Price Spikes in ERCOT – Who Pays?

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Price Spikes in the Texas Wholesale and Retail Electricity Markets

Whenever prices spike in the Texas electricity market it is inevitable that people will ask, “who paid these high prices?”, and symmetrically, “who made all the money from the high prices?”

These are both very fair questions but unfortunately the answers commonly provided are often either wholly or partially incorrect. Accordingly, this short presentation has two objectives:

1. Identify the relevant price(s) in the Texas electricity market(s)
2. Show who receives, and who pays, these price(s).

This reaction/concern is necessarily more pronounced in Texas than in any other State for two primary reasons:

1. The price cap in the Texas wholesale electricity market is the highest of any electricity market operated in the United States. As a result, high electricity prices have a more significant consequence in Texas than in any other State
2. The wholesale price of electricity – past and present – is the basis/foundation for all future Retail electricity prices.

The Electricity Reliability Council of Texas (ERCOT) operates the wholesale electricity market according to rules approved and overseen by the Public Utility Commission of Texas (PUCT).

This is why it is more important in ERCOT to get the prices “right” than it is in any other electricity market in the US.

The equilibrium market price reflects the balance of expectations between buyers and sellers about anticipated and unanticipated price spikes.

If expectations prove to be wrong, prices in the future will change.

The correct answers are: (1) Retail Electricity Providers (REPs) pay in the short run, but (2) ultimately end-use customers pay a multiple of these high prices, and (3) the ”generators” will be the recipient of the high prices.

Price Spikes in the Texas Wholesale and Retail Electricity Markets

ERCOT is responsible for providing non-discriminatory open access to the transmission system while ensuring the grid is reliable for approximately 90% of Texas. To do this ERCOT runs an algorithm called *Security Constrained Economic Dispatch*, or SCED, every 5 minutes to ensure electricity supply and demand are balanced at the lowest possible cost while maintaining reliability. SCED is the platform from which ERCOT dispatches generation, and it is, accordingly, the platform for the Texas wholesale electricity market. To maintain reliability, ERCOT must coordinate all the electricity generated in its footprint. As a result, every MW produced within the ERCOT footprint is subject to dispatch by ERCOT.

There are two primary outputs from every SCED run:

1. Generation Set Points – the amount of electricity ERCOT wants each generator to produce, and
2. The Locational Marginal Price or LMP, which is the spot price of electricity, at roughly 15,000 points (nodes) across Texas.

The Texas wholesale electricity market is a centralized market operated by ERCOT and has a single market clearing price at each of more than 15,000 locations. In contrast, the Texas retail electricity market is a de-centralized bilateral contract market between Retail Electricity Providers (REPs) and end-use customers.

REPs offer bilateral contracts by location for the purchase of electricity by end-use customers. For a given customer class in the same location, the contract price will be the same. Each individual retail electricity contract price is based on the risk adjusted expectation of LMP over the time frame of the contract for a given location.

There are two primary markets for electricity in Texas: (1) the wholesale electricity market, and (2) the retail electricity market

- The wholesale market is a centralized organized market operated by ERCOT that produces a single price every 5-minutes at over 15,000 locations in Texas based on actual supply and demand conditions
- The retail electricity market is a de-centralized bilateral contract market. The contract prices are based on the risk adjusted expected actual supply and demand conditions at the contract locations, i.e., the expected LMP, over the duration of the contract.

Scenario 1 (Base Case) – All Electricity is Bought/Sold in the Spot Market

To make things a bit simpler (without affecting the conclusions), assume (1) there are no transmission losses, and (2) there is no congestion anywhere on the transmission system. Given these two assumptions, the amount of electricity produced by the generator(s), Q_G, will be the same as the amount of electricity consumed by the customer(s) of the Retail Electricity Providers (REPs), Q_R, i.e., $Q_G = Q_R$. Similarly, the LMPs, i.e., the price(s), at the generator(s) node(s), P_G, will be the same as the price(s) at the node(s) where the REPs customers receive power, P_R, i.e., $P_G = P_R$.

The Wholesale Market

Base Case: The generator sells all the power required into the spot market and receives the LMP (the spot price) for every MWh produced. The REPs purchase all the electricity they need from the spot market and pay the appropriate LMPs (the spot price) at the appropriate location.

As a result of the assumptions, the generator receives $(P_G * Q_G)$, which exactly equals what the REP paid $(P_R * Q_R)$.

