GALP ENERGIA

COMPANY REPORT

OIL & GAS

7 JANUARY 2015

STUDENT: VALDEMAR SILVA

Upstream growth story threatened

… by Sheikhs vs Shale war

- Our FY15 price target of 11.77€ per share implies a potential upside of 50% over the current price levels, leading us to a BUY recommendation.

- The crude oil price shock over the last six months took c. 4€/share from E&P fair value, with the current market share war and the lower demand prospects being the main drivers behind it. Moreover, Petrobrás ongoing corruption scandals and liquidity constraints started to place Galp Energia's upstream investment plan at risk. Under the current low crude oil price scenario, the execution of the company's ambitious capex plan is expected to result in increased financial leverage until material production starts to flow by the end of the decade.

- The R&M segment is still waking up from a depressed European refining industry, with refining margins boosted by the oil shock. Although we expect return to profitability on the refining system, margins are unlikely to be sustained at 3Q14 levels.

- G&P recent outstanding performance should soon be wiped out as LNG arbitrage opportunities on the Asian markets already started to disappear.

Company description

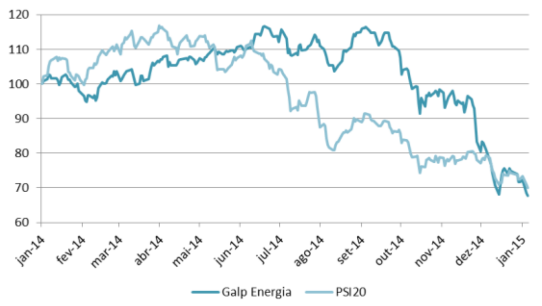
Galp Energia is an integrated multi-energy operator based in Portugal. The company's activities are divided in three segments: exploration and production of oil and gas with more than 60 projects, mainly in Brazil, Angola and Mozambique; refining and marketing of oil products; distribution, storage and supply of natural gas; international LNG trading; power generation and supply of electricity. The company shares have been traded on NYSE Euronext Lisbon since 2006, constituting a major component of the PSI-20 Index.

Recommendation:	BUY
Price Target FY15:	11.77 €
Price (as of 6-Jan-15)	7.97 €

Reuters: GALP.LS, Bloomberg: GALP.PL

52-week range (€)	7.81-13.75
Market Cap (€m)	6,612
Outstanding Shares (m)	829,252

Source: Bloomberg



Source: Bloomberg

(Values in € millions)	2013	2014F	2015F
EBITDA	1.141	1.150	1.221
EBIT	590	682	704
Net Profit	189	276	283
Net Debt (incl. loan Sinopec)	1,302	2,168	3,283
Debt/Assets	0.27	0.28	0.31
ROIC	6%	5%	5%
ROE	4%	5%	6%
EPS	0.23	0.33	0.34
P/E	23.9x		
EV/EBITDA	10.3x		

Source: Galp Energia, Analyst Estimates

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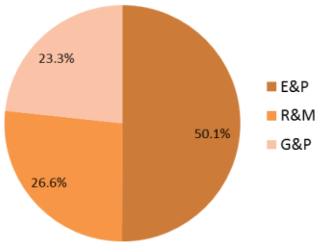
Company description

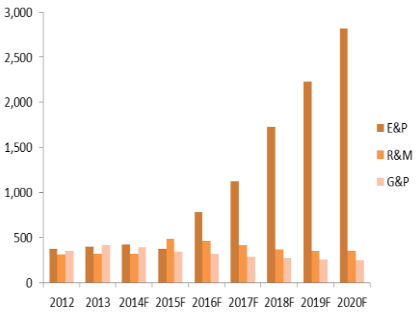
Figure 1: Segment contribution to EV (%)



Source: Analyst estimates, Galp Energia

Galp Energia was established in 1999 as a vehicle to restructure the Portuguese energy sector. Starting by being fully owned by the Portuguese state, the company was designed to operate at different stages of the oil and gas value chain by incorporating Petrogal (Oil & Gas) and Gás de Portugal (Utility). In the same year, Galp Energia started to be privatized. The company is now an integrated multi-energy operator based in Portugal, with activities divided in three segments: Exploration and Production (E&P), Refining and Marketing (R&M) and Gas and Power (G&P). Galp Energia has a current market capitalization of 6,889 million Euros (€m) and its shares have been traded on NYSE Euronext Lisbon since 2006, where it is one of the most traded stocks and constitutes a major component of the PSI-20, the Portuguese main stock index.

Figure 2: Segment EBITDA (k€)

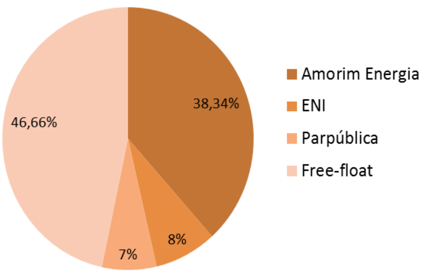


Source: Analyst estimates, Galp Energia

Galp Energia's E&P portfolio is diversified across 10 countries with more than 60 projects – mainly in Brazil, Angola and Mozambique – at different stages, including exploration, development and production. In the R&M segment, the company is one of the most important players in the industry for the Iberian Peninsula, integrating refining operations with the marketing of oil products activity. Regarding G&P, Galp Energia has becoming an integrated energy operator as the segment includes the procurement, distribution, storage and supply of natural gas in the Iberian Peninsula, LNG[1] trading in international markets and power generation and supply of electricity in Portugal. Historically, downstream operations, including R&M and G&P, have been the main source of Galp Energia's earnings, contributing with a stable cash flow to finance the company's upstream strategy in the exploration and production of oil and natural gas.

Shareholder structure

Figure 3: Shareholder structure (%)



Source: Analyst estimates, Galp Energia

Galp Energia's share capital, noted for its geographical dispersion, is composed of 829,250,635 shares, of which 46.66% is free-float. The remaining 53.34% of the share capital is controlled by the company's three main shareholders: Amorim Energia (38,34%); Parpública (7%) and ENI (8%). Amorim Energia, controlled 55% by the Portuguese investor and Galp Energia's chairman Américo Amorim and 45% by the Esperanza Holding (subsidiary of Sonangol, the Angolan state oil company) has been Galp Energia's key shareholder. Regarding ENI, the company gave up its ambitions to control Galp Energia and has been reducing its

[1] Liquified natural gas

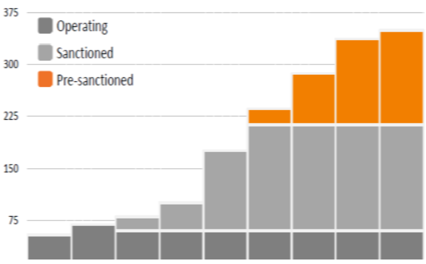
participation. During 2014, the Galp Energia suffered changes on its shareholder structure since ENI further reduced its stake from 16,34% to 8%, increasing the free-float. Moreover, Galp Energia's shares are still exposed to any placement discount of ENI's remaining 8%. Lastly, Parpública is a vehicle to manage the Portuguese state holding in the company. Considering that the Brazilian E&P operations represent the company's major growth driver, it is important to mention Galp Energia's partnership with Sinopec to jointly develop the Brazilian upstream portfolio. In 2012, the Chinese world class energy group acquired a minority holding of 30% in Petrogal Brasil and related companies, while Galp Energia retained the remaining 70%. While involving Sinopec in the management of Brazilian operations, a total cash-in of 5.19 billion USD ($b) strengthened Galp Energia's capital structure and liquidity in order to support the capital expenditures in the Brazilian upstream. Regarding the dividend policy, in practice since 2012, the company foresees an average dividend growth of 20% a year until 2016, taking into account the cash flow generation and the long-term growth strategy.

Exploration & Production

Figure 4: E&P geographical presence

Source: Galp Energia

Figure 5: E&P production targets (kbopd)



Source: Galp Energia

Galp Energia E&P portfolio is diversified across 10 countries – Brazil, Angola, Mozambique, Namibia, Morocco, Portugal, Uruguay, Equatorial Guinea, Venezuela and East Timor – with more than 60 oil and natural gas projects at different stages, including exploration, development and production.

While most of the projects are only at the initial stage of exploration, the company's Tier 1 assets are located in the pre-salt Santos basin in Brazil, in the Rovuma basin in Mozambique and in offshore Angola.

Galp Energia expects to reach a production of 300 kboepd[2] by 2020, based on sanctioned and pre-sanctioned projects. The development of the Lula/Iracema field will contribute the most for this target, assisted by the start in production from Iara, Carcará and Júpiter fields. Assets in Angola should contribute in a lesser extent, as the expected new production should more or less offset the decaying production from current producing fields in Block 14.

E&P activities have been focused on extended well tests to improve the knowledge of the reservoirs' production conditions; on the drilling of development wells so that production can be brought on stream when a FPSO[3] arrives; and on the deployment of the FPSOs. Moreover, pure exploration activities on other

[2] Thousand barrels of oil equivalent per day
[3] Floating production storage offloading unit

projects should improve visibility beyond 2020, as the company expects discover additional oil reserves, with an exploration target of 100-200 mboe[4] per year.

Delay risk still poses a threat to Galp Energia's growth story…

We focused our analysis on the projects that give us minimum visibility regarding the development plan schedule and reserves estimates. This approach disregards the upside potential from the reserves not included but reduces the risk of the valuation. However, we assess this potential upside value from the reserves not included. Most of Galp Energia's value is subject to different risks since the majority of the company's oil reserves is not yet developed. The risks of cost overruns, delays in the conclusion of development activities and delivery of FPSOs continue to be a great concern due to the local content requirements and supply chain constraints in the oil industry, which can ultimately affect cash flow generation that is critical to finance Galp Energia's different projects. More important, Petrobrás, the major Brazilian pre-salt operator, has been suffering from growing corruption scandals and investigations; lower oil prices harming the economic viability of the pre-salt projects; and weakening Brazilian real that increases the burden of USD denominated debt and capex. All in all, the Brazilian state-run oil company already admitted to reduce its 220 $b investment plan for the next 5 years, which may compromise Galp Energia's growth story. Project wise, some pre-salt plans may be delayed until the oil price environment stabilizes. We assume that possible cuts in the operator investment plan will only impact production that is not yet sanctioned, i.e., still far from generating cash flow. We expect Galp Energia to update its E&P investment plan and production targets by March 10, during the Capital Markets Day (CMD) 2015.

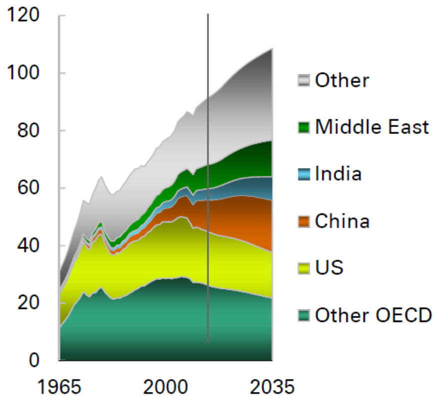
Market Environment

Unconventional discoveries and demand slowdown are changing the market dynamics…

Unusual discoveries of oil and gas together with economic and demographic dynamics are changing the energy sector. Global oil demand continues its upward trend, registering an average daily consumption of 91.2 mbbl[5] in 2013 (+1.1% yoy). Boosted by their GDP growth, non-OECD countries contributed the most for this increase (+3% yoy) whereas demand in OCED countries remained almost flat (+0.2% yoy) following the adverse economic conditions and increased energy efficiency that reduces oil dependency, a tendency that should continue in the future. On the supply side, the average daily production in 2013 was 91.6 mbbl (+0.6% yoy).

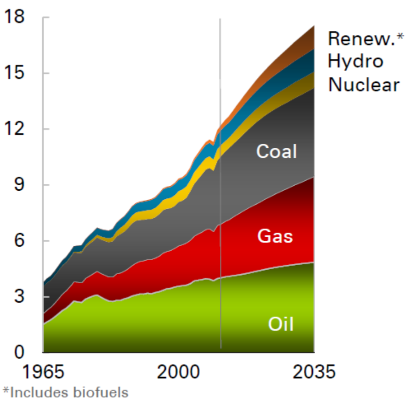
[4] Million barrels of oil equivalent
[5] Million barrels of oil

Figure 6: Oil demand by region (mbblpd)



Source: BP Energy Outlook 2035

Figure 7: Consumption by fuel (Billion tons of oil equivalent)



Source: BP Energy Outlook 2035

According to the World Energy Outlook 2014 published by the International Energy Agency (IEA), global energy demand (including oil, gas, coal, nuclear, hydro and other renewable energies) is expected to have a total increase of 37% between 2014 and 2040. This increase in demand will increase CO_2 emissions and consequently it will foster the pressure to adopt energy efficiency and environmental measures at a global level, which will help renewable energy technologies to increase its share. Equally important to highlight, the IEA predicts natural gas will face an outstanding increase in demand of 50% over the same period, following the significant recent natural gas discoveries that will maintain the relevant price discount relatively to oil, the energetic efficiency in developed countries and the different governmental policies to favor this energy source due to environmental issues (lower carbon content comparing to oil or coal). With these dynamics, the agency predicts global oil supply will lose its share to other energy sources, standing by an average daily production of 104 mbbl by 2040 (12.6% increase between 2014 and 2040 versus the 37% increase in global energy demand). Additionally, BP Energy Outlook for 2035 estimates supply will be almost evenly distributed between oil, natural gas, coal and nuclear/renewables.

