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Price risk management in power supply: physical vs. financial considerations

In our November 2019 discussion of the role of risk management in financing new power generation, we highlighted the changes taking place in market structure and the need for developers to enter into contracts that guarantee a portion of their revenues against volatile power prices. The brief survey covered physical contracts (PPAs) as well as less commonly-used derivatives such as revenue puts.

We now seek to look more closely at different types of fixed-price contracts utilized across energy markets, including oil and gas; to understand their role in helping companies manage their exposure to energy prices; and to highlight features that are unique to physical or financial structures.

We highlight a clear distinction along industry lines between the use of financial derivatives and fixed-price physical contracts. While oil and gas markets tend to manage their exposure overwhelmingly via financial contracts, the power market is firmly rooted in fixed-price physical agreements. And although the power market has developed various types of contracts to reduce exposure to spot prices there is still a clear preference for physically-settled ones. We explain why this difference exists between energy markets and why it will remain a distinguishing factor going forward.

We also address the limitations that physical contracts place on the potential to broaden the power market's attractiveness to non-commercials, and the importance of expanding the base of market participants beyond what currently exists. Ultimately, the power market's focus on physical contracts could be a limiting factor in the growth of new generation capacity, though perhaps not for a while.

Energy price risk and various approaches to managing it

It helps our understanding of price risk management in the power industry to understand standard practices in other energy markets. In oil and gas exploration and production (E&P) as well as in refining and liquids processing, the overwhelming majority of physical contracts between sellers and buyers is on a published index (i.e. floating) price. These various commercial enterprises are, by default, subject to commodity price risk, and how they handle that risk differs greatly among them.

Many E&P companies do not hedge at all, and prefer to maintain exposure to fluctuating prices. Managements who do not own their companies will often characterize their shareholders as wanting exposure to the commodity price. On the other hand, those that hedge their price exposure tend to be either relatively leveraged or may choose to hedge when they are acquiring a particular asset in order to more clearly guarantee the economics of that investment.

Similarly, most oil refiners and petrochemical companies tend not to hedge their feedstock or production. Managements typically say the same thing as E&P companies about their shareholders: they want the exposure to commodity prices. Nevertheless, in many cases, often involving leverage or tax structure (e.g. MLP), there is a preference to lock in their costs or revenues and, in some cases, both via a hedge on their gross margin.

Lastly, in the downstream portions of the oil, gas, and liquids markets, there tends to be the least interest in hedging commodity prices. This is because the downstream participants are typically acting in a cost-plus role, whether explicitly or implicitly. This somewhat-guaranteed margin is very typical of the petrochemical industry. Elsewhere, in fuels or natural gas distribution, it can be less formulaic but nevertheless allows participants to manage their exposure to their gross margins without having to enter into financial derivatives or any other fixed-price contracts. Still, as in the upstream and processing industries, there are exceptions in which some companies seek to reduce the volatility of their resale and distribution margins and thus to lock in a portion of their costs, revenues, or both.

The role of financial derivatives in energy markets

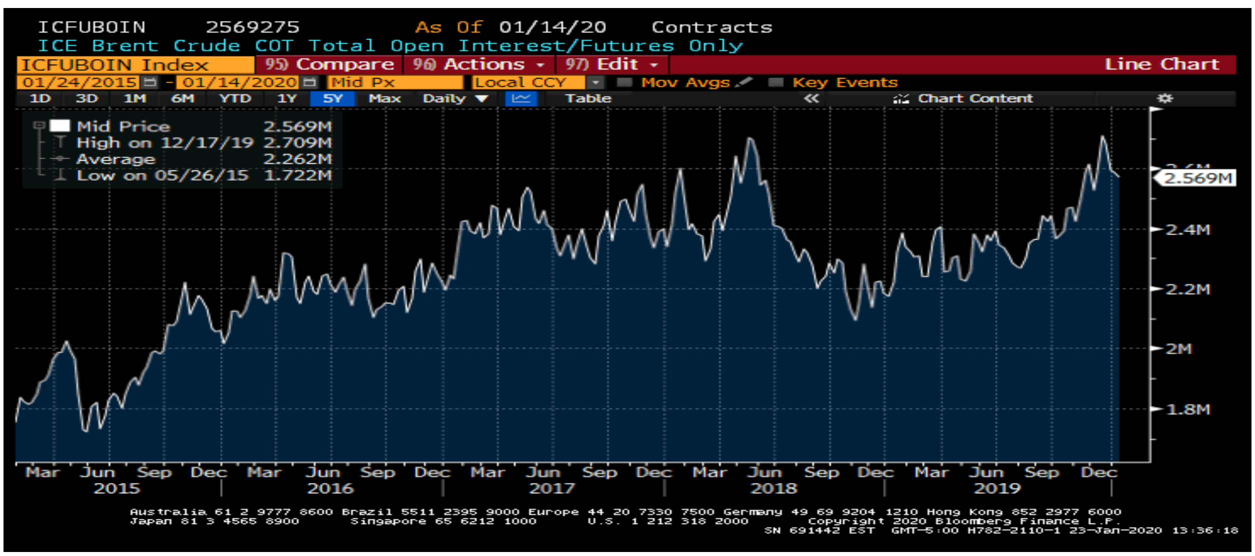
Among those corporations and governments that do manage their exposure to oil, gas and fuel prices, the vast majority utilize financial derivatives markets. Such instruments include futures, swaps, and options cleared by regulated exchanges, as well as a host of bilateral trades they can execute with direct trading counterparties. These markets are generally sufficiently liquid to absorb enterprises' commodity risk at minimal transaction cost, especially in the broadest benchmark indexes.

