GREEK ELECTRICITY MARKET DESIGN STUDY

December 2014

Future market design recommendations: Annex

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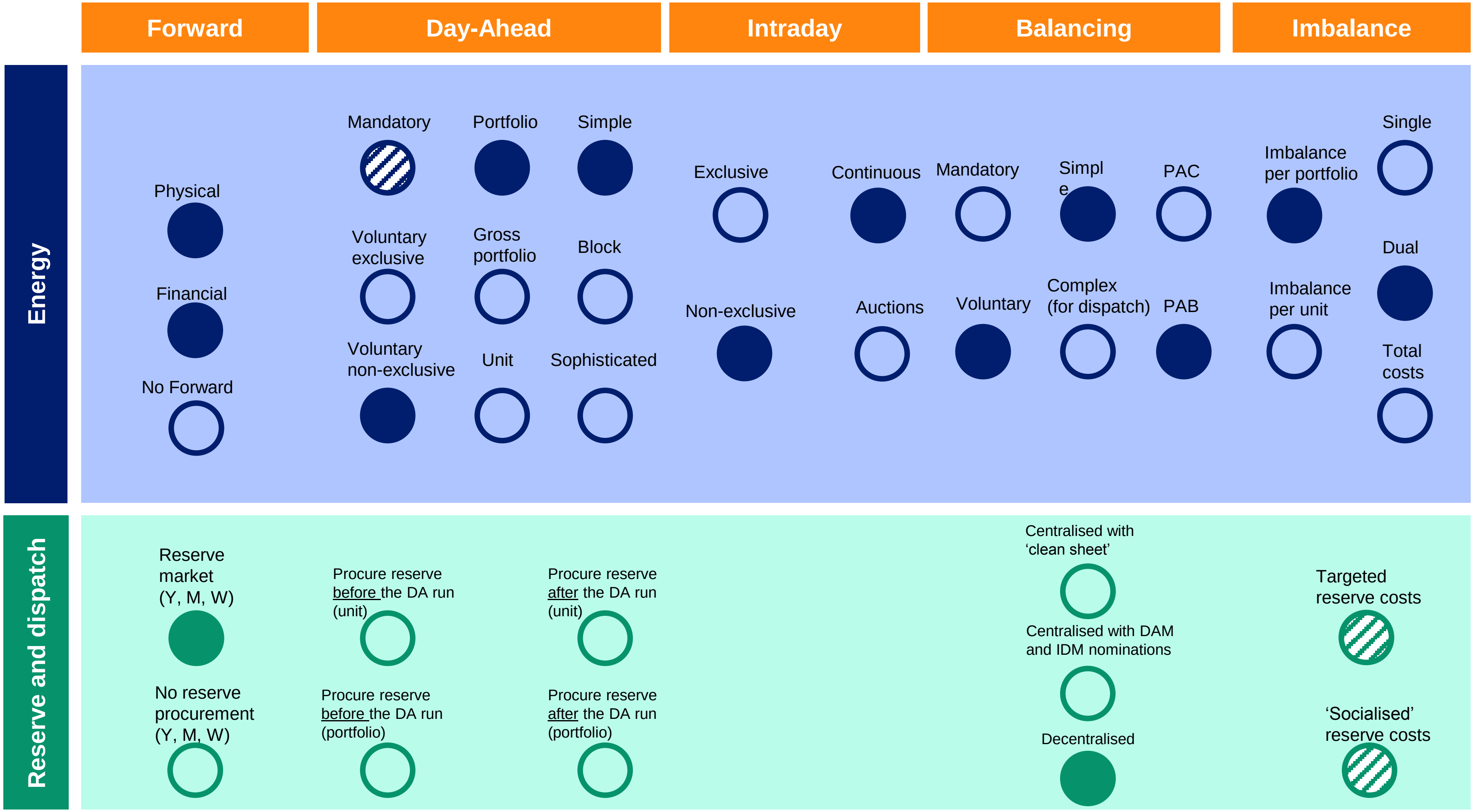
GB MARKET – ENERGY TRADING ARRANGEMENTS

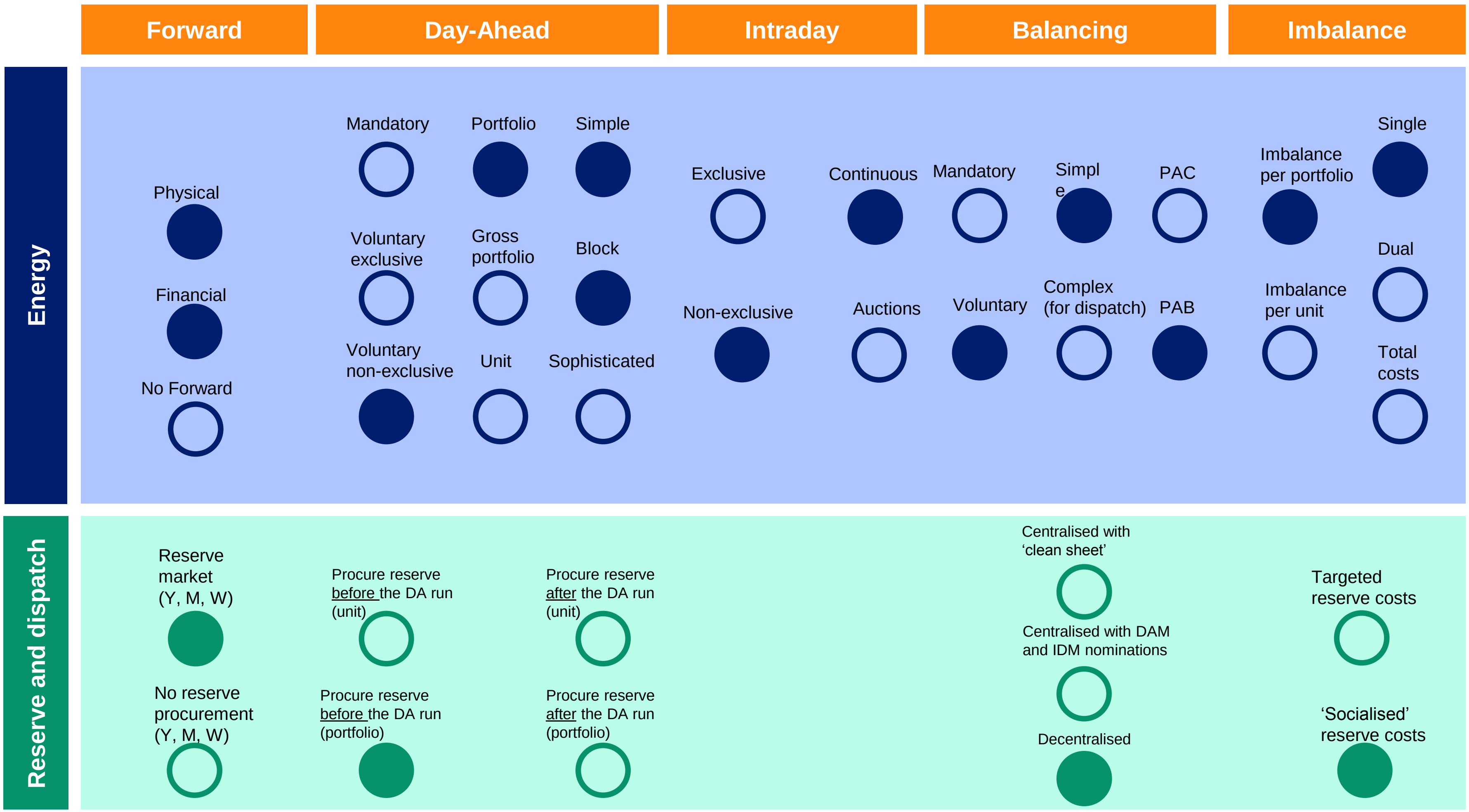
The GB market is based on allowing bilateral trading across all timeframes up to Intraday gate closure and decentralised dispatch arrangements



ANNEX – EU BENCHMARKING

GERMAN MARKET – ENERGY TRADING ARRANGEM

The German market is based on voluntary participation in central marketplaces and also supports decentralised dispatch



