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Reform of the Capacity Remuneration Mechanism in Greece

Report prepared for

the Greek Regulatory Authority for Energy (RAE)

ATHENS, JULY 2014

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A REPORT TO RAE, JULY 17, 2014

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1 INTRODUCTION

Electricity supply needs to balance demand in real time while meeting quality and reliability standards, such as maintaining frequency and voltage within regulated range. If the power system is short of resources, demand has to be curtailed ahead of shortage occurrence, otherwise a black-out is experienced. Involuntary service disruption is considered to entail high economic and social costs. As electricity storage possibilities are limited, meeting reliability standards at all times implies ensuring availability of sufficient power capacity and other resources well before actual requirements. Generation or resource adequacy describes such a situation which is targeted by security of supply policies.

Energy-only markets, i.e. designs without separate capacity remuneration mechanisms, deliver optimized mix of generation resources based on marginal costs, which is of course desirable from a least-cost perspective. Common market failures, such as price caps in energy-only markets, barriers to long-term full cost contracting between producers and customers, predatory pricing by abusers of market power, etc., imply insufficient or uncertain capital cost recovery which hinder investment and induce capacity mothballing. Both undermine capacity adequacy and imply high price volatility under deregulation which further leads to "boom and bust" investment cycles with undesirable economic and social implications. Capacity remuneration mechanisms are thus conceived as complements to energy market designs aiming at stabilizing investment cycles and at delivering high reliability performance at reasonable cost and under manageable uncertainty ranges. Nonetheless, as being out-of-market arrangements, capacity remuneration mechanisms need to be carefully designed and administrated to avoid unnecessary costs to consumers.

Traditional capacity remuneration mechanisms (CRM) reward power capacity availability (i.e. firm dispatchable power capacity), in particular at peak load times, irrespective of other capabilities of the power plants, for example in relation to ancillary services or to other policy goals, such as efficiency or environment. The conventional ways of designing capacity mechanisms can be grouped into three broad approaches: a) direct payments to capacity availability, b) obligations of load serving entities implying a decentralized market for procurement of capacity availability guarantees, c) centralized auctions for procurement of capacity availability guarantees. Until recently, direct payment CRM has been the only approach applied in the EU and has been implemented in few Member-States of the EU (Spain, Portugal, Ireland, Italy and Greece), while the remaining Member-States did not apply any CRM at all, except procurement of strategic reserve plants by some TSOs (e.g. Sweden, Poland). The CRM, mainly based on approaches imposing obligations on load serving entities and/or using centralized auctions for capacity guarantees, has been widely applied in several regional markets in the USA and in Latin America.

Since a couple of years, several European governments and regulators are looking at reforming by introducing capacity mechanisms. Although currently there is no immediate capacity adequacy concern in most countries, a view prevails that under anticipated market conditions, characterized by growing penetration of intermittent renewables, low demand growth, increasing carbon prices and reduced operating hours of conventional plants, new investment will be surrounded by high uncertainty. Potential threats to reliable supply are expected to rise under these circumstances manifested already by difficulties in raising funds for large power projects, including nuclear, early retirement of existing plants, including CCGT and cancelling of clean coal investments projects. In the aftermath of the economic crisis, and while energy demand prospects are still gloomy, the power exchanges experience electricity prices reflecting marginal costs of generation while demand net of renewables is in several countries not sufficient to accommodate minimum stable generation capacities. A mix of causes thus drive emergence of the capacity mechanism debate in the EU and decision making is uncertain; but, as the initiatives have been mostly at national levels and non-harmonized, the European Commission rushed to publish guidelines aiming at making potential CRM measures compatible with the EU market integration.

2 EXPERIENCE IN GREECE

Greece has experienced a general power blackout in July 2004 which was due to insufficient reserve capacities and lack of new investment in a time period of significant growth of demand for electricity. Incentivizing new investment, in particular from non-incumbents, has been the main priority of governmental policy and regulatory approaches towards electricity market liberalization in Greece. Already in early stages of the market opening process, it has been widely agreed that the market conditions were not providing sufficient incentives for the entry of new generators in the competitive part of the market. The incumbent (Public Power Corporation – PPC) enjoying a super-dominant position in supply and generation, with de facto exclusive use of lignite and hydroelectric resources, could accept retail electricity prices generally set at levels below long-term marginal costs of new entry. Potential independent power producers (IPP) being deprived from any possibility of forming a diversified generation portfolio should identify direct revenue sources to invest in CCGT or OCGT the only permissible technologies. Under these boundary conditions the only regulatory approach, aiming at promoting competition and expand available capacity, was to establish a mandatory pool and complement generator earnings via a capacity remuneration mechanism. The mandatory pool started operation in 2006 and the capacity mechanism adopted was based on direct payment to capacity availability at peak load times.

These choices effectively drove IPP's investment decisions for building new CCGT plants; this has also pulled PPC which has also built CCGT plants and has some new constructions in the pipeline. Today 2250 MW of CCGT gas plants owned by IPP operate in the Greek interconnected system, while PPC operates 1850 CCGT plants, 1250 open cycle gas and oil plants (which are maintained mainly as cold reserves), 4300 MW lignite[3] plants and 3020 MW hydro plants. An amount of additional 800 MW of CCGT owned by PPC is expected to be commission in a couple of years. Total dispatchable capacity exceeds peak demand which currently does not exceed 10,000 MW annually, while the sum of reliable dispatchable capacity defined by taking into consideration outage probabilities (UCAP definitions according to the Grid Code) amounts to 10,280 MW. Nominal capacity of renewables is already significant amounting to 4300 MW of which 1550 MW wind and 2450 MW solar PV.

The mandatory pool design comprises of a day ahead market which performs a unit commitment optimization based on stepwise economic offers by generation plants seeking social welfare maximization under technical constraints mirroring plant capabilities (minimum stable generation operation, ramping rates, minimum up and down times, startup/shutdown costs) and under transmission system limitations (which turned out not to be binding). The system operator is responsible for solving a plant dispatching problem in real time based on the unit commitment schedule and the procurement of balancing and ancillary service resources in the day before. The design does not provide for intraday market or any form of bidding by stakeholders during real time operation. Economic and technical offers for primary, secondary and tertiary reserves are mandatory for the plants and this takes place in the day before. The time resolution of the market is hourly, whereas the system operator controls generation minute-by-minute in real time dispatching. System marginal prices are hourly and are based on the most expensive offer among the plants retained in the unit commitment schedule. Hydroelectricity generation is dispatched in two ways, as mandatory generation due to dam or irrigation management (non-priced bid), and as part of the optimized unit commitment based on economic offers. The bidding prices of hydro are determined either by regulation (minimum price 53€/MWh) or by PPC bidding practice, aiming at water saving thus maximizing the annual value of water resources. As PPC has interest to keep system prices as low as possible (explained in other parts of this document), while maximizing the annual value of water resources, PPC's bidding practice for hydro has been to set maximum hydro prices at a level slightly above marginal costs (i.e. unit fuel costs) of CCGT plants (which are significantly below unit fuel costs of open cycle gas or oil plants). Because of PPC bidding behavior, confirmed by seeing observed data over several years, the hydro power prices define in practice a de facto price cap preventing system marginal prices to exceed marginal costs of combined cycle

[3] The latest commissioning of new lignite plant took place before market liberalization.

gas plants when hydro energy is available and also preventing any open cycle gas or oil plant from operating unless hydro is not available. Only at times of lack of hydro and peaking demand system marginal prices may climb up to the maximum price cap of 150 EUR/MWh or to levels of unit fuel costs of open cycle gas or oil plants. This occurs very seldom, in few hours per year (less than 10 hours and even not every year). The data for years 2013 and 2014 indicate that this de facto price cap has been continuously at levels below 90 EUR/MWh.

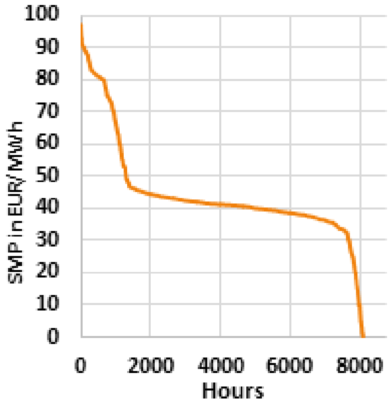
The power plants earnings mainly come from the day ahead market based on system marginal prices. The plants get small earnings or incur payments in the settlements of deviations from day ahead schedules during real time dispatching. The price for the settlement of deviations is determined using the economic offers in the day ahead market.

Table 1: Key statistics of day ahead market operation in 2013

Price making plant-type	Number of hours	% of total annually	Avg. Price of category in EUR/MWh	GWh committed	% of total annually	Avg. Load factor
Lignite (PPC)	5849	67%	40.4	23996.1	47%	64%
CCGT (PPC)	785	9%	62.1	4217.3	8%	26%
CCGT (IPP)	226	3%	76.6	6910.7	14%	35%
OCGT (PPC)	26	0%	80.9	2.1	0%	0%
Hydro (PPC)	220	3%	79.4	5492.1	11%	20%
RES*, Trade	1654	19%	25.0	10181.6	20%	25%
Entire year 2013	8760	100%	41.5	50799.8	100%	

*: *All dispatched thermal plants not above their minimum stable generation levels*

Figure 1: SMP Duration Curve in 2013



The statistics of day ahead market operation in 2013 indicate almost absolute dominance of PPC in the price making of System Marginal Prices (see Table 1). IPP gas plants have determined SMPs only in 3% of total hours in 2013. Because of the de facto price cap determined by PPC's hydro bidding behavior, the maximum SMP prices in 2013 did not exceed 95 EUR/MWhe while average marginal costs (mainly fuel costs) of CCGT plants where between 75 and 80 EUR/MWhe. The revenue margins of CCGT plants (i.e. revenues above variable operating costs) in the mandatory day ahead market have been extremely low in 2013 and did not allow recovering fixed and capital costs of the plants. This is also obvious by looking at the SMP duration curve for year 2013 (see Figure 1): during only 700 hours per year SMPs have exceeded the 75 EUR/MWh variable cost of CCGT plants while during 7800 hours SMPs have exceeded the 28 EUR/MWh minimum variable cost of lignite plants. Statistics for years previous to 2013 and also for year 2014 confirm the same findings.

The "missing money" problem is more than obvious in the Greek mandatory pool market and this has been the dominating feature since the beginning of market operation until today. The impossibility to set system prices at levels allowing comfortable earning above marginal costs for peaking and load following units is a structural feature of the Greek pool market and it is due to the de facto price cap defined through the bidding behavior for hydro and it is also due to the general bidding behavior of PPC which is strictly based on marginal costs for peaking and load following thermal units as PPC has interest in keeping SMP levels as low as possible. PPC being a vertically organized company, dominates at almost 100% the retail market and is practically a single buyer in generation, where roughly 30% of total is purchased from IPP (at SMP prices), renewables and imports.

New entry in retail market is hampered by the inability of new entrants to form economically attractive energy portfolios as they lack access to lignite and hydro. PPC recovers fixed and capital costs from collecting earnings in the retail market based on virtual contracts for differences (fixed tariff contracts) and thus by-passes the mandatory pool market, which serves only to determine the prices at which PPC purchases energy from the IPPs and imports. Potential competition drawing on purchasing energy from the mandatory pool for reselling purposes has little chances to emerge. Thus PPC has interest in keeping SMP prices as low as possible, in particular for the portion of SMP prices which tend to exceed variable costs of gas units. Keeping these prices as low as possible helps PPC minimizing the cost of purchasing energy from IPPs and imports. To avoid free riding (i.e. direct purchasing from the pool instead of concluding contracts) by base-load consumers, PPC bids lignite generation above marginal costs (see Table 1) but obviously below variable costs of gas units; this contrasts bidding by gas units which strictly reflect fuel costs.

Purchasing from IPPs practically at fuel costs in the wholesale market and also from imports remunerated through contracts for differences are economically optimal choices for the PPC portfolio. Such purchasing from the de facto single buyer is beneficial for PPC and obviously for the society, because the costs of purchasing from IPP and imports are lower than the substituted PPC-owned resources based on the old open-cycle gas and oil power plants which are significantly more expensive. In addition these old oil and gas plants entail to PPC only fixed maintenance costs as the plants have exceeded economic lifetimes and have no remaining book values.

Remunerating the new CCGT plants at marginal costs, as it is the case in the mandatory pool market, will evidently ruin them, will push early retirement and will discourage any new private investment. The CCGT owners have no possibility other than the pool market to recover fixed and capital costs as the owning companies have no economic way of entering the retail market and recovering capital costs through contracts for differences with customers since such contracts based only on CCGT generation cannot become attractive to customers as being deprived from access to other sources of energy, such as lignite and hydro.

As a consequence, the missing money problem in wholesale market cannot be compensated by bilateral contracting in the retail market and earning possibilities are detrimental to independent operators based on CCGT generation which is the only possibility allowed for new entry.

Are the CCGTs owned by IPP necessary from a system and society perspective? Economically yes, as explained above, since they have substituted significantly more expensive generation based on open cycle gas and oil.

From a system perspective, the answer is also affirmative, as it can be seen in Table 1: the CCGTs owned by IPPs have generated 14% of total electricity in 2013 and had an average load factor well above that of CCGTs owned by PPC although the latter have been price makers more often than the former. This is because the CCGTs, both private and PPC owned, have supplied load following, flexibility and ancillary services to the system, the reliability performance of which would be much worse otherwise; and in addition, the private CCGTs have been more efficient than PPC's CCGT in such a performance although not remunerated adequately through the SMPs.

The structural character of the missing money problem in the mandatory pool combined with the impossibility of new entry other than through CCGT, which cannot recover capital costs in retail market due to dominance by the incumbent, have justified the establishment of a CRM in Greece based on direct payments for capacity availability. The mechanism has incentivized private investment in CCGT in the early stages and afterwards it has served as a hedge against mothballing or early retirement of capacities which deliver load following and peaking services in the Greek power system. It turned out that such hedging has been relevant also during the low demand periods induced by the economic crisis because the emergence of intermittent renewables has driven higher requirements for load following and peaking services, as it is further explained below.

The finding that the CCGT plants were necessary for the system to provide load following and ancillary services rather than to provide energy can be further confirmed by calculating the number of hours over a year in which the plants have been in a synchronization status (which implies at least operation at a power level slightly below declared minimum stable generation power level), as well as the number of hours in which the plants were operating approximately at minimum stable generation power level, as compared to the number of hours in which the plants were operating at a level well above minimum stable generation levels. In the latter case they were providing energy, whereas in the former cases they were mainly providing flexibility and ancillary services.

