ask
Jan-03	416	30.20	30.45	30.70
Feb-03	384	28.40	28.65	28.90
Mar-03	416	26.60	26.85	27.10
Apr-03	416	26.85	27.10	27.35
May-03	416	28.65	28.90	29.15
Jun-03	400	35.60	35.85	36.10
Jul-03	416	54.45	54.70	54.95
Aug-03	416	63.95	64.20	64.45
Sep-03	400	52.50	52.75	53.00
Oct-03	432	32.60	32.85	33.10
Nov-03	384	30.60	30.85	31.10
Dec-03	416	31.60	31.85	32.10
Cal '03	4912	36.87	37.12	37.37
Month	Hours	Bid	Mid	Ask
Jan-04	416	30.50	30.75	31.00
Feb-04	384	28.60	28.85	29.10
Mar-04	432	26.70	26.95	27.20
Apr-04	416	26.95	27.20	27.45
May-04	400	28.85	29.10	29.35
Jun-04	416	35.90	36.15	36.40
Jul-04	416	54.75	55.00	55.25
Aug-04	416	64.25	64.50	64.75
Sep-04	400	52.80	53.05	53.30
Oct-04	416	32.70	32.95	33.20
Nov-04	400	30.70	30.95	31.20
Dec-04	416	31.70	31.95	32.20
Cal '04	4928	37.05	37.30	37.55
Month	Hours	Bid	Mid	Ask
Jan-05	400	30.70	30.95	31.20
Feb-05	384	28.70	28.95	29.20
Mar-05	432	26.70	26.95	27.20
Apr-05	416	26.95	27.20	27.45
May-05	400	28.95	29.20	29.45
Jun-05	418	36.10	36.35	36.60
Jul-05	400	54.95	55.20	55.45
Aug-05	432	64.45	64.70	64.95
Sep-05	400	53.00	53.25	53.50
Oct-05	418	32.80	33.05	33.30
Nov-05	400	30.80	31.05	31.30
Dec-05	416	31.80	32.05	32.30
Cal '05	4912	37.23	37.48	37.73

Cal 01-05 Strip: $36.72 / $37.22

c. Basis/Hub Spreads:

For illiquid hubs, long-term price curves can be developed using liquid hubs and the spreads, or basis differentials, to the more liquid points. For example, assume you have developed a long-term price curve for Cinergy as per the above illustration. If only short-term price quotes for Entergy are available, the spreads on those short-term quotes can be used as a paradigm for the Entergy curve:

Given: Cal '00 & '01 Cinergy curve by month
Cal '00 Entergy curve by month
Calculate: Cal '01 Entergy curve by month

		CINERGY			ENTERGY		
Month	Hours	Bid	Mid	Ask	Bid	Mid	Ask
Jan-00	336	28.00	28.15	28.30	27.25	27.88	28.50
Feb-00	336	28.00	28.15	28.30	27.25	27.88	28.50
Mar-00	368	22.15	22.23	22.30	22.95	23.00	23.05
Apr-00	320	22.85	22.90	22.95	23.90	23.95	24.00
May-00	352	26.90	27.00	27.10	27.70	27.78	27.85
Jun-00	352	62.25	62.50	62.75	59.50	60.25	61.00
Jul-00	320	134.00	135.50	137.00	130.00	131.25	132.50
Aug-00	368	134.00	135.50	137.00	130.00	131.25	132.50
Sep-00	320	30.75	31.00	31.25	31.40	31.63	31.85
Oct-00	352	23.65	23.75	23.85	24.30	24.40	24.50
Nov-00	336	23.65	23.75	23.85	24.30	24.40	24.50
Dec-00	320	23.65	23.75	23.85	24.30	24.40	24.50
Jan-01	352	27.15	27.38	27.60	26.50	27.13	27.75
Feb-01	320	27.15	27.38	27.60	26.50	27.13	27.75
Mar-01	352	21.70	21.75	21.80	22.25	22.53	22.80
Apr-01	336	22.80	22.85	22.90	23.70	23.90	24.10
May-01	352	27.30	27.38	27.45	27.90	28.15	28.40
Jun-01	336	55.00	57.50	60.00	54.00	55.25	56.50
Jul-01	336	102.00	105.00	108.00	98.75	100.75	102.75
Aug-01	368	102.00	105.00	108.00	98.75	100.75	102.75
Sep-01	304	29.00	30.00	31.00	29.90	30.65	31.40
Oct-01	368	23.70	23.78	23.85	24.30	24.43	24.55
Nov-01	336	23.70	23.78	23.85	24.30	24.43	24.55
Dec-01	320	23.70	23.78	23.85	24.30	24.43	24.55

d. Monthly Spreads:

When developing long-term price curves, monthly spreads should be taken into consideration. If only calendar quotes or quarterly quotes are available, in order to make sense of the individual months, decide what the differentials should be. For example, in the above Cinergy and Entergy curves, all of the months calculated for the Entergy '01 curve match the spread differentials of the months in Entergy '00.

e. Historical (Index) Shaping:

Another good reference point when determining the long-term price curve is to look at the historical price curve. Where the index came out should be a good approximation of where the forwards should be priced (under normal circumstances). The forwards are the market's interpretation of where the spot will "average out". If there is a huge discrepancy between where the forwa rds are and where the spot market will be for the same time frame, the smart trader will take a position in the forwards and hold it until delivery to make a profit. This potential to take the positions to delivery is why forwards are the market's guesses at where spot will be.

To take this one step further, you can look at the historical prices with respect to the underlying fundamentals during that time period. Then, when you find a historical period where the fundamentals match the anticipated fundamentals for the new forward period, you will have a higher probability of correctly shaping your curve.

For instance, assume that 1998 was an extremely wet year in the Northwest portion of the US. If the year 2000 is anticipated to be very wet, then the 1998 historicals should help you in shaping the Calendar 2000 price curve.

Calendar 2000 COB quote = $29.50/$30.80

Month	Symbol	1998 Hydro Conditions	1998 Actual	1999 Hydro Conditions	1999 Actual	2000 Hydro Conditions	2000 Forward Curve
January	F	83%	20.49	76%	21.07	80%	20.75
February	G	98%	16.22	68%	18.56	65%	19.25
March	H	78%	20.01	91%	17.93	68%	21.20
April	J	75%	22.28	103%	18.88	72%	25.15
May	K	94%	21.10	96%	21.61	83%	23.75
June	M	102%	26.35	81%	33.38	94%	30.75
July	N	101%	39.29	75%	47.08	103%	38.00
August	Q	96%	37.25	97%	36.55	99%	35.50
September	U	99%	27.28	85%	35.08	83%	36.00
October	V	94%	32.51	88%	36.60	80%	40.00
November	X	96%	31.91	83%	33.08	75%	34.50
December	Z	98%	26.05	90%	29.96	70%	37.00
Calendar		93%	26.73	86%	29.15	81%	30.15

f. Similar Commodity Curve Shapes:

If little is known about the specific commodity for which you are trying to develop a forward long-term price curve, similar commodities can provide a clue. For instance, there is an extremely liquid market for crude oil, but not much price discovery for Propane. In order to measure the risk associated with a propane position, you can take the correlative position in crude oil (which has already been discussed), or develop a long-term price curve for propane to measure your forward positions. Since crude oil is highly correlated to propane, using the liquid crude oil market as a template for the propane curve makes sense.

g. Common-Sense Approach:

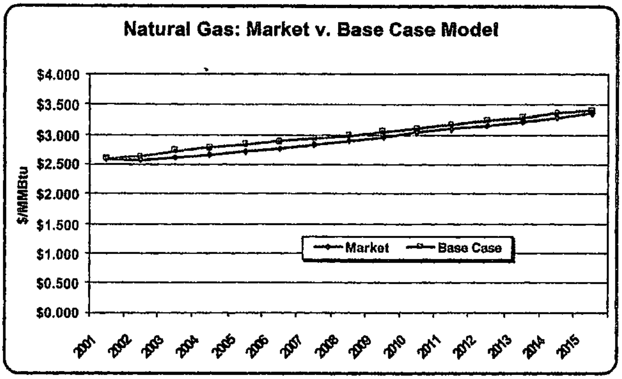
Once you have established a long-term price curve for a commodity, make sure that it is logical. Look at the relationships to other hubs to make sure that the spreads are not out of whack. Look at the relationships to the nearby months to make sure that the seasonals make sense. Look at the relationships to the same months, but in different years (i.e. June '01 vs. June '02) to make sure that the calendar rolls are appropriate. When you do this, certain things may jump out at you as being wrong. Obviously, you should fix them. But more importantly, some of the relationships that appear may point you towards trading opportunities.

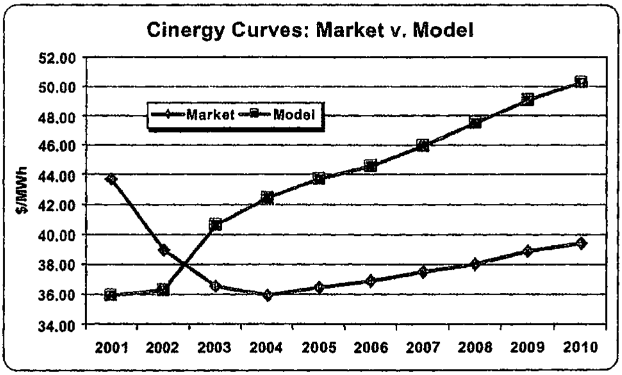
In the US, the northern states as compared to the southern states are almost always warmer in the early summer and cooler in the fall. Therefore, the Cinergy/Entergy spread for June should show Cinergy as a premium. For September, it should show Entergy as a premium. Looking at the historicals should back this up. And this makes sense, due to the tilt of the earth towards the Sun during that time period, and the traditional jet stream patterns that develop. If the long-term price curves show otherwise, you can attempt to validate these curves and put on a high probability trade by going into the marketplace.

h. Model Reference:

Another tool that will help you shape your curve is using the model as a reference. If you are trying to fill in a 10-year power quote with only one or two calendar quotes as a base, there will be almost infinite combinations that will work. Varying degrees of backwardation, contango, rolls, etc. can be shaped to match the long-term quote, but they may be drastically different.

When necessary, take a look at the long-term model price curves to help define your shape. Try to use a similar contango or backwardation structure, inflection point, and escalators. Although market and model are two entirely different animals, use whatever tools are at your disposal to give you an edge.





3. A Word on Model vs. Market:
Model price curves are a prediction of where supply and demand factors will determine fair value in the future. They are only a prediction. You cannot "trade" with a model. Just because a model "thinks" that prices should go to that level does not mean that will happen. You cannot transact with what a model says, but you can transact with what the marketplace is showing you as a bid and offer. Big Difference!!!

As an example, consider IBM stock. If IBM is currently trading for $125, and a Wall Street analyst has a 12-month target on the stock of $200, it does not mean that the current stock price will vault to $200. It does not mean that the analyst's firm will buy it from you today (or any day in the future, for that matter) for $200. It only means that if all goes according to the analyst's homework, earnings are met, margins continue to develop, the stock market and US economy in general remain in good health, etc. that the stock should be fairly valued at $200 in 12 months.

Just like any commodity – if the long-term supply and demand models say that Cal 2001 should be $3.50 for natural gas, and it is currently trading at $2.75, then $2.75 is the real price – the price at which you can transact today. The $3.50 is only a prediction. It may point you towards buying Cal '01 now at $2.75 if you believe the model will prove to be correct. But there are no guarantees that $3.50 will be achieved, and you cannot use the $3.50 to mark positions since it is not a market price.

4. Validating Long-Term Market Based Price Curves:

Once you have established your long-term market curves, you will need to validate them in the marketplace. This will consist of making a "two-way" market where other counterparties can transact. It may cost you money to do this, but it is a small price to pay for validating the marks on a long-term portfolio, or for valuing a long-term deal.

Assume that you have diligently done your homework, and your 10-year price curve for Palo Verde is $38.50/$39.50. Your asset development team, using these numbers, thinks that they can profitably build a 1,000 mW gas-fired generator that produces power for $33.00. They would like to commit to the project, because based on your curves, it will be a profitable deal. If your curves are correct, or if they are low and the actual prices prove to be higher, then great – everybody wins. But if your curves are incorrect, and are in fact high, you will be stuck with 1,000 mW that has a market value that is less than what you thought it would be.

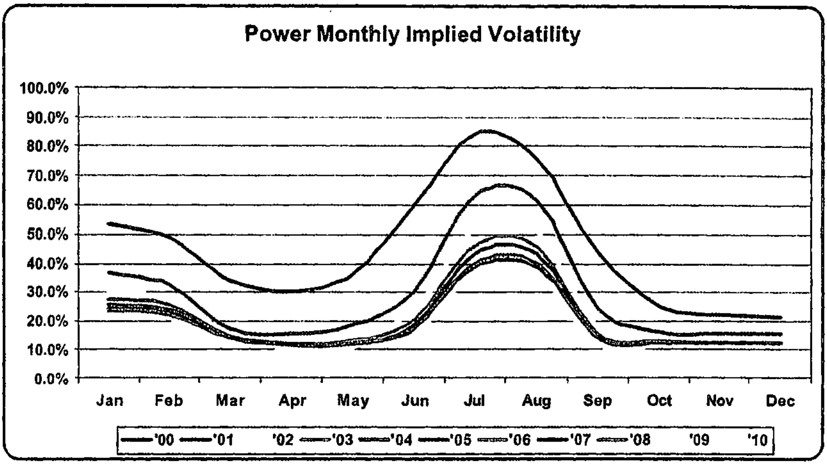
This is where you need to possibly spend some money. Using your $38.50/$39.50 market curve, you should go out into the bilateral market and make a two-way price of $37.50/$40.50, good for 50 mW. If somebody lifts your $40.50 offer, then great – your curves were low, you are short 50 mW at $40.50, and your developers will build you a generator to supply you with a position of 1,000 mW at a price lower than this. If you are wrong, your $37.50 bid will get hit, and now you are long $37.50 for 50 mW.

Your next price to the marketplace could then be $34.00/$38.00, good for 50 mW. If somebody lifts your $38.00 offer, you just made $1,056,000.00 (22 trading days per month x 12 months per year x 16 on-peak hours per month x 10 years x 50 mW x ($38.00 sale price - $37.50 buy price)). Additionally, you confirmed the market has buyers and sellers around the $37.00/$38.00 level, validating your curve and sending the signal to the developers to continue with the project.

If your $34.00/$38.00 market is still high, and your $34.00 bid is hit, then you are now long 100 mW at an average price of $35.75 (average of first hit of $37.50 and second hit of $34.00). Although being long 100 mW at higher prices is not an ideal situation, it does prove that the market is not there to support a 1,000 mW generator. All else being equal, you would rather be long 100 mW at $35.75 and know the market is somewhat lower, than to be long 1,000 mW from an asset and think that the market is actually much higher (your initial assumption in the price curve of $38.50/$39.50). You just spent a small amount of money relative to the large amount of money you could lose by being stuffed with an asset. Bottom line is to not be afraid of validating your curves in the marketplace.

C. VOLATILITY CURVES

Power Implied Volatility Shaping



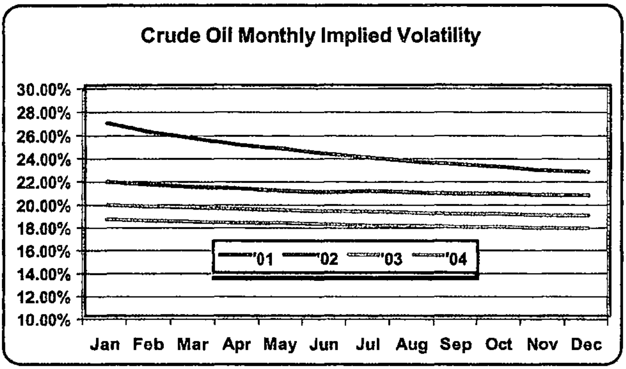
Implied volatility is most often calculated using option quotes obtained from the marketplace. The options commonly quoted for purposes of calculating implied volatility are At-The-Money straddles (straddle = call + put). In the power markets across the country, it is usually possible to get ATM straddle quotes for the front 12 months. The implied volatility is calculated by using a simple Black-Scholes equation.

To calculate implied volatility for the succeeding years, in this case through 2010, simply apply year-on-year rolls to each of the monthly premiums. For example, look at the table of year-on-year rolls below:

Y/Y:	Roll:
2001/2002	$2.00
2002/2003	$1.15
2003/2004	$0.60
2004/2005	$0.35
2005/2006	$0.20
2006/2007	$0.15
2007/2008	$0.10
2008/2009	$0.05
2009/2010	$0.03

With standard decreasing year-on-year rolls such as the ones above, implied volatility will decrease in the outer years until it flattens out around 10%. Since implied volatility indicates the rate and range of price movement, then this process accurately reflects the actual price movement in a forward power price curve. Forward prices change more broadly and more rapidly in the front years, in this case 2001 and 2002, than in the back years, 2009 and 2010. Please note that the above year-on-year premium rolls are positive, a fact that reflects that the associated forward price curve is most likely in contango. If, however, the forward price curve is in backwardation, especially steep backwardation, then the year-on-year premium rolls may have to be negative to accurately reflect the steady decrease in volatility in the outer years. Put simply, if you apply the above rolls to a steeply backwardated curve, then the implied volatility in the outer years may actually be calculated as higher than the implied volatility in the front years. This would imply that prices in, say, 2010, move more rapidly and in a wider range than prices in 2005, which is simply not true.

Crude Oil Implied Volatility



Implied volatility for crude oil is different from implied volatility for the electricity markets. Since crude oil is only traded up to four years out from the front year, it is possible to get ATM straddle quotes from the market for the entire period. Therefore, figuring year-on-year rolls and calculating implied volatility is not as subjective a process. As is illustrated in the chart above, the implied volatility curve for crude oil is backwardated just like the forward price curve.

There are several ways to "measure" risk, with no one way being the particular "right" answer.

A. Position Size

One way to limit exposure to commodity prices is to limit the size of your positions. The logic behind this is that with a controlled position size, you can control losses. Since the volatility of a commodity can be determined, and the standard deviations that can be expected in terms of the commodity's daily movement can be calculated, the anticipated daily profit or loss should theoretically be controllable.