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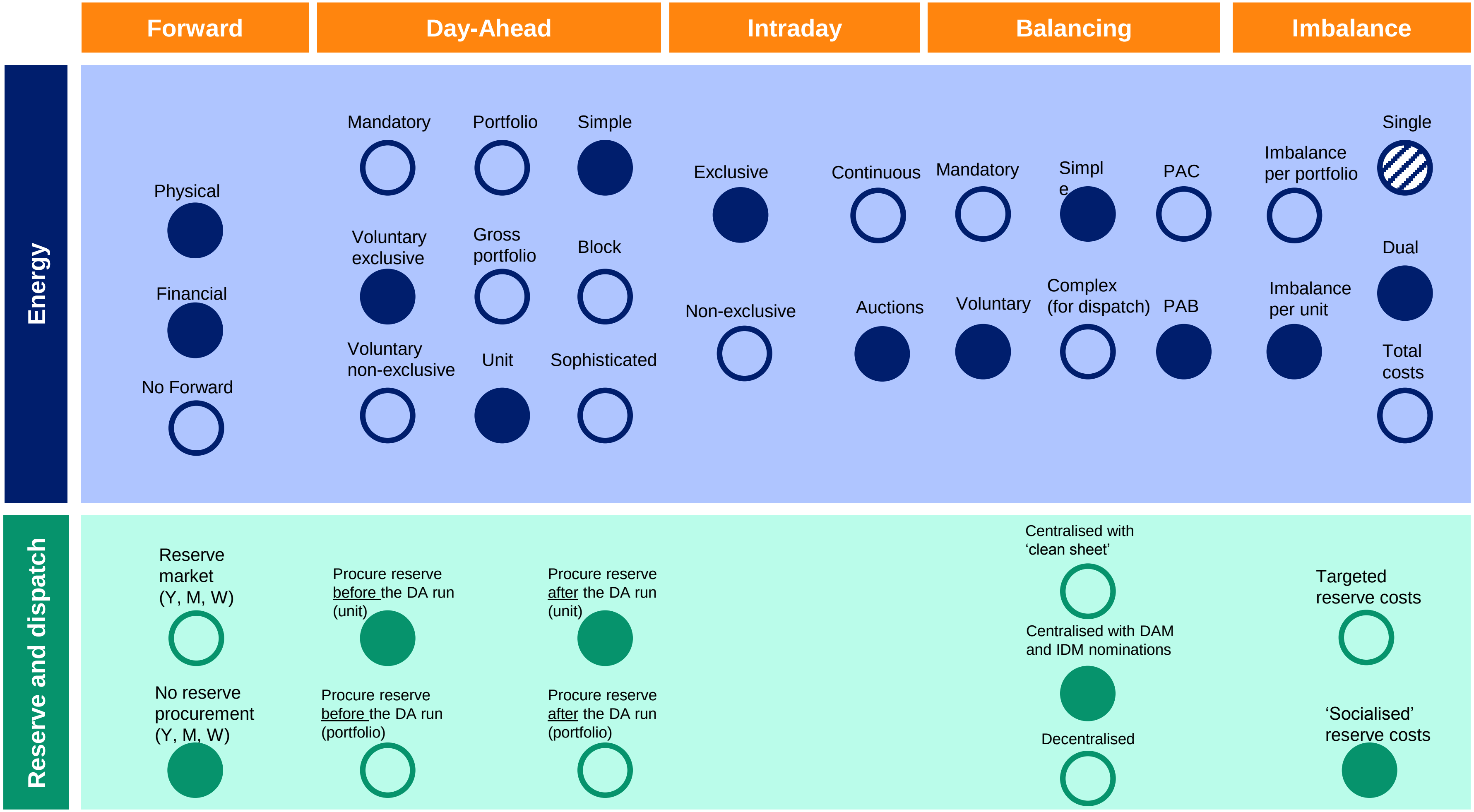
ITALIAN MARKET – ENERGY TRADING ARRANGEMENTS

The Italian market allows for physical forward trading but with a more centralised structure from Day-Ahead onwards



ANNEX – EU BENCHMARKING

GB MARKET – RES SUPPORT FORMAT

	GB today	GB future
Instrument	Renewables Obligation with Green Certificate (Renewable Obligation Certificates)	Variable 2-way FIP
Basis for payment	Per MWh, with 1MWh = 0.9-1 ROC and 1.8-2 ROCs for onshore and offshore wind[1]	Per MWh
Negative price incentives	None	Support capped at strike price for up to 6 hours of negative prices and thereafter support payments stopped
Wholesale reference price	Not applicable	Hourly day-ahead power exchange price

1. ROC band depends on vintage. Pre-2013/14 commissioned onshore wind receive 1 ROC per MWh, while 2013/14 and beyond onshore wind receive 0.9 ROC per MWh. Offshore wind ROCs drop from 2 per MWh for projects commissioned before 2014/15 and then reduce for projects commissioned afterwards.

GB MARKET – RES SUPPORT ALLOCATION

	GB today	GB future
Method	Administered, first come first served	Competitive (if application over-subscribed)
Technology neutrality	Banded	Variable 2-way FIP
Price	Set through Green Certificate market	Per MWh
Price limits	Renewables Obligation buy-out places a floor on value	Administratively
Budget limit	Support costs must fit within Levy Control Framework	Support costs must fit within Levy Control Framework

GERMAN MARKET – RES SUPPORT FORMAT

	Germany today – before August 2014	Germany future – since August 2014
Instrument	i. FiT ii. Variable FiP	Variable FiP
Basis for payment	Per MWh	Per MWh
Negative price incentives	None	Stop support, if EPEX hourly DA price is negative for 6 or more hours
Wholesale reference price	i. None ii. Monthly GWA for the specific technology calculated from DA price	Monthly GWA for the specific technology calculated from day-ahead price (hourly)

GERMAN MARKET – RES SUPPORT ALLOCATION

ANNEX – EU BENCHMARKING

	Germany today – before August 2014	Germany future – after August 2014
Method	Administered	Administered, first come / first served for all technologies with a expansion corridor per year, competitive for ground-mounted solar plants
Technology neutrality	Neutral	Neutral
Price	Administered	Administered, Pay-as-bid for ground-mounted solar plants
Price limits	No cap	No cap Maximum price in auction for ground-mounted solar plants
Budget limit	No – not a credible option	No – not a credible option

ITALIAN MARKET – RES SUPPORT FORMAT

	Italy today & future
Instrument	1-way variable FIP (introduced in 2013)
Basis for payment	Per MWh
Negative price incentives	Not applicable (no negative prices allowed, but negative price incentives may be considered)
Wholesale reference price	Zonal hourly day-ahead captured prices

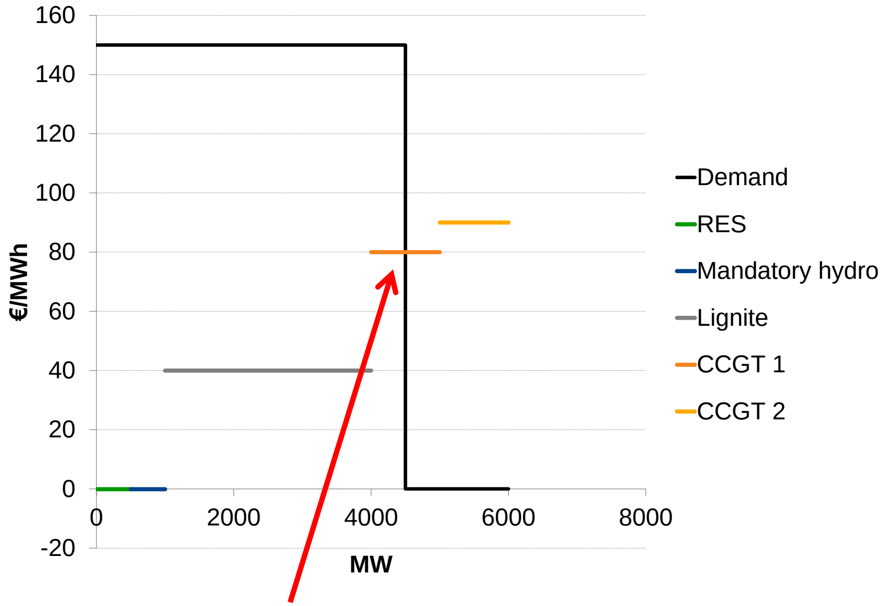
ITALIAN MARKET – RES SUPPORT ALLOCATION

	Italy today & future
Method	Competitive (through auctions) Administered for solar PV
Technology neutrality	Auctions different among technologies (different auction starting price)
Price	PAB Administered for solar PV
Price limits	Capped
Budget limit	Yes (capacity capped)

MARGINAL PRICING IN ONE-SHOT AUCTIONS

Marginal pricing is the basis for establishing the price in one-shot auctions; the Day-Ahead market is an example where marginal pricing is applicable

Simplified example of pricing in a one-shot auction



The marginal price of electricity is set at the point where supply and demand meet. The supply curve is formed through stacking all quantity-price offers to sell electricity by all providers in an ascending fashion. The demand curve is formed through stacking all price-quantity offers to buy electricity in a descending fashion. In this simplified example demand is assumed inelastic with the demand curve taking the form of a vertical line. The marginal price is equal to 80€/MWh.

