Monitor of Electricity Market Opening

August 12th, 2019

Ukraine opened its electricity wholesale market on July 1st 2019. This monitoring report is the second issue of an analytical publication series that aims to present and analyse key developments in the emerging market. The Market Opening Monitor appears regularly over the next months.

Executive Summary

I. We positively note that more market data has become available and that imports from EU countries and Belarus with lower electricity prices continue to increase.

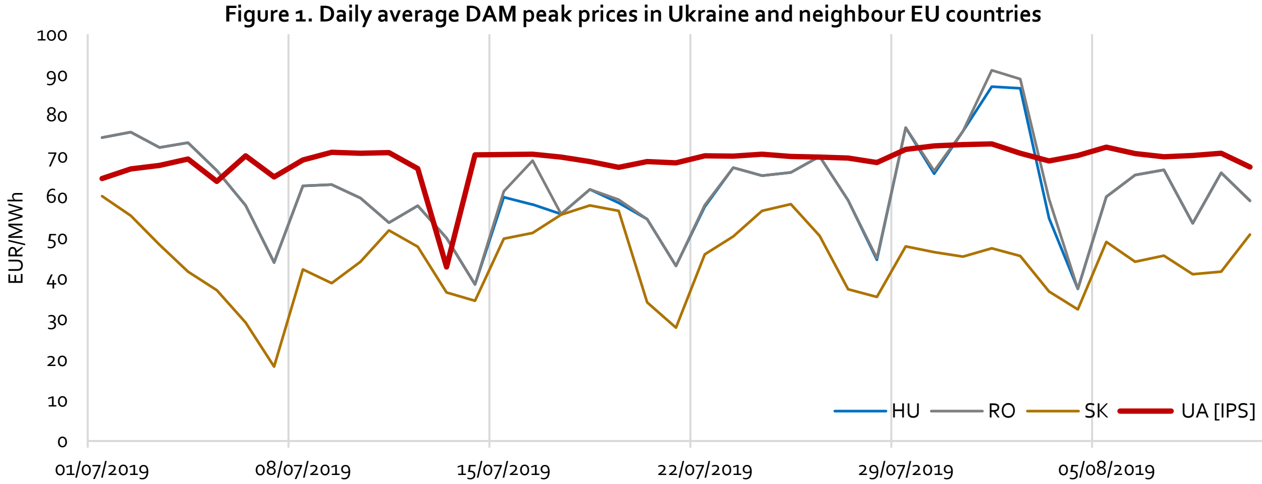
II. Prices inch closer to bidding caps in all visible market segments. Peak prices in Ukraine appear high compared to prices in neighbouring markets and very high compared to estimated generation cost. In addition, bidding curves appear to be managed in a way to ensure that in all demand situations, supply and demand meet very close, but not exactly at the bidding cap. These observations are consistent with the hypothesis that substantial market power is exercised.

III. Bid volumes in off-peak hours start to decrease and off-peak auctions are mainly oversubscribed. This poses the question at which segment and which prices buyers will be able to purchase the needed electricity. Declining volumes at the power exchange (with bidding caps) might indicate, that sellers with market power might have found a way to directly trade in unregulated segments.

IV. Currently, the big unknown is the balancing market. If sellers with market power are able to withdraw volumes to the balancing market (e.g., because they want to enforce higher off-peak prices), it would be very hard for the operator to ensure that supply meets demand. In addition, volumes in the balancing market will be an indication on how many consumers managed to secure over-the-counter contracts with producers.

V. Current price caps do fulfil their intended role to keep the wholesale prices below a certain level. But at the same time, they directly influence the behaviour of market participants and may be considered too high given the current coal prices on international market.

Figure 1. Daily average DAM peak prices in Ukraine and neighbour EU countries



Note: Peak prices on this graph are for EU countries 8-20h CET, for Ukraine – 9-21h EET.
Source: LCU calculations based on Ukrainian market operator data, HUPX, national banks' exchange rates

Prices in the Ukraine mainland trading zone show no volatility, compared to price patterns in neighboring Western markets. This pattern indicates that Ukrainian power prices are not driven by competition, but rather by administrative regulations in form of bid caps. Despite these price caps, the average peak price in Ukraine in the first six weeks since market opening (69 €/MWh) was much higher than in Slovakia (45 €/MWh), Hungary (62 €/MWh) and Romania (62 €/MWh).

We argue that the current system of price caps is insufficient to prevent the exercise of market power.

Low Carbon Ukraine
Policy advice on low-carbon policies for Ukraine

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Latest developments

Market Operator issues new data and report

The report on market operations for July 2019 was issued by the market operator. The number of market participants, remained stable at 210+ on the day ahead market (DAM) and 90+ on the intra-day market (IDM).

The Market Operator website (oree.com.ua) was updated with new information on trading results in both the mainland and the Burshtyn system, including:

- bid and ask volumes for both DAM and IDM;
- minimum and maximum hourly clearing prices for IDM;
- separate downloadable data on hourly clearing prices;
- hourly bidding curves for DAM.

Data on bidding curves is an important instrument which allows to see how demand and supply is formed in each hour. It allows analysis of the structure of market participants and their bidding behavior. These data can show the effects of administrative limitation and incumbents' market power on particular market segments. We investigate it further in this report.