The current discussion is whether or not the expected growth in oil demand will be enough to offset increased supply coming from the tight oil production in the USA, the oil sands in Canada and the pre-salt in Brazil and Angola. According to OPEC, these countries are expected to contribute with 1.36 mbblpd[6] for the increase in supply in 2015, after an increase of 1.72 mbblpd in 2014. With these discoveries, OPEC has been facing a growing competition. In fact, US are now energy independent and should become one of the world's largest oil producers alongside Russia and Saudi Arabia.

On the other side, demand perspectives have been affected by the economy slowdown, both in developed and emerging countries. The IEA estimates an average daily consumption of 93.3 mbbl in 2015 (+1% versus 92.4 mbblpd in 2014), a decrease of 230 kbopd[7] comparing to previous estimates and representing the fourth cut over the last four months. Additionally, OPEC cut the estimated demand for the organization's production in 300 kbopd, leading to a total OPEC production of 28.9 mbblpd, the lowest level since 2003 (-1.1 mbblpd comparing to the previous production target of 30 mbblpd). These recent downward revisions in demand were mostly driven by the economy slowdown in Europe and China, the US increasing energetic independency and the Russian crisis.

[6] Million barrels of oil per day
[7] Thousand barrels of oil per day

Despite acknowledging that there is currently an excess oil supply on the market, OPEC refuses to cut down production, mainly given to Saudi Arabic intentions in not giving up its market share. This is a way of jeopardizing US and Brazil competitors that have some productions that need high oil prices to be economically profitable.

Different breakeven prices lead to a market share war…

According to the International Monetary Fund, for the countries whose economy is highly dependent on oil exports, what matters is the "fiscal breakeven fiscal price", i.e., the minimum price to balance those countries public accounts, instead of the project breakeven price. This minimum oil price for the different oil exporters is far from being homogeneous. For Qatar and Kuwait it stands at c. 60 USD per barrel of oil ($/bbl) and Saudi Arabia is comfortable with oil at 90$/bbl. However, the current oil shock increased Venezuela's bankruptcy likelihood as it needs a minimum oil price of 120$/bbl to sustain its public accounts.

Project wise, the best shale explorations can be profitable with oil price between 4060$/bbl and 60$/bbl. But some shale oil production can also struggle to be viable, together with Artic and Canadian oil sands and some ultra-deep offshore pre-salt explorations in Brazil and Angola, which require the oil to be above $100/bbl. Regarding the Brazilian pre-salt projects, Petrobrás pointed that its break-even crude oil price stands between 41$/bbl and 57$/bbl.

Oil price will have to adjust by itself…

Furthermore, back in the mid-1980s, Saudi Arabia cut production in order to sustain crude oil prices but were the other exporters who benefited while Saudi Arabia sacrificed its revenues. Thus, we do not expect OPEC production will change significantly in the near future. In fact, in the cartel's last meeting in November, OPEC decision was to maintain current production levels, which led to a further decrease in oil price. The Saudi Oil Minister Ali Al-Naimi stated that OPEC's strategy is to maintain its 40% market share at all costs, being convicted that the cartel will not reduce production, not even if the crude price falls to 20$/bbl, and that the world may not see crude price to reach 100$/bbl ever again. Moreover, the Saudi Minister referred that if OPEC chose to cut production, the crude oil price would increase and the Russians, Brazilians, and shale producers would take the Saudi's part. Therefore, the market will have to adjust by itself and oil price can only go back to the previous high levels via an increase in demand or a decrease in production from US shale developments. Politically wise, this market share war can also be a form to mask US and Saudi Arabia intentions in using crude oil price to weaken geopolitical enemies that have most of their revenues coming from oil exports, such as the militant group from the Islamic State of Iraq and the Levant, Iran and Russia.

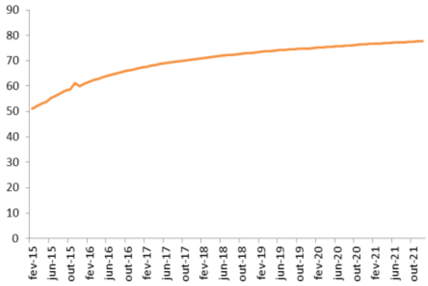
From an environment point of view, despite considering that a truly concerted global action is unlikely before 2020, the IEA World Energy Outlook 2014 baseline scenario already takes into account a comprehensive set of policy commitments announced by different countries to address climate change by reducing carbon emissions, putting a price on carbon, mobilizing funding or reducing subsidies to fossil-energy consumption. The United Nations hopes all countries will agree to a plan to cut greenhouse gas emissions under the United Nations Framework Convention on Climate Change during the 21st session of the Conference of the Parties that is expected to take place in December 2015.

Figure 8: Crude oil Brent price ($/bbl)

Source: Bloomberg

Over the last two years, the supply and demand dynamics, together with some volatility due to geo-political events, made the crude oil Brent price to fluctuate from 119$/bbl to its current values close to 50$/bbl. Since the oil shock that has been occurring over the last 6 months, Brent price decreased over 50%. Despite that future environmental regulation can place some upward pressure in the Brent price, we believe the market framework described above will not leave oil price to go above 70$/bbl in the medium term or 80$/bbl in the long term. Consistent with the IEA practice, the crude oil price assumptions in our model are based on the forward curve of Brent futures price.

Figure 9: Brent crude oil futures quote ($/bbl)



Source: Chicago Mercantile Exchange

Brazil

Galp Energia's main assets in Brazil are located in the pre-salt Santos Basin, an area located 300 to 350 km away from the coast, with reserves found between 5,000 and 6,000 meters below the sea level, in ultra-deep waters (1,900 to 2,400 meters) under the salt layer (which can go up to 2,000 meters). This pre-salt oil layer was formed more the 100 million years ago when the South American and African continents began separating. In line with the above assumptions concerning the minimum visibility over the projects development, this valuation covers the fields Lula/Iracema, Iara, Carcará and Júpiter. The company has been in production since 2010 with the FPSO #1 Cidade Angra dos Reis. Results from the 3Q14 revealed current production is at 18 kbopd, an increase of 50% yoy, influenced by the FPSO #2 Cidade de Paraty that already reached full capacity.

Figure 10: Brazil oil fields data

Field	Recoverable reserves (bboe[8])	Oil %	Operator	Galp Energia %	First Oil	Peak Oil	Stage
Lula & Iracema	10	83%	Petrobras	10%	2011	2020	Development and production
Iara	4	83%	Petrobras	10%	2017	2024	Appraisal and pre-development
Carcará	1	75%	Petrobras	14%	2019	2022	Appraisal and pre-development
Júpiter	5	40%	Petrobras	20%	2020	2025	Appraisal and pre-development

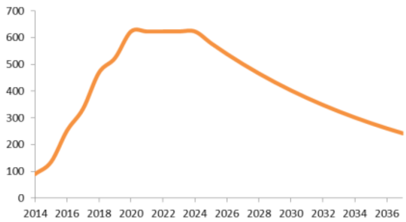
Source: Analyst estimates, Galp Energia, Petrobrás

[8] Billion barrels of oil equivalent

Figure 11: World's largest 5 offshore oil fields

Field	Recoverable reserves (mboe)	Peak avg. production (kboepd)
Safaniya	36	1500
Upper Zakum	21	750
Manifa	13	900
Lula/Iracema	9-11	1500
Kashagan	9	1500

Figure 12: Lula/Iracema production curve (mboe)



Source: Analyst estimates, Galp Energia, Petrobrás

Lula/Iracema

Lula/Iracema field of the Santos Basin (block BM-S-11) is the company key project due to its productivity and reserves volume, resulting in outstanding project economics. We considered Lula and Iracema as a single field despite the undergoing debate between the consortium and the ANP. The consortium argues, against the ANP, the existence of two different fields, which would result in lower tax rates since the Special Participation Tax level is progressive and a function of production in a single field. The ANP estimates that a separation of these fields would injury the Brazilian treasury in 30 billion BRL (Brazilian Real).Lula/Iracema ranks in the top 5 world's largest offshore oil fields, together with Safaniya (Saudi Arabia), Upper Zakum (Abu Dhabi), Manifa (Saudi Arabia) and Kashagan (Kazakhstan). With estimates for recoverable resources ranging between 9 and 11 bboe, a total of 11 FPSOs were already sanctioned, 3 already deployed, 7 under construction and 1 to be awarded. Under the current scenario of 11 FPSOs sanctioned, Lula/Iracema is expected to reach a peak oil production of c. 1.6 kboepd by 2020.

Three FPSOs are already in production: the FPSO (#1) Cidade de Angra dos Reis since 2010 production capacity of 100 kbopd; the FPSO (#2) Cidade de Paraty since 2013 with an oil production capacity of 120 kbopd and the FPSO (#3) Cidade Mangaratiba since October 2014 with an oil production capacity of 150 kbopd. The remaining 8, with installed capacities at 150 kbopd, are expected to be deployed until 2019, already considering one year delay for two FPSOs. By the end of 2015, a total of 4 FPSOs should be in production, following the deployment of FPSO (#4) Cidade de Itaguaí.

According to the consortium data, the first production wells achieved outstanding productivity, above 30 kboepd (we assume this figure for Lula), resulting in only 4 producing wells needed in the FPSO #1 and consequently, reducing the project costs. A list of the top 20 producing wells in the Brazilian pre-salt, from the ANP (Brazil's National Agency of Petroleum, Natural Gas and Biofuels) monthly production report, includes 8 wells from the Lula field, with an average flow rate of 32.5 kboepd (Appendix 1).

Figure 13: Lula/Iracema FPSO deployment schedule

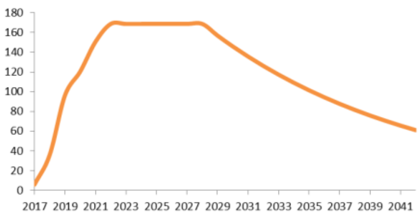
Unit	FPSO	Field/ Location	Chartered/ Owned	First Oil	Oil capacity (kbopd)	Gas capacity (mmscfd)	Sanctioned	Contract status
1	Angra dos Reis	Lula	Chartered	2010	100	177	Y	Awarded
2	Paraty	Lula NE	Chartered	2013	120	177	Y	Awarded
3	Mangaratiba	Iracema S	Chartered	2014	150	283	Y	Awarded
4	Itaguai	Iracema N	Chartered	2015	150	283	Y	Awarded
5	Maricá	Lula Alto	Chartered	2016	150	212	Y	Awarded
6	Saquarema	Lula Central	Chartered	2016	150	212	Y	Awarded
7	P-66	Lula S	Owned	2016	150	212	Y	Awarded
8	P-67	Lula NE	Owned	2017	150	212	Y	Awarded
9	P-68	Lula Ext. S	Owned	2017	150	212	Y	Awarded
10	P-69	Lula W	Owned	2018	150	212	Y	Awarded
11	P-72	Lula NE	Owned	2019	150	212	Y	To be awarded

Source: Analyst estimates, Galp Energia, Petrobrás

Iara

Iara is another giant field of block BM-S-11 with estimates of recoverable resources between 3 to 4 bboe. By December 2014, the consortium submitted the Declaration of Commerciality to the ANP for three different oil and gas accumulations, suggesting the division of the Iara area in three new fields: Berbigão, Sururu and Atapú West. Following the proposal for the three fields and considering the amount of reserves that we expect to be de-risked in the short-term, we modelled 3 FPSOs for the Iara area, with production expected to start in 2017. Additional, our FPSO deployment schedule considers two years delay on the last FPSO.

