Electricity Storage: The Essential Rebalancing Mechanism

By Ross McCracken*

The energy world has for the last three or more years been consumed by the American shale gas revolution, which has morphed into a liquids revolution that has profoundly changed perceptions about U.S. energy security and its international relations. This has overshadowed a revolution no less profound, but of a very different kind – the decarbonization of power generation in Europe in pursuit of sustainable non-hydrocarbon-based energy systems.

This could reshape Europe's energy relations with the outside world every bit as much as shale is doing for the U.S. Both of these revolutionary fronts have one aspect in common – they are driven by technology. But otherwise they are arguably in conflict; one offering a climate endangering extension of a hydrocarbon-based energy system, the other a radical, more sustainable alternative.

The U.S. revolution is in many ways simple; it promises major industry upheaval in terms of gas-for-coal displacement in the power sector and gas-for-oil displacement in transport, but it does so on the basis of standardized commodities, for which well-functioning and well-understood markets, transport and storage systems already exist.

Renewables are much more complex, involving the integration of multiple new technologies, each with their own operating characteristics, into conventional power systems, and working with electricity, which is difficult to store in efficient and affordable ways. Oil, gas and coal storage are relatively simple matters by comparison. They may be an unexciting part of those markets, but they are fundamental to the way in which they function. The physical ability to store and retrieve a commodity, and the affordability of doing so, define how a commodity is traded. The extension of storage in the electricity market can, therefore, be expected to have some weird and wonderful effects.

Storage Prospects

There are good grounds to be skeptical about the prospects for electricity storage for three main reasons. First, if built out at scale, storage undermines its own profits. It is hard to make a business case for it unless there are enduring differences in price at different times of the day and night that more than compensate for the loss incurred in storing the electricity. As storage is built out, the difference in Peak and Baseload prices should trend towards the average efficiency of the storage fleet. The returns for this fleet, should, in turn, trend towards zero, making it a relatively undesirable investment.

This is a problem from the viewpoint of a standalone storage facility, but what is really happening is a shift in beneficiaries. The value of storage increasingly accrues to generators, rather than to the storage operator directly. This makes the business case harder to make as the value of storage is spread across the system. It can, therefore, only be justified in the long-term within a diversified generation portfolio. Arguably, even then, the benefits accrue in part to generation outside of the portfolio. The delivery of system-wide benefits suggest some form of socialized compensation, which does not sit well with the current market structure, and generally requires regulatory and political approval.

The second reason is that the costs of storage are very high compared with the value of the commodity. Not only does an operator have to bear the capital cost of the investment, but take a substantial hit on what is returned. In the absence of any other form of payment, the operator has to make back in price the loss incurred by storage, which for pumped hydro is about 20%, and for emerging storage technologies more. Natural gas storage by comparison may not be free, but at least it returns the same amount of gas that has been put in.

Third, given the likely low margins, scale is important, but again difficult. Take the Dinorwig pump hydro station in Wales, the UK's largest storage facility, with a capacity of 1,728 MW. It can operate over six hours before running out of water, which equates to 10.3 GWh. By contrast, the Rough gas storage facility in the UK stores around 35 TWh of natural gas and can deliver 113.75 GWh in six hours, carrying on for months on end. It may be an unfair comparison in some ways, as Rough is a very large facility, but it makes the point that in a low margin business, scale is important. Emerging storage technologies are relatively small in scale.

The Need for Storage

The fact is that electricity systems have got by pretty well without storage, or with a limited amount of storage in the form of pumped hydro, up until now. Electricity demand varies both within the day and seasonally, while demand and supply has to balance at all times. The reason storage hasn't been necessary is that generation is flexible.

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Some forms of electricity generation can be brought on and off-line relatively easily, or can economically incorporate a degree of load variation within certain parameters, avoiding a total shutdown.

The reason for storage now is that it provides operational flexibility, and the reason electricity systems need greater operational flexibility is that new forms of electricity generation have been introduced into the system. The shared characteristic of the two most widespread renewable generation sources, wind and solar, are that they are variable 'must-run' generation. They are variable in that output cannot be predicted with any greater degree of accuracy than the weather and they are 'must run' because they have no fuel cost. They make sense to run no matter how low the price is, and, where subsidies are included, they can even bear a certain level of negative prices.