Flexibility is meant as a capacity of performing ramping required to follow load variation over the hourly granularity which implies that the corresponding plant has to stay at minimum stable generation power level over a minimum period of time and eventually also it has to stay at synchronization power level over another period of time. Because these preparation time periods are rather long, according to the declarations of the plants submitted to the system operator, the time length staying at minimum stable generation level or slightly below is much higher than the time length in which the plant operates above minimum stable generation levels to supply energy and follow the load variation.

The table below is very significant to that respect, showing very clearly that the CCGT plants have been used in 2013 to provide flexibility and ancillary services rather than energy, contrasting the lignite plants which have been used following very different pattern.

For the CCGT plants the second column shows that they have been operating at very high proportion of hours over the year, especially the CCGT owned by IPP. The second column which shows numbers much above the numbers in third column clearly confirms again that the CCGT were committed to stay at minimum stable generation levels rather than producing energy and that the service providing has been higher for CCGT owned by IPP rather than those owned by PPC.

These findings demonstrate the statement that the CCGT have been providing essential services to the system and thus their capacity has been required to maintain reliability standards.

Table 2: Operation statistics by thermal plant category for 2013

% of Total hours in 2013 where the Unit was on average committed at a power level

	Above synchronization	= or ~ minimum stable generation	Above minimum stable generation	At least at 70% of nominal capacity
Lignite (PPC)	77.6	0.9	65.5	33.3
CCGT (PPC)	53.8	38.3	15.3	10.0
CCGT (IPP)	70.0	55.0	14.7	0.3
OGT (PPC)	0.3	0.3	0.1	0.0

By combining findings from Table 1 and Table 2 it is remarkable that the CCGT plants have been price makers only over approximately 12% (9% for PPC and 3% for IPP) of total yearly hours in 2013, whereas they have been operating at a power level as high as their minimum stable generation levels (which is above 50% as declared to the system operator) over above 45% of total time (38% for PPC and 55% for IPP) and have been asked to stay at warm or hot status over more than 2/3 of total time.

The odd observation is that the CCGT have not been remunerated for having the capacity required to offer that flexibility service. In fact, because the system operator runs an integer programming algorithm to find optimal unit commitment for the day ahead scheduling, the CCGT are obliged to be committed to remain at minimum stable generation levels and in a warm state over long time periods during which they are not price makers, while lignite generation is price making or renewables and non-priced bids of imports drive SMPs close to zero. As a consequence the CCGT are not remunerated for the service. Even more, for the few hours they are price makers, they are capped by the ceiling price for hydro set by PPC and so they cannot earn above variable costs at all.

It is worth mentioning that the findings concerning the CCGT plants, i.e. their systematic use as providers of flexibility and other system services rather than for power producing purposes, are fully confirmed by the statistics of year 2014 (until first days of April 2014), as shown in the following tables:

Table 3: Key statistics of day ahead market operation in 2014

Price making plant-type	Number of hours	% of total	Average Price of category in EUR/MWh	GWh committed	% of total	Avg. Load factor
Lignite (PPC)	1129	52%	48.3	23996.1	47%	64%
CCGT (PPC)	545	25%	76.5	4217.3	8%	26%
CCGT (IPP)	252	12%	77.7	6910.7	14%	35%
OGT (PPC)	2	0%	83.9	2.1	0%	0%
Hydro (PPC)	81	4%	78.7	5492.1	11%	20%
RES or Trade	174	8%	39.9	10181.6	20%	25%
Entire year 2014	2183	100%	59.2	50799.8	100%	

% of Total hours in 2014 where the Unit was committed at level				
	Above synchronization	= or ~ minimum stable generation	Above minimum stable generation	At least at 70% of nominal capacity
Lignite (PPC)	78.0	3.6	64.0	38.3
CCGT (PPC)	52.7	28.8	23.9	13.1
CCGT (IPP)	30.4	16.9	13.4	3.0

In 2014, there has been an important change in the bidding rules which indirectly influence the System Marginal Price levels in the day ahead market: the economic offers of the power plants cannot anymore be less than unit fuel costs when the plant operates at a power level equal or higher than minimum stable generation power level. In 2013, the offers could be zero for the 30% of the maximum net capacity of a unit while the remaining capacity could not be offered below variable cost. Zero offers could not be SMP price makers in 2013 and consequently the zero bidding of 30% of capacities contributed to lowering SMP levels. By contrast, in 2014 the bids cannot go below minimum unit fuel costs and thus SMP levels are above prices in 2013. The change of rules explains that the frequency of CCGT setting the SMP increased in 2014 compared to 2013 and to previous years. Nonetheless the observation that the economic offers by hydro plants as offered by PPC continue in 2014 to impose a de facto price cap on thermal plant bidding as it has been the case in previous years. Average SMP has increased in 2014 compared to 2013 as a result of the change of rules of SMP calculation, however the change has affected at some degree only the frequency of SMP derived from gas plant bidding and not the level of the SMP at peak load times, as the hydro prices set the upper limits. In consequence the huge missing money problem for the gas plants remain in 2014 almost intact from 2013. Average SMP has increased in 2014 also because PPC is bidding lignite generation at higher levels in 2014 compared to 2013 although marginal costs of lignite generation have not increased; the increased lignite bidding levels, however, are not offering any opportunity for earnings by CCGT plants as the remain much below unit fuel costs of the latter.

It is therefore still valid in 2014 that the CCGT plants, despite the change of the SMP rule, continue not to obtain revenues above marginal costs because of the fuel cost and hydro bidding by PPC. It is also valid that the number of dispatching hours in which the CCGT plants are committed at their minimum stable generation level remains high (see second part of Table 3 which shows figures with similar structure and significance as those of Table 2).

As it has been explained above, PPC is largely indifferent about SMP prices in the day ahead market except for prices above marginal costs of gas plants for which PPC has interest keeping them at lowest possible level in order to minimize costs of purchasing energy from independent producers and sporadically[4] from spot market imports. The independent generators, which operate CCGT plants, do not have opportunities to set market prices at levels above marginal costs so as to earn against capital costs. This is mainly due to the hydro prices, controlled by regulation (range) and by PPC. The CCGT plants are required by the system to operate over long period of time every year, despite low demand, but they mostly remain at minimum

[4] PPC holds by far the largest share in net imports of electricity and in most cases the prices of net imports are fixed and independent of the SMP prices in day ahead market, being based on contracts for differences.

stable generation levels in order to be able to provide ramping services, ancillary services and seldom peak covering power over few hours. At minimum stable generation levels, the plants get revenues to compensate for fuel costs but no remuneration against fixed or capital costs because in off-ramping or off-peak times the SMPs are set by lignite generation bidding and also because the system services are either very poorly remunerated or not paid at all.

A major system service, which is not recognized as such, is thus the provision of ramping (up and down) services over time intervals larger than one hour (such intervals are not mentioned in the code as part of ancillary services). The supply of the ramping is ensured by solving the unit commitment algorithm which includes ramping constraints (by plant type) for intervals longer than one hour and also includes a series of technical constraints applying on plant operation, such as minimum stable generation level, minimum up-time, minimum down-time, minimum intervals between non synchronization, etc. According to the rules, the power plants declare parameters for the technical operating features of the plant and know that it is likely to be called by the unit commitment schedule to stay long at a minimum stable generation power level in order to supply a ramping service over a short period of time. As also they know that such a commitment is not remunerated above marginal costs, they have all interests to minimize technical risks and also minimize fixed maintenance costs and so declare technical operation values according to mostly conservative practices so as to avoid technical risks and plant maintenance requirements. This in turn implies that the fuel cost payments are needed over long periods of time implying the indirect system costs of ramping services are high. The structure of generation suggests that only the CCGT supply such ramping services and so the indirect system costs are high because gas plants have high fuel costs and also because that actually the CCGT plants stay long at their minimum stable generation power levels for the reasons mentioned above.

The ancillary services as defined by the system code do not include the ramping services over time intervals higher than one hour. The prices of the ancillary services are set by the most expensive offer which is required to meet demand as defined by the system operator. In a typical day, primary reserve demanded by the system operator is roughly 70 MW (per hour) and prices based on day ahead bidding do not exceed on average a few EUR per MW (0.36EUR/MW on average in January 2014). Demand for secondary reserve range between 400 and 800 MW (per hour) for upward power reserve and it is on average 100 MW (per hour) for downward power reserve. Average prices of secondary reserve are low, capped by the maximum bid price of 10 EUR/MW (4.18 EUR/MW on average in January 2014).

So, past statistics indicate that very low prices of ancillary services have prevailed until today, due to the reasons explained below.

Firstly the granularity of the market operation is hourly while ancillary services are mostly based on minute-by-minute fluctuations and the market prices of ancillary services are determined at the day ahead market where the resolution is hourly. Thus the SMPs being hourly determined do not take into account the minute-by-minute fluctuations which may vary by hundreds of MW much above the hourly variations and usually require more expensive generation, which however is not retained in the hourly based market and thus although used to provide ancillary services earns at low SMP levels as set by cheaper generation. In other terms, a day ahead market with a 5 or 15 minutes granularity, which would include the fluctuations as seen in real time dispatching, would allow generation supplying secondary reserve to earn at price levels reflecting of true capacity scarcity related to the system service.

Secondly, there is a combination of low amount for ancillary services demanded by the system operator, and a de facto large amount of supplied ancillary services; very frequently the market for ancillary service is in an excess supply condition which obviously implies low or zero balancing prices; excess supply is not resulting from general over-capacity in the system but is a consequence of the rules applied and the low pricing bids of PPC for reasons explained above. The reason of low demand is that system operator uses in real time dispatching significantly larger amounts of power through the AGC control systems, which apply only to CCGT plants, than the amounts of secondary reserve demanded in the day ahead market for which economic offers are submitted by the gas and hydro plants and this free-lunch balancing is essentially due to the rules governing operation under AGC. In addition, also according to the rules, the entire hydro generation is eligible to supply secondary reserve although the largest part of hydro is dispatched as mandatory[5] production (not based on economic offers) and as this service is free of charge the remaining part of the market for secondary reserve is very small and is rarely imbalanced.

The demand for primary reserve is very low because the system needs for frequency regulation by spinning resources is mostly covered by imports and hydro, the fluctuation of which is further managed through the secondary reserves. Finally, the tertiary reserves, which essentially are ramping requirements within time intervals roughly of half hour, are not remunerated at all, according to the rules, and are covered by spinning resources which abundantly have resources to increase power levels as required by the system operator for tertiary reserve purposes. In addition, non-spinning tertiary reserve is also abundantly covered by the hydro capacities which are highly available, except in very few hours per year, for power increase in half hour intervals.

So the current situation is characterized by insufficient and very low remuneration of ancillary services which are mostly provided by CCGT plants and are very poorly paid for their capacity availability in the ancillary services market.

The ancillary services market is based on economic offers submitted in the day before real time dispatching. The remuneration for ancillary services is extremely low. According to the statistics for the entire year of 2013, total payments for ancillary services (i.e. for primary and secondary reserve as tertiary reserve is not remunerated) represented only 1.1% of total wholesale and system operation payments to dispatchable power plants. The average payment for ancillary services by MWh produced in 2013 has been only 0.72 EUR/MWh and in the first two months of 2014 it has dropped to almost zero. This is clearly a market failure and is due to the regulatory rules in place (including a price cap which is in force), the lack of sufficient time granularity in the day ahead bidding (or the absence of intra-day bidding at sufficient time granularity) and to the domination of PPC in the bidding for ancillary services.

Figure 2: Illustration of load commitment differences between day ahead (blue line) and real time dispatching (red line) for a typical 400 MW CCGT plant operated under AGC (vertical axis in MW)

The CCGT power plants provide important services in terms of load regulation specifically by taking into consideration the intermittency of high wind penetration and the high figures of unforced outage factors of the old lignite plants. The offers of these plants are made on an hourly basis in the context of the day ahead market but in real time dispatching (RTD) the CCGT plants are controlled minute-by-minute by the AGC to balance wind power, load and outages fluctuations without having the possibility to re-submit economic offers (see Figure 2). The RTD statistics clearly indicate that if the market was designed with submitting economic offers for say 15 minutes intervals, then CCGT plants would be the only possible price-makers and because of scarcity they would signif-

[5] A mandatory hydro production is theoretically justified only in exceptional circumstances, when it is necessary for hydro dam management and for agricultural irrigation purposes. However, looking at the statistics, the very high frequency of mandatory hydro generation probably implies that hydro production is often submitted as mandatory by PPC for economic and not technical reasons, probably in order to minimize costs of system services and thus minimize payments to independent producers.

icantly increase their economic offers probably up to the price cap for SMP (150 EUR/MWh). Thus. CCGT encounter a very significant missing-money problem in the market involving ancillary services provision which is not compensated by other means within system operation.

In addition to ancillary services, which are poorly remunerated as explained above, the CCGT plants also provide very significant amounts of flexibility services which are meant over multi-hour time scales and consist of capacity ramping up and down during critical multi-hour load variation net of renewables and other must-runs and which are also practically not remunerated.

To provide the ramping services, the CCGT plants are committed over long periods of time to remain at minimum stable generation power levels. This is a result of the unit commitment algorithm solved in the day ahead scheduling process which follows an integer programming algorithm and includes detailed operational constraints of all plant types. This algorithm maximizes social welfare (in the absence of priced bids by demanders the algorithm minimizes system operation costs) using the step-wise (hourly) economic offers submitted by the plants.

The hourly system marginal prices are determined by the most expensive economic offer of the plant (or the importing energy) which at the limit is needed to meet hourly demand load net of renewables. At times when the CCGT is committed to remain at minimum stable generation level (in order to provide ramping services later on) the plant is treated as a must-run and cannot be SMP price-maker. During these periods of time, the CCGT plants earn at SMP price levels determined by the lignite plants which submit offers much below marginal costs of CCGT plants. Thus, the CCGT do not earn above fuel costs during long periods of time before or after providing the flexibility service. During the short periods of time in which the CCGT are price makers, at peak load times, the SMP prices remain low and only slightly above the marginal costs of these plants, mainly because the hydro plant bidding de facto sets a cap on bids. So, after the ramp-up service and during the peak load time the SMP remains low as compared to unit fuel costs of CCGT plants and so they cannot earn sufficiently to compensate for the fuel cost losses incurred during their stay at minimum stable load generation level.

