Single Electricity Market Operator – Training Module

Market Processes: Bid to Bill

July 2007
(Revision 6)

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Learning objectives for this module:

- An overview of the bidding process
- A simple example of how the ex-ante and ex-post UUC work
- An explanation of the key differences between ex-ante and ex-post scheduling
- An example of the settlement outcomes

Note: Please review the separate handout for reference data and definitions

A. BID SECTION

B. SETTLEMENT SECTION

A. BID SECTION

1. Setting the Scene

2. Bids

3. Ex Ante Generation Requirement

4. Ex Ante UUC Solution

5. Interconnectors & Dispatch Schedules

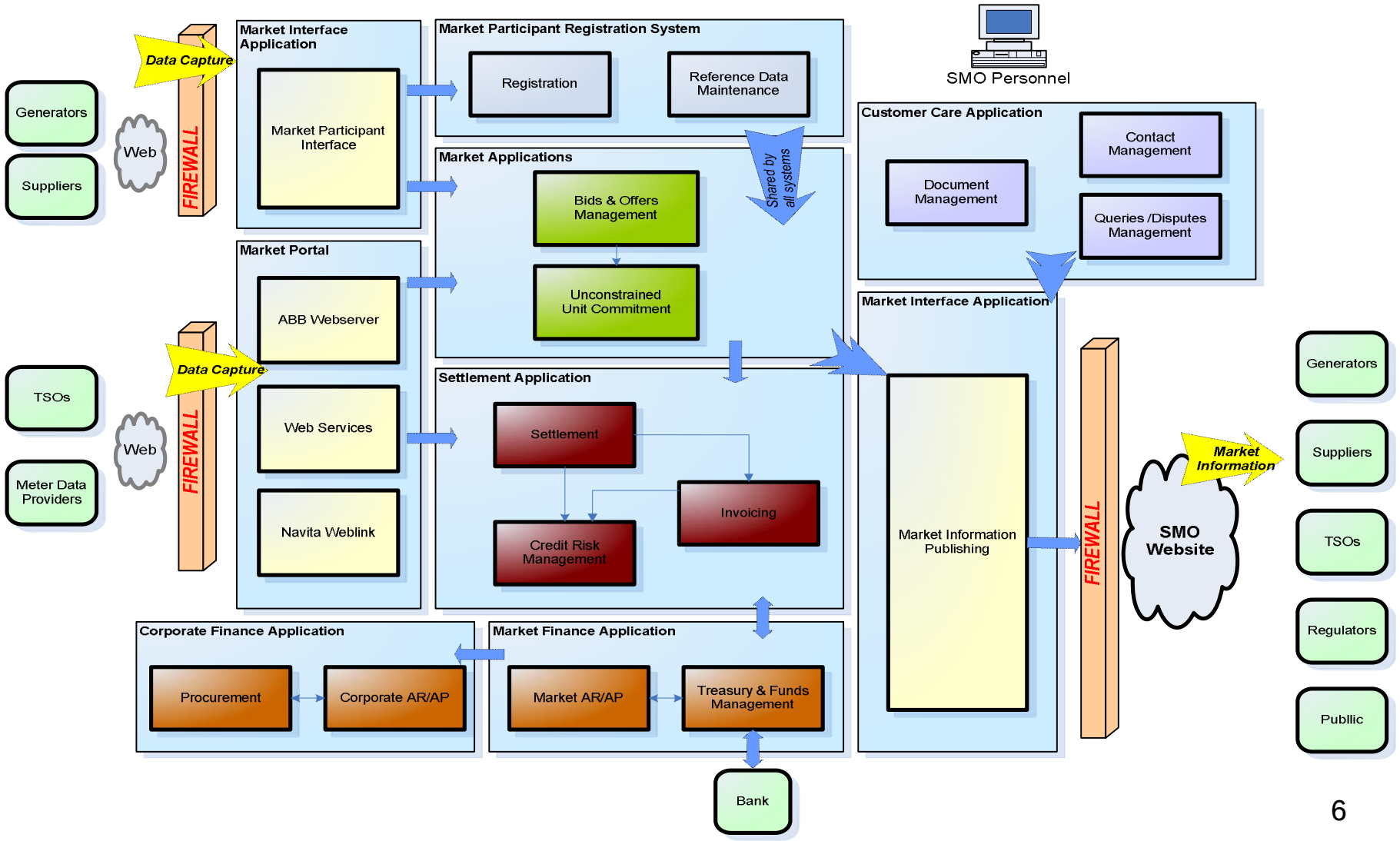
6. Meter Data

7. Ex Post Processing of Bids

8. Ex Post Generation Requirement

9. Ex Post UUC Solution

B. SETTLEMENT SECTION


Generators
Suppliers
Web
Data Capture
FIREWALL
Market Interface Application
Market Participant Interface
Market Participant Registration System
Registration
Reference Data Maintenance
SMO Personnel
Customer Care Application
Contact Management
Document Management
Queries /Disputes Management
Shared by all systems
Market Applications
Bids & Offers Management
Unconstrained Unit Commitment
Market Portal
ABB Webserver
Web Services
Navita Weblink
Settlement Application
Settlement
Invoicing
Credit Risk Management
Market Interface Application
Market Information Publishing
TSOs
Meter Data Providers
Web
Data Capture
FIREWALL
Market Information
SMO Website
Generators
Suppliers
TSOs
Regulators
Public
Corporate Finance Application
Procurement
Corporate AR/AP
Market Finance Application
Market AR/AP
Treasury & Funds Management
Bank

The Market Window opens at Gate Closure minus 28 days

- Ä Bids can be submitted anytime up to Gate Closure.
- Ä Gate Closure is at 1000 on the day prior to the Trading Day (D-1)
- Ä All bids are fixed at Gate Closure.

ÄThe Ex Ante Indicative Market Schedule is run by 1100 on D-1

- Ä Based mainly on forecast data and bids.

ÄThe Indicative Operations Schedule is run by 1600 on D-1

ÄTrading Day

- Ä The Trading Day runs from 0600 to 0600 (usually 24 hours, but can be 23 or 25 hours if daylight saving conditions apply).
- Ä Note: IMS and EPUS schedules represents the Trading Day plus an additional 6 hours so as to provide "end conditions" for the Trading Day. Overall, the optimisation is 29, 30 or 31 hours long, depending on daylight savings.
- Ä Dispatch Instructions are issued during the Trading Day.

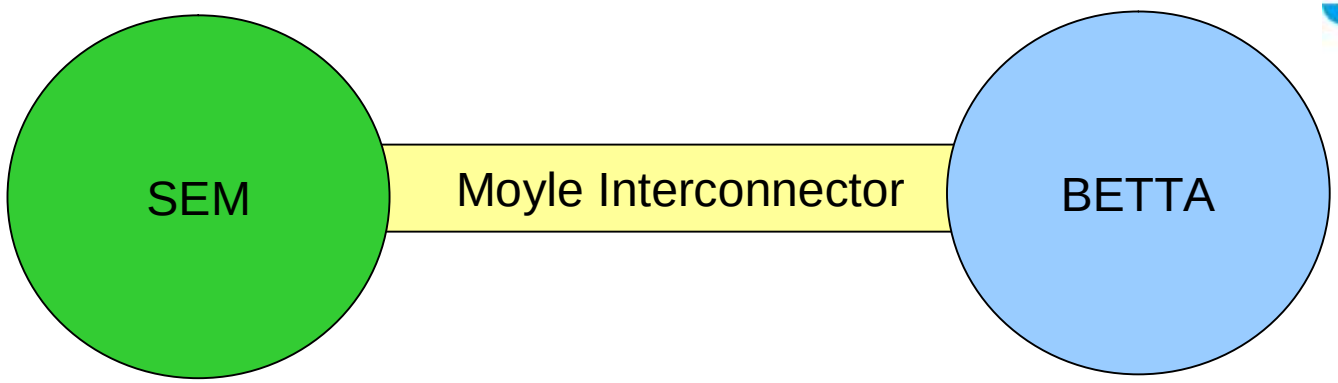
ÄThe Ex Post Indicative Market Schedule is run by 1600 on D+1

- Ä Indicative settlement gives Market Participants an idea of their financial position.
- Ä Some data is not available on D+1 (e.g. all meter data)

Ä The Ex-Post Initial Market Schedule is run by 1600 on D+4

- Ä All data will ordinarily be available to allow settlement to be undertaken

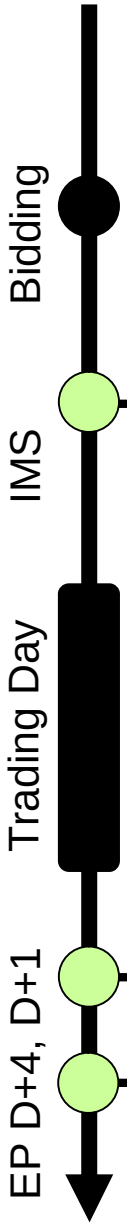
- In the following example registration data and standing bids are ignored.
  - Standing bid data is bid data defined for a given weekday which is used for that day if no bid has been submitted.
  - Standing bid data becomes “live” at the time of gate opening (28 days before gate closure)
  - If a Market Participant wants or needs to change bid data after that time then it must replace the data within the bidding systems using the normal bid process.
- Registration data can generally be submitted up to gate closure.
  - There are a few exceptions to this for data that is used in other processes



During previous months

- Interconnector Administrator periodically allocates capacity to Interconnector Users based on an auction.

- During Window for Bidding
  - Interconnector Users can bid like any other participant, but may not have certainty over their final capacity holdings.
- Day D-2
  - Interconnector Administrator determines the Active Import Capacity Holdings and Active Export Capacity Holders for each Interconnector User for Trading Day D.
  - SMO (Single Market Operator) publishes capacity
- Day D-1
  - The ex ante IMS only uses only bids within the Active Import/Export Capacity Holdings
  - The ex ante IMS run determines the total flow on the interconnector
  - If the I/C is ramp constrained, the MITS system allocates total scheduled flow between interconnector users based on their right holdings



The Ex-Ante IMS is produced following Gate Closure. It is based on:

- Participant Bids for Price Maker Units (within the Window)
- Unit forecast availabilities, minimum stable generation and minimum output
- Price Taker Nominations
- Composite Load Forecast (comprised of forecasts from ROI and NI)
- Wind Unit forecasts

The Ex-Post EPUS is run after the Trading Day (indicative on D+1 and initial on D+4). It is based mainly on actual data from the Trading Day, including:

- The same Participant Bids
- Actual availabilities, minimum stable generation and minimum output
- Actual generation (metered output)

Highlight the bidding and scheduling process with a numeric example

- More detail on the formal workings of systems in other presentations

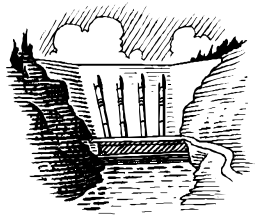
- The example serves to illustrate the concepts while avoiding the specifics
  - Only 3 half-hour periods are considered
  - Focus only on bids, availability, energy limits and the demand to be met. There are many other parameters available to participants.
  - Pump storage units are covered in a stand-alone example

- Transmission loss factors are assumed to be 1
  - No impact on the scheduling examples as transmission loss factors are not used
  - But does simplify the settlement examples.

- The example follows a mixture of price makers and price takers through the bidding, scheduling and settlement process.
  - A Price Maker is a generating unit that is scheduled in IMS/EPUS and which can set prices.
  - A Price Taker is a self scheduled generating unit that cannot set prices.

