Increasing Oil Production in the US Will Not Lower Domestic Oil Pricing

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Some energy pundits have recently claimed that reducing regulatory constraints on domestic oil and gas drilling could lead to a boom in US energy production and lower US crude oil pricing. While such goals are admirable and could result in an improved trade balance and a stronger dollar, there is no direct connection between the amount of crude oil produced in the US and its price.

Since crude oil became an internationally traded commodity over 50 years ago, the domestic price of US oil has instead been linked to the world market price. As described on the DOE's Energy Information Administration web page, "What Drives Crude Oil Prices," (www.eia.gov/finance/markets/) world crude oil pricing is impacted by seven factors, only one of which is produced by non-OPEC nations like the US.

While some nations have driven down domestic oil pricing via huge federal price subsidies or nationalizing their oil companies, such options are unlikely to be acceptable in the US. Price controls on commodities were also tried in the '70s under Nixon and abandoned within a year as ineffective.

But let's try to imagine what would be needed to drive down world (and thus US) oil pricing through increased domestic oil production and reduced domestic consumption. First, a bit of background…

OPEC is the single largest player in the crude oil market, pumping out over 30 million of the world's 90 million barrels a day (bbl/d). The OPEC nations work together as a cartel to keep pricing within an acceptable range by raising or lowering their total production.

That pricing then sets world crude pricing, though other factors (such as speculation and security issues) may briefly impact it. By comparison, present US production is only about 5.4 million bbl/d.

To cause a significant drop in world oil prices large enough to overcome OPEC production, adjustments would require that enough US oil be produced to meet all of the following conditions:

- To begin exporting a lot of US crude to the world market, all US oil needs (presently 18.8 million bbl/d) would have to be satisfied by US wells (i.e., no more imports). While the Energy Information Agency reported that this may occur by 2035 due to increased fracking and conservation, it is not clear that the extent of fracking will continue to be maintained. Even if we do reach this goal, significant exporting levels are not implied in the report.

- The US would need to begin producing an additional oil volume that rivaled a significant portion (e.g., 20%) of OPEC's capabilities so that it could not counter that effort by adjusting its own output. OPEC can, relatively quickly, raise or lower its own production by almost 10%.

Twenty percent of OPEC's capacity would be like adding the entire present output of another US onto the nearly tripled output discussed above.

- The US would have to add sufficient pipeline and port capacity to move that vastly larger volume of crude oil to market.

- To ensure continued high volume production, the unit cost of producing US crude (which is significantly higher than in many OPEC countries) would need to be held down while maintaining the existing profit margin for domestic oil producers, lest production begin to otherwise wane. It is unclear if that is physically possible without huge subsidies.

Even if OPEC's cartel power could be overcome, any international price drop large enough to cut US domestic pricing may then result in non-OPEC nations cutting back on their production (to avoid lowering the profit margin on their oil), thus driving prices back up again.

It is therefore unlikely that increased US oil production could significantly reduce domestic oil pricing.

Don't Lose Your "Head" Over Line Loss

During the process of delivering electricity, some power is lost through wire resistance, transformers, and other physical causes. Losses may also occur due to theft of service and meter error. Such line losses occur at two levels: while transmitting power at high voltage to a utility's zonal boundary, and again when distributing it at lower voltage across a utility's territory to customer meters. Transmission losses to a zone are typically included in a retail zonal price. On the utility side of that boundary, losses are calculated as the difference between the total kWh received at the boundary (plus whatever the utility generates inside its territory), and the total received at all customer meters, expressed as a percentage. The generic term for that latter difference is Unaccounted for Energy (UFE), though many know it simply as 'line loss'. Utilities charge power suppliers for the line loss by requiring that each supplier provide that much extra power to the utility boundary based on the losses seen in the prior day (or other time period). Any after-the-fact adjustments are then made up in the following time period.

UFE is built into tariff supply rates charged by utilities and in fixed rate commodity prices from third party suppliers. Under indexed pricing, however, one's power price floats based on the hourly wholesale market price (the "index"). A supplier then adds a fixed dollar per kWh adder that may include capacity, ancillary services (provided by the grid operator), and the supplier's management fees. Line loss may then be seen as an extra line item charge, or added to the index price.