Figure 14: Iara production curve (mboe)



Source: Analyst estimates, Galp Energia, Petrobrás

In the CMD 2014, Galp Energia revealed results regarding Iara appraisal works and tests that show us the field is somehow heterogeneous, with productivity level varying across the reservoir. Thus, we are more conservative and we assume peak well flow rates of 20 kboepd for this field.

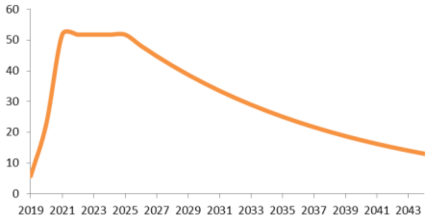
Figure 15: Iara FPSO deployment schedule

Unit	FPSO	Field/ Location	Chartered/ Owned	First Oil	Oil capacity (kbopd)	Gas capacity (mmscfd)	Sanctioned	Contract status
1	P-70	Iara Horst	Owned	2017	150	212	Y	Awarded
2	P-71	Iara NW	Owned	2018	150	212	Y	Awarded
3	P-73	Iara Surround	Owned	2020	150	212	Y	To be awarded

Source: Analyst estimates, Galp Energia, Petrobrás

Carcará

Figure 16: Carcará production curve (mboe)



Source: Analyst estimates, Galp Energia, Petrobrás

Carcará is the most significant discovery of block BM-S-8 in the Santos Basin and the field declaration of commerciality is expected in 2015. With low visibility on the resources volume, we assume 1 bboe since Petrobrás business plan already anticipates 1 FPSO to be deployed in 2018, and a figure close to our assumption is required to justify the project economics.

Technical problems related with higher than normal pressure levels led to the suspension of drilling activities due to the lack of drilling equipment capable of handling such pressures. Appraisal operations were scheduled to resume by the end of 2014 and results for the productivity and resource potential should be known by mid-2015. Similarly to Iara, we assume peak well flow rates of 20 kboepd for this field.

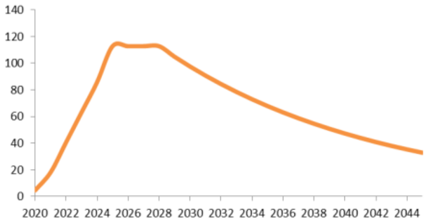
Figure 17: Carcará FPSO deployment schedule

Unit	FPSO	Field/ Location	Chartered/ Owned	First Oil	Oil capacity (kbopd)	Gas capacity (mmscfd)	Sanctioned	Contract status
1	Carcará	Carcará	Owned	2019	150	212	Y	To be awarded

Source: Analyst estimates, Galp Energia, Petrobrás

Júpiter

Figure 18: Júpiter production curve (mboe)



Source: Analyst estimates, Galp Energia, Petrobrás

Júpiter field is located in block BM-S-24 in the Santos Basin declaration of commerciality is expected by 2016. Discoveries in the field found oil, condensates and natural gas mixed with CO_2, with the results from the drilling activities during 2013 estimating the percentage of oil in the field at 40%. Moreover, the consortium estimates recoverable reserves to range between 5 and 6 bboe.

Petrobras business plan guides us to 1 FPSO starting production in 2019. Results from ongoing appraisal activities will be crucial to determine if the consortium should develop condensates and sanction additional FPSOs.

Our valuation assumes the field development plan will only cover the oil section of the reservoir, with production starting one year later than guidance and 2 FPSO to be deployed (+1 vs guidance). Given the lack of information from well tests, we are conservative assuming well flow rates of 15 kboepd.

Figure 19: Júpiter FPSO deployment schedule

Unit	FPSO	Field/ Location	Chartered/ Owned	First Oil	Oil capacity (kbopd)	Gas capacity (mmscfd)	Sanctioned	Contract status
1	Júpiter	Júpiter	Owned	2020	150	212	Y	To be awarded
2	Júpiter 2	Júpiter	Owned	2022	150	212	N	To be awarded

Source: Analyst estimates, Galp Energia, Petrobrás

Angola

Galp Energia's main assets in Angola comprise two production units: a CPT[9] in the BBLT field and a CPT in the Tômbua-Lândana field, both fields located in block 14. Additionally, the Company has assets under development in blocks 14, 14k and 32. Galp Energia also participates in Angola LNG II, an integrated natural gas project that is still on the initial phase of exploration.

Results from 3Q14 revealed current production in Angola is at 6.9 kbopd, a decrease of 18% yoy, influenced by decommissioning of the Kuito FPSO following its maturing stage.

Figure 20: Angola oil fields data

Field	Recoverable reserves (mboe)	Operator	Galp Energia %	First Oil	Peak Oil	Stage
Block 14 - BBLT	200	Chevron	9%	2006	2008	Production
Block 14 - T-L	300	Chevron	9%	2009	2011	Production
Block 14 - M-L	650	Chevron	9%	2017	2022	Development
Block 14K - Lianzi	100	Chevron	4.5%	2015	2018	Development
Block 32 - Kaombo	650	Total	5%	2018	2022	Development

Source: Analyst estimates, Galp Energia, Chevron, Total

Block 14: Galp Energia has been producing oil in Block 14 since 1999 in the Kuito field. BBLT and Tômbua-Lândana are the fields currently under production. By the end of 2013, the FPSO in the Kuito field was demobilized due to the maturity of the field and high maintenance costs that did not justify further operations.

New discoveries in Angola will offset the maturing stage of current production…

Operations in the BBLT field started in 2006 and the production is already on its maturing stage. On the other hand, the Tômbua-Lândana project (initial reserves estimate of 350 mboe) only started operations in 2009 with a CPT having capacity for 130 kboepd.

In 2013, appraisal and development activities were focused on the field Malange and Lucapa. The development plan for these areas include a subsea tie-back to the CPT in Tômbua-Lândana as the areas are relatively small and the recoverable resources does not justify a standalone development. We expect production to start flowing in 2017. The fields are estimated to contain recoverable resources of 650 mboe.

Block 14K: The development plan for Block 14K, located on the border between Angola and Congo, foresees a connection between the Lianzi field and the CPT platform in BBLT, given the small resources estimate. Production is scheduled for 2015 with a capacity of 46,000 kbopd.

[9] Compliant Piled Tower

Block 32: the development plan for the Kaombo field anticipates the installation of two FPSO units in the area due to the geographical dispersion of the discoveries. The first FPSO is scheduled for 2017 and the second for 2018, having a combined production capacity of 230 kbopd. Recoverable reserves are estimated at 650 mboe.

Mozambique

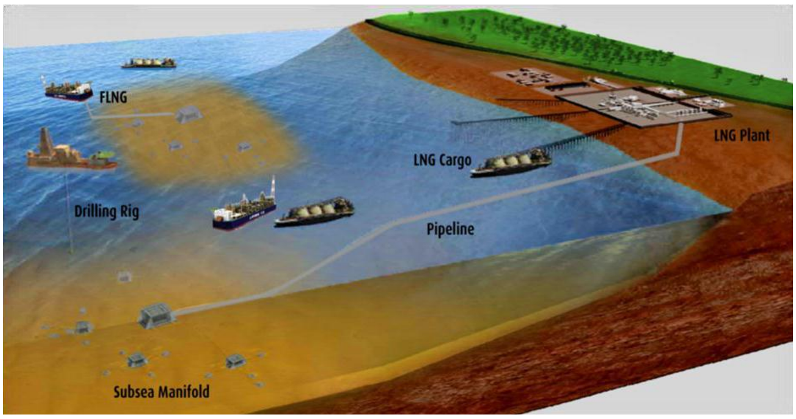
Mozambique is posed to become a reference player in the LNG markets…

The Rovuma basin stands out for the unprecedented natural gas discoveries made in Area 1 and Area 4, with natural gas reserves in the basin estimated to range between 150 and 200 tcf[10]. For comparison purposes, the world's largest gas field (Qatar's North Field) is estimated to hold 900 tcf of gas and supplies the world's largest LNG plant (Pearl GTL, a joint development by Qatar Petroleum and Shell). Rovuma's reserves should be enough to make Mozambique one of the world's largest LNG exporters, as there is neither a domestic market nor onshore infrastructures to take the gas. Galp Energia's 10% interest in Area 4, operated by ENI, provides diversification as it represents a new area of the company's portfolio. Considering huge amount of gas discovered, the exploration and production in Rovuma must involve long-term LNG supply contracts and considerable investments in liquefaction infrastructures. The consortium is still studying the best development alternatives, which can be divided between subsea wells connected to the onshore LNG trains and FLNG[11] units in each area.

We considered the project will lead to the development of ENI's current estimate of gas initially in place for Area 4, i.e., 85 tcf. From the total amount of gas, 27 tcf are located in fields fully located in Area 4, whilst the remaining 58 tcf are adjacent to Area 1. This has led to unitization talks between ENI and Anadarko (Area 1 operator). The two operators agreed to coordinate the development of common offshore activities and to build a common onshore liquefaction facility based on 10 LNG trains (Afungi LNG Park) in Northern Mozambique. The agreement will avoid the duplication of efforts and will reduce the overall development costs for the consortiums.

[10] Trillion cubic feet
[11] Floating liquified natural gas

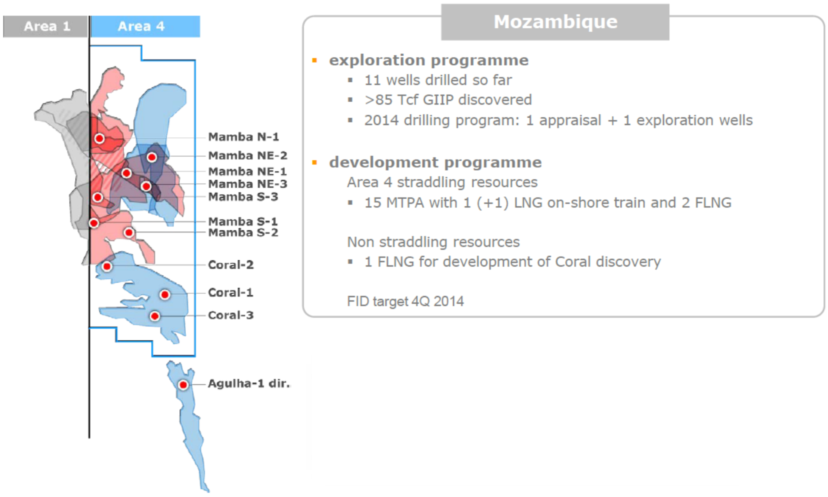
Figure 21: Afungi LNG Park



Source: Galp Energia

According to ENI's 2014 strategy presentation, the initial development phase for the unitized reserves encompasses two onshore LNG trains with a capacity of 15 mtpa[12] of LNG and 2 FLNG units, whereas for the non-unitized the initial plan includes 2 FLNG units.

Figure 22: Area 4 development plan



Source: ENI's 2014 strategy presentation

Although guidance points production to start following by 2019, we expect it to 2021 given the high risk of delays due to the fragmented ownership regarding the unitized reserves, the country lack of infrastructure, the government inexperience in the area and the need to establish long-term commercial terms. In addition, the falling global crude oil and LNG prices are likely to cause delays in the project final investment decisions. Our valuation of Area 4 is based on recent transaction multiples from deals in the Rovuma Basin. In 2012, PTTEP bought Cove Energy 8.5% interest in Area 1 for 1.8 $b. At the time, Anadarko estimated reserves at 65

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[12] million tons per annum

tcf, which gives us a multiple of 0.33 USD per mcf[13] ($/mcf). In 2013, ENI sold a 20% stake in Area 4 to CNPC for 4.21 $b. Considering ENI's gas reserves estimate for Area 4 at the time (75 tcf), we get a valuation multiple of 0.28 $/mcf. In 2014, Videocon sold its 10% interest in Area 1 to ONGC for 2.475 $b. With current reserves in Area 1 estimated at 70tcf, the transaction multiple was 0.35 $/mcf. Despite the still uncertain amount below the ground, this figure has been increasing over the time with the results from the exploration and appraisal activities, and we can see a normalization of the dollars paid per mcf.

Valuation

We valued each project separately by discounting the consortium cash flows at the WACC[14] we estimated for Galp Energia's E&P segment and then, taking the correspondent to Petrogal Brazil´s interest in each project. Since Galp Energia only owns 70% of Petrogal Brazil, we adjust Sinopec's 30% interest in the minorities' line. Moreover, we assume Galp Energia will be able to fulfil the cash flow requirements of each project.

Regarding taxes, the company faces different types of concession frameworks in Brazil and Angola. In Brazil, the government takings are composed of royalties (10% of revenues), SPT (Special Participation Tax – progressive and a function of production) and corporate tax. In Angola, the Production Sharing Agreement allows to cover the project costs while sharing the remaining production between the government and the consortium, the latter being subject to corporate tax.