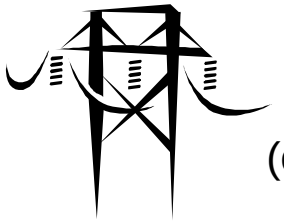
Unit 1
Thermal Generator
(e.g. gas or coal fired)

This unit has a fully controllable output and can be scheduled based on bids. Unit 1 is a "Predictable Price Maker"



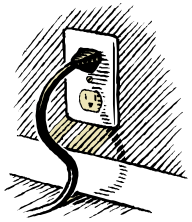
Unit 2
Hydro Generator
(water powered)

While generation is controllable, Unit 2 has very limited storage so its ability to generate depends on water availability. It is a "Variable Price Maker" (and is also an Energy Limited Generator Unit)



Units 3a and 3b
Interconnector Units
(e.g. imported/exported energy)

Two participants in BETTA can buy or sell across the Moyle Interconnector. One trader has Unit 3a, the other Unit 3b. These units are obliged to supply or consume so are "Predictable Price Makers".



Unit 4
Demand Side Unit
(e.g. curtailable load)

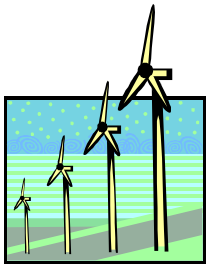
Demand side units are treated as being fully controllable and can be scheduled based on bids. Unit 4 is a "Predictable Price Maker"

Unit 5
Thermal Generator
(e.g. gas or coal fired)

This unit is a co-generator, producing power as a by-product of another process, & while its output is predictable its operator does not want to have to change its output based on price. Unit 5 is a “Predictable Price Taker”

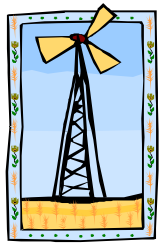
Unit 6
Thermal Generator
(e.g gas or coal fired)

This unit is a smaller co-generator, with less predictable output. It can be thought of as a “Variable Price Taker”, but the term used for Unit 6 is that it is a “Variable Price Taker” (non-wind powered)



Unit 7
Wind Unit
(e.g. wind unit, wind farm)

Unit 7 is a wind farm and as such cannot predict its output. Unit 7 is a “Variable Price Taker” (wind powered)



Unit 8
Wind Unit
(e.g. wind unit, wind farm)

Unit 8 is an individual wind unit that only wants to have limited involvement in the market. Unit 8 is an “Autonomous Generator”.

Unit	Type	Nature	How Scheduled
1	Thermal	Predictable Price Maker	Bids
2	Hydro	Variable Price Maker (Energy Limited)	Bids
3a	Interconnector Unit	Predictable Price Maker	Bids
3b	Interconnector Unit	Predictable Price Maker	Bids
4	Demand Side Unit	Predictable Price Maker	Bids
5	Thermal	Predictable Price Taker	Nomination
6	Thermal	Variable Price Taker (non-wind)	Nomination
7	Wind	Variable Price Taker (wind)	Forecast
8	Wind	Autonomous Generator	Forecast

A. BID SECTION

1. Setting the Scene

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4. Ex Ante UUC Solution

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9. Ex Post UUC Solution

B. SETTLEMENT SECTION

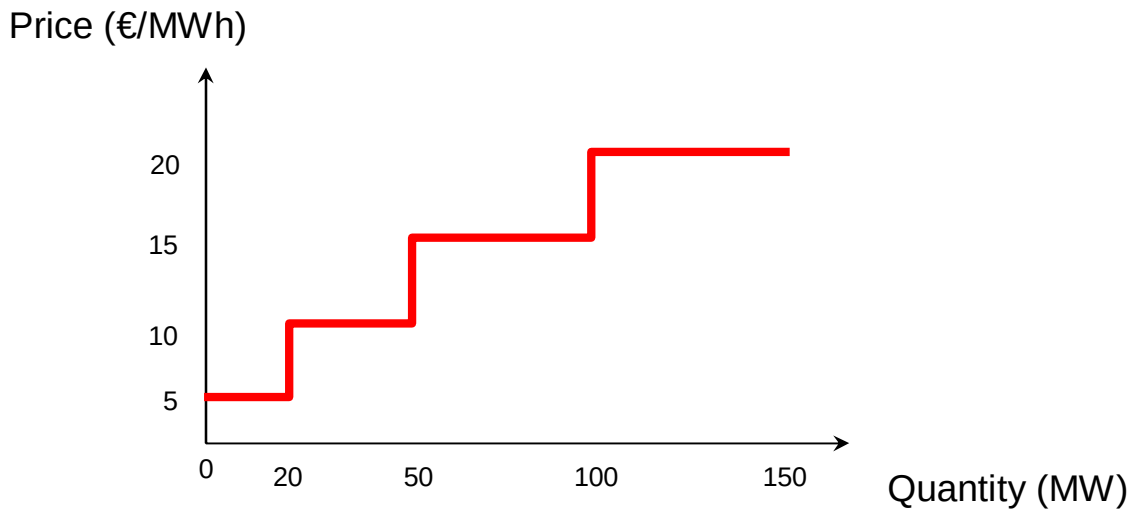
Price (€/MWh)	Quantity (MW)
5	20
10	50
15	100
20	150

- Price / Quantity Pairs
  - The Quantity represents the average MW level of energy to be supplied over a trading period.
  - The price represents the minimum payment required for each MWh delivered.
    - Price must increase with increasing quantity.
  - This bid corresponds to
    - Offering up to 20 MW for €5/MWh
    - Offering from 20 MW to 50 MW for €10/MWh
    - Offering from 50 MW to 100 MW for €15/MWh
    - Offering from 100 MW to 150 MW for €20/MWh

- Usage
  - Interconnector Units can submit up to 10 PQ pairs for each Trading Period in the Trading Day
  - Generators and Demand Side Units can submit 10 PQ pairs which apply for all Trading Periods in the Trading Day.

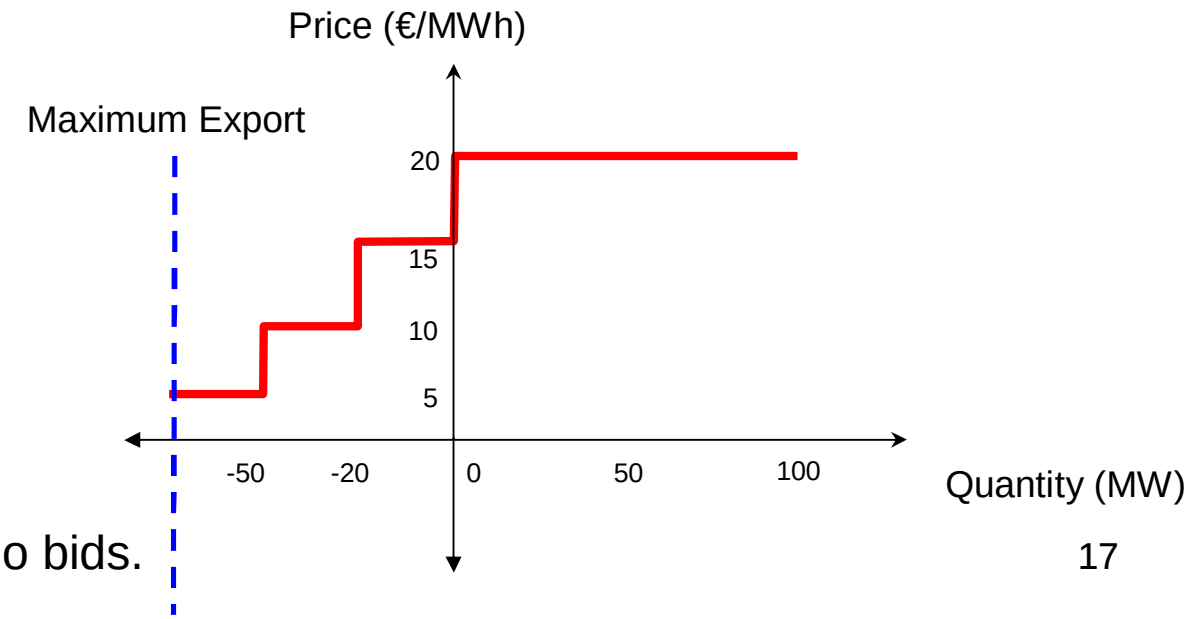
For a Generator or DSU

Price (€/MWh)	Quantity (MW)
5	20
10	50
15	100
20	150



For an Interconnector Unit

Price (€/MWh)	Quantity (MW)
5	-50
10	-20
15	0
20	100



Pump storage units have no bids.

UNIT 1 DATA

Start-up Cost per start (€)	1,000	No Load Cost (€/hour)	50

Price (€/MWh)	Quantity (MW)
10	100
20	200
30	300

Trading Period	1	2	3
Forecast Availability (MW)	250	250	200
Forecast Min Stable Generation (MW)	50	50	50
Forecast Min Output (MW)	0	0	0

Energy Limit (MWh)	N/A	Periods	N/A	N/A	N/A

- Each time Unit 1 is turned on a cost of €1000 will be incurred.
- Each hour it is on, Unit 1 incurs a no load cost of €50 irrespective of its output.
- When committed, Unit 1 operates at not less than its minimum stable generation of 50 MW.
- Unit 1 has 250 MW of capacity available in periods 1 and 2, but due to maintenance its capacity drops to 200 MW in period 3.
- Minimum output is zero for all Generator Units except for Pump Storage Units.
- No energy limits apply (only energy limited hydro units may use these).

THIS PARTICIPANT DATA

Start-up Cost per start (€)	1,000	No Load Cost (€/hour)	50

Price (€/MWh)	Quantity (MW)
10	100
20	200
30	300

Trading Period	1	2	3
Forecast Availability (MW)	250	250	200
Forecast Min Stable Generation (MW)	50	50	50
Forecast Min Output (MW)	0	0	0

Energy Limit (MWh)	N/A	Periods	N/A	N/A	N/A

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any*	50	Any*	50	Any *	50
10	50	10	50	10	50
20	100	20	100	20	100
30	50	30	50		

Start-up Cost per start (€)	1,000	No Load Cost (€/period)	25	Energy Limit (MWh)	N/A

*** In all our examples, "Any" means the quantity applies at any price provided that the unit is committed.**

UNIT 2 DATA

Start-up Cost per start (€)	0	No Load Cost (€/hour)	0

Price (€/MWh)	Quantity (MW)
10	50
20	100
25	200

Trading Period			1	2	3
Forecast Availability (MW)			200	200	200
Forecast Min Stable Generation (MW)			60	60	60
Forecast Min Output (MW)			0	0	0
Energy Limit (MWh)	120	Periods	ü	ü	ü

- This unit happens to have start-up and no-load costs of zero.
- When committed, Unit 2 operates at not less than its minimum stable generation of 60 MW.
- Unit 2 has 200 MW of capacity available in all periods. This equates to 100 MWh per half hour period or 300 MWh of potential energy over the three periods.
- But unit 2 has an energy limit of 120 MWh so will not be scheduled for more than this over the three periods.
- If committed, the generation output of Unit 2 above Min Stable Generation is based on the submitted PQ pairs.