The day-ahead market operation is incapable of compensating even for the fuel costs of the CCGT plants which are committed to provide flexibility (multi-hour) and ancillary (less than one hour) services. The fuel cost recovery mechanism has been conceived to compensate for this fuel cost loss in an ex-post manner. But despite the establishment of the fuel cost recovery mechanism, the missing-money problem remains in the Greek wholesale market since CCGT plants cannot recover capital and fixed costs although they are needed to meet peak load and also to provide the flexibility-ramping services.

The above described features of the mandatory pool market in Greece have been observed or correctly anticipated already in early stages. To address the resulting market failure the regulator has decided to establish a CRM consisting in direct payments to plants for capacity availability.

The aim of the CRM regulation is to provide incentives to generators to maintain old capacities in operation and to build new capacities; the regulation provides secure earnings to plant owners which partly cover fixed and capital costs in proportion to the "truly" available capacity of the plant; availability is measured statistically by accounting for forced and unforced outages and is also meant from a system requirements perspective, which implies that true availability is measured at times of peak load.

The general approach of the CRM regulation is based on obligation of load serving entities to have acquired capacity certificates in proportion to the peak load of their served load at times of system-wide peak load. The load serving entities can generally acquire the required capacity certificates from generators provided that the latter have issued and certified with the system operator such certificates.

Although this regulation points to a decentralized market of tradable capacity certificate, a transitory regulation has been decided which imposed a centralized acquisition of capacity certificates are regulated prices. Because of the super-dominant position of PPC in the retail market it was judged impossible to run a decentralized CRM in which the retailers are buyers of capacity certificates and thus certificate prices could be driven down to zero by the dominant incumbent.

The obligation amount of each load serving entity is calculated as mentioned above and the issuance as well as the amount of certificates by dispatchable plant are centrally regulated.

According to recent regulation (in fall 2013), total load obligation to hold capacity certificates is 10150 MW. The regulated price of capacity payment by certificate of 1 MW has been set at 56000 EUR/MW-year, which implies that total yearly payments by load serving entities is approximately 567 million EUR.

The amount of capacity certificates allowed to be issued by plants has been set by regulation in proportion to true plant availability and for each specific plant. The regulation allowed gas plants to issue two certificates for each available MW whereas all other plants were entitled to issue one certificate per MW. Consequently the total number of certificate issuance reached 14038 MW which implies that a 1 MW certificate is priced at 40423 EUR/MW-year.

Table 4: Currently applied capacity remuneration figures

(end of year 2013)	Net capacity of plants (MW)	Certified available capacity	Number of 1 MW certificates	Yearly capacity remuneration in EUR	Unit capacity remuneration (EUR/certified MW)
Lignite (PPC)	4,302.0	3,692.3	3,692	149,256,561	40,423
CCGT (PPC)	1,824.2	1,706.9	3,414	137,994,663	80,847
CCGT (IPP)	2,365.6	2,174.7	4,349	175,814,018	80,847
Hydro (PPC)	3,017.7	2,582.5	2,583	104,393,958	40,423
Total	11,509.5	10,156.4	14,038	567,459,200	55,872

Currently overnight investment cost of a 400 MW CCGT plant is of the order of 700 EUR/kW-net which implies that at a WACC of 10% capital cost annuity payment is 82250 EUR/MW-year based on installed capacity. The CRM figure represents approximately 90% of annual capital costs of new CCGT plants, since the unit capacity remuneration is paid on the net capacity further reduced by a forced outage rate (certified capacity), not accounting for fixed O&M costs. The CRM amounts for other types of plants, such as lignite and hydro, represent a significantly lower fraction of annual capital costs (below 20%).

The reasoning justifying these regulatory decisions are twofold: firstly, the lignite and hydro plant earn sufficiently high amounts against fixed and capital costs in the day ahead markets and so the CRM is a complementary incentive, whereas the CCGT plants earn very little in the day ahead market; secondly, the gas plants provide system services without receiving sufficient earning against fixed costs under current regulations. The second argument has not been stated explicitly, because of legal constraints, but it has been the main motivation for the decisions.

Both reasons point to regulatory and market failures, which obviously have to be remedied. Despite these failures, a market equilibrium has been reached under present conditions: both stakeholders, PPC and the IPP, are roughly recovering capital costs and fixed costs of generation through the wholesale market arrangements complemented by the CRM regulation and there are little complains to that respect.

The accounting calculations do not indicate any sort of super-normal profit earned by the stakeholders in generation and on the contrary it is widely agreed that earnings from all sorts of revenue sources above variable costs do not entirely cover all fixed and capital costs annualized using a reasonable WACC rate.

Thus from a consumer perspective, remuneration of generation is economically consistent with perfect competition, under current regulation, despite the failures in market design and competition.

Table 5: Estimation of costs and revenues from wholesale market and CRM by plant type

Data for first two months of year 2014	Lignite (PPC)	CCGT (PPC)	CCGT (IPP)	HYDRO (PPC)	***TOTAL***	All PPC plants
Day Ahead market (€/MWh)	67.54	57.66	58.69	57.99	***64.24***	65.15
Imbalances (€/MWh)	(5.58)	8.68	5.40	16.38	***(0.46)***	(1.41)
Fuel Cost Recovery Mechanism (€/MWh)	0.00	11.09	9.95	-	***2.88***	1.73
Ancillary services (€/MW)	0.00	0.01	0.01	-	***0.00***	0.00
Total Wholesale and System (€/MWh)	**61.96**	**77.43**	**74.04**	**74.37**	***66.67***	**65.47**
Estimated Variable Cost (€/MWh)	-32.00	-74.50	-72.80	-	***-40.98***	-35.79
Margin (€/MWh)	29.96	2.93	1.24	74.37	***25.69***	29.68
CRM earnings (€/MWh)	5.83	22.39	31.10	34.76	***14.08***	10.97
Capital and Fixed Costs (€/MWh)	-25.89	-30.93	-35.97	-182.78	***-39.93***	-40.57
Net position (EUR/MWh)	**9.89**	**(5.61)**	**(3.63)**	**(73.66)**	***(0.16)***	**0.08**

(Assumptions)	Load factor in first two months of 2014	Annual fixed Costs (EUR/MW)	Annual capital cost (EUR/MW) at WACC 8%	Fixed and Capital Cost per unit of output (EUR/MWh)
Lignite (PPC)	70.0%	30,000	128,705	25.88
CCGT (PPC)	34.1%	21,000	71,297	30.90
CCGT (IPP)	29.3%	21,000	71,297	35.96
Hydro (PPC)	11.7%	5,500	181,692	182.64

Notes:

(a) The above shown variable costs include ETS EUA costs (they are not shown explicitly in statistics)

(b) A replacement cost approach is followed to estimate annual capital costs of plants (an approach based on book values would lead to much lower capital costs for PPC)

(c) To calculate fixed costs per MWh a load factor is used as recorded on average over the first two months of 2014

(d) The open cycle gas and oil plants of PPC and of the IPP which exist (respectively 1210.4 and 351.9 MW) but have not been used in the first two months 2014 (they had not been used also in 2013) are not shown in the table although they entail fixed and capital costs to the owners. Only 147 MW of open cycle gas plants belonging to IPP were eligible to earn capacity remuneration in the context of the CRM. Unless they are soon decommissioned, the generators incur sort of stranded costs for open cycle gas and oil plants; these costs are not included in the above shown table.

Table 5 figures are drawn from statistics of January and February of 2014. Costs are based on author's estimations, assuming plant replacement costing approach for capital cost and a WACC equal to 8%.

The figures clearly show that CCGT plants of IPP earn from wholesale market amounts which practically do not exceed fuel costs. The same applies to CCGT of PPC. If the fuel cost recovery mechanism was abolished, then the CCGT plants of both stakeholders will incur significant losses in wholesale markets relative to fuel operating costs. This is because they operate at low power levels over long periods of time when SMP are determined by lignite plants at price levels obviously below fuel costs of the CCGTs in order to deliver ramping and other load following services over fewer time intervals in which SMP price levels due to hydro do not allow for margins above fuel costs. By abolishing the fuel cost recovery mechanism all CCGT plants will not be able to recover fuel costs from wholesale and system dispatching operations although they are obliged to commit capacities for serving system reserve and flexibility requirements. In consequence, remuneration of CCGT plants for reserve and flexibility services should firstly compensate for the entire fuel costs as incurred daily.

The generation fleet of PPC, taken as a whole, gets a significant margin over fuel costs in the wholesale market (30 EUR/MWh) mainly due to lignite plants. The wholesale market revenues (62 EUR/MWh) earned by the lignite plants exceed total costs of the lignite plants (between 52 and 59 EUR/MWh including all fixed and capital costs recovered at a load factor determined at the level of the entire electricity system), with capital costs estimated according to a replacement cost approach (obviously if capital costs are accounted based on book values, wholesale market margins are substantially higher than total lignite plant costs, as the PPC plants are on average old). On top of wholesale market revenues, lignite plants get capacity remuneration in the context of the CRM and thus total revenues largely exceed total accounting costs.

Based on these overall margins the lignite plants "cross-subsidize" the other plant types of PPC and so the net position of PPC is positive; in other words PPC covers total generation costs, inclusive of capital costs evaluated at replacement costs. It must be noted that replacement capital costs for hydro plants are significantly above book values for hydro plants (as also for lignite plants) and thus the margins of PPC are significantly above those shown in Table 5.

Although revenues of PPC from CRM are seemingly small (10.97 EUR/MWh), total revenues including the wholesale market margin more than suffice for recovering fixed and capital costs. Although the entire PPC fleet is fully balanced concerning costs and revenues, the CCGT fleet of PPC encounter small losses: although the margin at wholesale and system operation is slightly positive, the CRM revenues do not suffice to fully recover annual fixed and capital costs.

This is also true for the CCGT plants of the IPP: they get a slightly positive margin from wholesale market and system operation and the CRM revenue if not sufficient to fully cover annual fixed and capital costs. The loss per MWh is however small in magnitude.

The statistics for the two months of 2014 indicate that the wholesale and system operation is balanced in terms of costs and revenues and it can be calculated that total unit cost of the entire system generation is 80.9 EUR/MWh which is consistent with estimations published by other sources. Total generation costs would be lower if book values instead of replacement costs were used for the accounting of capital costs.

Table 5 figures thus confirm that from a consumer perspective, remuneration of generation is roughly cost reflective when seeing the entire fleet of dispatchable plants and in fact stakeholders do not earn supernormal profits. To that respect, the regulatory approach has been successful. The CRM regulations are compensating not only for capacity availability but also for the lack of market-based capital cost recovery due to wholesale and retail market failures. These failures are mainly threefold:

a) The missing money problem in the wholesale market due to de facto price cap by PPC's hydro prices and the control of SMPs exercised thanks to the dominant position of PPC;

b) The absence (or extremely low) of remuneration of ancillary, load following and ramping system services which are mainly supplied by the CCGT gas plants of both stakeholders, given that system services supplied by the hydro fleet have been remunerated through the range of PPC's hydro prices which are earned at times when hydro reduces peak load

c) The impossibility for IPP to conclude bilateral contracts for differences in the retail market because of economic unattractiveness of their generation portfolio as they lack access to sources with diverse economic characteristics such as lignite, hydro and imports.

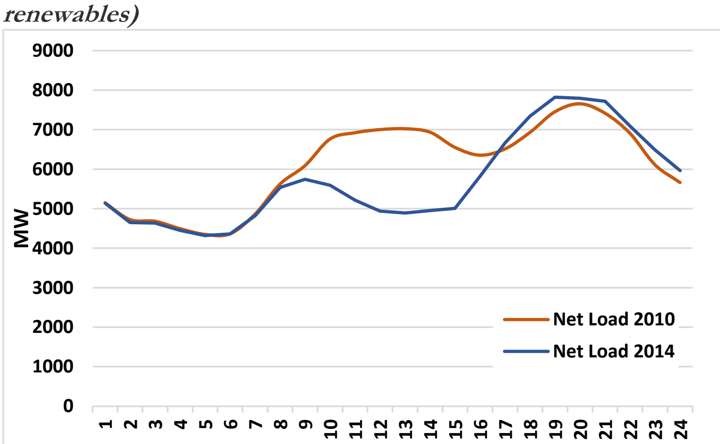
3 New Requirements for System Reliability

As mentioned in previous section delivering reliable power supply to customers has been a central objective of market design in Greece because of capacity shortages in the early stages of electricity market liberalization back in the first years after 2000. The capacity remuneration mechanism implemented in Greece originally aimed at addressing these shortages and also to attract private investment (by IPP) in order to promote development of market competition. For this reason the CRM was combined with a mandatory pool system so as to give revenue assurance to new entrants in generation as the restrictions about fuel type and technology (only gas-based CCGT investment was practically allowed) was not allowing new entrants to form attractive portfolios in the retail market. The design of the capacity mechanism was based on a conventional approach consisting in just remunerating availability of dispatchable capacities irrespectively of other capabilities of the different plant-types that might be important for the system.

In conventional approaches to capacity mechanism, power availability addresses the requirement to meet peak load demand with sufficiently secure margin. In the aftermath of the crisis of the Greek economy, meeting peak load demand is less of an issue at least in a conventional way, although according to Scenario Outlook & Adequacy Forecast 2013 – 2030 published by ENTSO-E, conventional capacity adequacy concerns could emerge beyond 2016. Depression drove slowdown of growth of demand for electricity but this is not the main factor explaining apparent overcapacity.

The main driver of low peak load requirements, owe to the rapid development of variable renewables, which are dispatched in priority, and in particular to the strong development of solar photovoltaic which is mainly absorbed in low voltage and is not seen as such by the system operator. The solar PV has already caused mid-day peak load to vanish and to experience load valleys during daylight (Figure 3). The reduction of demand for electricity (attributed to the crisis) is not the cause of the changes of load patterns which are mainly due to the development of renewables. Figure 3 shows the dramatic drop of daytime peak load which is observed over long periods per year and also the increase of the hourly differences of load levels during sunset.

Figure 3: Comparison of load of 2014 to 2010 for two similar typical days in January (Net Load: load minus contribution of variables renewables)



In fact the renewables and mainly solar PV have caused an increase in the ramp-up and ramp-down system requirements, which already at present is close to the upper limits of ramping capabilities of existing gas plants (measured in MW per minute).