This would be accomplished by setting specific volume limits for each commodity. A sample of this would be:

COMMODITY	MAX INTRADAY POSITION	MAX CLOSE-OF-DAY POSITION	1 STDEV	2STDEV	3 STDEV	MAX POTENTIAL LOSS
Natural Gas	1,200 lots	1,000 lots	0.317	0.634	0.951	-$9,510,000.00
Crude Oil	1,200 lots	1,000 lots	4.60	9.20	13.80	-$13,800,000.00
On-Peak Power (e.g., Palo Verde)	350 mW (1yr term)	200 mW (1yr term)	9.72	19.44	29.16	-$28,646,784.00

Two things must be kept in mind – the term or tenor of trading, and the yearly profit goal. With respect to the tenor, volatilities differ for different time frames. While the prompt month of natural gas may have a 3.00% move in one day, the 10-year calendar strip may only move 0.05%. So while the front is obviously move volatile than strips or the back of the curve, the notional value is also much larger. Longer tenors means playing with bigger points. A move of $0.05 in the natural gas '00 – '05 curve on 1/day will swing your P&L by roughly $1,000,000. This is the equivalent of a $1.00 move on 100 contracts in the front month, or a $0.10 move on 1,000 contracts in the front month. Keep the volatility of the different tenors in mind when setting position limits.

The second consideration should be the earnings target. If your goal is to make $10,000,000 as a trader, then a position limit of 10 contracts simply won't get you there. The position limit has to correspond with the profit objective. As a general rule of thumb, take the average daily high and low for each contract month for a commodity (or the monthly high and low, depending on your focus), assume that a good trader can capture 50% of this move, and then backsolve for a position limit.

CONTRACT	AVERAGE MONTHLY MOVE	50% OF MOVE CAPTURED	MONTHLY P&L TARGET	REQUIRED POSITION LIMITS	1 STDEV MOVE	EXPECTED AVERAGE WORST DAY
NGF8	$0.40	$0.20	$833,333.33	416	0.58	-2,412,800.00
NGG8	$0.38	$0.19	$833,333.33	438	0.46	-2,014,800.00
NGH8	$0.35	$0.175	$833,333.33	476	0.44	-2,094,000.00
NGJ8	$0.28	$0.14	$833,333.33	595	0.35	-2,082,500.00
NGK8	$0.23	$0.115	$833,333.33	724	0.29	-2,099,600.00
NGM8	$0.26	$0.13	$833,333.33	641	0.33	-2,115,300.00
NGN8	$0.27	$0.135	$833,333.33	617	0.36	-2,221,200.00
NGQ8	$0.27	$0.135	$833,333.33	617	0.38	-2,344,600.00
NGU8	$0.45	$0.225	$833,333.33	370	0.57	-2,109,000.00
NGV8	$0.36	$0.18	$833,333.33	462	0.42	-1,940,400.00
NGV8	$0.33	$0.165	$833,333.33	505	0.40	-2,020,000.00
NGZ8	$0.36	$0.18	$833,333.33	462	0.41	-1,894,200.00
			$10,000,000.00	AVG = 527	AVG = 0.42	-2,112,367.00

The common sense test is if you can live with the drawdowns (bad days) that will inevitably come. If so, then the position limits are probably correctly set. If not, then you must readjust your thinking in terms of acceptable drawdowns, position size, and profit targets, or percentage of the move that you think a competent trader can capture. The other variable in this is the standard deviation. Choose a number with which you are comfortable. If that is one standard deviation, it is no guarantee that a two, three or four standard deviation day won't occur. Be prepared for it, because it WILL happen sooner or later. Setting your pain threshold at one or two standard deviations does not control the market – it will move and do whatever it wants.

This system also provides a nice lookback, or metric, for performance. At the end of the year, when evaluating performance, you will have ample diagnostics to see how you should have done. If it is a particularly calm year, and the market does not provide the volatility needed to be profitable, this will be revealed when you look at the average size of the monthly moves that occurred. If the market was sufficiently volatile, then you can examine how much of the moves were captured by the trading group – the 50% target in this example may be too optimistic. And the position sizes and drawdowns can be reevaluated.

B. Loss Limits:

Some trading groups are not concerned with being profitable – their function is for price discovery, and as long as they don't lose too much money, then they serve a needed capacity. The price discovery and liquidity provided for the developers (who have the potential to make substantially more money for the company) are the primary focus. So the goal is to simply control the bad days.

For the trading groups that are expected to make money, one important element is to keep from negatively surprising management. Trading is a "sexy" business – exciting, fast-paced, and has unlimited profit potential. Many companies claim to devote full resources to trading and to be committed to having a trading operation that contributes to the bottom line – until there is a loss. Nothing will cause a company to rethink corporate strategy more than a massive short-term loss in a trading book. So the need to limit losses is paramount.

Loss limits can be set according to maximum amount that you are willing to lose, by the standard deviation method as illustrated in determining position size, or any other technique desired. It is merely a mechanical number.

C. Max Gain vs. Max Loss:

The ratio of maximum loss to maximum gain can be used to evaluate risk management rules. If the most amount of money you can make on any given day is $50,000, then you have no business risking, say $250,000. If your worst case scenario comes true, you can never recoup that loss. Acceptable loss limits should be, on a worst-case basis, equal to the amount of money made on your best day. This 1:1 ratio is extremely aggressive. A more realistic number would be to have the ratio at least 2:1, if not higher. This implies that when setting loss limits, you should look back at historical performances, and take into account the best trading day.

This technique can also be used on an average basis to help determine trading limits. Take a look at the historical average of the best trading days, and use this average as part of the ratio used to compute maximum permissible losses, and to "back into" P&L goals, etc. Specifically, you would take the historical performance on a daily basis for a one-year period, and average these numbers together. Then take ½ of this number (assuming you want a 2:1 ratio of Max Gain to Max Loss) to set your loss limits. As a common sense test, compare this to other established guidelines (such as position size) to see if the plan is feasible.

D. Optimal f:

Optimal f is a measurement used to determine position size, or exactly how much risk capital should be placed on any one trade. The specific formula is:

$$f = \frac{(B+1) \times (P-1)}{B}$$

where:

B = ratio of amount made on average winning trade to amount lost on average losing trade,
P = probability of winning on trade
f = optimal trade size (given as a percentage)

The thought process behind Optimal f is to determine how much of an initial investment should be used on each individual trade while ensuring that under normal conditions, you can remain in the game.

As an example, assume that you look back at last year's trading records, and find that the average winning trade was +\$25,000, the average losing trade was -\$8,000, and that you booked a profit on 40% of all trades taken. The calculation for Optimal f is:

$$B = (\$25,000)/(\$8,000)$$
$$= 3.125$$

$$P = 0.40$$

$$f = \frac{(3.125 + 1) \times (0.40 - 1)}{3.125}$$
$$= 0.408$$

This tells you that you should risk 40% of your trading capital on any given position. While this may seem like a large number (and it is!) consider that it is derived for a trader who wins on 40% of his trades, and has a risk/reward ratio of greater than 3:1. (Note: In reality, this number is usually between 4% and 15%).

If the trades results in a loss, but none of the system parameters are altered, then the next trade will also be risking 40% of the capital, but it will be 40% of a SMALLER number (the original trading capital less the amount lost on the first trade). This system will continue to reduce position size as losses mount, and increase the amount risked when a winning streak is hit.

PRO's:
1. Provides a science, or discipline to determining position sizes and risk amounts
2. Varies position sizes to account for performance (permits larger position sizes during winning streaks, and reduces position sizes during losing streaks to match trader performances).
3. Provides a metric, or feedback to evaluate performance

CON's:
1. The probability of winning on a trade cannot be known with any certainty. You can guess at it, or set it where you'd like it to be, or use historical results, but that is no guarantee of where it will actually come out at any given time.
2. The distribution of amounts won and lost in trading is variable (not normally distributed). Winners can be much larger or much smaller than losers, since there is no guarantee of a 1:1 payout (or a guarantee of any other ratio payout either, for that matter). Optimal f assumes a normal distribution.
3. As unrealized profits accumulate in an account (mark-to-market gains), Optimal f will dictate that you increase position size. This is unrealistic because the increase in equity is not actually in your account – it is just mark to market. You will, in essence, be adding to positions based on profits that you have not taken to the bank.

E. Sharpe Ratio:
The Sharpe Ratio is used to measure risk. The simple formula is:

$$SR = \frac{(E - I)}{\text{std dev}}$$

where:
E = expected return (typically stated in terms of percent return. Normally, this is assumed to be equal to the average past returns)

I = risk-free interest rate (normally assumed to be T-bills or LIBOR)

sd = standard deviation of returns (the time period used for the standard deviation should be equal to the time interval for segmenting the total period data – weekly, monthly, etc. In other words, the time period for the expected return (E) must match the time period for the risk-free rate (I) which must match the time period of the data used to calculate the standard deviations (sd).

The basic premise of the Sharpe Ratio is that the standard deviation is a measure of risk. That is, the more widespread the individual returns from the average returns, the riskier the investment. For individual traders or individual project measuring, the Sharpe Ratio is easily calculated because the starting amount of capital on which to base the return is known.

The higher the Sharpe Ratio, the better the returns with respect to the risk involved. It is a good yardstick for comparing how capital is deployed, or when considering a number of alternative investments.

PRO's:
1. Provides standard form of measurement that can be applied to multiple commodities.
2. Incorporates risk calculations when evaluating alternatives.
3. Takes into account the risk-free rate when evaluating investments.

CON's:
1. Failure to distinguish between intermittent and consecutive losses. Assume that Project A and project B both return $12,000 over a two-year period ($6,000/year). If A alternates between $2,000 monthly gains and $1,000 monthly losses, while B loses $12,000 in the initial 12 months and then gains $24,000 for the remaining year, both systems will have identical Sharpe Ratios. In reality, B is for riskier than A. The Sharpe Ratio does not penalize traders/projects/portfolios that have consecutive losses.
2. Dependency on time interval. Using two different time periods for the same investment in calculating the Sharpe Ratio will yield two different results (i.e. figuring out the Sharpe Ratio on two individual years will give a different result than when figuring it out on the two years combined). Yet it is the same portfolio that is evaluated, and it should yield the same number.
3. Failure to distinguish between upside and downside fluctuations. The Sharpe Ratio is a measure of volatility, and it considers upside and downside fluctuations to be equally bad. Thus, the Sharpe Ratio will penalize an investment which exhibits sporadic sharp increases in return, even if the drawdowns were small.
4. Failure to distinguish between retracements in unrealized profits versus retracements from "Trade Entry Date". If a project has small losses but large gains (a desirable characteristic), but before closing out profitable positions loses a major portion of the mark-to-market profits (yet still remaining profitable) the Sharpe Ratio would show this as a risky endeavor.

F. Value at Risk (VAR):

Value at Risk measures portfolio exposure due to potential changes in prices, interest rates or volatility. It is a statistically derived calculation which holds several variables constant while changing price across an expected range to develop a maximum expected change in portfolio value, assuming normal market behavior.

Value at risk measures the portfolio exposure to changes in value from:

1. Market price movements – As prices move, the underlying value of the portfolio will go up or down. One of the functions of VAR is to determine how much the value of the overall portfolio can be expected to move with a "normal" move in prices.
2. Interest rate changes – The expected cash flow payments and sensitivities of the various price curves to interest rate changes creates another source of value at risk. Additionally, if a long-term asset is being developed, interest rate exposure will affect the overall cost of the project. Materials, labor, etc. will fluctuate over time with an increase or decrease in rates.
3. FX impacts – While currency exposure can be hedged in a spot or forward market, the exposure to FX creates value at risk while the positions are still open.

Another element of Value at Risk is counterparty exposure. Although usually accounted for in a separate item such as "Reserves for Credit Exposure" or embedded in "Liquidity Premium" or "Market Risk Events", price movements and counterparty exposure are closely related. As the mark to market value of positions changes, the amount of money you would theoretically "owe" a counterparty will increase or decrease. If your portfolio is up $10,000,000.00 on a mark to market basis, and it is a result of one large position with one counterparty, and you have only $8,000,000 in credit lines, you most likely will have a problem.

As unrealistic as this sounds, assume that you have $8,000,000 of credit with counterparty "A". You purchase 100 lots of Calendar year 2000 at $11.00 during the beginning of January 1999 (which is where it actually was). By the fall of 1999, the Calendar year reached prices of $21.00. On a mark to market basis, you have exposure of $12,000,000 with this counterparty (100 lots/month x 12 months/year x 1,000 barrels per lot x ($21.00 current price - $11.00 purchase price)). Although there are several things your counterparty can do to mitigate the exposure, such as posting additional margin or letters of credit, the exposure and the value at risk still exist on your books. The point is that price and counterparty exposure are closely related.

Value at risk specifically measures the change in the value of a portfolio that may be experienced:

- ✓ over a specified time horizon
- ✓ with a given probability
- ✓ subject to reasonable market conditions

It is calculated based on the time required o liquidate the portfolio or unwind the position, and is a statistical measure, NOT a managerial or economic tool.

What the numbers mean: A one day VAR of $1,000,000.00 with a 95% confidence interval is:

1. The probability of a one-day trading loss exceeding $1,000,000 is 5.00%.
2. 95% of the time, the portfolio will change by less than $1,000,000.00
3. The portfolio will be expected to change by more than $1,000,000.00, on average, one time during every 20 trading days. The statistical probabilities could have it change by that much on eight consecutive days, or not change at all over a calendar year, etc. But the expectations are that you can be 95% confident that it will average out to occur only once every 20 trading days.

PRO's:

1. Allows measurement of risk across multiple asset classes to be aggregated.
2. Captures the "portfolio" effect (correlations)
3. Provides Methodology to set and enforce risk limits
4. Allows risk measurement across market sectors and asset classes
5. Essential for measuring risk adjusted returns

CON's:

1. Assumes risk factors are normally distributed
2. Assumes historical variances and correlation are good predictors of future variances and correlations
3. Does not identify the source of the risk
4. Does not quantify the size of a loss in an extreme event
5. Assumes the portfolio remains unchanged across the "unwind" time horizon

A simple one-commodity example:

VAR = position size x instrument volatility
Instrument volatility = % of value that may be lost at specified probability (i.e. 95%)

Assume position is long 100 June natural gas futures. Current market is $2.490/$2.510
Assume asset volatility = 35% (approx. $0.87/mmBtu) This number can be calculated historically or can be taken via market quotes for implied volatility.

VAR = 100 lots x 10,000 mmBtu/lot x $2.500 (mid-market) x 0.35
= $875,000.00

A simple multiple asset portfolio example:

$VAR = (VAR_1^2 + VAR_2^2 + 2\rho_{12}VAR_1 VAR_2)^{1/2}$

Total VAR = VAR Asset 1 + VAR Asset 2 + Price Correlation between Asset 1 and Asset 2.

Assume long 100 June natural gas futures at \$2.50. Volatility = 35%, VAR = \$875,000.00
Assume short 100 June WTI futures at \$20.00. Volatility = 25%, VAR = (200 lots x 1,000 barrels/lot x \$23.00/lot x 0.25) = \$1,150,000.00
Assume NGM9 to CLM9 correlation is 0.45.

$VAR = (\$875{,}000^2 + \$1{,}150{,}000^2 + 2 \times 0.45 \times \$875{,}000 \times \$1{,}150{,}000)^{1/2}$
= \$1,087,428.00

Notice that the VAR for the portfolio is less than the two individual VAR's combined. This is because of the correlation factor. Intuitively, as natural gas prices rise dramatically, crude oil prices should also rise due to the fact that the energy complex as a whole tends to act similarly. So while under normal conditions you would be making money on your natural gas long position, you would be expected to lose money on your crude oil short position. The offsetting gain and loss results in a lower aggregate VAR.

G. DER (Daily Earnings at Risk):

Daily Earnings at Risk is a measure of the value at risk for a twenty-four hour period, typically at the 95% confidence level. It utilizes the same calculation concept as VAR, changing the time horizon/unwind to one day. It is the expected change in the portfolio earnings that includes both realized and unrealized gains for portfolios managed under mark to market accounting.

Example: Consider the 100 lot June NatGas position with a one day volatility of 15%:
DER = 100 lots x 10,000 mmBtu's/lot x \$2.50 (mid-market price) x 0.15
= \$375,000

H. Cash Flow at Risk (CF@R):

Cash flow at Risk utilizes the same concepts and calculations at VAR. It is the expected change in the cash flow required to support the portfolio due to changes in market conditions. The cash flow required to support the portfolio is for such things as margin calls, derivative settlement terms, etc.

From a corporate finance manager's perspective, change in portfolio value may not be a relevant financial management tool. Since there is nothing he can do to affect it or to proactively manage the changes, it will not be used for any decision-making process. Instead, changes in margin requirements may impact cash flow and interest expense, adjusting the value of the enterprise from a balance sheet perspective.

Example: Value at Risk on June NatGas is \$875,000.
NYMNEX brokerage account requires 30% margin
CF@R = \$875,000 x 0.30 = \$261,000

I. Capital at Risk (C@R):

Capital at Risk is a form of measuring credit risk. The calculation methodology is similar to VAR, adjusted to reflect the change in counterparty credit risk resulting from changes in market conditions.

Increases in portfolio value result in increased counterparty credit exposure for those instruments which have increased in mark to market value.

The predominant approach is to measure capital at risk as a function of the probability distribution of economic loss. The probability distribution of economic loss is in turn a function of the distributions and correlations of potential replacement cost, default and recovery. Similar to value at risk, the worst case scenario (usually a 90% - 95% case) is used instead of the worst imaginable outcome.

Two Asset portfolio Example:
Long June NYMEX NatGas – VAR = $875,000
Short June OTC NYMEX "look-alike" swap – VAR = $875,000
Counterparty Credit Rating/Default probability = 10%
Probability of recovery = 30%

Assume the market experiences the 95% confidence interval move and the MTM value of the short position increases by $875,000, the long position experiences a corresponding decrease of $875,000. The portfolio VAR is zero because the position is "flat". However, potential counterparty default places the portfolio at risk as the portfolio is still "long" NYMEX and faces the following exposure to a counterparty default:

Replacement/Settlement Cost x (1 – Probability of Recovery) x probability of Default
= $875,000 x (1-0.3) x 0.10
= $60,900.

Thus, Capital at Risk captures the impact of changing exposures to multiple counterparties with different credit ratings.

J. RAROC (Risk Adjusted Return on Capital):

A technique for risk analysis and portfolio evaluation that requires a higher net return for a riskier portfolio than for a less risky portfolio. the risk adjustment is performed by reducing the return at the portfolio return level rather than by adjusting the capital charge.