Court ruling on transmission tariffs puts risk on renewables payments

Right after the market start, several energy-intensive companies won a court ruling to block the July 1st revision of TSO tariffs which foresaw to incorporate a component to finance the feed-in tariffs for renewables. That were previously financed via the regulated wholesale market price.

This created a financial deficit for the system operator, Ukrenergo, as a major part of consumers is now only paying the lower pre-July 2019 transmission tariff. This also created significant financial risks for renewables. According to information from the Guaranteed Buyer, renewable energy producers received only around 51% of their guaranteed revenues for July 2019.

NEURC has adopted a new tariff for TSO services on August 1st, making it possible to continue to finance feed-in tariffs for RES, yet the situation around July payments remains unclear. The latest controversial court ruling allowed only the plaintiffs to pay lower tariffs, while other market players are due to pay in full.

Ancillary services market remains non-operational

A letter from Ukrhydroenergo to the system operator became public, sparking a debate around the reasons for emergency dispatch commands. The operator of hydro power plants is forced to incur losses for imbalances due to a significant increase of emergency commands.

This seems to be a result of the non-operation of the ancillary services market. The latter was arguably not opened in time as the regulator adopted the rules for equipment certification only nine days before the start of the new market, and companies did not have time to be certified for providing ancillary services. In response, Ukrenergo proposed temporary changes to secondary legislation to the regulator to resolve this situation.

Regulator proposes to amend PSO mechanism

On August 1st NEURC has sent a letter to the Cabinet of Ministers (CMU) and proposed amendments to the public service obligation (PSO) mechanism. The main changes, that were proposed, are:

- to sell 90% of electricity from Energoatom and 50% from Ukrhydroenergo under regulated prices to the Guaranteed Buyer;
- exclude the direct sale of electricity from Energoatom to TSO/DSOs to cover technical losses in grids;
- oblige the Guaranteed Buyer to sell power to cover 80% of technical losses;
- transfer a responsibility to set household prices for electricity from the regulator to the CMU;
- to allow the Guaranteed Buyer to use profits from operations under PSO (from selling the electricity on DAM/IDM segments) to finance the difference between RES tariffs and market prices.

The CMU also considers to extend the PSO mechanism to water supply companies and other utilities.

However, in our view, the proposed changes will not help to develop a competitive electricity market in Ukraine.

Last resort supplier under state of default

Ukrinterenergo, the designated last resort supplier, is now under state of default on the electricity market. According to market rules, state of default is issued when a company cannot fulfill requirements for financial guarantees, and is barred from buying or selling electricity in DAM, IDM and the bilateral agreements segment.

As reported by NEURC, the level of payments of consumers supplied by the last resort supplier was 22% in July. This may be the (main) reason for the lack of financial resources of Ukrinterenergo.

The last resort supplier is now forced to buy electricity on balancing market with higher bid caps in order to supply electricity to its customers, incurring more costs.

Work on improvement of market rules

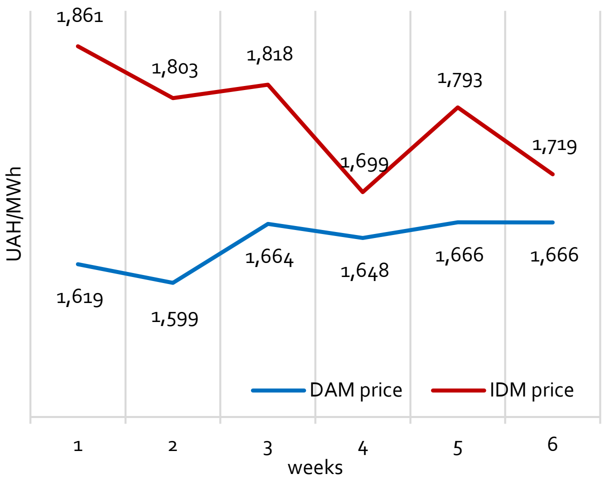
On August 9th, Ukrenergo and the Market Operator announced a working group for developing amendments to market rules. Market participants, as well as the Ministry of Energy, the regulator and the antimonopoly committee are invited to participate.

Key data: Wholesale market – Main system [IPS] trading zone

Prices inched close to the price cap

Average day ahead market prices increased slightly in the last weeks as peak and off-peak prices inched even closer to the price caps (see also Figure 9). This happened while load did not markedly change. The dynamics of the prices indicate that they may not be the result of supply and demand fundamentals, but of regulation and market power. We investigate this hypothesis further on page 5.

Figure 2. Prices dynamics [IPS]



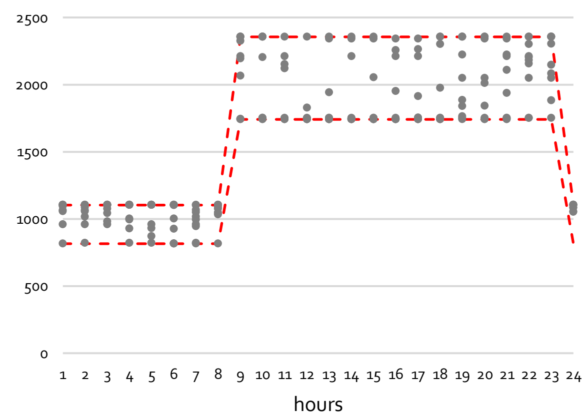
Source: LCU calculations based on Market Operator data, oree.com.ua

Balancing market

Ukrenergo published final prices for imbalances for the period 1-10 July 2019. The invoices for imbalances were also sent to market participants.