THIS PARTICIPANT DATA

Start-up Cost per start (€)	0	No Load Cost (€/hour)	0

Price (€/MWh)	Quantity (MW)
10	50
20	100
25	200

Trading Period	1	2	3
Forecast Availability (MW)	200	200	200
Forecast Min Stable Generation (MW)	60	60	60
Forecast Min Output (MW)	0	0	0

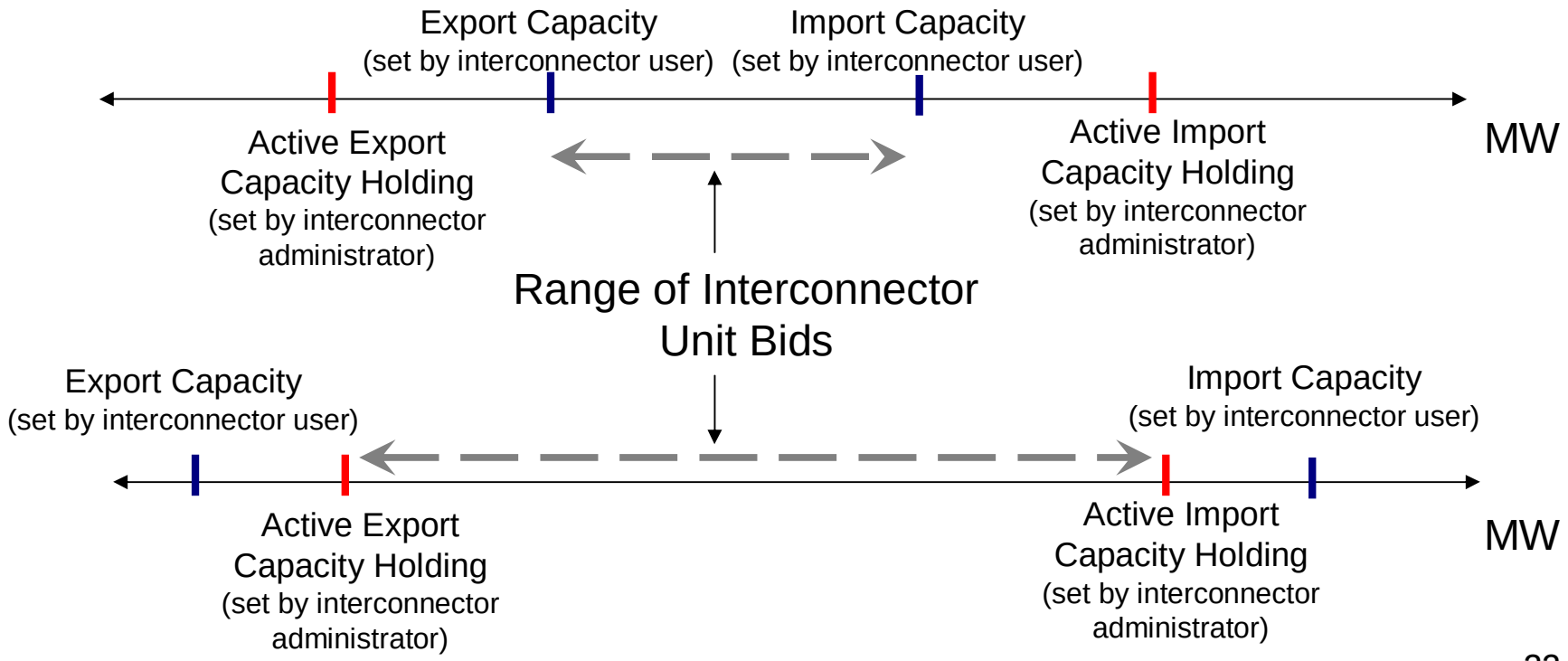
Energy Limit (MWh)	120	Periods	ü	ü	ü

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	60	Any	60	Any	60
20	40	20	40	20	40
25	100	25	100	25	100
Energy Limited Period		Energy Limited Period		Energy Limited Period	

Start-up Cost per start (€)	0	No Load Cost (€/period)	0	Energy Limit (MWh)	120

- Interconnector unit bids apply between the Export and Import Capacity set by the interconnector user.
- BUT, where this capacity violates the participants the active import or export capacity holdings, the active export or import capacity holding is used (as applicable)



INTERCONNECTOR USER DATA

Period 1

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Period 2

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Period 3

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Trading Period	1	2	3
Min(Import Capacity, Active Import Capacity Holding) (MW)	0	40	0
Max(Export Capacity, Active Export Capacity Holding) (MW)	0	-40	0

- This interconnector unit will be treated like a generator with a zero start up cost and no-load cost.
- Negative quantities are exports.
- The interconnector user submits its desired import and export capacity, but the capacity range used is limited by the active import and export capacity holdings.
- Unit 3a has no import or export capacity in periods 1 and 3.

THIS INTERCONNECTOR USER DATA

Period 1

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Period 2

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Period 3

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Trading Period	1	2	3
Min(Import Capacity, Active Import Capacity Holding) (MW)	0	40	0
Max(Export Capacity, Active Export Capacity Holding) (MW)	0	-40	0

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
0	0	Any	-40	0	0
		5	20		
		40	40		
		50	20		24

INTERCONNECTOR USER DATA

Period 1

Price (€/MWh)	Quantity (MW)
55	0
65	60

Period 2

Price (€/MWh)	Quantity (MW)
55	0
65	60

Period 3

Price (€/MWh)	Quantity (MW)
55	0
65	60

Trading Period	1	2	3
Min(Import Capacity, Active Import Capacity Holding) (MW)	0	60	0
Max(Export Capacity, Active Export Capacity Holding) (MW)	0	-60	0

- This interconnector unit will be treated like a generator with a zero start up cost and no-load cost.
- This interconnector unit is bidding a positive price for quantities below zero (exports), meaning it is prepared to pay to purchase energy to export.
- The interconnector user submits its desired import and export capacity, but the capacity range used is limited by the active import and export capacity holdings.
- Unit 3b has no import or export capacity in periods 1 and 3.

THIS INTERCONNECTOR USER DATA

Period 1

Price (€/MWh)	Quantity (MW)
55	0
65	60

Period 2

Price (€/MWh)	Quantity (MW)
55	0
65	60

Period 3

Price (€/MWh)	Quantity (MW)
55	0
65	60

Trading Period	1	2	3
Min(Import Capacity, Active Import Capacity Holding) (MW)	0	60	0
Max(Export Capacity, Active Export Capacity Holding) (MW)	0	-60	0

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
0	0	Any	-60	0	0
		55	60		
		65	60		
					26

UNIT 4 DATA

Shut Down Cost per stop (€)	500	No Load Cost (€/hour)	N/A

Price (€/MWh)	Quantity (MW)
120	100

Trading Period	1	2	3
Forecast Availability (MW)	100	100	100
Forecast Min Stable Generation (MW)	0	0	0
Forecast Min Output (MW)	0	0	0

Energy Limit (MWh)	N/A	Periods	N/A	N/A	N/A

- If the price reaches €120/MWh then Unit 4 will reduce its load by up to 100 MW.
- A shut down cost of €500 will be incurred in the first of each contiguous group of periods where the Demand Side Unit supplies load reduction.
- Unit 4 has availability in all periods.
- Unit 4 has no energy limits (only hydro units can have these)
- When this data is converted into the form used in the UUC the unit will be modelled as a generator with a start-up cost and a zero no load cost.

THIS PARTICIPANT DATA

Shut Down Cost per stop (€)	500	No Load Cost (€/hour)	N/A

Price (€/MWh)	Quantity (MW)
120	100

Trading Period	1	2	3
Forecast Availability (MW)	100	100	100
Forecast Min Stable Generation (MW)	0	0	0
Forecast Min Output (MW)	0	0	0

Energy Limit (MWh)	N/A	Periods	N/A	N/A	N/A

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
120	100	120	100	120	100

Start-up Cost per start (€)	500	No Load Cost (€/period)	0	Energy Limit (MWh)	N/A

- In the above data both Units 1 and 2 have bid steps priced at €20/MWh
  - How these units are treated depends on their Priority Dispatch status.
  - We assume Unit 1 has priority dispatch and Unit 2 does not.

- The costs of these units are modified:

  - Priority Dispatch units have their tied bid prices reduced fractionally by a small random amount.
    - E.g. Unit 1's €20/MWh price changes to €19.999/MWh.
    - If this sets the price, the price will be reported as €20.00/MWh

  - Non-Priority Dispatch units have their tied bid prices increased fractionally by a small random amount.
    - E.g. Unit 2's €20/MWh price changes to €20.001/MWh.
    - If this sets the price, the price will be reported as €20.00/MWh

  - This ensures that in the event of tied bids.
    - Priority Dispatch units are scheduled ahead of non-priority dispatch units.
    - But within each group (priority dispatch, non-priority dispatch) ties are resolved randomly.

UNIT 1 DATA WITH PRIORITY DISPATCH

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	50	Any	50	Any	50
10	50	10	50	10	50
19.999	100	*19.999*	100	*19.999*	100
30	50	30	50		

Start-up Cost per start (€)	1,000	No Load Cost (€/period)	25	Energy Limit (MWh)	N/A

UNIT 2 DATA WITHOUT PRIORITY DISPATCH

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	60	Any	60	Any	60
20.001	40	*20.001*	40	*20.001*	40
25	100	25	100	25	100
Energy Limited Period		Energy Limited Period		Energy Limited Period	

Start-up Cost per start (€)	0	No Load Cost (€/period)	0	Energy Limit (MWh)	120

A. BID SECTION

1. Setting the Scene

2. Bids

3. Ex Ante Generation Requirement

4. Ex Ante UUC Solution

5. Interconnectors & Dispatch Schedules

6. Meter Data

7. Ex Post Processing of Bids

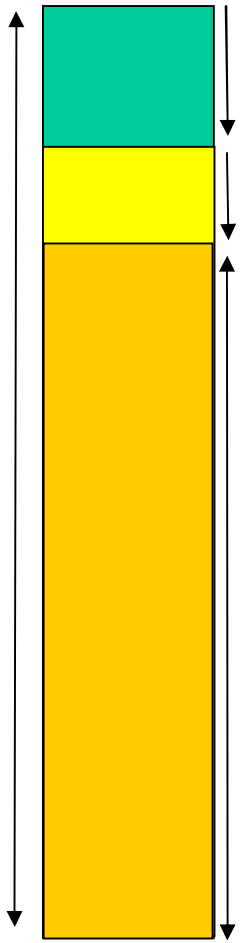
8. Ex Post Generation Requirement

9. Ex Post UUC Solution

B. SETTLEMENT SECTION

Ex-Ante Generation Requirement:

Composite TSO Demand Forecast
(Demand + Transmission Losses – Non-Wind Autonomous Generation)



Minus Price Taker Nominations (non-wind)

Minus TSO Wind Generation Forecast

Ex Ante Generation Requirement
(To be supplied by Price Maker Generator Units)

	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
Composite TSO Load Forecasts	**311**	**368**	**428**
Less			
Unit 5 (predictable price taker nomination)	15	15	15
Unit 6 (variable price taker nomination – non-wind)	8	5	5
Unit 7 (variable price-taker forecast - wind)	2	2	2
Unit 8 (autonomous generator forecast - wind)	6	6	6
Total Price Taker Nominations & Wind Unit Forecasts	31	28	28
Ex-Ante Generation Requirement to be met by Price Makers	**280**	**340**	**400**

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B. SETTLEMENT SECTION

The real problem involves solving a Unit Commitment

- Not just a question of determining an optimal schedule given a "merit order" (or list of bids in order of increasing price), but a problem of determining the optimal cost mix of generators, interconnector units and demand side units to consider in forming the merit order given there are costs of starting these units and keeping them available.

To keep it simple we assume:

- Units 1 and 2 are committed for all three periods and incur any associated start up costs.
- Units 3a and 3b are committed for the one period (Period 2) they are available – they have no start up or no load costs.
- Only Unit 4's commitment is determined in this example. This is an easier problem – given everything else is committed and Unit 4 has the highest bid price we will only commit Unit 4 if we have no other supply options.

Remember Unit 2 is energy limited to 120 MWh

- It is committed & has a minimum stable generation of 60 MW, meaning it must generate 30 MWh per period.
- Over three periods its minimum stable generation accounts for 90 MWh.
- It only has 30 MWh available to be scheduled above minimum load.
- We will see that the price in period 3 is the highest & all 30 MWh is scheduled then.
- Hence seemingly cheap Unit 2 bids are not scheduled in Periods 1 and 2.