Up to mid-2009, Con Edison provided monthly line loss factors for each of its 3 zones (H, I, and J). It then began publishing zonal hourly line loss factors through its ESCo news bulletins, typically three months after the fact (find them at www.coned.com/escos/news/index.asp.) Those hourly factors, however, are initially based on standard system-wide load profiles. They are then corrected in the next day's (or month's) line loss percentage for the same hour. Such corrections may occasionally result in negative line loss.

<u>Several Ways To Charge For It</u>

Most suppliers use a fixed line loss rate for the term of a contract, but that number varies among suppliers. In recent indexed bids, some used Con Edison's standard average of 7.9%, but others offered factors as low as 5.5%. Based on discussions with the latter, they developed their loss numbers in roughly the same way they generate fixed priced bids. They calculate annually weighted averages based on a customer's monthly usage. It remains unclear why, using the same data, one offered 6.3% while another offered 5.5%.

Some ESCos use more complex methods involving floating factors that cannot be compared in advance, such as:

- Con Edison's posted average monthly line loss numbers

- Creating a rolling 12-month average weighted rate based on a customer's particular on and off-peak usages

- Con Edison's hourly line loss numbers multiplied by a customer's hourly kWh usage; this can be especially tricky because Con Edison's hourly numbers – during a given month – have ranged from +26.1% to -12.8%. How can a line loss be negative, you ask? Because each hour's loss is initially based on the standard load profile for each rate class, and then corrected in the following hour based on real data.

<u>Several Ways To Invoice For It</u>

In a supplier's bill, line loss may appear by:

- bumping up the customer's hourly kWh consumption by the line loss percentage, yielding different kWh from the supplier and that delivered by the utility

- bumping up the hourly pricing by the line loss factor; it then won't match that posted by the grid operator

- a separate line item that sums the costs into one monthly dollar number.

<u>Is One Way Better Than Another?</u>

To answer that question, both dollar impact and price risk need to be considered.

To see the difference between two fixed line loss offerings, let's assume an average floating supply rate of $0.08 per kWh wherein capacity is responsible (on average) for $0.01 per kWh of that total. That leaves $0.07 per kWh to be impacted by line loss. If supplier A charges an annual fixed 7.9% and supplier B charges 5.5%, that's a difference of about 1.7 mills (i.e., tenth of a cent) per kWh. That could be the difference between the winner and the next closest bidder, and may be more than the fee paid to the broker or consultant handling the deal. For a large customer (e.g., 35,000 MWhr per year), that number translates to $61,000 annually. (About one full-time staff salary for a typical customer.)

In an indexed bid, the supplier offering a lower fixed adder and a lower fixed line loss rate should be the winner. But if the line loss rate is not the lowest, and the fixed adder is, some number juggling is needed to see which is offering the lower total rate. But what do we do with the more sophisticated UFE calculation methods?

The weighted rolling 12-month average introduces additional price uncertainty because the line loss is now floating and can't be compared to the fixed rate offerings. How consistently a facility uses energy month-to-month may now become important, e.g., an industrial with highly variable (or seasonal) production, or those with wide year-to-year variations. Accurately forecasting a comparable annual rate may not be possible.

Trying to project the impact of an hourly varying line loss factor, however, requires taking into account a customer's hourly kWh usage (from a prior year), and may thus carry even more price risk. Because Con Edison's hourly line loss numbers flop across such wide ranges, a facility's hourly load profile – and its year-to-year consistency – become crucial to calculating this method's net impact. But there's an additional wrinkle: Con Edison's hourly line loss numbers are published 3 months after the fact. What happens in the first 3 months of a contract, before the corrected line loss numbers are available? Is it even contractually legal to use data from a time period that precedes the start date of a contract by three months? The supplier answered that. "If accepted by the client, then it's contractually OK." His contract, however, contained no description of his line loss process, and it took several emails to elicit that information.

In *Alice in Wonderland*, the Queen of Hearts' most famous line, one which she repeats often, is "Off with their heads!" We don't want you to lose your head negotiating this. For facilities seeking indexed pricing, it may make sense to simply demand that a fixed annual line loss rate be part of each bidder's offering – and an experienced and knowledgeable consultant should be used to oversee the process.

Fairy Tale: Solar PV Cuts Peak Demand Charges

Solar power from photovoltaic (PV) panels, when secured through long-term contracts, has become competitive with power supplied by utilities. Under a Power Purchase Agreement (PPA), a developer designs, installs, owns, maintains, and operates the PV system at a customer's site, and sells the power generated by the system to the customer at a competitive rate. Through such arrangements, many facilities are now securing years of lower cost and pollution-free electricity.