Since the data on imbalance volumes is not public, it is impossible to estimate daily averages and compare them directly to prices in other segments.

Figure 3. Hourly imbalances prices, IPS 1-10 July 2019



Note: red dotted line represents bid caps, individual points prices.
Source: Ukrenergo data

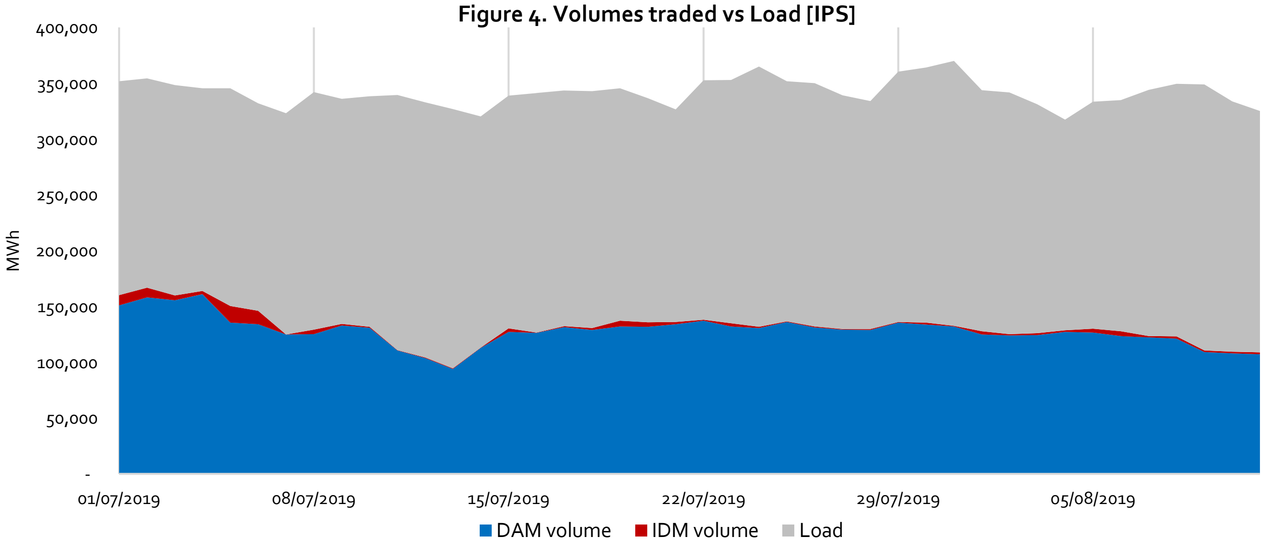
Decreasing share of transactions on power exchange

The share of electricity traded in the DAM and the IDM decreased from ~45% in week 1 to ~35% in week 6 (see Figure 4 below). The remaining 60% of electricity were sold in bilateral auctions for public services, bilateral auctions for state-owned companies, the balancing market and in over-the-counter (incl. intragroup) trades. The activities on the last two segments remain largely hidden to the outside observer.

Intraday market is insignificant

Trading volumes on the intraday market shrank further. Low bid volumes on the IDM segment suggest that sellers prefer to benefit from higher price caps in the balancing market, as opposed to "waste" electricity at slightly lower prices at the IDM (see Table 1 on price caps on page 5). Unfortunately, with no detailed data on the balancing segment available, it is hard to verify this.

Figure 4. Volumes traded vs Load [IPS]



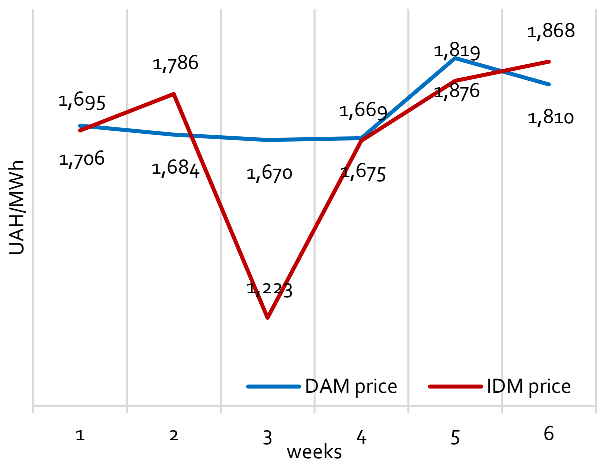
Note: DAM and IDM volumes are shown as part of load volumes.
Source: Market Operator data, Ukrenergo data

Key data: Wholesale market - Burshtyn island [BEI] trading zone

Prices inched close to the price cap

Similar as in the main system, average day ahead market prices in Burshtyn island increased slightly in the last weeks as peak and off-peak prices inched even closer to the price caps. This happened while load in Burshtyn island did not markedly change either. In fact, increasing imports did not lead to lower prices.

