Thursday, January 23, 2014 | research report

Energa: buy (new)

ENG PW; ENGP.WA | Utilities, Poland

Powered by Distribution and Green Energy

Energa is a vertically integrated company whose core business is regulated distribution of electricity, responsible for 70% of annual EBITDA. With renewable energy representing a considerable share of total output, the Company also offers positive exposure to changes in prices of electricity and carbon allowances. Distribution and renewables will be the main focus of Energa's capital investment in the future, with no plans for extensive capacity building in conventional power generation. Last but not least, what distinguishes Energa from other utilities is a safe balance sheet and steady cash flows which ensure attractive dividend payments in the future. We are initiating coverage of Energa with a buy rating and a price target of PLN 19.9 per share.

A safe business profile

With distribution accounting for as much as 70% of annual EBITDA, Energa offers a stable and predictable earnings outlook underpinned by low sensitivity to unfavorable shifts in economic trends. Further, thanks to a superior quality of transmission assets (low network losses, few disruptions in supplies, upgrades), the Company is immune to the changes in regulatory policy (quality benchmarks) expected to take effect in 2015. Moreover, Energa is actively pursuing investment in smart grid technology which offers higher returns (WACC+7% from 2014).

High clean energy ratio means profits from carbon pricing

Renewable energy (no including co-generation) accounted for about 30% of Energa's total (pro-forma) power output, but this ratio goes up to 50% if we take into account the so-called "reliability must run" capacity of its power plant in Ostrołęka. This gives Energa positive exposure to carbon price movements (we are currently witnessing a rebound in the allowance market), ensuring that any upturn in electricity prices directly translates to higher profits thanks to low variable costs. One issue that the Company may face in the coming years is the planned discontinuation of allowances for hydroelectric power plants.

Capital investment focuses on distribution and renewables

The bulk of Energa's planned capital expenditures in 2013-2021 is earmarked for distribution infrastructure upgrades (representing 63% of planned CAPEX or 78% not counting "contingent" projects) and renewable energy OZE (25%). Future investment in conventional energy is conditioned on the situation in the electricity market and regulatory incentives. This approach, one example of which is the recent withdrawal from a coal-fired power plant project, is why Energa has much lower exposure to future drops in electricity prices compared to other utilities.

Attractive dividend policy

Energa has consistently distributed a portion of its annual earnings to shareholders in the past years, and its mid-term dividend policy caps the standalone payout ratio at 92% (except certain limits applied in 2013-14). According to our calculations, the annual payouts in the future will hover around PLN 500-600 million, supported by a healthy balance sheet and a balance maintained between capital expenditures and operating cash flow.

(PLN m)	2012	2013F	2014F	2015F	2016F
Revenue	11,176.8	11,411.7	10,828.4	11,610.4	11,989.6
EBITDA	1,629.2	1,955.4	2,084.8	2,110.1	2,272.3
EBITDA margin	14.6%	17.1%	19.3%	18.2%	19.0%
EBIT	906.0	1,151.0	1,187.8	1,134.7	1,259.9
Net profit	457.0	776.9	758.6	681.1	731.1
DPS	1.58	1.20	0.97	1.21	1.39
P/E	15.0	8.8	9.1	10.1	9.4
P/CE	5.8	4.3	4.2	4.1	3.9
P/BV	0.9	0.9	0.8	0.8	0.8
EV/EBITDA	5.1	5.3	5.2	5.5	5.4
DYield	9.5%	7.2%	5.8%	7.3%	8.3%

Current Price	PLN 16.60
Target Price	PLN 19.90
Market Cap	PLN 6.87bn
Free Float	PLN 3.44bn
ADTV (3M)	PLN 81.19

Ownership

State Treasury*	50.0%
Others	50.0%

*50%+6,400 shares

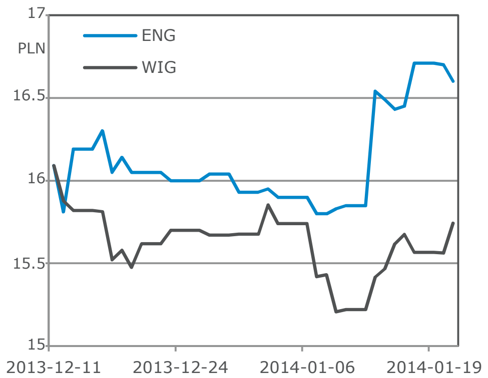
Sector Outlook

Declining demand and lower electricity prices have negatively impacted the profits of the power sector and the way utilities are perceived by investors, especially in light of their extensive capital investment plans. The sector is currently seeing signs of revival (higher volumes and carbon allowance prices), and this, combined with upside earnings surprises in distribution and trade, should improve investors' sentiment.

Company Profile

Energa is one of the four largest vertically integrated power utilities in Poland. It ranks third largest among distribution system operators (20.1 TWh in 2012) and traders (17% market share). The Company produced approximately 4.4 TWh of electricity from its own sources in 2012 (pro-forma including wind farms acquired in the period), one-third of which were renewable power plants.

ENG vs. WIG



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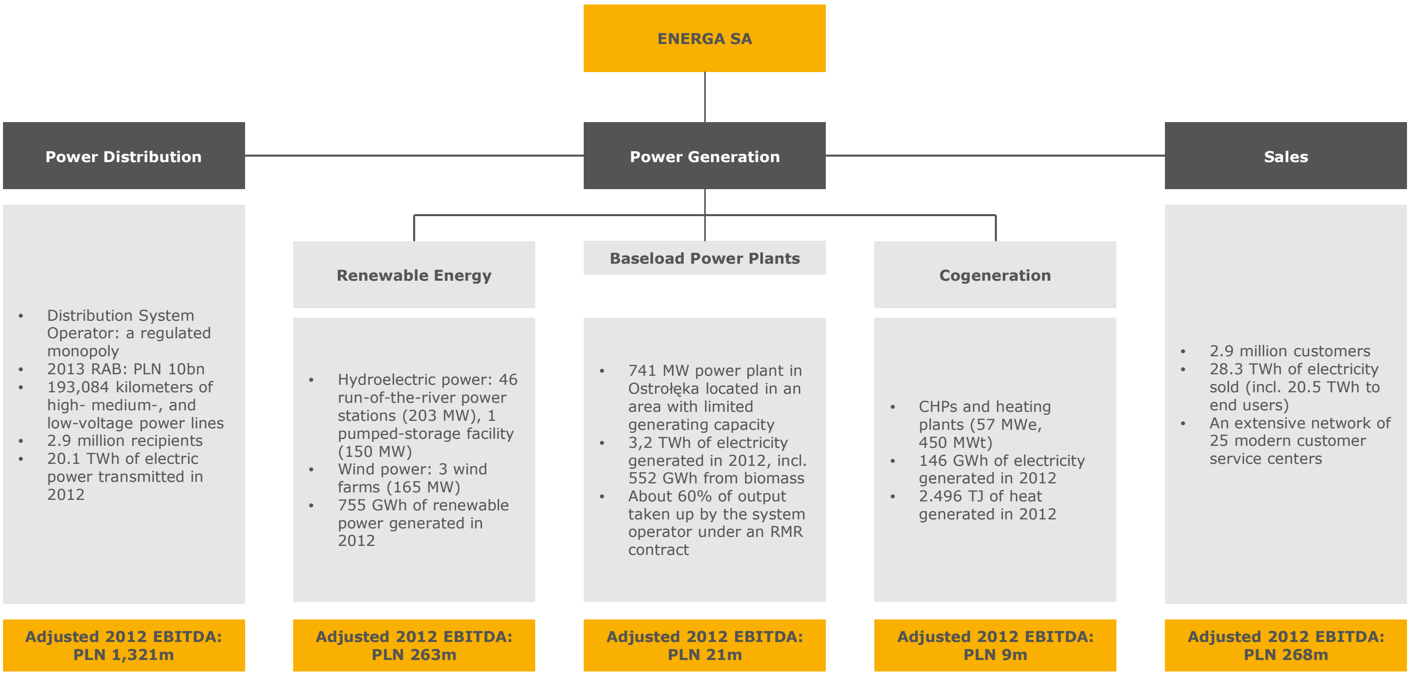
Profile

Organizational Structure



Source: Energa, Dom Maklerski mBanku

Energa was established in 2004 following the reorganization and consolidation of the Polish power industry, and today it is one of the four biggest vertically-integrated power generation groups in Poland (next to PGE, Tauron and Enea). Energa's core operation is distribution of electricity, generating over 70% of the consolidated EBITDA. Energa is the third largest distribution system operator in supply volumes (20.1 TWh, representing 16% market share), and its transmission assets, covering about 25% of the country, are located in northern and central Poland. The Company is also ranked third in electricity sales to end users with 17% market share. Energa's power plants generate an annual power output of approximately 4.4 TWh (pro-forma data for 2012 including wind farms), one-third of which is produced from renewable sources, including by Poland's biggest run-of-the-river hydroelectric power plant in Włocławek (160 MW). The remaining megawatts are produced by a coal-fired power station in Ostrołęka using fuel provided by external suppliers. Energa also owns heat-generating assets, most notably two combined heat-and-power plants in Elbląg and Kalisz. As a result of consolidation processes completed in the last few years, the parent company of the Energa Holding, Energa SA (which does not conduct any business operations of its own), today controls almost 100% of the key subsidiaries, which means minority interests have a negligible impact on profits, and account for just 0.6% of the consolidated equity of the Holding.

About Energa

A safe business profile

Distribution generates a staggering 70% of Energa's annual EBITDA, implying steady and predictable profits and little vulnerability to adverse macroeconomic trends. Energa stands out from its competitors in the power sector thanks to high-quality transmission assets (low network losses, few interruptions in supplies) which make it immune to the changes in regulatory policy (quality benchmarks) coming after 2015.

High share of clean energy means positive exposure to carbon pricing

Energy from renewable sources (excluding cogeneration) currently accounts for ca. 30% of Energa's total power output, but this ratio increases to 50% after adjustment for the so-called "reliability must run" capacity of the Ostrołęka power plant. This gives Energa positive exposure to carbon price movements (we are currently witnessing a revival on this market), and ensures that any upturn in electricity prices will translate into higher profit margins thanks to low variable costs.

Capital investment targeted at distribution and renewable energy

The bulk of Energa's planned capital expenditures in 2013-2021 are earmarked for distribution infrastructure (63% of the planned CAPEX, rising to 78% if we take out contingent projects) and renewable energy (25%). Future investment in conventional energy is conditioned on the situation in the electricity market and regulatory incentives. Compared to other companies in the sector, Energa has much lower exposure to future drops in electricity prices. The recent withdrawal from a coal-fired power plant project is just one example of the Company's reasonable approach to capital investment.

Attractive dividend yield

Energa has been making regular distributions to shareholders in past years, and its medium-term dividend policy envisions payouts of up to 92% of standalone annual profits (not counting the limits set for 2013 and 2014 payouts). According to our estimates, in the years ahead, the Company can be expected to pay dividends between PLN 500m and PLN 600m, supported by a healthy balance sheet and a balance struck between capital expenditures and operating cash flow.

Ever-improving effectiveness

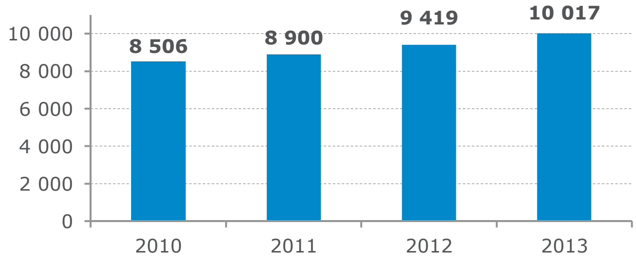
Energa places great emphasis on improving the effectiveness of its operations, and it was one of the first in the industry to launch a voluntary turnover program for its employees which has the potential to generate annual payroll savings of PLN 180m (this according to our estimates which are based on the size of the average salary and the scale of the downsizing plan). In addition, Energa is working toward centralizing some functions (IT, accounting, HR) and outsourcing other (including design and construction functions currently being managed from within the distribution segment).

Electricity Distribution

- Annual power distribution volumes of 20.1 TWh, 16% market share.
- Prices are fully regulated, and profits are earned based on Regulatory Asset Value and weighted average cost of capital adjusted annually.
- High efficiency reflected in reduced operating costs and network losses below the limit set by the energy regulator.
- Continued network development and acquisition of new customers will allow for further RAV growth from the current PLN 10bn to over PLN 12bn in 2018.
- Significant investment in 'intelligent networks' (a total of PLN 1.7bn by 2021) which are rewarded by the regulator with a premium to standard WACC (WACC+7% from 2014).
- Distribution currently accounts for 70% of consolidated EBITDA, and its contributions are set to grow in the years ahead.

Electricity distribution service at Energa is provided by the subsidiary Energa-Operator which runs medium- and low-voltage transmission infrastructure located in northern and central Poland, serving nearly 2.9 million customers. In 2012 the Company transmitted a total of 20.1 TWh of electricity to end users, giving it a market share of 16%. The business of power distribution is a natural monopoly, with price tariffs subject to approval by the energy regulator URE. Tariff sales are calculated as a sum of operating costs (the regulator sets eligible cost limits for tariff periods of several years in an effort to elicit higher cost effectiveness), D&A expenses, costs of transmission services provided by the TSO, costs of network losses (both the volume and the price of the electricity purchased to cover the losses factor in as variables into the equation), taxes on network properties, and return on capital calculated as the product of weighted average cost of capital and the regulatory asset value (RAV).

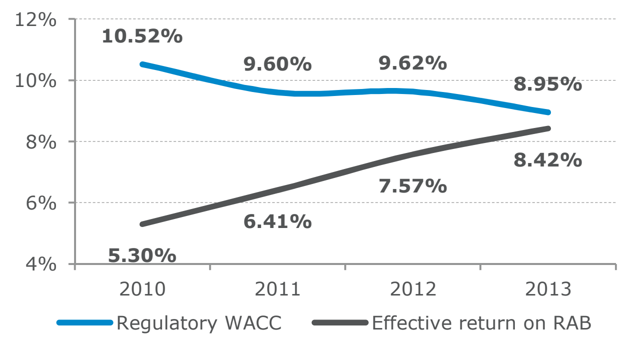
Regulatory Asset Base of Energa-Operator (PLN m)



Source: Energa

The formula described above was introduced in 2010 as an incentive for operators to invest in the modernization of an obsolete power distribution infrastructure (returns achieved under the previous price regime did not leave any surplus for such investment). In order to avoid sharp hikes in distribution fees for end customers, the regulator introduced a transition period to allow time for operators to gradually achieve full return on RAV. In 2010, the assets of network operators were adjusted to their fair market fair value (i.e. by as much as 2-3 times), and it was decided that return on RAV would be calculated as the sum of: Return on Capital for the previous year (RC_{t-1}), 1.5% of regulated revenue for the previous year (RR_{t-1}), and return on net capital investment made after 2008 (ROI_t), producing the following formula: $RC_{t-1} + 1.5\%*RR_{t-1}+WACC*ROI_t$. The formula will remain in effect so long as the returns calculated this way are lower than $WACC*RAV_t$, i.e. until sometime next year for most operators (including Energa). The process of moving toward the achievement of full return on RAV is illustrated in the diagram below.

Cost of capital and return on RAB as per URE tariff



Source: Energa

Aside from regulatory rewards for assets, the profits generated from electricity distribution are also influenced by regulatory decisions regarding the level of acceptable operating expenses and network losses. Under the current 2012-2015 tariff regime, after taking into account the energy regulator's required effectiveness and scale metrics and inflation rate assumptions, the costs factored into the tariff increase at an average annual rate of 6%. As shown in the following table, the expenses incurred by Energa-Operator last year came close to the assumptions of the regulator, and, if the Company sticks to the cost discipline, it may start to reap the benefits of the performance-enhancing measures completed in previous years already this year. As for network losses, in the years 2010-2012, Energa-Operator managed to reduce the costs by 14% (with the loss-to-distribution-volume ratio decreasing by 11% from 6.9% to 6.2%). Combined with falling prices in the balancing market, this allowed the Company to post extra profit margin in 2012 (defined as a difference between tariff costs and costs actually incurred). We expect a similar situation this year.

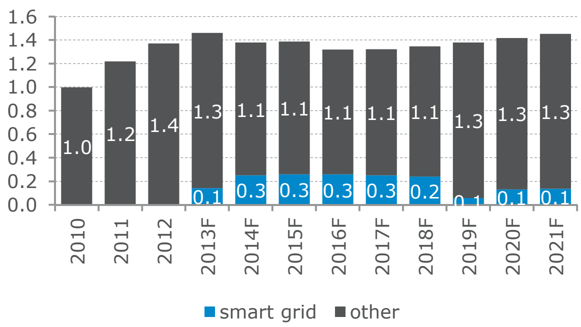
Regulated sales of Energa-Operator*

(PLN m)	2010	2011	2012	2013P
Regulated sales	2,888	3,072	3,365	3,478
Total revenue	*3,223*	*3,389*	*3,684*	*3,780*
Regulator-approved costs	744	771	818	880
Actual operating costs	*847*	*858*	*845*	*845*
Transmission costs	798	792	802	667
D&A	416	434	502	563
Regulator-approved network losses	313	323	339	318
Actual network losses	*355*	*325*	*307*	*286*
Taxes	167	182	190	207
Return on capital (regulatory)	451	570	713	844
EBIT	*159*	*378*	*610*	*774*

*2013 data in grey fields are estimates by Dom Maklerski mBanku
Source: Energa, estimates by Dom Maklerski mBanku

Apart from technical parameters and costs, another important consideration for the URE when setting the annual distribution tariff are the volumes of electrical power expected to be transmitted per year. Regulated revenue is calculated on a aggregated basis, but then it has to be split into the unit rates charged from end customers. This means that the regulator's ex-ante presumptions about future transmission volumes can impact a distributor's revenues and EBIT, especially since current regulations do not offer any compensation mechanism in case demand is lower than expected. The composition of the end-customer base is also not without significance, as the different tariff groups pay different transmission fees.