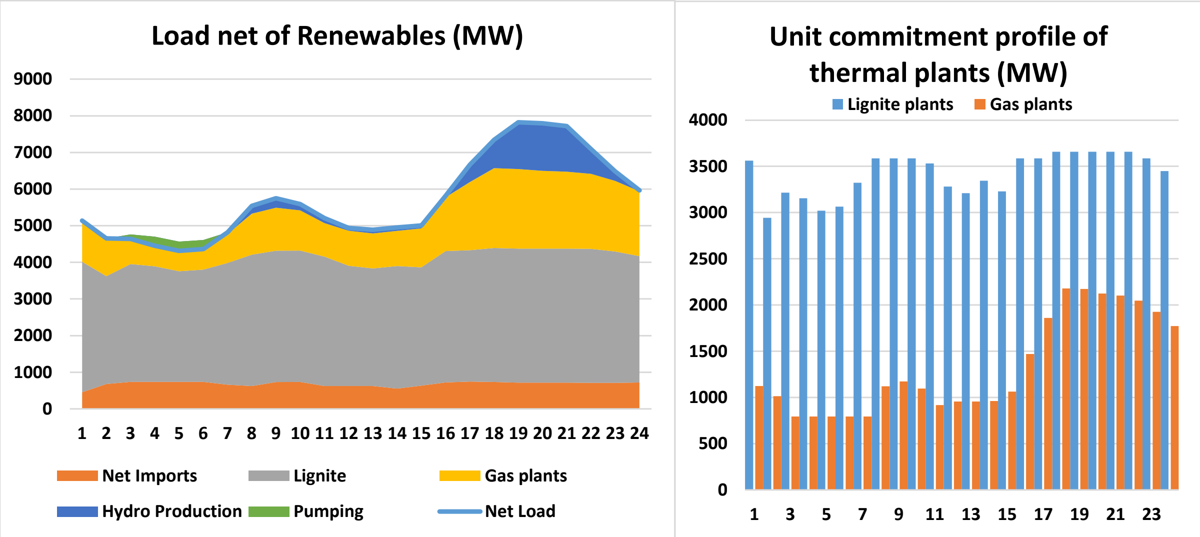
Figure 3 shows that the system requires 3 thousand MW ramp-up in an interval less than 4 hours which implies that plants with total available capacity of 3000 MW must deliver 12.5 MW/min ramp-up power. Figure 3 also shows that the system requires equal amounts of ramp-down power at a rate also above 12 MW/min. Lignite plants cannot deliver such ramping services as these plants have very low ramp-up and ramp-down rates.

Considering also the possibilities of flow change in the interconnectors (imports during low load hours due to collapse of prices in Italy during noon – because of the PVs effect – followed by exports after sunset), the ramping requirements could by further increased up to 1000 MW.

Given the current levels of resources in the Greek power system, addressing the ramping challenge, which is present almost every day, needs hydropower to reduce peak load hence reduce ramping requirements combined with significant capacity of gas plants to provide the ramp-up and ramp-down services. As the gas plants have certain restrictive technical features, such as non-negligible minimum stable generation capacity and significant minimum up and minimum down times, it will be necessary for the system to keep the gas plants at a status of load synchronization over long period of time in order to be able to provide the ramping services at times when required.

Figure 4 shows how the system met load and reliability requirements in the same typical day of January 2014 as the one shown in Figure 3. It is obvious that hydropower was committed to shave peak load, over both peak times during the typical day, while substantial amounts of gas capacities delivered the load following services by meeting rapid ramp-up and ramp-down system needs. By contrast, power level changes of lignite generation has been very limited due to limited capabilities of lignite plants, while it's clear that imports had almost zero contribution in meeting the system's ramping requirements.

Figure 4: Unit commitment in a typical day of January 2014



At peak time, gas capacities were committed at a level above 2100 MW which is a remarkably high share of total gas capacity which is an important contribution seen from a conventional capacity adequacy angle. Except when ramping, over several hours, and when meeting peak load, over few hours, the gas capacities has to remain at minimum stable generation levels over almost the entire day. As a peaking unit, gas plants were SMP price makers only during short times of peak load, over not more than two or three hours per day.

Because at the same time hydropower was committed to reduce peak load, gas bidding prices were de facto capped by the hydro power bids which were slightly above unit fuel costs of CCGT plants. So during the few peak hours, the CCGT gas plants although needed to meet peak load they did not succeed to earn revenues above marginal costs and so failed to collect margins against meeting capital and other fixed costs.

During the rest of the day, the gas plants while being at minimum generation levels or being in a ramping process were earning revenues at SMP levels determined by the lignite plant bidding which is well below marginal costs of gas plants. So the gas plants were incurring variable cost losses during many hours per day and also insufficient margins over the few peak load hours.

Their net position is well below total marginal (i.e. fuel) costs during that typical day. According to the regulations in place, the gas plants get additional revenues to recover the difference between fuel costs and the SMP revenues at times when SMP are lower than gas marginal costs, provided of course that the gas plants are committed in the system. According to the news in the press, the regulator has thoughts about abolishing the mechanism of fuel cost recovery. If this is not replaced by another mechanism the gas plants will incur serious losses against variable costs in a typical day as the one shown in the graphics.

But even if the fuel recovery mechanism is maintained, the gas plants get insufficient revenues above marginal costs although they are supplying significant and viable services to the system to meet ramping requirements. As mentioned in previous section, the gas plants are also the main providers of ancillary services, together with hydro power, and are insufficiently remunerated for this purpose.

The important new concept about system reliability is therefore related to ramp-up and ramp-down power which is increasingly required to maintain reliability standards due to development of variable renewables. The conventional approach described by the term capacity adequacy refers to ensuring availability of dispatchable capacities at amounts sufficient to meet peak load or to meet load when unforced outages occur in some of the plants. Of course this a valid reliability requirement still today but is less of a problem at least in the short term. The conventional regulatory approach to capacity adequacy is to forecast trends of capacity and demand over long term and establish incentives favoring investment in new capacities or preventing capacity mothballing. A known measurement of reliability from a conventional capacity adequacy perspective is the loss of load probability (LOLP). It measures the probability of not fully meeting load as a result of insufficient available capacities due either to lack of plants or to forced outages of plants. Regulators usually set a standard in terms of LOLP, typically above 95%, so as to oblige system operators to take measures for ensuring that LOLP effectively stays above the standard in future times. Such measures are the capacity mechanisms or the procurement of capacity reserves.

In a system where variable renewables develop rapidly, overcapacity in a conventional sense is frequent because the increase of renewables generally imply lower peak load and unless early retirement takes place dispatchable capacities are in excess. Nonetheless, the so-called extreme events may still occur, as for example occurrence of weather conditions with low or none wind and solar resources. Capacity availability becomes a serious concern in such extreme conditions. Meeting reliability standards in extreme events conditions requires significant amounts of dispatchable capacities which will be used for a short period of time while they will eventually be idle over long period, typically over one or two years. Obviously, these are extreme requirements also from an economic perspective. A combination of demand cuts with activation of capacities maintained in cold reserve is probably the optimal system response from a cost perspective. Nonetheless in a free market the system has to pay to maintain capacities in cold reserves; such payments should be covering fixed maintenance and part of capital costs of old existing plants, otherwise plant owners would prefer decommissioning.

A new reliability issue emerges because of the development of variable renewables. It is generally described as a system flexibility issue. Flexibility is defined as the ability of the dispatchable resources of the system to follow net load variations in a time scale of more than one hours so as to minimize loss of load probability, minimize the probability of curtailing variable renewables and minimize operational stressing of thermal plants, while achieving least possible system operation costs including the cost of procurement of ancillary services. Flexibility as a system service should not be confused with usual ancillary services because the latter are defined for different time scales, namely seconds for primary reserve (regulation), few minutes for secondary reserve (spinning) and less than half an hour for tertiary reserve (spinning and non-spinning). Flexibility can be defined with a time granularity of half an hour or one hour depending on system/market operation rules. Depending on load variation, variation patterns and stochastic features of variable renewables, as well as on the availability of hydro power and storage resources, flexibility requirements can be exactly measured and defined for a given system. The capabilities of thermal plants to deliver flexibility services can be also measured, as also the flexibility capability of the thermal fleet taken as a whole. Failure of meeting system flexibility requirements is multifaceted, as it can manifest as loss of load in conventional terms, but also as unnecessary curtailment of renewables and as undesired de-synchronization of a thermal plant. Such failures are valued from a society perspective, along with cost of electricity supply, and thus have to be avoided as a result of system planning. A challenging question in this context is how the system resources will have to evolve while sufficient resources are available to meet the flexibility operational needs which are much broader than capacity needs. Policy and regulation has therefore to address resource adequacy in the future through appropriate market design and establishment of incentives rather than capacity adequacy, differently from what was commonly practiced in the past.

The significant changes of net load due to variable renewables as experienced in 2014 (Figure 3) are expected to accentuate in the coming years and in particular towards 2020. Greece, as all other Member-States of the EU, has legal obligation to cover 18% of total gross final energy demand from renewables. All available forecasts predict that due to optimal distribution of renewable development across the sectors, such as heating/cooling, transport sector and electricity generation, the latter will have to accommodate above 35% generation from renewables of which 25% of total to be generated by variable renewables. In 2014 these figures are expected to be approximately 25% and 15% respectively. Greece has also the obligation to increase energy efficiency and according to the latest Energy Efficiency Directive to perform significant energy savings in the buildings sector. In addition, economic growth is expected to shift to a positive sign in the remaining years until 2020 but to remain at moderate levels as the austerity measures will have to continue for years after financial stabilization which is close to be achieved in 2014. These trends imply that demand for electricity is expected to increase in absolute terms but to grow at rates significantly below levels experienced before the economic crisis (1-2% annual growth in the coming years as opposed to above 3% per year experienced between 2000 and 2007).

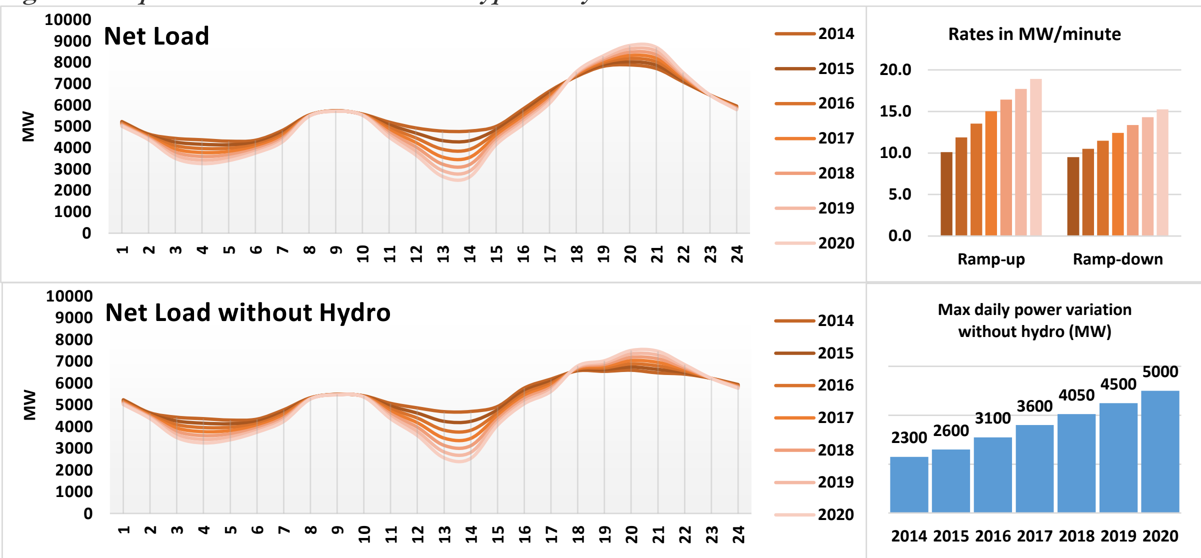
The structure of demand of electricity will be influenced by the expected structure of economic growth and, as incremental value added is increasingly based on services rather than on heavy industry, it is unlikely to see increase in base-load demand for electricity. New uses of electricity, mainly for heating, low enthalpy heat in industry and in the longer term in mobility, imply higher peak load demand in particular in the morning and in the evening and less demand over the night. Due to solar PV energy, net load is increasingly reduced during daylight. Wind patterns are partly correlated with solar irradiation during daytime and also wind blowing is more intense in nights and in mid-days rather than early in the morning or late in the evening. These diurnal cycling features imply that in the coming years we should expect accentuation of the variability of net load while maintaining the pattern already seen today. This is depicted in Figure 5. The amount of ramping requirements are expected to increase in the coming years, both in terms of ramping rates and for the amount of power capacity of plants which have the capability of delivering fast ramping services.

Resource adequacy requirements are thus expected to rise in the near future and although it is unlikely to face conventional capacity adequacy problems (in the sense of inability of meeting peak load) it is likely to face other resource adequacy problems, such as insufficient ramping resources, over-generation issues at times when minimum stable generation of the system (which is an aggregation over the committed units) exceeds net load and renewable source curtailments.

Figure 5 illustrates that net load in mid-day and in the night may be insufficient to maintain the entire set of plants in minimum stable generation levels as this is needed in order to make possible the achievement of the power amounts of ramping required in the morning and after sunset. To manage both, it will be needed to increase load for example by accumulating water in pumped storage facilities during the period of low load and reduce ramping requirements by using accumulated water to produce energy at peak times. This requires vast pumping resources which are not available in Greece at a scale as it will be required. Other ways is to curtail renewables at mid-day times and in the night or to cut demand through demand response measures at peak times. All these measures are costly and some are undesirable for many reasons.

It is worth noting that conventional ancillary services cannot and are not meant to address the mentioned multi-hours resource problem, firstly because they are conceived and operate at different, much shorter, time scales. This is why the unit commitment algorithms, as currently applied in Greece and in many other systems in Europe and in the USA, includes separate constraints for ancillary services and for ramping capabilities of the plants. The algorithm currently includes a penalty value for not meeting demand but not for renewables curtailment or for over-generation. This is because the resource adequacy issue, as currently faced by systems needing to accommodate large amounts of variable renewables, has more dimensions (in other terms criteria to meet) than conventional reliability standards mirrored in commonly used unit commitment algorithms.