The natural gas extracted in the Brazilian pre-salt Santos basin (c. 20% of the production mix) can be reinjected into the reservoirs or exported onshore to supply the domestic market through pipelines: Lula-Mexilhão (already operating), Lula-Cabiunas (under construction), Lula-Comperj (in bidding process) and others yet to be awarded. The gas reinjected into the reservoirs has been tested under the WAG (Water Alternating Gas) injection system that aims to maintain pressure in the reservoir and improve flow, with great expectations for improved productivity, oil recovery factors and improved production curve with increased duration of the plateau. Moreover, we expect the weight of natural gas reinjected and auto-consumed to be 50%, with the other half being exported onshore.

We considered the guidance from Galp Energia and its consortium partners for the first oil, reserves estimates, number of FPSOs sanctioned or pre-sanctioned and the FPSO deployment schedule. First oil included our prediction for delays

[13] Million cubic feet
[14] Weighted average cost of capital

based on the operator track record and the different risks above mentioned, with the most relevant issue being Petrobrás' ability to come across its current corruption scandals while meet its investment plan in a low oil price scenario.

We assumed a ramp-up period of 15 months until each FPSO reaches full capacity and, as we assume the success of the WAG mechanism, we modelled the peak production plateau will last 5 years, before production enters in a declining phase until the end of the concession period.

Regarding the wells productivity, we estimate well peak flow rates to range between 13 and 30 kboepd, depending on each field and accordingly to the track record from current production and to the visibility provided by Galp Energia and its consortium partners. The consortium base case for the commercial development of the Brazilian pre-salt field has been 20 kboepd, which is also consistent with the ANP reports. However, as referred before, the outstanding well productivity from Lula field led us to accept 30 kboepd for the field. For Iara and Carcará we assume 20 kboedp, whilst for Júpiter we modelled this figure at 15 kboepd given the lower visibility. For the Angolan fields, we assume an average well flow rate of 13 kboepd.

Installed capacity also varies with number of FPSOs sanctioned for each field and guidance from the FPSO contracts already awarded, resulting in an average capacity of 150 kbopd (or 188 kboepd including natural gas capacity). Moreover, we assume an average utilization rate of 90% of that capacity. Considering the well productivity for each field, the number of FPSOs and its capacity, our model results in different figures for the number of production and injection wells required in each field. With the average FPSO capacity at 188 kboepd, the number of producing wells needed varies from 6 to 11, accordingly to the assumed well flow rate.

On average, to extract 1 bboe over a concession, a project would require 1 FPSO (capacity at 150kbopd), and 20 wells (10 producers and 10 injectors), with a 20 kboepd well flow rate. For this standard project of 1 bboe, we modelled the cost of each FPSO at 1.7 $b. According to Petrobrás and to recent contracts awarded, each FPSO costs from 1.5 to 1.8 $b. The operator adds that an additional 5 $b are required to add the wells and support equipment before starting production. Regarding the well drilling component, Petrobrás guides for an average cost of 1 $m per day (including drilling rig, materials, services and labor costs). The major component of this figure corresponds to 500-600 thousand USD in daily rents to charter a drilling rig (according to Petrobrás contracts with Ocean Rig and Sete Brasil). Considering the average time for drilling a well at 130 days, we add 2.6 $b to the project capex (130 days x 20

Figure 23: Galp Energia's avg. well drilling and completion days

Source: Galp Energia

Figure 24: E&P 1 bboe standard project capex

Component	Cost ($/boe)	% weight
FPSO	1.7	22%
Well Development	2.6	33%
Subsea equipment	2.4	31%
Exploration & Appraisal	1.1	14%
Total	7.8	

Source: Analyst estimates

wells x 1 $m/day). The remaining 2.4 $b (that make up the $5 billion to add to the FPSO cost) are allocated to the subsea support equipment. Lastly, for the exploration and appraisal activities, we add $1.1 billion (1.1$ per boe[15], which corresponds to Galp Energia's guidance for finding costs during the CMD 2014). All in all, we sum-up $7.8 billion (7.8$ per boe) for the capex required for a life-of-field production of 1 bboe. This capex is quite sensitive to the well development performance, as it accounts for 33% of capex, and it is directly proportional to the assumptions for the average well flow rate and average number of days to drill a well. Although this USD figure currently corresponds to c. 6.5€ per boe, Galp Energia's cash outflows are extremely exposed to the EUR/USD exchange rate.

Until the company reaches its strategic target production of 300 kboepd, the several projects on the way will drive up capex, especially in the Lula/Iracema field. Galp Energia's guidance in the CMD 2014 guided the company's annual capex to 1.5-1.7 €b (90% to E&P), which is in line with our valuation.

Regarding production costs, Petrobrás guidance and current production points to 14-15$/bbl. The consortium's figures include the FPSOs costs under operating costs since the first six FPSOs deployed or to be deployed in Lula are chartered. Our assumption for production costs is 11$/bbl, lower the consortium guidance since we include the FPSOs costs on the capex component, being account in our model as depreciations. This figure already includes the oil transportation cost to access international markets of 3$/bbl, as assumed by the consortium partner BG Group, but does not include any kind of taxes. Other operating costs, including corporate overheads, are estimated at 6$/bbl, lower than current data, as we expect them to be diluted with future increase in production. Considering capex, production costs and other operating costs altogether, we obtain a total cost of c. 25$/bbl, which goes in line with Repsol's assumption for total capex and opex in the Brazilian pre-salt. Finally, we further assume 1.9% cost inflation (USD) for capex and opex over the concession period.

Regarding the major valuation driver, in line with our market environment analysis, the Brent price assumption follows the crude oil Brent futures price, leading to 65$/bbl by 2016 and gradually increasing to 77$/bbl by 2021 (remaining constant until the end of the projects). Moreover, the average oil sale price includes a 5% discount over the Brent price to account for the difference in API gravity, assuming an average API of 30º for Galp Energia's projects. Lastly, the average sale price also includes the effect of oil/gas mix, with the natural gas exported onshore modelled with a fixed parity of 1/3 versus the crude oil price, leading to an average natural gas price of c. 24$/boe over the life of the projects.

[15] Barrel of oil equivalent

Our valuation of the Mozambique LNG project in Area 4 is based on recent transaction multiples from the deals detailed previously in this analysis. We assume a multiple of 0.28$/mcf for the 85 tcf reserves in Area 4 estimated by ENI. Moreover, we consider a 30% discount over the multiple to reflect the risks identified in our analysis and the decreasing margins in LNG trading (analyzed in the G&P section of this report), resulting in a valuation of 1.3 €b (0.2$/mcf) for Galp Energia's 10% interest in Area 4.

We reach an enterprise value of 7,053 €m (€8.5/share) for the E&P, corresponding to a total life-of-field production of 3,352 mboe. If we were to consider the 4,630 mboe total 3P + 3C reserves, reported by Galp Energia based on the DeGolyear and MacNaughton report, we would increase the risk of the valuation given the risks and little visibility of projects not yet sanctioned. The additional 1,278 mboe, valued with a multiple of 2.5$/boe, assuming the full success of the projects not included, would increase our E&P valuation by 3,195 €m, or €3.85/share. Lastly, knowing that the crude oil price assumption constitute our major valuation risk, the following table allows the evaluation of the significant impact on the price target per share, given certain percentage variations on the crude oil price assumption.

Figure 25: Crude oil price sensitivity analysis

Crude oil price variation (%)						
-20%	-10%	0%	10%	20%	30%	40%
9.78 €	10.78 €	11.77 €	12.75 €	13.72 €	14.68 €	15.65 €

Source: Analyst estimates

Refining & Marketing

Galp Energia is one of the most important players in the Refining & Marketing (R&M) industry for the Iberian Peninsula, integrating refining operations with the marketing of oil products activity.

Market Environment

Excess capacity and high crude oil prices weighed the European refining industry's performance…

The global refining and marketing businesses have been facing a deep transformation over the last few years. Several factors put the European Refining industry in trouble, with refining margins and refining capacity utilization reaching five-year lows. As it has no local crude supply and together with the decrease in crude oil production output in the North Sea, the industry is exposed to oil imports at higher prices, transportation costs and sourcing risk. Previous high crude oil prices weighed oil demand which have a direct impact on refining margins and utilization rates. As the crude oil price is a key driver for oil demand, it will end up driving price of refined products, and consequently, refining margins. Moreover, a high crude oil price deteriorates refinery cash costs through auto-consumption and losses. Additionally, the demand for oil products also suffered with the financial crisis and austerity measures, placing a downward pressure in the prices of key oil products like diesel and gasoline (pre-tax).

The increase in exports of refined products by the USA (currently benefiting from domestic crude oil supply at a lower cost and access to lower natural gas prices) and the Middle East (increase in installed refining capacity with barrel conversion facilities and local supply of cheaper crude) to Latin America, West Africa and Europe also put pressure on the prices. Additionally, it reduced the European exports share.

Despite having excess capacity, Europe has been a net importer of refined products due to the dieselization process that started in the 80s with the preference for diesel motors. Moreover, the unfair energy taxation directive in the European Union (2003) created a retail market where diesel prices are cheaper than those of gasoline, while open market prices show the opposite (gasoline's lower energy content per unit of fuel resulted in higher tax because previous tax levels were based mainly on the volume of energy consumed). Despite the intention to force diesel and gasoline prices to reach similar levels at the European Union level, the amendment to the directive (2011) that aimed to favor the consumption of more environmentally friendly products (decreasing gasoline price due to its lower CO_2 content per unit of fuel burned) only influenced the minimum tax levels, and therefore did not reach the desired impact because most of the countries have taxation policies above the minimum levels.

Being short on diesel and long on gasoline, European refineries started to be directed to conversion projects in order to solve the mismatch between production and demand.

The European industry should expect more competition as the IEA estimates a distillation capacity additions to surpass demand growth in the upcoming years.

Conversion projects and increasing efficiency gains will also lead to increase spare capacity in the upcoming years. Although expected capacity additions are in line with expected demand growth, the IEA estimates that 65% of demand will be met by supplies that bypass the refining system (NGLs and biofuels).

Additionally, the industry will soon be more and more affected by increasing regulation aiming to reduce CO_2 emissions and limit the production and consumption of oil. Also, the increasing impact of technology in the development of vehicles using renewable energy should start affecting the consumption of gasoline and diesel in the long run.

Regarding the product mix, gasoline demand has been growing due to the growth in emerging markets while falling in OCDE due to weaker economy and efficiency standards. However, its prices can become under pressure as it can be supplied not just from refineries but also with light end shale components. Demand for diesel follows a similar pattern but, as emerging markets growth has cooled and new refineries have strong diesel yield, diesel prices can become under pressure.

All factors considered, the adverse situation in the industry has been exposing refineries cash flows. As revenues barely cover fixed costs and refining margins persist at such low levels, some refineries have started to close operations and outages/maintenances were extended to minimize cash costs. Although closures seem to be to optimal choice from a financial standpoint, when combining with politics, shutting down operations in some countries should not be a reckless process and a refinery will not permanently close from one day to the other.

Refining

The refining activity incorporates the Matosinhos hydroskimming refinery and the Sines cracking refinery, with a capacity of 110 kboepd and 220 kboepd, respectively. In the Iberian refining industry, Galp Energia holds 20% market share and competes with Repsol, Cepsa and BP. Regarding the Portuguese market, the company is better positioned, with c. 70% market share, leveraging the Portuguese Marketing operations.

Since Galp Energia’s downstream businesses have been the main source of company´s earnings, the weak European refining environment led the company to upgrade its two refineries, improve higher energy efficiency and optimize the segment integration. Otherwise, the uncompetitive refinery plants could compromise the firm marketing positioning.

Galp Energia is currently benefiting from the upgrade to its refining system with a considerable premium to its benchmark refining margins…

The upgrade project involved an investment totaling 1.4 €b and has been at cruising speed since January 2013. The project aimed to optimize the refineries’ capacity utilization by adjusting the production profile to the needs of the Iberian market, by increasing the annual production of diesel (c. 50%) in order to benefit from higher diesel crack spreads, at the expense of gasoline, whose market value is cheaper.

The new fully integrated refining system is a competitive advantage for the company as it is now better able to adapt to market dynamics given the higher flexibility on the choice of crude oils to be processed. Moreover, raw material costs were reduced with the increased capacity to process heavy crude oil (c. 80%), which is available on the market at lower prices than light crude oil. Refining margins were expected to improve from 2 to 3$/bll with the project.