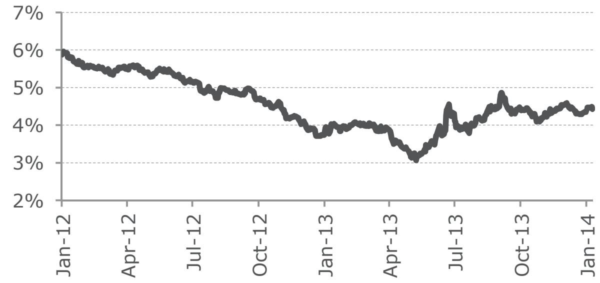
Distribution CAPEX projection (PLN bn)



Source: Energa

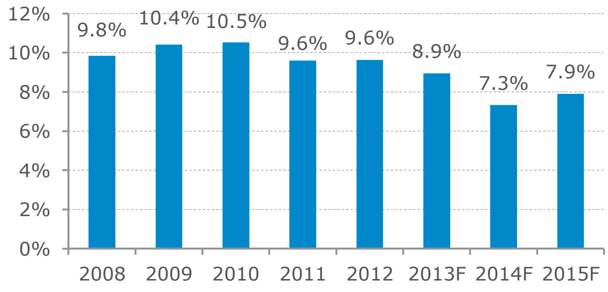
Under the existing regulatory regime and the tariff framework described above, the profits achieved by Energa are proportional to the size of its regulated assets which, in turn, is a function of net capital investment. Energa must consult its capital projects with the regulator, and only the approved CAPEX can be added to the regulated asset base. However, if necessary expenditures exceed the level approved by the regulator (and are deemed justified), they can be accounted for in the next settlement period. The capital improvements that Energa is planning to make in its distribution infrastructure from 2014 through 2021 suggest stable annual CAPEX of PLN 1.32-1.46bn. The total PLN 12.5bn budget will be spent on modernization (25%), new clean power capacity (15%), acquisition of new customers (37%), and IT (9%), with the significant amount of PLN 1.7bn allocated towards the implementation of the so-called intelligent networks. The reason why this is so important is that investing in intelligent networks is rewarded in the tariff (with target return from 2014 to 2023 calculated as WACC+7%, compared to WACC+2% in 2013). Initially, the regulated value of the 'intelligent infrastructure' will obviously be relatively low (PLN 50m in our estimates), however, by 2015-2016, the annual return on these assets may reach PLN 50-100m at the level of EBIT. Intelligent networks have the potential to generate the added value of even lower network- and sales losses (facilitating a swifter response to failures and illegal electricity hookups), as well as reducing the costs related to meter readings.

10-year Treasury yields



Source: Bloomberg, URE

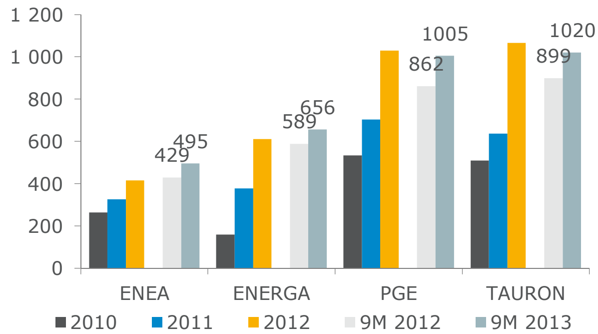
Distribution WACC as per URE tariff



Source: Bloomberg, URE, estimates by Dom Maklerski mBanku

The final key factor defining the profitability of power distribution is the cost of approved capital calculated using the variable of 10-year Treasury bond yields. When setting a tariff regime for a given year, the URE looks at the average yield in the period from October through September that proceeds the new tariff period. The average yield calculated from October 2012 to September 2013 amounted to 3.99% vs. 5.42% the year before, which means we can expect a considerably lower WACC applied to the 2014 tariff (according to our estimates it will be 7.33% vs. 8.95% this year). Such a significant reduction in cost of capital can mean a loss of PLN 16m in EBIT for every PLN 1bn of RAV, i.e. ca. PLN 160m in case of Energa. Assuming that the debt market stays at the average levels observed in recent weeks (4.4%-4.5%), we should see WACC rise to 7.9% in the 2015 tariff.

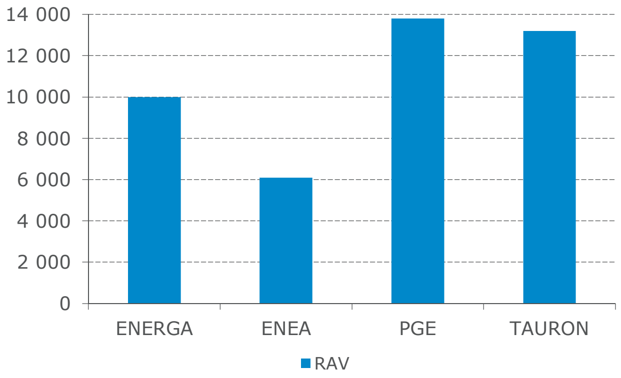
Distribution EBIT of utilities (PLN m)



Source: Companies, estimates by Dom Maklerski mBanku

The past earnings results of Energa's Distribution business fully reflect the changes that took place in the regulatory requirements in 2010-2012, namely: (a) The convergence toward the target return on the "old" regulated assets (full return on the RAV set in 2009 should be achieved in 2014), (b) The growing share of 'new' assets in RAV (the capital investment made from 2009 counts toward a new category of RAV rewarded using the WACC*RAV formula, and the total net CAPEX of Energa-Operator for the last four years exceeded PLN 2bn), and (c) The cost savings achieved relative to the path set by the energy regulator for the years 2012-2015. Note that Energa incurred voluntary turnover costs in the last few years (since 2010 until H1'13 the employee headcount dropped by 2000 or 16%), and its profits were additionally affected by charges and reversals related to legal disputes, and by allowances for settlements with the Sales segment, amounting to PLN 32m in 2012, eliminated through intercompany accounts.

2013 regulatory asset values (PLN m)



Source: Companies

2013 has seen a continuation of positive trends (in the year through September, EBIT grew by 12% y/y, in line with the sector average) led by an expanded base of rewarded RAV, payroll savings, and lower-than-expected expenses to cover electricity imbalance charges. The EBIT growth would have been even higher if it had not been for severance pays (PLN 72.6m) and a reduction in WACC (from 9.6% to 8.95%) in line with contracted bond yields. It is worth noting that, when reviewing regulated revenues, the URE does not take into account any adjustments (e.g. actuarial) made to accounts payable, litigation allowances, or reserves for potential damages, which are often recognized by power distribution companies in the fourth quarter.

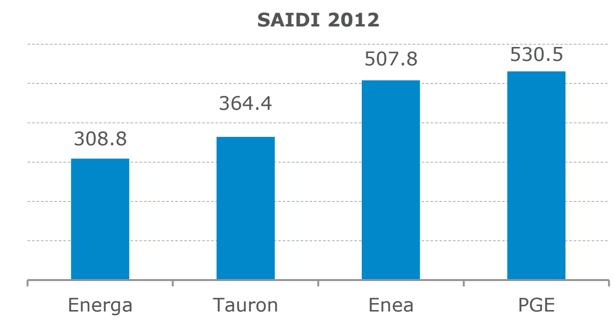
Distribution at Energa: past earnings and future forecasts

(PLN m)	2010	2011	2012	2013F	2014F
Revenue	3,223	3,389	3,684	3,780	3,726
EBIT	159	378	610	774	745
share in total EBIT	20%	44%	67%	67%	63%
EBITDA	654	916	1,218	1,434	1,466
One-offs	-97.4	-37.9	-103	-72.6	0.0
EBITDA (adjusted)	751	954	1,321	1,506	1,466
share in total	47%	59%	70%	72%	70%
EBITDA margin (adj.)	23%	28%	36%	40%	39%
Volumes (TWh)	19.3	19.6	20.1	19.7	20.1
RAV	8,506	8,900	9,419	10,017	10,747

Source: Energa, estimates by Dom Maklerski mBanku

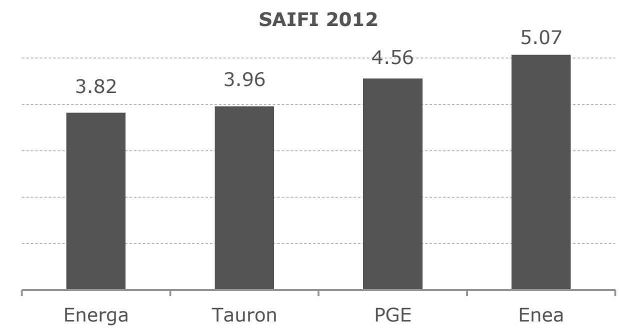
Our future financial forecasts for Energa assume continued growth in the value of both its regulated conventional power-generation assets and intelligent network assets, driven by capital investment (in 2014-2021 CAPEX less D&A may exceed PLN 4bn). We are also expecting further improvement in efficiency, achieved mainly through downsizing as the expected increase in the market prices of electricity, which the regulator will most likely take note of with a delay, may slightly hike up the future costs of network losses. Note that system operators and the URE are currently in the process of discussing tariffs for the next 2016-2020 period. We are guessing that the core of the regulated revenue measurement formula will remain unchanged, but the regulator will introduce additional correction factors based on the performance of the transmission network (without amending existing legislation). First and foremost, operators will be evaluated based on the SAIDI (representing average outage duration in minutes for each customer served) and SAIFI (average number of interruptions per customer) metrics, with any divergence from benchmark likely to be factored into the WACC calculations. The URE may introduce other performance indicators in the future, however, an analysis of Energa's SAIDI and SAIFI numbers suggests that the Company has nothing to worry about when it comes to guaranteeing service reliability.

2012 SAIDI reliability indicators for distribution companies



Source: Energa

2012 SAIFI reliability indicators for distribution companies



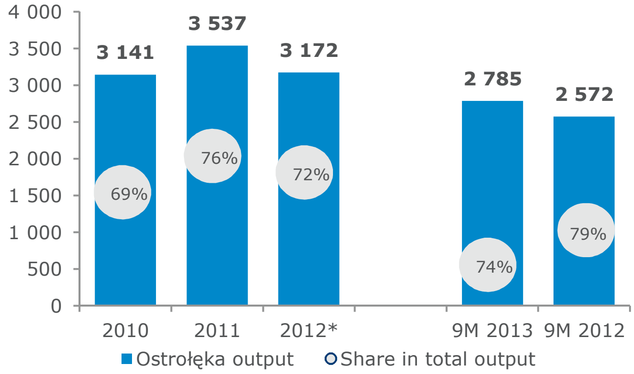
Source: Energa

Baseload Power Plants

- Energa's core baseload generation assets are two coal-fired power plants in the Ostrołęka Power Station with 741 MW capacity and 3.2 TWh annual output.
- More than a half of the capacity is 'must-run' under a contract with the TSO, priced at variable cost plus 5% margin and carbon emission costs.
- Annual coal usage: 1.2-1.3 million tons.
- Limited capital projects planned through 2021 (PLN 0.7bn in total); Energa has dropped plans to build another 900 MW unit in Ostrołęka, and future investment in CCGT will depend on positive changes in regulations.
- Baseload power has a negligible share in consolidated EBITDA, and it will remain marginal even after the profit rebound expected in 2015 (after the addition of a heat recovery steam generator to one of the power generators in Ostrołęka).

Energa's segment of Baseload Power Plants is represented by the power station in Ostrołęka with 741 MW installed capacity. The station consists of two units: unit A (93.5 MW, launched in 1956) and unit B (647 MW, launched in 1972). The older plant, which is going out of service in 2015, operates primarily as a supplier of heat to the city of Ostrołęka (its total heating capacity is 417 MWt, and its annual output amounts to 1.6 TJ). Generation of electric power is concentrated in unit B (with 2012 annual output of 3.1 TWh) which, however, due to its technical parameters and strategic location (as the only major power plant in north-eastern Poland) is used extensively to serve the needs of the transmission system operator PSE.

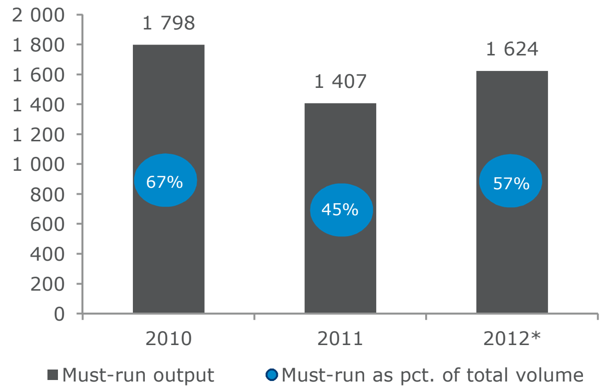
Ostrołęka power output as pct. of total Energa output (GWh)



*pro-forma data
Source: Energa, Dom Maklerski mBanku

Last year, must-run power accounted for a whopping 57% of the unit's net output, and this has great significance for the plant's profitability and its vulnerability to external factors. PSE pays for the inputs received from unit B under the must-run arrangement by refunding variable costs and adding a 5% margin and the equivalent of costs incurred on carbon emission allowances.

Must-run capacity as pct. of net output (GWh)

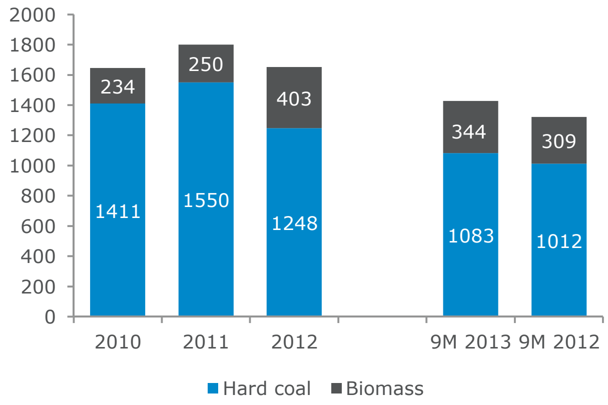


*pro-forma data
Source: Energa, Dom Maklerski mBanku

Baseload power has a negligible share in

The Ostrołęka power plant runs mostly on hard coal purchased from three Polish suppliers (the largest being LW Bogdanka which accounts for 56% of total deliveries). Its annual coal usage amounts to ca. 1.2-1.3 million tons. Prices are set based on bilateral negotiations with mines and are not indexed directly to European benchmarks. Prices of coal on the Polish market partly reflect the global trends represented by ARA ports through the import parity price (freight costs are a major factor as most of the buyers are located in the south of Poland), but they also correlate significantly with electricity prices. Coal producers and power producers are currently in the process of working out a compromise as regards the prices for new long-term supply contracts. Signals coming from the sector suggest that the price formulas might correlate directly with the market prices of electricity, coal, and carbon emissions. This year, the power industry managed to negotiate price discounts ranging from 5% to 10%.

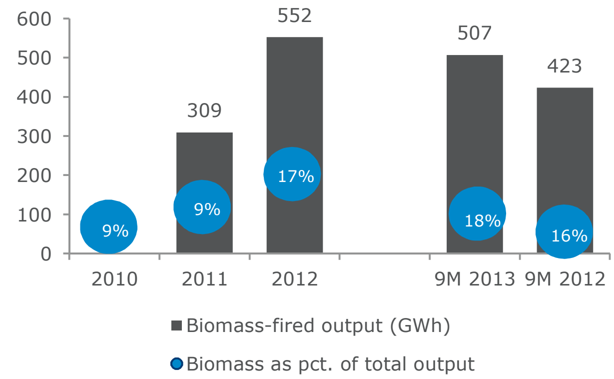
Fuel usage at Ostrołęka ('000 tons)



Source: Energa financial statements

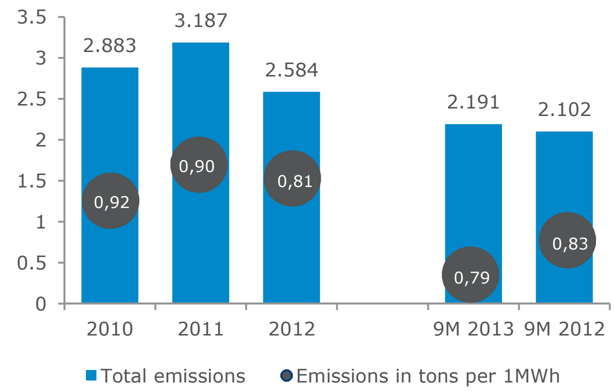
Energa is increasingly using biomass co-firing technology (another boiler was upgraded in 2012), which accounted for over 17% of electricity produced in Ostrołęka power plant last year. Not only does this generate additional margins thanks to green certificates, but it also lowers carbon emissions (in case of the Ostrołęka power plant the emission ratio dropped to 0.81 t/MWh, while if it had run on coal alone it would have amounted to 0.99t/MWh). The situation with co-firing got complicated this year due to a sharp plunge in the prices of certificates of origin (the issue is described in more detail in the chapter 'Renewable Energy'), and the possible cutbacks in government support for this technology in a new energy bill. For the time being, the profitability of biomass co-firing has been restored thanks to a 25-30% drop in biomass prices (Energa's profits for 9M 2013 do not yet reflect a decrease in biomass usage, but this was thanks to the increased burning capacity referred to above and the must-run contract with the TSO). In the future, however, biomass usage will depend on final legislative regulations.

Biomass-fired power output from Ostrołęka (GWh)



Source: Energa financial statements, estimates by Dom Maklerski mBanku

CO_2 emissions from Ostrołęka (millions of tons)



Source: Energa financial statements, estimates by Dom Maklerski mBanku

Energa abandons plans to develop 900 MW unit in Ostrołęka

In 2012 Energa decided to stop preparatory works for the construction of a new 900 MW coal unit in Ostrołęka. The reasons why this, once flagship, project was put on the backburner included difficulties with securing financing in the 'project finance' formula, negative trends in the electricity market, and slowdown in the construction industry. This year, Energa also tried to find a potential partner or a buyer for the project. Although several investors initially voiced their interest, no satisfactory offers were submitted. For the time being, Energa is not planning to re-launch this project.

Investment plans

Energa's 2013-2021 capital investment in baseload power plants is estimated at PLN 740m. The lion's share of this amount will be spent on adapting unit B of Ostrołęka power station to a combined-cycle facility. The plans stem from the fact that starting from 2015 unit A will have to be replaced with another source of heat, and that the Company has investment obligations towards the city of Ostrołęka which arose when the heating network was originally purchased (minimal CAPEX on development is set at PLN 320m). The upgrades planned for unit B will help improve its efficiency and reduce pollution (by reducing SOx and NOx emissions). As part of the so-called contingent CAPEX (conditioned on a favorable market and regulatory environment) another PLN 150m has been earmarked towards further modernization of the Ostrołęka power station, and PLN 90m has been allocated to preparatory works to construct two gas-fired CCGT units with 500 MW capacity each in Grudziądz and Gdańsk. Energa is keeping these projects on hold for the time being due to unfavorable market conditions, but it may reconsider implementing them once they stand more chance of generating profits. Originally, the combined-cycle units were scheduled for a launch in 2016-2017. We do not take them into account in our valuation model and financial forecasts.

Past financial results and future forecast

Even though baseload power plant segment has a lion's share in Energa's total electricity volumes, its contributions to consolidated EBITDA have been losing in significance in recent years. Adjusted for one-offs (mostly assets write-offs in Ostrołęka and voluntary turnover), the baseload power plants generated the highest profits in 2010 which they have not been able to repeat since despite rising electricity prices. The reasons include rising coal costs and a lower share of must-run capacity. This year we are expecting further pressure on margins led by falling prices of green certificates (which depress profits on biomass co-firing), lower standalone revenues electricity sales, and additional costs of emission allowances. In 2014, the negative impact of falling electricity prices and growing emission costs will be even stronger (although it will be – as usual – mitigated by the 'must-run' contract with the TSO), but positive EBITDA margins will be seen again in 2015-2016 thanks to the increased effectiveness of the plants (heat generation in unit B and the closure of unit A), combined with an expected rebound in electricity prices.