Figure 5. Prices dynamics [BEI]



Source: LCU calculations based on Market Operator data, oree.com.ua

Stable trading zone with no cross-border impact so far

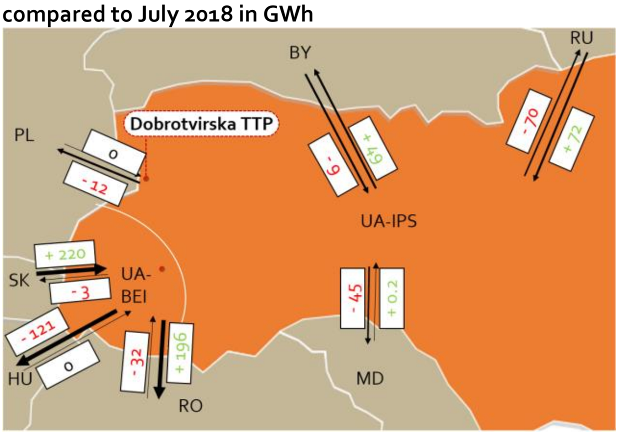
Electricity consumption in Burshtyn is less than 5% of that in the Ukrainian main system (see Figure 6). This lack of liquidity could partly explain more volatile prices (see IDM in week 3) and volumes. The share of DAM and IDM remains stable around 66-68%. Yet the share of IDM increased during week 5 and 6.

Import-export

The Ministry of Energy and Coal Industry of Ukraine reported, that in July 2019 Ukraine imported 275 GWh and exported 494 GWh.

Ukraine's net exports (exports minus imports) to the EU decreased by around 100 GWh compared to July 2018. This indicates, that cross-border trade starts to better reflect price differentials - as prices in Ukraine tend to be higher than in the EU.

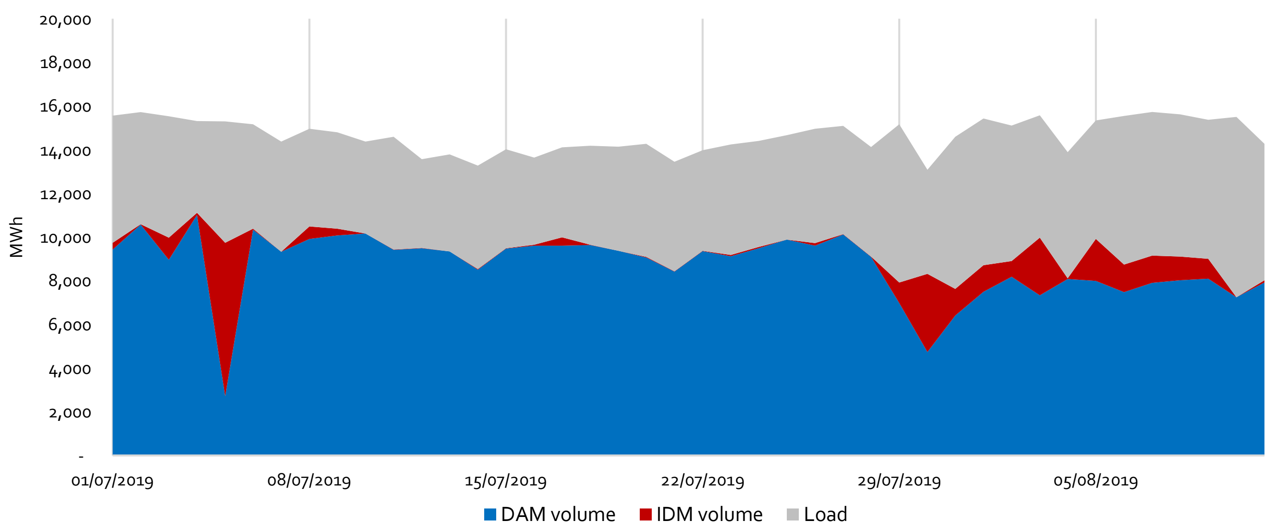
Figure 7. Changes in cross-border flows in July 2019 compared to July 2018 in GWh



Note: The numbers represent the deviation of aggregated cross-border flows of July 2019 compared to July 2018. The thicker the arrow, the higher the volume of cross-border flows in the direction of the arrow.
Source: LCU calculations based on ENTSO-E Transparency Platform

According to ENTSO-E data, net-imports from Russia (where currently electricity prices are very low – but where no formal agreement for market-based electricity exchanges exists) increased by 140 GWh and net-exports to Moldova increased by 45 GWh.

Figure 6. Volumes traded vs Load [BEI]



Note: DAM and IDM volumes are shown as part of load volumes. Please note that this figure and the similar Figure 3 on page 3 are not to scale.
Source: Market Operator data, Ukrenergo data, ENTSO-E transparency platform

Bilateral agreements auctions

Bilateral agreements auctions results

Bilateral agreements (BA) is the only segment without price caps (see Table 1).

Table 1. Administrative bid caps in the Ukrainian electricity market segments (in UAH/MWh)

	DAM & IDM	Balancing	PSO	
			Energoatom	Ukrhydro
peak hours (9h-23h)	2048	min 1741 max 2355	567	674
off-peak hours (0h to 8h & 24h)	959	min 815 max 1103	567	674

Note: caps on DAM and IDM are valid until April 2020, on balancing market – until full synchronization of the Ukrainian power system with ENTSO-E.

In Ukraine, there is no single organized platform for bilateral agreements but state-owned generation (e.g., Centrenergo) is obliged by law to sell power through a competitve auction platform.

These auctions for bilateral agreements are not to be confused with auctions for fulfilling Public Service Obligations (PSO), under which state-owned Energoatom and Ukrhydroenergo are forced to offer a certain share of their production under regulated prices.