Financial derivatives are typically settled in cash, based on the eventual outcome of prices relative to those that prevailed at the time of the trade. Since there is no exchange of physical product, there is no need to schedule shipments on vessels or batches on pipelines; no need to worry about delivery times and inventory space. All of that physical activity takes place in the background at floating-market prices. The financial hedges have the offsetting effect of price volatility and, taken together with all of the physical transactions, smooth out the enterprise's revenues, costs, or gross margins.

Importantly, financial derivatives markets for oil, gas, and fuels benefit from the presence of risk-absorbing financial traders that want to participate and trade with commercial risk managers who are seeking to shed that risk. These traders provide liquidity that makes it relatively easy for risk managers to line up quotes on any given structure (tenor, location, etc.) and find a willing counterparty to provide the hedge. That counterparty may do so bilaterally, via direct trading relationship, or via an exchange.

Traders have been active for a long time in the benchmark oil and gas indexes (e.g. Brent futures in chart below). But they have gotten more active on local indexes, or grades, in recent years. Hundreds of new contracts have been listed for clearing on exchanges corresponding to various locations where commercial risk managers are seeking to hedge their exposures. This interest in trading various locations has made it increasingly easy for the risk manager to receive quotes and to trade their hedges in a competitive and transparent environment.

The competition and transparency of the financial derivatives markets is superior to what enterprises would find if they were to seek similar fixed-price structures in their physical supply agreements. There are considerably more counterparties to choose from in the derivatives markets than there are in any given physical market. The enterprise may still retain basis risk between their physical exposure and financial hedge – a topic we discuss in greater detail below – but in general the efficiency of the financial markets makes them the most attractive venue for managing price risk in oil, gas, and fuels.



Source: Bloomberg

Financial derivatives not as well developed in power

Power markets are different from other energy markets. Firstly, they are subject to a unique market structure that effectively guarantees returns to the distribution network (utilities). And given the stabilizing force that such a market structure imposes on retail prices, there is less demand from the consumer to hedge forward purchases. There is some price volatility, to be sure, but the vast majority of the volatility is at the wholesale level where buyers may have other means to deal with it.

Where hedges do exist in power markets, they tend to be overwhelmingly incorporated into physical supply contracts. Much has been written – including our November report – about the increasing use of Power Purchase Agreement (PPAs) over the past several years. These contracts grant developers of new power generation a fixed price on which they can base their revenue estimates and thus finance their construction with the most attractive credit terms.

Banks had been active in providing financial hedges to power generators and developers who needed price certainty in order to qualify for loans, much as they do for E&P companies borrowing for capital projects in oil and gas development. But the incidence of financial hedging in the power markets has declined in recent years and has been replaced by physical supply agreements such as PPAs. There have been some exceptions, notably in options (e.g. heat rate calls and revenue puts) but, for the most part, those hedge programs tend to be less ubiquitous than PPAs. The tables below list participants in PPAs, none of which have reported financial hedges in public filings (although in the case of non-public companies it is impossible to tell). Please see note at end regarding data availability.