Apart from the competitive advantages of its refining system, Galp Energia is able to sustain better margins than its benchmarks also because of its close location to its distribution network that brings proximity to demand and distribution centers. Refineries are close to the company's main demand source and both have exclusive access to oil terminals in the Portuguese ports.

Although the challenging environment in Europe has weighed on Galp Energia's earnings in recent years, the firm is better positioned in Europe given the improved margins and location.

Still, due to the policy of optimizing capacity given the weaker margins and due to the system outages, the utilization rate of Galp Energia's refining capacity in 2013 only reached 73%.

However, Galp Energia's third quarter results for 2014 set up better expectations for the new refining system, with an increase of the share held by diesel production (at the expense of fuel oil). The production of middle distillates (diesel and jet) accounted for 47% of total production while gasoline and fuel oil accounted for 22% and 16%, respectively. Crude oil accounted for 80% of raw materials processed, of which, 71% was medium and heavy crude.

Also during the quarter, Galp Energia's benchmark refining margin increased to $2.3/bbl following the decrease in crude oil price and improved hydrocracking and cracking margins. The crude oil price shock had significant impacts on the European refining industry profitability. In fact, mainly in Europe, fuel prices lag to drop and therefore, the decreased crude oil price was not immediately passed to retail consumers. Further improvement was achieved by the company's focus on the efficiency of its refining system (crude sourcing and efficient integration of refineries) that led to refining margins of $5.6/bbl, representing a premium to the benchmark margin of $3.3/bbl. On a negative note, cash costs increased to $3.1/bbl. However, this deterioration was mainly due to the lower dilution of fixed costs, as a result of the refining capacity optimization and maintenance of the Sines refinery in 1H14, resulting in lower volumes processed.

Marketing

Galp Energia is a leading operator in its marketing activities, selling oil products, mostly produced in its refineries, to direct clients (through the wholesale, retail and LPG channels) in the Iberian Peninsula and several African countries. The company's production is also channel to other operators or to exports.

Galp Energia is the third main player in Iberia and competes with three other leading operators, BP, Cepsa and Repsol, and also with independent retailers and supermarkets. By December 2013, according to the company data, the refined oil markets in Iberia were estimated at 58.6 mton[16] per year. With a retail network of 1,305 service stations in Iberia, Galp Energia's retail market share in 2013 in Portugal and Spain was 30% and 6%, respectively. In the wholesale segment, the company had a 50% market share in Portugal and 15% in Iberia.

Overall, volumes sold are still on a downward trend, with the weak demand due to the austerity measures in Iberia being the main contributor to an expected decrease of 6% in 2014. Moreover, integrated oil companies are facing increased competition from supermarkets selling low-cost oil products, whose market share already reached 20% of the retail market. Despite being considered lower quality items (lower quantity of additives and oil concentration), the reduction in consumers budgets has been fostering this trend. Still, price competition is limited because supermarkets do not refine their own products and Galp Energia also supplies to these operators, who have extremely reduced margins. We note that under new low cost fuel legislation in Portugal, every service station will be forced to offer low cost fuels, similarly to supermarkets. The company's CEO already referred that Galp Energia may close service stations because the offering of these lower quality fuels will imply new investments and will reduce the retail margins.

Nevertheless, contrary to the refining business, marketing performance has remained stable in terms of earnings generation. In a way to preserve the leadership in the Portuguese retail market, the company supported its customer relationships with a partnership with Sonae, the largest retail group in Portugal.

African current operations might be a trigger for a growing opportunity…

Moreover, the company continues to expand its marketing operations in Africa as it appears as a growing opportunity. Galp Energia has operations in Angola, Mozambique, Gambia, Swaziland, Cape Verde and Guinea-Bissau with 130 service stations.

Sales to other operators in Iberia also take a stable and significant share of the refineries production, totaling 3.3 mton in 2013 (c.20% of total volumes). Lastly,

[16] Million tons

exports to non-Iberian and non-African countries accounted for 4 mton. This contribution is less stable as it is mainly a way of offloading production and the performance of the other contributors will dictate more or less availability of products to export.

Valuation

In our valuation of Galp Energia's Refining & Marketing segment, we use a DCF approach to value the two activities together as they make sense as an integrated business, using the wacc as a discount rate and a 1% long-term inflation as a terminal nominal growth rate.

The refining business is valued based on our prediction for the key value drivers: benchmark refining margin, Galp Energia's premium to the benchmark, refining cash costs and refining capacity utilization rate.

The company is benefiting from the upgrade on its refining system through a premium to the benchmark refining margin. However, our analysis demonstrates that the company still faces the risk of low refining margins. Refining spare capacity is expected to reach 10 mboepd by 2015 (according to OPEC); demand for oil products in Europe might remain flat should the oil prices increase again; and new environmental requirements should be in place by 2015 (established by the International Maritime Organisation and the Emission Control Areas). This scenario will contribute to keep low utilization rates and thus, downward pressure in refining margins is expected.

R&M performance is set to rebound with the current low oil price scenario…

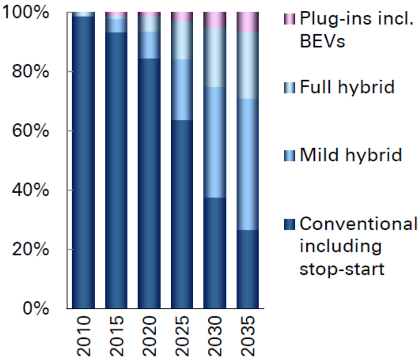
Alternatively, a shift in the European refining adverse cycle is highly dependent on the extension of the current low oil price scenario, on a major recovery in the European economy to improve demand and on some refineries shut-downs to solve the current capacity mismatch. With Brent at the current low levels, the industry can regain its competitiveness as this is a key determinant to increase the refining margin and decrease refining cash costs.

We expect that the structural problems of the sector will not be solved in the short term, and spare capacity will place a downward pressure on utilization rates. However, in line with our analysis for the E&P segment, we forecast a Brent price below 80$/bbl over the valuation, which will be a key driver to recover the refining industry from the current depressing environment, with benchmark refining margins gradually above 2$/bbl until 2017, and stabilizing at 1.7$/bbl by 2020.

Furthermore, considering the company's competitive advantages and the upgraded refining system, Galp Energia's refining margin should have a 1.5$/bbl premium (below the upgrade project prospects) above international benchmark margins, placing the company's margin at 3.2$/bll by 2020. Even considering an economic recovery in Europe, utilization rates should profit just from a small improvement and stabilize at 70% in the long term.

The refinery cast costs should accompany the positive evolution of utilization rates and stabilize at 2.6$/bbl, below the current figures that were pressured by the previous high Brent prices (consumption and losses make up 9% of the company's production), by the extended maintenance at the Sines refinery and by the lower dilution of fixed costs, given the lower volumes processed.

Figure 26: Vehicles sales by type (%)



Source: BP Energy Outlook 2035

Regarding the marketing segment, its mature stage should contribute to stable earnings, being mainly influenced by the Brent price and economic cycles in Iberia and, additionally, the growth of the company presence in Africa. Besides leveraging the potential recovery in the Iberian economy, our pattern for the evolution of Brent price should be reflected in lower prices for refined products, being key determinant for a gradual increase in demand. However, we should not expect an over optimistic boost in consumption because the high debt burden will be reflected in weak multiplier effects. On the other hand, in the long term, the impact of growing renewable energy transport solutions at lower prices will decrease consumption of gasoline and diesel, placing a downward pressure in sales. All in all, total sales should remain stable above 16mton, with limited upside.

Assuming that Galp Energia will retain its leadership and positioning in retail and wholesale markets, the company has control to reflect variations in operating costs in higher final prices and thus, marketing margins should be stable. However, we introduce a gradual decrease in marketing margins in order to account for the current Portuguese Government's project to introduce low cost fuels in all service stations.

R&M started generating positive cash flow after the substantial capex required by the refining system upgrade over the past years. As we do not anticipate significant investments in the future, we assume a capex of 170M€/year for maintenance and to cover depreciations. The following table presents the impact from a stress test to the company's refining margins, which results in lower variations compared to the crude oil price, given the segment lower weight on the enterprise value.

Figure 27: Refining margins sensitivity analysis

Crude oil price variation (%)						
-20%	-10%	0%	10%	20%	30%	40%
11.44 €	11.60 €	11.77 €	11.93 €	12.09 €	12.26 €	12.42 €

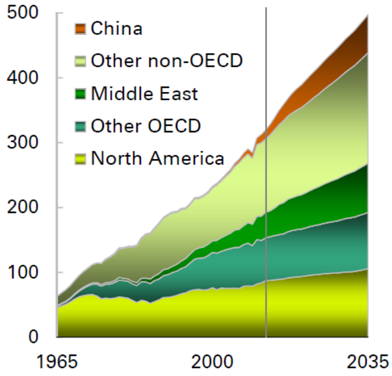
Source: Analyst estimates

Gas & Power

Galp Energia has becoming an integrated energy operator as its G&P segment includes the procurement, distribution, storage and supply of natural gas in the Iberian Peninsula, LNG trading in international markets and power generation and supply of electricity in Portugal.

Market Environment

Figure 28: Gas demand by region (billion cubic feet)

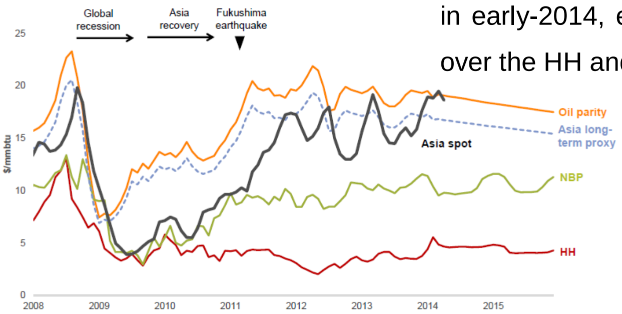


Source: BP Energy Outlook 2035

Natural gas importance has been increasing over the last years (up 1.8% in 2013) and this pattern is expected to continue, mostly drive by the significant discoveries made, by economic growth in BRIC countries (up 3% in 2013) and by government policies to lead with environmental issues and energy dependency. According to BP Energy Outlook 2035 consumption in non-OECD countries should maintain a solid growth at 2.7% per year, whereas consumption in OECD countries (down 1% in 2013) is expected to grow at 1% per year over the outlook period. Accordingly to the IEA, the natural gas share in the global supply of energy will reach c. 25% by 2040.

Natural gas markets growth will always be constrained by the shortage of infrastructure for transportation and storage, which make them dependent on the proximity to consumer centers. Gas natural has three reference markets with different prices and dynamics: HH - Henry Hub (North America); NBP - National Balancing Point (Europe); and Japan LNG (Asia). These issues made LNG trading to grow faster than the conventional natural gas market. LNG consumption increased 2% in 2013, accounting for c10% of total natural gas demand. The main LNG demand center is the Asia Pacific region, with Japan and South Korea responsible for more than 50% of global demand in 2013, given the closure of most of these countries nuclear capacity following the Fukushima disaster that led to the intention of reducing exposure to nuclear energy. The shortage of LNG to meet demand took the Japan LNG price to its five-year highs in early-2014, escalating into considerable differences in the price per mmbtu[17] over the HH and the NBP spot prices.

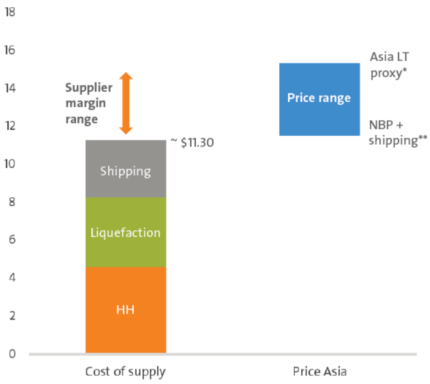
Figure 29: Gas and LNG Prices ($/mmbtu)



Source: BG Group

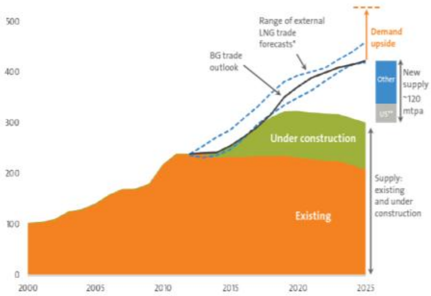
17 Million British termal unit

Figure 30: LNG shipping and liquefaction price ($/mmbtu)



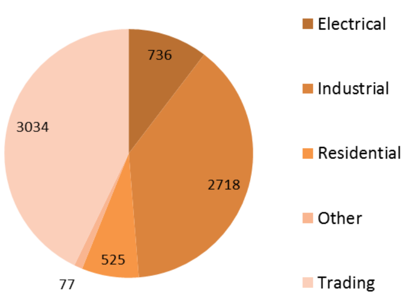
Source: BG Group

Figure 31: Global LNG supply (mtpa)



Source: BG Group

Figure 32: 2013 gas sales volumes by segment (mcm)



Source: Galp Energia

In the upcoming years, LNG demand should continue to increase. Thus, upstream investments are being directed to LNG facilities to take advantage of the substantial price difference in the three natural gas reference markets. However, according to the BG group, if we include the transportation and liquefaction costs over the Henry Hub price, the cost of supplying LNG to Asia is c. 11.30$/mmbtu, which reduces considerably the arbitrage opportunities.