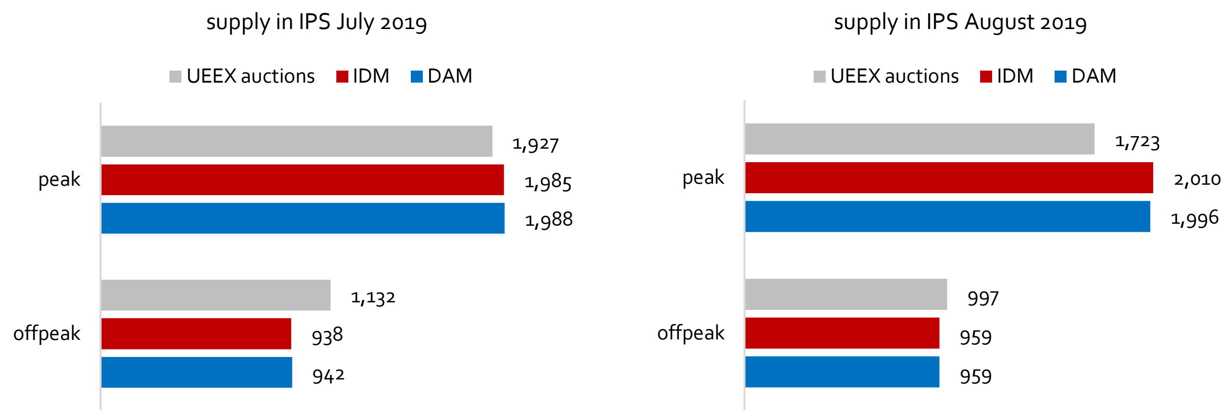
Since the start of the market on July 1st 2019, the government temporarily selected one provider, Ukrainian Energy Exchange (UEEX), to conduct bilateral auctions. Apart from state-owned generation, UEEX is also open for any private market player – but the interest was low. In fact, only two successful trades occurred, with insignificant volumes - between suppliers, not power producers.

In July, only 2 participants were auctioning their electricity, namely state-owned Centrenergo in IPS and Kalush CHP in Burshtyn Island. Total volumes sold on UEEX auctions (excl. PSO) during the first 6 weeks were 508 GWh for July and 829 GWh for August. Volumes sold for July supply amounted to 4.8% of IPS total load and 0.2% of BEI load.

Figure 8 compares resulting UEEX prices with DAM/IDM. Under normal circumstances, clearing prices for bilateral agreements auctions should not be higher than those on the DAM and IDM segment.

Results in Ukraine follow this logic for peak hours. It is worth noting that Centrenergo operates coal-fired power plants and sells at prices lower than other private companies at the DAM/IDM.

Figure 8. Average monthly prices comparison between market segments, UAH/MWh



Source: LCU calculations based on Market Operator data, UEEX data

Potential market distortion

Higher prices on the UEEX for off-peak hours indicate that buyers are willing to pay more than the bidding caps on the DAM or IDM segment. This raises the question why buyers would incur additional costs instead going directly to the DAM or IDM segment. One reason may be the limited supply on organized segments during off-peak hours.

The clearing prices on UEEX auctions raise two questions:

1) Does the obligation for state-owned generation to sell via auctions put them at a disadvantage compared to private companies, who may enjoy higher market prices on DAM and IDM?
2) What is the real reason for changes in bid and ask volumes on DAM/IDM between peak and off-peak hours?

A hypothesis to explain lower bid volumes during off-peak hours would be the withdrawal of power by the generators that prefer to sell in segments without the relatively low off-peak bid caps (see next section).

Market power monitoring: convergence to the caps

Price increase as a result of market power

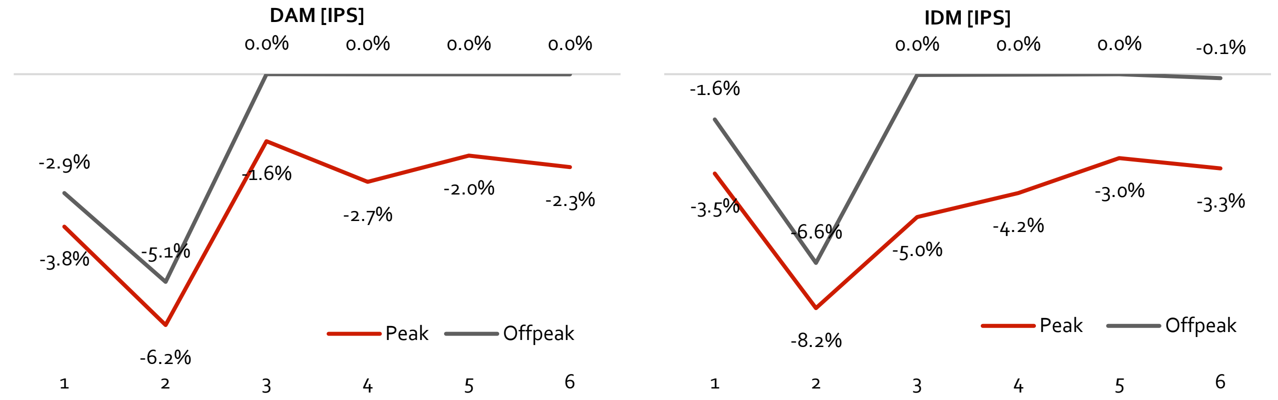
Prices for electricity in Ukraine continue to increase and price patterns are more and more determined by the different bid/price caps in the different market segments. This is clearly visible when comparing the steady price pattern in Ukraine with the volatile and unpredictable price patterns in Ukraine's western neighbors (see Figure 1). Prices in Ukraine are, for example, unaffected by weekends.