Assuming no or low growth, which is fairly reasonable given the current economic situation in Europe, the build out of renewables has two primary impacts; it reduces the amount of electricity required from existing traditional forms of generation and it imposes on them much greater demands in terms of flexible generation. This, it turns out, is not particularly optimal. Gas-fired generation suffers most, partly because it has the operational capacity to be flexible and partly because it has the highest fuel costs. Gas-fired plants are operating less time overall and have to display greater operational flexibility, neither of which is good for returns.

Gas may appear the most complimentary generation technology for renewables from an operational perspective, but that is not the way it is working out within the current hybrid subsidized/market system. This raises an interesting question: does the EU need a power system, in which storage is a necessary piece of kit, like a transmission line; or is storage a business proposition, built on a commercial basis that makes a profit from the dysfunctionalities that are increasingly evident within the EU electricity markets?

Dysfunction

The emergence of increased incidents of negative electricity prices in recent years have been well documented. First in northern Europe, then in ERCOT West in Texas, an area with a lot of wind farms, but only limited interconnectivity with other areas of the ERCOT system. In June, at the Mid-C hub in the U.S. a combination of high hydro and wind output sent wholesale prices plummeting towards zero. All these areas have high levels of wind capacity.

The most recent and dramatic manifestation was in Europe in June when negative prices struck across EU borders, ironically combining Germany's large build out of solar and wind with north European experiments in market coupling, which in many other respects have been highly successful. Less promising from a market integration perspective have been Poland's attempts to build infrastructure designed to limit surges of excess power coming through its electricity system. Both are evidence of growing problems.

French, Belgian and German/Austrian spot power prices turned negative for delivery June 16 with some hourly prices falling to minus €200/MWh ($262/MWh), owing to low demand and high levels of non-flexible generation. Baseload prices in France and Belgium cleared at minus €40.99/MWh and German/Austrian baseload at minus €3.33/MWh. Prices for German/Austrian day-ahead peak cleared at minus €18.99/MWh. French day-ahead peak cleared at minus €20.29/MWh.

The cause was low consumption on a warm weekend day and high levels of nuclear, hydro, wind and solar power production in France, Germany and Belgium, causing a generation surplus. Combined German wind and solar output peaked at 1400 hours June 16 at 29.5 GW, according to EEX transparency data. The Netherlands did not have a surplus, but could not absorb more electricity, owing to a lack of import capacity. Day-ahead baseload for the Netherlands cleared at plus €36.16/MWh.

Negative power prices only affect a very small amount of traded electricity, but they are the visible tip of a larger process in which wholesale prices are depressed by must-run subsidized renewable generation. On the one hand, the differentials between Peak and Baseload prices in Germany have been compressed, reducing the potential arbitrage and economics of short-term electricity storage. On the other hand, negative pricing incidents create a valuable arbitrage in themselves, and their occurrence is growing.

These events are clear evidence that there is less control over the generation side of the power system as a result of renewable energy sources. Negative prices represent 'wrong-time' electricity. A recent report on liquid air as a potential storage technology, published by the UK's Centre for Low Carbon Studies, said that the UK is on course to build 31 GW of wind capacity, compared with 20 GW of baseload demand. The result will be large amounts of 'wrong time' electricity.

All EU countries, at different speeds, are on the same general course. The construction of multiple interconnectors and the extension of market coupling will delay the problem, but only re-create it on a grander scale in the longer term.

Price Trends

The EU's wholesale electricity markets will find it hard to work with increasing incidents of negative prices. They may be rare for the moment and account for very small volumes of traded electricity, but larger trends are at work. Strange things are occurring in terms of electricity price relationships.

In the Germany/Austria area, the average difference between Baseload and Peak power appears to be contracting. For the April-June period, when solar irradiance starts to have more of a seasonal impact, the average price difference has fallen steadily each year since 2010 from €5.7/MWh to €2.79/MWh in 2013.

The number of days in which Baseload and Peak time prices were inverted was 22 in April-June 2013, compared with just 5 in the same period in 2010. The average difference between Peak prices and Off-peak II, representing hours 21-24, went negative in 2012, growing to minus €2.86/MWh in 2013, compared with plus €2.72/MWh in April-June 2010. These calculations are based on Phelix database prices provided by the European Energy Exchange.

These trends have significant implications for storage technologies, which need to make money from the differences between electricity prices at different times of the day and night. Based on EPEX spot auction market prices for Germany/Austria, such a facility trading the difference every day between Peak and Baseload prices in an automated fashion would have made big losses.