- Generation Requirement = 280MW
- Units 1 and 2 are assumed to be committed so must cover their minimum stable generation (50 MW and 60 MW at any price)
- The interconnector units have no availability for this period.
- Unit 1's €10 & priority dispatch adjusted €20 bids scheduled next.
- We need 20 MW more to cover the demand.
- Unit 2 has the next cheapest bids, but Unit 2 is energy limited and makes more money in period 3.
- Hence Unit 1's €30 bid supplies the last 20 MW & sets the shadow price.
- Unit 4 is too expensive and is not needed.
  - Shadow Price is €30/MWh

Unit	Price	Incremental Quantity	MSQ	Cumulative MSQ
1	Any	50	50	50
2	Any	60	60	110
1	10	50	50	160
1	19.999	100	100	260
2	20.001	40	0	260
2	25	100	0	260
1	30	50	20	280
4	120	100	0	280
			TOTAL	280

- Generation Requirement = 340MW
- Units 1 and 2 are assumed to be committed so must cover their minimum stable generation (50 MW and 60 MW at any price)
- Units 3a and 3b are assumed to be committed so will provide their maximum export at any price (-40 MW and -60 MW)
- We continue up the merit order skipping Unit 2 again because of its energy limit.
- Units 1 and 3a are scheduled to capacity while Unit 3b has 50 MW scheduled beyond its maximum export implying a net flow of -10 MW.
- Unit 4 is too expensive and is not needed.
  - Shadow Price is €55/MWh

Unit	Price	Incremental Quantity	MSQ	Cumulative MSQ
1	Any	50	50	50
2	Any	60	60	110
3a	Any	-40	-40	70
3b	Any	-60	-60	10
3a	5	20	20	30
1	10	50	50	80
1	19.999	100	100	180
2	20.001	40	0	180
2	25	100	0	180
1	30	50	50	230
3a	40	40	40	270
3a	50	20	20	290
3b	55	60	50	340
3b	65	60	0	340
4	120	100	0	340
			TOTAL	340

- Generation Requirement = 400MW
- Units 1 and 2 are assumed to be committed so must cover their minimum stable generation (50 MW and 60 MW at any price)
- The interconnector units have no availability for this period.
- Unit 1's €10 & priority dispatch adjusted €20 bids scheduled next.
- Unit 2 provides all its 30 MWh of available energy in this period by supplying 60 MW for 30 minutes.
- We still need to cover 80 MW of load, so must commit Unit 4, incurring its start-up cost of €500. The bid price of Unit 4 sets the price in this period.

- Shadow Price is €120/MWh

Unit	Price	Incremental Quantity	MSQ	Cumulative MSQ
1	Any	50	50	50
2	Any	60	60	110
1	10	50	50	160
1	19.999	100	100	260
2	20.001	40	40	300
2	25	100	20	320
4	120	100	80	400
			TOTAL	400

Period	1	2	3
Shadow Price (€/MWh)	30	55	120

Unit	Period 1 MSQ (MW)	Period 2 MSQ (MW)	Period 3 MSQ (MW)
1	220	250	200
2	60	60	120
3a	0	40	0
3b	0	-10	0
4	0	0	80

- The IMS and EPUS do not incorporate start-up, shut-down or no-load costs into the shadow price calculation.
  - *The shadow price only reflects the cost of supplying an infinitesimal change in demand.*
- As a result, situations can arise where Units do not recover their "full" costs over a continuous period of running.
- An SMP price is defined which
  - Cannot be less than the shadow price
  - Aims to recover the bid related costs, the no load cost and a proportion of the start-up costs over the period the unit runs.
    - Cannot guarantee this in all circumstances, e.g
      - if to recover all costs would imply an SMP price above the market price cap.
      - if the unit carries on operating into the next day then only some of its start-up costs will be apportioned to the current day.
- An SMP price each trading period in the trading day is determined as part of each run of the UUC software
- The following slides illustrates the concept, showing
  - a Unit that recovers its costs based on the shadow price.
  - a Unit that can only recover its costs if a higher SMP is set

Ä A Start-Up cost for Unit 1 = €1000 is incurred at the start of the day.

Period	1	2	3
Status	ON	ON	ON
No load	25	25	25
Schedule Quantities (MSQ) in MW	220	250	200
Running Cost (a function of P and Q)	1800	2250	1500
Start up cost pro-rated by MSQ	328.358	373.134	298.508
Per period cost (Total)	2153.358	2648.134	1823.508
Schedule Quantities in MWh	110	125	100
Shadow price (€/MWh)	30	55	120
Earnings at shadow price	3300	6875	12000

- Ä Unit 1 recovers its costs in each period
- Ä Earnings=MSQ * Shadow Price
- Ä Hence the unit recovers its costs at the Shadow Price and makes a profit. Any higher SMP will just increase the units profit.

Running Cost =

Quantity (MWh)	Bid Price	Cost
100/2 = 50	10	500
100/2 = 50	20	1000
20/2 = 10	30	300
Total Running Cost		1800

- Unit 2 has no start up or no load costs and has not been forced to run uneconomically by any constraint. Hence it will recover its costs based on the shadow price.
  - While Unit 2 has an energy limit, this only restricts the degree to which it can run, it does not force it to run.

- Units 3a and 3b are interconnectors, and have no start up or no load costs. They are not considered in the calculation of SMP prices.

- Findings for units thus far suggest that SMP could equal shadow price in all periods. However, the situation for Unit 4 may change this…

Ä A Start-Up cost for Unit 4 = €500 is incurred in that one period it operates.

Period	1	2	3
Status	OFF	OFF	ON
No load	0	0	0
Schedule Quantities (MSQ) in MW	0	0	80
Running Cost (a function of P and Q)	0	0	4800
Start up cost pro-rated by MSQ	0	0	500
Per period cost (Total)	0	0	5300
Schedule Quantities in MWh	0	0	40
Shadow price (€/MWh)	30	55	120
Earnings at shadow price	0	0	4800

- Ä Unit 4 does not recover its fuel costs
- Ä For period 3, SMP must be set to at least:
  €120/MWh * (5300/4800) = €132.5/MWh
- Ä SMP at this level ensures that Unit 4 breaks even, but this same price applies to all units.
- Ä While this is the correct SMP value, the method we have used is a simplification.

Running Cost =

Quantity (MWh)	Bid Price	Cost
80/2 = 40	120	4800
Total Running Cost		4800

A. BID SECTION

1. Setting the Scene

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B. SETTLEMENT SECTION

- The Moyle Interconnector Trading System (MITS) determines modified interconnector user nominations (MIUNs)
  - MIUNs are effectively the interconnector capacity available to each interconnector user in real-time.

- MITS essentially allocates the total flows on the interconnector between the interconnector units in proportion to their right holdings.

- In this example there is no ramp restriction on the interconnector and MITS does not change the solution.

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
3a	0	40	0
3b	0	-10	0
TOTAL	0	30	0

Ä Real-time scheduling is performed by operators assisted by the Reserve Constrained Unit Commitment (RCUC) model.

Period 1: Demand lower than expected so Unit 1 backed off.

Period 2: Demand *lower* than expected so Unit 1 backs off. Plus a transmission constraint limits Unit 1's output, shifting output to Unit 4.

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
1	220 194	250 212	200
2	60	60	120
3a	0	40	0
3b	0	-10	0
4	0	0 20	80 92

IMS Schedule
Dispatch Schedule

Period 3: Demand higher than expected

- Dispatch instructions are instructions to move to a specific output in a specific time.
- The market systems include an Instruction Profiling function that converts these instructions into an average MW dispatch instruction quantity per trading interval
- Note that while we have shown all price makers here:
  - Interconnector "dispatch values" are just their MIUN values
  - Demand side unit dispatch quantities are used as their metered quantities.

Dispatch Schedule

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
1	194	212	200
2	60	60	120
3a	0	40	0
3b	0	-10	0
4	0	20	92

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B. SETTLEMENT SECTION

Unit	Period 1 (MWh)	Period 2 (MWh)	Period 3 (MWh)
1 (predictable price maker)	92	106	95
2 (variable price maker)	35	30	65
3a (predictable price maker)	0	20	0
3b (predictable price maker)	0	-5	0
4 (predictable price maker)	0	10	46
5 (predictable price taker)	7	7.5	7.5
6 (variable price taker, non-wind)	4	3	2.5
7 (variable price taker, wind)	1	1	1
8 (autonomous generator)	2.5	3	3
TOTALS	141.5	175.5	220

Note that Unit 2 had an energy limit of 120 MWh but actually produced 130 MWh (i.e. it exceeded both its dispatch instructions and its energy limit)

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
1 (predictable price maker)	184	212	190
2 (variable price maker)	70	60	130
3a (predictable price maker)	0	40	0
3b (predictable price maker)	0	-10	0
4 (predictable price maker)	0	20	92
5 (predictable price taker)	14	15	15
6 (variable price taker, non-wind)	8	6	5
7 (variable price taker, wind)	2	2	2
8 (autonomous generator)	5	6	6
TOTALS	283	351	440

The MWh to MW conversion is done by simply doubling the half hour meter quantity.

Period 1: Unit 1 supplies less than it was supposed to, but Unit 2 supplies more.

Period 3: Unit 1 supplies less than it was suppose to, but Unit 2 supplies more.

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
1	220 194 184	250 212	200 190
2	60 70	60	120 130
3a	0	40	0
3b	0	-10	0
4	0	0 20	80 92

In settlements, the non-compliance in each period is discouraged by charging Unit 1 an "imbalance price" greater than the market price for its 10 MW shortfall, while paying Unit 2 an "imbalance price" less than the market price for its 10 MW supply.

IMS Schedule
Dispatch Schedule
Metered Schedule

Note: Only results that differ from expectation are shown.

Ä For settlement purposes, the price taker meter data is used as their dispatch instructions.

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
5	15 14	15 15	15 15
6	8 8	5 6	5 5
7	2 2	2 2	2 2
8	6 5	6 6	6 6

Ex Ante Forecasts/Nominations

Dispatch Schedule = Metered Schedule

Unit	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
1 (predictable price maker)	194	212	200
2 (variable price maker)	60	60	120
3a (predictable price maker)	0	40	0
3b (predictable price maker)	0	-10	0
4 (predictable price maker)	0	20	92
5 (predictable price taker)	14	15	15
6 (variable price taker, non-wind)	8	6	5
7 (variable price taker, wind)	2	2	2
8 (autonomous generator)	5	6	6
TOTAL	283	351	440

- Supplier Unit metering is not used in the pricing and scheduling process.

- It only becomes available to the Single Market Operator after all scheduling has been completed and is only used in Settlement .

Unit	Period 1 (MWh)	Period 2 (MWh)	Period 3 (MWh)
Supplier Unit 1	-100	-140	-180
Supplier Unit 2	-35	-32	-37

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B. SETTLEMENT SECTION

- There are two ex post schedules
  - Indicative produced on day D+1
    - Uses some approximate data where no meter data is available.
  - Initial produced on day D+4
    - All data available.

- The Generator Requirements in these runs only make use of meter data for Generators.
  - Demand-side meter data is only required for settlement

- In this example we assume that we are running an Initial Ex Post Schedule

- All that is different for an indicative Ex Post Schedule is the source of some of the data.