If the LMP = $100 MW (= $0.10/kWh) and the quantity produced and consumed = 1000 MWh. Then the generator gets paid $100,000 ($100 * 1,000 = $100,000) – exactly what the REP pays for the electricity.

The Retail Market

Most end-use customers do not pay LMPs – they pay the bilateral contract price.

In the short run, the REPs pay the LMP for electricity delivered to the end use customers and receive the contract price from the consumers.

If the retail price > $0.10 kWh, then the REP made a profit. If the retail price < $0.10 kWh, then the REP had a loss.

Scenario 2 - Avoiding (?) Price Spikes in the Texas Wholesale Electricity Market With Forward Contracts

In Scenario 1, neither the generator or the REP entered into bilateral forward contracts for electricity i.e., a forward contract for the sale and purchase of physical electricity. Both a Power Purchase Agreement (PPA) and the ERCOT-operated Day Ahead market are examples of a forward contract. A forward contract accomplish five things. It defines the: (1) quantity of electricity that will be transacted, (2) price of that electricity, (3) the delivery point(s) where the transfer will occur, (4) interval of the transaction, e.g., peak, off peak, around-the-clock, etc., and (5) duration of the contract. A forward contract provides a means whereby generators and REPs can manage volume risk, i.e., knowing how much physical energy they will need to produce or use, and price risk, i.e., the risk that prices are higher/lower than expected.

Assume expected load is 1000 MW for the given interval and further assume there is a single Generator, Gen_a, and a single Retail Electricity Provider, REP_a, who enter into a bilateral forward contract for 500 MW at a price of $75 per MW.

In real time load is 1000 MWh. As a result of the bilateral contract, Gen_a is "on the hook" to provide 500 MWh. Because there is an ERCOT-operated spot market Gen_a has essentially three choices: (1) schedule and produce 500 MWh, (2) purchase 500 MWh from the spot market, or (3) buy from somebody else to fulfill the contract. It makes no difference to REP_a what choice Gen_a makes regarding the 500 MWh – they will pay the contract price for those MWh.

Regardless of what choice Gen_a makes, REP_a will pay the contract price ($75/MWh) for 500 MWh and will then purchase the remaining 500 MWh they need to serve their load from the spot market and will pay the LMP. And the generator(s) will receive the LMP for the 500 MWh not under contract.

If the LMP > $75, (the contract price) then REP_a saved money and Gen_a lost money on the contracted 500 MW.

On average. the bilateral forward contract price should equal the expected risk adjusted LMP. including anticipated and unanticipated price spikes, over the duration of the contract.

Scenario 3 - Avoiding (?) Price Spikes in the Texas Wholesale Electricity Market With Futures Contracts

In Scenario 2, the generator and the REP entered into a bilateral forward (physical) contract for 500 MW. An alternative risk management "tool" for managing just price risk is to purchase/sell futures contracts on a centralized organized futures exchange such as the Intercontinental Exchange (ICE), the Nodal Exchange, or the Chicago Mercantile Exchange (CME). Exchange traded futures contracts (1) have a defined quantity, e.g., a block of 50 MWs, (2) have a defined location, e.g., ERCOT-North, (3) are for a defined interval, i.e., peak, off-peak, around-the-clock, and (4) are over a defined time period, i.e., daily, weekly, monthly, etc. The contracts will settle against the relevant LMPs. Thus, the settlement price of a futures contract for the ERCOT North Hub is the arithmetic average of the appropriate actual LMPs.

A futures contract is a financial contract offered and traded on a centralized organized exchange that serves to manage price risk, i.e., the risk of a change in the settlement LMP caused by a change in circumstances or new information that was unavailable at the start of the contract time period. A given futures contract can be exchanged, i.e., traded, many times before it goes to settlement and each time it trades the market will determine the price for that contract. Unlike a forward contract, there is no requirement for physical delivery.

Since a futures contract settles against the *actual* LMP for the appropriate time period at the defined location, the contract will trade prior to settlement, at prices the market *expects* will be the appropriate risk adjusted actual LMP at settlement. As with all the scenarios, end use customers pay the relevant bilateral contract price.

As with forward contracts, price spikes should, in a well functioning market, be reflected in the existing price.

Unlike a forward contract – which serves to directly reduce the exposure of a buyer or seller to the relevant LMP – a futures contracts reduces the financial effect of price spikes – both positive and negative – by providing the contract holder at settlement with a profit or loss on each contract. The profit/loss is zero sum across the buyers and sellers transacting through the exchange.