Figure 5: Expected net load variation in a typical day



The multi-dimensional feature of resource adequacy, as opposed to conventional capacity adequacy, can be further illustrated by defining a set of failure probabilities:

- LOLP: loss of load probability. This is a conventional measurement of the probability of not meeting demand as a result of insufficient capacities either because of under-investment or because of a sequence of plant outages.
- LORP: loss of renewable probability. This indicator measures the probability of renewables curtailment, as a symptom of over-generation due to the need to maintain at a system-wide level a certain amount of minimum stable generation of dispatchable plants in order to meet system reliability requirements at other times. Two different indices can be calculated by separating solar and wind resources. The latter generally present higher variability and uncertainty than solar, and the time scale of variability call also upon secondary reserve resources in addition to multi-hour flexibility resources. Failure in meeting secondary reserve requirements, due to wind variability or impossibility to predict with sufficient accuracy, implies higher requirements for spinning tertiary reserves which are deployable in a time frame less than half an hour. Shortage at that time scale may imply wind curtailment. Shortage of flexibility at a multi-hour time scale can also lead to wind (or solar) curtailment. Wind and solar curtailment probabilities are interdependent and their superposition leads to the loss of renewable probability.
- IRRP: insufficient ramping resource probability. This indicator measures the probability of shortage of ramping capacities either upwards or downwards. The indicator is calculated at a system-wide level and depends on the deployment space of generating units, their ramping capabilities and their minimum stable generation levels. Calculating this probability requires taking into account probabilities of forced outages of dispatchable plants.

There exist two approaches for the calculation of the above mentioned probability indicators by time segment for an existing system or in the context of planning for the future. The sophisticated method is to use system simulation and apply convolution of probability functions defined by individual plants so as to estimate a joint probability function. A simpler method is to use weighted average aggregators if indicators which are defined individually for each plant. The sophisticated method can be used in the context of system planning studies as they require time and mathematical modelling techniques. The simple method can be used in real time or in unit commitment algorithms which operate in the context of the day ahead market. The system operator using the simple method can predict requirements for flexibility and other system resources in order to avoid pre-defined standards for each probability type.

At a system-wide level it is possible to calculate system capability indicators of flexibility by aggregating the capabilities of the individual resources, such as the flexible generation plants. Four system-wide flexibility indicators are identified which can be depicted in Figure 6 with the same numbering:

1. Downward ramping capability
2. Upward ramping flexibility
3. Minimum stable generation flexibility
4. Peaking capability

Disposing sufficient resources for these four capabilities at a system-wide level ensures good performance in terms of the probability of failure indicators so as to exceed the standards set by regulatory authorities. These resources are meant at a time scale which significantly exceeds the time scale of conventional ancillary services (Figure 7).

Figure 6: System flexibility cases shown on a typical daily load variation where net load includes the contribution of variable renewables

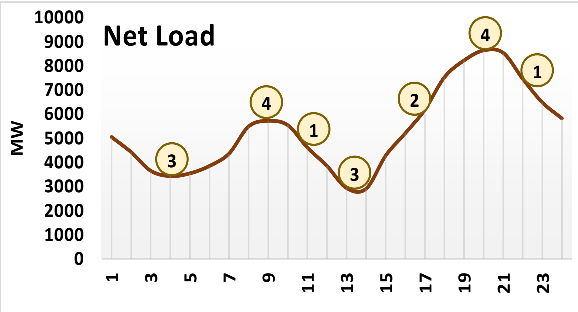
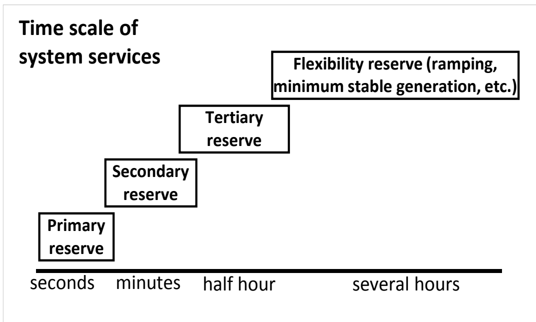


Figure 7: Illustration of time scheduling of system services for managing reliability



To commit resources so as to achieve performance above standards measured by all probability indicators requires multi-hour scheduling due to technical constraints of plant operation. Minimizing renewables curtailment (case No 3 in Figure 6) implies reducing risk of over-generation by using resources so that net load can accommodate committed capacities at minimum stable generation power levels. In addition, the committed capacities must be capable of delivering sufficient performance of ramping-up to preserve system stability. Depending on plant features and on plant mix ramping performance is closely related to the avoidance of over-generation and to reliable generation at peak load times.

Similarly to conventional measurements of the capability of a system to supply ancillary services, such as primary, secondary and tertiary reserves, it is possible to define indicators measuring system flexibility which apply over multi-hour time frames. An example of such an indicator is presented below. Firstly, it is necessary to measure flexibility for each dispatchable plant:

$$rampup_{i,t} \leq Min\{LMax_i - L_{i,t}, Maxrampup_i \cdot \Delta t\} \ \forall i \in \text{dispatchable plants}, \forall t$$

$$rampdown_{i,t} \leq Min\{L_{i,t} - LMin_i, Maxrampdown_i \cdot \Delta t\} \ \forall i \in \text{dispatchable plants}, \forall t$$

The $Maxrampup, Maxrampdown, LMax\ and\ LMin$ denote technical characteristics of a plant, namely the maximum ramp-up rate, maximum ramp-down rate, maximum dispatchable capacity and minimum stable generation power level, respectively. Δt is typically 60 minutes and $L_{i,t}$ is the scheduled generation level. A flexibility index can be defined for each plant so as to reflect both power margin relative to minimum stable generation and the ramping capabilities.

$$flex_i = \frac{{}^1\!/_2\,[LMax_i - LMin_i] + {}^1\!/_2\left[\frac{rampup_{i,t} + rampdown_{i,t}}{2} \cdot \Delta t\right]}{LMax_i}$$

Notice that the above measurement of flexibility does not include the minimum up-time and minimum down-time parameters, which are declared by the power plant owners and are used in the unit commitment algorithm as restrictions. Decreasing the values of minimum up and down time parameters implies lower system costs but not higher flexibility per se. System costs are reduced especially when minimum up-time decreases because the plant needs to be committed at minimum stable generation level over a shorter period of time. Obviously, decreasing the minimum up and down time constraints implies that the power plant is willing to accept a shorter shut-down starting-up operation cycle which further implies that the plant is stressed by the more frequent start-ups.

The flexibility index for the entire system can be calculated as a weighted sum of flexibility indices of the committed plants:

$$flex_{system} = \sum_{i \in Committed\ Plants} \frac{LMax_i}{\sum_{j=i} LMax_j} \cdot flex_i$$

The above mentioned formulas are just an illustration of a simple approach for the calculation of flexibility performance of a system. More sophisticated formulas can be specified but this is out of the scope of the present report.

4 NEW APPROACH TO ADEQUACY ASSESSMENT AND PLANNING

The requirements to ensure system reliability both at present and in the near future, in view of higher penetration of variable renewables, call upon broadening the way reliability and generation adequacy is measured and addressed. The new system requirements imply going beyond capacity adequacy approaches. A modern approach has to address resource adequacy and assess current system performance as well as plan towards system evolution in the future from a broader perspective. Planning and assessing resources of the system is much broader than considering capacities.

It is emphasized that currently in Greece but also in other countries of the EU and in the USA, although capacity sufficiency is expected to be adequate or even in excess of forecasted peak load, as measured in a conventional way by comparing total available capacities (MW) against peak load, resource adequacy is already at stake and will worsen in the coming few years, when adequacy is measured using the new probability indicators mentioned above. Although generation resources are sufficient to meet peak demand augmented by a reserve margin (this is a conventional way of addressing loss of load probability in system planning), the resources are hardly sufficient for addressing ramping and other flexibility requirements as they increase due to renewables penetration. In other terms, the probabilities of failure in terms of renewable curtailment, over-generation and insufficient ramping capabilities are not zero and the resources have to be maintained and probably increased (in a targeted manner) in the near future even if they are in excess relative to requirements for meeting peak load.

Therefore system planning towards evaluating capacity adequacy has to broaden its scope, include the above mentioned probability indicators as criteria, associate monetary valuation to the said failure types (such as the value of loss of load by defining in an analogy similar values for the other types of failure) and plan for ensuring adequate resources depending on incentives, such as CRM, and eventual procurement procedures. The regulators will also have to define standards (thresholds) for all three probability indicators, as defined above, so as to allow the system operator to appropriately plan for adequate resources. We are talking about a resource adequacy planning rather than for a capacity adequacy planning procedure and reporting.

The resources are the dispatchable plants and other load balancing sources, which can be divided in four categories: a) thermal dispatchable plants (excluding CHP or biomass plants); b) dispatchable hydro power plants; c) electricity storage facilities; d) demand response (load reduction accepted by the consumer and effected automatically by the system operator); e) imported electricity. They are discussed below:

(a) Thermal dispatchable plants have certain flexibility capabilities which depend on mainly five technical constraints, namely: a) upward ramping capability, b) downward ramping capability, c) minimum stable generation power level, d) minimum up-time and e) minimum down-time. The various plant types have different technical constraints for the above characteristics; as it is known base-load plants such as nuclear, lignite and coal have limited ramping capabilities and relatively high minimum stable generation levels; by contrast, the gas plants are more flexible with respect to all technical characteristics. A plant may have some possibilities to improve its flexibility performance in terms of one or all of the above mentioned technical characteristics. For an existing plant operating under conditions delivering higher flexibility than planned in plant design implies stressing effects which have consequences for fixed operating and maintenance costs. Fixed costs thus increase with plant flexibility performance at levels above thresholds defined at plant design stage. Thus the supply of flexibility performance by a thermal plant is generally an economic function of remuneration which has to cover in addition to traditional fixed costs the incremental fixed and variable operating and maintenance costs associated to the offering of flexibility performance above plant design thresholds. Such economic functions may be seen as based either on costs or on economic bidding. The functions have to be taken into account as locus of possibilities in system optimization or in system planning. As an example, the system may find as optimum (least cost) to spent additional money for incremental cost of maintenance and operation of plants so as to increase system flexibility and minimize the probabilities of failure and so avoid over-generation which would otherwise imply de-synchronization of a cheap base-load unit. Essentially it is necessary to extend the unit commitment algorithm, as applied today, by including the flexibility-cost functions for the plant types which can vary flexibility performance as a function of remuneration.

(b) It is common that dispatchable hydro power plants have scarce water resources, in particular in Southern countries including Greece. Water availability has a specific annual cycling pattern and total amount of water per year usually follows multi-annual cycles. Scarcity of water resources implies management of hydro power over an annual time horizon. Profit maximization implies drawing maximum values of water scarcity from the market; therefore, in systems like in Greece, optimality is obtained when dispatching hydro power mainly for reducing (shaving) load at peak load times; the amounts of reduction of peak load integrated over an entire year has to be compatible with total water availability and with the annual water cycling patterns. The latter imply use of hydro power at non-peak times during some seasons and this may also be mandatory for agricultural irrigation purposes. It is certain for the Greek case that there are no sufficient water resources to reduce peak loads as much as needed to flatten out the daily load curves. Dispatching hydro-power under water scarcity, such as those prevailing in Greece, implies maintaining hydro's role if possible only for peak shaving purpose and less, if possible not at all, for ramping purposes. Of course peak shaving by hydro power reduced system requirements for ramp-up and ramp-down capacities. But for the remaining ramping services, it will be uneconomic to expect significant contribution by hydro power capacities because of the water scarcity over the annual water cycle; hydro power is very powerful in terms of ramp-up and ramp-down rates and can deliver peak shaving effectively without generating large amounts of electricity in the hours before and after the peak load. High generation amounts by hydro power during these hours would imply much larger water requirements than when limiting generation to peak load hours while remuneration at system marginal prices would be limited as load is not at maximum daily peak. The statistical data on hydro power operation in Greece confirm that the amounts of generation during hours before and after daily peak load hour are much lower compared to gas plants; the latter do provide the bulk of ramping service, as the statistics also confirm, while the hydro power mainly reduces the ramping requirements by reducing peak load. The market designs and the planning reports have to be appropriate so as to incentivize hydro power operation consistent with maximization of the value of water scarcity over an entire year. The basic principle for doing this is to recognize and remunerate the peak load shaving contribution of hydro but not the ramping capability of hydro power, given annual water scarcity constraints. From a planning perspective, significant uncertainty surrounds annual water availability because of multi-year water cycles with substantial variability. Therefore, resource adequacy, according to the broader scope, needs to take a risk avert position towards water uncertainty and hedge against such uncertainties in order to minimize the probabilities of failure over the planning horizon.

(c) Electricity storage facilities essentially demand for electricity at low load times and produce electricity at peak load times and so they contribute to the smoothing of the load curve. By doing this they reduce ramping requirements of the system, as they increase load levels at times of valleys and they reduce load at peak times. Storage operation incur energy losses. Storage facilities are generally highly capital intensive. Based on pumped storage the Greek system already benefits from storage operations, mainly used to increase load in the night and increase hydro power at peak load times. Total storage capacity in Greece is limited and can cover a small fraction of system requirements. The ramping needs to follow variation of net load as it remains after using hydropower and pumped storage is very significant already today; it is expected to increase towards 2020, as mentioned above, as both hydro power and storage facilities have limited possibilities. It is worth examining however which money incentives could bring additional pumped storage into the Greek system. Currently the economics based on revenues from the day ahead market and other regulated remunerations are not sufficient to incentivize new investment in pumped storage.

(d) Demand response can play an important role in the optimization of system costs in view of the increasing flexibility requirements. An essential condition however is to define the rules and the mechanisms concerning the availability, the costs and the activation of demand responses. According to experience in many countries which have promoted the insertion of demand response mechanisms in electricity wholesale markets, consumers take the commitment to declare availability for load cut provided that they are sufficiently remunerated for that purpose. Such availability must be known to the system operator, sufficiently in advance of unit commitment scheduling, and the system operator must have the ability to cut the committed load in a systematic (as opposed to ad hoc) way and usually without further notice to the consumer. Committing load cuts depends on system cost optimization which has to include load cutting amounts as a function of marginal costs, as derived from the economic offers of consumers, which may be collected within a tendering process. Such load cuts essentially act as peak load reducing interventions and not as cuts which reduce ramp-up or ramp-down requirements; this is because it is very difficult to contract with customers variable level load cuts with conditional terms and over multiple hour time frames.