RAROC = Portfolio mark to market/Portfolio VAR
(from previous example):

Long 100 june NatGas futures @ 2.25, current market is $2.50
portfolio has a VAR of $875,000
MTM Value (market price [$2.50] – Contract Price [$2.25])
= (2.50 – 2.25) x 10,000 mmBtu's/lot x 100 lots = $250,000
RAROC = $250,000/$875,000
= 28.5%

K. Return on Risk Adjusted Capital (RORAC):

RORAC is similar to risk adjusted return on capital except that the rate of return is measured without risk adjustment whereas the capital charge will vary depending upon the risk associated with the instrument or project.

Risk Adjusted Capital = Capital required to operate the fusiness consisting of:

- Credit VAR – Capital required to support unexpected credit losses
- Market VAR – Capital required to support market losses on portfolio

RORAC = Portfolio MTM/(VAR + Capital at Risk)

(from previous example):

substitute the NYMEX OTC lookalike from the previous example with $60,900 of credit risk.
Capital at Risk = $60,900
Portfolio has a VAR of $875,000
MTM Value (market Price – Contract Price) = $250,000
RORAC = $250,000/($875,000 + $60.900)
= 26.7%

CONTROLLING RISK

A. Establishing hedging guidelines

In order to avoid "wilding", or having no discipline around hedging activities, a well thought out hedging program should be implemented. Traders need only position limits and risk parameters before they are "cut loose" to do what they want. Their primary focus is how much money to make each day within those risk parameters. Their secondary focus should be to provide liquidity for the asset developers and to collect market intelligence.

Hedging, however, requires a different type of mentality. The corporation is making massive investments in assets. Just like a stock or bond portfolio, the generation, processing, and energy assets should be treated like a portfolio. The shareholders want a portfolio-type return, not a trade-shop type return inherent with wild P&L swings and drawdowns. Shareholders want slow and steady profits, or returns for their investments. this is the purpose of asset development, and the underlying positions should be managed accordingly.

The corporation (and the shareholders) do not want to have one particular individual making the buy and sell decisions with respect to the assets. They want to have well-established return targets via a disciplined hedging program. The group responsible for hedging then has to merely execute the strategy, monitor the positions and the market, and report results. It is much more acceptable for a company and for the shareholders to make an investment based on an asset development program which is complimented by hedging based on desired returns than to make a "bet" with their money on an asset development program which is hedged merely by an individual who thinks the market may be bid or offered, and is not following any set guidelines.

1. Return on Investment

One way to instill discipline in the hedging program is to focus on return on investment. The simple calculation involves comparing the forward price curve used in the pro-forma economics when an asset was acquired versus where the forward market is today. When the desired return level is achieved, you hedge – simple as that.

The key assumption in this process is that the original economics are done at or better than the current forward market. If the original price curves are not in line with what was used for the deal economics, then the possibility exists that you could be locking in a loser (undesirable or negative return). In this instance, the comparison for rates of return should again be against the economics used in the deal versus the current forward market curve.

Example:

Assume that Company "A" is about to invest in a shallow-water natural gas drilling program. The expected output of the well is to be a constant 1.2 BCF per year for 3 years. With all capital expenditures properly allocated across the life of the program, the breakdown is:

YEAR	**ORIGINAL ECONOMICS (10% I.R.R.)**	**CURRENT FORWARD PRICE CURVE**	**CURVE NEEDED FOR 8% RETURN**	**CURVE NEEDED FOR 12% RETURN**
2000	$2.500	$2.580	$2.400	$2.600
2001	$2.550	$2.615	$2.450	$2.650
2002	$2.600	$2.650	$2.500	$2.700

If the current forward market permits you to realize the desired return targets on the investment, then you simply hedge. One note of caution – the tenor, or time horizon for your hedges, is important. The situation may develop where only certain months, or certain years, out of a long-term investment allow for desired returns. One such example would be if only the Jan/Feb strip of 2000 permits the desired returns. Another would be if calendar year 2000 achieves the desired results, but 2001 and 2002 does not.

If cases like these arise, you must make a decision as to what will be hedged. By hedging a fractional amount, you are making a bet that either 1). Eventually, the other pieces will eventually permit desired returns, or 2). The other pieces will NEVER reach the desired returns, and you should take what you can off the table while the opportunity still exists.

If the hedging guidelines are clear as to what to do in this situation, then the decision makes itself. if the guidelines are not clear, then you will have to make a serious decision which may significantly affect the profitability of the project.

If you decide to hedge only a portion, then you run the risk of hedging, at a sub-optimal price, the only piece of a strip which may prove profitable. For instance, assume that you are long power (via an asset acquisition) under the following scenario:

MONTH	ORIGINAL ECONOMICS	CURRENT FORWARD CURVE	ROI BY MONTH
January	$28.90	$29.25	8%
February	$26.85	$27.25	8%
March	$25.45	$22.55	6%
April	$20.55	$18.20	6%
May	$20.25	$19.10	7%
June	$27.95	$30.75	10%
July	$35.15	$42.10	12%
August	$47.45	$56.85	12%
September	$47.45	$55.00	12%
October	$32.35	$34.00	9%
November	$32.85	$34.50	9%
December	$34.25	$35.25	9%
Calendar	**$31.60**	**$33.73**	**9%**

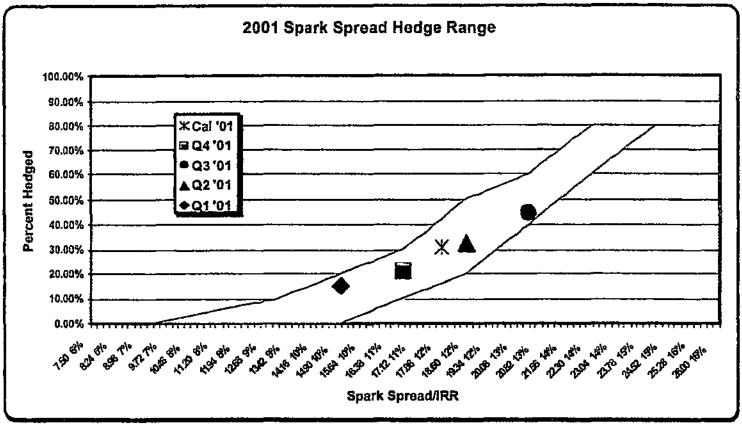
Since in power, the summer (July/August) usually drives the price of the calendar strip, you may be selling the only piece that is moving up. The July/August piece may continue to rise, with only a minimal effect on the other months. If you hedge only the summer piece, there is a strong chance that the other months never reach the desired hedging targets. If you wait, however, the chance does exist that the summer months may drag up the entire value of the calendar strip, and you could possibly hedge the entire 12-month piece at desired return levels. The possibility also exists that the summers have "topped out", and you may be missing the only opportunity to lock in any returns whatsoever. A difficult decision to make.

2. "Greenfield"

Greenfield refers to the costs associated with building a new asset from scratch (hence the name "Greenfield" – you would be starting with a "green field' and then building a new project on it.). Greenfield is most commonly associated with power plant developments, although it can be applied to other energy assets.

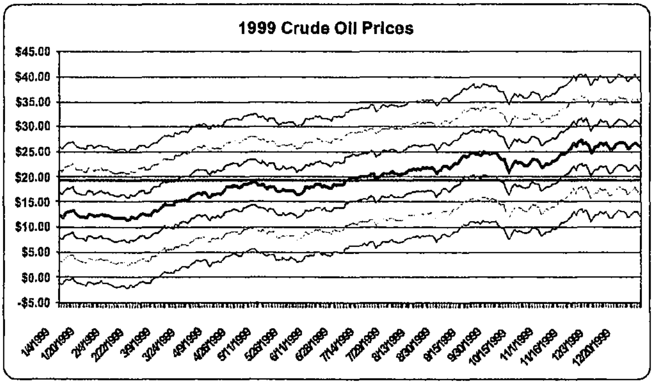
The thought process behind using Greenfield as a hedging guideline is best illustrated using an example by exaggeration. Assume that you could build a generator, purchase natural gas, burn the gas to produce power, and sell the power to realize a 75% return on your money. Would that be a good investment? The answer is a screaming "Yes". So there is a certain level of return that attracts new capital to the market, where every player wants to get involved. Conversely, if you were to build a generator, buy and burn gas, sell the power, and realize only a 1% return on money invested, would this be a wise investment? Again, the answer is obvious – obviously "no". So there is a certain level of return where nobody wants to be involved in the marketplace.

At the higher levels of return, with new money entering the marketplace, you should be an aggressive hedger. With large influxes of capital expected, if you are not the first to hedge, then others will beat you to it, and drive down prices, which will ultimately have a negative affect on your returns. At the lower levels of return, nobody will enter the marketplace, and the laws of supply, demand and economic growth will eventually pull up the marketplace to where respectable returns can be achieved.

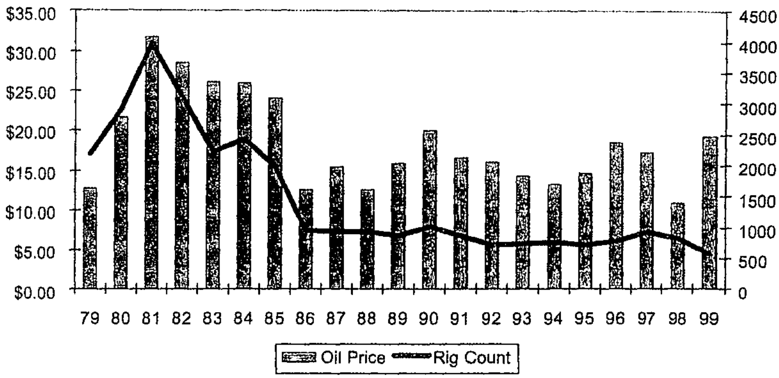


3. Statistical/Historical Reference

Another disciplined approach to hedging commodity exposure is to use an historical/statistical reference. This involves taking a long-term chart of commodity prices, and overlaying +/- 1, 2, and 3 standard deviations for the chosen time period.



The methodology behind this process is that prices on established commodities with long-term price histories will tend to be mean-reverting. They will oscillate around the marginal cost of production over this term. When the prices are significantly above this mean, it will attract new participants into the marketplace, and eventually force down prices. When the market is significantly below this mean, then the marginal cost operators can no longer function, will be driven out of the marketplace, and the supply/demand equation will be tipped in favor of demand, moving prices upwards again towards the mean. This same technique is used by hedge funds who speculate in commodities and by producers of various commodities such as for gold, silver, "softs" (wheat, corn, soybeans, coffee, cocoa, etc.). Generally, when the price of a commodity looks too low or too high to be real, it usually will correct.



Note: Simple justification for standard deviation hedging and mean reversion. More rigs = more crude = lower prices. Lower prices lead to fewer rigs = higher prices—and the cycle continues to revert.

The hedging guidelines center on the movements around the mean. Towards the upper bands of the standard deviations, you would be an aggressive seller. Towards the bottom (negative standard deviations) you would hold off on selling, or even be a buyer.

An aggressive hedging guideline would permit scale-in selling as the various +1, +2 and +3 standard deviations are approached, and allow for scale-in BUYING when the -1, -2, and -3 standard deviations are hit. The rationale behind buying is two-fold - 1). It permits a potential profit opportunity, as prices are historically due to rebound, and 2). If selling occurred during the upper bands, it permits a chance to "reload" by buying back at the lower bands in anticipation of selling again should the upper bands be reached. This technique is similar to gamma scalping of options to remain delta neutral.

The flexibility of the amount to be hedged is arbitrary, allowing for a "range" of hedging within the guidelines. The reasons for the ranges are:

1. Provides allowances for liquidity. If a market is thin, but prices dictate that hedging should occur, it allows for buying/selling over a time period while the desired amount is hedged. The market may not be liquid enough to permit hedging 100% of

the desired amount. By providing a "band" or range, you have the ability to work orders to hedge the desired amount without violating the guidelines.

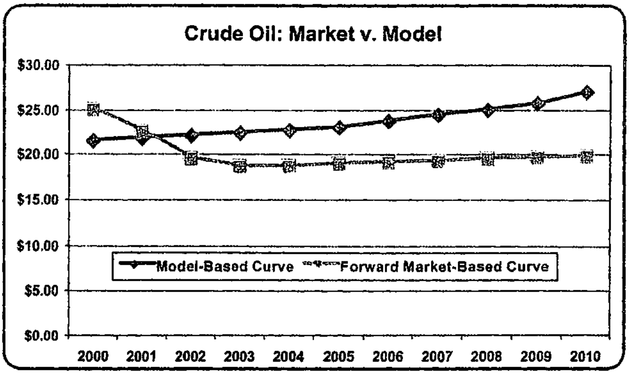
2. Allows hedgers to be proactive. Assume that you are long a commodity, and have hedged to the middle range of the allowable band. If there is a strong possibility that additional length will be in your portfolio in a short amount of time (i.e. the asset developers are about to sign another contract on building a generator) you can anticipate this by aggressively selling (within your portfolio hedging guidelines) down to the bottom end of the band. This allows for realizing acceptable prices and minimizing the risk of receiving the additional length while maintaining the integrity of the hedging program.
3. Optimization. By permitting a range of hedging, it is possible to "scalp" the market by holding on to length in a rising market, and maintaining an aggressive short position in a falling market. Using bands, the guidelines permit for some discretion in determining market direction, and allow for constant portfolio position adjustment by buying back in a falling market while selling in a rising market.
4. Fundamental Analysis/View

   This involves working closely with the models of supply and demand for each commodity. If the corporation chooses to make an investment based on a fundamental view of the underlying commodity, then that particular curve will dictate all hedging activities. The premise is that a market may be over or under valued based on the current balance of supply and demand. All market and price activity surrounding the fundamental curve is "white noise" or random movements surrounding where prices will ultimately materialize.

   The problems with this approach is that consultants and other groups who publish fundamental curves do not have a financial stake in the outcome – they publish curves only, and do not take positions in the market. if a consultant's curves prove to be wrong, he will just simply revise them. However, you are left to explain the economic consequences of hedging based on this data.

   The second problem is that fundamental supply and demand equations are constantly changing. You may be left waiting for a market price move that may ultimately never occur.

   And finally, there are volumes of work surrounding the random walk and efficient market theories. If the market has, in fact, priced in all known future economic news and other events, then waiting for a curve to move to your analysis could be a futile endeavor.



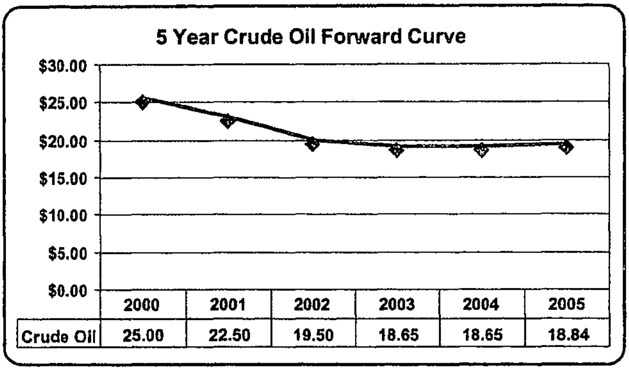
5. Market View
This is the least favored hedging technique. It merely involves subjective input from the hedging group as to where prices are headed. Again, as previously mentioned, this is an undisciplined approach which is risky at best.
The shareholders are looking for a return on their investment. Whether it is a utility, natural gas processing company, refinery, etc. they are investing to get the returns associated with that type of business. They do NOT want the swings associated with a trading company. Wall Street analysts who follow the various industries exposed to commodity prices reward those who have in place a well-though hedging program, and punish those who do not.
Additionally, you will constantly be second-guessed as to your buy and sell decisions. If you do a superb job of calling market direction, the best-case scenario is that you will be left alone by the board of directors. If you miss the exact tops and bottoms of the market, but still manage to make money and do an adequate job of calling direction, you will be scrutinized. Everyone has an opinion regarding commodity markets, and the people who are not making decisions are quick to point out the flaws in those who do. If you lose money trying to hedge, then you will most likely be out of a job.

B. Determining how to hedge
1. Outright Sales/Purchases
One of the easiest ways to hedge an asset is through the sale or purchase of the underlying commodity. If you are dealing with a liquid commodity, in a liquid time frame, this should be no problem. Whether you are adhering to hedging guidelines, studying fundamentals to make a "market call" or trying to technically "time" your trades, simply line up the buyers or sellers and conduct your business. It is as straightforward as that.

2. Stack and Roll
If you are dealing with an illiquid commodity or an illiquid time frame, "stack and roll" may provide a solution. Stacking and rolling involves putting on a larger position than required in the front, or liquid part of a commodity curve, and less (if any) in the back, or illiquid part of the curve.

The reasoning behind this is that commodity price curves should, under normal conditions, exhibit normal movement. That is to say, if the front part of the curve is rising (increasing in price), the back part of the curve should also become more valuable (also increase in price). In order to take advantage of the liquidity in the front part of the curve, you will "overhedge" (buy or sell too much) in order to compensate for the fact that nothing can be done to hedge in the outer years.

As an example, assume that it is January 1999, and you are short 1,000 lots of crude oil per month (a sizable position) for the next 5 years due to a refinery commitment. The current price curve is as follows:



Enough liquidity exists in the first year for you to conduct business for the required size (buy 1,000 lots/month or 12,000 lots for the Calendar year 1999). However, the liquidity dries up (does not exist) past the first year, and it is impossible to do any significant volume past the first 18 months. In order to provide some measure of price protection, you will "overbuy" the front part of the curve. The designed intent is that if the prices start to rise, the back part of the curve should rise along with the front. Since you can't buy the back part of the curve, the additional volume you purchase above what is needed in the front part of the curve should offset any losses you incur in the latter years, thus providing a "hedge".

1. Determine volume needed to be hedged:
   1,000 lots/month x 12 months/year x 5 years = 60,000 lots

2. Determine amount that can be hedged in all years
   Liquidity assumptions:

	1999	2000	2001	2002	2003	2004	TOTAL YEARLY VOLUME
LIQUIDITY	10,000/mo.	5,000/mo.	1,000/mo.	100/mo.	0	0	43,200
INITIAL VOLUME	1,000/mo.	1,000/mo.	1,000/mo.	1,000/mo.	1,000/mo.	1,000/mo.	72,000
EXCESS	N/A	N/A	N/A	900/mo.	1,000/mo.	1,000/mo.	40,800
HEDGE VOLUMES	3,267/mo.	1,633/mo.	1,000/mo.	100	0	0	72,000

Since years 2002 – 2004 do not have enough liquidity to handle the desired hedge volumes, you will "max out" those years by hedging as much as possible. The excess amount is then divided pro-rata among yers 1999 – 2000, based on how liquid each year is. Since 1999 is twice as liquid as year 2000, 1999 is allocated twice as much of the "stack" volume.