The decline of volumes traded on DAM and IDM negatively impacts liquidity on these segments. As shown in Figure 9, the distance of average clearing prices from bid caps decreases every week. In fact, off-peak prices completely converged to the bid caps in the main zone.

Market prices at a given segment are the result of the interaction between demand and supply curves. Both supply and demand behavior are affected by market conditions, whichinclude bid caps in DAM, IDM and balancing segments, accessto electricity outside spot markets, e.g. the PSO mechanism oraccess to intra-group bilateral agreements.

To understand the bidding patterns between off-peak and peak, we analyze bid and ask volumes during each hour of trading. Figure 10 shows the difference between total bid and total ask volumes for each hour for the last six weeks. We compare this to the average deviation of the resulting prices from the bid caps. During off-peak hours total ask volumes always exceed bid volumes. There is a clear correlation between resulting price and liquidity – the bigger the supply on the market, the lower the price.

Figure 9. Average weekly deviation of hourly prices from bid caps in IPS trading zone



Source: LCU calculations based on Market Operator data

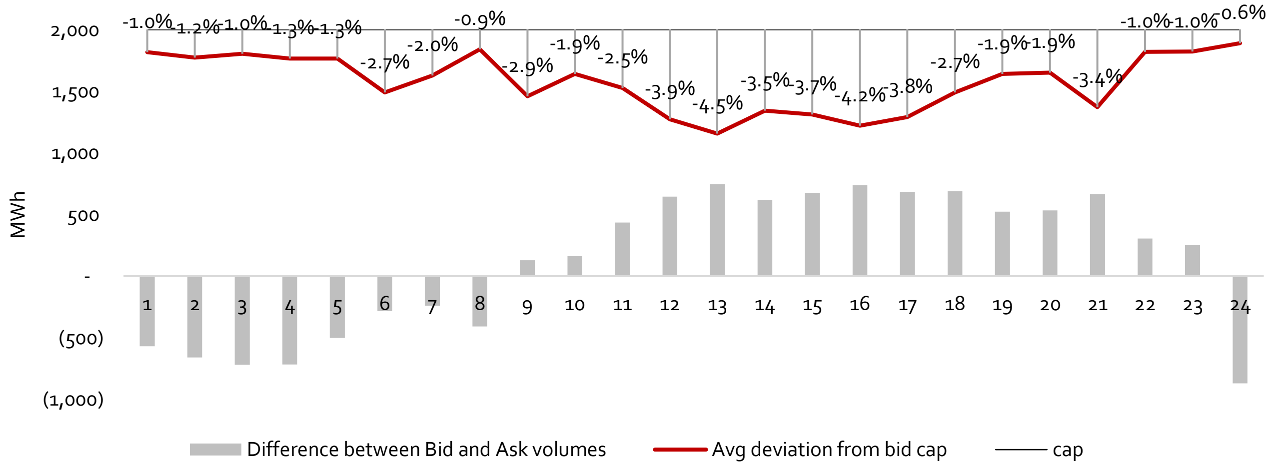
Total bid and ask volumes on DAM and IDM are influenced not only by bid caps, but also the load forecast, the portfolio of bilateral agreements and financial power of each participant. Thus, these differences between maximum demand and supply volumes do not directly represent actual demand and supply for electricity, but only show commercial bidding strategies of market participants.

We have two complementary hypotheses for this observation:

First, we might see capacity withdrawal in off-peak hours. If generators find the bidding cap too low, they might simply abstain from bidding - causing lower supply and higher prices.

Second, we might see excess demand in off-peak hours. Buyers that need electricity know they will only be able to buy it at higher prices at the balancing market. They also know that there is more demand than supply at this fixed price.

Figure 10. Correlation between prices and demand/supply each hour, 6 week average



Source: LCU calculations based on Market Operator data

Market power monitoring: withholding off-peak supply

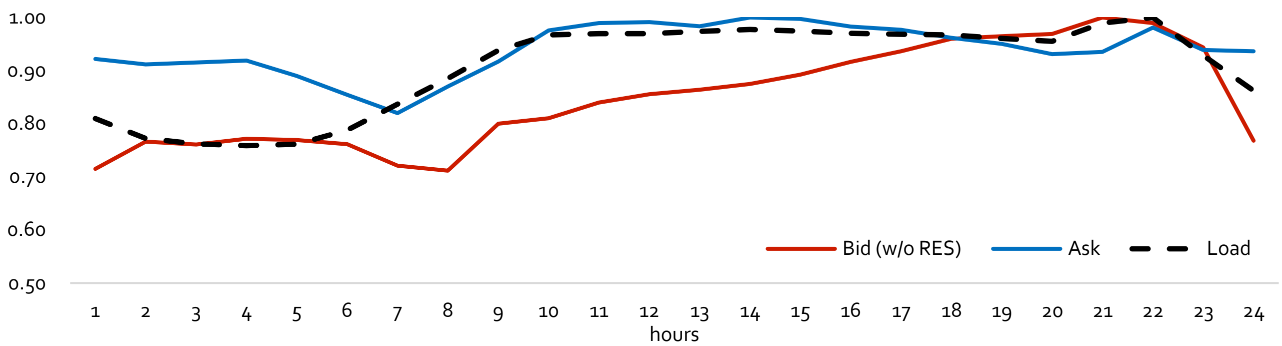
Reasons for off-peak/peak liquidity deviations

During peak hours, buyers' demand patterns mostly follow the load profile. But during off-peak hours, buyers tend to ask for more volume than they need. Sellers' behavior mirrors the buyers' in the opposite way. During some off-peak hours producers tend to decrease the amount of their bid volumes (see Figure 11).