Details of marginal pricing in electricity auctions

Marginal pricing is used for pricing electricity in the majority of electricity markets.

Generating units offer their entire or part of their output at a given price. This means that a single generating unit can offer its entire output at a single price in €/MWh or different levels of quantities at different prices in €/MWh. These price-quantity offers are stacked in an ascending order and form the supply curve.

Demand on the other hand offers to buy quantities of electricity at different prices . The price-quantity offers for buying electricity are then stacked in a descending order and form the demand curve. In some markets however, including the current Greek market, demand is assumed to be inelastic and does not reflect its willingness to pay for electricity. Graphically this is represented through a vertical demand curve.

The clearing price or marginal price is set at the intersection of the supply and the demand curve. Strictly speaking, the marginal price is the price of the offer that would be meet an incremental increase in demand. In practice, as electricity is offered in finite quantities it will be the last offer which is used to meet demand.

In our simplified example in a given trading period the price is set at 80€/MWh, which is the price at which the supply curve meets the demand curve. In this case the marginal offer to sell electricity comes from a CCGT at a price of 80€/MWh.

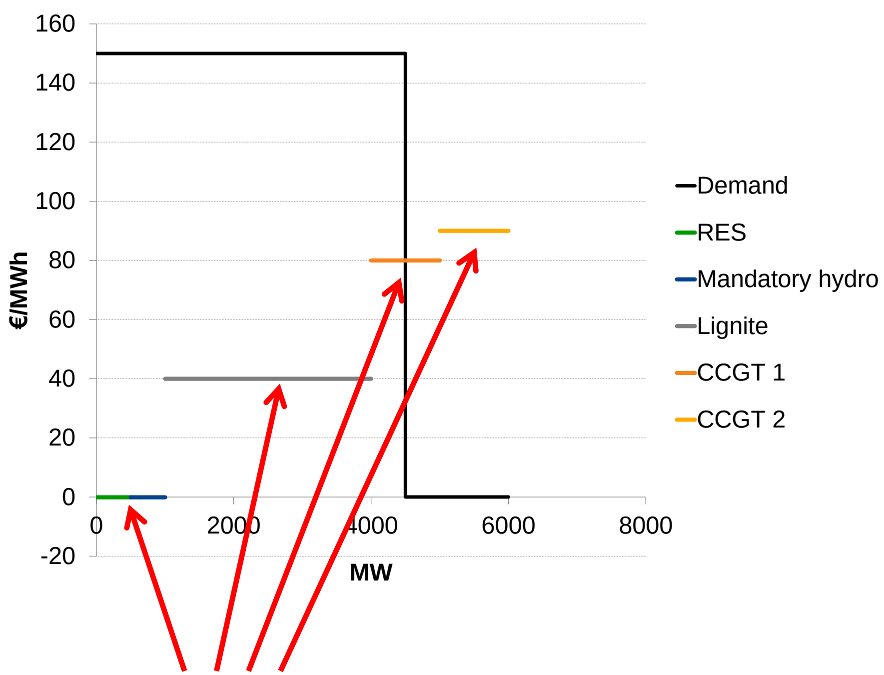
This example assumes simple bidding, meaning simple price-quantity offers,. Pricing in electricity markets can be more complex if we account for intertemporal constraints (and/or assume block bids or complex bid structures). The philosophy however remains similar. It is only when complex bidding (including start-up costs) in a mixer integer problem when pricing becomes more complicated

Marginal pricing is applied in the algorithm used for the European Day-Ahead auction, Euphemia. Similarly, in the presence of Intraday auctions marginal pricing can be used. Intraday and also for pricing balancing energy.

PAY-AS-CLEARED VS PAY-AS-BID

It can be argued that PAC leads to more efficient outcomes when compared to PAB as providers are incentivised to bid loser to their marginal cost

Simplified example of a PAC scheme



Providers offer quantities at their marginal cost in a PAC auction. The most economical resources are 'scheduled' and the price is cleared at the marginal cost of the marginal unit (CCGT 1). In a PAB it could be that CCGT 1 would have a different expectation of demand and would attempt to bid up even above the level of CCGT 2. If now CCGT 2 does not alter its offer, CCGT 2 would be 'cleared' and CCGT1 would not sell its output, resulting in a less efficient outcome.

Trading under a PAB scheme

In theory, if providers had perfect foresight the outcome of a PAB system and a PAC auction would be the same. With perfect foresight, providers would know what the 'marginal' offer would be, assuming that demand and costs (or offers by other providers) can be accurately forecasted. The provider would then bid marginally below the expected marginal offer, provided that is above its marginal cost.

In practice, however, perfect foresight is not a realistic assumption. As providers attempt to 'guess' the outcome of the market, this may lead to inefficiencies. Such inefficiencies could present in the form of les economical resources providing the service.

In the proposed new market design PAB would apply in the Intraday market once that becomes continuous. A continuous market has to , by definition, take the form of a PAB scheme. For a provider this now means that it makes a price-quantity offer to sell electricity, whereas demand submits a price-quantity offer to buy electricity. Once a positive difference between the system buy ad system sell emerges then a trade is struck.

Example 1 – continuous Intraday

A wind farm offers 50MW at price of 0€/MWh to the power exchange. At the same time demand is wiling to buy 50MW at a price of 80€/MWh. This means that a trade takes place with the wind farm receiving the bid price of 0€/MWh for 50MW.

Example 2 – continuous Intraday

A wind farm has an expectation that the next best offer by a provider is 51€/MWh and decides to offer 50MW at price (marginally below the 51€/MWh) of 50€/MWh to the power exchange. At the same time demand is wiling to buy 50MW at a price of 80€/MWh. This means that a trade takes place with the wind farm receiving the bid price of 50€/MWh for 50MW.

Example 3 – continuous Intraday

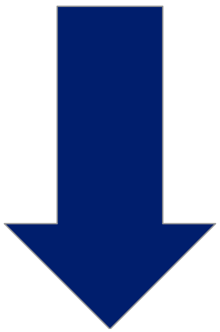
A wind farm has an expectation that the next best offer by a provider is 51€/MWh and decides to offer 50MW at price (marginally below the 51€/MWh) of 50€/MWh to the power exchange. At the same time demand is wiling to buy 50MW at a price of 80€/MWh. The wind farm's expectation is proven mistaken and another provider exists, which offers 50MW at a price of 40€/MWh. This means that a trade takes place between the other provider and demand. The wind farm does not sell its output.

PRIORITY DISPATCH

Priority dispatch is the concept of providing priority to generating units using renewable energy resources

Indicative System Operator dispatch hierarchy

Redispatched first



Redispatched last

- ‘Price makers’
- Interconnector trading
- CHP/Biomass
- Small hydro
- Controllable PV
- Wind (controllable)
- Wind (not controllable)
- Controllable PV
- Generation used to manage safety risks (e.g. mandatory hydro)

Priority dispatch

The EU Renewables Directive states that when dispatching generators the TSOs should give ‘*priority to generating installations using renewable energy resources insofar as the operation of the national electricity system permits*’. This concept is known as Priority Dispatch (PD).