However, it only makes sense to generate when the requisite price difference is there. This opportunity occurred on 21 days in the April-June period in 2009. In the same period this year it didn't occur at all. In fact, it would bizarrely have been more profitable to buy selectively Peak electricity and resell it as Baseload -- this arbitrage worked six times between April-June in 2013, returning an average €3.46/MWh.

For storage developers, the idea that Baseload and Peak time prices are moving closer together is a disaster, but they may in fact simply be passing each other by. The difference between average Peak and Off-Peak II prices narrowed to parity and then kept on going. It may have been an average minus €2.86/MWh in 2013, but that was wider than the minus €1.98/MWh in 2012 and the plus €0.51/MWh average of 2011. It doesn't matter to the stor-

Average difference between Peak and Base load (April-June)

	2010	2011	2012	2013
Average price	5.7	4.37	3.43	2.79
No. of price inversions (days)	5	9	19	22

Average difference between Peak and Off-Peak I (April-June)

	2010	2011	2012	2013
Average price	15.73	12.08	11.28	9.81
No. of price inversions (days)	0	1	6	5

Average difference between Peak and Off-Peak II (April-June)

	2010	2011	2012	2013
Average price	2.72	0.51	-1.98	-2.86
No. of price inversions (days)	25	31	44	49

Off-Peak I Hours 01-08, Off-Peak II Hours 21-24

Phelix Future is a financial derivatives contract referring to the average power spot market prices of future delivery periods of the German/Austrian market.

Phelix Price Data, German/Austria Market Area (€/MWh)

Source: EEX, author's calculations

	2009	2010	2011	2012	2013
No. of Peak/Baseload price inversions (days)	0	5	9	19	22
No. of Peak/Night price inversions (days)	0	0	4	8	6
Av. Peak load price (€/MWh)	38.83	47.21	57.98	43.8	35.39
Av. Baseload price (€/MWh)	32.38	41.52	53.61	40.39	32.6
Difference (€/MWh)	6.45	5.69	4.37	3.41	2.79
Av. Peak load price (€/MWh)	38.83	47.21	57.98	43.8	35.39
Av. Night price (€/MWh)	17.76	28.52	42.66	29.9	22.35
Difference (€/MWh)	21.07	18.69	15.32	13.9	13.04

EPEX Spot Market Auction Germany/Austria

Source: EPEX Spot, author's calculations age developer whether the differential between time periods is positive or negative so long as it is there.

A second aspect to this is that averages do not reveal changes in volatility. Take, for example, trading Peak prices against Night in the German/Austria area, where the differential is significantly larger than between Peak and Baseload.

The average difference in price between Peak and Night got smaller for the April-June period each year between 2009-2013. It fell from €21.07/MWh in 2009 to €15.32/MWh in 2011. The average profit to be made from 80% efficient storage also plummeted from €13.45/MWh to €7.07/MWh over the same period. Worse still, the number of days on which it was profitable to operate dropped from 90 in April-June 2009 to 66 in 2011. Price and volume were both down.

From 2011 to 2013, the average Peak/Night differential for April-June contracted further from €15.32/MWh to €13.04/MWh, but, perhaps surprisingly, the average profit from storage rose from €7.07/MWh in the April-June period in 2011, to €8.84/MWh in 2012 and €9.30/MWh in 2013, while the number of days of profitable operation stayed broadly the same – 66 in 2011, 65 in 2012 and 68 in 2013. A similar pattern is displayed for the Phelix prices for the Off-Peak I period versus Peak. The increase in price was less, but the increase in the number of days of operation was greater.

A third factor of interest is that the inversions seen between Baseload and Peak for the EPEX data and between Off-Peak II and Peak for the Phelix data can be highly complementary to the main trade -- Night versus Peak and Off-Peak I versus Peak respectively.

Looking at the Phelix data, there were 49 Peak/Baseload inversions in April-June 2012. Of these, 24 produced a price difference making storage profitable. Of these, 20 were more profitable than the same day Off-peak I versus Peak trade. And, of these, 13 occurred on days when the main trade was negative. As a result, on seven days the complimentary trade boosted price return and on 13 days it provided not just a positive price but additional volume. However, it should be noted that while this had a big impact in 2013, and sizeable effects in 2010 and 2011, it had no impact in 2012.