Baseload Power Plants: Past earnings and future forecasts

(PLN m)	2010	2011	2012	2013F	2014F
Revenue	860	1 218	1 038	966	801
EBIT	42	63	-168	-175	-131
share in total EBIT	5%	7%	-	-	-
EBITDA	97	116	-107	-112	-66
One-offs	-78,3	-4,4	-129	-123,4	0,0
EBITDA (adjusted)	175	120	21	11	-66
share in total EBITDA	11%	7%	1%	1%	-
EBITDA margin (adj.)	20%	10%	2%	1%	-8%
Electricity price PLN/MWh*	190.0	195.0	201.9	190.1	159.4
CO2 price EUR/t*	14.5	13.3	7.5	4.5	5.3
Power output (TWh)	3.1	3.5	3.2	3.2	3.2
hard coal	2.9	3.2	2.6	2.6	2.7
cogeneration	0.3	0.3	0.6	0.6	0.4

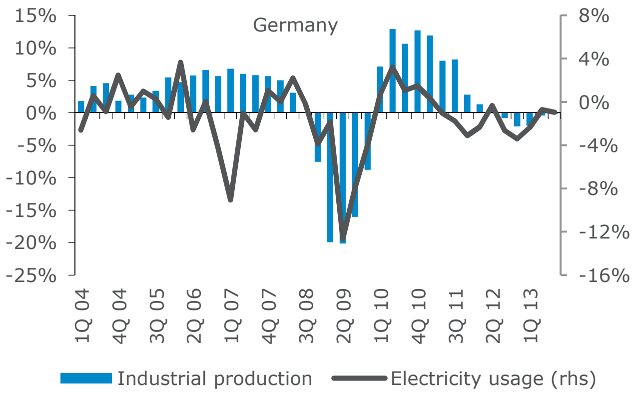
*estimates by Dom Maklerski mBanku, historical market data (TGE, EEX)
Source: Energa, Dom Maklerski mBanku

Electricity Market Outlook

Central Europe – Germany and Czech Republic

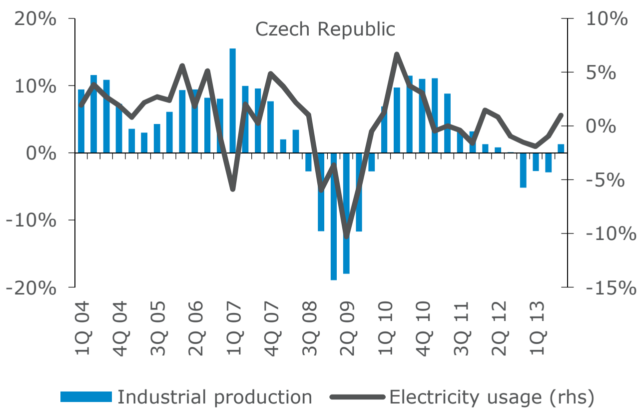
The primary factor which determines power consumption aside from the weather is activity in the manufacturing sector, as was clearly demonstrated last year by the performance of most European electricity markets. As manufacturing activity contracted, demand for electric power remained under considerable downward pressure (with industrial usage in Germany down a whopping 4.6%), particularly in the second half of the year, and the shrinkage would have been even stronger had it not been for cold temperatures recorded in February which provided an extra boost to demand. The slump in the European economy has continued into 2013, resulting in further power usage declines of about 2% in Germany as well as Czech Republic in the first quarter. The second quarter brought some positive signs in Germany where the year-on-year slowdown was much less severe smaller both in industrial production and in electricity usage (-0.7% y/y). Leading indicators have improved, offering hope for acceleration in manufacturing activity in the quarters ahead which in turn will mobilize the EU's electricity markets. Demand in Central Europe in H1 2013 was about 8-9% lower than before the 2008 crisis, and this indicates the extent of the growth potential that these markets face once economic momentum returns. Not counting weather effects, we expect power consumption to start growing again as soon as next year.

German electricity usage vs. industrial production



Source: Eurostat, ERU, BDEW

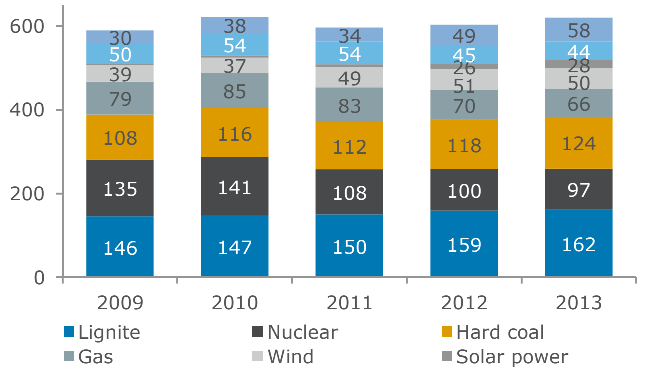
Czech electricity usage vs. industrial production



Source: Eurostat, ERU, BDEW

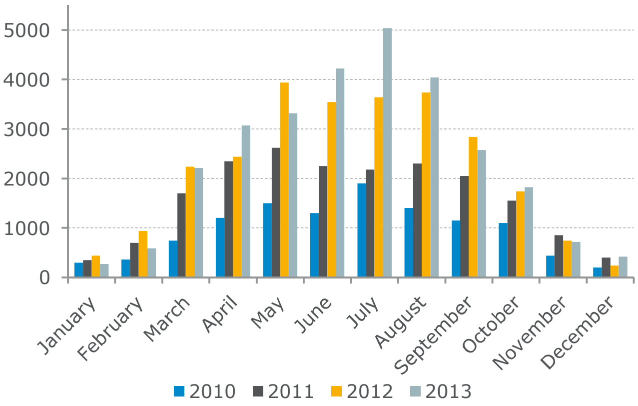
As demand contracts, the demand/supply imbalance in the Central European power market is exacerbated by an ongoing expansion in renewable power generation capacity in Germany where installed photovoltaic capacity increased by 30% and wind capacity rose by 9% in 2012, resulting in a combined share of 36% in the German grid. On the one hand, this results in conventional power plants being pushed out of the merit order (at its peak, solar power accounts for as much as 40% of the total electricity output), and on the other hand it periodically creates unmanageable export volumes (so-called loop flows). Consequently, last year Germany saw record cross-border trade over 23 TWh, mostly with the Netherlands. This caused much turmoil in the Dutch market (forcing closures of some of the peak-load capacity), and necessitated the installation of phase-shifting transformers to manage flows. A similar situation is developing on Germany's border with Poland which may put in place solutions to block German loop flows in 2015. Under these circumstances, Germany has to slow down the pace at which it is building renewable power capacity until it has enough infrastructure to handle the output. Also supporting such deceleration are increasing costs of renewable energy subsidies which since 2012 have increased from EUR 17 billion to EUR 31 billion annually. These subsidies make up 20% of the electricity price paid by an average German household whose utility bills have surged by an average 23% in the course of the last five years. This means much lower willingness of end users to subsidize green power, and increased political risks. Further, Germany is having a national debate over how to protect the grid against instability caused by renewable power. The solutions being discussed include a national capacity reserve and offering payments to power plants willing to remain on standby (the regulator is in the process of recruiting producers expected to provide 2.5 GW of power, and it intends to continue such recruitment in the future ahead of the planned closure of a 1.3 GW nuclear plant in 2015). With all this in mind, we expect gradual balancing of the German power grid going forward, supported by recovering demand.

German power output by source (TWh)



Source: BDEW

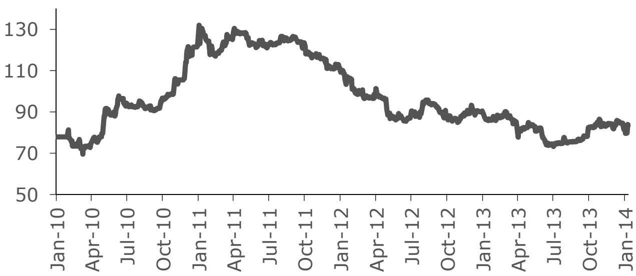
Solar power production in Germany (GWh)



Source: BDEW

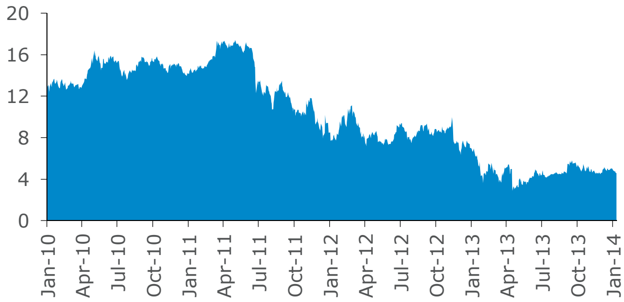
The obvious consequence of excessive power supply is the sharp downturn in prices observed since 2011. However, the oversupply is only one of the price-shaping factors alongside feedstock costs and costs of carbon emissions which have also dropped led by global trends. Prices of thermal coal have been on a downward path due to lower demand (depressed by an economic slowdown in China and lower power output) combined with increased supply from the United States stemming from increasing usage of cheaper natural gas. Thermal coal prices at ARA ports are currently hovering around USD 76 a ton, about 15-16% below last year's levels, signifying much lower feedstock costs for coal-fired power plants. As for emissions, their prices have plummeted in the last twelve months, led by globally decreasing emissions (which decreased by over 2% in the EU relative to last year), and a lack of legislative solutions that could mend the broken European Emissions Trading System. The backloading solution proposed by the European Commission (postponement of part of carbon allowance auctions) is only a temporary fix which provides limited support to emission prices. As an effect of falling electricity prices led mostly by coal and CO2, sources which do not depend on these parameters, namely nuclear, hydro and gas power plants were affected the most and the decline in revenues was not matched by shrinking costs. In fact, gas-fired power plants reported year-on-year growth in feedstock costs, which virtually ousted them from the market. The closures of conventional peakload power plants for economic reasons was a source of concern for transmission operators (problems with balancing and safety of the network), which provided further fuel to the discussion on introducing capacity payments.

Coal prices at ARA ports (USD/t)



Source: Bloomberg

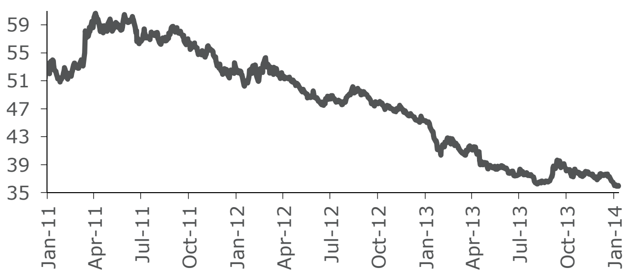
Prices of carbon emission allowances (EUR/t)



Source: Bloomberg

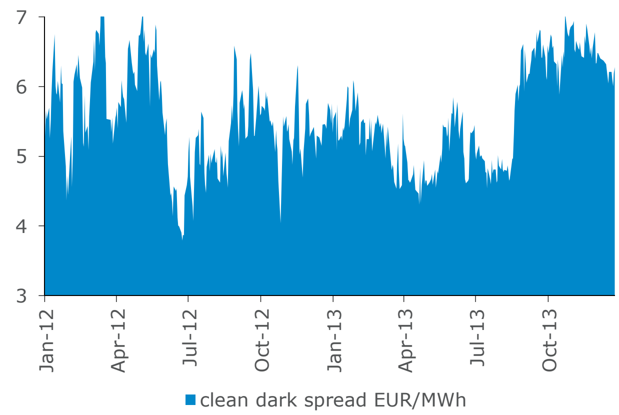
September 2013 witnessed the start of more upbeat sentiment on the German power market triggered by the publication of the highest PMI readings in two years. The positive reaction to the manufacturing recovery was additionally bolstered by the European Commission which decided to reduce the amount of free emission allowances available to the industry (by 12% on average relative to the motions submitted by the member states), which caused an automatic rebound in COO prices by over EUR 1/t to EUR 5.2/t. At the same time the market was shocked by an announcement of German government advisors regarding plans to change the renewable energy subsidy scheme, and although no specific legislative proposals have been presented yet, investors have already begun to discount a scenario supporting electricity prices (subsidies at the stage of investment process based on competitive tenders, sales of all renewable energy on arm's-length basis instead of guaranteed fixed revenues which have a destructive impact on wholesale prices). As a result, 1-year contracts on the EEX exchange surged by 7% in the span of one week from their August low, and the clean-dark spread for a typical coal-fired power plant reached EUR 8.6/MWh (2014 contracts). By the final weeks of 2013, however, EEX prices retreated back to their earlier lows led by stagnant electricity demand and warm winter temperatures.

EEX 1Y electricity futures (EUR/MWh)



Source: Bloomberg

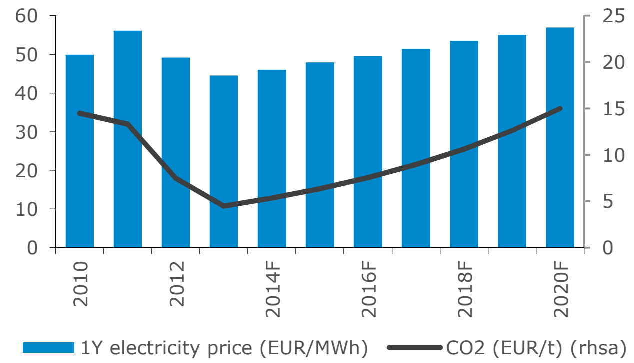
Theoretical clean-dark spread of German coal-fired power plants (EUR/MWh)



Source: Bloomberg

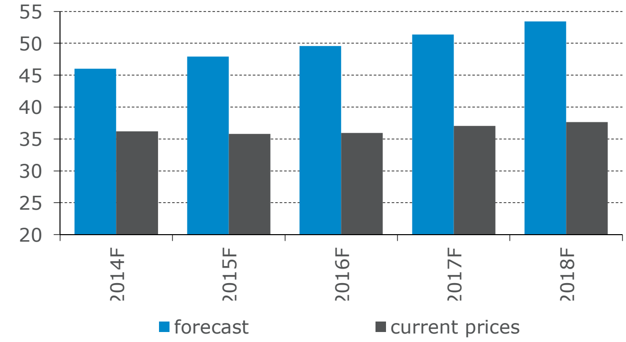
Sentiment toward utilities remains subdued for now, as evidenced by a flat futures curve and a high shared of hedged sales in 2015 contracts. However, if the economic recovery persists in the coming months (which is our baseline scenario), the electricity market will reflect this. In our forecasts for Energa we estimate electricity prices based on their correlation with gas and coal prices on European power exchanges, while separating the CO_2 component out of the benchmark as an independent variable. The scenario assumed for the base resources implies a slight increase in conventional energy prices (excluding the costs of CO_2) led by the inflation trajectory assumed for coal. Moreover, our forecasts for the coming years take into account the growing costs of emission allowances (expected to reach EUR 15/t in 2020 as a result of the introduction of ETS-repair mechanisms and a tighter balance driven by increasing industrial pollution). Relative to the current curve, our post-2013 projections are higher by ca. 20-25% as we have taken into account the trajectory for coal and allowances (the price curve for CO_2 is ca. EUR 2 below our assumptions).

Forecast of electricity* and emissions prices (EUR/MWh)



*price forecast for 1-year futures contracts (e.g. 2014F is a forecast for electricity deliveries in 2015)
Source: Bloomberg, estimates by Dom Maklerski mBanku

Price forecast vs. current futures curve (EUR/MWh)

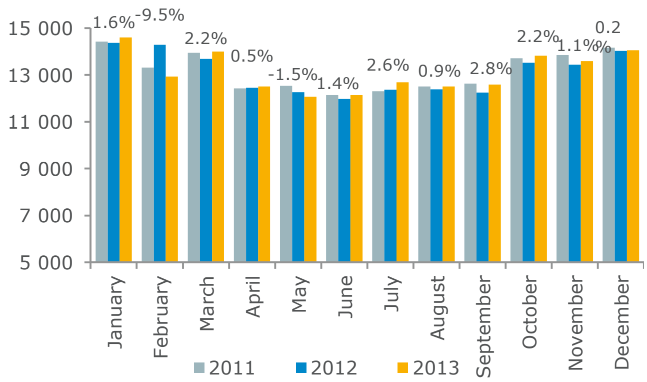


Source: Bloomberg, estimates by Dom Maklerski mBanku

Electricity market in Poland

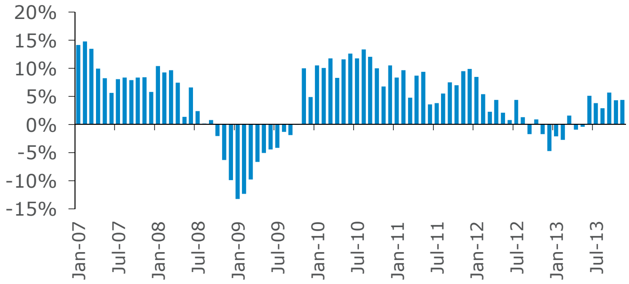
Electricity usage in Poland contracted by just 0.6% in 2012 in spite of considerable deceleration in manufacturing activity, owing primarily to freezing temperatures in February which gave rise to extra demand of 1 TWh. Adjusted for weather effects, demand showed an obvious correlation with manufacturing growth, reflected in year-on-year drops of 2% in monthly usage recorded in the second half of the year. In 2013, given the deceleration in Polish GDP, we originally expected a 2.5% drop in power usage, meanwhile, usage actually increased by 0.3% even though 2012 included the freezing February (which in addition to being extremely cold featured an extra day as 2012 was a leap year). For 2014, we project an increase in annual usage in the range of 1.5%-2.0%, and in 2015 consumption should exceed the 2011 high. At this stage we are not ruling out positive surprises, however, led by a statistical shift in the long-term correlation between electricity consumption and GDP growth (usage starts to increase when GDP growth reaches 1-2%, while previously this threshold was 2-3%).

Electricity usage in Poland (GWh)



Source: PSE

Industrial production index for Poland



Source: GUS

Electricity production is supported not only by higher demand, but also by growing net exports (+1.7 TWh through September) encouraged obviously by a positive price spread to the German market. Hydropower plants are reporting growing outputs (+20% due to hydrological conditions), and so are hard coal-fired plants (+0.1%) and brown coal-fired plants (2.5% despite the closure of a 206MW unit in Turów due to higher availability of capacity in Bełchatów). We are, nevertheless, observing a decline in gas-fired power stations (due to a lack of support). A lower-than-expected increase in wind energy supply may be surprising (+46%) when compared to an over-100% surge in average installed capacity. Available grid capacity in 2013 was lower by an average of 0.4% than in 2012 due to maintenance downtime and closure of three obsolete coal units (one in Turów and two in Łagisza). Although last year several new biomass units were delivered (Jaworzno, Tychy, Stalowa Wola, Połaniec) and a new installation in Bielsko-Biala was launched, only the GDF unit actually adds to installed capacity as the other units only replace older ones.