More importantly, priority dispatch should not confer ‘must-run’ status on any plant and priority dispatch generation can be instructed to reduce generation if required to maintain system security. For example, the TSO cannot facilitate wind output in circumstances where that may mean putting the security of the system at risk. The TSO may need to prioritise other generation providing services relating to frequency response or curtail wind output if network constraints arise. Effectively, priority dispatch status for a generating unit means that the TSO will try to facilitate output from that unit ahead of other units as long as that does not compromise the security of the system.

Wind and other variable renewable generation have low or even close to zero variable operating cost. This means that they have an ‘economic’ priority dispatch as a result of their lower, when compared to thermal generation, variable cost. For example in the Day-Ahead market they will be positioned low in the merit order and their output is expected to be scheduled ahead of thermal generation. When the TSO then attempts to create a feasible dispatch in a least cost manner, it will first facilitate such low cost generation. This makes the concept of priority dispatch somewhat redundant as economics should result to the same outcome.

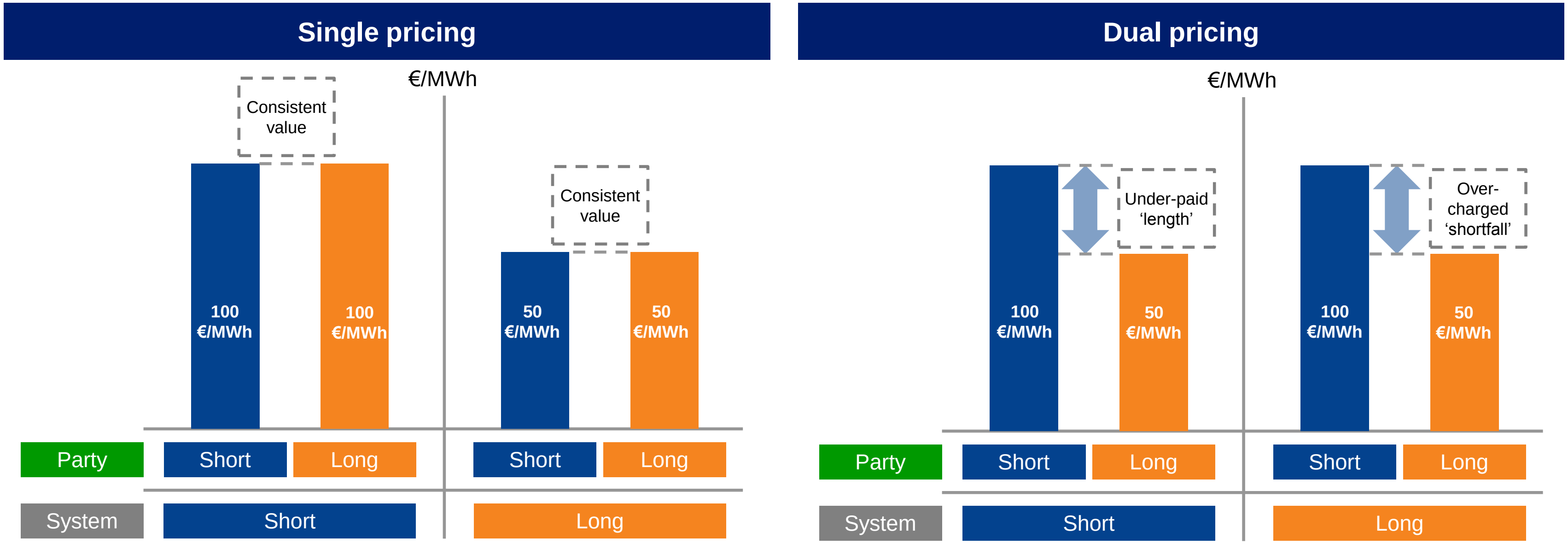
What is important is establishing rules regarding market schedule curtailment in case of tie breaks and the compensation when curtailment takes place as a result of system conditions.

When it comes to market schedule curtailment, in order for that to take place it will mean that there is more than enough variable renewable generation to cover demand on the system. Wind will start being ‘curtailed’ based on economics.

A clear hierarchy needs to be defined for when the TSO needs to take actions to curtail generation in order to maintain security of the system. We present an indicative hierarchy which could be used. In addition further consideration is needed when it comes to curtailment within a group. In any case, if a generating unit is re-dispatched as a result of system constraints it should be made whole and there should be provisions for compensation for any lost revenue (in the case of renewables this means lost RES support).

WORKED EXAMPLE FOR A WIND FARM

This example showcases the inconsistency in payments and charges to a wind farm when helping the system in a dual price system, unlike a single price regime



1) System: short

a) WF: short (-50MWh imbalance)

-50MWh x 100€/MWh = **- 5,000€**

b) WF: long (50MWh imbalance)

50MWh x 100€/MWh = **5,000€**

2) System: long

a) WF: short (-50MWh imbalance)

-50MWh x 50€/MWh = **- 2,500€**

b) WF: long (50MWh imbalance)

50MWh x 50€/MWh = **2,500€**

3) System: short

a) WF: short (-50MWh imbalance)

-50MWh x 100€/MWh = **- 5,000€**

b) WF: long (50MWh imbalance)

50MWh x x 50€/MWh = **2,500€**

4) System: long

a) WF: short (-50MWh imbalance)

-50MWh x 100€/MWh = **- 5,000€**

b) WF: long (50MWh imbalance)

50MWh x x 50€/MWh = **2,500€**

When the system is short and the wind farm is long (ie. delivering 'valuable' electricity to the system) the wind farm gets paid less in a dual price system. When the system is long and the wind farm is short, the wind farm pays more in a dual price system.

ANNEX – SIMPLIIFIED WORKED EXAMPLES FOR RES IN THE NEW MARKET DESIGN

A DAY IN THE LIFE OF A 'NEW' WIND FARM

It is important to understand and explore the practicalities with regards to the interaction of a new RES project with the markets

- In the following worked example we showcase, in a simplified manner, the way a 'large' wind farm would participate in the energy markets assuming our new proposed energy trading arrangements and RES support scheme are in place. The wind farm is 'large' in the sense that it is above the de minimis level, is balance responsible and does not participate in the markets via an aggregator. That said, under our proposals it could have chosen to participate in the markets via an aggregator. It is trading its own output in the ex-ante markets by choice.

- This 'new' wind farm is assumed to be under a variable 2-way FiP with the Day-Ahead price acting as the reference price. The energy trading arrangements are assumed to have taken the proposed enduring format, and in particular Intraday trading is assumed to be continuous.

- All examples relate to a single trading/settlement period within a given day. Prices in the ex-ante markets and forecasted and outturn output of the specific wind farm are hypothetical.

- All values used, and more specifically the strike price for the FiP contract, are indicative and do not form a recommendation from our side. Ultimately the choice of the FiP strike price should either be the outcome of a competitive auction (once auctions are deemed to be fit for purpose in the Greek market) or administratively set at a level, which would deiver the required rate of return for an 'average' RES project

- For simplicity in these examples we assume that the trading periods in a ex-ante timeframes and the imbalance settlement periods are the same.