High LNG margins should continue in the short-term, based on the strong demand predictions in Asia and Latin America, on the shortage of liquefaction/regasification facilities, and on the medium/long-term nature of LNG contracts. The same cannot be said for trades in the spot market. In fact, during last December, LNG Japan spot price was already less than half the all-time peak in early-2014, reaching levels below 10$/mmbtu. Although long-term contracts make-up 70-80% of Japan's LNG imports, these are also correlated with crude oil prices and thus, margin might decrease sooner than expected.

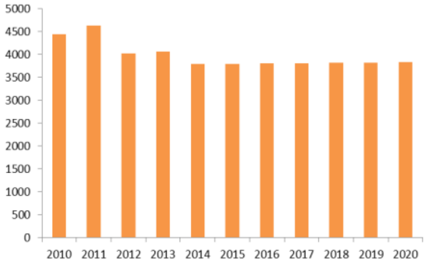
In the medium term, several dynamics will change the LNG markets, decreasing its margins. The current investments in LNG (mainly US, Australia and Russia) will take more capacity on stream (+37% by 2017). It is important to note that the increase in exports from US shale gas production will impact the competitiveness of LNG projects in the long-term, or in the short-term for those who are not hedged or pre-contracted. Also, the high cost of LNG imports in Japan should lead to a gradual reopening of the country's nuclear plants and consequently, decrease LNG demand. The great uncertainty is whether demand from other Asian countries and Latin America will be sufficient to absorb the possible decrease in demand from Japan and the new supply capacity coming on stream.

Supply & Trading

The supply and trading business encompasses the supply of natural gas in the Iberian Peninsula and the trading of LNG in international markets, totaling 7090 mcm[18] in 2013. Galp Energia estimated natural gas markets in Iberia at 32.6 bcm[19] in 2013. In order to reduce risks, Galp Energia assures its supplier position in the Iberian market through long-term sourcing contracts (20 years) and occasionally through the spot market. Currently, the company sources 2.3bcm of natural gas per year from Algeria and 3.5 bcm of LNG from Nigeria.

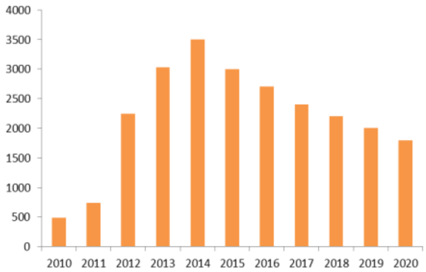
[18] Million cubic meter
[19] Billion cubic meter

Figure 33: Gas sales volumes excl. trading (mcm)



Source: Analyst estimates, Galp Energia

Figure 34: LNG trading volumes (mcm)



Source: Analyst estimates, Galp Energia

The activities of supply of natural gas in Iberia are mainly directed to the residential/commercial, industrial and electrical segments, where Galp Energia is the third largest operator, with an estimated number of 1.3 million clients in 2013. Despites some variations due to the sector seasonality, these customer segments represent a stable demand of 4bcm per year in Iberia. In 2013, this number represented 4bcm (vs 4.6 bcm in 2011), following the current economic environment in the region. The volumes sold to the residential and commercial segment totaled 525 mcm a figure that has been decreasing following the liberalization of the Portuguese natural gas market. On the industrial segment, volumes increased to 2.7bcm (+29% yoy) on the back of consumption of natural gas from Galp Energia's own refining system and cogeneration units that started in full operation in 2013. On the negative side, the electrical segmented consumption decreased to 736 mcm (-41% yoy) following the increased use of alternative sources to produce electricity, such as hydroelectric and wind generation.

With a saturated gas marker in Iberia, especially at the electrical segment level, Galp Energia focused on LNG trading operations in order to capture current market opportunities in Asia and Latin America.

In order to assure earnings and attractive margins recurrence, the company signed three year contracts for the sale of 1.4 bcm per year until 2015 and is currently diverting LNG cargoes from Nigeria (agreed with the supplier). In 2013, LNG volumes traded reached 3,034 mcm, a significant increase since 2010 (494 mm³), and now accounts for the majority of earnings within G&P segment. However, as analyzed in the market environment section, we do not expect this segment's volumes traded and profitability will be sustained in the future.

Infrastructure

Galp Energia's Infrastructure segment includes the regulated storage and distribution of natural gas in the Portuguese market, whose returns are regulated by ERSE, the Portuguese energy market regulator.

Galp Energia's regulated distribution business includes 12,159 kilometers of distribution network hold by five companies operating under 40-year concession contracts (Lisboagás, Duriensegás, Paxgás, Medigás and Dianagás) and another four operating under 20-year concessions (Lusitaniagás, Beiragás, Tagusgás and Setgás). Considering the firms' participation in each of these companies, this business has a Net Regulated Asset Base (RAB) of 1,041 €m with a remuneration rate of 8.4% (pre-tax nominal).

The regulated storage business, operated by Transgás, encompasses a public-service 40-years concession and functions in two sites, TGC 1S with a storage capacity of 40 mcm and TGC-2 with 752 mcm. The business represents a Net RAB of 67 €m and is remunerated at 7.9% (pre-tax nominal). We note that just before the end of the 2014 first semester, Galp Energia announced the partial sale of the storage business to REN for 71.7 €m (subject to regulatory approvals), including the two storage caves and the rights and obligations associated to the concession. Galp Energia's CEO referred that the business was not a core asset. Under the concession, the company would have to invest in two additional caves, which was not part of Gal Energia's core strategy. In this context, the storage business is not included in our valuation.

The regulator calculates the return on RAB as a weighted average cost of capital, estimating the cost of debt and the cost of equity for the gas sector, taking into account the sector average capital structure. ERSE calculates these rates at nominal values and before taxes because taxes are not accepted as costs for regulatory purposes. In the current regulatory period (2013-2016), in order to adjust the capital cost to the current market conditions, allowed returns started to be linked to the average yield of 10-year Portuguese government bonds, with a cap and floor mechanism (in order to maintain the regulatory stability and control the consumers' risk). A variation of 1% in the return on RAB (RoRAB) needs a 6% change in the average yield of government bonds. Additionally, the minimum RoRAB is set to 7.83% (bond yield of 2.5%), whereas the maximum is set to 11% (bond yield of 21,5%). ERSE sets the allowed revenues as the sum of the cost of capital (product of RAB and RoRAB, plus depreciations) plus the recovery of operating costs and adjustments/tariff deficit (difference between actual and estimated allowed revenues for year n-2).

Power

Figure 35: Regular vs Special Regime tariffs (€/MWh)

Source: ERSE

The power business includes power generation and supply of electricity. Galp Energia built its presence in the power generation business through its cogeneration plants in Portugal, with a total installed capacity of 254 MWh[20]. In 2013, sales of electricity to the grid reached 1,904GWh[21]. However, this figure should decrease about 200GWh in 2014, mainly influenced by the shutdown of the Energin cogeneration.

The electricity produced in cogeneration plants is regulated by the ERSE which establishes a special regime to provide priority access to the network and to set a

[20] Megawatt hour
[21] Gigawatt hour

regulated tariff, much higher than the regular electricity tariff. The fact that the high tariff created an incentive for producers to sell electricity to the grid under the special regime instead of consuming it, created gas tariff deficits over each of the past years, which are then passed to the consumers with increased tariffs. However, circumstances may change as the Troika Memorandum recommended a downward revision of these special regime tariffs given that the special regime production has been increasing over the years and already accounts for c. 40% of the total electricity consumed in Portugal.

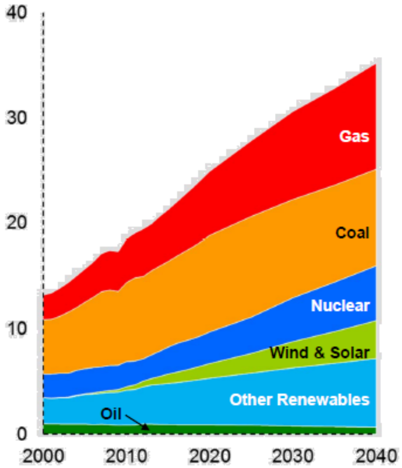
Following the liberalization of the electricity and gas markets in Portugal, the increased competition forced Galp Energia to enter in the supply of electricity business with the strategy of selling combined electricity and gas packages to its existing natural gas customers. By the end of 2013 the company had around 100,000 clients and it aims to continue to improve its weight in the electricity sector.

Valuation

In our valuation of Galp Energia's G&P segment, we use the DCF method, applying the wacc as the discount rate and a 1% long-term inflation as a terminal nominal growth rate. We have valued the supply & trading, the regulated infrastructure and the power businesses separately.

Earnings from the gas supply business for the Iberian market, despite a stable demand of roughly 4 bcm, will be mainly affected by the volume growth for its different segments. The Iberian natural gas market should slightly recover leveraging the recovery of the economic environment in Iberia. Regarding the company sales to residential clients, following the shift to the liberalized market, operations should have more fluctuations and we predict that increased competition will continue to affect Galp Energia's retail market share.

Figure 36: Global electrical demand by fuel (Thousand Terawatt hour)



Source: Exxon Mobil Energy Outlook 2040

In a more positive side, we expected improved demand from the electrical sector given the likelihood of new energy policies reducing subsidies on renewable energy, which will increase the load factor on CCGT[22] plants. Regarding the LNG trading activity, currently the main source of earnings for the G&P segment, in line with the above analysis, we expect the company will not be able to sustain the current trading volumes and margins. Although the company has some visibility until 2015 given the LNG contracts signed, we predict trades on the spot market will gradually decrease, stabilizing at 1.8 bcm by 2020. Moreover, margins for trades in the spot market already decreased considerably to level

[22] Combined cycle gas turbine

below 10$/mmbtu, which will rip out the arbitrage opportunities as it may not be enough to cover liquefaction and transportation costs. Despite the still strong demand and the shortage of LNG facilities, the LNG spot price for trade in Asia was largely affected by the crude oil price shock. Between 2015 and 2017, we expect margins will start to decrease with increased capacity and lower demand, mainly affected by expectations of Japan turning on its nuclear capacity and by the amount of gas exported from the US.

The infrastructure business should continue stable as it is mainly a function of the RAB and RoRAB. Considering the company's guidance, we expect only a maintenance capex of 30 €m and therefore, total net RAB should be stable at current levels (1,041 M€ considering only the distribution business), being mainly affected by inflation adjustments at the end of each regulatory period. The net RAB results from Galp Energia's participation on each of the regulated companies. Also, following the current mechanism for the remuneration rate, we expect this rate to slightly decrease on the medium term following the decrease on the Portuguese sovereign risk. Thus, we assume the regulator will adjust the allowable rate of return for the regulated natural gas distribution 8% (pre-tax nominal). Furthermore, and because variations in the natural gas regulatory returns have been historically linked to those of electricity, ERSE 2015 proposal for electricity tariffs already include a cut of 1.4% on the rate of return for the electricity regulated assets. Lastly, the difference from the current regulatory rate to our estimated wacc for the segment (8.4% vs 5.04%) is mainly related with a higher risk-free rate and higher beta of equity used by the regulator. Following the lower wacc, our valuation for the infrastructure business is higher than the RAB.

The power segment was valued based on the current installed capacity and our prediction for utilization levels. As we do not expect additional investments, installed capacity stood at 212MWh, a decrease of 42MWh from 2013, following the closure of Energin cogeneration.

The most critical valuation driver should be the tariff for the special regime (with an average price for cogeneration of c.124€/MWh in 2013), which we expect to be cut in the near term, following the Troika Memorandum call to reduce the government subsidies. Therefore, we applied a gradual reduction on the tariff, stabilizing at 90€/MWh by 2020. In this context, the current capacity utilization levels of c. 85% should also be reduced with the loss on the segments margins.