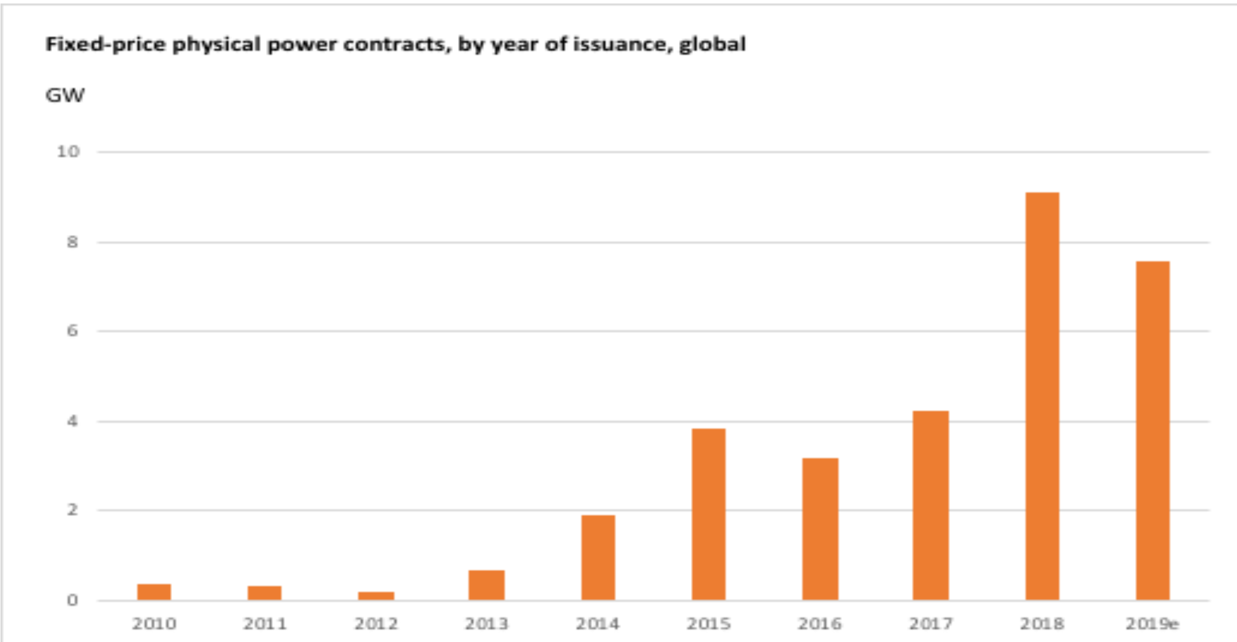
Meanwhile, more consumers – especially at the wholesale level – are seeking to expand their sources of power supply to include renewable generators and others with a smaller carbon liability than traditional coal and natural gas generators. In so doing, they are willing to enter into direct, physically-settled agreements with their suppliers, even though the power they take may be generated by completely different sources than the power provided by their vendors.

Food and Beverage PPA buyers		
Anheuser-Busch InBev	Hormel Foods	Royal Wine Corp
Campbell Soup	JM Smucker	Smithfield Foods
Coca Cola	Lagunitas Brewing	Snyder's-Lance
Dietz & Watson	Mars, Inc.	Turkey Hill
Frito-Lay	National Raisin / Sunshine	United Natural Foods
General Mills	Nestle	US Foods
Hawaii Food Proc.	Poindexter Nut Co.	Wampler Foods
Source: Bloomberg		

Technology PPA buyers		
Adobe	Apple	HP
Agilent	AT&T	Intel
Akamai	Bloomberg	Intuit
Alphabet / Google	Cisco	Microsoft
Amazon	Facebook	Yahoo!
Source: Bloomberg		

The prices that consumers pay – and those received by their suppliers – are highly negotiated and subject to the same limitations on competition as similar fixed-price physical transactions in other energy markets. But unlike oil, gas, and fuels markets, the power market doesn't have a deeper and more liquid financially-settled alternative. The futures markets for power exist, but they are not as attractive to banks and other traders as platforms for proprietary trading and market making. As such, they do not have a similar degree of participation as oil and gas futures markets.

Those enterprises seeking to manage their exposure to power prices thus have less incentive to consider financial hedges. They tend to stick to the PPA model, further solidifying its outsized role in the market. Indeed, public data show that the frequency and size of utility and commercial PPAs far outstrip both measures of financial swaps and options. And while this has been the case throughout the past decade, the difference seems to be growing. Physical PPAs continue to grow in size and frequency (chart below) while the use of financial contracts remains comparatively static.