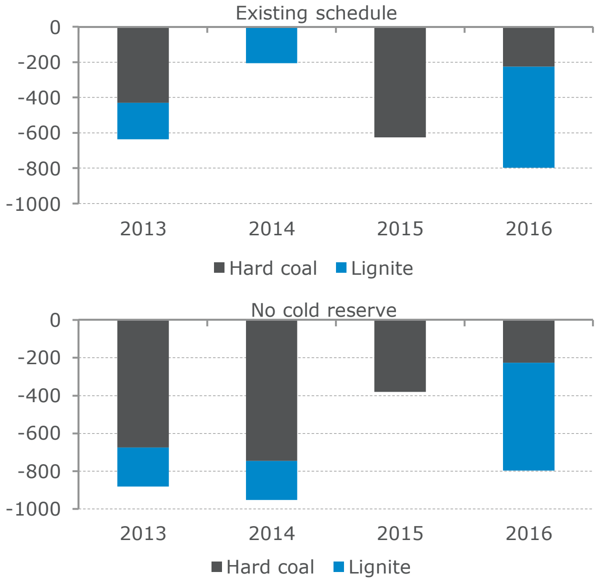
Polish power plant output by fuel

(TWh)	2010	2011	2012	9M'13	9M'12	change
Utilities	146.1	151.3	146.8	134.9	133.8	0.8%
thermal plants	142.8	148.8	144.6	132.4	131.7	0.5%
hard coal	89.2	90.8	84.5	77.3	76.6	0.8%
lignite	49.5	53.6	55.6	52.3	51.1	2.3%
gas	4.2	4.4	4.5	2.9	4.0	-27.7%
hydropower	3.3	2.5	2.3	2.5	2.1	20.7%
Captive power	8.9	9.0	9.0	8.3	8.1	2.5%
Renewables	1.3	2.8	4.0	4.9	3.6	36.3%
Total	156.3	163.2	159.9	148.1	145.5	1.8%
change	3.6%	4.4%	-2%			

Source: PSE

Wind turbines will be an important factor increasing power generation capacity in Poland for another consecutive year, however, as it happened in 2012, the scale of adding new capacity may diverge from what was assumed in official PSE forecasts. As a reminder, last year out of 1.3 GW planned capacity only 0.7 GW was actually launched. Some of the projects were probably postponed until next year, but the new capacity additions fell short of PSE's 1.1GW projection at 0.8GW. The delays stem from normal implementation problems, but utilities are also holding off investment due to uncertainty surrounding renewable energy subsidies and the lack of new legislation. This second factor may be more visible in subsequent years as wind farm projects take long time to complete.

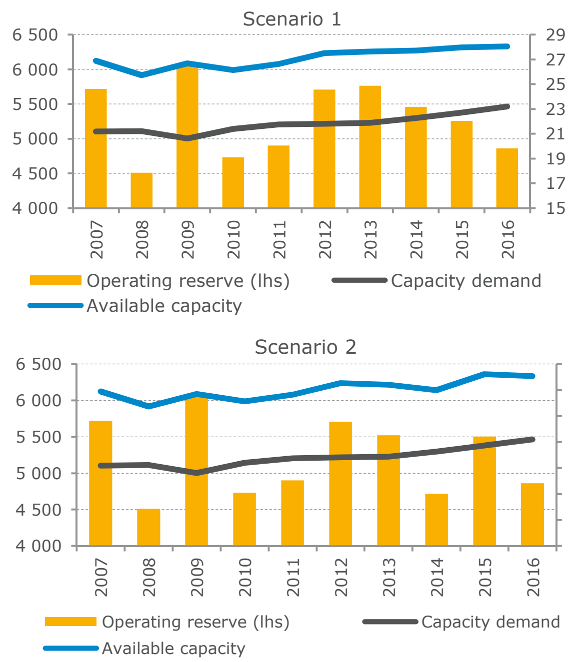
Planned capacity shutdowns (MW): existing schedule vs. if no cold reserve put into place



Source: PSE, Energa, Dom Maklerski mBanku

The size of the operating reserve of the Polish power grid in the medium term depends on the rate of old power plant decommissioning which, as it turns out, may be faster than we thought to date. For example, Tauron has recently requested permission to shut down two obsolete 120MW units early, and it also intends to close six more units with a combined capacity of 746MW starting next year if a cold reserve mechanism is not put into place in Poland. This would put considerable strain on the grid since the next new major power plant openings are not scheduled before 2015-2016, assuming there are no delays. The operating reserve prospects in a scenario where Tauron does not (Scenario 1) and does (Scenario 2) shut down the six plants are illustrated in the following diagrams. The scenarios assume that power demand in Poland will increase at an annual rate of 1.5%-2.5% starting in 2014.

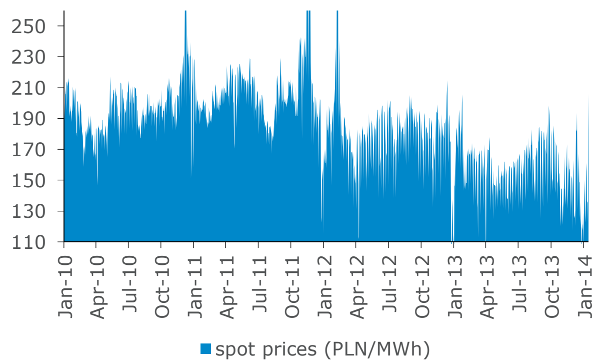
Two scenarios for operating reserve (MW)



Source: PSE, Dom Maklerski mBanku

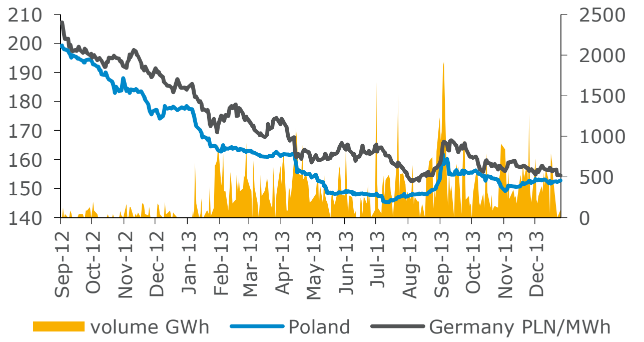
The 2014 drop in operating reserve in the second scenario shows the lack of structural flexibility of the Polish grid, especially while imports capacity remains limited. It is hard to assume that utilities will be willing to maintain obsolete generators as supplemental capacity reserve in a market where low sales prices do not even cover overheads. More likely, a cold reserve mechanism will be put into place after all (a tender for cold reserve from 2016 has already been issued and the regulator announced it would include additional several hundred million zlotys in the network operator's tariff for operating reserve in 2014), or, prices will rebound in response to reduced available capacity. Poland is poles apart in this respect from Germany which has created a structural oversupply of power. Recently, electricity contracts in Poland corresponded to European trends or were even trading with 10% discount to EEX. September brought a rebound in the German market and a visible increase in the prices quoted on the Polish power exchange TGE, combined with record-high trading volumes. Prices increased by over 10% from the July minimum and partly filled the gap to European benchmark in September, but they retreated to lower levels by the end of the year. Apart from regional factors, this increased activity could have been influenced by the information released with Q2 results that the main market players hedged the portfolio. The volumes contracted in 2013 for 2014 delivery amounted to 100 TWh, compared to just 66 TWh the year before. We are speculating that increased activity on power exchanges may have be a result of events observed in 2012 when large players with natural short positions (larger sales portfolios than generation portfolios) delayed purchases in anticipation of a downturn in prices. Moreover, Tauron took advantage of the freedom to make intercompany sales (thanks to a lack of an LTC regime), putting a burden on even those units that generate high variable costs. This year, PGE must have accelerated electricity sales as a way of avoiding closing a large position at the end of the year, as suggested by the extremely conservative price projections released recently (and write-offs, the cancelation of the Opole power plant project, and the higher LTC receipts recognized in this year's results).

Polish spot electricity prices



Source: TGE

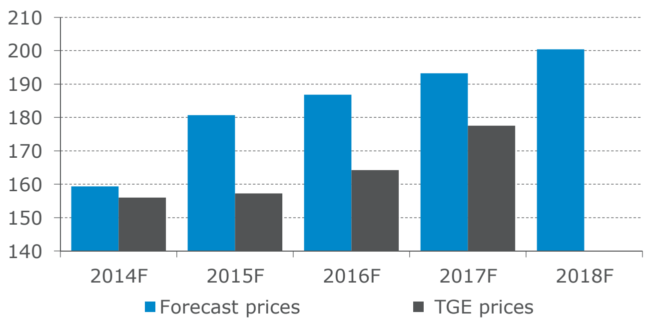
Polish vs. German electricity futures



Source: TGE, Bloomberg

Weighted average in contracts for 2014 amounts to ca. PLN 156/MWh, therefore it seems that the average price of energy sold in 2014 will be close to the amount we forecasted, namely PLN 159/MWh. The year-on-year decline will reach PLN 25-30/MWh, which may be only in part attributed to falling costs of emission allowances (ca. PLN 14/MWh). Taking into account that almost half of emission allowances will be free for Polish power plants, the profitability of the Polish generation sector this year will be affected even more than last year. As a reminder, in 2013 prices fell by PLN 20/MWh (driven by discounts on CO2 prices), and additionally power plants negotiated 10% reductions in prices of Silesian coal. This year year, a discount will be hard to get given the financial struggles and the expected downsizing of inventories at Polish coal mines. The price downturn will have a particularly severe impact on power plants that incur practically only fixed costs (captive lignite-fired generators operated by coal mines).

Forecast of wholesale electricity prices vs. TGE quotes (PLN/MWh)



Source: estimates by Dom Maklerski mBanku, TGE

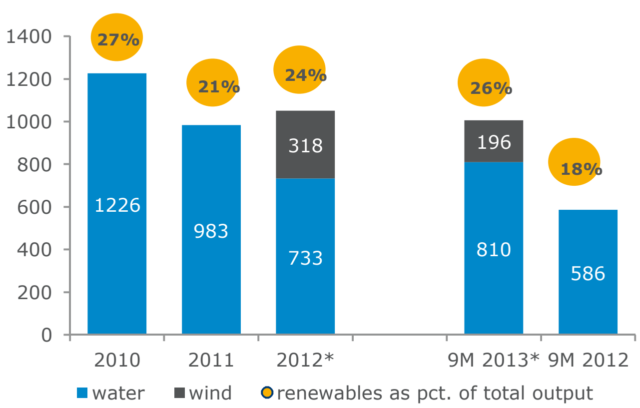
Our long-term price projections for Poland are linked to our forecasts for the German market adjusted for EUR/PLN effects. We consider the current small discount built into EEX and TGE contracts to be a temporary one. Our forward price curve is shaped by assumptions regarding prices of coal and carbon emissions. Still, in the medium-term, we are more optimistic than the market. Note that in upcoming quarters prices on Poland's TGE exchange may be higher than on the German exchange due to a much tighter demand/supply balance. Data presented by PSE suggest that, in practice, despite commonly formulated expectations, coal-fired power plants have not been pushed out from the price stack by wind turbines (it was mostly gas-fired CHPs that fell out of the merit order due to a lack of green certificates for cogeneration, but they have never had a say in setting prices in the system). With expected growth in demand and a lack of new capacity in the system, for the next two years the Polish market may function under the pressure of a low available reserve and heavier workloads put on less effective power plants.

Renewable Energy Sources

- Energa's renewable energy assets comprise hydroelectric power plants with a combined capacity of 203 MW (including a 160 MW unit in Włocławek), three wind farms (165 MW), and a pumped-storage power station (150 MW) serving exclusively the TSO.
- The earnings of the Renewables segment are highly dependent on prices of green certificates and the upcoming changes in the renewable energy subsidy mechanism.
- Energa's Renewables investment focuses primarily on wind farms (40-80 MW new capacity added annually); one possible hydroelectric power plant project hinges on government support.
- We expect the share of Renewables in consolidated EBITDA to decrease by several percentage points in 2015 due to the loss of RECs by the hydroelectric plants under the new laws set to enter into force that year.

The segment of Renewable Energy Sources at Energa comprises forty-six run-of-the-river (RoR) power stations with a combined annual capacity of 203 MW and an annual output of 733 GWh. The largest of these is the Włocławek power station on the Vistula river which has an annual capacity of 160 MW and which produced 603 GWh of electricity in 2012. The remaining plants are much smaller, with installed capacity ranging form 0.04 MW to 6.7 MW. Moreover, Energa generates renewable energy through its pumped-storage power station in Żydowo with a considerable annual capacity of 150 MW. The Żydowo plant averaged an operating rate of just 2% last year, but this has no relevance from the point of view of Energa's earnings because the plant is dedicated exclusively to the transmission system operator PSE subject to fixed annual compensation determined in advance. This year, Energa's Renewables segment expanded to include three wind farms with a combined capacity of 165 MW acquired from Dong Energy and Iberdrola.

Renewable power output at Energa (incl. wind power) (GWh)**

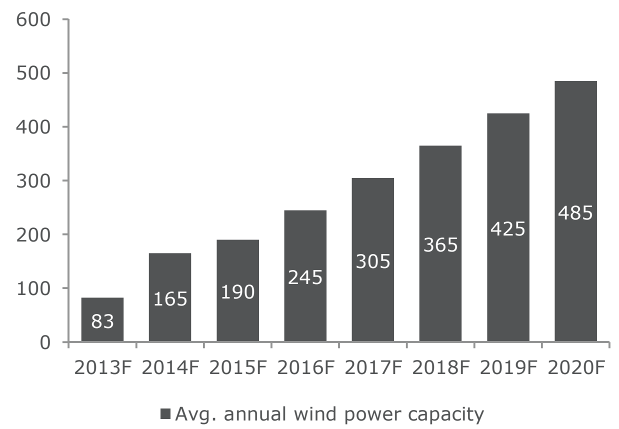


*pro-forma figures (Energa did not provide pro-forma financials for 9M 2012)
**run-of-the-river hydropower and wind power excl. pumped-storage and biomass-fired plant output
Source: Energa

Wind farm acquisitions

Working together with its partner PGE, Energa has completed two wind farm acquisitions this year from Denmark's Dong Energy and the Spanish utility Iberdrola. The June deal with Dong encompassed an existing wind farm in Karcin (51 MW) and five projects in the north of Poland with a combined capacity of 252 MW. The price was PLN 302m, implying per-megawatt price of PLN 6.5m (the 2012 load factor of these plants was 27%). The July transaction consisted in the acquisition of two wind farms with a combined capacity of 114 MW and a portfolio of wind farm projects with an aggregate capacity of 1.2 GW from Iberdrola and the EBRD. The price was PLN 804m, implying a per-megawatt price of PLN 7m (the 2012 load factor of these plants was 22%). The prices that Energa paid for the wind farms were consistent with similar transactions finalized earlier in Poland (PLN 7-9m/MW), and they fell in line with the average replacement costs typical for this type of investment (PLN 6.5-7m/MW), especially considering that the acquired assets included a considerable portfolio of work in progress. What worries us is that the wind farms have long-term contracts in place with Energa for sales of green certificates, which means that Energa bears the full consequences in case the prices of green certificates go down. Given the uncertainty surrounding the government's plans with respect to future renewable energy subsidies at the time of the acquisition, we would have expected a discount for the risk.

Average annual installed wind capacity (MW)

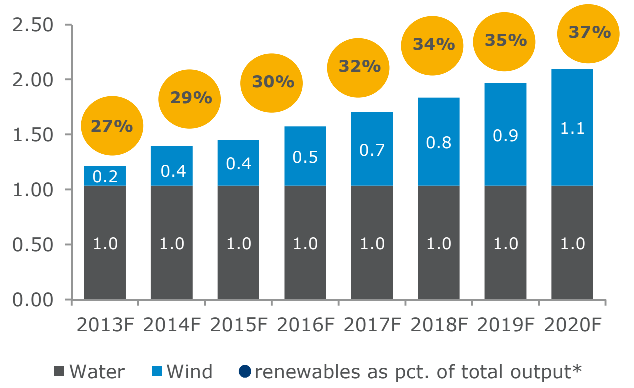


Source: Energa, estimates by Dom Maklerski mBanku

Investment plans

Energa's 2013-2021 capital investment budget provides for expenditure of PLN 1.7 billion on renewable energy sources, of which PLN 1.1 billion has been spent this year on the wind farms acquired from Dong and Iberdrola. About PLN 390 million of the remaining balance has been allocated to two organically developed wind farm projects in Myślino (21 MW) and Drzewiany (28MW), scheduled for completion in 2015, and two solar power plants with 6 MW capacity. Further, Energa is planning to spend PLN 230 million on upgrading its RoR plants as well as the pumped-storage plant in Żydowo (among others by increasing its capacity by 9 MW). The Company has also made an allowance of a little under PLN 3 billion toward contingent wind farm projects conditioned upon the incentives that may become available under the new renewable energy subsidy scheme. In the best-case scenario, Energa's goal is to complete 40-80 MW of new annual wind energy capacity until 2021. We assume for valuation purposes that Energa's installed wind power capacity will increase at a rate of 60 MW a year in the medium term starting in 2015-16.

Renewable energy as pct. of projected annual output (TWh)*



*ex. biomass-fired output and pumped-storage plant output
Source: Energa, estimates by Dom Maklerski mBanku

New RoR power plant project on the Vistula river

Energa is currently studying the feasibility of building a barrage across the Vistula river with a turbine system of 70MW capacity, generating an annual power output of ca. 400 GWh. The new RoR plant would have to be built downstream of the existing Włocławek plant. Aside from increased hydropower capacity, the main objectives behind the project are to provide long-lasting backup to the 40-year-old Włocławek barrage (which has to support large water quantities and causes erosion of the riverbed), and to increase flood safety. The project is currently at the stage of preparations for environmental permit applications. It has a very tentative start date in 2017. For now, it is only factored into Energa's CAPEX budget to the extent of the preparation costs (PLN 150m) as its future depends on government subsidies (e.g. whether adequate correction factors will be applied to large hydropower plants allocated certificates of origin (COO), and whether the government will offer financing guarantees). Our rough estimate of the costs of the second Vistula hydropower project is PLN 3.0-3.5 billion, but we do not take the project into account in our valuation of Energa on the Company's direction.