With the previous analysis, despite the stale infrastructure business, we expect G&P's contribution to change during the next years, with downward pressure from the shrinkage of trading volumes and margins at lower levels and from the regulatory risk in the special regime power generation.

SOTP

Our valuation follows a sum of the parts approach in order to analyze the individual contribution from the different businesses in Galp Energia's portfolio. Using the DCF model for the different segments – E&P, R&M and G&P – we estimate future cash flows at current prices taking into account the company's strategy, available historical data, the market environment prospects and the different industries' dynamics and risks.

For the R&M and G&P segments, our valuation considers a cash flow forecasting period until 2020. From then onwards, the terminal value includes a terminal nominal growth rate of 1%, corresponding merely to our expected inflation rate, given the mature stage of the businesses. Additionally, the valuation for the natural gas regulated infrastructure business takes into account the end of the respective concessions. Regarding the E&P segment, given the limited nature of each field reserves and concession periods, instead of applying a terminal value in our valuation, we estimated cash flows over the life of each project.

Concerning the discount rates, as we expect the company capital structure to remain stable over time, we use different waccs at nominal values to discount the cash flows from the different activities.

The cost of equity for each activity was computed applying the CAPM[23]. Regarding the proxies for the risk-free rates, accordingly to the main currencies at which transactions are denominated (EUR or USD), we used the yields from the 10-year US Treasury Bond (E&P) and from the 10-year Germany Government Bond (R&M and G&P). For the market risk premium, with a consensus ranging from 5% to 7% among the financial literature, we used 7%, considering the more recent market performance.

For the beta component of the CAPM, we unlevered the betas from comparable companies for each sector (similar business and level of risk), using the comparables' levered betas and respective information regarding market capitalization and net debt. Then, we relevered each beta using our prediction for Galp Energia's debt-to-equity target ratio at market values (0.33). The beta used on the CAPM for each sector corresponds to the average relevered betas from the sector comparables (E&P: 1.22; R&M: 0.8; Gas: 0.63; Power: 0.65).

[23] Capital asset pricing model

The cost of debt was computed by adding a credit default swap (CDS) to the risk-free rate. Additionally, considering Galp Energia's yields from its bonds outstanding, we believe the company has a BB+/Ba1 fundamental credit risk profile and consequently, our model uses a probability of default of 2.5% and a recovery rate of 80%. Moreover, in consensus with articles from Standard and Poor's and Moody's and academic papers relating credit ratings with corporate CDSs, we assume 3.5% for Galp Energia's CDS. Lastly, we used different tax rates for each sector, according to the corresponding markets where the activities take place.

Applying the sum of the parts approach, the company's enterprise value expected by December 2015 is obtained by adding up the present value of each segment. Lastly, subtracting the value of net debt and minorities and summing the value of non-operating assets (net of non-operating liabilities), we modelled Galp Energia's equity value at 9,758 M€, corresponding to a €11.77 price per share (829,250,635 shares outstanding), a potential upside of 50% vs current share price.

Figure 37: Valuation summary

	Galp life-of-field reserves (mboe)	Value M USD	Implied $/boe	Value M EUR	% of EV	EUR per share	Valuation Method
Exploration and Production	**3352**	**8,816**	**2.63**	**7,053**	**50.1%**	**8.50**	
Angola	139	469	3.38	376	2.7%	0.45	DCF
Block 14	99	366	3.69	293	2.1%	0.35	
Block 14K	6	18	2.76	14	0.1%	0.02	
Block 32	33	85	2.57	68	0.5%	0.08	
Brazil	1748	6,681	3.82	5,344	37.9%	6.44	DCF
Lula & Cernambi	989	4,663	4.71	3,730	26.5%	4.50	
Iara	302	862	2.85	690	4.9%	0.83	
Carcara	112	287	2.56	230	1.6%	0.28	
Jupiter (oil section)	345	868	2.52	695	4.9%	0.84	
Mozambique	1465	1,666	1.14	1,333	9.5%	1.61	Transaction Mult.
Refining & Marketing				**3,750**	**26.6%**	**4.52**	**DCF**
Gas & Power				**3,282**	**23.3%**	**3.96**	**DCF**
Gas Supply & Trading				1,799	12.8%	2.17	
Gas Infrastructure				1,098	7.8%	1.32	
Power				385	2.7%	0.46	
Enterprise Value				**14,085**		**16.99**	
Non-Operating Assets/Liabilities (Associates, Pension Funds)				100			Book Value
Net Debt (Debt - Cash - Loan to Sinopec)				3,283			Book Value
Minority Interests				1,144			DCF (30% Brazil)
Equity Value				**9,758**			
Shares (#M)				829,251			
Price per share EUR (year-end 2015)				**11.77**			
Dividend per share to be paid in 2015				0.18			
Current Market Price				7.97			
Upside/Downside				50%			

Source: Analyst estimates

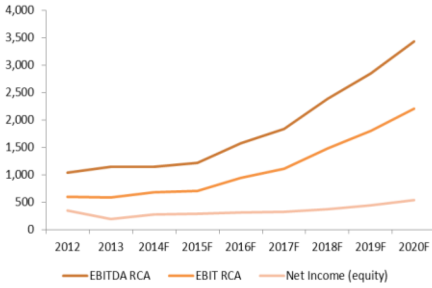
Figure 38: WACC assumptions

	E&P África	E&P Brazil	R&M	Gas	Power
Risk-free rate	2.4%	2.4%	1.5%	1.5%	1.5%
Market Risk Premium	7.00%	7.00%	7.00%	7.00%	7.00%
Sector Levered Beta	1.22	1.22	0.80	0.63	0.65
Cost of Equity	**10.99%**	**10.99%**	**7.03%**	**5.88%**	**6.01%**
Risk-free rate	2.44%	2.44%	1.46%	1.46%	1.46%
Credit Default Spread	3.50%	3.50%	3.50%	3.50%	3.50%
Probability of Default	2.50%	2.50%	2.50%	2.50%	2.50%
Recovery Rate	70.00%	70.00%	70.00%	70.00%	70.00%
Cost of Debt	5.04%	5.04%	4.09%	4.09%	4.09%
Tax Rate	50.00%	34%	30%	30%	30%
After-tax cost of debt	**2.52%**	**3.33%**	**2.88%**	**2.88%**	**2.88%**
Target D/EV	**25%**	**25%**	**25%**	**25%**	**25%**
Target E/EV	**75%**	**75%**	**75%**	**75%**	**75%**
WACC	**8.89%**	**9.09%**	**6.00%**	**5.14%**	**5.23%**
Currency	USD	USD	EUR	EUR	EUR

Source: Analyst estimates

Financials

Figure 39: Galp Energia's forecasted results



Source: Analyst estimates

We expect FY14 EBITDA (RCA – our estimates from FY14 onwards do not include non-recurring results and inventory effects) at 1,150 €m, in line with FY13. FY15 EBITDA is expected to grow 13% yoy to 1,221 €m. However, from FY16 onwards, earnings dynamics will start to change, as upstream operations start to mature. At the same time, we anticipate a better performance from the R&M segment, whereas G&P's earnings should lose its strength. Galp Energia's EBITDA is expected show an extraordinary record, with a CAGR[24] of 20% over the 2014-2020 period. Shareholders' net income is predicted to grow at a CAGR of 12%, increasing from 189 €m in 2013 to 532 €m in 2020. This lower grow is justified by a more than proportional increase in interest expenses given the significant increase in financial debt. Also, the tax burden will see its share increased given the higher weight from the E&P earnings that face the higher tax rates (including SPT in Brazil).

The E&P growth story will start to mature from 2016 onwards, as the deployment of 15 FPSOs (13 in the Brazilian pre-salt) until 2020 will lead to a dramatic increase in net entitlement production, from 20.8 kboedp in 2013 to 248 kboedp in 2020. However, this production output is still below the company's 300 kboepd target, following our assumptions to consider delays in the deployment of some FPSOs. Nonetheless, E&P's EBITDA is expected to show a 37% CAGR until 2020, increasing from 396 m€ in 2013 to c. 2,800 m€ in 2020. Being the company's main value driver, the E&P projects account for c. 50% of our SOTP and the segment's EBITDA weight on the total EBITDA is expected to increase from 35% in 2013 to 82% by 2020. The Brazilian, Angolan and Mozambican upstream operations account for 38%, 3% and 9% of our SOTP, respectively. Over the next years we should be able to confirm the materialization of the Brazilian production curve prospects, as well as obtaining additional visibility for the E&P strategy beyond 2020.

After the weak environment in the European refining industry over the last few years, the R&M segment (27% SOTP) could only see its earnings contribution to recover. We expect R&M EBITDA to increase from €315M in 2013 to €349M in 2020, remaining below the company's guidance of more than €400M. In the meantime, the segment's performance should improve significantly, reaching €488M in 2015, following the predicted recover in demand and improved European refining scenario. However, we do not expect this improved scenario will be sustained and thus, the refining contribution should gradually decrease to

[24] Compound anual growth rate

the referred levels by 2020, given the structural European excess refining capacity and the improvement of the oil price scenario over time. Also, despite having a more stable demand, we expect marketing margins to slightly decline over the years. Despite significant variations, the segment EBITDA is expected to have a 1% CAGR until 2020, with its weight on the total EBITDA decreasing from 28% to 10% in 2020, being diluted by the upstream operations.

Despite the historically stable source of earnings from the natural gas sales to direct clients (Supply and Trading sub-segment) and from the regulated gas distribution business, we predict the G&P (23% SOTP) contribution over the following years we be affected by a significant decrease in volumes and margins in the LNG trading activity and, in a lesser extent, by a decrease in the major regulatory parameters: the remuneration rate for the gas distribution regulated assets and the electricity price for the special regime. In this context, we expect G&P EBITDA to gradually decrease from €412M in 2013 to €247M in 2020. Despite being the main contributor in 2013, the segment weight on the total EBITDA, also diluted by the upstream operations, should decrease from 36% to 7% by 2020, with a -7% CAGR for the 2014-2020 period.

Despite significant variations in the R&M and G&P EBITDA over the last years, mainly justified by the depressed European refining industry and by the LNG trading opportunities, these segments include a stable source of earnings, which will be crucial to support the upstream ambitious investment plan. Comparing to the company's guidance (2013-2018) for the combined EBITDA higher than €700M, we expect the EBITDA of these segments to stabilize at c €600M from 2018 onwards.

Regarding capex, we expect it to range between 1.3€ to 1.7€ billion over 2014-2020, in line with the company's guidance. No major investments are expected for the downstream activities, for which we predict a combined maintenance capex of 215€ per year. On the other side, E&P capex will be the critical cash outflow at least until the end of the decade. The upstream capex will face significant increases from last years, varying from 1.1€ to €1.5 billion, with special relevance in 2016, 2016 and 2020, when more production units will be deployed. Also, we expect investments in Mozambique to be more relevant from 2020 onwards.

In line with the above estimates, mainly given the capex relevance, we expect Galp Energia will only start to be cash flow positive in 2018, when Lula/Iracema production curve should materialize and start to generate enough cash flow to sustain the segment investments.

Our forecasts for the company's value delivery are translated into a return on equity (ROE) return on equity growing from 4% in 2013 to 13% in 2020. However, the same meaningful performance is not expected for the return on the invested capital (ROIC), as it should stay at 7% in 2020 (from 5.5% in 2013). Again, since Galp Energia assumed a 90$/bbl crude oil price on its strategic plan, the company's 15% guidance for the ROIC does not go in line with our valuation. Additionally, we note that the E&P segment ROIC only exceeds our estimated wacc be the end of the decade, when Lula/Iracema reaches its peak production. In the R&M, the assumed slight improvement on the European refining industry will not be sufficient to support a meaningful return on invested capital, as our wacc largely exceeds the ROIC (6% vs c. 1% by 2020). We recall that the R&M ROIC fell to close to zero in 2012 due to a huge increase on invested capital with the refineries upgrade project, whose prospects did not materialized in the middle of a depressed European refining environment.

Regarding the company's financial position, we expect net debt to EBITDA ratio (including cash, cash equivalents and loan to Sinopec) to increase from 1.1x in 2013 to 3.0x in 2017, which goes in line with the above predictions regarding cash flow generation. From 2018 onwards, positive cash flows will re-establish the current sound financial position, as the ratio is expected to start falling, reaching 2.4x by 2020. This forecast does not go in line with the company's guidance in the CMD 2014. However, Galp Energia was not assuming its cash flow generation to be deteriorated by the current shock in the crude oil price. In line, net debt to equity ratio (book values) increases from 20% to 133%. This deterioration opens room to some asset sell offs, with the main possibilities being a minority stake in the infrastructure business or some of the company's interest on the upstream projects. Debt to assets ratio shows a more stable capital structure, stabilizing at 33% by 2018. The G&P current above wacc ROIC (7% vs 5%) is expected to fall to 4% by 2020, following the drop in LNG trading operations.