Hopefully, when (and if) the prices are bid up again, the extra weighting in the front of the curve will make up for the fact that you will be losing money in the back of the curve where you were unable to sell, and are therefore not directly hedged.

As the tenor of the markets is extended (i.e. as time goes on, and the outer months and years become more liquid and can handle more volume) you can then execute the "roll" portion of your stack and roll. When doing this, you must keep in mind what the "front-to-back" spreads (time spreads) are doing. To do this, you will need to look at the relationships of the prompt months to what the desired time spreads are when trying to "time" the rolls.

This method attempts to determine the correct stack and roll amounts based on matching volumes across the time frames. Another way to try and "perfect" your stack and roll is to try and use volatility to determine the proper volumes. The thinking behind this is that the back years are not as volatile as the front years, so equal volume weighting is not required. A $1.00 move in Calendar 1999 is probably not going to result in a $1.00 move in year 2004, so allocating the amount to be stacked from 2004 to 1999 should most likely not be equal. Overweighting can provide extra revenue if you are on the right side of the market, but can just as easily lose money if you are on the wrong side of any market move. To use volatility in determining stack and roll amounts, consider:

	1999	2000	2001	2002	2003	2004	TOTAL YEARLY VOLUME
LIQUIDITY	10,000/mo.	5,000/mo.	1,000/mo.	100/mo.	0	0	43,200
INITIAL VOLUME	1,000/mo.	1,000/mo.	1,000/mo.	1,000/mo.	1,000/mo.	1,000/mo.	72,000
EXCESS	N/A	N/A	N/A	900/mo.	1,000/mo.	1,000/mo.	40,800
VOLATILITY	0.450	0.250	0.200	0.165	0.130	0.10	
1999 VOL ADJUSTED WEIGHT	N/A	N/A	N/A	0.165/0.45 = 0.367	0.13/0.450 = 0.289	0.10/0.450 = 0.222	
2000 VOL ADJUSTED WEIGHTS	N/A	N/A	N/A	0.165/0.25 = 0.660	0.130/0.250 = 0.520	0.100/0.250 = 0.400	
YEARLY WEIGHTING *	N/A	N/A	N/A	1999: 0.45/(0.45 + 0.25) = 0.64 2000: 0.25/(0.45 + 0.25) = 0.36	1999: 0.45/(0.45 + 0.25) = 0.64 2000: 0.25/(0.45 + 0.25) = 0.36	1999: 0.45/(0.45 + 0.25) = 0.64 2000: 0.25/(0.45 + 0.25) = 0.36	
1999 GROSS AMOUNT				900 x 0.367 = 330	1,000 x 0.289 = 289	1,000 x 0.222 = 222	
199 NET AMOUNT				330 x .64 = 211	289 x .64 = 185	222 x .64 = 142	
2000 GROSS AMOUNT				(900) x 0.66 = 594	(1000) x 0.520 = 520	(1000) x (0.400) = 400	
2000 NET AMOUNT				594 x .36 = 214	520 x .36 = 187	400 x .36 = 144	
OUTRIGHT HEDGE VOLUMES	1,000/mo.	1,000/mo.	1,000	100	0	0	72,000
STACK AND ROLL 1999	211 (2002) 185 (2003) 142 (2004)						
STACK AND ROLL 2000		214 (2002) 187 (2003) 144 (2004)					
TOTAL VOL ADJUSTED HEDGE VOLUMES	1,538/mo.	1,545/mo.	1,000/mo.	100/mo.	0	0	50,196

* Yearly weightings are determined as follows: In 1999, 2000, and 2001, it is possible to do the desired hedge volumes because of market liquidity. 2002, 2003, and 2004 need to be hedged using other years. The only years which provide enough liquidity for the unhedgable years of 2002 – 2004 are 1999 and 2000. In order to allocate the excess from 2002 – 2004 to 1999 and 2000, take the volatilities of each year and compare them to 1999 and 2000. As one example, you would take year 2002, where the volatility is 0.165, divide that by 1999's volatility of 0.45, and get 0.36. Then take 2002's volatility of 0.165 and divide that by 2000's volatility of 0.250, and get 0.66.

These numbers mean that if you were to hedge 100% of 2002 in 1999 only, you would use 36% of the volume for 2002, and if you were to hedge 100% of 2002 in 2000 only, you would use 66% of 2002's volume. This makes intuitive sense, in that you would not need to use as much volume for 2002 in a 1999 hedge, since 1999 is more volatile. And it follows that since 2000 is less volatile than 1999 but more volatile than 2002, the hedge weighted amount for 2002 in year 2000 is less than 1999 but more than 2002.

Once you have these gross volumes determined, you can use those gross amounts on either year you choose. For instance, you could hedge 2002 in 1999 by using 1,000 lots of desired hedge, less the 100 that you could do in 2002 because of the limited liquidity, times the volatility-adjusted ratio of 36%, and then hedge 330 lots is 1999. OR, you could choose to hedge 2002 in 2000 by using the 1,000 lots of desired hedge, less the 100 lots that you could do in 2002 because of the limited liquidity, times the volatility-adjusted ratio of 66%, and then hedge 594 lots is 1999. Under this scenario, it is EITHER 330 lots in 1999 OR 594 lots in 2000 for your 2002 hedge. Again, these numbers make sense, since 1999 is more volatile than 2002.

Alternatively, rather than "loading up" on one particular year, you could spread out the exposure on any and all years where there is sufficient liquidity. This would provide you with some measure of protection in case the ratios and relationships between years suddenly "blow out", or no longer hold true. it also helps allocate the exposure to different years, and not use up too much liquidity in any one year.

In order to take the final step, which is to allocate the hedges across all years, you must weight them according to how volatile each year that will be used in the stack and roll is in comparison to the other. Continuing with the 2002 example, the only years where sufficient liquidity exists is 1999 and 2000. If you choose to weight your 2002 exposure in 1999 and 2000, you would take the volatility of 1999 and weight it over the combined volatilities of 1999 and 2000. With 1999 volatility of 0.45 and 2000 volatility of 0.25, you would weight 1999 as 0.45/(0.45 + 0.25), or 64%. 2000 would be 0.25/(0.45 + 0.25), or 36%.

Using these weights against the volatility adjusted volumes, the 1999 portion of the 2002 hedge would be (0.64 x 330), or 211. The 2000 portion of the 2002 hedge would be (0.36 x 594), or 214.

AN IMPORTANT NOTE: A volatility-based front-to-back spread, or ANY type of stack and roll, should provide you with a reasonable measure of protection. But it is no guarantee. anything could happen which may cause historical relationships to "blow out" or render your hedge useless against a change inthe shape of the term structure. The stack and roll is only as good so long as the historical relationships hold true. For an example of what can happen when this breaks down, and for exactly how bad it can get, examine the problems caused for Mettaligishcafft (MG):

From eRisks.com:

Metallgesellschaft

Summary:

In 1992, Metallgesellschaft Refining and Marketing (MGRM) implemented what it believed to be a profitable marketing strategy. The company agreed to sell specified amounts of petroleum products every month, for up to ten years, at fixed prices that were higher than the current market price. MGRM then purchased short-term energy futures to hedge the long-term commitments – a "stack" hedging strategy.

This hedging theory failed to take into account one detail: when oil prices drop, the gains from the sale of oil are realised in the long-term, but the losses from the energy futures will be realised immediately. Thus, when oil prices dropped, the company faced a cash flow crisis. In December 1993, the company cashed in positions at a loss that totalled more than $1 billion.

Overview:

Metallgesellschaft Refining and Marketing (MGRM) is an American subsidiary of Metallgesellschaft (MG), an international trading, engineering, and chemicals conglomerate. In 1992, MGRM implemented what it believed to be a profitable marketing strategy. The company agreed to sell specified amounts of petroleum products every month, for up to ten years, at fixed prices that were higher than the current market price.

MGRM then purchased short-term energy futures to hedge the long-term commitments -- a "stack" hedging strategy. The idea was that if oil prices dropped, the hedge would lose money while the fixed-rate position increases in value; if oil prices rose, the hedge gains would offset the losses on the fixed-rate position. While some economists believe that this theory is correct, the problem is that when oil prices drop, the gains from the sale of the oil are realised over the long-term, but the losses on the hedges will be realised immediately as margin calls come in. This creates a negative cash flow, leading to a funding crisis.

This is exactly what happened in late 1993. The cost of rolling over the futures contracts was a staggering $88 million in October and November. In order to cover these costs, MGRM had to obtain funding from its parent organization, Metallgesellschaft (MG). MG management, either not understanding or disagreeing with the strategy, decided to close out the positions to curtail further losses. Thus, in December 1993, the company cashed in its positions at a loss totalling over $1 billion.

There is still disagreement as to whether the marketing strategy was sound. Proponents of the strategy maintain that had MG been able to persevere, they would have made a profit in the long-term and recouped the losses on the futures through profits on the monthly sales of petroleum. However, an auditors' report commissioned by MG shareholders maintained that 59 million barrels worth of the long-term contracts had a negative value of about $12 million, so the value of these contracts could never have offset the losses, even in the long term.

This episode illustrates a concept that can be referred to as "funding risk" -- the risk that positions which may be profitable in the long run can bankrupt a company in the short run if negative cash flows are mismatched with positive cash flows. These funding issues interacted with communication problems in the structure of the organisation to create the MGRM fiasco. If proponents of the strategy are correct, then better communication between subsidiary and parent might have persuaded the parent company not to prematurely close out the open positions. If the auditors were correct, then better communication could have led MG to point out the fallacy of the strategy in enough time to prevent such large losses from mounting. In either case, there clearly was a disconnect between two parts of the organisation, a condition that probably made it only a matter of time before problems arose.

Events:

1992: MG begins selling fixed-rate contracts for the delivery of petroleum and buying short-term futures contracts to hedge these contracts.

1993: Oil prices fall throughout much of the year. Additional long-term contracts are sold to offset the losses on futures positions.

June 1993: According to the auditors' report commissioned by MG's shareholders, MG head Heinz Schimmelbusch is by this point attempting to convince the CFO to reduce MGRM's positions, which amount to 100 million barrels.

December 1993: MG has long positions in energy derivatives totalling 185 million barrels of oil resulting in an immense cash drain. Rolling over the contracts costs $88 million in October and November alone. Mr. Schimmelbusch and other senior MG managers are removed from the board, and contracts are closed out to avoid further losses.

27 January 1995: An auditor's report commissioned by MG's shareholders, including Deutsche Bank, places the blame on Schimmelbusch and other former MG executives.

Lessons to be learned:

It is management's responsibility to fully understand the key risks in the business
MGRM executives should have foreseen the possibility of large negative cash flows creating a liquidity crisis.

From a financial risk perspective, it is important to assess the interrelationships between market risk, liquidity risk, and basis risk

In the MGRM case, the losses resulted from the confluence of significant market price movements, liquidity issues from cash flow mismatch and concentrated futures positions, and basis risk between the forward and futures prices.

Failure to set limits/boundaries

The positions continued to grow larger even as oil prices fell. By the time the petroleum positions were liquidated, they had grown to equal 85 days worth of the entire output of Kuwait, according to an MG spokesperson.

Failure to listen to warning signals

Schimmelbusch's warning in June apparently went unheeded, as did the cash burn of the rolling over of contracts ($88 million in October and November alone).

Failure of communication

MG and MGRM apparently weren't in close enough contact for MG to understand what MGRM was doing. If MG had understood what was going on from the beginning, it might have prevented the strategy from being used if it disagreed with it, or, if it supported the strategy, might have avoided closing out the positions when they were in such a weak position. Either way, a loss of such a large magnitude might have been avoided.

3. Basis Spreads: Basis spreads involve using different locations for hedging exposure in a particular location. Examples of basis spreads are given in the chapters for the various commodities (electricity, natural gas, and petroleum products/NGL's).
4. Time Spreads:
5. Correlated Commodities: Correlated commodities involve taking positions in other commodities where there is an established relationship with the underlying base instrument. specific examples are given in the chapter for Petroleum Products/NGL's with crude oil, natural gas and the associated liquids. Other examples that could be used are interest rates to crude oil and/or gold/silver; corn, wheat and soybeans to electricity (weather dependent – particularly in the summer), etc.

   A note about hedging with correlated commodities – there are two particular schools of thought regarding the proper hedge ratios (volumes) to be used. The first is to take the two cross-commodities to be hedged and apply the applicable volatilities to each so that a corresponding move in one will react the same to the other commodity. The second school of thought is to take the dollar value of each contract of each commodity to be hedged and apply a ratio to make them equal. The examples are:

   Volatility Adjusted: Assume that you are long 1,000 lots of December Crude oil, and for whatever reason, wish to hedge it with T-Bonds. The volatility of December Crude is 25%, and the volatility of Dec Bonds is 16%. Under this method, you would hedge in a ratio of 1.56/1.00. That is, for every 1 lot of crude, you would need to hedge with 1.56 lots of bonds. For your stated amount of 1,000 lots of crude, you would need to use 1,560 lots of bonds, since the crude is more volatile than the treasuries you are using.

   Dollar-Value: Assume the same scenario, where you want to hedge 1,000 lots of crude with T-Bonds. Under this technique, you would take the dollar value of the crude to be hedged, and attempt to match it with an equal dollar amount of bonds. 1,000 lots of crude has a notional value of 1,000 lots x 1,000 barrels/lot x assumed underlying price of $23.48/barrel = $23,480,000.00. The notional value of one Bond contract is 100,000. Dividing the crude notional by the underlying bond contract amount gives a proper bond hedge of 235 lots.

   As you can see, the two techniques yield vastly different amounts for the proper hedge. A more scientific way would be to use the correlation between each commodity and apply that factor to the cross-commodity to be hedged (similar to the example used in the stack and roll illustration). But do not be surprised to see a number of professionals in the industry using either one of these techniques.

6. Options: Techniques for hedging with options are covered in the options section, as well as the "gamma scalping" involved with the dual variable option.
7. Asset Divestiture: One final hedging technique to be considered is divesting the underlying asset which creates your position to be hedged. This is covered under the asset development chapter.

C. Feedback Loop – Measuring Hedging Performance:

Once a hedging program is in place, it makes sense to measure how it is performing. This will allow you to determine if the program is worthwhile, needs to be fine-tuned, or should be scrapped altogether. If the hedging program does not add any value to the overall management of the portfolio, there is no sense in keeping it static.

No one measure is an accurate reflection of how well a hedging program is performing. In order to make an accurate assessment, you should see how well the program performs against an unhedged portfolio (i.e. if you did nothing to mitigate financial risk in the long-term, and just bought or sold at daily index). The program should also be evaluated to assess the skill level of the individuals who are implementing and/or executing it. If there is any discretion in the program, evaluating the overall ability of the operators to decide (execute discretion) should also be measured against a benchmark. And finally, since the most important factor to any corporation is the bottom line, the hedging program should be evaluated against how well it contributes to EBIT, daily earnings, MTM, or any other overall profit measurement.

1. Hedged vs. Unhedged: Whether you are using IRR's based on original deal economics, or "greenfield" returns, or any other measure to hedge, the program should be compared to an unhedged program. To accomplish this, you would take the results of the hedged program versus index to see which offered the better return. Specifically, if you were to hedge using your predetermined program vs. index, the results could be compared.

2. Portfolio MTM: If the hedges are losing money, then the underlying position should be making money (depending on aggregate position size). An evaluation of the two components will help determine the effectiveness of any risk management and hedging program.

3. Sharpe Ratio Hedged v. Unhedged: The reduction in volatility of earnings should be compared to the returns which are achieved. This can be benchmarked against other metrics to evaluate the overall program effectiveness.

IX. Appendix

A. Trading Tricks

Note: The following is reprinted (with permission) from Larry Connor's book, Connors On Advanced Trading Strategies. It provides an invaluable framework from which to evaluate various trading and hedging strategies. In presenting the various "Trading Tricks", every attempt is made to follow the discipline set forth from this excerpt.

As I have grown older, I have learned to lessen my expectations. I have come to realize that it is good to think big, but success in trading is not dependent on finding the Holy Grail trading system. It is much more dependent upon having a trading method that meets the following three criteria:

1. The method must be conceptually correct.
2. It must provide you with a small "edge".
3. Most importantly, the method must be able to manage the "bad tail".

Let's look at each component in further depth.

COMPONENT ONE – THE STRATEGY MUST BE CONCEPTUALLY CORRECT

If a strategy is not based upon inherently correct market principles, it is probably useless. I suspect that if I looked at the schedule of every Major League Baseball team over the past decade, I could infer some sort of pattern that predicted market behavior. An example would be when the Seattle Mariners win by two runs or more on Tuesday night, and Randy Johnson doesn't pitch the game, soybeans rise 72% of the time the following day. You may laugh at this example (don't trade it), but I have seen methodologies and strategies sold to traders that make as much sense as the one above.

Markets have built-in characteristics. For example, strongly trending markets will pause, pull back, and then continue their original move; in bear markets, sessions tend to close below their opening; low volatility is preceded by high volatility, etc. Any middle level student of the game has come to know these and similar truths. When you read the upcoming chapters, you will see that the inherent market features I have just listed and others like them are the basis of my strategies.

I strongly believe that in order to improve upon your trading you must only trade strategies that exploit inherent market characteristics.

COMPONENT TWO – THE EDGE

Over the past 100 years, which industry has been one of the most consistently profitable? The insurance industry. Why? Because insurance companies have a built-in "edge". They can statistically show that based on a normal distribution of events – mortality rates, average life spans, etc. – they will profit from the same long-term statistical probabilities.

In sports betting, there is a 4.5% edge to the house. It is even higher on parlays, teasers, etc. Last year an acquaintance of mine used this edge to earn more than $12 million from his offshore sports betting establishment. Even though it is a bit more complicated than this, this gentlemen needs only to match up both sides of a game and he is assured a profit. The same edge holds true for the casinos in craps, roulette, and any other game of chance. A well-known casino executive wasn't kidding when he said, "When a sheep is on the way to the slaughter, he *may* kill the butcher...but we always bet on the butcher!"