Past earnings and future outlook

Renewables are a major component of Energa's profits (accounting for 25% of consolidated EBIT), but the core operating profits provided by this segment have been deteriorating steadily in the last few years. Renewable energy sources do not incur any variable costs, which means their profitability is a direct results of sales. Accordingly, the EBIT contraction reported in 2011 and 2012 can be blamed on lower output volumes (caused by changing hydrological conditions – 2010 saw record water flow) and fluctuations in the prices of green certificates. In 2013, Energa is experiencing continued price declines in certificates of origin, combined with falling prices of coal-fired power on the one hand, but on the other hand it is able to produce larger volumes of hydropower thanks to improved weather conditions, moreover, the newly acquired wind farms will start contributing to its profits in the second half of the year. Consequently, we anticipate EBITDA growth of nearly 50% in FY2013. In FY2015, Energa's profits are set to slow down again due to potentially unfavorable terms of the new renewable energy subsidy scheme which will probably take away green certificates from fully-amortized hydroelectric power plants (we assume the Economy Ministry's latest subsidy proposals will enter into force in their current shape in January 2015). Further, the proposed changes to the renewable energy funding regime have given rise to uncertainty about the cost-benefit balance of power cogeneration which will be a product of carbon allowance costs, coal costs, and green certificate prices. We assume in our projections that biomass prices will be appropriately adjusted to reflect lower income from certificates of origin (under the proposed scheme of a half a certificate per 1 MWh of power). Energa's EBIT is expected to resume its upward move in the following years thanks to new wind farms. Our working assumption is that new projects eligible for the feed-in tariff will continue to receive government support at the same level as today (maximum subsidies are set at an equivalent of the average green certificate price in the two years prior to the entry into force of the new laws plus the electricity price prevailing in the previous year). We realize that this assumption will be put to a test during the first auctions.

Financial projection for Renewables

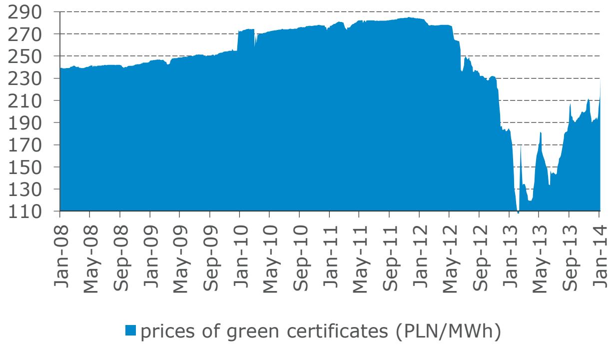
(PLN m)	2010	2011	2012	2013P	2014P
Revenue	580	458	352	500	547
EBIT	447	338	230	330	333
share in total EBIT	55%	39%	25%	29%	28%
EBITDA	484	372	261	388	414
One-offs	-7.7	-3.0	-1.4	0.0	0.0
EBITDA (adj.)	491	375	263	388	414
Share in total EBITDA	31%	23%	14%	19%	20%
EBITDA margin (adj.)	85%	82%	75%	78%	76%
Green certificates*	264.0	274.9	255.0	170.0	200.0
Renewables output (TWh)	1.2	1.0	0.7	1.2	1.4
Hydropower	1.2	1.0	0.7	1.0	1.0
Wind power	0.0	0.0	0.0	0.2	0.4

*TGE spot prices (PLN/MWh)
Source: Energa, estimates by Dom Maklerski mBanku

New renewable energy support scheme coming in 2015

The Polish power industry is still waiting for a new renewable energy law which is supposed to completely change the subsidy regime. The bill was supposed to enter into force this year, but the legislative process is dragging on due to cabinet reshuffling within the Ministry of the Economy, and a lack of consensus on the main points. The first draft of the renewable energy bill set new correction factors for different energy sources (with different subsidies offered depending on the type of generator), and it canceled financing for fully-amortized hydroelectric power plants. The proposals changed in the course of last year, and the changes included a cap on the funding period for biomass co-firing to five years, and revisions to the correction factors proposed earlier. The new set of proposals submitted by the Ministry in recent weeks is supposed to be the final framework for the new subsidy regime which, however, will probably not enter into force until 2015. In its latest incarnation, the renewable energy bill provides that subsidies for hydroelectric power plants with over 1MW capacity will be discontinued, and financing for biomass co-firing will be cut in half (a half a certificate per 1MWh, with the eligible volumes not exceeding the 2011-2012 averages). Subsidies for existing renewable power plants will be offered for a period of fifteen years from launch, but green certificates for these plants will stop being issued in 2021. New plants will operate under a feed-in-tariff mechanism whereby they will be selling their output at auctions on a competitive basis (subject to specific price caps set for the different types of generating technology). The energy will be bought up at predetermined prices by a new government-run vehicle, and sold through the TGE exchange. The buying vehicle will be financed (by filling the gap between the feed-in-tariff and the market prices of electricity) from a renewable energy fee which will be included in the tariff charged by the transmission system operator PSE. Without knowing the specifics of the benchmark price setting mechanisms, we believe the new subsidy regime will continue to be an incentive for wind power projects, even if the rates of return on these projects will diminish under the competitive auction scheme which will fully reflect the changing costs of technology.

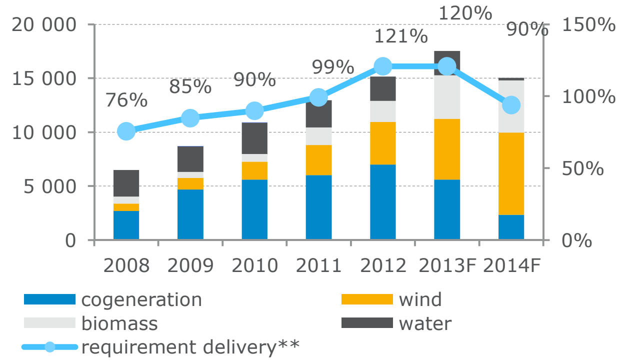
2008-2013 green certificate prices



Source: TGE

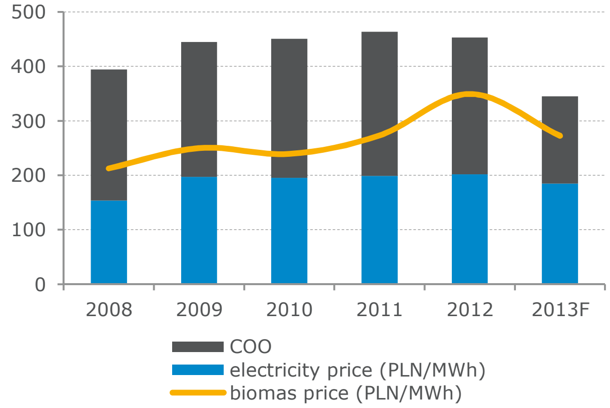
In addition to offering financial support, the new renewable energy law is also expected to address the slump in the Polish market for green certificates whose prices have plummeted from over PLN 270/MWh to PLN 130-150/MWh (the YTD average is PLN 146 vs. PLN 251 last year). The excess supply of green certificates was expected to be removed through reduced financing allocated to certain energy sources. Last year, the fast-paced expansion of alternative capacity (wind, cogeneration, biomass) led to a surge in renewable energy output to the extent that it exceeded the ca. 10% quota set for electricity sellers by over 20%. The same is expected to happen this year even though the renewable energy requirement has been raised to 12% and despite reduced production of co-fired power due to margin shrinkage caused by lower overall electricity demand and increasing wind capacity. The changes in the renewable energy laws announced by the government have potential to restore balance to the market for green certificates, as evidenced by TGE quotes for renewable energy certificates of origin (COO) which were seen to hit well over PLN 200/MWh in response to the announcement. In addition to mitigating excess supply by discontinuing the allocation of certificates to hydropower and cogeneration plants, the new regime requires that certificates of origin be sold via entities trading under the old regime through the energy exchange (30% through 2015 and 50% after 2015), and provides that the quotas for exchange-based renewable energy sales should be aligned with the renewable energy output forecasts for "old" plants. The ratio will decrease as power plants lose government financing or switch to the auction system, and it will take into account electricity usage projections and regulatory changes. We assume for valuation purposes that prices of certificates of origin will average PLN 200 in 2014 and PLN 250 in 2015.

Renewable energy production in Poland by source (GWh)



*2014 output forecast allows for discontinuation of subsidies for hydroelectric power plants which is most likely actually going to take place in 2015
**ratio of total renewable power output to the renewable power requirement
Source: URE, TGE, estimates by Dom Maklerski mBanku

Effective biomass prices (incl. calorific values and plant efficiency) vs. electricity prices (PLN/MWh)



Source: TGE, estimates by Dom Maklerski mBanku

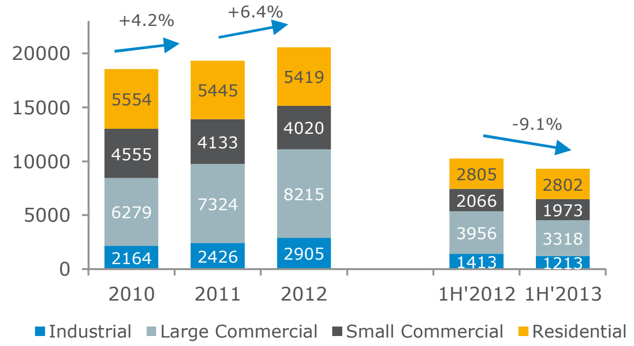
From the point of view of Energa, the new subsidy scheme will have a noticeable impact on profits, first through a possible loss of revenues by hydropower plants (2013 green certificate sales by these plants are estimated at PLN 176m), and secondly through reduced profitability of biomass cofiring (we estimate the 2013 cofiring margin after just biomass costs at PLN 30-40m). Energa will feel the impact of the new subsidy scheme more than most of its peers due to its larger hydropower capacity.

Sales Segment

- Energa sells 20.5 TWh of electricity to end-customers annually, and this volume gives it a market share of 17%.
- A short position as a marketer (with in-house production accounting for 19% of the sales volumes) means Energa buys power in the wholesale market.
- Its location is northern Poland means Energa has to serve in the – currently quite costly – capacity of supplier of last resort and purchase renewable power at regulated prices.
- 2013-2014 margins are set to be high thanks to falling costs of certificates of origin (although the benefits in case of Energa are smaller than enjoyed by competition due to its long-term contracts for green certificate purchases).
- The Sales segment retains a steady, over-10% share in consolidated EBITDA, and generates high operating cash flows.

Energa sold 20.5 TWh of electricity to end-customers in 2012, representing a market share of 17%, and ranking the Company the number three power utility in the country after Tauron and PGE. Energa's sales territory covers basically the same area as its transmission infrastructure (the same is true for other vertically-integrated utilities, being a consequence of the past structure of the Polish electricity market), but the Company is undertaking marketing initiatives aimed at extending reach beyond the home regions of northern and central Poland. As well as retail sales, the Sales segment is also actively involved in wholesale sales of electricity (in 2012, wholesale volumes totaled 7.7 TWh). Energa has a short position in electric power (i.e. its own net output accounts for just 19% of total sales), which means it has to actively manage the ensuing risks through the energy exchange and bilateral spot and forward contracts. The Company does not disclose the details of its hedging policy, but the standard industry practice is to maintain exposure to spot price volatility at 10-15% max of the total portfolio.

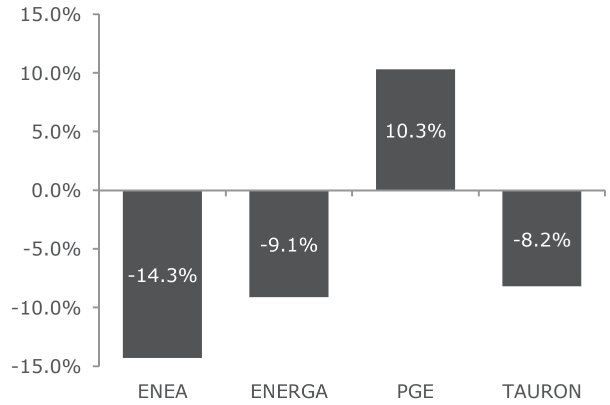
Energa's sales volumes by tariff group (GWh)



Source: Energa, Dom Maklerski mBanku

Households, which are the only customer category subject to regulated electricity price rates, accounted for about 26% of Energa's total sales in 2012 (a share similar to those recorded by other major sellers). The largest, 40% share in sales is attributed to large business customers using medium-voltage electricity, such as hospitals, shopping centers, etc. Business users are where competition is the most intense at the moment, as these types of customer are the most open to changing suppliers, as evidenced by the operating results of power utilities for the first half of the year. Almost all major utilities (except PGE) were losing business volumes during the period, and these losses can be only partly explained with subdued business activity. The willingness of players like Enea, Energa, and Tauron to give up market share is not so much a mark of their passiveness or ineffective marketing strategies as it is a reflection of their strategic focus on maximizing profits even if it means foregoing sales. The customer group which is the main profit driver for Energa's Sales segment are small and mid-sized businesses who show the least inclination to switch providers.

H1 2013 retail sales growth by utility

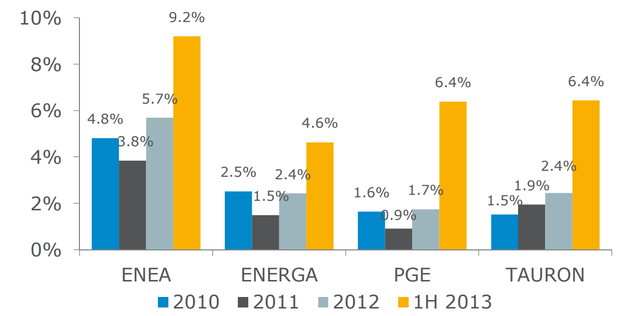


Source: Energa, Companies, Dom Maklerski mBanku

Past earnings and future outlook – can Sales continue to post record margins?

All Polish power utilities have been reporting record profits from retail sales this year, making up for the falling profits from power generation. Thanks to the 2012 drop in prices of certificates of origin for renewable energy, combined with the discontinuation of the cogeneration certificate redemption mandate, operating margins multiplied in H1 2013 as sellers did not fully pass the lower costs of coal-fired energy and certificates onto customers. This applies to all tariff groups except major industrial users, i.e. to about 75% of total sales volumes. Based on H1 earnings presentations, we concluded that trading companies shared half of the change in the wholesale price of electricity (PLN 15-20/MWh yoy) with their customers. As for the extra proceeds from COO, they were mostly retained by the traders. The surge in H1 profit margins was so huge that it overshadowed the volume contraction reported by most companies (except PGE). Energa experienced margin growth as well in H1, although not quite as robust as the competition (even after taking into account a PLN 21.7m gain on certificates of origin recognized under intercompany eliminations), the reason being the fixed-price purchases of green certificates which minimized the sensitivity of the costs of renewable energy quotas to changes in market prices. Being located in a close vicinity of a number of wind farms, Energa has been a natural partner for wind farm developers looking to stabilize their revenues in the long term so as to increase their chances of securing financing. According to TGE data, the average price of green certificates this year in after-hours trading is about PLN 230/MWh, which compares to a market price of just PLN 150/MWh. That is why Energa's Sales business has been benefitting primarily from a lack of cogeneration certificate costs rather than from extra margins on green certificates. What is more, as the supplier of last resort within its region, Energa is required to purchase renewable power at regulated prices (which are set as the average price prevailing in the previous year), which today are higher than market prices (the regulated price this year is PLN 201.36/MWh, while the average wholesale market price is a little over PLN 190/MWh), resulting in negative margins. The disparity was painfully obvious in Q3 2013 when profits deteriorated as the volume of wind power produced in Poland in the period was nearly 30% higher than last year.

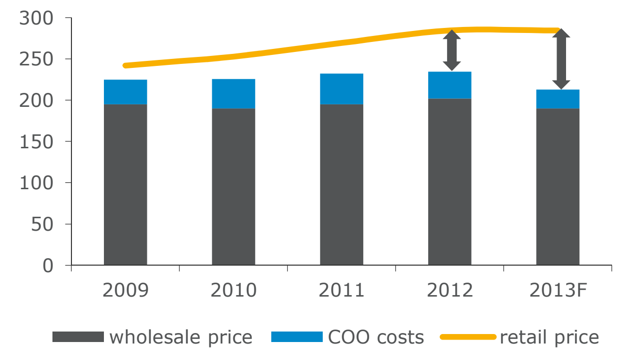
Trade EBIT margins by utility



Source: Companies

The margin trends should not change much in the quarters ahead, especially since the new energy law (which resumes support for cogeneration) is most likely not going to take effect until 2015. Utilities have been experiencing some downward pressure on prices, but the pressure is very small due to the nature of contracts and to the low awareness of market movements among certain groups of consumers. Further, the 4-5% reductions in residential tariff rates coming in the second half of the year will also not hurt trade profits too much (we estimate the consequent EBIT losses through to the end of 2013 at PLN 32m for Energa, PLN 24m for Enea, PLN 58m for PGE, and PLN 72m for Tauron).

Margins on residential electricity sales (PLN/MWh) (an approximation ex. excise duty)



Source: URE, estimates by Dom Maklerski mBanku

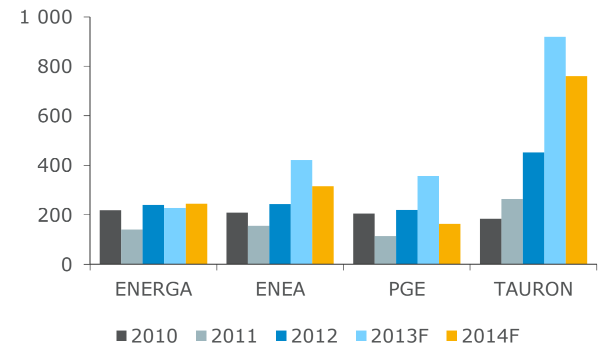
Contrary to most analysts, we do not think 2013 has been an anomaly at all, and we believe Polish utilities will continue to generate stellar margins from retail sales in 2014. Granted, the extra profits derived from lower COO costs will disappear (higher prices of green certificates, adjustments of sales prices for the full effect of the lack of cogeneration certificates), but at the same time the price spreads on coal-fired energy will widen. Wholesale electricity prices are expected to fall at twice the rate seen this year in 2014 (the YoY drop is estimated at PLN 30/MWh), and we can assume that at least half of this amount will go to traders. Accurate margin predictions are impossible at this point as much will depend on competitive pressures, but we would not expect a price war between utilities next year. The following is a summary of our trade EBIT projections for Energa and other major utilities:

Trade EBIT projection for Energa

(PLN m)	2010	2011	2012	2013F	2014F
Revenue	5,646	6,804	7,179	6,865	6,405
EBIT	218	140	240	226	245
share in total EBIT	27%	16%	26%	20%	21%
EBITDA	243	168	264	251	269
one-offs	-2.3	-39.5	-3.5	0.0	0.0
EBITDA (adj.)	245	207	268	251	269
share in total EBITDA	15%	13%	14%	12%	13%
EBITDA margin (adj.)	4%	3%	4%	4%	4%
Volume (TWh)	18.6	19.3	20.5	19.1	19.4

Source: Energa, estimates by Dom Maklerski mBanku

Trade EBIT projection by utility (PLN m)



Source: estimates by Dom Maklerski mBanku

CHP Segment

- The CHP segment comprises combined heat-and-power plants in Elbląg and Kalisz (where Energa also operates a district heating network).
- CHP sales are subject to price regulation. Profits going forward are expected to recover at a slow but steady pace.
- Planned capital investment in the segment focuses on existing capacity replacements in compliance with commitments made to local authorities. Acquisitions are not out of the question.
- CHPs make marginal contributions to total earnings.