An Actual Recent Example – Putting It All Together

Every market is, in actual practice, a system of interconnected and interdependent "pieces of a puzzle". The weekend of August 26/27, 2023 provides a good example of how the pieces of the Texas Electricity Market fit together.

Beginning with the futures market – the price of the 50 MW futures contract for Saturday and Sunday traded at $75 per MW for weeks.. In other words, the market participants – both buyers and sellers – had, for weeks, reached a conclusion that the average of the actual LMPs for Saturday and Sunday would average $75 over the 2 24-hour time blocks

On Monday, August 21, 2023, five days from the weekend. The price of the contract suddenly exploded, moving from $75 per MW to a range of $550 to $850! That is, the market suddenly came to believe that the actual average LMPs for the two 24-hour time blocks for the coming weekend would be as much as $850 per MW. The rising expectations did not end on Monday as the futures price rose to as much as $1,300 per MW by the end of the week. A 50 MW contract that had been valued at $180,000 (50 MW for 48 hours at $75) on Sunday, August 20, 2023, was by the end of the week worth $3,120,000!

What caused this meteoric rise in the expected value of the LMPs for both Saturday and Sunday? Three things: (1) the possibility of a shortage of generation over the weekend, (2) uncertainty about ERCOT operations since the implementation of "ECRS" (ERCOT Contingency Reserve Service) in early June, and (3) announcements from ERCOT calling for conservation – all of which led the market to believe the expected situation for the weekend was very bad.

So, what happened? There was no shortage on either Saturday or Sunday. Accordingly, the average LMPs for Saturday and Sunday were $486.66 and $155.32 respectively.

A REP who had no hedge would have paid ($486.66 *50 MWh *24 hours) + ($155.32*50 MWh*24 hours) = $770,336 for every block of 50 MWh. In contrast, a REP who acted prudently and hedged their exposure to the expected high prices for the weekend spent $3,120,000 and lost $2,349,664 on every 50 MWh purchased. A loss they will have to recover from their customers over time.

But That Isn't the End of the Story!

We know that REPs will have to raise the price of retail price of electricity in the future in order to recover their losses on the futures contracts they (prudently) purchased to avoid the expected price increases for the weekend.

But that is not the end of the story. Because ERCOT unnecessarily withheld capacity from being dispatched in real time, the actual prices on Saturday and Sunday ($486.66 and $155.32 respectively) were far higher than they would have been if ERCOT had not withheld the capacity.

These artificially manufactured higher prices will result in all REPs raising future electricity prices to end use customers. Not only will end use customers pay for the losses incurred on the futures contracts, but they will also pay a risk adjusted multiple of the higher prices caused by ERCOT from artificially withholding capacity for SCED to dispatch in real time.

ERCOT's long-standing and militant refusal to embrace running the Texas Electricity Market, does not mean their decisions and actions do not have consequences for the market. We have shown that ERCOT's actions regarding the weekend of August 26th and 27th will end up costing Texas end-use customers potentially billions of dollars…and for what? What exactly did end-use customer receive in return?

Observations and Conclusions

Conclusions

The three scenarios provide the answers to the initial questions:

- Who pays when electricity prices spike in Texas?
- Who receives the payment for a price spike?

Who pays?

- In the short run, any Retail Electric Provider that does not have forward contracts to cover their entire demand and must purchase power in the ERCOT-operated spot market will pay the high prices.
- In the long-run, end use electricity customers will pay for the price spike and the increased risk in the form of higher electricity prices offered by REPs.

Who receives the revenue from the price spike?

- In the short run, any "generator" that was producing electricity during the interval of the price spike
- In the long-run, all "generators" producing and selling power in Texas.

Observations

The market design in the ERCOT wholesale electricity market creates identifiable incentives/results.

As compared to other electricity markets in the US, the high price cap creates greater potential price volatility in the Texas wholesale electricity market.

Anticipated volatility can be managed through forward and futures contracts. Unanticipated volatility, i.e., price spikes that were not expected, can only be managed by raising prices to reflect the unanticipated risk in the wholesale and retail electricity markets. Accordingly, Texas has one of, if not the highest margin between the wholesale and retail electricity prices of any market in the US (93.2% in 2021)

The only sustainable business structure capable of managing the unexpected risks created by the ERCOT market design/operation is for generation and load to be integrated, i.e., the "gentailer" model, and balanced – generation capacity must be equal to load exposure). Independent REPs will be forced out of the market.