(e) Flexibility resources provided from imported electricity are also among the candidate resources to be studied in the context of the resource adequacy planning. Ensuring flexibility services from imports by maintaining commitment and assurance at the same ground as the services from national resources is currently a challenge for market designs in the EU internal electricity market. The experience and the regulatory framework as in place in Greece as well as in the South East European are far from being compatible with commitment and assurance requirements by system operators. The incompatibilities can be attributed firstly to the existence of independently operating national TSOs mainly acting based on national aspirations and perspectives and secondly on current market practices for import/export flows which are driven by energy price differences between control areas rather than differential system reserve requirements. Due to national approaches for the definition of net transfer capacities at the borders, the capacities available for market operations are small compared to theoretical capacities of interconnectors. As they are scarce, the capacities are auctioned and the reservation bidding reflects profitability of energy transfers between control areas due to energy price differences. To obtain commitment assurance as appropriate for system reserve and ramping purposes, the TSOs must cooperate across the borders and further restrict the capacities that will be available for energy market transactions. Until today there has been no such attempt in the area of Greece and generally in the area of South East Europe. The commercially available capacity in the Greek-Bulgarian borders as defined commonly by the two TSOs fluctuates between zero and 600 MW on a monthly basis. The auctioning results show high equilibrium prices which indicates scarcity of available capacities. The market experience also indicates that the reservations support contracts for difference, rather than spot market imports, between PPC and some Greek industries and suppliers outside the northern borders of Greece. Restricting these contracts for system reserve purposes would be clearly uneconomic and anti-competitive. The Greek-Italian connection is based on a DC cable which presents frequent unforced and forced outages. In addition, the AC/DC converting technologies are sensitive to frequent energy flow changes and generally are inappropriate for providing system services. This link is also suitable for market coupling purposes, rather than for sharing flexibility and ancillary system services. So under current circumstances it is unlikely to see significant development of import-based resources for providing flexibility and ancillary system services for both linkages of the Greek system within the EU internal electricity market.

The monetary valuation of the broader scope of system reliability goes beyond the traditional value of loss of load concept and has to introduce valuation of other possible failures such as the renewables curtailment and the impact of over-generation. Essentially a multi-objective approach is needed to simultaneously seek for minimizing the monetary values of the possible failures. Renewable curtailment entails costs for the society stemming from costs of externalities such as those related to environment climate change and energy independence. Costs may also arise because of discouragement of investment in renewables due to eventual lack of proper integration in the system. Cost impact of over-generation come from impossibility to fully use non expensive base-load (but inert) generation plants (lignite in the case of Greece) which leads to premature decommissioning and to discouragement of new investment in such plants. This further implies higher system generation costs, hence higher consumer prices, and also stranded investment costs as far as existing capacities are concerned. Optimizing the use of flexibility resources bring cost saving benefits to generation by allowing base-load non-expensive generation to remain in the system despite increase of variable renewables.

In essence, overall system optimization under multiple reliability constraints (as opposed to conventional approaches which have used a single reserve margin constraint) is required to obtain accurate planning of system evolution and resource adequacy in the presence of increasing generation by variable renewables. Significant approaches were recently proposed in the literature which extend conventional capacity expansion planning and put into proper perspective the prediction of future inadequacy concerns.

Planning and managing resource adequacy (as opposed to conventional capacity adequacy planning) can be performed by the system operator using reliability failure values and performance thresholds defined by the regulator. To illustrate how to conduct a resource adequacy study we sketch below a mathematical model as a possible basis of the study. Suppose that G denotes the vector of system resources, such as dispatchable generation which has to develop in the future to ensure adequacy. Investing to increase capacity of G entails unit fixed costs f. Depending on the fuel mix of new generation and also on its capability to provide flexibility and ancillary services (at different time scales) operational variable and fixed costs will be expected to increase, which is captured by $\Delta v(G)$. Investment in generation which has higher capability of providing flexibility and ancillary services reduces the probability of loss of load at peak load times (because of incremental capacity but also because of increase of capability of load following) and also reduces the probability of renewables curtailment (or can be consider as equivalent of reducing the probability of over-generation). Suppose that the regulator has associated value to these failure possibilities, namely the value of loss of load (VOLL in EUR/MWh) and the value of renewable curtailment (VOLR in EUR/MWh). Avoiding de-synchronization of inexpensive base-load generation at low peak load times is captured by the change of system variable costs $\Delta v(G)$. So planned generation capacity G implies changes in monetary valuation of reliability failures, captured by $\Delta R(G)$ which has two components namely for the value of unserved energy

($\Delta UE(G) * VOLL$) and for the value of renewables curtailment (or value of avoiding over-generation) ($\Delta RC(G) * VOLR$). Expanding G in such a way as to increase system flexibility, as opposed to expanding capacity irrespective of flexibility, renders the system more expensive but reduces the monetary damage of reliability failures. Thus by cost minimization, the optimal level of development of flexible G can be determined as a compromise between system costs and adequacy performance. The cost function to minimize can be illustrated as follows:

$$\min_{G} C(G) = f \cdot G + \Delta v(G) + \Delta UE(G) * VOLL + \Delta RC(G) * VOLR$$

The model to be used for system planning can be more sophisticated by including stochastic representation of variable renewables (also for outages and load variations) and by incorporating operational limitations of generating technologies such as minimum stable generation level, minimum up and down times, ramp-up and ramp-down capabilities, etc. As a consequence of a planning exercise for resource adequacy, the regulator can determine the amount of flexibility delivering capacity to be needed in the future and thus define incentives to promote investment and/or launch procurement procedures. The described procedure fully replaces the conventional capacity adequacy planning procedures which are currently practices in most of the EU countries, including Greece. The resource adequacy planning studies can be carried out at regional levels, i.e. broader than national system control areas, in order to take into account resources provided by flows over interconnectors.

5 NEW APPROACH TO CRM IN GREECE

According to the guidance documents published by the European Commission in November 2013, any generation adequacy assessment will have to make distinction between missing money and missing capacity as eventual symptoms of inadequacy.

Missing money circumstances are clearly market or regulatory failures. They have detrimental effects on future investment and on available capacity as it drives withdrawal or mothballing of existing capacities. We have explained in previous sections, that missing money is a persisting symptom in the Greek market mainly affecting the CCGT gas plants of both PPC and IPP stakeholders, while the latter have no chances for obtaining revenues to cover fixed and capital costs, neither in the retail market not from cross-subsidisation as PPC is doing. Serious concerns will be arising in Greece concerning both conventional capacity adequacy and modern resource adequacy issues if the missing money circumstances persist in the future, as from both perspectives lack of gas plant capacities will be detrimental to system reliability in the presence of increasing generation from variable renewables. Resolving the missing money problem requires profound changes in the entire market, both in wholesale and retail. Traditional analysis about this problem emphasizes on the removal of all kinds of direct or indirect price caps in the wholesale and real time markets as well as development of competition in the retail market to allow recovery of fixed and capital costs mainly from revenues within bilateral contracts for difference with customers or load serving entities. Removal of price caps in wholesale and real time market requires some regulatory changes but the main reason of the caps cannot be tackled without weakening the dominant position of PPC in the retail market and regarding the access to lignite and hydro resources. Without such changes, PPC will continue to have strong interest in keeping energy and service prices as low as possible in the wholesale markets and so will continue to bid hydro and other resources as low as possible. Enabling CCGT plants to collect revenues from bilateral contracts of differences also has as prerequisite the opening of retail market to competition and of the access to lignite and hydro resources. Thus, the structural changes that potentially would mitigate the missing money problem are difficult to implement and experience teaches that it has been extremely difficult to pursue them in Greece. Actions towards this end are in progress at present (examples are small PPC, NOME tender), but their success is still very uncertain.

Part of CRM regulations decided in 2013 have aimed at also addressing the missing money problem as it became more acute with the emergence of variable renewables. It is very premature to consider eliminating all components of CRM which address the missing money problem of gas plants, because large uncertainties surround the effectiveness of ongoing market reforms on creating competition for removing structural causes of the missing money problem. Removing CRM regulations which are specifically addressed to gas plants prior to the achievement of healthy competition conditions will be detrimental to capacity and resource adequacy in Greece and will have long lasting adverse effects, as capacity decisions are mainly irreversible in capital intensive sectors, such as the power sector.

It is thus strongly recommended to pursue CRM reform in a very cautious way so as to ensure that CCGT gas plants continue to collect revenues for covering fixed and capital costs while the more profound structural changes are in progress and have not yet proved to be effectively implemented.

We strongly argue that from a resource adequacy perspective which is broader than the traditional capacity adequacy perspective the CCGT gas plants are essential system resources to balance the emerging variable renewables in Greece as required by the EU legislation towards achieving the 2020 targets. The European Commission's guidance talks about generation adequacy which is already broader than traditional reserve margin approaches, as followed for example by the ENTSOE capacity assessment reports. The studies accompanying the European Commission's guidance published end 2013 clearly identify system flexibility as the main and continuously increasing requirement in Europe as power systems move towards significantly high generation by variable renewables.

Technical studies identify that gas power plants are at present the main flexibility providing resources to increase complementing hydro and pumped storage, which have limited incremental potential. To provide flexibility the gas capacities need to remain in the system as capacities but less as energy providers; in other terms the gas plants will experience continuously lower rates of utilisation but their capacity needs to be maintained and expanded. The forecasts show that this is an issue in all EU countries, including Greece. They also show that cross-border trade is an essential ingredient to enable cost-efficient flexibility services but it cannot solve the problem without the particularly increasing role of the gas plants. And finally by simulating wholesale markets in the EU the studies calculated that the missing money problem concern mainly, almost entirely only, the gas plants, both CCGT and open cycle.

A traditional wholesale market cannot solve the missing money problem in circumstances where the gas plants are mainly required for flexibility and other load following system services rather than for producing energy at peak load times. This is obvious: the bids by gas plants are de facto capped at high peaking times because of lack of scarcity at that time and the gas plants are rarely price makers at all other times collecting insufficient revenues as their fuel costs are below system prices although they are required to remain in operation for the purpose of providing system services. The gas plants are scarce in the provision of multi-hourly flexibility services but there is no a concrete market for pricing that scarcity. Even if the gas plants were price makers in peaking times, the frequency and the intensity of these peaking times are continuously decreasing with the increase of variable renewables rendering extremely uncertain the collection of revenues above marginal costs by gas plants. Under such conditions it is very unlikely to see private investors further investing in gas plants or maintaining operation of existing gas plants, unless specific market mechanisms develop to remunerate the gas plants for their capacity of providing the flexibility and load following services.

The literature is new and inconclusive about which market design could ensure sufficient capital revenues for the gas plants in a more appropriate way. Some argue that strong market components operating intra-day and in real time could complement wholesale markets and ensure the capital revenues of gas plants. Although there is general agreement that such market components need to strengthen in the future and develop where they are inexistent today, there are strong doubts about their effectiveness, mainly because the intra-day and the real time markets will also be surrounded by large uncertainty in the presence of high renewable generation. Gas plant owners do not have ways of hedging against this increasing uncertainty; for example hedging through bilateral contracts with retailers and customers is unlikely as the gas plants are less required to provide energy but more to provide system services.

In addition, the flexibility service in particular which is delivered aver multi-hour time scales is unlikely to be remunerated sufficiently in intra-day and real time markets, which are capable of remunerating generation response on short time scales but not on long ones. There is not a single market design example that has today fully addressed this issue. The recent experience in California, where the regulator and the system operator are now introducing specific provisions which recognise flexibility services and their separate remuneration, illustrate that it is unlikely that traditional market designs, including conventional real time markets, can effectively address remuneration of flexibility services. So it is premature to argue that pure market competition approaches can address capacity remuneration of gas plants which are increasingly needed in systems with increasing variable renewables generation.

It is widely recognised that at present the main missing capacity or the potentially missing capacity problem in the EU, including Greece, concerns the gas-fired plants in their capacity of ensuring system flexibility. Therefore the Commission's guidance on missing capacity has to be read primarily as missing resources for flexibility and load following services and secondarily as capacities for meeting peak load.

Based on the above, we argue that in the case of Greece failing to address the missing money problem will lead to acute resource and generation inadequacy and that under current conditions addressing the missing money problem for gas plants in their capacity of providing flexibility services to the system requires mainly capacity remuneration because pure market-based mechanisms will take significant time to develop and even when mature it is uncertain whether or not they will succeed in addressing the gas plant remuneration issue. This argument is valid in Greece also because of the super-dominance of PPC implying that intra-day, real time market and other similar arrangements, including the ancillary services markets, are unlikely to be successfully reformed unless profound changes in competition take place.

In this market context and in view of expected further increase of variable renewables generation in Greece, it is proposed to reform the current CRM to a new framework which will address resource adequacy in a broad sense rather than solely conventional capacity adequacy and will cautiously link specific incentives to specific services so as to prepare the ground towards a more complex and market-based reform to be established later when competition conditions are mature and allow for.

The proposed reformed CRM is a framework based on four distinct pillars, each addressing a different resource adequacy requirement (Table 6).

Table 6: Basic form of the proposed CRM reform

Pillars	*Resource adequacy purpose*	*Mechanism of remuneration*
Capacity Availability	Meeting peak load (with adequate reserve margin at a probability below a threshold – LOLP)	Remunerate true capacity availability of dispatchable plants using a unit capacity payment approach
Flexibility	Meeting ramping system requirements and avoiding over-generation or renewables curtailment (at a probability below a threshold – LORP)	Remunerate capability of dispatchable plants to perform ramping at rates beyond a certain threshold using a mixed system which combines a fixed payment and a variable payment component
Strategic Reserve	Meeting peak load in rare cases of extreme events involving simultaneously high demand and very low availability of renewable resources	Conclude contracts with plants remaining in cold reserve for strategic reserve purposes, following a procurement procedure
Demand Side Response	Meeting peak load at times of high demand on a daily and seasonal basis through interruption of load by large industries	Remunerate energy demand reduction at system marginal price levels or at prices determined after a tender for a limited collection of times of high demand

1st pillar: Capacity Availability

The first pillar of the proposal for the reformed CRM aims at supporting capacity availability in a conventional way. The goal is to maintain sufficient available capacity of dispatchable plants plus a reserve margin to meet peak load demand as it occurs daily. For this purpose it is proposed to continue applying the capacity assurance mechanism as currently implemented but abolish the granting of two capacity certificates per MW to the CCGT power plants. Thus all dispatchable power plants will be granted one capacity certificate per MW. Capacity accounting must continue to be evaluated on the grounds of true availability, taking into account forced and unforced outages. It is proposed that the evaluation takes place over an extended set of hours per year, compared to the currently defined set, in order to fully capture the entire set of daily peak load times, as chronological load curves driven by variable renewables seem to follow a regular pattern with two significant load peaks per day. Roughly more than 600 hours must be included in the set of time zones against which capacity availability is measured, much above the current 200 hours. It is proposed to maintain for the time being the present system of direct capacity payment to dispatchable plants and keep using the rate of 40,000 EUR/MW-year uniformly to all eligible plants. Using data from 2014, this proposal implies a distribution of capacity payments by plant type as shown in the table below.