Energa's key CHP assets are two cogeneration plants located in Elbląg (49 MWe, 293 MWt) and Kalisz (8 MWe, 128 MWt), together with distribution networks (the district heating scheme in Kalisz was purchased in 2013 for PLN 46m). Heat sales are subject to price regulation using a formula based on eligible costs plus return on capital (similarly to distribution prices, the regulator's approach is to combine the path toward maximum return on capital with performance benchmarks). Utilities benefitted from cogeneration certificates until 2013, but these certificates lost their profit-boosting ability earlier, around mid-2012, after their prices took a sharp downward turn (resulting in a drop in CHP earnings last year). Energa estimates capital expenditures in the CHP segment in the years 2013-2021 at PLN 620m, including the district heating network acquisition completed this year as well as completion of a 25 MW biomass-fired facility in Elbląg (PLN 60m), construction of a new unit in Kalisz and modernization of the existing plant including fuel switch (PLN 220m), and further acquisitions of district heating systems (PLN 290m). In addition, Energa is considering investing in a new 115 MW combined-cycle plant in Elbląg depending on the upcoming changes in the regulatory and market environments. Of the capital investment projects described above, we decided to only factor in the biomass power plant and the capacity replacements in Kalisz into our valuation model. We expect the CHP segment to post improving profits in the years ahead, while continuing to make marginal contributions to Energa's consolidated profits.

CHP earnings projection for Energa

(PLN m)	2010	2011	2012	2013F	2014F
Revenue	167	150	158	160	162
EBIT	2	4	-4	10	15
share in total EBIT	0.3%	0.4%	-0.4%	0.9%	1.3%
EBITDA	10	10	4	18	31
one-offs	-9.4	-3.6	-5.1	0.0	0.0
EBITDA (adj.)	20	14	9	18	31
share in total EBITDA	1%	1%	0%	1%	1%
EBITDA margin (adj.)	12%	9%	6%	11%	19%
Power output (TWh)	0.1	0.1	0.1	0.2	0.2
Heat output (TJ)	2,826	2,450	2,496	2,496	2,496

Source: Energa, estimates by Dom Maklerski mBanku

Other Segments

The segmental breakdown of Energa's operations includes "Services" (defined as intercompany services in the areas of HR, IT, and investment management), and "Others" (comprising transportation services, hotels, training centers, and general holding company management expenses; back in 2010-11, the "Others" segment also included heat distribution and street lightning which were later reclassified to "CHP" and "Sales," respectively). When it comes to Services, now that Energa has finalized the centralization of certain functions, we do not expect major developments as regards the segment's earnings results in the coming years. As for "other" operations, they represent mostly general and administrative expenses which cannot be assigned to any of the other segments, and which, we assume, will increase in line with annual inflation in the years ahead. We would like to address briefly Energa's intercompany sales account which has had a varying impact on consolidated earnings in the past, with 2012 and 9M 2013 intercompany transactions providing a boost to the bottom line. According to Energa, the reasons why intercompany losses turned to gains in 2012, adding PLN 70m to the year's EBIT result, included derecognition of allowances set aside in Distribution (to cover PLN 31.9m settlements with Sales) and adjustments to asset depreciation charges (PLN 28m). The intercompany gains recorded in 9M 2013 included a PLN 11.8m gain on wind farm acquisition, D&A adjustments totaling PLN 15.5m, and a PLN 21.7m gain from intercompany payments for green certificates (a reduction in overestimated allowances set aside for certificate redemptions in the Trade segment). Based on these trends, we estimate the recurring annual impact of adjustments for intercompany transactions at around PLN 40m.

Earnings projection for other operating segments *

(PLN m)	2010	2011	2012	2013P	2014P
Revenue	320	395	485	497	509
EBIT	-53	-59	-2	-14	-19
Services	-1,5	-5,3	10,0	24,0	23,9
Others	-20,0	-50,0	-81,8	-83,8	-85,9
Intercompany trans.	-31,1	-3,7	69,6	45,6	43,3
EBITDA	-80	-62	-11	-23	-28
one-offs	0,0	-2,2	-5,3	11,5	0,0
EBITDA (adjusted)	-80	-60	-6	-35	-28

*Other operating segments as presented in Energa's financial statements include "Services," "Others," and "Intercompany Transactions"
Source: Energa, estimates by Dom Maklerski mBanku

Financing: Net debt

At PLN 3.0 billion, Energa's net debt as of 30 September 2013 was a relatively low multiple of annual EBITDA. The "gross" debt was mostly comprised of two outstanding bond issues: a PLN 1bn zloty tranche maturing in 2019, carrying interest rate at WIBOR+150bps (issued as part of a PLN 4bn bond program), and a EUR 0.5bn eurobond tranche maturing in 2020 with a coupon rate of 3.25% p.a., backed by currency interest rate swaps. Further, Energa uses external preferential financing to further capital investment in the Distribution segment, including a 2009 EIB loan of PLN 1.05bn payable in 2025, a 2010 EBRD loan of PLN 800m due in 2021, and a 2010 NIB loan of PLN 200m due in 2022. The interest debt owed to these banks is a little over PLN 200m. This year, to ensure completion of its other investment plans, Energa signed two further financing deals with EIB and EBRD for respective amounts of PLN 1bn (payable in 15 years) and PLN 0.8bn (payable in 12 years). Altogether, therefore, the Company still has unused credit of PLN 2.8 billion at its disposal, and this, combined with the repayment schedules of these facilities, makes for a very healthy balance sheet position as reflected in relatively low interest margins.

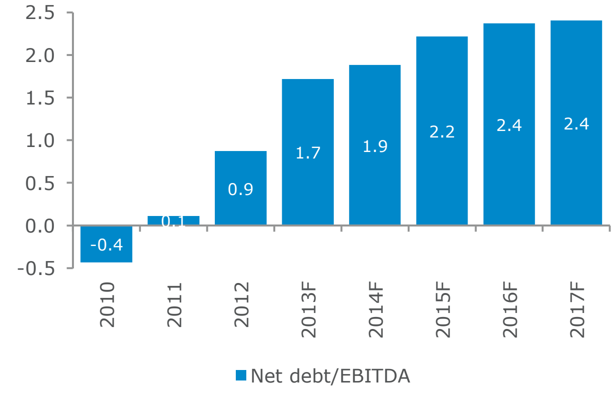
Net debt overview

(PLN m)	2009	2010	2011	2012	9M'13
Loans	346	1 076	1 949	2 416	2 096
short term	57	1 034	1 904	2 026	1 812
long term	289	43	45	390	283
Bonds	0	2	0	1 079	3 206
Leases	19	10	5	14	8
Financial debt	365	1 088	1 954	3 509	5 309
Cash	887	1 684	1 777	2 069	2 307
Net debt	-522	-595	177	1 440	3 002
Net debt/Equity	-8%	-8%	2%	19%	38%
Net debt/EBITDA	-0,50	-0,42	0,12	0,88	1,67
Net debt/EBITDA (adj.)	-0,53	-0,37	0,11	0,77	1,44

Source: Energa

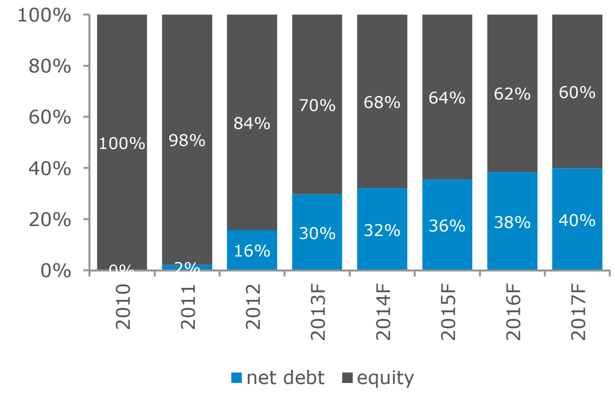
Energa's debt is set to increase in the coming years as necessary to further the planned capital investment and the dividend policy. However, the Company has pegged its target debt-to-EBITDA ratio is at 2.5x max, which is a realistic goal in our view assuming the costly contingent projects (natural gas-fired CCGTs and the new hydropower facility on the Vistula) do not actually take off. We like Energa's controlled approach to using leverage as it ensures an improving financing structure and hence also lower cost of capital. This is particularly important from the point of view of the WACC formula used by the regulator to calculate distribution tariffs (the 2013 ratio of debt to enterprise value is set at 42%, scheduled to increase to 50% in 2015). It would be best if this formula was reflected in the balance sheet of Energa-Operator, which, we believe, will be achievable in 2016-2017 (the projected 2016 leverage ratio for the Energa Group is 38%, and the expected share of Distribution in the consolidated 2016 EBITDA is ca. 78%).

Net debt/EBITDA ratio projection



Source: Energa, estimates by Dom Maklerski mBanku

Enterprise value financing*

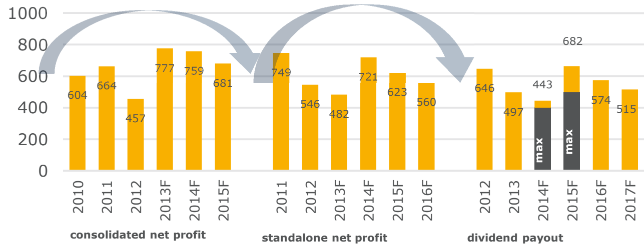


*defined as debt and equity as percentage of enterprise value, calculated based on projected debt and equity
Source: Energa, estimates by Dom Maklerski mBanku

Dividend Policy

Energa has been making regular distributions to shareholders for the last few years, with dividend payout ratios relative to consolidated FY2011 and FY2012 net income at a whopping 97% and 109%, respectively. This year's payout implies a dividend yield of about 6% (calculated based on the mid point of our valuation range). Under the dividend policy currently in force, Energa intends to distribute 92% of standalone net earnings in the coming years, except that the distribution against the 2013 profit will not exceed PLN 400m, and the distribution from 2014 earnings will not exceed PLN 500m. Starting in 2015, dividend payments are to be adjusted for at least the rate of inflation. The dividend calculation formula is important in that Energa is a holding company which derives a major portion of its annual earnings from dividends received from subsidiaries. This means that, for example, the payout made in 2013 (PLN 497m) corresponds to the consolidated earnings for fiscal 2011 (t-2). Technicalities such as one-time events or a lack of "negative" dividends from lossmaking subsidiaries make Energa's standalone net profits fall in the range of 80-100% of the consolidated profit generated in the "t-1" period (the dividend-shaping mechanism is illustrated in the diagrams below). According to our calculations, the amount of shareholder distributions in 2014 and 2015 will be equivalent to the relevant caps set in the policy (i.e. PLN 400m and PLN 500m, respectively). In the following years, we project that Energa shareholders can expect payouts between PLN 500m and PLN 600m. If these assumptions are correct, the average dividend yield in the 2014-2017 period (based on the mid-point of the valuation range) can be as high as 6.4%.

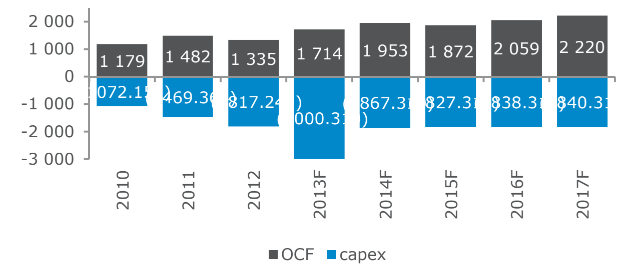
Annual earnings vs. dividends* (PLN m)



*payouts shown as percentage of consolidated net profit for the previous year and for t-2 year
Source: Energa, estimates by Dom Maklerski mBanku

As for where the cash for the future dividend payments will come from, most of the funding will be raised by increasing debt. We expect future cash flows will be enough to cover the planned capital investment, and the high payout ratios set in the dividend policy will be observed through the achievement of optimal cost of capital by increasing leverage until it reaches the target level of 2.5x EBITDA. The generous payments to shareholders give Energa a considerable advantage over competition which is forced to cut payouts in order to be able to carry out capital projects.

Operating cash flow vs. CAPEX (PLN m)

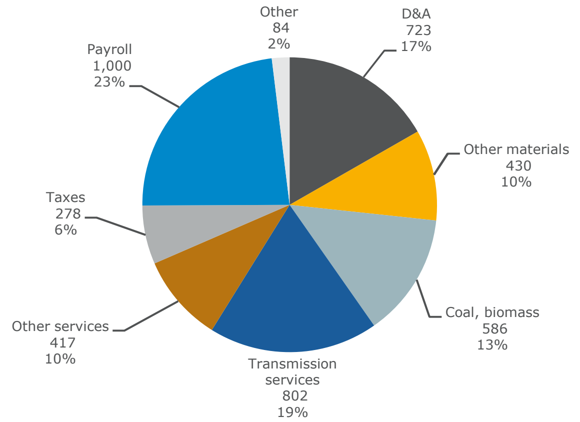


Source: Energa, estimates by Dom Maklerski mBanku

Cost Restructuring

Energa's Management Board has implemented a number of initiatives to date designed to streamline the workforce, assets (reduction of network losses in Distribution, management of power generation at the level of the Sales segment), internal functions (centralization of IT, HR, accounting), purchases (building services, parts, materials), and external services (outsourcing of cleaning, security services). As is the case with all other Polish utilities, payroll expenses make up the bulk of Energa's costs, and payroll is where the Company has the most room to make savings. However, the reduction of the surplus workforce which is a legacy of the power sector's past is a very gradual process as employers have to honor their labor commitments (according to a H1 2013 survey, approximately 60% of all power sector workers are union members, and collective bargaining agreements with unions provide for employment guarantees until August 2017). Energa has addressed overstaffing by putting in place a voluntary separation program in 2010 which has resulted in a reduction in the worker headcount by approximately 2000 (i.e. 16%) in the last three-and-a-half years. Severance packages have cost the Company PLN 300m so far, but the annual savings are estimated at over PLN 180m (based on average salary not adjusted for inflation, and the number of employees who have left).

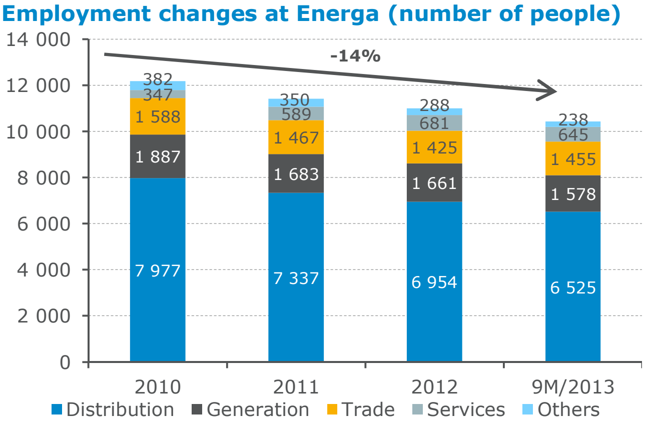
2012 cost breakdown*(PLN m)



*excluding asset impairment losses and costs of electricity purchased for resale
Source: Energa, estimates by Dom Maklerski mBanku

The future downsizing potential is hard to predict, but, considering that the productivity indicators for Energa's Distribution employees (who account for 62% of the total headcount) have already surpassed those of the competition (e.g. RAV per employee is 17% higher than average), and given the small share of employees nearing retirement age (only 3% are 60 years old or older), the pace of payroll cost reductions is likely to decelerate in the years ahead. From a savings standpoint, the efficiency-enhancing measures that can prove to be more effective in the future will include intelligent networks and lower costs of fuel incurred by the Ostrołęka power plant.

Employment changes at Energa (number of people)



Source: Energa, estimates by Dom Maklerski mBanku

As part of an organizational restructuring initiative, Energa's Management Board has also reviewed the Company's asset holdings and decided to sell those that are not part of the core business (mainly hotels and other real estate). Moreover, Energa is in the process of selling several engineering service providers that cater to the distribution network operator. The book value of the net assets earmarked for sale is not high at some PLN 70m, but the main objective of the divestments is to improve the effectiveness of network maintenance through outsourcing (the Board believes the divestment and restructuring processes will be finalized within twelve months).

Financial results for 9M 2013

At an impressive PLN 610m, Energa's net profit for the nine months through September 2013 is equivalent to 79% of our full-year forecast. The strong 9M profit was owed in no small part to low financing costs (which decreased by PLN 4m relative to 9M 2012 even as average net debt increased) stemming from a PLN 64m YoY surge in revenue after reversals of a PLN 27.4m claim reserve and a PLN 12m charge connected with the Company's holdings in a street lighting company. Financing costs are bound to increase in the fourth quarter given the increased debt after the acquisition of the wind farms. Energa's 9M 2013 EBITDA amounted to PLN 1.5bn, and it reached 77% of our full-year estimate in spite of impairment charges on baseload power plants totaling PLN 123m, combined with restructuring costs (one-time events produced a net expense of PLN 180m in the period). Last year, the EBITDA figure generated in the first nine months was equivalent to 82% of the full-year figure, but Energa's profits for the final three months of the year were depressed by one-time losses totaling PLN 108m. That is why our FY2013 financial forecast for the Company should be viewed as conservative even after taking into account seasonal factors (the Distribution segment usually books reserves in Q4, and CHPs and hydropower plants typically generate weaker profits in the latter part of the year). By operating segment, it is worth noting the improvement observed this year in Renewables (where volumes expanded thanks to favorable hydrological conditions), the margin expansion recorded in Sales (in line with a general industry trend owed to certificates of origin and lower costs of wholesale electricity' the YoY margin contraction seen in Q3'13 was due to lower volumes and "supplier of last resort" duties), and the expected continuation of profit growth in the Distribution segment. In turn, Baseload Power Plants reported deteriorating profits in the first nine months due to falling electricity prices, additional emission costs, and the power plant impairments mentioned above (the segment's adjusted EBITDA would be a PLN 18.5m loss vs. a profit of PLN 19.6m posted in 9M 2012).