And the incentives to cover part of the installation cost just keep getting better. NYSERDA recently announced its NY-Sun Initiative (http://ny-sun.ny.gov/) to expand PV installations at NY customers' sites.

The initial rate that the developer charges the customer depends on a variety of factors, including the installed cost of the system; any rebates, tax incentives, or renewable energy certificates associated with the system; and the developer's required return on investment. PPA's are especially attractive to non-profit institutions who cannot otherwise take advantage of the tax incentives. The initial rate per kWh can be up to 15% lower than the utility rate, or it can be at or even slightly higher than the utility rate. In the latter case, the system can still be economically beneficial to the customer if the annual PV rate escalation is less than the projected utility rate escalation over the 15 to 20 year term of the PPA.

But care is needed before signing on to a flat electric rate for PV power, especially over a contract that may run 15 to 20 years. While a flat price may be fine for a residential customer whose utility rate is based solely on his kWh consumption, many commercial rates include a separate charge for monthly peak kilowatt demand (kW). In such cases, a flat PV rate may assume that both kWh and kW will be saved proportionately, but some analysts have challenged that assumption.

A typical flat panel PV system orients the units to maximize kWh production. With such fixed positioning, output varies as the sun moves across the horizon, being greatest when the sun's rays are perpendicular to a panel at noon. But earlier or later in the day, output drops off sharply as those rays strike the panel at shallower angles. To reduce a building's peak demand by the kW capacity of the panel, the building's load would therefore need to peak close to noon. If the load peaked much earlier or later in the day, the PV impact on peak kW could be marginal, or even zero.

In such cases, the dollar value of the PV power may be closer to the marginal daytime kWh price – without peak demand – rather than the overall average kWh rate, which has the full cost of monthly demand built into it.

How a customer's tariff defines peak demand may also impact demand savings. Many tariffs calculate a customer's monthly peak demand based on the highest peak seen during a specified weekday period (e.g., 8 am to 6 pm) even when demand may be significantly lower the rest of the month. Under such tariffs, even if a building's load peaked at noon, a month's potential demand savings may be reduced if – only once in that billing period – the sky at that time is heavily overcast or if it's raining, either of which may noticeably reduce hourly PV output.

To properly determine the value of a flat PV electric rate thus depends on understanding a building's load profile and its electric tariff.

In a recent analysis of an industrial facility considering installation of a large PV system, hourly interval data was used to diagram how that system would affect its load profile. We tracked demand usage versus power generation from the PV. We noted peak demands occurred in the morning between 8 AM and 10 AM. The load drops slightly in the middle of the day and afternoon. We simulated the impact of the PV. The results showed that midday loads would have been suppressed by the PV system's output but the morning peak demands, while shortened, were essentially unchanged in magnitude. All days were assumed to be bright and sunny, with none overcast or raining.

In this case, the PV system would have generated millions of kWh savings, but its peak demand charges would have remained the same. The PV developer wanted to charge a flat $0.15/kWh (plus an annual escalation) for his electricity for 20 years. That $0.15 was promoted as a 12% discount off the customer's present $0.17/kWh average utility rate – which included peak demand charges. When that rate was calculated without any demand charges, it averaged about $0.10/kWh. In light of that difference, the developer was asked to revise his proposal, but refused to do so.

Another study found similar results with other types of buildings, due mainly to the non-coincidence of PV output and time of peak demand. Sampled apartment buildings, for example, peaked most often after 5:30 pm, when PV output was quite low. In all cases, electric bills would have shown significant reductions in kWh but, to a lesser degree, reductions in actual cost.

To avoid surprises, those considering large PV installations should have a competent consultant review their annual hourly load profile and their utility tariff before signing a long-term contract. Don't accept the step sisters' claims of fitting into Snow White's shoes without making her try them on.

Fairy Tale: All LED Lights May Be Dimmed

The advent of light emitting diode (LED) lamps and fixtures for area and spot lighting has created both opportunities and pitfalls. Dimming, in particular, has presented some new challenges.