The demand side pattern may be influenced by a combination of bid caps, market clearing algorithm and the possibility to exercise market power, which together affect the behavior of market players.

To maximize the chance of getting electricity, under normal circumstances buyers would place their bid at a high price. But with the bid cap in place, all market participants buy bids at the same price – the bid cap. A typical example of such a situation is represented in Figure 12. Note, that the total ask-volume during the night hour exceeds the ask-volume at the day hour.

Figure 11. Hourly distribution of supply and demand patterns in DAM [IPS]



Note: Renewable energy volume is factored out of supply profile, since the Guaranteed Buyer's strategy for bidding RE is simple, and RE cannot be withdrawn while bidding.

Source: LCU calculations based on Market Operator data, Ukrenergo data

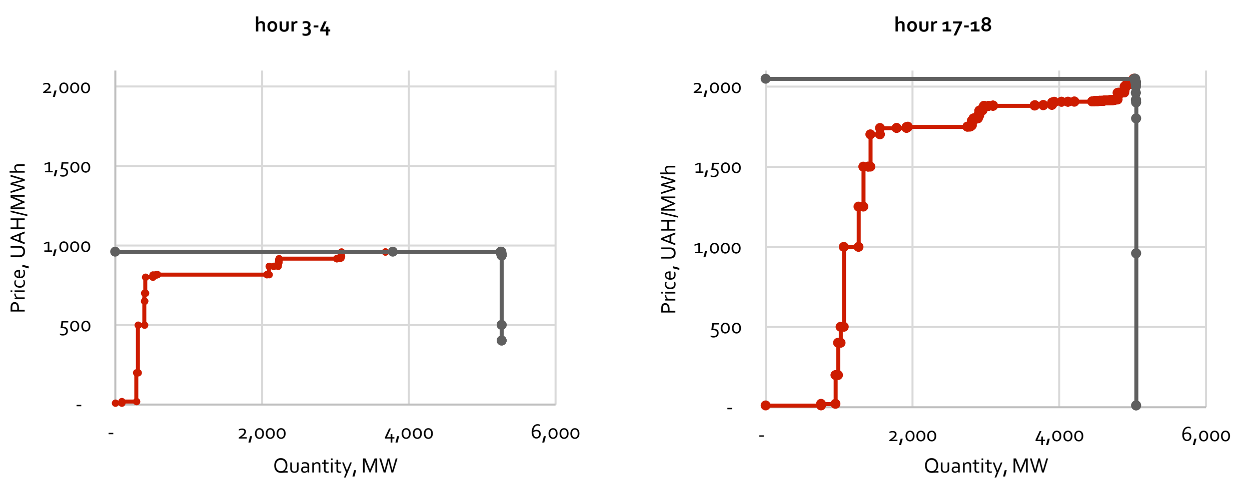
According to market rules, the oversubscribed electricity is distributed pro-rata. This means that even with the highest price currently possible, the ask-volume won't be met in full if there is not enough bid-volume. This affects buyers' behavior, forcing them to increase the individual ask-volumes, artificially creating a situation of oversubscription. Sellers can also adjust their strategies accordingly, withdrawing their power from DAM and selling it on the balancing market.

At the same time, the bidding power of buyers depend on their financial resources, dictated by financial guarantees for market participation. Bigger companies, especially those that are part of a vertical integrated holding with access to intra-group bilateral agreements, are in a better position, and may exercise their power to gradually push smaller buyers from the segments with bidding caps.

The final effect on the number of active participants on organized market segments is yet to be seen. For now, costs for imbalances are not yet incurred in full, as market participants only received invoices for the first ten days of July.

Under existing bid caps and market rules, combined with unregulated intra-group operations, there is a potential for companies with market power, on both buyers' and sellers' side, to exercise market power and to secure an even bigger share of the market.

Figure 12. Supply-demand curves for different hours, DAM trading day 09/08/2019



Source: Market Operator data

Market power monitoring: comparing prices to production cost

Why compare to marginal cost?

In a highly competitive market, each market participant would bid its capacity at the marginal cost, i.e. at the additional cost this plant incurs for producing one more MWh. In this case, the plant operator does not take into account the cost of capital or its employees in its bidding decision – because those cost will occur irrespective of how much he eventually produces.

The reason the plant operators in full competition bid its marginal cost is that if the plant bids below the cost it would make a loss from producing, but if it bids (too much) above the cost, a competitor might be chosen and it might forego a profit (sell price minus marginal cost) from producing. In a well-functioning market, the operator of an efficient plant would recover its (not directly production-related) cost in situations, where a more expensive power plant sets the price.

How to estimate marginal costs?

Marginal costs of coal plants are mainly driven by fuel costs. Fuel costs are determined by the cost of a ton of coal and the plant's efficiency, i.e. the amount of coal it takes to produce one MWh of electricity. Efficiency slightly differs between plants and we deduce average plant-level efficiency from annual coal consumption and electricity generation in 2018, based on data from open sources.