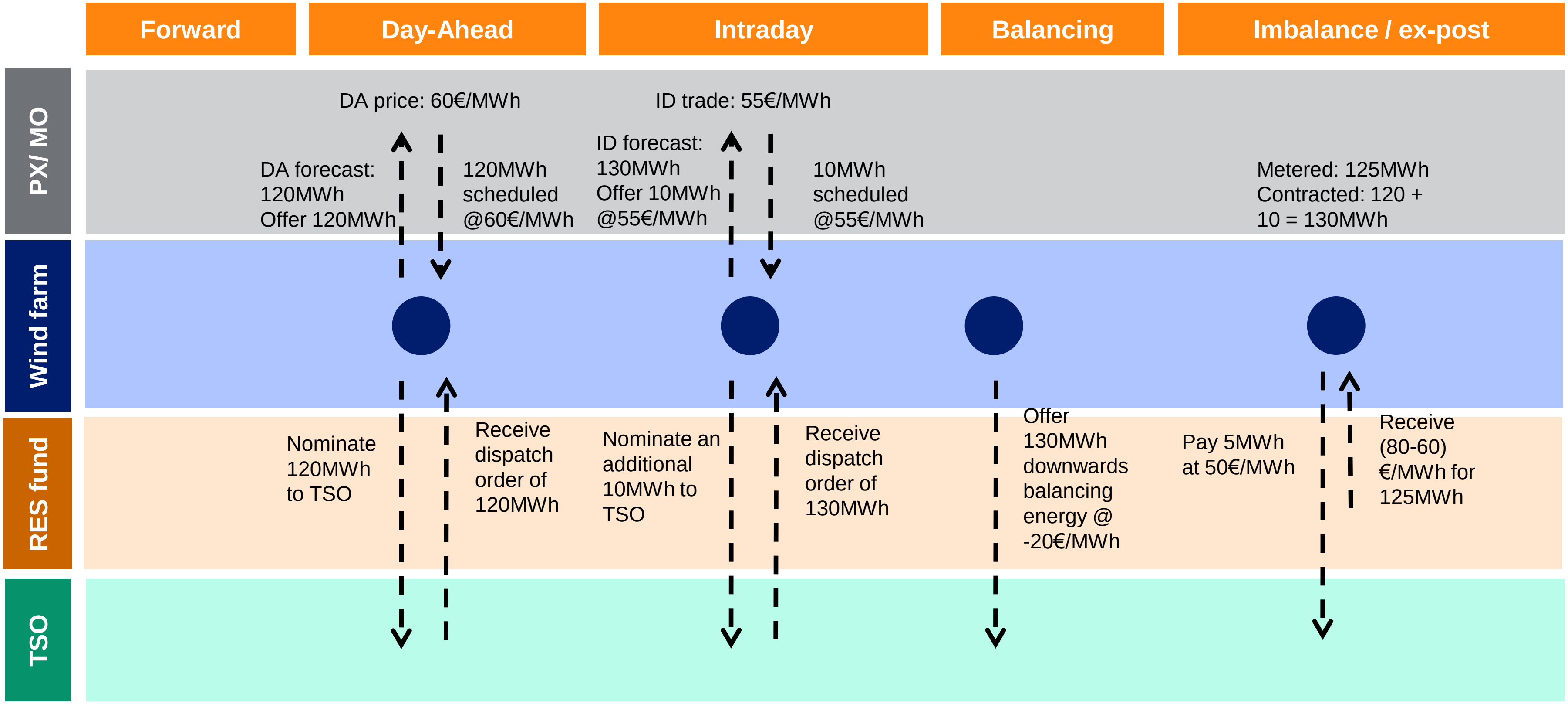
- The 'RES fund' refers to a 'green' independent company, appointed to manage RES support payments.

- The worked examples show the importance of ex-ante markets for RES projects to hedge their risks. Both access to liquid markets and efficient pricing are important to allow for RES integration.

A DAY IN THE LIFE OF A 'NEW' WIND FARM

The wind farm has to become more active in the ex-ante markets to maximise its market value and manage market risks

Example 1



Day-Ahead: 120MWh x 60€/MWh = 7200€

Intraday: 10MWh x 55€/MWh = 550€

Imbalance: 5MWh x 50€/MWh = -250€

RES support: 125MWh x 20€/MWh = 2500€

Total = 10000€

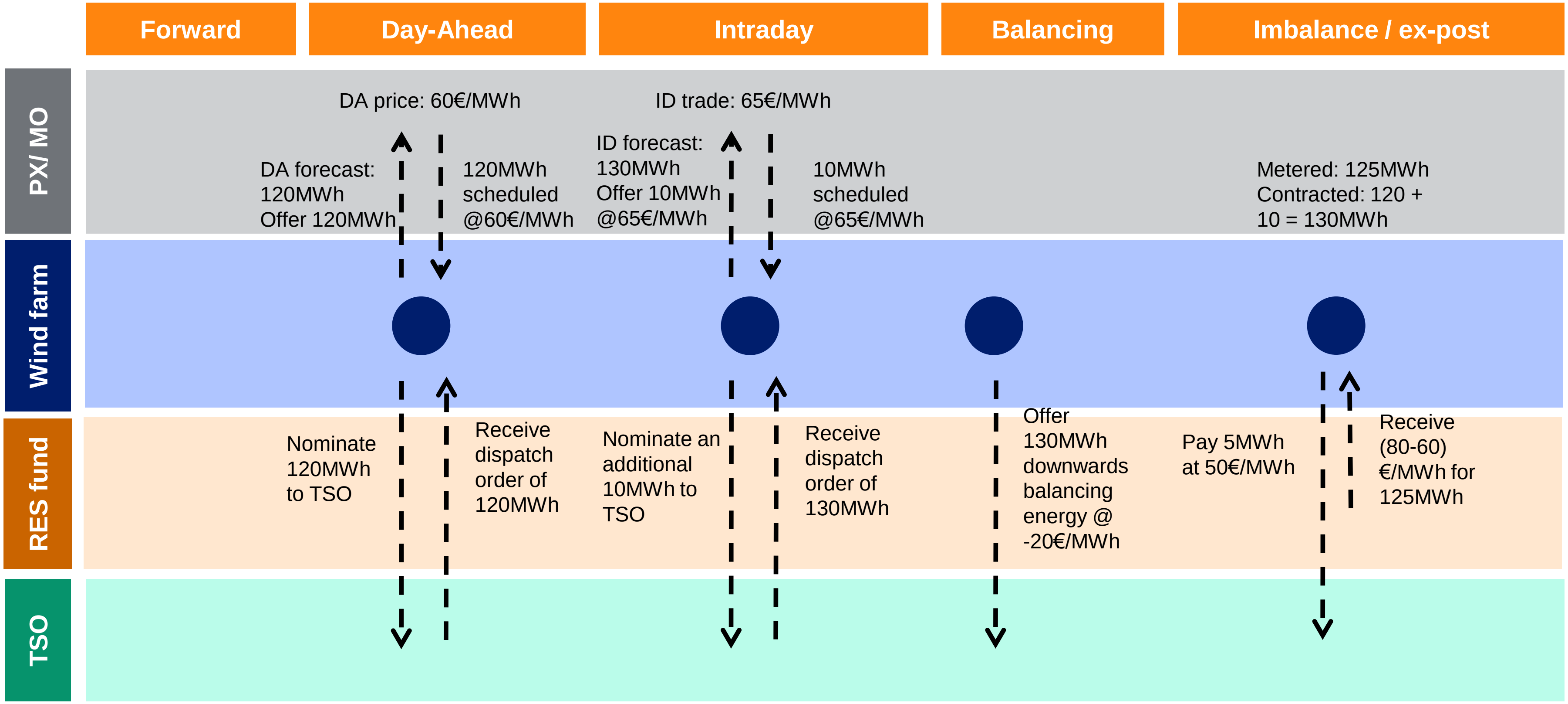
Captured price = 10000€/125MWh = **80 €/MWh**

In this example the wind farm captures exactly the same revenue it would have received assuming a pure FiT scheme was in place.

A DAY IN THE LIFE OF A 'NEW' WIND FARM

Depending on trades in the ex-ante markets, and in particular Intraday, the wind farm can be even more or less profitable