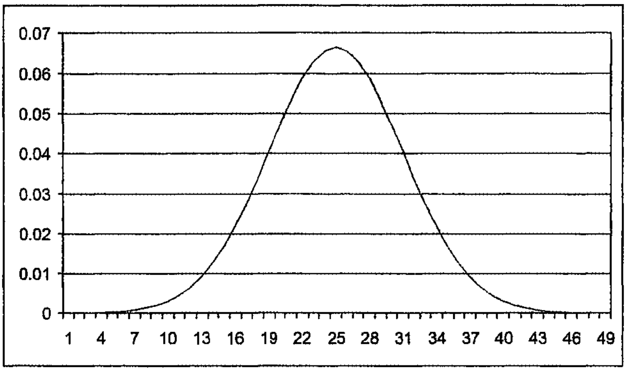
In trading, the edge immediately goes to players like the market makers who buy on the bid and sell on the offer. One does not need to be a genius to figure out that the guy who buys at 46 and can immediately sell it at 46 ½ has the edge over guys like me who have to buy it at 46 ½ and can only immediately sell it at 46.

Your strategies must provide you with some sort of edge. It does not have to be big! The casino's edge is usually only a few percentage points and the edge for he market maker in the previous example is less that 1.5%. This small edge is enough to make one rich if the opportunity arises enough times and if you can conquer the third component, which is...

COMPONENT 3 – YOU MUST MANAGE THE BAD TAIL!

This is the single most important and critical point I will make in this book. It must be burned into your memory. Anyone can make money when things work out as they *normally* should. The majority of traders who blow out, do so when they succumb to the "it will never happen to me" syndrome.

Let's look at a bell curve to understand this further:



As you can see, normal events occur around 67% of the time. In market terms, this means that prices will fall within one standard deviation of their mean (average) 67% of the time. Within a specific time frame. When this happens, (approximately two-thirds of the days are like this) one's methodology makes some money and loses some money. As we move further and further away from the mean we get into the areas where the large profits or substantial losses occur. This is when our normal $200/trade edge makes $5,000 or loses $5,000. When our methodology makes $5,000, we are geniuses, and when it loses $5,000, it hurts badly, but usually not enough to wipe us out. It is when a trade occurs on the "very edge" of the tails that the rumor mill gets cranked up. When the trade lands on the "good tail", it becomes the story of the trader who turns $10,000 into over $3 million in one option trade (a true event told to me by a friend who handled the trade) and on the other end of the spectrum, it is the well-known money manager who recently sold thousands of naked puts into a severe market decline and turned his client's money into dust after a decade of stellar performance (the "bad tail").

My main concern for you (and for me) is how to manage the bad tail. The risk of ruin can never be eliminated but it cn be greatly lessened when the bad tail occurs. It is mostly done with protective stops, it is done with spreads on options (instead of naked positions), and it is done with adjusting your trade size to reflect current volatility. As you will see, trading 1,000 shares of a stock that has a current volatlity of 10% is vastly different than trading the same stock when its volatility rises to 40%.

There are many unsuccessful traders who grind themselves to death because they do not have an edge. There are more traders, though, who die because of one reason: they did not manage the bad tail!

TRADING TRICKS:

POWER:

1. Ratio Spreads

Ratio spreads are ideal as a hedge against a generating asset or as a speculative play for someone that is long generation and has some operating flexibility. The most common example involves buying one or more of a higher-priced put, and selling a greater number of lower strike puts. The net premium paid out (or credit received) is up to the discretion of the trader. An analysis of the break-even needed for the trade will help decide if the money paid or received is worth the risk.

Note that as a general rule of thumb, if the higher strike is at or close to at the money, then the correct net premium to be paid for the put spread usually equals 1/3 of the strike differential (if a 1:1 ratio is used). For example, if the \$50.00 put is trading for \$12.00, (and is at or close to the money), then the \$20.00 put should be trading for around \$2.00. (The difference in strikes is \$50.00 - \$20.00, or \$30.00. 1/3 of this differential is \$10.00. If the \$50.00 put is trading for \$12.00, then using the rule of thumb, the put spread should be worth the strike differential of \$10.00, which means that the \$20.00 put usually will trade for \$2.00)

Continuing with this example, a worthwhile trade (or hedge against an asset) would be to buy 1 of the \$50.00 puts for \$12.00, and sell 4 of the \$20.00 puts for \$2.00. The net premium paid for this position is 1 x \$12.00 (for the \$50.00 put) less 4 x \$2.00 (for the \$20.00 put) for a cost of \$4.00.

Continuing with this trade, the math to compute the upper and lower break-even points is:

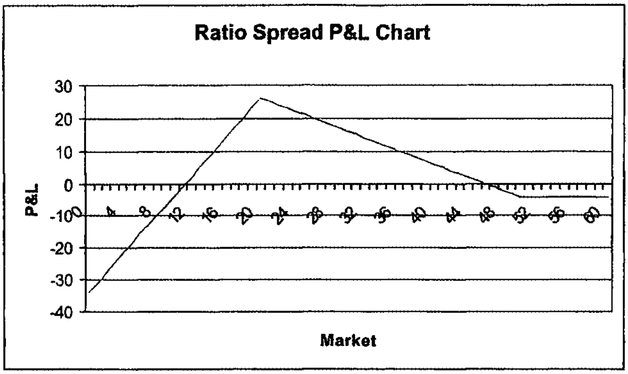
Upper Break-Even: \$50.00 strike - \$4.00 total premium paid, or \$46.00. At \$46.00, the trade breaks even, and below that, it starts to make money, all the way down to the lower break-even point.

Lower Break-Even:

$$\text{lower strike} - \frac{((\text{upper strike} - \text{lower strike}) \times \#\ \text{upper strikes bought} + \text{debit or credit})}{-1 \times (\#\ \text{lower strikes sold} + \#\ \text{upper strikes bought})}$$

$$= 20 - \frac{(50-20) \times 1 - 4}{-1 \times (1 - 4)}$$

$$= \$11.33$$



From \$46.00 to \$11.33, the trade makes money. Below \$11.33, the trade begins to lose money very rapidly. But if you are long generation, who cares? As discussed, gas units, which have a high degree of operational flexibility, are much more expensive than this to operate. And coal-fired units, which are cheaper than gas units and have slightly less flexibility, are usually more expensive than the lower break-even to operate. If you are long generation, you can put on this trade, and risk a small amount of money to make significantly more. For those who are long generation, the most amount of money you can lose is the premium paid. This is because at the lower break-even, which should be cheaper than your cost of generation, you can always turn off units and use the power that is "put" to you (via the 4 puts sold less the one bought) to meet load, and still save money.

1. Does the trade make sense? Yes. So long as you pick the strikes which have a high probability of occurring (high net delta for the put spread) then it is a worthwhile "do". However, if you pick two highly unlikely strikes (say the \$15.00 and the \$10.00 put strikes for summer, which would have a low net delta and therefore a low probability of making money) the trade is probably not wise. Likewise, if you pick two very high strike puts which yield a poor lower break-even (greater than generation costs) then again, it is probably a bad trade.
2. Do you have an edge? Yes. If you are long generation, you have a different break-even (the cost of your most expensive unit that is operating) than someone who puts on the naked position.
3. Do you control the tails? Yes. With generation costs limiting your downside, the most amount of money that can be lost on this trade is the premium paid.

2. Butterflies (outrights)

Historically, September produces price "surprises" to the upside. Because of this fact, October tends to rise in sympathy. Typically, November then lags, as people expect a normal month. And December tends to stay "bid" in anticipation of a cold winter. Whether or not a cold winter materializes does not matter – as long as the market psychology anticipates the potential for price surprises to the upside in December, the December futures will stay bid.

In order to capitalize on this mentality, a safe play is the October/November/December "butterfly". This trade involves buying one October, selling two Novembers, and buying one December. The 1/2/1 ratio gives equal volume to the trade so that exposure on each part is matched.

Typically, this spread can be entered for a +$0.25 to +$0.50 premium. (Look at 8/7, for example. Buying 1 CNV9 for $24.75, selling 2 CNX9 @ $25.75, and buying 1 CNZ9 for $26.40 will yield a premium, on a per-lot basis, of +$0.35 (receive 2 x $25.75 for Nov sold, pay 1 x $24.75 for Oct and pay 1 x $26.40 for Dec).

Historically, this spread rarely, if ever, trades at more than a $0.70 premium. So the risk on the trade is usually no more than -$0.35. This "fly" has a tendency to "blow out" to $0.75.

One way to exit this trade would be to keep it intact as a butterfly. Using 9/15 as an example, you would sell 1 CNV9 @ $24.50, pay $24.63 for 2 CNX9, and sell 1 CNZ9 @ $25.50, and receive +$0.74. Not a bad risk/reward scenario – risking $0.35 to make roughly $1.00 ($0.30 credit on trade initiation + $0.74 to close out position).

Another way to exit this trade would be to treat it as two individual spreads – the Oct/Nov spread (in which you are long one Oct and short one Nov) and the Nov/Dec (short one Nov and long one Dec). If you choose, you can pick an opportune time to exit the Oct/Nov, and wait for a later time to exit the Nov/Dec (or vice versa).

As an example, using the previous illustration, the "fly" was entered on 9/15 in the following way: Buying 1 CNV9 for $24.75, selling 2 CNX9 @ $25.75, and buying 1 CNZ9 for $26.40 will yield a premium, on a per-lot basis, of +$0.35 (receive 2 x $25.75 for Nov sold, pay 1 x $24.75 for Oct and pay 1 x $26.40 for Dec). On 9/14, you can pay $23.85 for 1 CNX9, and sell 1 CNZ9 @ $25.00 (This nets you $1.15, less the $1.00 paid when the Nov/Dec leg of the fly was initiated, nets +$0.15). Then, on 9/16, you can exit the Oct/Nov spread by selling 1 CNV9 @ $25.50 and paying $25.41 for 1 CNX9. (This nets $0.09 in addition to the $1.00 you received for initiating the Oct/Nov leg of the butterfly, for +$1.09). The total of the two "nets" results in "catching the fly" for $1.24.

A third way to exit the trade would be as individual legs. This involves more risk, as there is no inherent "protection" provided by the other legs of the spread. However, on 9/1, you could sell the 1 CNV9 @ $25.55 (+0.80), on 9/8 buy back the short by paying $24.61 for 2 CNX9 (+$1.14), and on 9/25 sell 1 CNZ9 @ $28.00 (+$1.60). The overall net is $3.54, or much higher than the butterfly or spread legs. Again, this involves much more risk.

Past performance is no guarantee of what will happen in the future. However, if seasonal "plays" continue to repeat, and if the trade makes sense, and offers a low risk/reward scenario, it is worth a try. So long as the risk/reward is defined, and a "stop/loss" point is predetermined, the odds should be in your favor, and you will know where to get out if you are right, as well as where to exit if you are wrong.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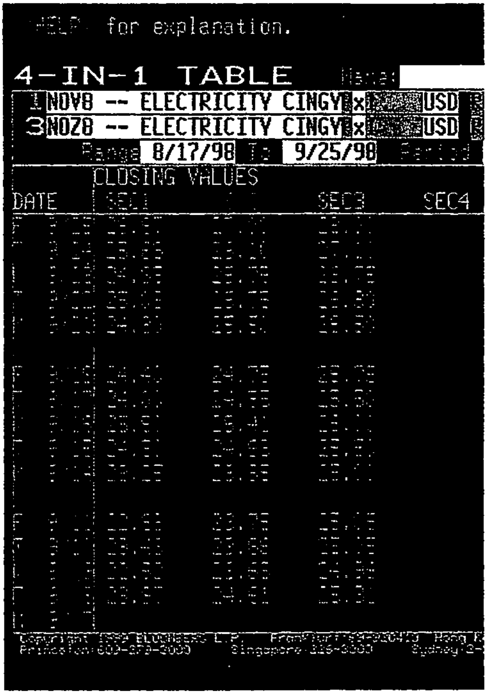
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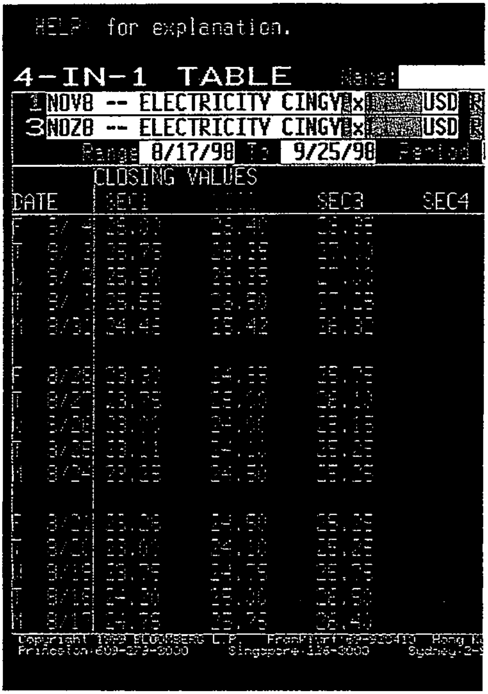
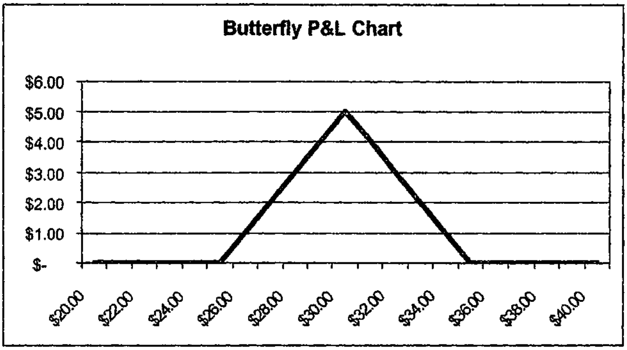


3. Butterflies (daily options):

Daily butterfly options provide a low-risk way to make money in the power markets. They involve selling two (or more) of a daily put (called the "body" of the butterfly) and buying a higher strike and a lower strike put (the "wings" of the butterfly) in net amounts equal to the body. An example would be to buy one $25.00 daily put, sell 2 $30.00 daily puts, and buy one $35.00 daily put. These trades can generally be put on for "flat" (no net debit or credit paid out to enter the position), but paying a small premium may be worthwhile. The amount of premium paid is up to the discretion of the trader, but a general rule of thumb is again, the "1/3 rule" if the strikes of the body are at the money – i.e. do not pay more than 1/3 of the difference between $35.00 and $30.00 (or $30.00 and $25.00 – same thing) for this trade.

An example of this would be to buy one $35.00 daily put for $5.00, sell two $30.00 puts for $3.00, and buy one $25.00 put for $1.00. The total net premium paid is zero (pay $5.00 for the $35.00 and $1.00 for the $25.00, netted against the $6.00 received for selling two $30.00 puts for $3.00).

If you carefully selected the body of the butterfly, then you should have a good chance of making money. The WORST you can do on this trade is break even (if zero premium was paid) or not recoup any premium if you paid a credit to initiate this position.



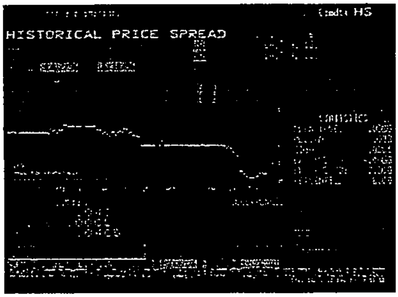
1. Does the trade make sense? Yes. If you select a body where the strikes have a high probability of finishing at the money, then "framing" the expected outcome with a low-risk trade makes perfect sense.
2. Do we have an edge? Yes. You have initiated a trade for little or no money that has a high probability of being profitable.
3. Do we control the tails? The most you can lose is the premium paid, if any.

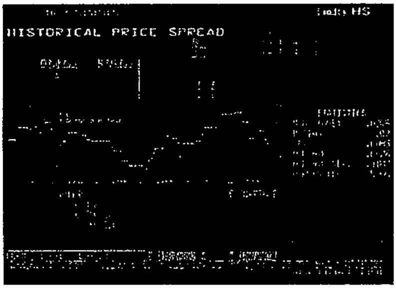
GAS:

1. June/Sep Spread

Simple trade – sell June, and buy September in equal amounts.

1. Does the trade make sense? Yes. Historically, it is warmer in the southern US in September than it is in June. And the southern US uses more natural gas than the other regions of the country. Additionally, if there is any anticipated hurricane activity, September will be "bid up" in anticipation of a run-up in prices.
2. Do we have an edge? Yes. Statistically, the distributions tell you that you have a greater chance of the spread going your way than against you, if you time your entry points well. Additionally, if you are wrong, you always have the potential to "leg out" of the trade – sell out the Sep and stay short the June, or buy back the June and stay long the Sep. Damage control at its finest!
3. Do we control the tails? If you adhere to the statistics and predetermine your stop/loss, then yes.


HISTORICAL PRICE SPREAD

HISTORICAL PRICE SPREAD

HISTORICAL PRICE SPREAD

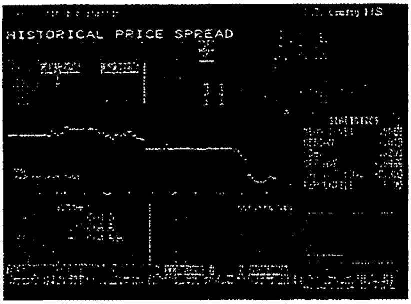
HISTORICAL PRICE SPREAD

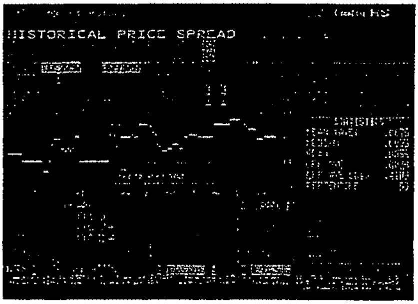
Jul/Aug Spread

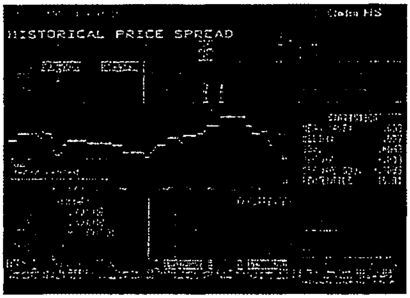
Another simple trade – sell July and buy the August.

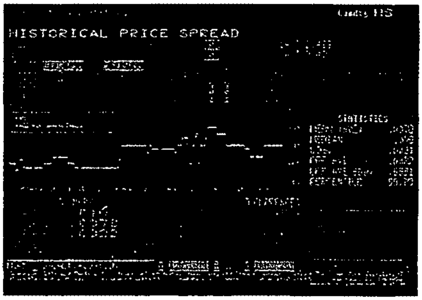
1. Does the trade make sense?
2. Do we have an edge?
3. Do we control the tails?