9M 2013 results vs. our FY2013 forecasts

(PLN m)	1Q 13	2Q 13	3Q 13	2013P	9M'13
Revenue	2 934	2 856	2 748	11 412	75%
EBIT	282	468	182	1 151	81%
one-offs	-118	8	-63	-172	100%
EBITDA	472	656	374	1 955	77%
Distribution	400	420	316	1 434	79%
Sales	101	78	9	251	75%
Generation	-21	128	92	294	68%
Renewables	90	143	80	388	81%
Baseload PP	-123	-19	16	-112	-
CHPs	12	4	-3	18	69%
Services	9	8	9	36	74%
Others	-16	-20	-18	-77	70%
Intercompany tr.	-1	41	-33	18	36%
Financing costs	-39	-9	-69	-154	76%
Net profit	192	353	65	777	79%

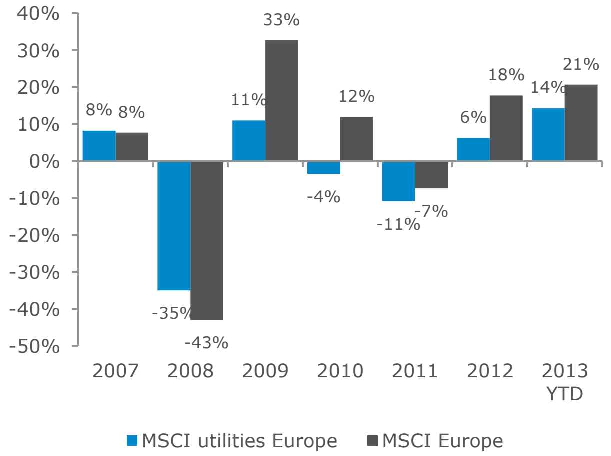
Source: Energa, estimates by Dom Maklerski mBanku

Operating cash flow amounted to PLN 1.49bn in 9M 2013 vs. PLN 852m in 9M 2012 (OCF before changes in working capital and reserves showed a YoY increase of about PLN 310m). After capital expenditures of PLN 2.3bn (including acquisitions) and dividends (PLN -480m), Energa's net debt as of 30 September 2013 was PLN 3.0bn. We expect debt to increase further in Q4 2013, led by seasonal fluctuations in working capital and a higher organic development CAPEX (in 9M 2013, Energa spent only 60% of the annual CAPEX budget set aside for Distribution).

Improving sentiment for utilities

Market sentiment for European power utilities has been persistently bearish for the past few years, but by early Q4 2013 the underperformance vis-à-vis the broad MSCI has been offset in some part by an 10% upturn in the prices of electricity, combined with rising prices of carbon allowances. An analysis of the medium-term returns on leading power stocks reveals that traders have been quite selective in their choice of companies, both in terms of business lines (generation, distributions), and in terms of geographic location. Aside from the usual operating factors, investors have been evaluating the sector based on possible changes in dividend policies, the potential for financing cost reductions in case of more indebted businesses (narrowing margins on corporate debt), and cost-cutting programs.

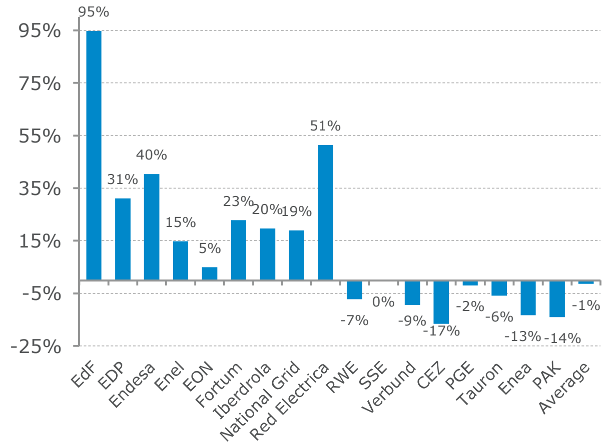
Annual total returns on MSCI indices



Source: Bloomberg

Interestingly, such a selective approach has not been taken with respect to Polish utilities in spite of their vastly differing sensitivities to current macroeconomic trends (whether in power generation, distribution, or sales), their varying approaches to cost savings, and the divergent quality of their earnings. The way the market reacted to the electricity price rebound in September, it is safe to assume that if the recovery continues (through higher demand, capacity payments, and caps designed to restrict the uncontrolled proliferation of renewable power capacity), utility stock valuations will rise across the board, and only then will traders become more selective again. Today, investors are significantly underweight power utilities, and their expectations for the sector are very low. Note that fluctuations in electricity prices affect not only the current earnings of producers (Polish companies have the advantage of shorter hedging periods applied to their generation portfolios which ensure better exposure to the price rebound, with positive effects for earnings results in 2014 and 2015), but they also influence the net present values of any new projects, assessed based on current prices of electricity contracts.

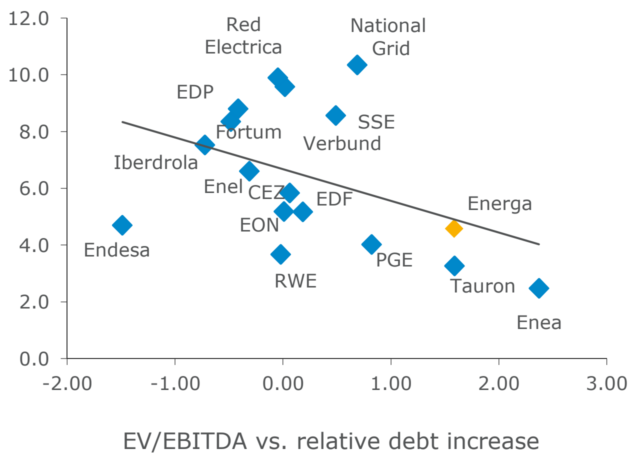
2013 total returns on utility stocks (incl. dividends)



Source: Bloomberg

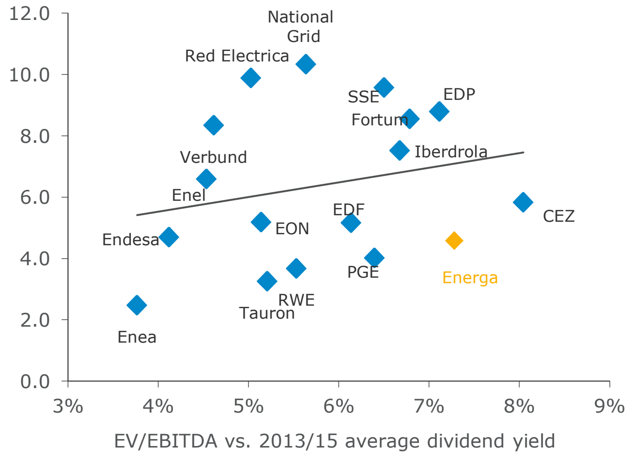
An analysis of the relationships between acceptable EV/EBITDA and P/E multiples and specific financial parameters has helped us to identify several key categories which have a significant impact on the way different power utilities are perceived by investors. Our conclusions are not surprising, and they overlap with our intuitive assessment reflected in discounts led by the prospect of negative net cash flows in the coming years, lower dividend yields, and expected declines in profits. Interestingly, in most cases Polish companies appear below the regression curve. This means that if sentiment to the Polish market improves, with all other things held constant, utility stocks should gain considerable value, especially if their capital investment plans are delayed and their profits deteriorate at slower rates than implied by analysts' consensus. Energa's ratios also fall below the regression curve.

Regression analysis: EV/EBITDA dependence on debt growth *



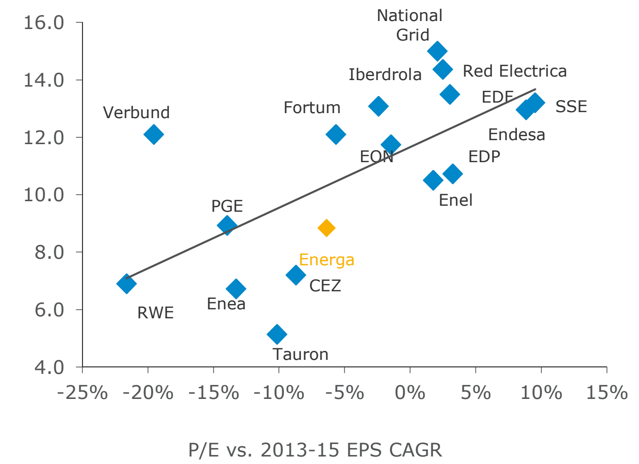
*net debt/EBITDA ratio calculated as the change in net debt as of year-end 2015 relative to December 2012 vs. average 2013-2015 EBITDA
Source: Bloomberg, Dom Maklerski mBanku

Regression analysis: EV/EBITDA dependence on dividend yield



Source: Bloomberg, Dom Maklerski mBanku

Regression analysis: P/E dependence on EPS growth



Source: Bloomberg, Dom Maklerski mBanku

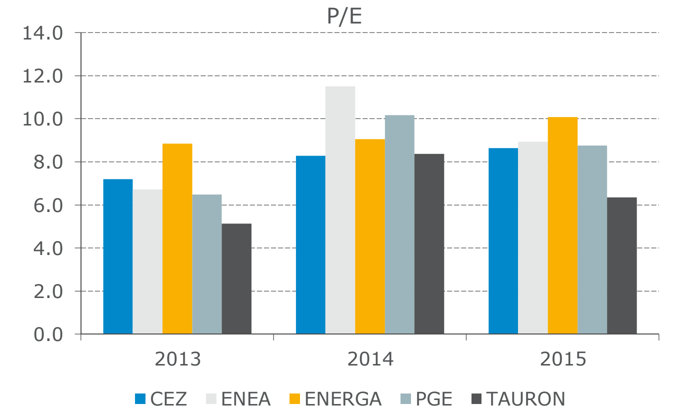
Financial and Valuation Risks

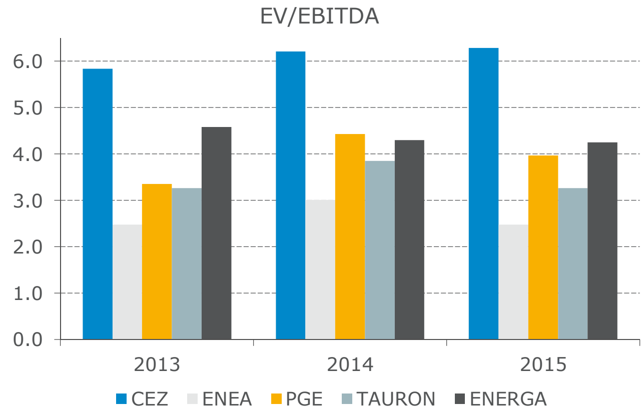
The following is an overview of possible risks which may affect our financial forecasts for, and valuation of Energa:

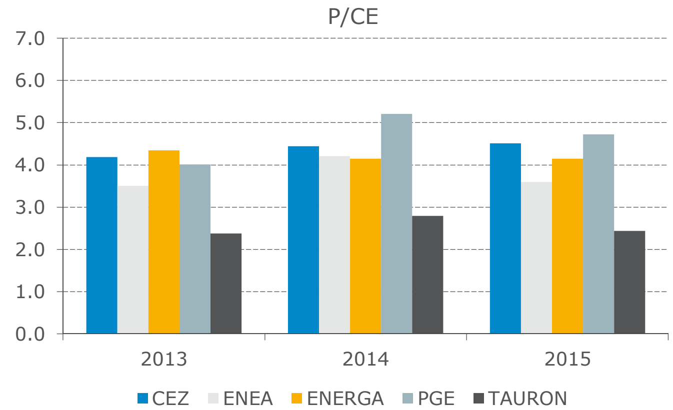
- **Changes in prices of electricity, carbon allowances, and basic materials** – our forecasts are based on specific price assumptions which reflect historical trends, and any divergence form these assumptions can affect the delivery of our financial forecasts and value estimates;
- **Regulatory policy** – certain areas of Energa's business (Distribution, heat generation, residential electricity sales) are subject to regulation by the Energy Regulatory Office (URE) which is tasked with finding a balance between the interests of consumers, power producers, and power distributors. URE's regulatory policy, including price tariff decisions, directly influences Energa's profits; the more restrictive the policy, the greater the risk that the Company will fall short of our forecasts;
- **Government bond yields** – the profits generated by the core segment of Distribution are correlated with yields on 10-year Treasury bonds through the ROA calculation formula, so any major fluctuations in the debt market may impact Energa's financial performance;
- **Changes in the renewable energy subsidy scheme** – the Polish government is working on a new bill changing the terms of state support for renewable energy sources. The preliminary general changes to the existing subsidy scheme are described earlier in the report, and they are factored into our financial forecasts to the extent possible. The legislative proposals can still change at this stage. Another source of uncertainty are the future prices of green certificates;
- **Environmental regulation** – the utilities sector has to observe a host of environmental regulations which include greenhouse gas emission caps and renewable energy quotas applied to sales. Any further limitations and restrictions may have an impact on Energa's profits;
- **Labor unions** – 60% of Energa's employees were unionized as of 30 June 2013, and this fact may shape the Company's operating costs in the future if the unions put pressure on the Management to raise salaries or mitigate downsizing measures.

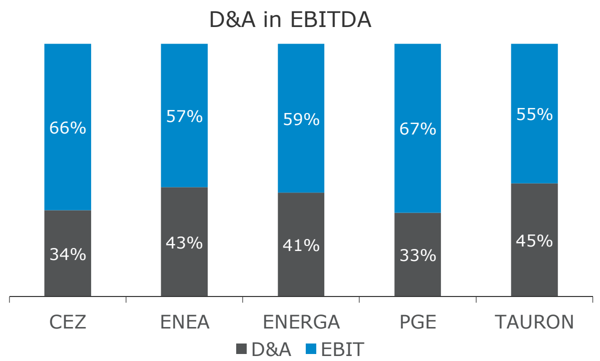
Relative Valuation Charts

P/E, P/CE, and EV/EBITDA multiples for power utilities, D&A share in EBITDA (the higher the D&A component, the greater the accuracy of the P/CE multiple vs. P/E)



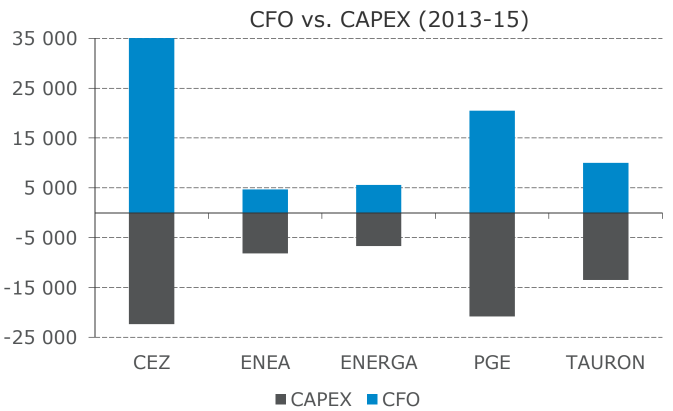


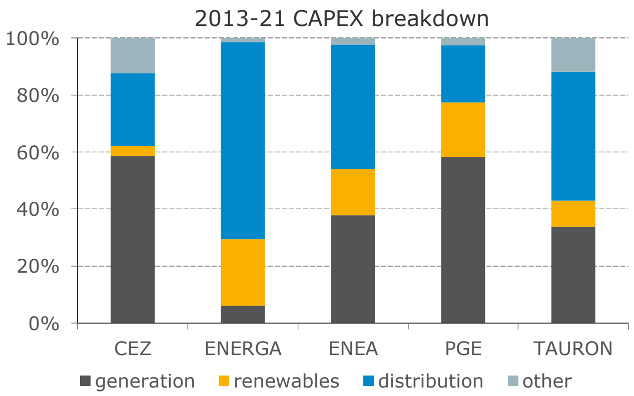




Source: Companies, estimates by Dom Maklerski mBanku

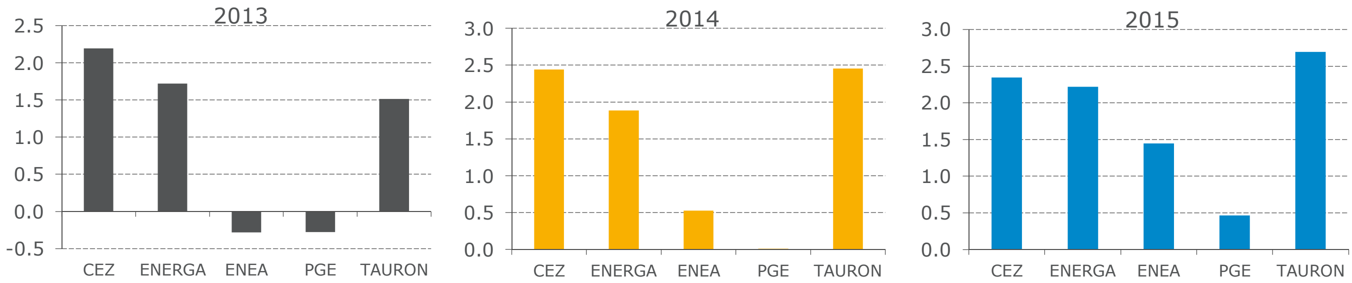
2013-15 CAPEX vs. CFO forecast (PLN m) (L) 2013-21 CAPEX budgets by operating segment (R)





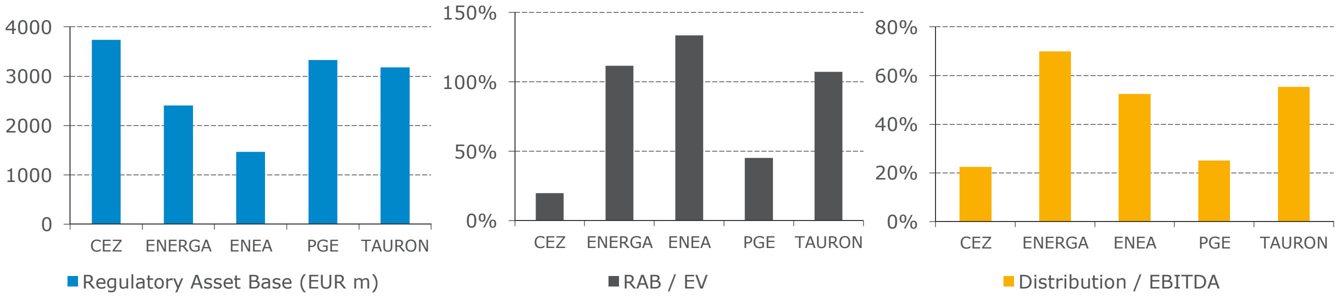
Source: Companies, forecasts by Dom Maklerski mBanku

2013-2015 net debt/EBITDA forecasts



Source: Companies, forecasts by Dom Maklerski mBanku

2013E RAB (L), Distribution RAB as pct. of EV (M) vs. Distribution as pct. of EBITDA (R)



Source: Companies, estimates by Dom Maklerski mBanku

Valuation

Using DCF analysis and multiples comparison, we set our new nine-month price target for Energa at PLN 19.90 per share.

(PLN)	Weight	Price
Relative Valuation	50%	17.9
DCF Analysis	50%	19.5
	Estimated Price	18.7
	9M Target Price	19.9

DCF Analysis

Assumptions:

- Cash flows are discounted to their present value as of 31 December 2013. Equity value calculations factor in minority interests and net debt as of 31 December 2012 adjusted for PLN 497m dividend paid out in 2013 and a possible PLN 123m compensation which may be awarded to the TSO.
- Macroeconomic assumptions are as set out in the table below.
- We assume that FCF after FY2022 will grow at an annual rate of 2%. The risk-free rate is 4.5%, and beta is 0.9x.