Source: Bloomberg

Local pricing vs. benchmarks and the basis risk between them

Any discussion comparing hedging methodologies across energy markets must address basis risk, which arises whenever a hedge is placed on an index that is not the same as the underlying exposure. Basis risk can be small, as when regional prices move together on similar frequency. Prices may not move perfectly in unison, but there are plenty of examples where price movements are highly correlated and, thus, basis risk is minimized. These situations tend to occur when there are low hurdles to moving the energy product – whether oil, gas, or power – across various geographical regions.

Where there is fluid and easy transportation, price differences should only reflect the cost of transportation. The cost of transportation, in turn, tends to be relatively constant under such conditions and may indeed be fixed for a period of time. Pipeline tariffs for oil liquids, for example, may hold for months or years without adjustment if they are not fully utilized, allowing regions that are long product to export with consistent flow to regions that are short.

Waterborne markets – those involving tankers moving among various ports – typically move in fairly close unison because freight charges can be relatively constant and, aside from weather or other short-term factors, ports can handle uneven flows by utilizing their storage capacity. Nevertheless, tanker rates do fluctuate based on supply and demand for vessels, and can sometimes move significantly – raising the volatility of price differentials between ports.

Typically, basis risk is greater when there are higher hurdles to moving the energy product from one location to another. This is more evident in the natural gas market, which is dependent on pipelines to transport the vast majority of supply to demand centers. Pipelines in most regions have sufficient excess capacity to handle spikes in supply and demand but can suddenly become bottlenecked due to a pipeline outage (e.g. maintenance) or a weather event that raises demand significantly versus normal.

There is perhaps no better example of the volatility of basis risk than in the power market, where transmission is fixed by existing infrastructure and supply and demand can fluctuate from one region to the next. During extreme weather conditions, transmission can easily become bottlenecked, causing a surplus in one region and a deficit in another. This may only occur for a few hours or less, but the price impact can be quite significant and affect longer-term price relationships given the magnitude.

Warehousing basis risk

If basis risk is more significant in power markets than in other energy markets, should it matter to risk managers' decision whether to manage price exposure using financially-settled or physically-settled transactions? The answer comes back to the issue of overall participant activity and relative liquidity in financial and physical fixed-price markets.

All enterprises and their risk managers are subject to exposures at certain locations where they buy or sell their energy. In the cases of those exposed to oil and gas prices, there is typically a choice to make about whether to hedge in the most specific location (closest to their production or plant) or whether to hedge in a more benchmark (broader regional) index. The latter tends to be considerably more liquid and, thus, cheaper to hedge. The cost of opting for the cheaper alternative is the basis risk between that benchmark and the actual exposure.

But as we've discussed above, in most oil and gas markets the basis risk is small and the cost savings from hedging in a benchmark index more than compensates for the risk of warehousing the basis risk. One way to think about it: benchmark indexes are liquid, with small transaction costs, because there is always a large number of buyers *and* sellers in the market. On the other hand, specific locations tend to have lower liquidity because not only are there fewer participants but those participants tend to be predominantly buyers or sellers, depending on whether the location is a demand or supply center.

Anyone seeking to buy a derivative on an index which is characterized by a predominance of buyers is likely to find very high long-term prices, above spot prices, to compensate the sellers for the risk they take. That price will often reflect the worst-case scenario in terms of relative price moves in that index versus the benchmark. For most risk managers, such a price is too high to justify and they choose to hedge in the more liquid benchmark and take their chances on the basis. Their hedge in the benchmark index probably covers the vast majority of the price risk, so they can justify their decision in the broader context of being hedged on a macro level.

For power, however, the concept of hedging via a broad benchmark index has considerably less merit than it does in oil and gas markets. At the outset, macro hedges don't come cheaply. The cost of hedging a few years forward, *even at the benchmark level,* is higher than in oil and gas markets. And, with basis volatility being considerably greater, the cost of hedging in a local index can be punitive.

Nevertheless, most participants are willing to pay such a price to avoid the risk of experiencing an even more disruptive spike in local prices. And the best way for risk managers to deal with illiquidity is to find others in the market with complementary exposures. Those with such exposures are, by definition, consumers or generators of physical power.

Simplicity vs. risk and efficiency

The power industry's relative dependence on fixed-price physical supply agreements has its merits. Such an agreement is a one-stage process that does not require setting up a secondary apparatus to transact financial derivatives with various counterparties. That apparatus can involve significant cost related to human capital and systems support.