The answers to all of these questions are similar to those for the June/Sep spreads.


HISTORICAL PRICE SPREAD


HISTORICAL PRICE SPREAD


HISTORICAL PRICE SPREAD


HISTORICAL PRICE SPREAD

2. Volatility Play (Historical < Implied):

This is more of a pure trading trick than a probabilistic way to take a speculative position. The reasoning behind this technique is that volatility tends to be mean reverting. If the implied volatility (as calculated from options premiums quoted in the market) are less than the historical volatility (as determined by what actually occurred with prices) then you want to be a buyer of volatility.

All else being equal, if an option is correctly priced, then the buyer should exactly make up for the premium he spent by profitably scalping positive gamma. Conversely, the seller of the same option should exactly lose the premium he collected by trying to cover his negative gamma. Stated another way, the buyer of an option is buying implied volatility. If, after the contract stops trading (expires), if the option was perfectly priced, the realized volatility (which will become the historical volatility once the option stops trading) perfectly matches the volatility that was used in calculating the premium, then the money made by running a delta-neutral position and scalping off the positive gamma should be equal to what was paid for the option. This only makes sense. The implied volatility is used to predict how much the underlying will move. If that prediction turns out to be perfect, then the price was fair, the implied volatility was realized, and the premium was exactly recaptured (but there will be no P&L loss or gain) by trading around the option position.

The same holds true for the seller of the option. He is selling implied volatility and receiving a premium based on this. By maintaining a neutral position, he is selling in a declining market or buying in a rising market (because of the short gamma) and losing money trying to stay neutral. If this implied volatility turns out to exactly match the volatility that does occur, then the premium will be spent, no more or no less, in maintaining this neutral position.

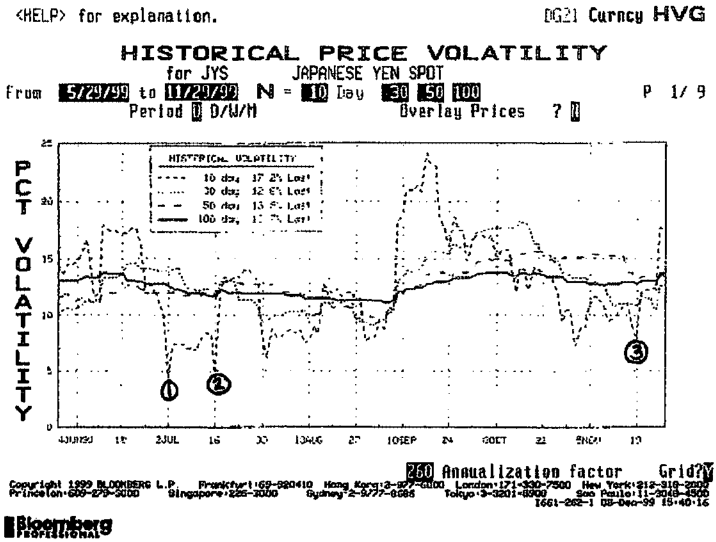
For these reasons, if the implied volatility is less than the historical volatility, then buying vol, trading around the position and staying neutral should result in capturing more money than is spent on the option premium.

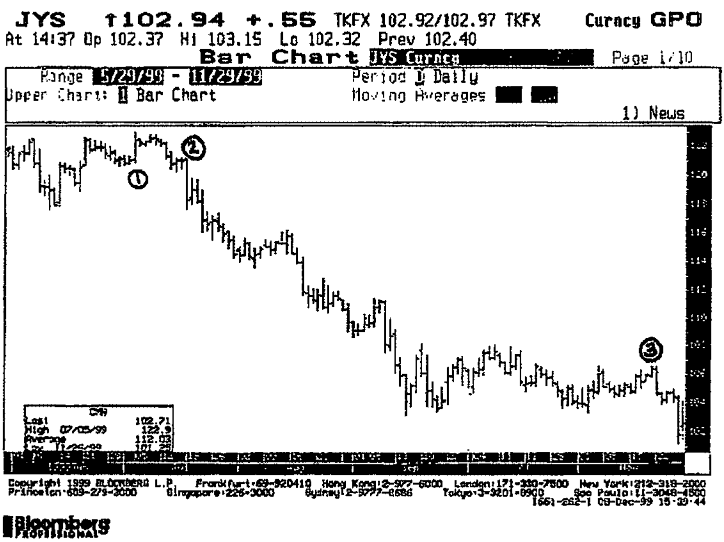
1. Does the trade make sense? Yes. We are taking advantage of an observed tendency for volatility to be mean reverting.
2. Do we have an edge? Yes. By buying low volatility, we have a greater chance of the mean-reversion phenomena occurring, and can capture profits by scalping off the "greeks".
3. Do we control the tails? Certainly. The only risk is the premium spent.

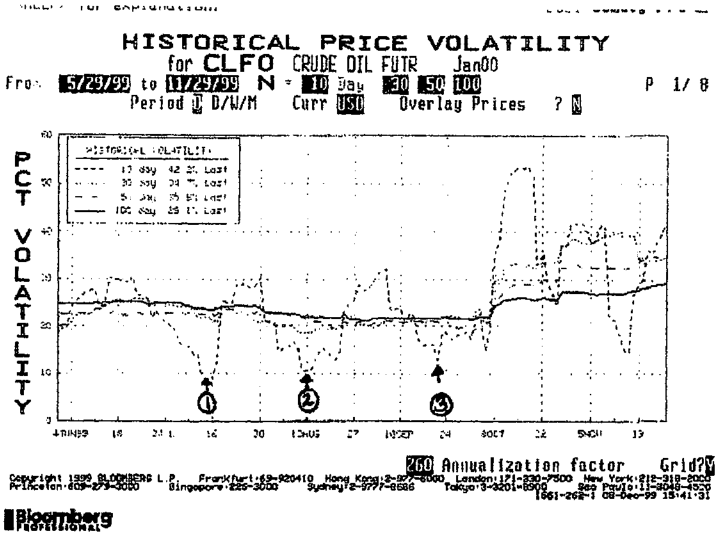
3. Volatility Screen (10< ½ 100)

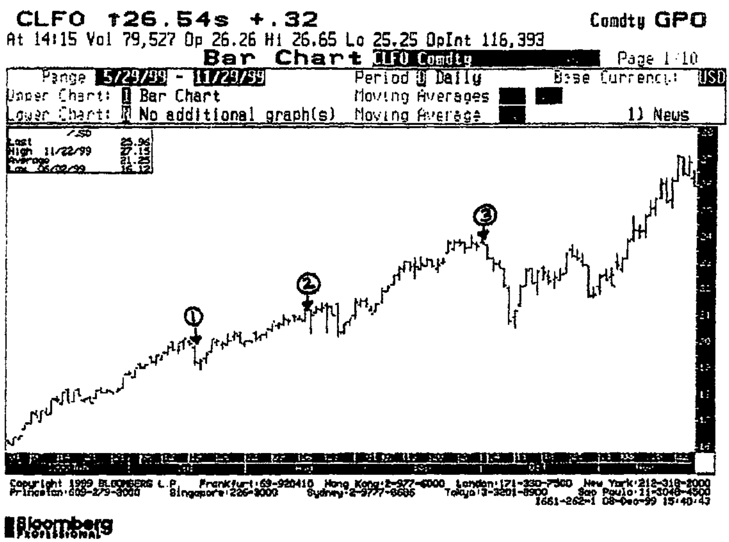
This is a filtering technique made popular by Larry Connors. Since volatility tends to be mean-reverting, you would like to capture events which are about o demonstrate this phenomena. If the 10-day historical volatility is less than 1/2 of the 100 day historical volatility, then the market is due to make a big move (volatility is due to revert back to the mean). While this system does not predict direction, it can be used as a straight "vol" play, or can be combined with any preferred technique to help predict direction.

For a straight volatility play, once the 10-day is less than ½ of the 100-day, then buy at-the-money straddles or strangles which cover the most recent range. For s directional play, either go long the underlying, buy calls or sell puts if an up-move is expected (or sell the underlying, buy puts or sell calls if it is a down-move you are anticipating).


<HELP> for explanation.
DG21 Curncy HVG
HISTORICAL PRICE VOLATILITY
for JYS JAPANESE YEN SPOT
From 5/29/99 to 11/29/99 N = 10 Day 30 50 100
P 1/ 9
Period D D/W/M
Overlay Prices ? N
PCT VOLATILITY
HISTORICAL VOLATILITY
1
2
3
260 Annualization factor
Grid? Y
Bloomberg PROFESSIONAL


JYS ↑102.94 +.55 TKFX 102.92/102.97 TKFX
Curncy GPO
At 14:37 Op 102.37 Hi 103.15 Lo 102.32 Prev 102.40
Bar Chart JYS Curncy
Page 1/10
Range 5/29/99 - 11/29/99
Period D Daily
Upper Chart: B Bar Chart
Moving Averages
1) News
1
2
3
Last 102.71
High 07/05/99 122.9
Average 112.03
Bloomberg PROFESSIONAL


HISTORICAL PRICE VOLATILITY
for CLFO CRUDE OIL FUTR Jan00
From 5/29/99 to 11/29/99 N = 10 Day 30 50 100
P 1/ 8
Period D D/W/M Curr USD Overlay Prices ? N
PCT VOLATILITY
260 Annualization factor Grid? Y


CLFO ↑26.54s +.32
Comdty GPO
At 14:15 Vol 79,527 Op 26.26 Hi 26.65 Lo 25.25 OpInt 116,393
Bar Chart
Page 1/10
Period D Daily
Base Currency: USD
Upper Chart: B Bar Chart
Lower Chart: N No additional graph(s)
Moving Averages
Moving Average
1) News

1. Does the trade make sense? Yes. We are taking advantage of the observed tendency for volatility to be mean reverting.
2. Do we have an edge? Yes. We are waiting for the deck to be stacked in our favor while waiting for the 10-day to drop to less than ½ of the 100-day. In addition, we are playing for the big move which should result once this filter is triggered.
3. Can we control the tails? Yes. By playing this from the options-side, the maximum loss is limited to option premiums.

CRUDE OIL:

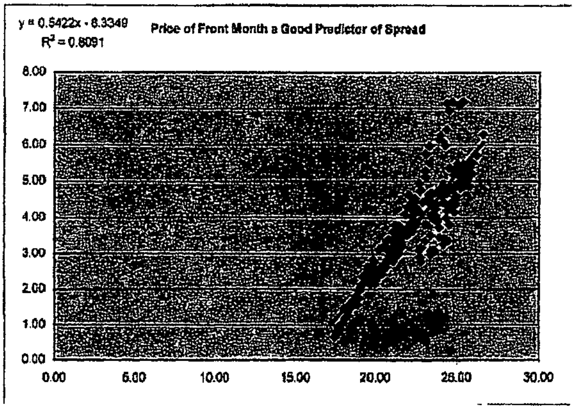
In general, crude oil is a very liquid commodity that has been "seasoned" (i.e. it has been around long enough that it behaves in a rational manner, lends itself to numerous technical and fundamental analyses techniques, has demonstrated what types of news events will cause price shocks, and can be modeled with some degree of confidence). Because of this, many of the tricks and arbitrage techniques which exist in undeveloped markets such as power do not apply. However, some of the more general tricks that can be used for bonds, currencies, metals, stocks, S&P's and other commodities work very well with crude. One such traders trick which has become popular and is specific just to crude oil is:

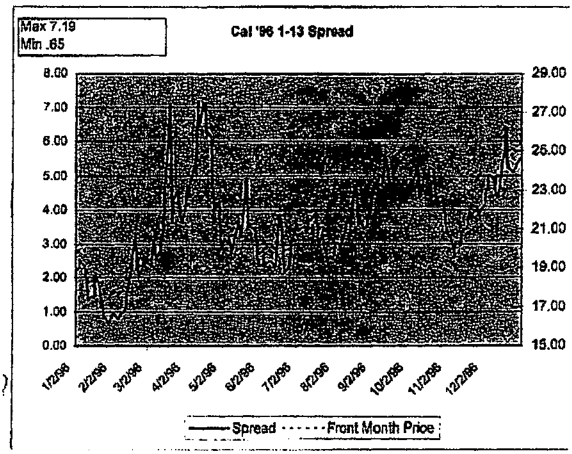
1. Front to Backs using Historical Relationships:

Because of the cost of carry, storage, insurance, and time value of money, crude oil is a market that is normally in contango. However, there are instances when it reverts into backwardation. This shape, or curve structure, can be reasonably predicted and is a good vehicle for helping to determine the market's bias to go higher or lower.

One such popular technique for trading crude oil is the "rolls", or front to back spreads. The two most common are Dec/Dec and June/June (December of year one spread against December of year two; and June of year one spread against June of year two).

The following chart depicts the historical relationships of the spreads:


y = 0.5422x - 6.3349
R^2 = 0.6091
Price of Front Month a Good Predictor of Spread
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0.00
5.00
10.00
15.00
20.00
25.00
30.00


Max 7.19
Min .65
Cal '96 1-13 Spread
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
29.00
27.00
25.00
23.00
21.00
19.00
17.00
15.00
1/2/96
2/2/96
3/2/96
4/2/96
5/2/96
6/2/96
7/2/96
8/2/96
9/2/96
10/2/96
11/2/96
12/2/96
Spread
Front Month Price

The preferred way to use this technique is to take a look at the particular spread you are focusing on. If that spread is tending to go from contango into backwardation, or if it is in backwardation and getting wider, then you can trade this in one of two ways. The first is to initiate the year-on-year spread in the direction of the spread trend (i.e. if the tendency is to go from contango to backwardation, then initiate the year on year spread by buying the front month and selling the back month. If the spread is narrowing, or going from backwardation to contango, then sell the front month and buy the back month).

The second technique is to use the trend of the front to back spread as a predictor for taking a position in the front month. If the year-on-year spread is widening, then go long the front month only. If it is narrowing, then sell the front month only.

Taking a position in the front month versus taking a position in the spread is a bit more risky, as the front months tend to be more volatile than the spreads. Additionally, the margin requirements for the front month only are greater than for a spread position.

1. Does the trade make sense? Yes. Using the term structure of the market to tell us which direction it wants to go makes perfect sense. If the supply/demand equation does something to upset the normal price curve, then it merits attention. Something else is happening, and the market will tell you what it wants to do.
2. Do we have an edge? Yes. By looking at the historical relationships, you can place the probabilities on your side. Rather than taking a random position, the curve structure will show you in the past what has happened. While past occurrences are no guarantee of future success, if the trade makes sense (which it does) and the historical odds are in your favor, then go for it.
3. Do we control the tails? Yes – if you are disciplined. Once you are in the trade, as long as the historical relationships hold true, you should be fine. If they start to vary such that your "blueprint" is no longer valid, then get out, and do not hesitate.

GENERAL:

1. Key News Reversal:

"Key News Reversal", "Fade Opening Call", "Buy the rumor/sell the fact" and a host of other terms have been used to describe this technique. While a number of people lay claim to inventing this method, it's widespread use and lack of proprietary indicators do not make for easy "ownership".

The basis of this technique is simple. Just before a major news announcement, note where a particular commodity is trading (it can be bonds, S&P's, or currencies for the usual slew of data that is released from the government at 0830 eastern prevailing time. Additionally, it can be API's, refinery outages or an OPEC announcement for crude oil, or AGA's, hurricane activity or unexpected but widely distributed weather revisions from a major news service). Write down the actual level where the commodity is trading just before the news is made public.

Once the news comes out, watch which direction the underlying commodity trades. If it is bullish news, of course it will trade higher, and bearish news will cause it to trade lower. It is this initial "thrust" or momentum in a particular direction that is important. Traders in the pits and all over the world will be buying on the bullish news or stopping out of short positions, adding to the bullish frenzy. Should the news be bearish, traders will be selling into a falling market or stopping out of long positions, further pushing the market down.

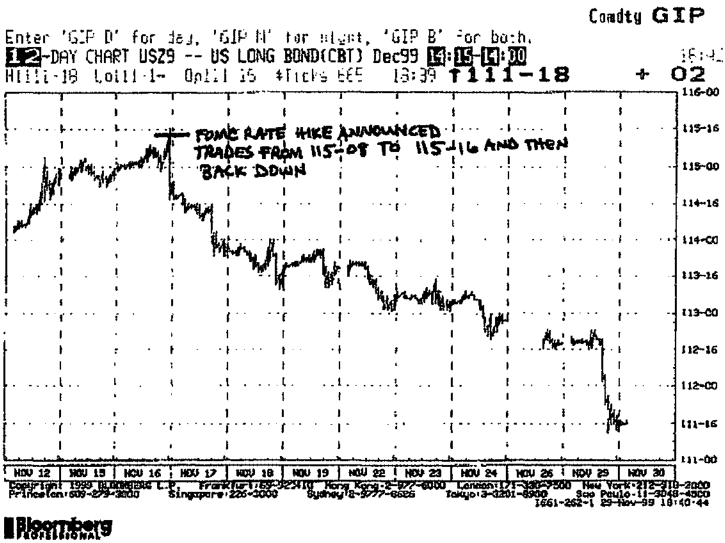
These traders will look for the initial thrust, whichever direction it may be, to continue. These traders will not want to lose any money, so they will tend to bunch their stops at "break-even" – which is the point that you have written down just before the news was released. If the news is bullish, the buyers will have sell stops at the pre-news price. This will allow them to participate in any upside, but not take a loss. Conversely, if the news is bearish, the sellers who piled into a position due to the news will have buy stops at the pre-news price as to not allow a winning trade to turn into a loser.