Daily trading Baseload v Peak			**Daily trading Night v Peak**		
April-June	**Av. profit (€/MWh)**	**No. of Days**	**April-June**	**Av. profit (€/MWh)**	**No. of Days**
2009	-1.32	91	2009	13.30	91
2010	-3.75	91	2010	9.25	91
2011	-7.22	91	2011	3.72	91
2012	-5.35	91	2012	5.14	91
2013	-4.28	91	2013	6.00	91

Profitable days only -- Baseload v Peak			**Profitable days only -- Night v Peak**			
April-June	**Av. profit (€/MWh)**	**No. of Days**	**April-June**	**Av. profit (€/MWh)**	**No. of Days**	**Inc. Adjusting for profit & volume (daily = 100)**
2009	1.74	21	2009	13.45	90	100.02
2010	1.42	6	2010	10.80	81	103.93
2011	3.67	1	2011	7.07	66	137.84
2012	0.80	2	2012	8.84	65	122.85
2013	0.00	0	2013	9.30	68	115.82

Profitable days only -- Baseload v Peak			**Optimization - Night v Peak and Peak v Baseload**			
April-June	**Av. profit (€/MWh)**	**No. of Days**	**April-June**	**Av. profit (€/MWh)**	**No. of Days**	**Inc. Adjusting for profit & volume (daily = 100)**
2009	0.00	0	2009	13.45	90	100.02
2010	0.00	0	2010	10.80	81	103.93
2011	2.70	1	2011	7.00	67	137.95
2012	0.35	1	2012	8.71	66	122.90
2013	3.46	6	2013	8.83	74	119.67

Trading Possibilities: EPEX Spot Market Auction Germany/Austria

Source: EPEX spot

For the EPEX data, optimizing Night versus Peak by combining with Peak versus Baseload provides similar results, but on a much smaller scale as both the number of inversions and profits generated are smaller. But it may not be unreasonable, based on the rising incidence of Peak/Baseload inversions, to expect that the profitability of this trade will also grow.

Profit in Storage

The introduction of renewables, while wholly positive in terms of a geopolitical definition of security of supply and in terms of emissions, are undermining the flexibility profile of the generation side of the industry and producing increasing amounts of wrong time electricity. The impact can be seen in the form of increased incidences of negative pricing and in the changes in relationships between pricing periods in the wholesale market. Some analysts predict that solar in Germany will account for the whole of summer peak time demand within three years, and potentially more, eating into baseload. Peak demand will exist; peak pricing will not.

Decades of painfully slow effort have gone into creating competitive, integrated wholesale markets based primarily on competition between fossil fuels to create a marginal price that provides useful signals for investment. More recently, an increasingly large subsidized sector, in which the generation sources have very different operating characteristics, has grown up alongside this market. As a result, the market's operation has become distorted and the price signals it produces increasingly unhelpful from a conventional point of view.

The implication is a generation mix that has a huge amount of installed capacity in comparison with actual electricity demand, split between under-utilized conventional generation and renewables, like solar, with low capacity factors. It is a very expensive mix, but one which will increasingly demonstrate the value of storage, the implied value of which is represented by the capacity payments that will have to be made to keep conventional generation plant economic.

There are grounds to argue that the current market system simply isn't compatible with the growth in renewable energy generation without major adjustments. But it may be that the changing pattern of price relationships is starting to produce the right signals. In a system undergoing such rapid transformation, those price signals and relationships should be different from anything seen before. Arguably, they are beginning to show that electricity storage is the essential rebalancing mechanism that could make a renewables-based energy system work both as a power system and as a market.

Daily -- Off-peak I versus Peak (€/MWh)

April-June	Av. profit	No. of days
2010	6.33	91
2011	1.19	91
2012	2.64	91
2013	2.80	91

Profitable days only -- Off-peak I versus Peak (€/MWh)

April-June	Av. profit	No. of days	Inc. adjusting for profit & volume (daily = 100)
2010	7.92	76	104.50
2011	4.86	52	232.00
2012	5.8	59	142.40
2013	5.85	62	142.30

Optimization -- Off-peak I v Peak and Peak v Off-peak II (€/MWh)

April-June	Av. profit	No. of days	Inc. adjusting for profit & volume (daily = 100)
2010	7.94	80	110.30
2011	5.7	57	298.30
2012	5.8	59	142.20
2013	7.64	75	224.90

Off-Peak I Hours 01-08, Off-Peak II Hours 21-24

Phelix Future is a financial derivatives contract referring to the average power spot market prices of future delivery periods of the German/Austrian market.

Trading Possibilities: Phelix Price Data, German/Austria Market Area

Source: EEX