THIS DATA

(There has been no change relative to the IMS run)

Start-up Cost per start (€)	1,000	No Load Cost (€/hour)	50

Price (€/MWh)	Quantity (MW)
10	100
20	200
30	300

Trading Period	1	2	3
Actual Availability (MW)	250	250	200
Actual Min Stable Generation (MW)	50	50	50
Actual Min Output (MW)	0	0	0

Energy Limit (MWh)	N/A	Periods	N/A	N/A	N/A

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	50	Any	50	Any	50
10	50	10	50	10	50
20	100	20	100	20	100
30	50	30	50		

Start-up Cost per start (€)	1,000	No Load Cost (€/period)	25	Energy Limit (MWh)	N/A

THIS DATA (Energy Limit increased to reflect higher meter data, while availability in period 2 decreased)

Start-up Cost per start (€)	0	No Load Cost (€/hour)	0

Price (€/MWh)	Quantity (MW)
10	50
20	100
25	200

Trading Period	1	2	3
Actual Availability (MW)	200	190	200
Actual Min Stable Generation (MW)	60	60	60
Actual Min Output (MW)	0	0	0

Energy Limit (MWh)	130	Periods	ü	ü	ü

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	60	Any	60	Any	60
20	40	20	40	20	40
25	100	25	90	25	100
Energy Limited Period		Energy Limited Period		Energy Limited Period	

Start-up Cost per start (€)	0	No Load Cost (€/period)	0	Energy Limit (MWh)	130

(The treatment of MIUN changes the input to the UUC)

THIS DATA

Period 1

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Period 2

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Period 3

Price (€/MWh)	Quantity (MW)
5	-20
40	20
50	40

Ex ante, unit could be scheduled between -40 and +40, but now it is limited to a range between 0 and its MIUN value of 40.

Trading Period	1	2	3
MIUN	0	+40	0
Max Capacity = Max(0, MIUN) (MW)	0	+40	0
Min Capacity = Min(0, MIUN) (MW)	0	0	0

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
0	0	Any	0	0	0
		40	20		
		50	20		
					59

(The treatment of MIUN changes the input to the UUC)

THIS DATA

Period 1

Price (€/MWh)	Quantity (MW)
55	0
65	60

Period 2

Price (€/MWh)	Quantity (MW)
55	0
65	60

Period 3

Price (€/MWh)	Quantity (MW)
55	0
65	60

Ex ante, unit could be scheduled between -60 and +60, but now it is limited to a range between 0 and its MIUN value of -10 MW.

Trading Period	1	2	3
MIUN	0	-10	0
Max Capacity = Max(0, MIUN) (MW)	0	0	0
Min Capacity = Min(0, MIUN) (MW)	0	-10	0

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
0	0	Any	-10	0	0
		55	10		
					60

THIS PARTICIPANT DATA

(There has been no change relative to the IMS run)

Shut Down Cost per stop (€)	500	No Load Cost (€/hour)	N/A

Price (€/MWh)	Quantity (MW)
120	100

Trading Period	1	2	3
Actual Availability (MW)	100	100	100
Actual Min Stable Generation (MW)	0	0	0
Actual Min Output (MW)	0	0	0

Energy Limit (MWh)	N/A	Periods	N/A	N/A	N/A

IMPLIES THIS UUC INPUT

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
120	100	120	100	120	100

Start-up Cost per start (€)	500	No Load Cost (€/period)	0	Energy Limit (MWh)	N/A

UNIT 1 DATA WITH PRIORITY DISPATCH

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	50	Any	50	Any	50
10	50	10	50	10	50
19.999	100	*19.999*	100	*19.999*	100
30	50	30	50		

Start-up Cost per start (€)	1,000	No Load Cost (€/period)	25	Energy Limit (MWh)	N/A

UNIT 2 DATA WITHOUT PRIORITY DISPATCH

Period 1		Period 2		Period 3	
Price	Inc Quantity	Price	Inc Quantity	Price	Inc Quantity
Any	60	Any	60	Any	60
20.001	40	*20.001*	40	*20.001*	40
25	100	25	90	25	100
Energy Limited Period		Energy Limited Period		Energy Limited Period	

Start-up Cost per start (€)	0	No Load Cost (€/period)	0	Energy Limit (MWh)	130

A. BID SECTION

1. Setting the Scene

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B. SETTLEMENT SECTION

Ex Post Generation Requirement

	MW
Meter Generation Price Maker Units	A
Plus Meter Generation I/C Units	B
Plus Meter Generation Demand Side Units	C
Plus Load Shedding Estimate	D
Plus DQ for Interconnector Residual Capacity Unit*	E
Minus Constrained Up/Down for Price Takers	F
Ex Post Generation Requirement	A+B+C+D+E-F

*** This is effectively the inter-jurisdictional trade across the interconnector. We assume this is 0 MW.**

	Period 1	Period 2	Period 3
Metered Price Maker Generation (non DSU/IU)			
Unit 1	184	212	190
Unit 2	70	60	130
Total (A)	254	272	320
Metered IU Generation (Calculated)			
Unit 3a	0	40	0
Unit 3b	0	-10	0
Total (B)	0	30	0
Metered DSU Generation (Calculated)			
Unit 4	0	20	92
Total (C)	0	20	92
Load Shedding Estimate (D)	0	0	0
Dispatch Quantity for Interconnector Residual Capacity Unit (E)	0	0	0

All measurements in MW.

Sum of Price-Taker differences (Nomination/Availability Profile-Metered)	Period 1	Period 2	Period 3
Unit 5 (Predictable Price Taker) Nomination			
Nom Profile	15	15	15
Meter	14	15	15
Difference	1	0	0
Unit 6 (Variable Price Taker, Non-Wind) Nomination			
Nom Profile	8	5	5
Meter	8	6	5
Difference	0	-1	0
Unit 7 (Variable Price Taker, Wind) Forecast			
Availability Profile	2	2	2
Meter	2	2	2
Total	0	0	0
Sum of Differences (F)	1	-1	0

All measurements in MW.

Unit 8 is not included. It is an autonomous unit and as such there is no expectation that it will comply with any specific schedule level.

	Period 1	Period 2	Period 3
Metered Price Maker Generation (non DSU/IU) (A)	254	272	320
plus Metered IU Generation (B)	0	30	0
plus Metered DSU Generation (C)	0	20	92
plus Load Shedding Estimate (D)	0	0	0
plus Dispatch Quantity for Residual I/C Unit (E)	0	0	0
Less Sum of Price Taker differences (Nom Profile/Avail-Metered) (F)	-1	1	0
Ex-Post Generation Requirement (MW)	253	323	412
Ex-Ante Generation Requirement	*280*	*340*	*400*

All measurements in MW.

In period 1 the ex post generation requirement of 253 MW reflects:

- 254 MW of metered price maker generation
- Less 1 MW because price taker Unit 5 provided 1 MW less than it nominated. This is assumed to be due to a constraint, so that 1 MW should have been provided by Unit 5, not the price maker units.

In period 2 the ex post generation requirement of 323 MW reflects:

- 272+30+20 = 322 MW of metered price maker generation
- Plus 1 MW because price taker Unit 6 provided 1 MW more than it nominated. This is assumed to be due to a constraint, so that 1 MW should have been provided by price maker units, not Unit 6.

A. BID SECTION

1. Setting the Scene

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3. Ex Ante Generation Requirement

4. Ex Ante UUC Solution

5. Interconnectors & Dispatch Schedules

6. Meter Data

7. Ex Post Processing of Bids

8. Ex Post Generation Requirement

9. Ex Post UUC Solution

B. SETTLEMENT SECTION

- Generation Requirement = 253MW
- Units 1 and 2 are assumed to be committed so must cover their minimum stable generation (50 MW and 60 MW at any price)
- The interconnector units have no availability for this period.
- Unit 1's €10 bid is scheduled next.
- Unit 1's priority dispatch adjusted €20 bid supplies the last 93 MW required and sets the price.
- The remaining bids are too expensive.
- Note that the tie between bids from Units 1 and 2 has been resolved in favour of the unit with priority dispatch.

Unit	Price	Incremental Quantity	MSQ	Cumulative MSQ
1	Any	50	50	50
2	Any	60	60	110
1	10	50	50	160
1	19.999	100	93	253
2	20.001	40	0	253
2	25	100	0	253
1	30	50	0	253
4	120	100	0	253
			TOTAL	253

- Shadow Price is €20/MWh

- Generation Requirement = 323MW
- Units 1 and 2 are assumed to be committed so must cover their minimum stable generation (50 MW and 60 MW at any price)
- Units 3a and 3b are assumed to be committed so will provide their maximum export at any price (0 MW and -10 MW)
- We continue up the merit order skipping Unit 2 because of its energy limit which will have it scheduled in period 3.
- Unit 1 is scheduled to capacity.
- Unit 3a's €40 bid and part of its €50 bid are scheduled before the load is covered.
  - Shadow Price is €50/MWh

Unit	Price	Incremental Quantity	MSQ	Cumulative MSQ
1	Any	50	50	50
2	Any	60	60	110
3a	Any	0	0	110
3b	Any	-10	-10	100
1	10	50	50	150
1	19.999	100	100	250
2	20.001	40	0	250
2	25	90	0	250
1	30	50	50	300
3a	40	20	20	320
3a	50	20	3	323
3b	55	10	0	323
4	120	100	0	323
			TOTAL	323

- Generation Requirement = 412MW
- Units 1 and 2 are assumed to be committed so must cover their minimum stable generation (50 MW and 60 MW at any price)
- The interconnector units have no availability for this period.
- Unit 1's €10 & priority dispatch adjusted €20 bids scheduled next.
- Unit 2 provides all its 40 MWh of available energy in this period by supplying 80 MW for 30 minutes.
- We still need to cover 72 MW of load, so must commit Unit 4, incurring its start-up cost of €500. The bid price of Unit 4 sets the price in this period.

- Shadow Price is €120/MWh

Unit	Price	Incremental Quantity	MSQ	Cumulative MSQ
1	Any	50	50	50
2	Any	60	60	110
1	10	50	50	160
1	19.999	100	100	260
2	20.001	40	40	300
2	25	100	40	340
4	120	100	72	412
			TOTAL	412

Period	1	2	3
Ex Post Shadow Price (€/MWh)	20	50	120
Ex Ante Shadow Price (€/MWh)	*30*	*55*	*120*

Unit	Period 1 MSQ (MW)	Period 2 MSQ (MW)	Period 3 MSQ (MW)
1	193	250	200
2	60	60	140
3a	0	23	0
3b	0	-10	0
4	0	0	72

Ä A Start-Up cost for Unit 1 = €1000 is incurred at the start of the day.

Period	1	2	3
Status	ON	ON	ON
No load	25	25	25
Schedule Quantities (MSQ) in MW	193	250	200
Running Cost (a function of P and Q)	1430	2250	1500
Start up cost pro-rated by MSQ	300.155	388.803	311.042
Per period cost (Total)	1755.155	2663.803	1836.042
Schedule Quantities in MWh	96.5	125	100
Shadow price (€/MWh)	20	50	120
Earnings at shadow price	1930	6250	12000

- Ä Unit 1 recovers its costs in each period
- Ä Earnings=MSQ * Shadow Price
- Ä Hence the unit recovers its costs at the Shadow Price and makes a profit. Any higher SMP will just increase the units profit.

Running Cost =

Quantity (MWh)	Bid Price	Cost
100/2 = 50	10	500
93/2 = 46.5	20	930
Total Running Cost		1430

Ä A Start-Up cost for Unit 4 = €500 is incurred in that one period it operates.

Period	1	2	3
Status	OFF	OFF	ON
No load	0	0	0
Schedule Quantities (MSQ) in MW	0	0	72
Running Cost (a function of P and Q)	0	0	4320
Start up cost pro-rated by MSQ	0	0	500
Per period cost (Total)	0	0	4820
Schedule Quantities in MWh	0	0	36
Shadow price (€/MWh)	30	55	120
Earnings at shadow price	0	0	4320

- Ä Unit 4 does not recover its fuel costs
- Ä For period 3, SMP must be set to at least:
  €120/MWh * (4820/4320) = €133.89/MWh
- Ä SMP at this level ensures that Unit 4 breaks even, but this same price applies to all units.