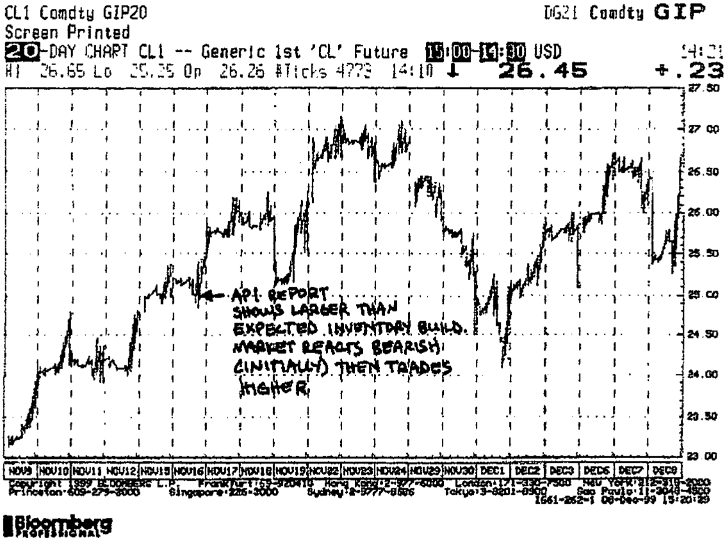
It is these bunching of stops, and the tendency for short-term day traders to not hold a losing position, which allows us an opportunity to make money. The technique is this —if bullish news causes the market to trade higher, and then retrace back down through the pre-news price, sell on a break to the downside with a buy/stop just above your entry price. For bearish news, if the market trades lower and then subsequently reverses back through to the upside of the pre-news price, initiate a long position with a stop/loss just below entry price.

Now lets check how this measures up against our "Three Trading Criteria":

1. Does the trade make sense? Yes. If bullish news can't keep the market up, or if bearish news can't keep the market down, then there is something else at work here. Either the news has already been priced into the market, there is a different interpretation of the news than previously thought, or something is at work here which most people do not understand.
2. Do we have an edge? Yes. We are not in the market with a position when the news comes out. Therefore, we are not subject to the initial wave of panic buying or selling. We can remain calm, keep our powder dry, and wait for the right opportunity. We are not subject to the fear and greed that rule the markets at this point. The traders with winning trades watch their profits evaporate, point by point, slowly back to the initial break-even. The psychology of not taking a loss, as well as the bunching of stops, give us an edge over those market participants who tried to ride the initial wave of price direction.
3. Do we control the tails? Sure do. We have our stop/loss point predetermined, which is break-even or a tick or two away. When and if that level is reached, we get out – no questions asked. Therefore, we are entering a trade with a predetermined stop/loss point, and risking only a point or two on the trade. The tails are controlled.

Examples of the Key News Reversal Trick:


Comdty GIP
12-DAY CHART US Z9 -- US LONG BOND(CBT) Dec99
111-18
+ 02
FOMC RATE HIKE ANNOUNCED
TRADES FROM 115-08 TO 115-16 AND THEN
BACK DOWN
116-00
115-16
115-00
114-16
114-00
113-16
113-00
112-16
112-00
111-16
111-00
NOV 12
NOV 15
NOV 16
NOV 17
NOV 18
NOV 19
NOV 22
NOV 23
NOV 24
NOV 26
NOV 29
NOV 30



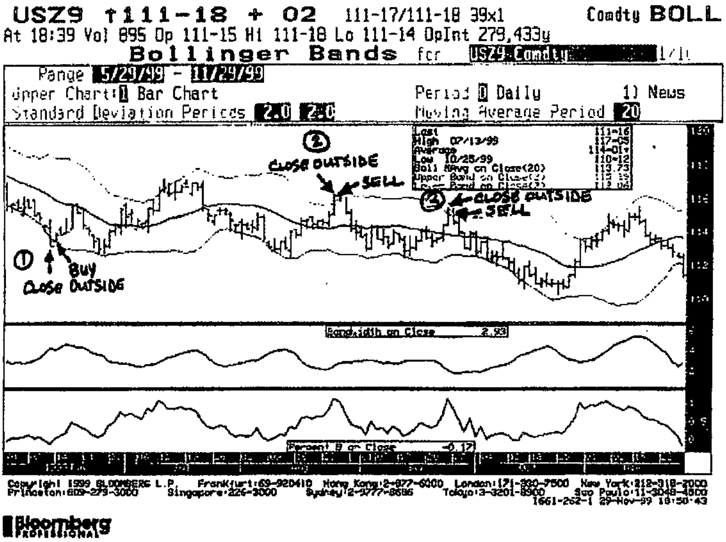
2. Bollinger Band Closes:

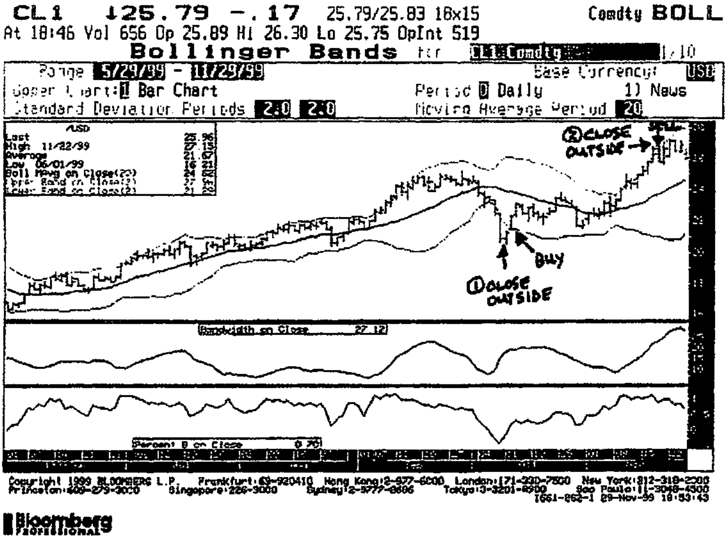
There are a number of different ways to use Bollinger Bands (a proprietary indicator developed by John Bollinger, which uses a moving average of the standard deviation of price to place "envelopes" around the central price action). Some people use the bands to indicate when to buy and sell (selling when it touches an upper band, and buying when it touches a lower band, since 96% of all price action is supposed to be contained within the bands.). Others have refined the technique to include filters such as moving averages, ADX/DMI, etc. The problems that surround most Bollinger band techniques are that you could be selling into strength or buying weakness, and getting chewed up in the process.

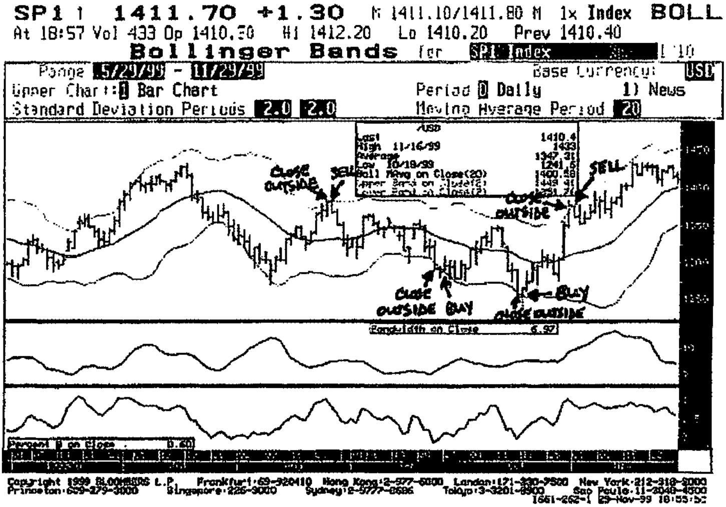
One very simple yet powerful technique involves using Bollinger bands to find market reversals. When a market closes outside of a Bollinger band, and the next day retraces through the band, take a position in the direction inside the band with a stop at the high or low of the previous bar.

Specifically, if a market closes above its Bollinger band today, and then tomorrow retraces back down through its band, take a short position in the market. Place your stop at the high of the previous bar. On the flip side, if a market closes below a Bollinger band and the next day reverses back up through the band, take a long position, with a stop/loss at the low of the previous bar.

1. Does the trade make sense? Yes. Since statistically, 96% of all price action is to be contained within Bollinger bands, it would be logical to expect prices to retrace back from an extreme move.
2. Do we have an edge? Yes. We are waiting for the probabilities to dictate when to enter a position. We are not caught up in the emotion of the big moves that resulted in closes outside of the bands.
3. Do we control the tails? Yes. Predetermined stop/loss points keep us from being undisciplined. A continuation in the extreme direction will indicate when we are wrong.


USZ9 ↑111-18 + 02 111-17/111-18 39x1 Comdty BOLL
At 18:39 Vol 895 Op 111-15 Hi 111-18 Lo 111-14 OpInt 279,433y
Bollinger Bands
Period D Daily
1) News
Moving Average Period 20
CLOSE OUTSIDE
SELL
CLOSE OUTSIDE
SELL
BUY
CLOSE OUTSIDE
Bloomberg

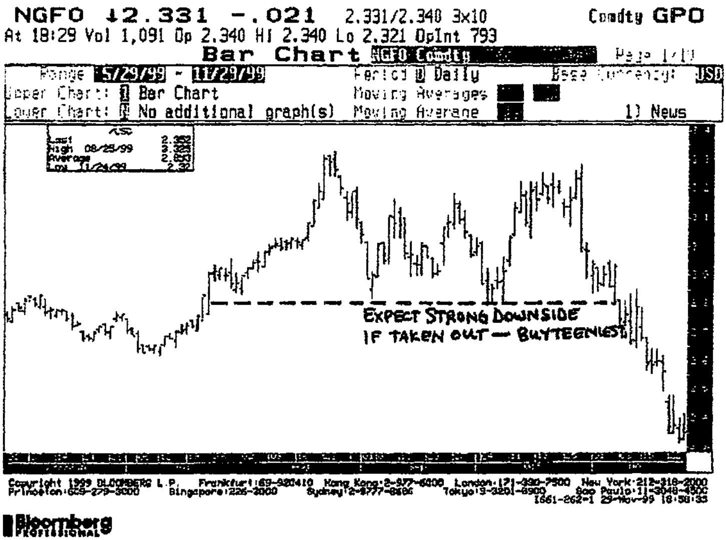

CL1 ↓25.79 -.17 25.79/25.83 18x15
Comdty BOLL
At 18:46 Vol 656 Op 25.89 Hi 26.30 Lo 25.75 OpInt 519
Bollinger Bands
Bar Chart
Daily
1) News
②CLOSE OUTSIDE
BUY
①CLOSE OUTSIDE
Percent B on Close

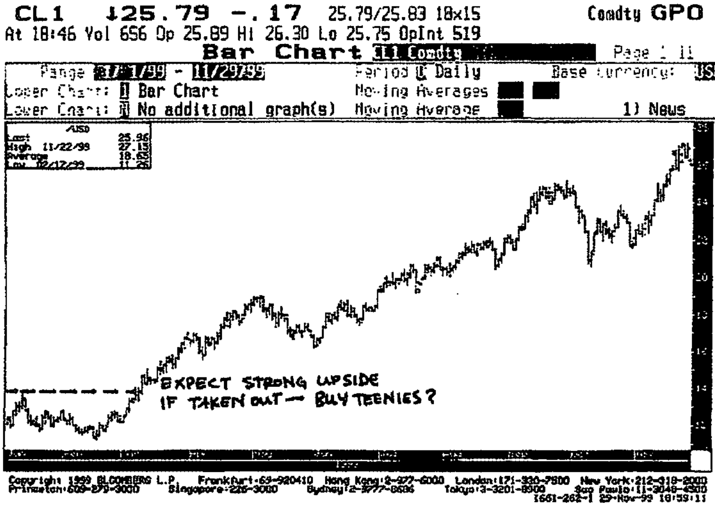


3. Buying Teenies:

"Teenies" are commonly referred to as deep out of the money options. Many traders like to sell teenies with the thought being "the price can never get there." For the person selling them, the rsik/reward is not very attractive. You can go for long periods of time selling teenies and collecting the small associated premium. But once in a great while, the teenies will hit big, and the seller can get wiped out.

The delta associated with an option has several definitions. One of the more useful definitions for an options trader is that the delta is the probability of the option finishing in the money. If you use this thought process, you can find some attractive teenies to purchase. If you have an idea of where a commodity might trade, but a straight outright position does not offer an attractive reward, a teenie might be the answer. Here is how the option delta, used as a probability, might justify the trade:

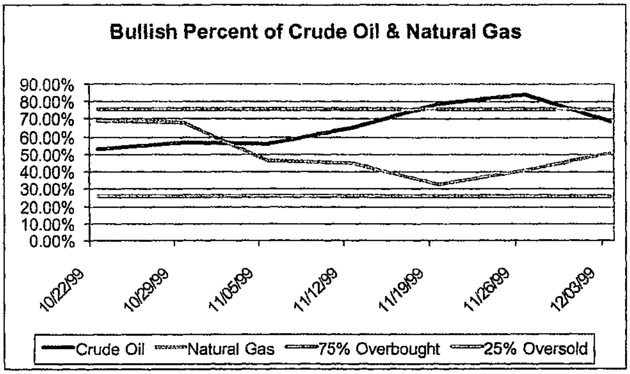

NGFO ↓2.331 -.021 2.331/2.340 3x10
Comdty GPO
At 18:29 Vol 1,091 Op 2.340 Hi 2.340 Lo 2.321 OpInt 793
Bar Chart
Upper Chart: Bar Chart
Lower Chart: No additional graph(s)
Daily
1) News
EXPECT STRONG DOWNSIDE
IF TAKEN OUT — BUYTEEGNIEST

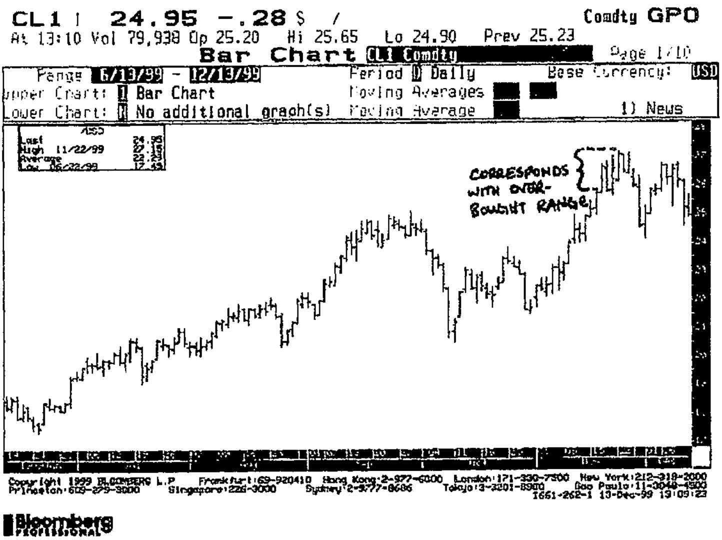


1. Does the trade make sense? Yes. It is a high reward/low risk trade where you try to capture an expected value that seems attractive.
2. Do you have an edge? Yes. By playing the teenie instead of the underlying option, you can withstand significant moves against you, since the only risk is the premium. Additionally, if the expected value shows that this is a trade worth entering, then the odds are in your favor as compared to someone taking a naked position.
3. Do you control the tails? Yes. The only risk is your premium spent. Unlike the seller of the teenies, all you can lose is the initial cash outlay.

4. Commitment of Traders/Market Sentiment:

Another useful set of tools is the Commitment of Traders report and the market sentiment report. These two tools are used to determine how market participants view the current situation. The "trading trick" is to fade the reports. If market sentiment and commitment of traders shows a strong bullish bias, then sell. If the bias is bearish, then buy


Bullish Percent of Crude Oil & Natural Gas
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
10/22/99
10/29/99
11/05/99
11/12/99
11/19/99
11/26/99
12/03/99
Crude Oil
Natural Gas
75% Overbought
25% Oversold


CL1 24.95 -.28 $ /
Comdty GPO
At 13:10 Vol 79,938 Op 25.20 Hi 25.65 Lo 24.90 Prev 25.23
Bar Chart
Range 6/13/99 - 12/13/99
Period D Daily
Base Currency: USD
Upper Chart: B Bar Chart
Moving Averages
Lower Chart: X No additional graph(s)
Moving Average
1) News
Last 24.95
High 11/22/99 27.15
Average 22.23
Low 06/22/99 17.45
CORRESPONDS WITH OVER-BOUGHT RANGE
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1. Does the trade make sense? Yes. If everyone is bullish, then there is nobody left to bid up a commodity. All bullish news, market expectations, and positive price action has already occurred – there is nothing left to take the market higher. Therefore, once the selling starts, since the market is significantly long, a mass liquidation can be expected. It may be the correction of a continuing up move, or it may be a trend reversal. Whatever the reason, you don't care. The technique provides a quick scalping opportunity.
2. Do you have an edge? Yes. You can determine what the other market participants are doing and anticipate their next action. Not many people follow the commitment of traders reports, and even fewer still follow the market sentiment numbers.
3. Do you control the tails? If you are disciplined, yes. This technique does not provide for any mechanical or predetermined stops. The trader must determine his own proper stop placement, whether it is from technical analysis, time stops, or a dollar level.

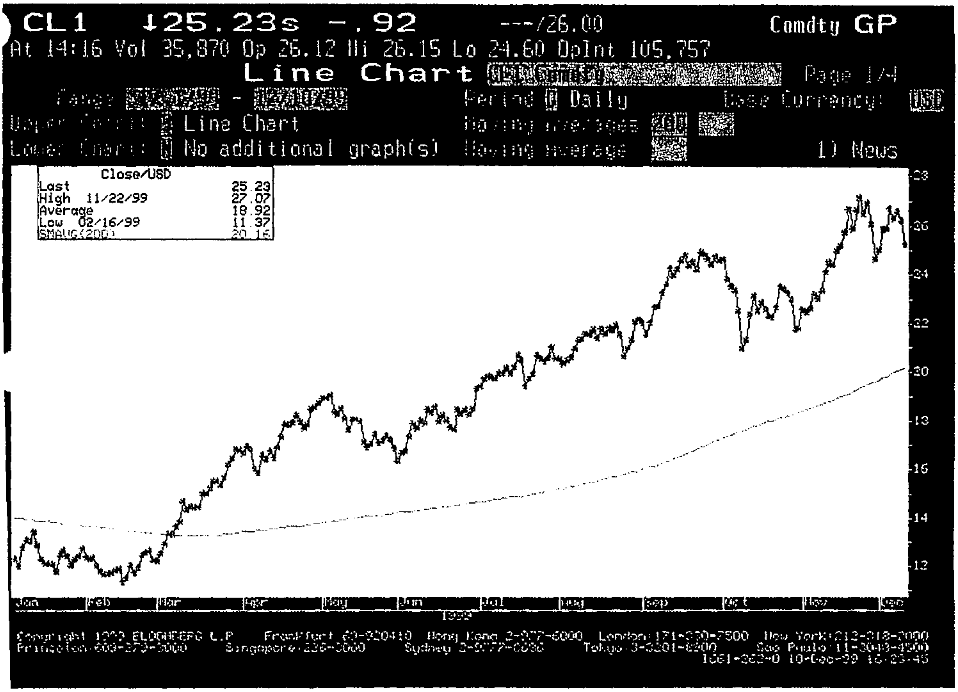
5. 200-day Moving Average:

Supposedly if you were to interview 100 doctors and ask the following question, "If you were stranded on a desert island, what would be the one medicine you would choose to have with you?", the predominate answer would be "Aspirin".