Example 2



Day-Ahead: 120MWh x 60€/MWh = 7200€

Intraday: 10MWh x 65€/MWh = 650€

Imbalance: 5MWh x 50€/MWh = -250€

RES support: 125MWh x 20€/MWh = 2500€

Total = 10100€

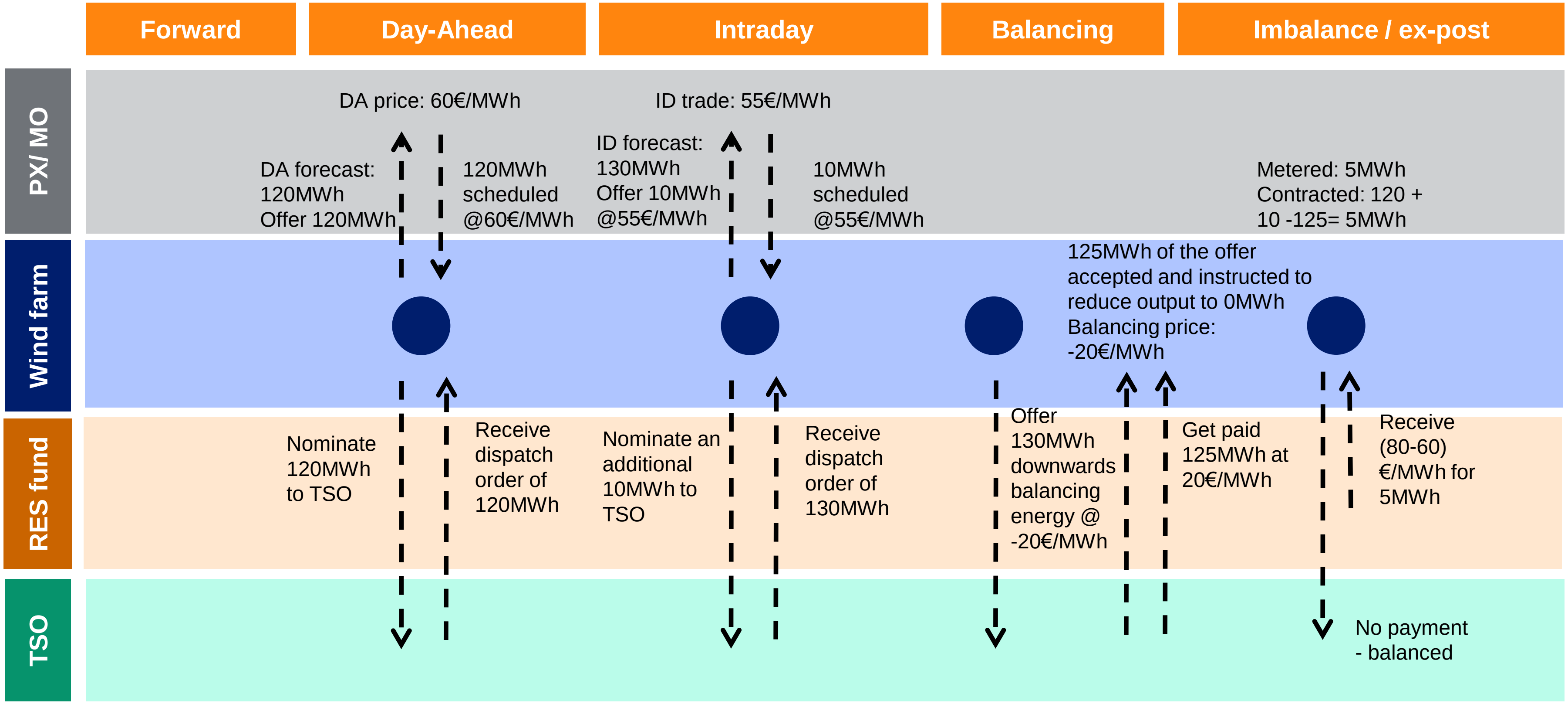
Captured price = 10100€/125MWh = **80.8 €/MWh**

In this example the wind farm captures more than what it would have received assuming a pure FiT scheme was in place. This is a result of successfully trading Intraday.

A DAY IN THE LIFE OF A 'NEW' WIND FARM

When a wind farm's balancing offer is accepted it most likely means the balancing and therefore the imbalance price will be equal to or less than zero

Example 3



Day-Ahead: 120MWh x 60€/MWh = 7200€

Intraday: 10MWh x 55€/MWh = 550€

Balancing: -125MWh x -20€/MWh=2500€

Imbalance: 0MWh x -20€/MWh = 0€

RES support: 5MWh x 20€/MWh = 100€

Total = 10350€

Captured price = 11000€/125MWh = **82.8 €/MWh**

In his example the wind farm is able to recover the lost RES support through bidding negatively in the balancing market

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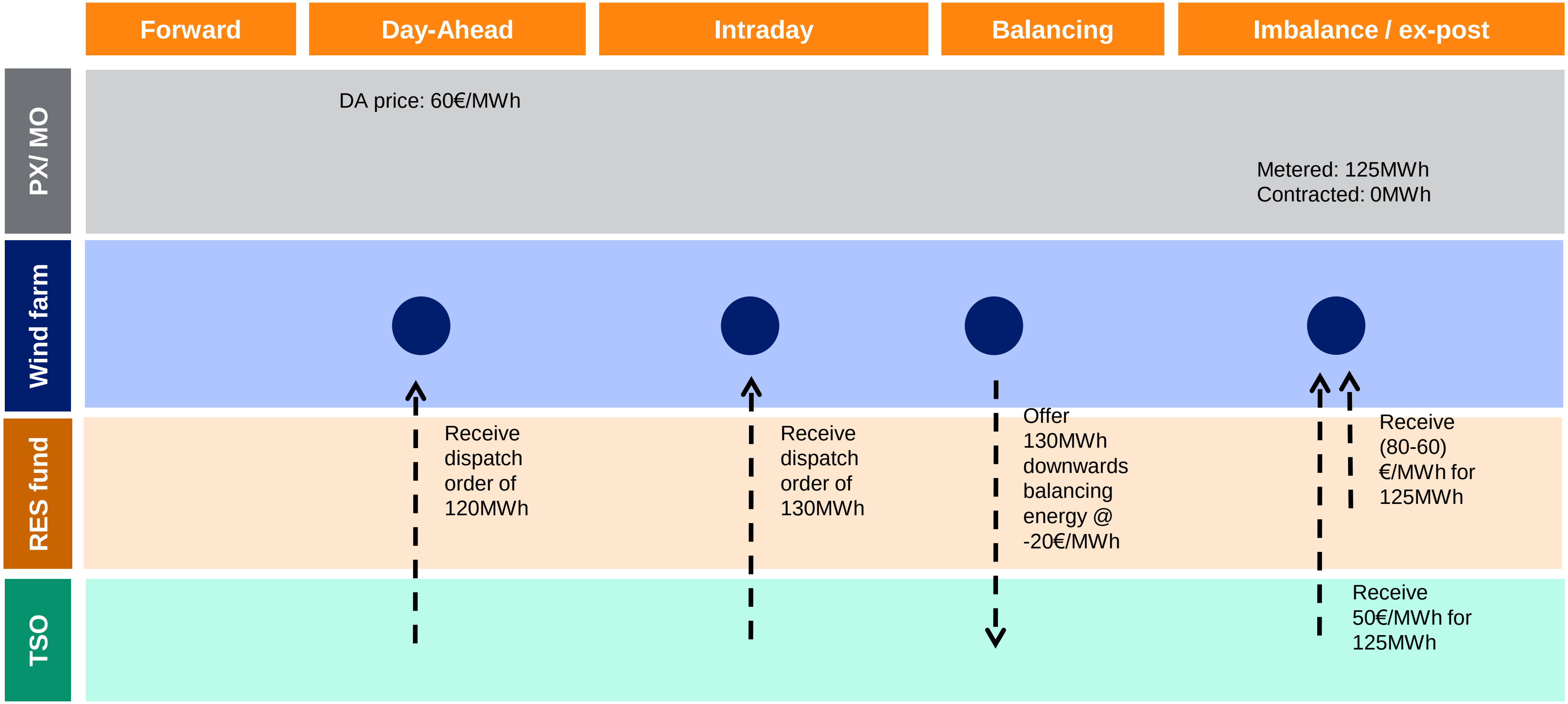
A DAY IN THE LIFE OF A 'NEW' WIND FARM

The wind farm does not participate in the ex-ante markets and is exposed to imbalance; access to the ex-ante markets is important for hedging