Table 7: Distribution of proposed capacity payments by plant type (approximate calculations)

(Proposed figures applied on data as in year 2014)	Net capacity (MW)	Certified available capacity (MW)	Number of 1 MW certificates	Yearly capacity remuneration in EUR	Unit capacity remuneration (EUR/certified MW)
Lignite (PPC)	4,302.0	3,692.3	3,692	149,256,561	40,423
Gas (PPC)	1,824.2	1,706.9	1,707	68,997,332	40,423
Gas (IPP)	2,365.6	2,174.7	2,175	87,907,009	40,423
Hydro (PPC)	3,017.7	2,582.5	2,583	104,393,958	40,423
Total	11,509.5	10,156.4	10,156	410,554,859	40,423

Note: Considering also the new capacity which is expected to be added during 2014, namely the hydro plant Ilarionas and the CCGT plant (owned by PPC) in Megalopoli, the annual capacity remuneration under the 1st pillar is estimated to reach 445 million Euros. It is assumed to maintain a unit capacity remuneration by plant as shown in the last column to the right hand side.

The rationale of the proposal on the 1st pillar is as follows:

a) As mentioned above, the aim is to ensure availability of sufficient dispatchable capacity in Greece to meet load at peak times which seem to follow a regular pattern with two significant peaks per day and with significant seasonal variation.

b) Availability of dispatchable plants when needed is uncertain due to outages which are particularly high in Greece as lignite plants are old and hydropower capacity depend on very uncertain water cycle conditions which follow multi-year and seasonal patterns with great variability. Thus, availability will have to be accounted for with scrutiny in order to capture effective availability as close as possible.

c) Greece is located at the end of the periphery of the ENTSOE network and the certified availability of electricity from interconnectors is very uncertain, as can be seen from past statistics about available capacity as published by the TSOs both regarding Northern interconnection and the DC link with Italy. The increasing penetration of variable renewables simultaneously in Greece and Italy, but also in Bulgaria, following RES share obligation legislation of the EU implies correlation of peak times between the neighboring systems, as such peak load times are strongly influenced by availability of renewable resources.

d) The variable renewables, despite their strong development in nominal capacity terms, do not provide significant certified capacity to system operator; this is known as a capacity credit which is a little higher for solar than for wind, albeit both estimated far below nominal power capacities. It would be detrimental to security of supply to include significant amounts of capacity credits from variable renewables in the system reliability margins calculated at peak times.

e) Demand for electricity is expected to increase in Greece in the aftermath of the economic crisis. The reduction of demand for electricity as experienced during the crisis was not a result of energy efficiency improving investments but was a sort of curtailment of useful energy services by consumers and was also due to low industrial production. It is anticipated that both demand reducing effects will vanish in the process of economic recovery of the Greek economy and a growing pace will be re-established for electricity demand probably not at 3% annual rates as experienced before the crisis but at least at 1 to 1.5% annual rates in the time period post 2015. In addition, electricity will be increasingly utilized for heating/cooling purposes (also because of the persisting high excise taxes on heating oil) hence driving higher demand. An important change of demand will occur when non-interconnected islands will be connected to the mainland system. The interconnection of Cyclades islands is an on-going project and interconnection of Crete is planned to be completed before 2020. The additional demand from interconnecting the islands is of the order of 10% of mainland load in 2020. According to recent forecasts by the Greek TSO (February 2014) peak annual demand in 2020 is likely to attend 11,700 MW. Evening peak load is forecasted to reach 10,700 MW. These projections of demand, if adjusted to take into consideration distributed production by renewables, are very close to the projection published by the European Commission (Reference scenario 2013) based on the PRIMES model.

f) Due to the market conditions which discourage new entrance in competitive power generation market segments and also due to morose funding conditions in Greece following the crisis, it is unlikely to see new investments in dispatchable plants except plants which are today under construction. To the horizon of 2020 only one CCGT power plant of 800 MW owned by PPC is expected to be commissioned in a couple of years. New lignite plant construction (undertaken by PPC) concerns a single power plant of 600 MW in the North of Greece which at earliest would be commissioned after 2022. Because of environmental restrictions due to second large combustion plant directive and the ageing of plants, a substantial amount of lignite plants is scheduled to be decommissioned until 2020 and also in the first years after 2020. Some of the lignite plants will be obliged already in 2015 or 2016 to reduce operation to one third of actual levels due to the environmental constraints. The Greek TSO has submitted to ENTSOE (published as final draft in 2013) a decommissioning plan for lignite plants which foresees reduced lignite capacity by 1,500 MW a few years before 2020 (out of 4,300 MW present capacity). It is foreseen that less of 2,000 MW lignite plants will remain in operation by 2023 despite the commissioning by 2022 of the new 600 MW plant. So the projection of dispatchable capacity shows decreasing figures while demand projections indicate increasing ones. Reserve margins are projected to decrease at levels below acceptable thresholds in a couple of years before 2020.

g) The missing capacity margin, as projected, is however mainly for power plants able to ramp quickly and to operate over a limited time frame. As explained above, it is very unlikely to see bilateral contracts (with customers or load serving entities) financing capital costs of plants with such peculiar utilization profiles. Because of the de facto price caps and the high uncertainty surrounding collection of revenues over few peaking load times, it is also unlikely that investors seek financing capital costs of these plants based on wholesale market revenues. The increasing penetration of variable renewables render more and more difficult the recovery of capital costs from pure market competition, including from wholesale or bilateral contracting markets.

h) It is therefore a logical consequence, that the eventual absence of direct capacity remuneration will undermine the economic balance of flexible plants, both for the existing CCGT gas plants and any possible additions in the future, including simple cycle gas plants. Under these conditions, the owners will be obliged to stop operation prematurely and to cancel new additions. System reserve margin will be at stake without CRM addressed to the gas plants.

i) Continuation of capacity remuneration is therefore necessary for the flexible dispatchable plants, which include gas and hydro plants. For non-discrimination reasons it is proposed to continue capacity remuneration of lignite plants. Although today lignite plants are able to recover capital costs from the wholesale market it is expected to see decreasing rates of utilization in the coming years due to environmental restrictions and to over-generation bottlenecks driven by the penetration of variable renewables. In particular the environmental restrictions are expected to cut to half or by two thirds the annual operability of several of the lignite plants. Consequently it is necessary from a system perspective to keep incentives in place, such as the CRM given that effective availability is calculated over the peaking load hours, so that lignite plants do maintain the peaking load hours as effectively operational hours and do the forced outages over less peaking seasonal time periods. As shown in Table 5 lignite plants earn from wholesale and system operation payments amounts above total costs, inclusive of capital and fixed costs. The bidding of lignite generation in the day ahead market has a large safe range, from unit variable cost of lignite generation (roughly 30 EUR/MWh) to unit variable cost of CCGT generation (roughly 65-70 EUR/MWh). As currently PPC is acting as a single buyer, PPC is indifferent of system marginal prices during times when lignite generation is a price maker, except for the remuneration of the zero bidding imports which anyway are mostly remunerated through contracts for differences. Essentially PPC is charging lignite costs onto the prices of the retail contracts with various customer categories. Applying a CRM on lignite plants or not matters only in case customers or suppliers purchase from the day ahead market; if CRM is not applicable and an independent entity purchases from the day ahead market, PPC has interest to bid lignite close to unit fuel costs of CCGT plants which is largely sufficient to recover capital costs; if CRM is applied also for lignite plants and PPC bids lignite generation significantly above unit variable costs of lignite, then independent entities would be discouraged to purchase from the day ahead market. So, the regulator has to watch lignite bidding in the aim of non-obstructing independent entities in the purchasing from day-ahead market; this has to be performed independently of applying or not CRM also to lignite plants. In other words, as far as PPC is the single owner of lignite plants and holds a de facto single buyer position in the market, CRM on lignite plants is not an issue as the important issue is the eventual predatory lignite pricing in day ahead acting against self-supply of independent entities.

j) The amount of CRM for capacity availability purposes, of 40,000 EUR/MW-year, is defined on the basis of annual capital costs of a typical open cycle gas plant. For example overnight investment cost of 400 KEUR/kW, a WACC of 8% and 20 years of economic lifetime correspond to 40,740 EUR/MW-year levelized annual capital cost. From a system perspective, contracting capacity only for peak load times through a least-cost procurement procedure would result in the selection of open-cycle gas capacity as a marginal plant for system expansion, the marginal cost of which inclusive of capital cost recovery defines the long term marginal cost of the system.

k) Theory suggests that, consistently with maximization of long term social surplus, the eventual procurement of available capacity for security of supply reasons should only remunerate (part of) fixed costs but not variable costs. This further implies that this remuneration of fixed costs, calculated as EUR per MWh of avoided loss of energy, must be aligned to the willingness of pay by end-consumers for avoiding the loss of energy (avoiding the power cut). In other words, there must be consistency between the accepted Value of Loss of Load by regulators and the remuneration of ultimately available capacity. It can be easily shown that the 40,000 EUR/MW-year is quite compatible with a reasonable value of loss of load which correspond to the very low end of the range of values reported in the literature. Assuming that the ultimate open cycle gas plant is remunerated at 40,000 EUR/MW-year and is necessary only 25 hours per year to avoid power cuts, it implies that the implicitly assumed value of loss of load is 1600 EUR/MWh of energy cut avoided). A recent report prepared for Ofgem by London Economics in July 2013, "The Value of Lost Load (VoLL) for Electricity in Great Britain" proposes values ranging between 1500-2000 €/MWh. The report prepared by Sweco in February 2014 on capacity markets in Europe, "Capacity Markets in Europe: Impacts on Trade and Investments" assumes a VoLL of 10,000 €/MWh in continental Europe, assuming a bidding cap of 3,000 €/MWh.

l) Therefore the proposal according to the 1st pillar is compatible with the "Generation Adequacy in the internal electricity market - guidance on Public Interventions" (EU/05.11.2013) which states that «in order to ensure cost-effectiveness, the costs invested in avoiding generation shortages or network outages should be assessed against the "value of lost load", i.e. the costs to the economy and society of unforeseen supply interruptions».

m) Under the conditions prevailing today, it is proposed to grant CRM only to domestically available capacity resources. As mentioned in a previous section, under current practices in the management of the interconnectors imported capacities cannot be from a system perspective as reliable as domestic ones because they are uncertain as depending on market conditions outside the Greek borders and on availability of capacity in the interconnectors. A plant outside Greece could be considered as equally reliable from a system perspective as domestic plants only if the plant has concluded a fixed commitment contract with the Greek system operator and if that contract was endowed by an available interconnecting slot.

2nd pillar: Flexibility

The second pillar of the proposal for the reformed CRM aims at supporting those plant capacities which provide flexibility services to the system, which are defined on a multi-hour time scale. Flexibility service is defined as fast increase (ramp-up) or decrease (ramp-down) of committed capacity by a plant so as to meet load following requirements of the system on a multi-hour time scale. Commitment at minimum stable generation level over a certain period of time as a condition of performing requested ramping over other times is considered to be part of the delivered flexibility service by a plant. This is obviously justified by technical restrictions on operational capabilities of such plants. A system requires such a service because of high variability and uncertainty mainly due to the variable renewables. Variability occurs over different time scales, such as over minutes in which case it is met by ancillary services such as secondary reserve and also over time intervals longer than half or one hour in which case it is met by unit commitment scheduling of a sequence of minimum stable generation and fast ramping. The Greek system experiences already today such variability due to renewables and both variability and uncertainty are expected to significantly increase over the coming few years as the power mix moves towards higher contribution by renewables in view of meeting the 2020 obligations. The main purpose of the proposed 2nd pillar of the CRM is to remunerate capacity of plants which support the daily net load cycle which presents great variability due to the renewables. In addition, the 2nd pillar intends also to remunerate for capacity the plants which operating under AGC support variability due to renewables at the time scale of secondary reserve.

It is assumed that the currently applied unit commitment algorithm will continue to handle the operational characteristics of the various power plants as constraints so as to solve for unit commitment using mixed-integer programming. This implies that a commitment schedule of power plant providing flexibility services comprises ramping time periods as well as time periods of commitment at minimum stable generation levels and eventually starting up times. Such a plant cycle is considered as an offer towards meeting system's requirements for flexibility services. More concretely, the plant's technical characteristics are mainly upward ramping capability, downward ramping capability, minimum stable generation power level, minimum up-time and minimum down-time. For each synchronized plant, its ability to provide up reserve is limited by its spare capacity and ramping up rate. Likewise, their position relative to minimum stable generation and ramp down rate describe their maximum allowable capacity available for down reserve. The plants operate within their minimum stable generation and maximum capacity, and when necessary the minimum up time constraint imposes as a restriction the minimum time that a unit must be 'on' before it can be shut down. Conversely, once the plant is de-committed, there is a minimum time before it can be re-committed. These operational restrictions are respected by the unit commitment algorithm, which by defining a certain operation schedule for a plant can also define scheduling cycles which can be identified as a provision of a flexibility service by a plant. So simple accounting rules can be defined and used for recording the number and the amount of flexibility services provided by each plant within the unit commitment schedule.

Thus it is possible to define simple and standard metrics of flexibility services provided by power plants. The metrics can be defined on the basis of the unit commitment schedule and may comprise at least two components, namely the ramping availability power (RAP) and the ramping service power (RSP). Provided that the commitment cycle of a plant is identified as a flexibility service provision, a proportion of the time the plant is committed at minimum stable generation level and so RAP can be calculated in MWh. Within the same commitment cycle the plant is scheduled to perform ramp-up or ramp-down generation at a ramp rate above a pre-defined threshold, typically close to the plant's maximum rate. RSP is then calculated as the integral, measured in MWh, of power commitments which increase or decrease, respectively for ramp-up and for ramp-down, excluding time intervals during which the plants remains at a certain unchanged power level. Obviously RAP is a prerequisite of RSP and both must be identified in a commitment cycle to qualify as a flexibility service provision. There could be more sophisticated definitions of the flexibility service by a plant; the purpose of the present report is only to illustrate that flexibility metrics can be defined in a simple and operational way. Further technical elaboration will be required to insert into a system or market code a detailed definitions of flexibility measurement.

Having measured both RAP and RSP for an individual plant, remuneration of the flexibility service is proposed as follows:

a) For the entire RAP and RSP commitment cycle, the remuneration scheme has firstly to ensure that the plant is paid for the variable operating costs. To ensure this, an asymmetric contract for difference is assumed to be concluded between the plant and the system (or market) operator for the time period spanned by RAP and RSP. The operator will pay to the plant the difference between variable operating costs and revenues defined using the system marginal prices (SMP) only at time intervals when SMP are lower than variable operating costs.

b) A capacity premium is paid to plants delivering flexibility services as a reward for their capacity availability to deliver flexibility service measured by the amount of RSP. The capacity premium is justified for allowing the plants to recover fixed operation and maintenance costs and as well as partly capital costs since during the ramping period the plants delivering flexibility operate practically as must-run plants based on the unit-commitment scheduling.