If you were to ask a large sampling of technical traders and ask, "If you could choose only one technical indicator to trade with, what would it be?", the predominate answer would be "200-day moving average".

The 200-day moving average is a favorite indicator of many large momentum players and hedge funds who specialize in commodities. There are several time frames and techniques that can be used with moving averages, but the 200-day moving average is still the most simple and reliable of the bunch. It shows where the true trend is, and eliminates whipsaws and "white noise" that occurs on a small (daily or intraday) time frame, and focuses on the big moves.

The technique is simple – buy when a commodity crosses upward through its 200-day moving average, and sell when it crosses through the downside.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6. 50% retracement/0.618 stop (Modified Fibonocci):

Edward Dobson writes in "The trading Rule that Can make You Rich" that the one reliable indicator he has found is the 50% retracement rule. Dobson's recommended tactic is simple – buy on a 50% retracement of a major move, with a stop/loss at the 0.618 retracement level. As simp le as it may sound, a number of market technicians believe in this one simple rule, including:

W.D. Gann: You can make a fortune by following this one rule alone. A careful study and review of past movements in any commodity will prove to you beyond doubt that this rule works and that you will make profits following it." How To Make Profits In Commodities.

Burton Pugh: The 50% reaction is one of the most valuable of market habits and the trader should follow and profit by this most dependable of all market laws...This remarkable form of market action is far the safest and surest movement on which the trader can base his moves." Commodity traders Instruction Book.

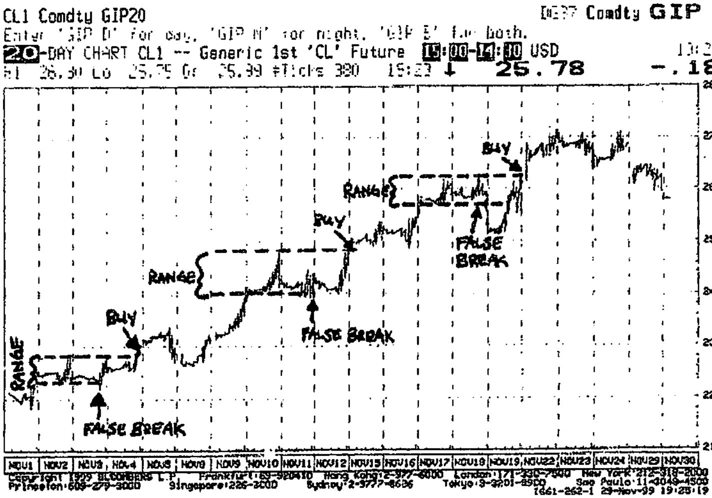
7. Range False Breakout/Reversal:

A number of technical traders will take breakouts from ranges as a quick play. It has been statistically shown that markets trend only 20% of the time – the other 80% of market action is confined to ranges. The moves out of a range can be a precursor to a powerful trend, or a move into another consolidation or range-bound area. Regardless, the explosive moves that often occur out of ranges can often result in large profits.

Taking these explosive moves can also result in losses. The general trading crowd will buy on an upside breakout from a trading range, and place their stop/losses on the bottom of the range (the reverse holds true for downside breakouts).

The traders trick is to take advantage of TWO forces acting in concert – the tendency after a range breakout in one direction for stops to be bunched at the other end of the range, combined with the herd mentality of playing breaks. As an example, consider a market that has traded in a tight consolidation pattern for an extended period of time. Once the market makes a break to the upside, there will be a number of market participants who buy on this break. Their stops will be placed at the lower end of the range. Should the market then trade down to the lower end of this range, these stops will be hit. Add to this the market participants who want to sell the downside break (just like those who wanted to play the upside break) and you have a potential explosive move that could sustain some follow-through.

The specific trick is this: First, identify a market that has traded in a range or been consolidating. Next, watch for a breakout in either direction. If the market retraces through that breakout level and past the other end of the range, jump onboard.



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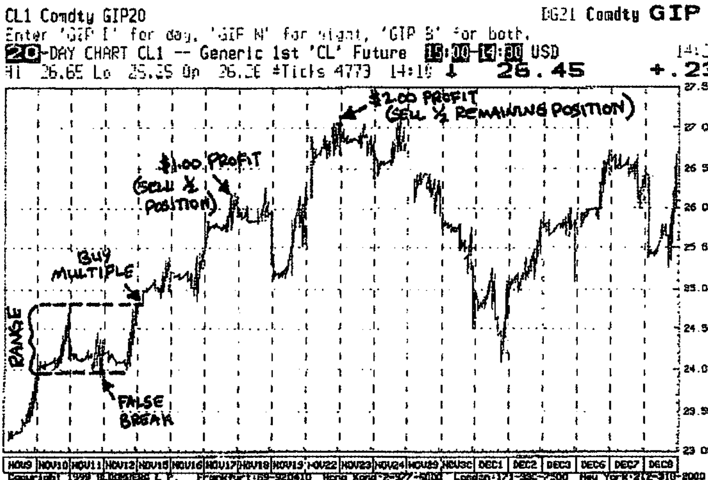
8. Multiple Contracts/Scale Profits

This is more of a money management technique than a particular entry method into a market. It involves trading with multiple contracts in order to improve your P&L. The two adages, "Open pocket, insert profit" and "You never go broke taking profits" are in play here.

Simply put, you initiate positions with multiple contracts. When the trade turns profitable, you scale out of the position, and move the stop/loss on the remaining contracts to break-even. This allows you to get a "running start" on profits, and guarantee that you will not take a loss on a trade.

There are many ways to apply this technique – here is but one example:



CONCLUSION

There are no "Holy Grails" in trading. No magic formu las, no secret techniques passed down from elders, and no divine strategies which are 100% accurate. The tricks mentioned above are not 100% accurate or foolproof. But they do tilt the odds in your favor, and they apply a discipline and methodology to trading.

B. Market Orders

1. **Market Order:** An order to buy or sell immediately, at whatever best price is currently available. This order is guaranteed to be filled, but there is no guarantee as to the price. Example: "Buy 500 Dec '00 crude at the market".
2. **Limit Order:** An order to buy or sell a security at a specific price. The order can only be filled at this specific price or better. A buy limit order can be filled at the specified price or lower. A sell limit order can be filled at the specified price or higher. There is no guarantee that the order will be filled. Partial fills are allowed. Example: "Sell 200 Sep '01 gas at $2.17 limit."
3. **Stop Order ("Stop-Out" or "Stop/Loss"):** A stop order is used to buy or sell once a specific price is penetrated. Once the price is penetrated, the order automatically becomes a market order. The order is guaranteed to be executed, but there is no guarantee as to price.
   - **A.** Sell Stop Order: A sell stop order is placed below current market prices. It is used to "stop the loss" when you are long and prices are declining, or to enter a position on a technical breakout. Example: You are long 100 mW of generation in Entergy for September, at a production cost of $20.00. The market is currently $30.00/$31.00. You think that prices are going higher, but you would like to protect your profit, so the following order can be used: "Sell 100 Sep Entergy at $25.00 stop". If the market trades $25.00, then your stop automatically becomes a market order. The individual handling your order will immediately begin selling 100 mW at the best prices available. You are guaranteed to sell 100 mW, but there is no guarantee as to the prices.
   - **B.** Buy Stop Order: A buy stop order is placed above current market prices. It is used to "stop the loss" when you are short, or to enter a rising market on a technical breakout to the upside. Example: You are short 200 contracts of natural gas for January due to a keep-whole provision. The market is currently $3.05/$3.06. You think that prices are going to decline and that you will have a chance to buy this back at better levels. However, you do not want to have the position "run away" from you and lose too much money, so you enter the following order: "Buy 200 Jan gas at $3.15 stop." If the market should trade $3.15, your order immediately becomes a market order, and your broker will begin buying 200 lots at the best available prices.
4. **Stop Limit Order:** A stop limit order is the same as a stop order in that it will become a market order once the price objective is hit. The difference is that a specific price target is specified, meaning that your order can only be filled at your price or better.
   - **A.** Sell Stop Limit Order: A sell stop limit order is placed below current market prices. It is used to "stop the loss" when you are long and prices are declining, or to enter a position on a technical breakout. Example: You are long 100 mW of generation in Entergy for September, at a production cost of $20.00. The market is currently $30.00/$31.00. You think that prices are going higher, but you would like to protect your profit, so the following order can be used: "Sell 100 Sep Entergy at $25.00 stop, limit $20.00". If the market trades $25.00, then your stop automatically becomes a market limit order. The individual handling your order will immediately begin selling up to 100 mW at the best prices available, but will not sell below $20.00 (your production costs, or your "limit" on the order). This guarantees that you will make a profit, and not sell below your production costs ($20.00, which would be a loss).
   - **B.** Buy Stop Limit Order: A buy stop limit order is placed above current market prices. It is used to "stop the loss" when you are short, or to enter a rising market on a technical breakout to the upside. Example: You are short 200 contracts of natural gas for January due to a keep-whole provision. The market is currently $3.05/$3.06. You think that prices are going to decline and that you will have a chance to buy this back at better levels. However, you do not want to have the position "run away" from you and lose too much money, so you enter the following order: "Buy 200 Jan gas at $3.15 stop." If the market should trade $3.15, your order immediately becomes a market limit order, and your broker will begin buying 200 lots at the best available prices, but will not pay more than $3.15.
5. **Day Order:** A day order is good only for the day that it is placed, and only for normal market hours (night sessions are not included). It is automatically canceled at the end of the day. All orders are day orders unless otherwise specified.

6. **Good till Canceled (GTC)/Open Order:** GTC orders remain in effect until specifically canceled or executed.
7. **At the Opening:** This is an order to buy or sell during the first few minutes that a market opens. If it is not executed on the open, it is then canceled.
8. **At the Close:** This is to be executed during the last few minutes that a market is open. The goal is to obtain the settlement price (final or closing price of the day) but there is no guarantee this will be achieved.
9. **Not Held:** This gives the person executing the order discretion. The person will work on a best-faith effort to fill the order, but will not be held responsible for the fill. These types of orders are usually given in thin markets, as it allows the individual on the exchange floor the ability to gauge liquidity, market price action, and other factors which may affect the fill. Example: It is 31 December, and the exchange closes at one o'clock for a half day due to the holiday (New Year's Eve). You need to "close your books" for the year, and would like to be flat (no positions) before you go home. You give your broker an order to "buy 200 October natural gas at $2.85, market not held". If the current price is $2.85, the broker will begin to buy slowly, as not to "chase the market up". He may get in 50 mor so contracts at $2.85, and then determine that he can get in the balance between $2.86 to $2.87. He will then exercise discretion, and buy the remaining contracts up to $2.87. He may also realize that there are no more offers for any significant size, and decide not to chase the market or tip your hand.
10. **All or None (AON):** This order must be filled in it's entirety or not at all. It does not have to be executed immediately, and may be worked throughout the day. However, no partial fills will be accepted. This type of order is used when you have specific price targets and quantities to work off, usually against an origination or customer order.
11. **Immediate or Cancel (IOC):** This order specifies that as much as possible should be executed immediately, and the balance should then be canceled. It is used as "quick cover" such as when an unexpected news announcement occurs, and you want o cover a position as quickly as possible and as fully as possible without having to chase the market or monitor every tick.
12. **Fill or Kill (FOK):** Combines AON and IOC. This order must be exercised immediately and in it's entirety or not at all.

SUMMARY OF ORDERS:

EXPLANATION	BUY	PRICE	SELL	EXPLANATION
		$21.00		
		$20.90		
		$20.80		
Buy Stop Limit $20.75 Day Order		$20.70	-100	All or None Day Order
Buy Stop Limit $20.75 GTC	+1,000	$20.60		
Buy Stop GTC	+350	$20.50		
		$20.40		
		$20.30		
		$20.20		
		$20.10	-5	Market Not Held Day Order
Current Market Price		**$20.00**		**Current Market Price**
		$19.90		
		$19.80	-200	Sell Stop GTC
Buy $19.75 Not Held Day Order	+50	$19.70		
		$19.60	-150	Sell Stop Limit $19.50 GTC
		$19.50	-400	Sell Stop Day Order
		$19.40		
		$19.30		
Buy Limit $19.25 Day Order		$19.20		
Buy Limit $19.05 GTC	+100	$19.10		
GTC	+ 500	$19.00		

C. Buying and Selling

A. Placing Orders:

1. Selling: Specifics in order are:
   a. Size
   b. Price
   c. Examples:
      1). "200 to go at $19.75"
      2). "Work 200 at $19.75"
      3). "Offer 200 at $19.75
      4). "Sell 200 at $19.75"

2. Buying: specifics in order are:
   a. Price
   b. Size
   c. Examples:
      1). "Pay $19.75 for 10"
      2). "$19.75 for 10"
      3). "$19.75 bid for 10"
      4). "Bid $19.75 for 10"

B. Making Markets:

1. Bidding: If you are a buyer, and you enter a bid into a market, your bid will be active only if it is the best bid. If someone else subsequently betters your bid (higher number – willing to pay a higher price), it is automatically canceled. For instance, if the current market is $22.50/$23.00, you must be $22.50 bid or better to be "in play". If you bid $20.75, you are the best bid, and therefore it is your bid in the market. If someone else betters your bid, say $22.80, then your $22.75 is automatically canceled. Do not confuse market making with market orders. Market makers are trying to scalp a few points, and are there for the primary purpose of liquidity. If someone else betters the price, the liquidity function has been improved via a tightened market, and therefore the price is not in play. Market orders are specific points where someone "off the floor" wants to transact, and the orders have a time element (GTC, Day Order, etc.) specified with them.

2. Offering: If you are a seller, and you enter an offer into a market, your offer will be active only if it is the best offer. If someone else subsequently betters your offer (lower number – willing to sell at a lower price), it is automatically canceled. For instance, if the current market is $22.50/$23.00, you must be $23.00 offered or lower to be in play. If you offer $22.75, you are the best offer, and therefore it is your offer in the market. If someone else betters your offer, say $22.70, then your $22.75 offer is automatically out. Again, do not confuse making markets with market orders. The person on the floor or OTC making markets is trying to scalp the difference between the bid/ask spread, or is trying to ascertain market direction by testing the price action. The person giving market orders has specific goals to accomplish, and specifies the price willing to sell with a time limit associated to it (GTC, Day Order, etc.).

C. Market "Taking": There are two primary ways to buy and sell. The first is market making, where you show a bid (if you are trying to buy) or an offer (if you are trying to sell). The second way is to act on someone else's price. The associated terminology for this is:

BUY	SELL
Lift	Hit
Buy	Sell
Mine	Yours
Take	Give

(hand action towards)	(hand action away)

Examples: (assume the current market is $22.50/$23.00)

1. Buying:
   a). "Take the $23's"
   b). "Mine 100"
   c). "Buy the $23's"
   d). "Lift the $23"
2. Selling:
   a). "Give you $22.50"
   b). "Yours the $22.50"
   c). "Sell you the $22.50"
   d). "Hit the $22.50"

D. Practical Examples: (Assume the current market is $22.50/$23.00)

1. Buying:

   a). Give your broker a market order. He will immediately buy the $23.00 for you.
   b). Give your broker a stop or stop limit order above the market. He will immediately execute it for you if the market gets to that price.
   c). Give your broker an order below the market (GTC or Day Order). He will execute it for you if the market gets down to that price.
   d). Be a Market Maker:

      1). Join the $22.50 bid. If no one betters the bid, you are in play. If you join someone else's bid, there is no guarantee you will get filled (the market could move higher without transacting at your price). Additionally, if you were not the first bid in at that price level, you will not be the first one to get filled. The market could trade $22.50 one time, filling the first bidder, then move higher without you. Any higher bid which comes in automatically cancels yours
      2. Better the $22.50 bid. You could come in as a market maker, bidding up to but not including the $23.00 offer (bidding the same price as the offer is the same as lifting the offer). There is still no guarantee you will get filled, as the market could have only buyers, and no sellers, and would move higher without you. And as before, any higher bid automatically invalidates your bid.

   e). Be a market "taker" by lifting/buying/taking the $23.00 offer.

2. Selling:
   a). Give your broker a market order. He will immediately sell the $22.50 for you.
   b). Give your broker a stop or stop limit order below the market. He will immediately execute it for you if the market gets to that price.
   c). Give your broker an order above the market (GTC or Day Order). He will execute it for you if the market gets up to that price.
   d). Be a Market Maker:

      1). Join the $23.00 offer. If no one betters the offer, you are in play. If you join someone else's offer, there is no guarantee you will get filled (the market could move lower without transacting at your price). Additionally, if you were not the first offer in at that price level, you will not be the first one to get filled. The market could trade $23.00 one time, filling the first seller, then move lower without you. Any lower offer which comes in automatically cancels yours.
      2. Better the $23.00 offer. You could come in as a market maker, offering down to but not including the $22.50 bid (offering the same price as the bid is the same as hitting the bid). There is still no guarantee you will get filled, as the market could have only sellers, and no buyers, and would move lower without you. And as before, any lower offer automatically invalidates your offer.

   e). Be a market "taker" by hitting/selling/giving the $22.500 bid.

And that is the true secret. Imagine this scenario – you pull two individuals off the street, and give them 100% of your own personal money to trade. On a random day, you stop by to ask how they are doing. The first individual says that the market feels bid, so he is long – the market is going against him, but he thinks it will turn so he's holding on to the position. The second person is also long, and says the reason is that he's playing a spread. He breaks out a chart, shows you where he entered the position and how. He then shows you historically where the market go under similar circumstances, points out where he expects to get out with a profit, and where he'll say that he's wrong and stop himself out. The risk/reward he's identified is 3:1.

Which trader gives you a better comfort level about your money? Both are in identical losing positions. But it is obvious that one person has done his homework, while the other one is just shooting his gun off up in the air.

And that is the whole point. If you can apply a discipline to what you are doing, show some research and homework to your decisions, and keep any losses small, you will live to fight another day. It all comes back to:

1. Does the trade make sense?
2. Do you have an edge?
3. Do you control the bad tails?

Good luck and good trading.