Example 4



Day-Ahead: 0MWh x 60€/MWh = 0€

Intraday: 0MWh x 55€/MWh = 0€

Imbalance: 125MWh x 50€/MWh = 6250€

RES support: 125MWh x 20€/MWh = 2500€

Total = 8750€

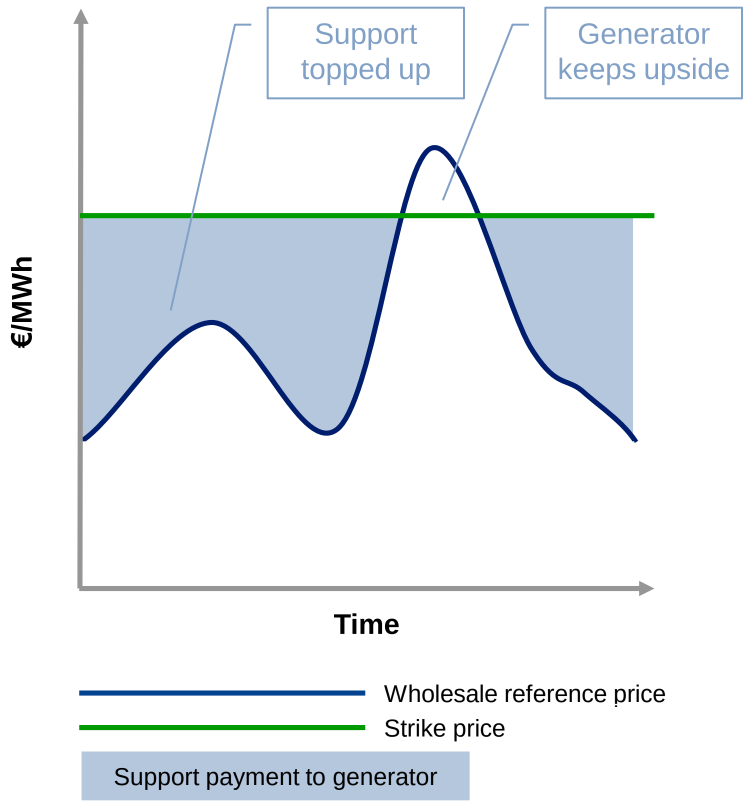
Captured price = 8750€/125MWh = **70 €/MWh**

In this example the wind farm captures the imbalance price and the additional RES support. The revenue is below that under a pure FiT scheme.

VARIABLE FEED-IN PREMIUM FLEXES SUPPORT BASED ON DIFFERENCE BETWEEN WHOLESALE PRICE AND STRIKE PRICE

One-way payments allow for top-up to the strike price, but no pay-back

VARIABLE PREMIUM, 1-WAY PAYMENTS



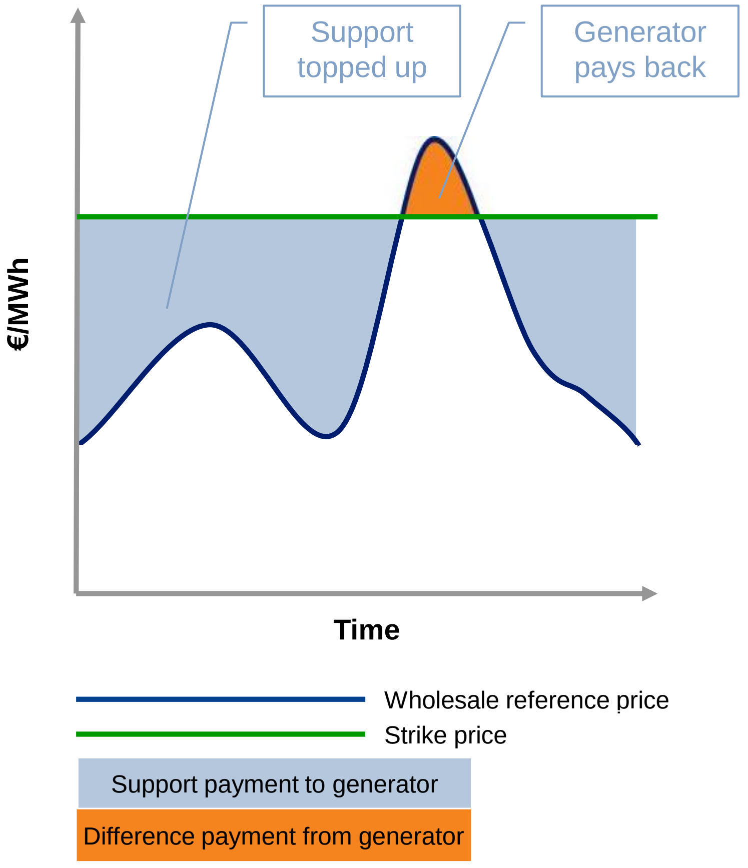
- Variable premium in €/MWh is paid to the generator on top of the energy market price to reach a 'strike price' based on combined revenue streams
  - if energy price is below strike price, support payment tops up to strike price
  - if energy price is above strike price, there is no support and generator keeps the upside
- Generator relies on wholesale revenue and so must interact with market (directly or indirectly)
  - electricity market price risk is limited given variable top-up
- Degree of risk faced is linked to basis for wholesale reference price
  - closer to real-time reduces risk
- Uncertainty in terms of policy cost
- Applied in:
  - Italy

ANNEX – RES SUPPORT MECHANISMS

VARIABLE FEED-IN PREMIUM FLEXES SUPPORT BASED ON DIFFERENCE BETWEEN WHOLESALE PRICE AND STRIKE PRICE

Two-way payments allow for top-up to the strike price and pay-back

VARIABLE PREMIUM, 2-WAY PAYMENTS

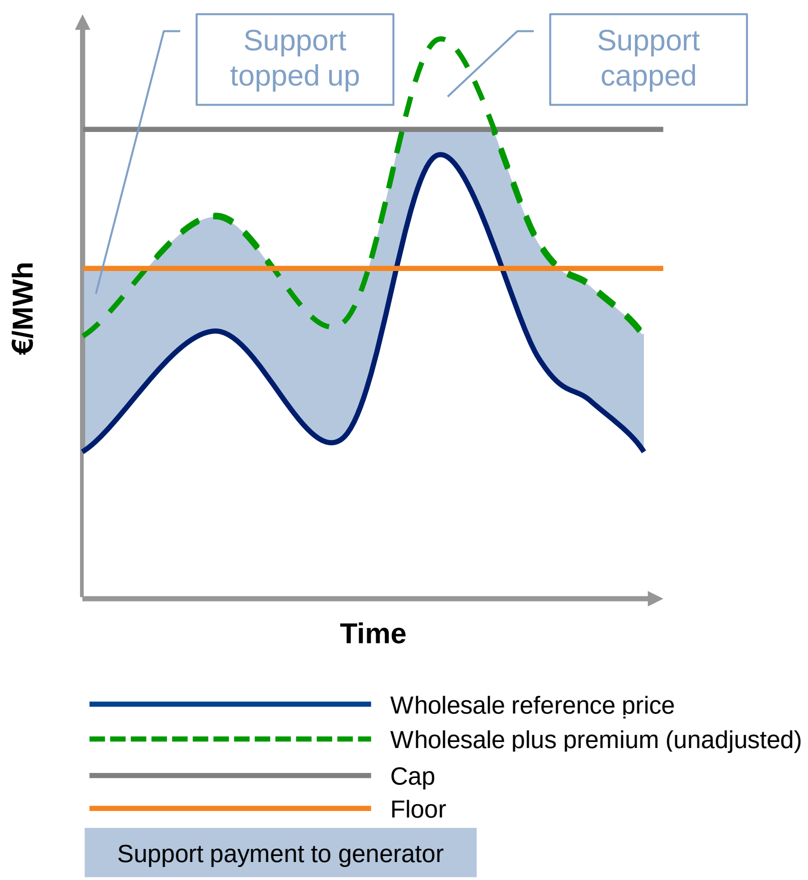


- Variable premium in €/MWh is paid to the generator on top of the energy market price to reach a ‘strike price’ based on combined revenue streams
  - if energy price is below strike price, support payment tops up to strike price
  - if energy price is above strike price, generator makes difference payment to return the upside
- Generator relies on wholesale revenue and so must interact with market (directly or indirectly)
  - electricity market price risk is limited given variable top-up
- Degree of risk faced is linked to basis for wholesale reference price
  - closer to real-time reduces risk
- Uncertainty in terms of policy cost
- Applied in:
  - GB (being adopted)