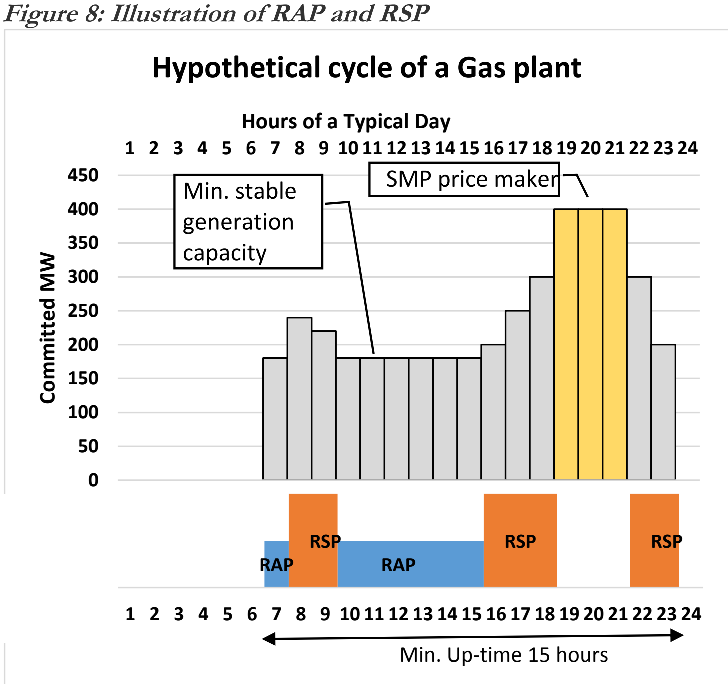
c) The capacity premium may have a fixed and a variable component. The fixed component will constitute the main part of the premium that rewards capacity availability for flexibility service provision. The variable component can be conceived as an incentive: it will be paid and eventually increased if the plant offers additional flexibility relative to the default flexibility capability of the plant. Some of the plants do have the possibility to increase flexibility capability by operating under modified technical restriction parameters than the default values. For example they can resume more shutdown cycles annually than provided in a standard maintenance contract. They can also increase the maximum ramping rate. Such modifications entail additional fixed maintenance costs for the plants. Plant owners would be willing to provide such additional flexibility services to the system provided that they get sufficient remuneration to face additional maintenance costs. From a system perspective, remunerating plants for the provision of flexibility capability above default levels can be profitable because this allows to reduce system costs during RAP times, reduce risk of over-generation and also reduce probability of renewables curtailment. Based on system cost optimization, the system operator can define the value of the variable remuneration component for the RSP amounts which corresponds to net profits for the system. It may be also possible to organize a bidding process between eligible plants for the definition of a market equilibrium value of the variable RSP remuneration.

It is proposed that a fair capacity premium for RSP services provided by a CCGT plant is of the order of 50-55 EUR/MWh where the MWh amount to the energy during the provision of flexibility services (RSP). The proposed value is based on the estimation of long run marginal cost of a fully flexible power plant (in fact an open cycle gas plant), which is consistent with the aim of maximizing social surplus. The long run marginal cost of an open cycle gas plant is currently of the order of 120-125 EUR/MWh. A CCGT plant has higher thermal efficiency performance than an open cycle gas plant and so unit variable costs are in a range between 65 and 75 EUR/MWh. Consequently, the capacity premium to be earned by a CCGT plant for the provision of flexibility services is between 50 and 55 EUR/MWh of RSP services. Although the capacity premium is calculated per unit of RSP services, it is proposed to remunerate the CCGT plants in proportion to available capacities and not pro rata to the amounts of RSP services. The reason is that at present the market conditions are not suitable for establishing competition among the CCGT plants in the provision of flexibility services. It is proposed nonetheless to take all necessary steps so as to establish such competition in the near future, which as proposed below could be combined with a bidding process for enhanced flexibility services by the gas plants.

The amount of RSP (i.e. ramping up or down) was estimated to be of the order of 3,000 GWh for the year 2013 (see Figure 8 for the calculation of energy at RSP times); it is likely to increase in 2014 as solar PV continuous to develop. By multiplying this amount of RSP service by the proposed unit capacity premium, we calculate that total payment as a capacity premium for flexibility services (apart payments for ancillary services) needs to range between 150 and 170 MEUR annually. This amount is comparable to the capacity payment to natural gas plants for the additional capacity certificate per MW is awarded to them in 2013. It is reminded that the CRM under 1st pillar proposes awarding a single certificate per MW to all plants. It is proposed that in the beginning of implementation of the 2nd pillar of CRM, the CCGT plants share an annual amount between 150 and 170 MEUR pro rata to available capacities of the plants.

The payments against variable operating costs during the period of RAP and RSP do not entail additional costs to the system as the regulations provided that variable costs of plants were anyway recovered. The variable cost recovery system is proposed to be abolished and be replaced by the asymmetric (one-way) contracts for differences which ensure at least variable operation cost remuneration of plants qualified for flexibility services and only during the operation at times RAP and RSP.

Figure 8: Illustration of RAP and RSP



The figure shows commitment of a typical CCGT plant as resulting from the unit commitment algorithm running in the day ahead market. The plant is committed to synchronize on a minimum stable generation level at 7th hour, and perform a sequence of ramping and commitment at minimum stable generation level, except at hours 19 to 21 when the plant (or another gas plant) is an SMP price maker. The figure illustrates the distinct time periods of RAP and RSP. Notice that between 19 and 21 hours none of RAP or RSP applies as CCGT is an SMP price maker. Over the periods of RAP and RSP other plants (i.e. more likely lignite plants) with lower economic bids than marginal costs of CCGT are the SMP price makers. The flexibility service provided by the plant is defined as the power (MWh) produced during RSP hours. Due to the minimum up-time constraint, the power plant has to remain at minimum stable generation level over the RAP hours. Between 19 and 21 hours, when a gas plant is price-maker, the gas plant illustrated in the figure operates at a stable level above minimum stable level and does not provide flexibility services.

The typical plant illustrated in the figure receives revenues based on the asymmetric contract for differences during the entire period RAP and RSP and revenues based on System Marginal Prices over the period between 19 and 21 hours. In addition the plant receives a capacity premium for being available (certified by the Must Offer submission, see below) to provide the flexibility services to the system.

Summing up, a plant qualified to provide a flexibility service, as identified within the unit commitment schedule, receives variable cost remuneration during the commitment cycle (only at RAP and RSP times) and a capacity premium during only the ramping cycle (only at RSP times). Adding together these two components for a CCGT plant we find that remuneration at ramping times (RSP) is approximately 115 EUR/MWh which is roughly the total cost (including capital cost) of an open cycle gas plant which is fully flexible and is the ultimate resource of the system for procuring the required flexibility service. So from a least cost system operating perspective the proposed remuneration of flexibility service is optimal and corresponds to the long term marginal cost of the ramping services.

We complete the 2nd pillar proposal by defining plan eligibility for flexibility service provision. From a system perspective, to ensure minimization of risk of over-generation and of curtailment of renewables it is necessary to promote in priority the dispatchable technologies with fastest possible ramping rates. Lignite plants have very low ramping rates, significantly high minimum stable generation power levels and also cannot afford shutdown cycling. In consequence they are not eligible for providing flexibility services. Future coal plants built to be more flexible than conventional designs may be eligible in the future.

Hydropower plants are important for the effective management of flexibility services and for ancillary services. Hydropower plants reduce the need for flexibility services at a multi-hour time scale by reducing net peak load as hydro-power with limited water resources stored in reservoir are best managed when dispatched purely for the purpose of peak load reduction. Maximization of water value at a yearly horizon implies such a dispatching rule. Consequently, the current regulation as in force in Greece allows hydropower owners (actually only PPC) to submit volume-based offers to the day ahead market accompanied by economic offers which must be higher than a floor threshold (53 EUR/MWh) and lower than the general bid cap (150 EUR/MWh). Obviously it is worth to reduce peak load when hydropower economic offer is above marginal costs of CCGT; this is exactly the practice of PPC bids until today and is consistent with maximization of water value over each year. Such a bidding behavior is submitted for any hour of the day, and so hydro power are used only when being really needed and thus consistently with maximization of scarcity value of water. The hydro-power plants are remunerated on the basis of the economic offer which stands above marginal costs of CCGT and theoretically they could be remunerated up to the maximum allowed bid level; PPC is not submitting such high offers for hydro-power because under the current market circumstances PPC has interest in keeping SMP as low as possible. It is not economic and it is not in the interest of hydro-power owners to increase hydro-power dispatching at times of strong ramp-up of capacities because at such times there is still spare capacity of CCGT and so hydro-power should bid below maximum to increase committed power. This would further imply using water at sub-optimal price levels and thus would be opposite to the optimality rule of maximizing water scarcity over the annual water cycle. For this reason, hydro-power is proposed to be excluded from the capacity remuneration to be given for flexibility purposes, but as mentioned above hydro-power is maintained within the 1st pillar capacity remuneration scheme.

So, CRM for flexibility services (2nd pillar) is proposed to be granted only to CCGT and open cycle gas plants, provided that they are committed to operate within a cycle which includes fast ramping (e.g. above 3 MW/min) and commitment at minimum stable generation level as required for the ramping.

To organize how the CRM for flexibility services is allocated to beneficiary power plants it is necessary to establish a formal procedure and a formal assessment which will have to be pursued by the system operator under the supervision of the regulator. The system operator will have to periodically perform the following main tasks, according to provisions which must be included in the relevant Code:

a) Evaluation of Requirements for Flexibility Services: this is a forecasting exercise which has to be performed at least once per year.
b) Control of Plant Inclusion according to Eligibility criteria: this is a technical evaluation task based on technical characteristics submitted by plants which intend to be included among flexibility providers and has to be performed once or twice per year.

c) Control of Must Offer obligation of eligible power plants: this is a more frequent task which aims at evaluating whether must offer obligations of plants which are included in the eligible set are in conformance with minimum requirements for flexibility providers.
d) Assessment of service provision by eligible power plants: this is an ex post statistical report based on recorded provision of flexibility services by plants.

The above mentioned tasks have to be seen as an extension of the current monitoring and planning activity performed by the system operator for the conventional capacity assurance mechanism which continues under the 1st pillar of the current proposal.

It is proposed that in the first year of application of the 2nd pillar of CRM the flexibility providing plants will be remunerated through fixed payments for capital cost premiums and through variable payments (depending on actual operation) to cover the rest of the costs, following the method mentioned above. After the first year and based on the experience and the eventual proposal by the system operator, it is proposed to consider to make part of the fixed remuneration for capital cost premium a function of the technical/economic characteristics of the offers by eligible plants. It will be also worth to examine possible combination of intra-day bidding market to be eventually established in the future with bidding for flexibility services. The basic principle is that any plant accepting to provide higher flexibility will have to be additionally remunerated as fixed cost/capital premium and the bidding process will ensure that the remuneration level is defined as a market equilibrium for the provision of specific services. To establish such a market procedure, it will be required that the market achieves sufficient competition.

3d pillar: Strategic Reserve

The aim of strategic reserve is to address security of supply threats at times of extreme events. In systems with high variable renewables extreme events can occur in rare circumstances of very low renewable resources due to weather conditions combined with high demand. Statistically such extreme events may have a frequency once or less than once per year but the risk of disruption of supply is high especially when large amounts of renewables have to be replaced by dispatchable plants. It is very uneconomic to avoid disruptions during extreme events only by means of power supply resources; demand cuts will be necessary to reduce costs. It is obvious that the dispatchable plant capacities that will be needed in addition to address disruption risk under extreme events will not be needed at other times. Only stand-by open cycle plants or plants in cold reserve can be candidate for that purpose.

The approach proposed for the 3d pillar is based on pure procurement procedures: the system operator organizes tenders for strategic reserve and requests offers by open cycle plants and by plants to be decommissioned; the tender offers coverage of mainly fixed maintenance costs and eventually a small part of capital costs.

The 3d pillar is an option which has to be considered in the Greek conditions as a possible necessary assurance component in view of high development of renewables in the coming years. A study has to be carried out by the system operator to evaluate the probability and the possible frequency of extreme events before pursuing any tender for strategic reserve. Candidates for remuneration under the 3d pillar are old PPC plants in cold reserve and newer open cycle gas plants.

4th pillar: Demand Side Response

The aim of Demand Side Response (DSR) is to reduce demand for electricity at times of high demand. Providers of Demand Side Response services can be large industrial plants connected with high voltage grid. The service consists of interrupting plant operation at times of high system demand in order to reduce plant's demand for electricity. Eligibility of industrial plants for such service provision requires at least the following: A) Proof, based on statistical information and other investigations to be performed by the system operator, that the industrial plant would not interrupt plant operation and would continue to consume electricity at uniform load profile in the absence of DSR service provision; this is controlled ex-ante (prior to conclusion of contract with system operator for the provision of DSR) and ex-post (after the provision of the service based on the plant's load profile before and after the time of provision of DSR). B) Communication system ensures real time supervision of plant's meter by the system operator and provides for the possibility of scheduling interruption in both day-ahead and intra-day operation. The system operator will have to submit to candidate industrial plants annual or seasonal planning of industrial plant operation interruption requirements and conclude annual contracts with such plants provided that they meet the eligibility criteria. Based on a study aiming at achieving least cost system operation, the system operator will propose a selection of high demand times on a daily and seasonal basis which deserve from a least cost perspective to be eligible for demand side response interruptions. For this selection system simulations will be needed including consideration of flexibility and ancillary services and their remuneration. Based on this planning information, the system operator will tender for DSR services in order to conclude contracts with eligible industrial plants. For the first application of DSR remuneration of the service will be based on system marginal prices which usually are determined by hydropower bids at times of high demand. It is proposed that depending on participation by industrial plants the system operator will later organize auctioning (based on economic offers with decreasing slope and a predetermined floor price) among the industrial plants to determine the price of remuneration. Execution of the demand interruption contracts must rely on the discretion of the system operator: depending on day ahead planning and on intra-day load following information, the system operator will schedule demand interruptions and may also cancel planned interruptions based on least-cost system operation considerations. The unit commitment algorithm will have to be amended for that purpose by including integer variables which point to the interruption option and by including interruption remuneration costs in the objective function.

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