In addition, fixed-price physical transactions typically allow both buyer and seller to incorporate local pricing considerations into the contract (i.e. little or no basis risk). As discussed above, this certainty is most valuable in those regions with constrained power transmission capacity.

Lastly, physical agreements most often do not require marking the entire contract to market, even if their tenor extends several years into the future. Under such long-term agreements, marking to market could have very significant implications for any given period's financial performance. Not having to consider the changing values of long-term fixed prices allows enterprises to record only those changes in prices taking place during a given reporting period (e.g. quarter).

There are, nevertheless, risks to fixed-price physical agreements that need to be considered, among which a significant one is credit exposure. Each side of the transaction needs to be confident that the other side will perform on its obligations. When several years of supply are fixed at a given price, any fluctuation in the value of the commodity means that one side is advantaged versus the other. For example, if prices rise it is the buyer that needs to be sure the seller will continue to transact at the original – lower – price. The buyer has credit risk that rises and falls with prices.

On the other hand, if each side agrees to floating prices, then there is considerably less worry about either participant's fulfillment of the physical contract. If either party cannot uphold it's expected purchase or sale, then the other side simply can turn to alternative companies and transact with them. This is key to explaining the prevalence of floating-price physical transactions that are the default structure for most energy markets. All participants are free to exercise their most leveraged position as they negotiate terms of the physical supply agreement. They can then hedge their price exposure with financial derivatives that may involve limited credit risk via margining agreements.

Moreover, choosing to keep a physical sale on floating-price terms and hedging price exposure via financial derivatives benefits from a more competitive process, at lower transaction costs. Physical transactions are negotiated between on highly specialized terms involving volumes, scheduling and delivery locations. Those terms can be simplified if the pricing is based on a recognizable index, plus or minus a constant term, and a substantial portion of vendors may only transact on such terms. By introducing a fixed price, competition can suffer.

But, as discussed earlier, such concerns tend to be limited to oil, gas, and fuels markets. The power market has demonstrated a willingness to absorb credit risk and to accept the inefficiencies inherent in fixed-price physical transactions. Moreover, since commercial participants do not benefit from highly liquid financial futures market alternatives, they aren't as tempted to embrace the risk-management practices of other energy markets.

Liquidity for the future

PPAs and other fixed-price physical agreements have facilitated a crop of developers to move ahead with utility-scale projects that have been growing steadily and, indeed, accelerating. One could argue that commercial buyers of power have stepped up sufficiently to allow such rapid development to date. But there is a limit on the amount of forward buying to which consumers are willing to commit. As with other energy markets, the need for hedging is greater on the supply side. This extends from E&P companies in the oil and gas markets to developers and generators in the power market.

Fortunately for oil and gas producers, they can count on speculators and other traders to take the other side of a significant portion of their forward selling. Those traders may need especially large risk premia, in the form of comparatively lower forward prices relative to spot prices, in order to participate more meaningfully. But they will participate at various price points and there are plenty of data attesting to the significance of their role in the overall market.

Electric power producers do not benefit from the same level of speculative trader interest in their markets. And with fewer buyers of long-dated power contracts, the markets are shifting away from their traditional contango (upward sloping) shape, toward a flat shape or even backwardation (downward sloping). This shift should encourage more buyers of those long-dated contracts, but participants are limited in their number and buying power.

The power markets need additional liquidity that comes from more vigorous participation by speculative traders. This will become increasingly important as developers sell ever-greater quantities of forward power into the market. Commercial buyers will only be able to commit to so much of that volume. The rest will have to come from non-commercial interests.

A note on data available on corporate risk management programs

Data on commercial use of fixed-price power contracts are available from two main sources: Financial disclosures filed by public corporations to the U.S. Securities and Exchange Commission (SEC), and operational filings by utilities and commercial firms to the U.S. Federal Energy Regulatory Commission (FERC). In general, the SEC's financial filings tend to reflect financially-settled transactions and the operational filings tend to disclose physically-settled deals. There is a bit of overlap, especially in the financial reports as *any* fixed-price agreements tend to be reported with public companies' financial disclosures regardless of how the long-term agreements are settled.

As for non-public (private) and foreign companies, physically-settled fixed-price contracts may be reported to FERC. But there is typically no disclosure of financially-settled transactions, except where those companies have issued public debt. As a result, there are significant limitations on the availability of financial data and on the ability for analysts to cross-check among sources.