Running Cost =

Quantity (MWh)	Bid Price	Cost
72/2 = 36	120	4320
Total Running Cost		4320

Period	1	2	3
Ex Post SMP (€/MWh)	20	50	133.89
Ex Ante SMP (€/MWh)	*30*	*55*	*132.5*

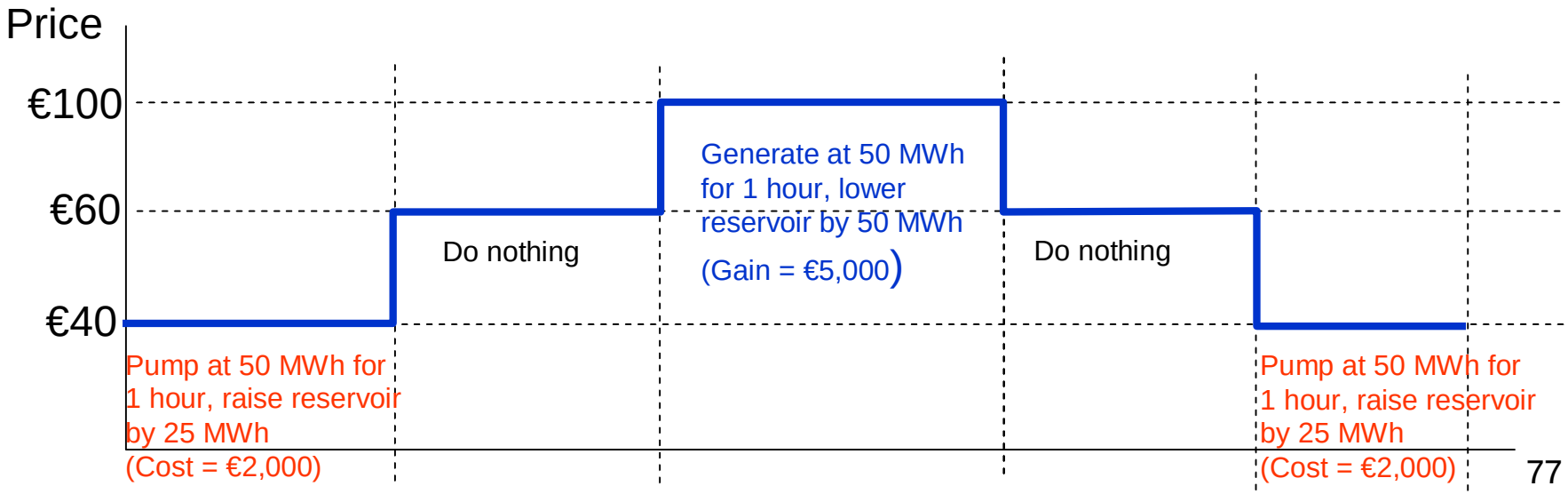
Unit	Ex Ante Schedule (MW)	DSQ (MW)	Meter Schedule (MW)	Ex Post Schedule (MW)
1 (predictable price maker)	250	212	212	250
2 (variable price maker)	60	60	60	60
3a (predictable price maker)	40	40	40	23
3b (predictable price maker)	-10	-10	-10	-10
4 (predictable price maker)	0	20	20	0
5 (predictable price taker)	15	15	15	15
6 (variable price taker, non-wind)	5	6	6	6
7 (variable price taker, wind)	2	2	2	2
8 (autonomous generator)	6	6	6	6
TOTAL	368	351	351	352

→ Changes due to constraints and lower demand than forecast

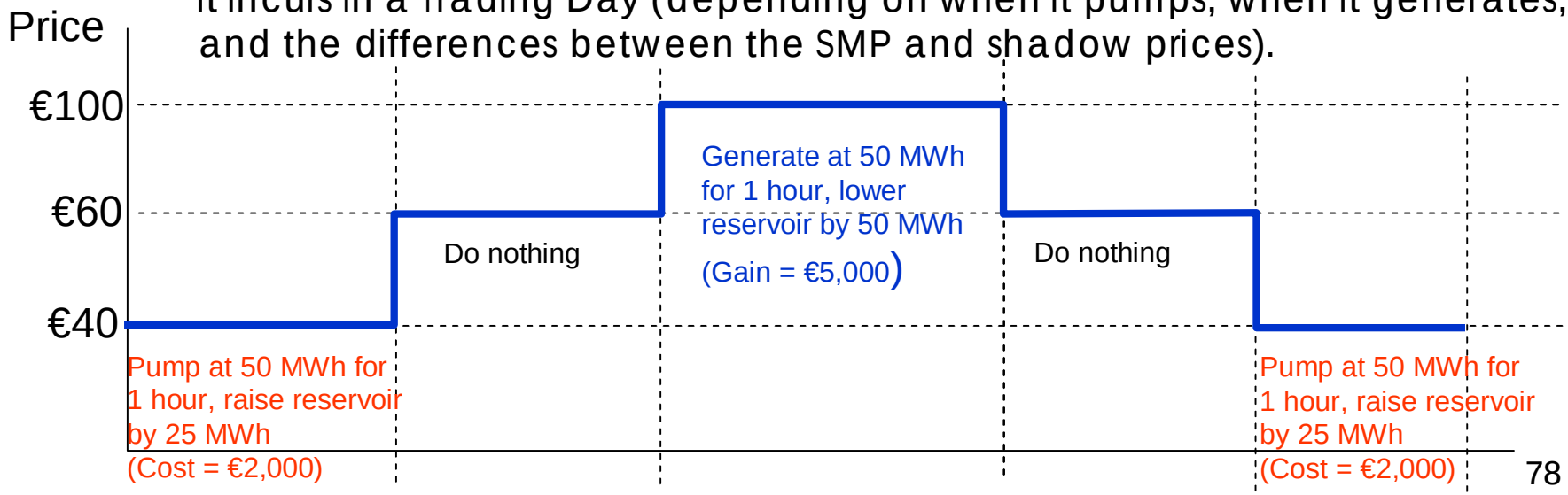
→ Changes due to 1 MW over-supply by price takers. Unit 3A now supplies that 1 MW so it is priced.

→ Changes due to re-optimising schedule with different interconnector limits.

- We have not considered these so far due to the complexity of the inter-temporal relationships.
  - Our pump storage unit which can pump at 50 MW or generate at 50 MW
  - 1 MWh of pumping raises reservoir by 0.5 MWh
  - 1 MWh of generation lowers reservoir by 1 MWh
  - In this example, no net change in reservoir level is allowed over the day.
- In this example we assume some shadow prices to illustrate how the unit is scheduled (note the they are settled based on SMP prices)



- Note that the unit cannot make money by pumping at €40 and generating at €60, or by pumping at €60 and generating at €100 because it must pump 2 MWh for each 1 MWh it generates. This is not profitable at these prices.
- It will only generate or pump at €60 if the reservoir level is forced to increase or fall over the day (due to end of day targets) of if some other constraint applies to it.
- Total gain over day at the shadow price is €1000
  - But this is based on the shadow prices over the optimisation horizon
  - Actually settled on SMP prices, and only settled for first 24 hours.
  - A pump storage unit may under-recover or over-recover the pumping costs it incurs in a Trading Day (depending on when it pumps, when it generates, and the differences between the SMP and shadow prices).



A. BID SECTION

B. SETTLEMENT SECTION

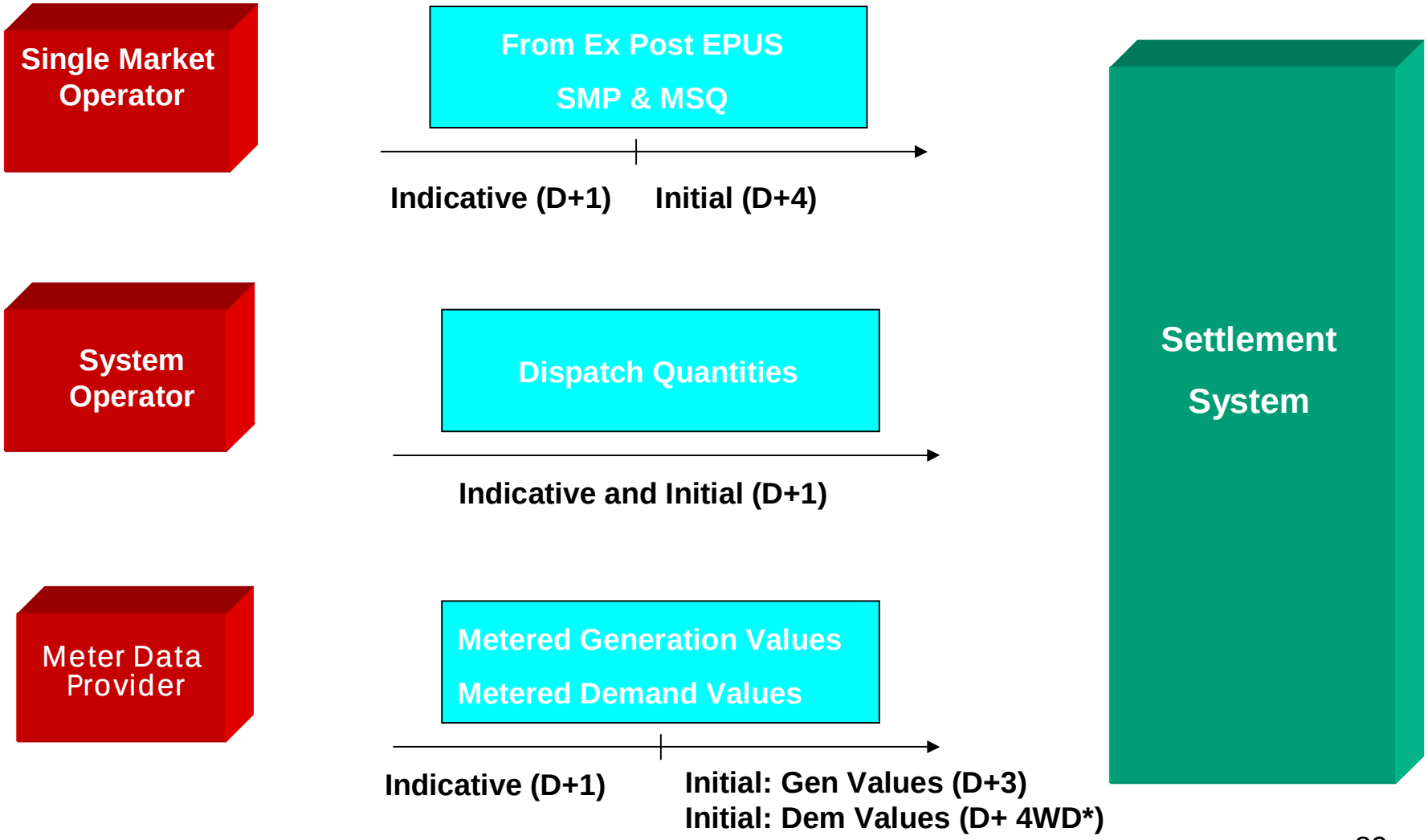
1. Introduction

2. Energy Payments and Charges

3. Capacity Payments and Charges

4. Market Operator Charges

5. Payment Timeline



*WD = Working Days

- Settlement Statements
  - Issued on the same days as Indicative and Initial Settlement Runs
  - Issued electronically
  - Has settlement data by Trading Period by Generating Unit / Supplier Unit
  - Most of the details shown in our example are at the level of detail that would appear on Settlement Statements
  - Sign convention for payments and charges on Settlement Statements
    - A positive number is a positive payment to a participant by the SMO while a negative number is a positive payment by a participant to the SMO.

- Invoices
  - Issued less frequently, at the end of each Billing Period
  - Different types of invoices for different payments/charges
  - Issued electronically and by mail
  - Has aggregate total data for the Billing Period for all Generating Units and (on separate invoices) for all Supplier Units
  - Sign convention for payments and charges on Invoices
    - The reverse of Settlement Statements. A positive number is an amount owed to the SMO while a negative number is an amount owed by the SMO.)