Many LED product vendors have labeled their units as "dimmable" using standard incandescent dimmers. If the dimming level is relatively minor (e.g., 20%), that may indeed occur successfully. Dimming for energy savings during off-hours, cleaning, or daylighting may, however, involve reductions of 50% to 70%, while architectural dimming for presentations or events may require dimming by 95%. In such cases, dimmed LEDs have demonstrated unacceptable flickering or fluttering.

Unlike incandescent lamps, which have filaments that continue to glow briefly after power is shut off, LEDs fully extinguish very quickly once power to them ceases. Many incandescent dimmers (called "triacs") chop out parts of the normal alternating sinusoidal current flow (called "phase cutting"). Those interruptions are close enough together in time so that an incandescent filament continues to glow between them, thus avoiding flicker. When an LED lamp experiences those chopped waves, however, it may rapidly flicker.

For some people, that may be simply irritating. For those few with a particular vision disorder, it may induce headaches, fatigue, and possibly convulsions. (Just as Little Red Riding Hood was unable to see that the wolf was not her grandmother.)

In some cases, an LED unit may simply not dim at all. It may just go off, even at a high dimmer setting. In others, LEDs may experience non-linear dimming: a visible reduction in output requires a large adjustment of the dimmer, only to be followed by a big drop in output when the dimmer is turned down a bit further.

To avoid such situations, facility personnel often test sample screw-in LED lamps with existing dimmers across their full range. But note this important point: screwing in only one LED lamp, while the rest remain incandescent, or installing only one LED even when the remaining sockets are empty, may yield falsely acceptable results. Due to the impact that some inexpensive LED units may have on the power wave shape even when not dimmed, a proper test requires relamping <u>all</u> sockets controlled on a dimmer circuit with the same type and brand of LEDs. If no flickering occurs, no mixing of brand or type on the same circuit should be allowed thereafter.

Because LED vendors are unlikely to loan their products, such a test may require buying a batch of non-returnable units, only to find that they all flicker on an existing dimmer. To help clarify the situation, the lighting controls industry has developed tables of what types of dimmers being sold today are compatible with various LED products. To deal with incompatibilities, new standards for LED dimming are being developed.

For many applications, it may make more sense to instead replace an existing dimmer with a new unit designed to work with LEDs. Several manufacturers now offer "universal" dimmers designed to work with any lamp labeled "dimmable" (including compact fluorescents).

But be ready for sticker shock. While an incandescent dimmer can be purchased for $15, a fully compatible "universal" dimmer may cost several times that price. Note also that some new dimmers may require a neutral wire at the switch box which may not be present in some older or residential buildings.

Further information is available at the web site of the Lighting Controls Association at http://lightingcontrolsassociation.org/lca/topics/led-dimming/

On A Personal Note...

Frequently when our firm is with clients or talking to colleagues in the industry, we hear "tall tales." Many go to great lengths to sell energy projects or commodity services and frequently a few details are misstated, omitted, or presented in misleading fashion. This issue of *LA Confidential* is a series of cautionary Fairy Tales that we hope will educate you when you pursue your next energy or efficiency purchase.

What would have happened if Prince Charming just accepted the claims of Cinderella's stepsisters without insisting on a shoe fitting? This parable reminds us of the importance of vetting all claims about how much "our new technology," will save. Is it possible that a flickering LED was the reason that Little Red Riding Hood could not recognize that the wolf had donned her grandmothers' bed clothes? Do you really want to take the Queen of Hearts advice and "lose your head," trying to understand obscure details of line losses that can be better managed by an expert? At Luthin Associates, we tend to say, "Show me the money." Or at least the evidence that it makes sense.

My cautionary tale was in 2011 when Hurricane Irene hit our recently purchased building that the firm was renovating as our new home. We ended up with two feet of water in our basement and our relatively new HVAC systems needed to be replaced. Since we are about a half-mile away from the beach, we knew we needed to plan for the future. Caution meant investing in a 20kW natural gas fired Generac standby generator. In the aftermath of Sandy, our building suffered only minor damage, but we lost power for 12 days. The generator performed flawlessly the entire time. Other cautionary solutions involved putting some of our servers in the "cloud." Our physical servers were installed on the second floor, way above the potential for storm damage. It seems we received good advice from our suppliers. We were also lucky that neither phone nor cable service was affected.

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Thanks to Jim Farrell of All Seasons Service Inc, and the Generac generator he installed, we were able to be fully operational for 12 days while no electricity was available in our area.

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