ANNEX – RES SUPPORT MECHANISMS

FIXED FEED-IN PREMIUM WITH CAP AND FLOOR LIMITS UPSIDE AND DOWNSIDE POTENTIAL ON OVERALL REVENUE

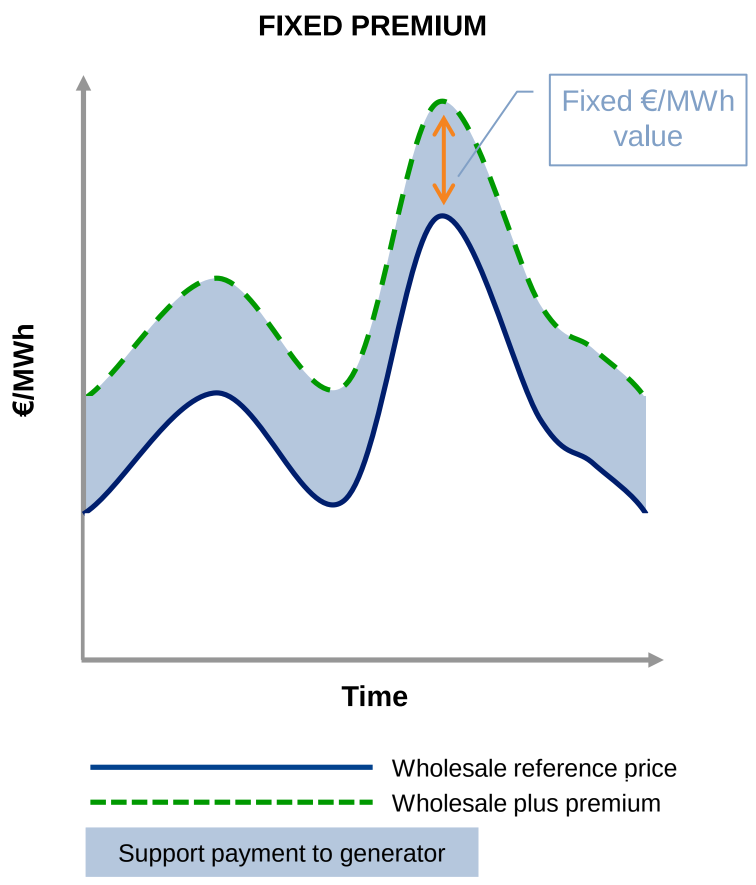
FIXED PREMIUM, CAP AND FLOOR



- Fixed premium in €/MWh within the limits of a cap and floor is paid to the generator on top of the energy market price
  - if energy price plus fixed premium is below floor, support is topped up to reach floor
  - if energy price plus fixed premium is above cap, support is restricted at cap
- Generator relies on wholesale revenue and so must interact with market (directly or indirectly)
  - generator faces limited electricity market price risk within the cap/floor values
- Calculation of premium relies technology cost assessment and on expectations of future wholesale electricity prices
- Applied in:
  - Spain (now suspended)

ANNEX – RES SUPPORT MECHANISMS

FIXED FEED-IN PREMIUM PROVIDES CONSTANT €/MWH SUPPORT PAYMENT IN ADDITION TO WHOLESALE REVENUE

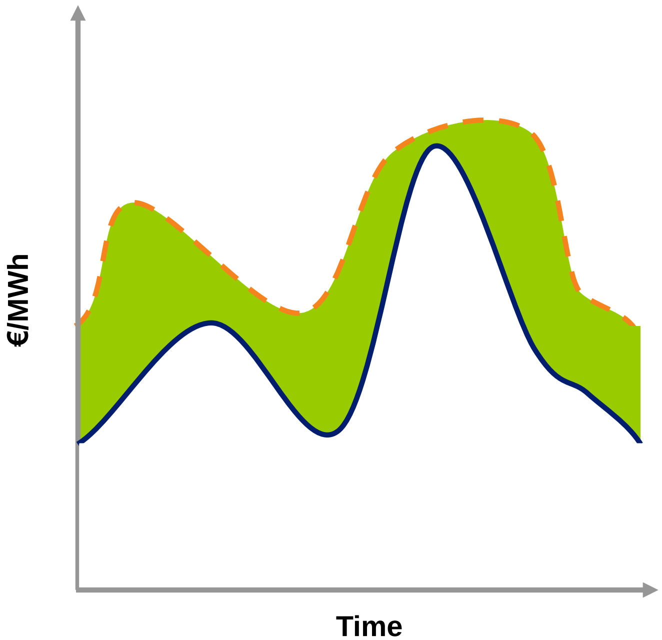


- Constant premium in €/MWh is paid to the generator on top of the energy market price
- Generator relies on wholesale revenue and so must interact with market (directly or indirectly)
  - generator faces full electricity market price risk
- Calculation of premium relies technology cost assessment and on expectations of future wholesale electricity prices
  - if expectations prove to be low vs outturn, then upside exists (and vice versa)
- Applied in:
  - Czech Republic

ANNEX – RES SUPPORT MECHANISMS

GREEN CERTIFICATE MARKET VALUE AVAILABLE IN ADDITION TO WHOLESALE MARKET VALUE

GREEN CERTIFICATE



Wholesale reference price

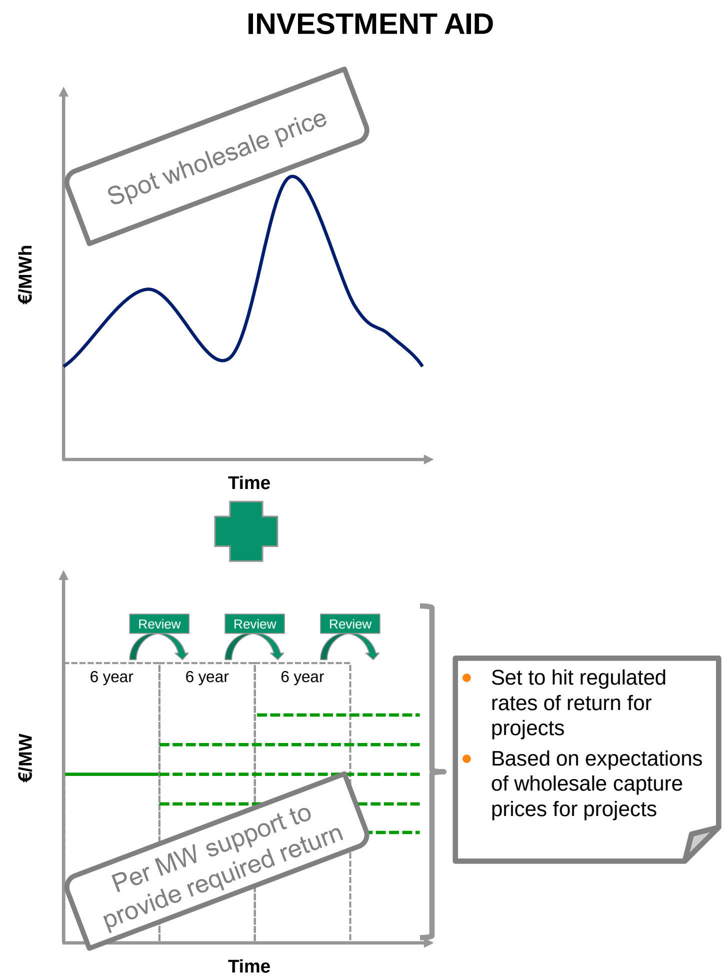
Wholesale plus premium

Green Certificate revenue

- €/MWh of the Green Certificate market is captured by the generator on top of the energy market price
- Generator relies on wholesale revenue and so must interact with market (directly or indirectly)
  - generator faces full electricity market price risk
- Generator also faces Green Certificate market price risk
  - influenced by rules on buy-out, quotas
- Applied in:
  - Sweden, Norway, Romania, UK (being phased out)

ANNEX – RES SUPPORT MECHANISMS

INVESTMENT AID OR €/MW SUPPORT CAN BE USED TO SUPPLEMENT WHOLESALE



- €/MW support provided to generator on top of the energy market price
- Generator relies on wholesale revenue and so must interact with market (directly or indirectly)
  – generator faces full electricity market price risk
- Based on expectations of wholesale capture revenues, support is set to provide ‘missing money’ needed to provide a defined return for a set capex
  – regulatory process
  – scope for periodic reviews to update wholesale capture revenue expectations
- Can link payments to minimum number of operating hours
- Applied in:
  – Spain (variant)

ANNEX – RES SUPPORT MECHANISMS

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