- Transmission Loss Adjustment Factors
  - To keep things simple, these are all assumed to have values of 1.0
- Settlement Reallocation
  - One participant can re-allocate its settlement obligations to another participant. This option is ignored
- Simplified representation of Trading Sites
  - We ignore of complexities associated with Trading Sites
- Smaller set of Generating Units and Supplier Units
  - In examples we only consider Generator Units 1 & 2 and Supplier Units 1 & 2
  - All diagrams of invoices show Generator Unit 1 data or Supplier Unit 1 data, depending on the type of invoice.
- Where we use values not shown in the earlier scheduling examples, the numbers used are entirely made up and should NOT be viewed as representative of real values that might arise in the market.

A. BID SECTION

B. SETTLEMENT SECTION

1. Introduction

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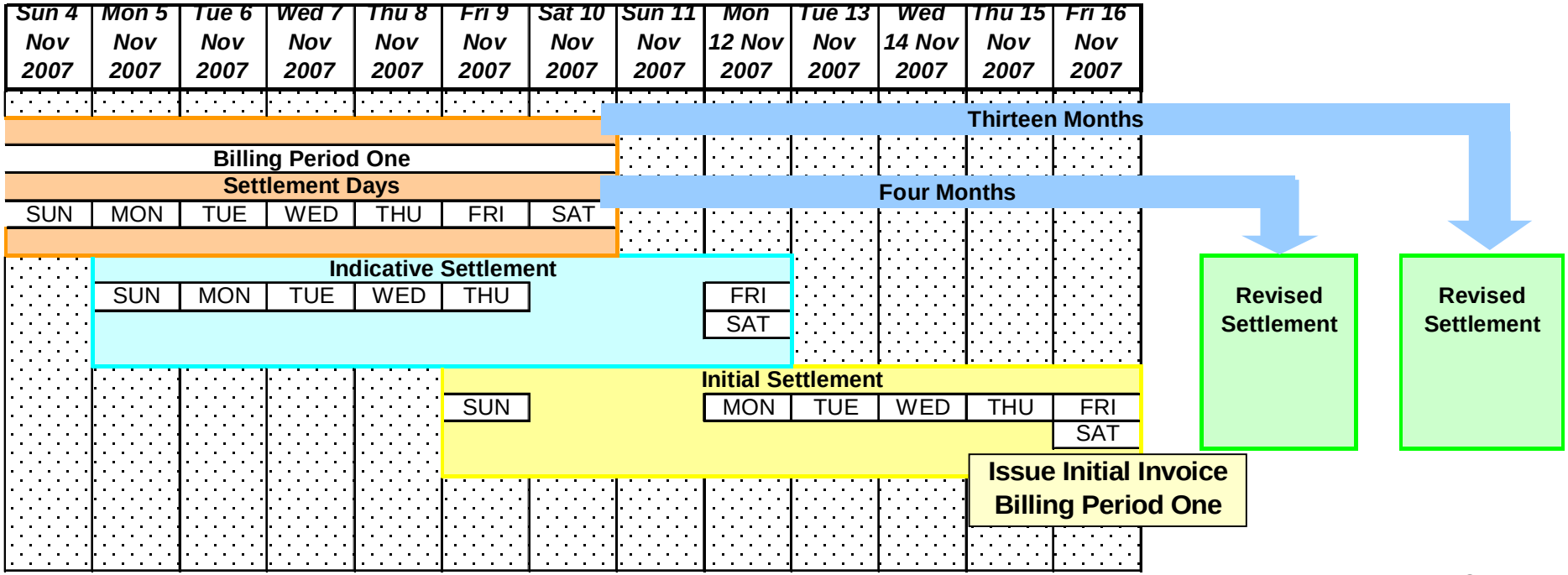
5. Payment Timeline

Timing of Indicative, Initial and Revised Settlement for a Billing Period

- A Settlement Day is calendar day which includes the last 6 hours of one Trading Day and the first 18 hours of the next.
- Indicative Settlement occurs 1 Working Day after the Settlement Day
- Initial Settlement occurs 5 Working Days after the Settlement Day
- A Billing Period is one week



From : Power Station Co
Baggot Street

Self Billing Invoice

PART 1232

To: Market Operator
42 Merrion Square

Date of Issue: 23/2/07
Due Date: 1/3/07
Billing Period: 7

Invoice 12
Settlement Type - Initial
Invoice Type - Energy

7654321

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
	Energy Payments	- 21,568.89	- 2,911.80	- 24,480.69
	Constraint Payments	560.00	75.60	635.60
	Uninstructed Imbalance Payments	3,037.45	410.06	3,447.51
	Total Invoice	- 17,971.44	- 2,426.14	- 20,397.58
	Settlement Reallocation(s)			
	Amount Due			- 20,397.58

From : Market Operator
42 Merrion Square

Invoice

PART 1232

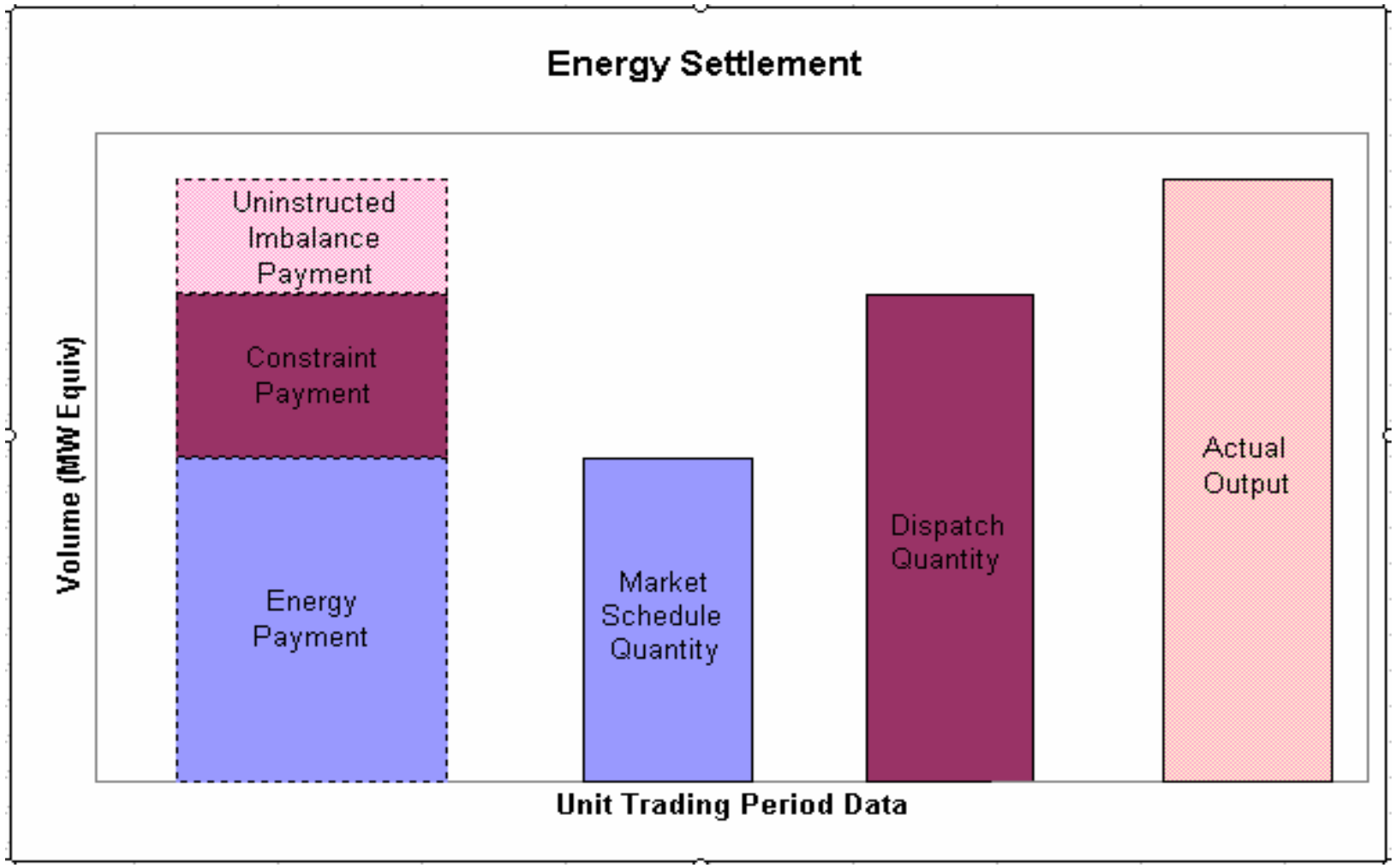
To: Supplier Co
Baggot Street

Date of Issue: 23/2/07
Due Date: 1/3/07
Billing Period: 7

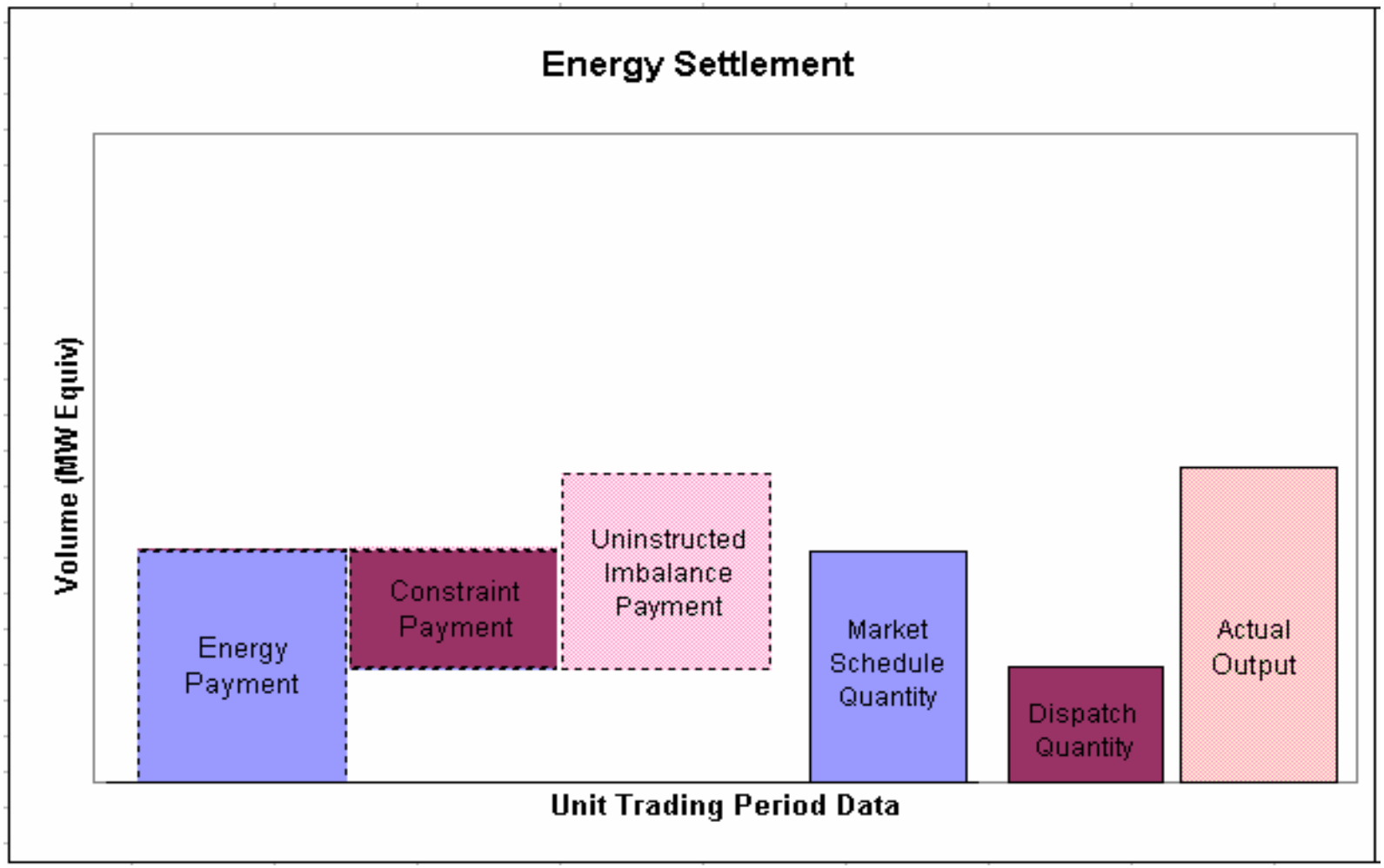
Invoice 12
Settlement Type - Initial
Invoice Type - Energy