Additional assumptions:

	2011	2012	2013	2014F	2015F	2016F	2017F	2018F	2019F	2020F	2021F	2022F
Price of Brent crude (USD/Bbl)	111.0	111.9	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
EEX electricity price (EUR/MWh)	56.1	49.2	44.6	46.0	47.9	49.6	51.4	53.4	55.0	56.9	56.9	56.9
Polish electricity price (PLN/MWh)	195.0	201.9	190.1	159.4	180.6	186.8	193.2	200.4	208.4	214.7	222.1	222.1
Price of carbon allowances (EUR/t)	13.3	7.5	4.5	5.3	6.3	7.5	9.0	10.6	12.6	15.0	15.0	15.0
Green certificate price (PLN/MWh)	274.9	255.0	170.0	200.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
Coal price (PLN/t)	273.2	300.5	285.6	282.3	288.0	293.8	299.7	299.7	299.7	299.7	299.7	299.7
Avg. annual EUR/PLN exchange rate	4.14	4.17	4.11	3.98	3.93	3.90	3.90	3.90	3.90	3.90	3.90	3.90
Net electricity output (TWh)	4.5	3.9	4.4	4.6	4.6	4.7	4.9	5.0	5.1	5.3	5.4	5.5
hard coal	3.2	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7
cogeneration	0.3	0.6	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
wind	0.0	0.0	0.2	0.4	0.4	0.5	0.7	0.8	0.9	1.1	1.2	1.3
hydroelectric power	1.0	0.7	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Dom Maklerski

DCF Model

(PLN m)	2013F	2014F	2015F	2016F	2017F	2018F	2019F	2020F	2021F	2022F	2022+
Revenue	11,412	10,828	11,610	11,990	12,477	12,953	13,443	13,897	14,390	14,676	14,676
change	2.1%	-5.1%	7.2%	3.3%	4.1%	3.8%	3.8%	3.4%	3.5%	2.0%	0.0%
EBITDA	1,955.4	2,084.8	2,110.1	2,272.3	2,458.9	2,626.2	2,812.2	2,972.8	3,158.1	3,304.6	3,185.6
EBITDA margin	17.1%	19.3%	18.2%	19.0%	19.7%	20.3%	20.9%	21.4%	21.9%	22.5%	21.7%
D&A expenses	804.4	897.0	975.4	1,012.4	1,078.0	1,108.8	1,156.6	1,211.2	1,273.6	1,331.3	1,331.3
EBIT	1,151.0	1,187.8	1,134.7	1,259.9	1,381.0	1,517.3	1,655.6	1,761.6	1,884.5	1,973.3	1,854.3
EBIT margin	10.1%	11.0%	9.8%	10.5%	11.1%	11.7%	12.3%	12.7%	13.1%	13.4%	12.6%
Tax on EBIT	218.7	225.7	215.6	239.4	262.4	288.3	314.6	334.7	358.0	374.9	352.3
NOPLAT	932.3	962.1	919.1	1,020.5	1,118.6	1,229.0	1,341.0	1,426.9	1,526.4	1,598.4	1,502.0
CAPEX	-3,000	-1,867	-1,827	-1,838	-1,840	-1,866	-1,899	-1,935	-1,942	-1,874	-1,874
Working capital	-21.5	53.3	-71.4	-34.6	-44.5	-43.4	-44.8	-41.5	-45.0	-26.1	-26.1
FCF	-1,285.1	45.1	-4.2	160.0	311.7	428.1	553.6	661.3	812.7	1,029.8	933.5
WACC	7.6%	7.5%	7.4%	7.3%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.5%
discount factor	100.0%	93.0%	86.6%	80.7%	75.3%	70.3%	65.6%	61.2%	57.1%	53.3%	53.3%
PV FCF	-1 285.1	41.9	-3.7	129.2	234.8	300.9	363.1	404.7	464.1	548.4	

WACC	7.6%	7.5%	7.4%	7.3%	7.2%	7.2%	7.2%	7.2%	7.2%	7.2%	7.5%
Cost of debt	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Risk-free rate	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
Risk premium	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Effective tax rate	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%
Net debt / EV	29.7%	32.1%	35.5%	38.4%	39.8%	40.3%	40.4%	40.4%	40.0%	39.1%	32.0%
Cost of equity	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
Risk premium	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Beta	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9

FCF after the forecast period	2.0%
Terminal value	16,832
Present value of residual value (PV TV)	8,964
Present value of FCF in the forecast period	1,198
Enterprise value (EV)	10,162
2012 year-end net debt (adj.)	2,046
Minority interests	47
Equity value	8,069
Number of shares (millions)	414.1
Equity value per share (PLN)	19.5
9M cost of equity	6.7%
Target price	20.8
2014E EV/EBITDA	5.1
2014E P/E	11.3
TV / EV	88%

Sensitivity Analysis

	FCF growth in perpetuity				
	0.0%	1.0%	2.0%	3.0%	4.0%
WACC +1.0 p.p.	12.68	14.67	17.26	20.79	25.87
WACC +0.5 p.p.	13.61	15.87	18.88	23.08	29.35
WACC	14.67	17.26	20.8	25.87	33.82
WACC -0.5 p.p.	15.87	18.88	23.08	29.35	39,75
WACC -1.0 p.p.	17.26	20.79	25.87	33.82	48.00

Relative Valuation

We compared Energa's projected FY2013-2015 P/E and EV/EBITDA multiples with those of its peers. The peer group comprises vertically integrated power producers as well as utilities focusing mainly on regulated distribution of electricity (Red Electrica, EDP, National Grid).The peer group is greatly diversified in terms of technology used (fuels, emissions, age of installed capacity), and the shares of different operating segments in total earnings. We assigned equal weights to each multiple and forecast year. The calculations pertaining to PGE are adjusted for receipts under long-term contract compensation. The forecasted 2013-2014 earnings estimates for Energa are adjusted for the proceeds expected to be earned from green certificates by its hydroelectric power plants since we predict these certificates will be discontinued in 2015. At the same time, we added these proceeds, which have an estimated two-year value of PLN 327m, to the final valuation.

Multiples Comparison

		P/E				EV/EBITDA*			
	Price	2012	2013F	2014F	2015F	2012	2013F	2014F	2015F
EDF	25.79	12.5	13.2	11.9	11.0	5.4	5.2	5.0	4.7
EDP	2.86	10.0	10.5	11.6	10.1	8.7	8.8	9.0	8.3
ENDESA SA	22.50	11.5	13.5	13.7	12.7	4.4	4.7	4.9	4.8
ENEL SPA	3.40	9.2	10.7	11.0	10.1	6.4	6.6	6.8	6.7
E.ON SE	13.66	6.4	12.1	14.5	13.6	4.4	5.2	5.5	5.4
FORTUM OYJ	16.37	12.8	13.1	14.1	13.7	9.7	9.6	10.2	10.4
IBERDROLA SA	4.64	10.5	11.7	12.8	12.1	7.2	7.5	7.8	7.5
NATIONAL GRID	794.00	16.3	15.0	15.5	14.4	10.7	10.3	9.8	9.4
RED ELECTRICA	53.67	15.1	14.4	14.3	13.7	10.0	9.9	9.6	9.2
RWE AG	26.91	6.5	6.9	11.4	11.2	3.7	3.7	4.2	4.3
CEZ	523.00	6.8	7.2	8.3	8.6	5.6	5.8	6.2	6.3
ENEA	13.21	8.1	6.7	11.5	8.9	2.9	2.5	3.0	2.5
PGE (ex LTC)	16.96	14.8	8.9	15.7	11.8	5.3	4.0	5.4	4.6
TAURON	4.27	7.4	5.1	8.4	6.4	3.8	3.3	3.9	3.3
Maximum		16.3	15.0	15.7	14.4	10.7	10.3	10.2	10.4
Minimum		6.4	5.1	8.3	6.4	2.9	2.5	3.0	2.5
Median		10.2	11.2	12.4	11.5	5.5	5.5	5.9	5.9
Energa	16.60	15.0	8.8	9.1	10.1	5.5	4.6	4.3	4.2
(premium / discount) to median		46.7%	-21.3%	-26.7%	-12.5%	-0.4%	-16.8%	-26.8%	-27.4%
Implied value									
Median		10.2	11.2	12.4	11.5	5.5	5.5	5.9	5.9
Multiple weight		50.0%				50.0%			
Year weight		0.0%	33.3%	33.3%	33.3%	0.0%	33.3%	33.3%	33.3%
Implied value of Energa		17.9							

*EV/EBITDA calculations are based on 2012 year-end net debt, but the relative valuation model accounts for the expected changes in future net debt

Income statement

(PLN m)	2010	2011	2012	2013F	2014F	2015F	2016F
Revenue	9,467.8	10,368.0	11,176.8	11,411.7	10,828.4	11,610.4	11,989.6
change	13.0%	9.5%	7.8%	2.1%	-5.1%	7.2%	3.3%
EBIT, of which	816.2	862.9	906.0	1 151.0	1 187.8	1 134.7	1 259.9
Baseload Power Plants	41.8	62.8	-167.6	-175.0	-131.1	-93.4	-33.8
Renewable Energy Sources	446.7	337.6	229.5	329.8	332.9	169.0	198.4
Power Distribution	159.4	377.8	610.3	774.0	744.8	820.0	850.0
Sales	218.4	139.8	239.9	226.4	244.5	238.0	241.6
Heat	2.4	3.9	-3.9	10.1	15.5	17.9	20.4
Services	-1.5	-5.3	10.0	24.0	23.9	24.8	25.7
Others and intercompany eliminations	-51.1	-53.7	-12.2	-38.2	-42.6	-41.6	-42.3
EBIT	816.2	862.9	906.0	1 151.0	1 187.8	1 134.7	1 259.9
change	63.8%	5.7%	5.0%	27.0%	3.2%	-4.5%	11.0%
EBIT margin	8.6%	8.3%	8.1%	10.1%	11.0%	9.8%	10.5%
Financing gains / losses	-21.2	35.2	-279.9	-154.1	-251.5	-294.0	-357.6
Extraordinary gains/losses	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.7	1.1	0.2	0.2	0.2	0.2	0.2
Pre-tax profit	795.6	899.2	626.3	997.2	936.5	840.9	902.5
Tax	171.0	196.6	166.5	214.5	177.9	159.8	171.5
Minority interests	19.9	38.7	-0.6	0.0	0.0	0.0	0.0
Discontinued operations	-0.4	0.0	-3.4	-5.8	0.0	0.0	0.0
Net profit	604.3	663.9	457.0	776.9	758.6	681.1	731.1
change	52.1%	9.9%	-31.2%	70.0%	-2.4%	-10.2%	7.3%
margin	6.4%	6.4%	4.1%	6.8%	7.0%	5.9%	6.1%

D&A expenses	591.4	656.8	723.2	804.4	897.0	975.4	1 012.4
EBITDA	1 407.6	1 519.7	1 629.2	1 955.4	2 084.8	2 110.1	2 272.3
	33.7%	8.0%	7.2%	20.0%	6.6%	1.2%	7.7%
EBITDA margin	14.9%	14.7%	14.6%	17.1%	19.3%	18.2%	19.0%

Shares at year-end (millions)	414.1	414.1	414.1	414.1	414.1	414.1	414.1
EPS	1.5	1.6	1.1	1.9	1.8	1.6	1.8
CEPS	2.9	3.2	2.9	3.8	4.0	4.0	4.2

ROAE	9.0%	8.9%	5.9%	9.9%	9.3%	8.1%	8.5%
ROAA	5.1%	5.0%	3.2%	4.8%	4.3%	3.7%	3.8%

Balance Sheet

(PLN m)	2010	2011	2012	2013F	2014F	2015F	2016F
ASSETS	12,640.1	13,685.3	14,912.8	17,148.7	18,026.7	19,018.6	19,916.0
Fixed assets	8,965.1	9,713.4	10,697.4	12,893.3	13,870.6	14,729.5	15,562.4
Property, plant and equipment	8,451.1	9,150.7	10,000.9	11,987.9	12,866.3	13,636.3	14,382.3
Intangible assets	269.4	312.5	378.6	587.5	686.4	775.3	862.3
Other financial assets	32.5	1.6	1.0	1.0	1.0	1.0	1.0
Other nonfinancial assets	96.1	77.3	107.1	107.1	107.1	107.1	107.1
Deferred tax assets	116.0	171.4	209.9	209.9	209.9	209.9	209.9
Current assets	3,675.0	3,971.8	4,215.4	4,255.3	4,156.1	4,289.1	4,353.6
Inventories	313.0	395.9	376.9	384.8	365.2	391.5	404.3
Trade debtors	1,454.9	1,521.4	1,524.1	1,556.1	1,476.6	1,583.2	1,634.9
Other current assets	223.4	272.8	235.1	235.1	235.1	235.1	235.1
Assets held for sale	0.2	4.5	10.2	10.2	10.2	10.2	10.2
Cash and cash equivalents*	1,683.6	1,777.3	2,069.1	2,069.1	2,069.1	2,069.1	2,069.1

(PLN m)	2010	2011	2012	2013F	2014F	2015F	2016F
EQUITY AND LIABILITIES	12,640.1	13,685.3	14,912.8	17,148.7	18,026.7	19,018.6	19,916.0
Equity	7,026.1	7,825.8	7,671.2	7,951.0	8,309.4	8,490.3	8,647.6
Share capital	4,968.8	4,968.8	4,968.8	4,968.8	4,968.8	4,968.8	4,968.8
Other equity	2,057.3	2,857.0	2,702.4	2,982.2	3,340.6	3,521.5	3,678.8
Minority interests	887.5	59.7	47.3	47.8	47.8	47.8	47.8
Long-term liabilities	2,631.7	3,571.7	4,801.5	6,522.6	7,025.2	7,691.0	8,322.1
Loans	1,033.6	1,904.2	3,105.4	4,826.5	5,329.1	5,994.9	6,626.0
Other	1,598.1	1,667.5	1,696.1	1,696.1	1,696.1	1,696.1	1,696.1
Current liabilities	2,094.8	2,228.1	2,392.8	2,627.2	2,644.4	2,789.5	2,898.5
Loans	42.8	45.0	389.6	605.6	668.7	752.2	831.4
Trade creditors	970.4	893.6	880.3	898.8	852.8	914.4	944.3
Other	1,081.6	1,289.6	1,122.9	1,122.9	1,122.9	1,122.9	1,122.9
Debt	1,076.4	1,949.2	3,495.0	5,432.1	5,997.7	6,747.1	7,457.4
Net debt	-607.2	171.9	1,425.9	3,363.0	3,928.7	4,678.1	5,388.3
(Net debt / Equity)	-8.6%	2.2%	18.6%	42.3%	47.3%	55.1%	62.3%
(Net debt / EBITDA)	-0.4	0.1	0.9	1.7	1.9	2.2	2.4
BVPS	17.0	18.9	18.5	19.2	20.1	20.5	20.9

*the difference between cash as shown on the balance sheet and the cash flow statement is a result of an overdraft facility

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Cash flows

(PLN m)	2010	2011	2012	2013F	2014F	2015F	2016F
Cash flow from operating activities	1,179.2	1,481.9	1,334.7	1,713.7	1,953.1	1,871.9	2,059.2
Net profit	604.3	663.9	457.0	776.9	758.6	681.1	731.1
D&A expenses	591.4	656.8	723.2	804.4	890.0	968.4	1,005.4
Working capital	-35.0	-213.9	-124.7	-21.5	53.3	-71.4	-34.6
Other	18.5	375.1	279.1	153.9	251.3	293.8	357.4
Cash flow from investing activities	-1,003.3	-2,003.7	-1,803.1	-2,902.5	-1,817.0	-1,761.4	-1,751.8
CAPEX	-1,072.2	-1,469.4	-1,817.2	-3,000.3	-1,867.3	-1,827.3	-1,838.3
Other	68.8	-534.3	14.1	97.8	50.3	65.9	86.6
Cash flow from financing activities	620.6	616.5	742.3	1,188.8	-136.2	-110.5	-307.4
Share float	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Debt	789.0	917.9	1,546.6	1,937.1	565.7	749.4	710.2
Dividend (buy-back)	-114.6	-189.4	-653.9	-496.9	-400.0	-500.0	-573.5
Other	-53.8	-112.0	-150.4	-251.4	-301.8	-359.8	-444.2
Change in cash	796.5	94.7	273.8	0.0	0.0	0.0	0.0
Cash at period-end	1,660.8	1,755.5	2,029.4	2,029.4	2,029.4	2,029.4	2,029.4
DPS (PLN)	0.28	0.46	1.58	1.20	0.97	1.21	1.39
FCF	129.5	-360.2	-479.2	-1 280.8	92.8	51.6	227.9
(CAPEX/Sales)	11.3%	14.2%	16.3%	26.3%	17.2%	15.7%	15.3%

Trading Multiples

	2010	2011	2012	2013F	2014F	2015F	2016F
P/E	11.4	10.4	15.0	8.8	9.1	10.1	9.4
P/CE	5.7	5.2	5.8	4.3	4.2	4.1	3.9
P/BV	1.0	0.9	0.9	0.9	0.8	0.8	0.8
P/S	0.7	0.7	0.6	0.6	0.6	0.6	0.6
FCF/EV	1.8%	-5.1%	-5.7%	-12.5%	0.9%	0.4%	1.9%
EV/EBITDA	5.1	4.7	5.1	5.3	5.2	5.5	5.4
EV/EBIT	8.8	8.2	9.2	8.9	9.1	10.2	9.8
EV/S	0.8	0.7	0.7	0.9	1.0	1.0	1.0
DYield	1.7%	2.8%	9.5%	7.2%	5.8%	7.3%	8.3%
Price per share (PLN)	16.60						
Shares at year-end (millions)	414.1	414.1	414.1	414.1	414.1	414.1	414.1
MC (PLN m)	6,873.5	6,873.5	6,873.5	6,873.5	6,873.5	6,873.5	6,873.5
Minority interests (PLN m)	887.5	59.7	47.3	47.8	47.8	47.8	47.8
EV (PLN m)	7,153.8	7,105.2	8,346.7	10,284.3	10,850.0	11,599.4	12,309.6

List of abbreviations and ratios contained in the report:
EV – net debt + market value
EBIT – Earnings Before Interest and Taxes
EBITDA – EBIT + Depreciation and Amortisation
P/CE – price to earnings with amortisation
MC/S – market capitalisation to sales
EBIT/EV – operating profit to economic value
P/E – (Price/Earnings) – price divided by annual net profit per share
ROE – (Return on Equity) – annual net profit divided by average equity
P/BV – (Price/Book Value) – price divided by book value per share
Net debt – credits + debt papers + interest bearing loans – cash and cash equivalents
EBITDA margin – EBITDA/Sales

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HOLD – we expect that the rate of return from an investment will range from –5% to +5%
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