For coal prices we use three assumptions:

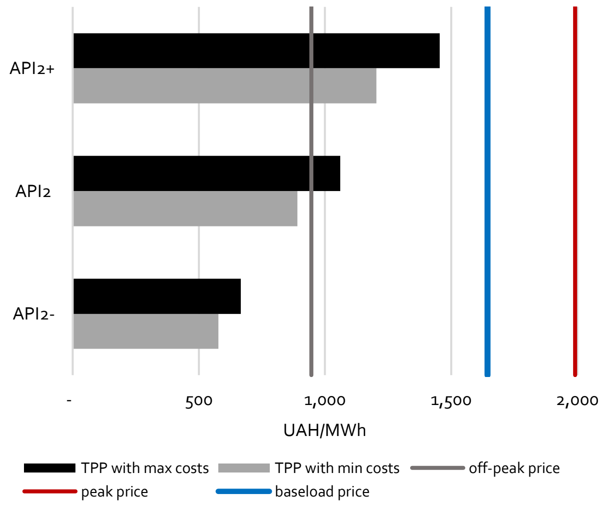
(1) the current EU coal price in Rotterdam spot market (API2).

(2) The Rotterdam+ coal price that adds transportation cost (used in Ukraine before liberalization) as it assumes that coal would need to be imported to Ukraine (API2+).

(3) A Rotterdam- coal price that subtracts transportation cost from the Rotterdam coal price which implicitly assumes that Ukraine is able to export coal (API2-).

Finally, we add an international estimate for operation and maintenance (O&M) cost to the marginal cost of coal plants.

Figure 13. Marginal costs of coal TPP in Ukraine under different coal prices



Source: LCU calculations based on API2 coal prices and data on fuel consumption of Ukrainian power plants from Ministry of Energy and DTEK annual reports. For calculation methodology please refer to Annex.

What are the results?

The main observation is, that peak prices are significantly above the marginal cost curve, even when assuming high coal prices. This indicates that plant operators make substantial profits in these hours. Moreover, it suggests that market participants bid substantially above their marginal cost, indicating that they are not facing enough competitive pressure to reduce their bids. Contrarily, off-peak prices are relatively close to the marginal cost of coal plants in the medium and high coal price scenario.

Furthermore, the observed prices do not at all reflect the volumes. First, off-peak residual demand is often higher than peak residual demand – while peak prices are double the off-peak prices. But also, within peak and off-peak hours, higher residual demand does not necessarily correspond to higher prices.

Implications

There is a risk, that too high prices cause inefficient dispatch decisions. Both, an expensive and a cheap plant might profitably run at the high peak prices – so it might well be that the more inefficient (and hence polluting) plant runs more than needed.

This project is part of the International Climate Initiative (IKI). The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) supports this initiative on the basis of a decision adopted by the German Bundestag.

All results of the project are available online at www.LowCarbonUkraine.com.

We will be grateful for your feedback on the Monitor of Electricity Market Opening, in particular comments how to make it even more useful for parties interested in understanding processes and outcomes in the emerging electricity market in Ukraine.
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Annex. Estimating marginal cost of Ukrainian coal plants

Example of Kryvorizhska TTP

Table: Data for Kryvorizhska TTP (7 blocks; total electricity generation capacity: 2079 MW):

Data type	Data	Source
Coal consumption 2018	1,125,396 t	Ministry of Energy
Electricity generation 2018	2,482,545 MWh_{el}	Ministry of Energy
Average calorific value of Ukrainian coal	5.9 MWh_{therm} /t	DTEK
API2 for August 2019	56.75 USD/t	Barchart.com
Average transport cost to Ukraine	10.5 USD/t	Report by EURACOAL
Operation and maintenance cost for coal power plants (median)	9 USD/ MWh_{el} =230 UAH/ MWh_{el}	IEA: Projected Cost of Electricity Generation
Carbon tax	10 UAH/ t CO_{2e}	Worldbank
Emission factor	0.98 t CO2/ MWh_{el}	Article from Mykola Shlapak

1. **Calculating the efficiency** of the power plant

a. Coal consumption * calorific value = **Coal consumption**
1,125,396 t * 5.9 MWh_{therm} /t = **6,683,676.8 MWh_{therm}**

b. Generation / Coal Consumption = **Efficiency**
2,482,545 MWh_{el} / 6,683,676.8 MWh_{therm} = **0.371 MWh_{el}/MWh_{therm}**

2. **Coal prices in Ukraine**

For coal prices we assume **3 scenarios:**
- Coal Price = API2
- Coal Price = API2+ (API2 + transport costs as used in Rotterdam+ formula)
- Coal Price = API2- (API2 – transport costs as exemplary lower bound)

- Transform coal price per ton (UAH /t) to coal price per MWh (UAH/ MWh_{therm}).

Example for API2 scenario:

coal price per ton / calorific value = coal price per MWh_{therm}
1450 UAH /t / 5.9 MWh/t = **244 UAH/ MWh_{therm}**

3. **Calculating the marginal cost**

Coal price per MWh / efficiency
\+ Operation and Maintenance cost
<u>+ Carbon Tax * Emission factor of coal</u>
= **Marginal Cost**

244 UAH/ MWh_{therm} / 0.371 MWh_{el}/MWh_{therm}
\+ 230 UAH/ MWh_{el}
<u>+ 10 UAH / CO_{2e} * 0.98 t CO2/ MWh_{el}</u>
= **897 UAH/ MWh_{el}**