Considering Galp Energia's operational and financial performance evolution, our valuation sets the year-end 2015 enterprise value at 14,085 €m, with an implicit EV/EBITDA15 of 10.3x.

Appendix

Appendix 1: Brazilian pre-salt top 20 well flow rates

#	ANP well ID	Field	Basin	Oil (bbl/d)	Natural gas (Mm³/d)	Production (boe/d)
1	7LL28DRJS	Lula	Santos	35,140	1,249	42,995
2	7SPH5SPS	Sapinhoá	Santos	34,279	1,129	41,382
3	7JUB34HESS	Jubarte	Campos	33,485	1,093	40,359
4	7LL22DRJS	Lula	Santos	29,606	1,067	36,319
5	9BRSA928SPS	Sapinhoá	Santos	29,668	1,038	36,199
6	7SPH4DSPS	Sapinhoá	Santos	29,231	982	35,406
7	9BRSA716RJS	Lula	Santos	23,749	1,805	35,101
8	7LL11RJS	Lula	Santos	25,400	1,080	32,195
9	3BRSA1132RJS	Tld-Bm-S-11	Santos	29,332	352	31,547
10	7LL3DRJS	Lula	Santos	25,429	888	31,015
11	3BRSA496RJS	Lula	Santos	23,840	1,126	30,925
12	7JUB36ESS	Jubarte	Campos	25,340	842	30,637
13	7BAZ8ESS	Baleia Azul	Campos	19,985	635	23,982
14	7BFR12PAESS	Baleia Franca	Campos	19,137	743	23,813
15	6BRSA639ESS	Jubarte	Campos	18,814	676	23,068
16	6BRSA631DBESS	Baleia Azul	Campos	17,718	585	21,395
17	7BAZ4ESS	Baleia Azul	Campos	17,249	621	21,155
18	7BAZ6ESS	Baleia Azul	Campos	16,859	634	20,845
19	1BRSA594SPS	Sapinhoá	Santos	15,558	544	18,980
20	3BRSA821RJS	Lula	Santos	13,812	808	18,894

Total	**483,631**	**17,897**	**596,212**
Average	**24,182**	**895**	**29,811**
Average Lula	**25,282**	**1,146**	**32,492**

Source: ANP

Appendix 2: Comparables per segment

Segment	Company	Levered Beta	Market Cap.	Net debt	D/E	Unlevered beta	Currency
	Galp	0.84	6612	2,418	0.37	0.62	EUR
E&P							
	BP PLC	1.72	71307	22164	0.311	1.31	GBP
	Total SA	0.91	95192	29556	0.31	0.69	EUR
	Repsol SA	0.91	19734	6112	0.31	0.69	EUR
	Chevron	1.13	204223	11227	0.055	1.07	USD
	BG Group	1.15	28969	11691	0.404	0.82	GBP
R&M							
	Repsol SA	0.91	19734	6112	0.31	0.69	EUR
	ERG Spa	0.73	1369	1087	0.794	0.41	EUR
	Total SA	0.91	95192	29556	0.31	0.69	EUR
Gas							
	Gas Natural	0.74	19799	13512	0.682	0.44	EUR
	Spectra Energy Corp	0.92	22767	14483	0.636	0.56	EUR
	Enagas	0.7	5940	3894	0.656	0.42	EUR
Power							
	EDP	0.96	11350	18006	1.586	0.54	EUR
	REN	0.63	1281	2489	1.943	0.32	EUR
	Iberdrola	1.08	34964	23962	0.685	0.73	EUR

Source: Analyst estimates, Bloomberg, Reuters

Financial Statements

Balance Sheet (M€)

	2013	2014F	2015F	2016F	2017F	2018F	2019F	2020F
Assets								
Tangible assets	4,565	5,380	6,185	7,142	8,111	8,680	9,023	9,693
Intangible Assets (w/Goodwill)	1,778	1,829	1,880	1,941	2,003	2,035	2,050	2,089
Invesments in other companies	518	518	518	518	518	518	518	518
Loans to Sinopec	871	812	752	692	633	573	513	454
Financial instruments at FV	35	35	35	35	35	35	35	35
Other assets - Non-operating	52	52	52	52	52	52	52	52
Trade/other Receivables	2,244	2,361	2,556	3,243	3,737	4,823	5,732	6,908
Inventories	1,846	2,033	2,465	2,938	3,226	3,949	4,583	5,444
Deferred tax assets	271	281	315	418	496	656	790	962
Current tax assets	33	22	25	33	40	53	64	78
Cash and equivalents	1,503	1,020	765	593	244	240	254	193
Total Assets	13,717	14,344	15,548	17,606	19,094	21,613	23,613	26,425
Equity:								
Share capital	829	829	829	829	829	829	829	829
Share premium	82	82	82	82	82	82	82	82
Reserves	2,395	2,395	2,395	2,395	2,395	2,395	2,395	2,395
Retained earnings	1,666	1,559	1,481	1,338	1,143	858	498	58
Consolidated net profit for the period	189	276	283	315	328	376	442	532
Equity attributable to equity holders of the parent	5,161	5,142	5,070	4,960	4,777	4,539	4,246	3,896
Non-controlling interests	1,255	1,347	1,441	1,546	1,656	1,817	2,006	2,234
Total equity	6,416	6,489	6,511	6,506	6,432	6,356	6,253	6,130
Liabilities								
Financial Debt	3,677	4,000	4,800	5,700	6,400	7,200	7,800	8,800
Trade/other Payables	2,837	3,056	3,421	4,533	5,357	7,073	8,509	10,358
Other Liabilities - Non-operating	155	155	155	155	155	155	155	155
Retirement and other benefit liabilities	338	338	338	338	338	338	338	338
Provisions	154	154	154	154	154	154	154	154
Deferred tax liabilities	129	139	156	208	246	325	391	477
Financial instruments at FV	12	12	12	12	12	12	12	12
Current tax liabilities	0	0	0	0	0	0	0	0
Total Liabilities	7,302	7,855	9,037	11,100	12,662	15,257	17,360	20,294
Total Equity and Liabilities	13,717	14,344	15,548	17,606	19,094	21,613	23,613	26,425

Income Statement (M€)

	2013	2014F	2015F	2016F	2017F	2018F	2019F	2020F
EBITDA RCA	**1,141**	**1,150**	**1,221**	**1,576**	**1,839**	**2,385**	**2,849**	**3,436**
Exploration & Production	396	424	372	777	1,126	1,730	2,226	2,822
Refining & Marketing	315	320	488	464	410	366	347	349
Gas & Power	412	388	343	317	285	270	257	247
Other	18	18	18	18	18	18	18	18
Depreciation & Amortization	**-461**	**-416**	**-453**	**-541**	**-612**	**-747**	**-856**	**-997**
Provisions	**-90**	**-52**	**-64**	**-92**	**-115**	**-158**	**-193**	**-238**
EBIT RCA	**590**	**682**	**704**	**942**	**1,112**	**1,479**	**1,800**	**2,200**
Exploration & Production	231	319	219	508	764	1,190	1,543	1,952
Refining & Marketing	3	19	187	163	109	65	46	48
Gas & Power	340	328	283	256	224	209	196	185
Other	15	15	15	15	15	15	15	15
EBIT IFRS	**401**	**682**	**704**	**942**	**1,112**	**1,479**	**1,800**	**2,200**
Financial Results	**-26**	**-28**	**-63**	**-102**	**-133**	**-168**	**-194**	**-238**
Interest	-160	-175	-209	-249	-279	-314	-340	-384
Financial Income	123	106	106	106	106	106	106	106
Other Financial Costs	-104	-57	-57	-57	-57	-57	-57	-57
Share of profit in associates	116	99	99	99	99	99	99	99
Other non-operating gains (losses)	-1	-2	-2	-2	-2	-2	-2	-2
	0	0	0	0	0	0	0	0
EBT	375	653	641	840	979	1,311	1,606	1,963
Income Tax Expense	-136	-285	-264	-420	-542	-775	-974	-1,202
Effective tax rate	36%	44%	41%	50%	55%	59%	61%	61%
Net Profit for the Year	239	368	377	421	437	537	632	760
Equity Holders	189	276	283	315	328	376	442	532
Non-Controlling Interests	50	92	94	105	109	161	190	228

Segment results (M€)

E&P RCA	2014F	2015F	2016F	2017F	2018F	2019F	2020F
Sales + Change in Production	645	681	1,342	1,899	2,892	3,702	4,699
Average working interest production (kboepd)	41	54	88	115	166	207	258
Average net entitlement production (kboepd)	35	48	83	109	160	199	248
Average realised sale price (USD/boe) incl oil/gas mix	64	47	53	57	59	61	62
Production costs	112	163	288	387	577	730	929
Production costs (USD/boe)	11.0	11.2	11.4	11.6	11.9	12.1	12.3
Other operating costs	61	89	157	211	315	398	507
Other Operating costs (USD/boe)	6	6	6	6	6	7	7
Royalties 10% Revenues Brazil	48	56	121	175	271	347	442
Ebitda RCA	424	372	777	1,126	1,730	2,226	2,822
Depreciation & Amortisation	79	116	204	274	409	518	659
D&A (USD/boe)	8	8	8	8	8	9	9
Provisions (incl. Abandonment provisions)	25	37	65	88	131	166	211
Ebit RCA	319	219	508	764	1,190	1,543	1,952

R&M RCA	2014F	2015F	2016F	2017F	2018F	2019F	2020F
Ebitda	320	488	464	410	366	347	349
Refining	-30	147	137	97	65	43	42
Marketing	350	341	327	314	301	304	307
Depreciation & Amortisation	-284	-284	-284	-284	-284	-284	-284
Provisions	-17	-17	-17	-17	-17	-17	-17
Ebit	19	187	163	109	65	46	48

G&P RCA	2014F	2015F	2016F	2017F	2018F	2019F	2020F
Ebitda	388	343	317	285	270	257	247
Supply & Trading	216	183	162	134	122	111	102
Infrastructure	138	128	124	121	120	120	118
Power	34	32	31	29	28	27	27
Depreciation & Amortisation	-50	-50	-50	-51	-51	-51	-52
Provisions	-10	-10	-10	-10	-10	-10	-10
Ebit	328	283	256	224	209	196	185
Supply & Trading	204	170	150	122	109	98	90
Infrastructure	108	98	94	91	90	89	86
Power	16	14	13	11	10	9	9

Cash Flow Map (M€)

	2013	2014F	2015F	2016F	2017F	2018F	2019F	2020F
Operating Activities								
EBIT	590	682	704	942	1,112	1,479	1,800	2,200
Taxes	-144	-293	-282	-450	-581	-824	-1,031	-1,272
NOPLAT	446	388	421	493	531	655	769	928
Depreciation	461	416	453	541	612	747	856	997
Capex	723	1,282	1,309	1,559	1,644	1,347	1,214	1,706
NWC (incl. operating cash)	80	76	534	86	-71	144	175	321
FCFF op	104	-554	-968	-611	-429	-90	236	-102
Non-Operating Activities								
Assets	605	605	605	605	605	605	605	605
Changes in Assets	134	0	0	0	0	0	0	0
Liabilities	505	505	505	505	505	505	505	505
Changes in Liabilities	2	0	0	0	0	0	0	0
Net Financial Results minus interest paid	134	146	146	146	146	146	146	146
Taxes	-39	-43	-43	-43	-43	-43	-43	-43
FCFF non-op	-38	103	103	103	103	103	103	103
Total FCFF	67	-451	-865	-508	-326	14	339	2
Financing CF								
-Changes in Excess Cash (excl. operating cash)	422	487	508	149	274	-39	-23	92
Interest Paid	-160	-175	-209	-249	-279	-314	-340	-384
Tax Shield	47	51	62	73	82	93	100	113
Change in Debt (net of loan to Sinopec)	154	383	860	960	760	860	660	1,060
Change in Equity	-529	-296	-355	-426	-511	-613	-735	-882
Total Financing CF	-67	451	865	508	326	-14	-339	-2

Disclosures and Disclaimer

Research Recommendations

Buy	Expected total return (including dividends) of more than 15% over a 12-month period.
Hold	Expected total return (including dividends) between 0% and 15% over a 12-month period.
Sell	Expected negative total return (including dividends) over a 12-month period.

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