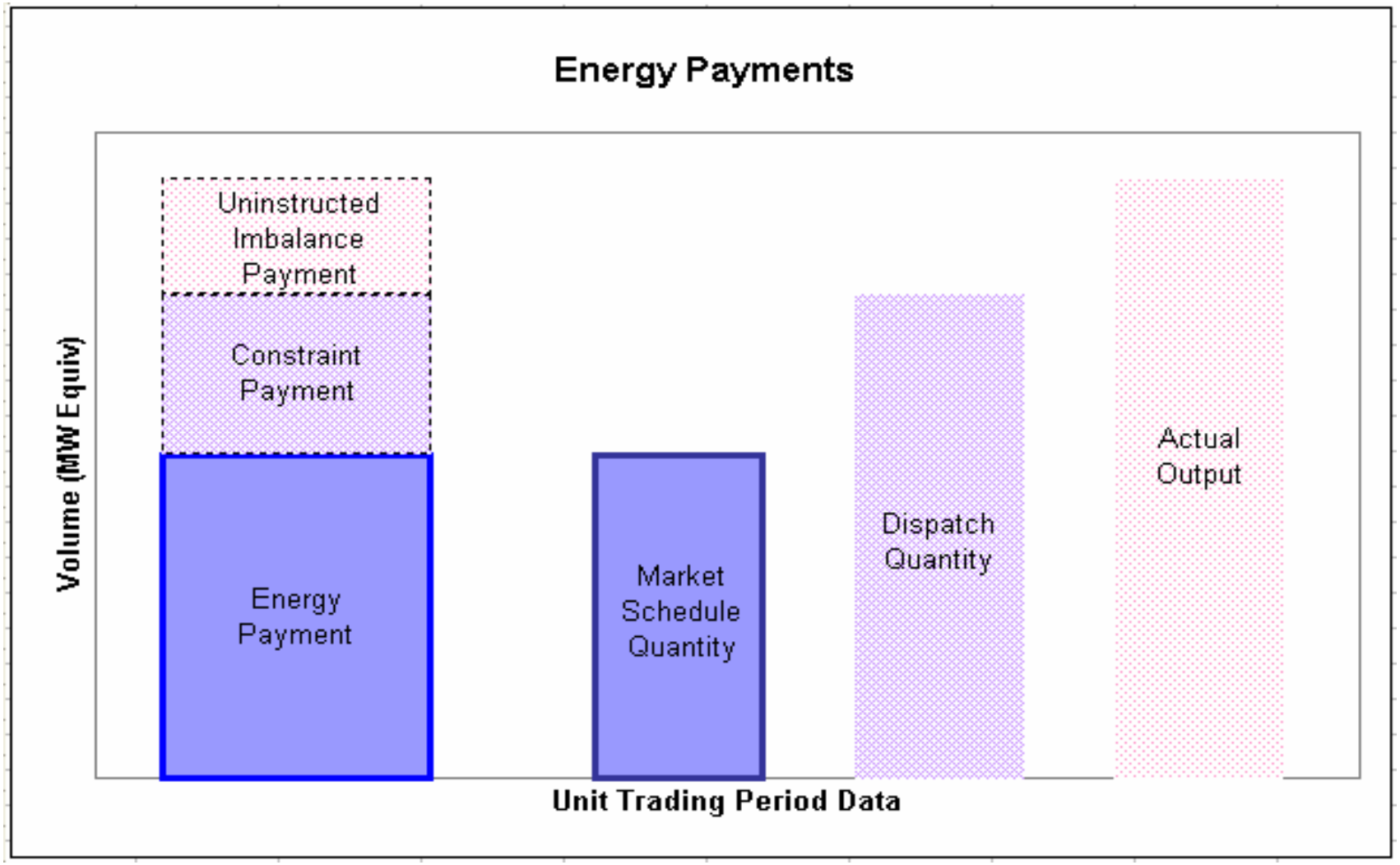
1234567

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
	Energy Charge	33,100.00	4,468.50	37,568.50
	Imperfections Charge	1,050.00	141.75	1,191.75
	Total Invoice	34,150.00	4,610.25	38,760.25
	Settlement Reallocation(s)			
	Amount Due			38,760.25


Energy Settlement
Uninstructed Imbalance Payment
Constraint Payment
Energy Payment
Market Schedule Quantity
Dispatch Quantity
Actual Output
Volume (MW Equiv)
Unit Trading Period Data

The purpose of this slide is to show that there are many permutations as to how Energy Payments, Constraint Payments and Uninstructed Imbalance Payments can interact.




Energy Payments
Uninstructed Imbalance Payment
Constraint Payment
Energy Payment
Market Schedule Quantity
Dispatch Quantity
Actual Output
Volume (MW Equiv)
Unit Trading Period Data

Energy Payment = 0.5 x Market Schedule Quantity x System Marginal Price

UNIT 1	Period 1
MSQ	193 MW
SMP	€20/MWh

The factor of 0.5 converts the Market Schedule Quantity from MW to MWh

Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
1	**1,930.00**	**6,250.00**	**13,388.89**
2	**600.00**	**1,500.00**	**9,372.22**

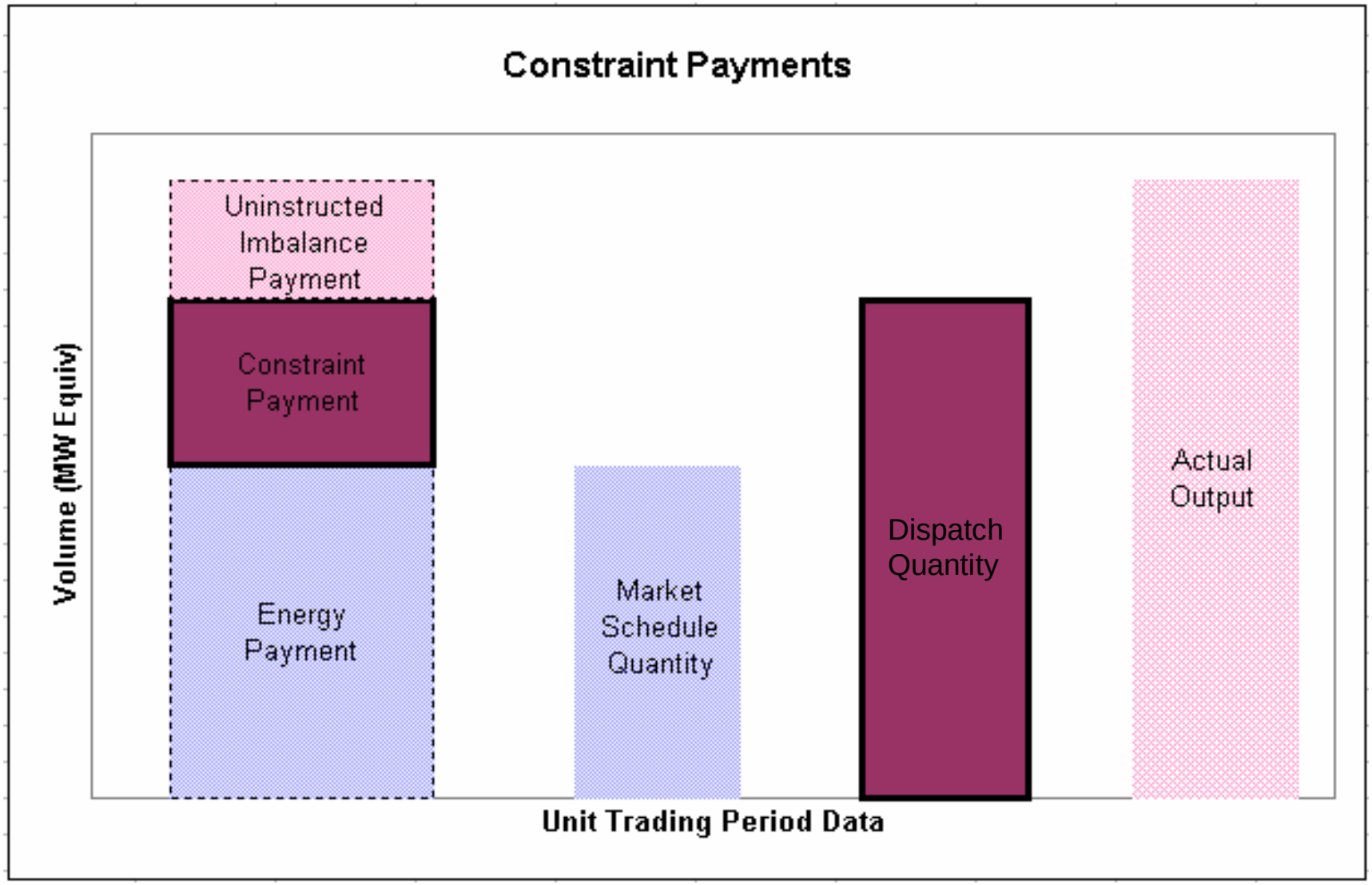
UNIT 2	Period 2
MSQ	60 MW
SMP	€50/MWh

Energy Charge = Net Demand x System Marginal Price

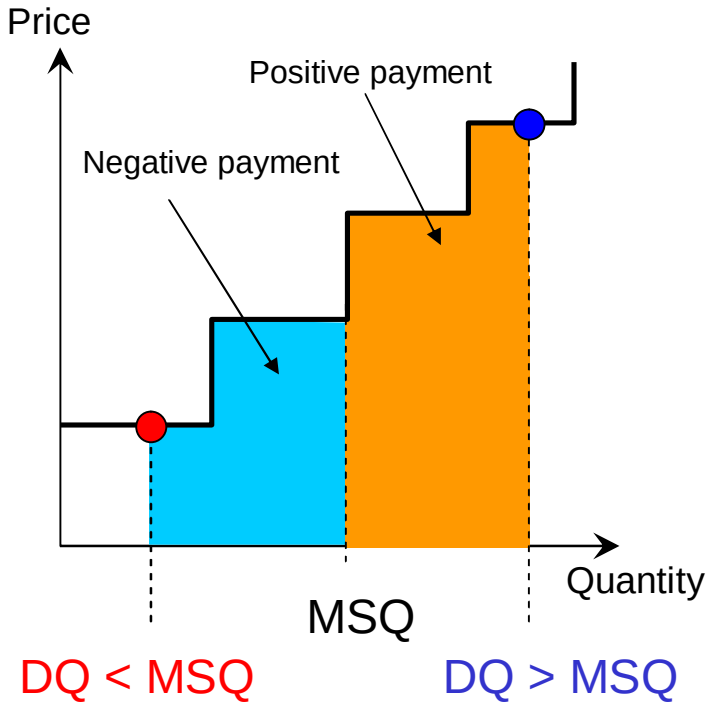
Net Demand is a MWh quantity reflecting the import of energy onto a Trading Site.

Supplier Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
Supplier Unit 1	-2,000.00	-7,000.00	-24,100.00
Supplier Unit 2	-700.00	-1,600.00	-4,953.89

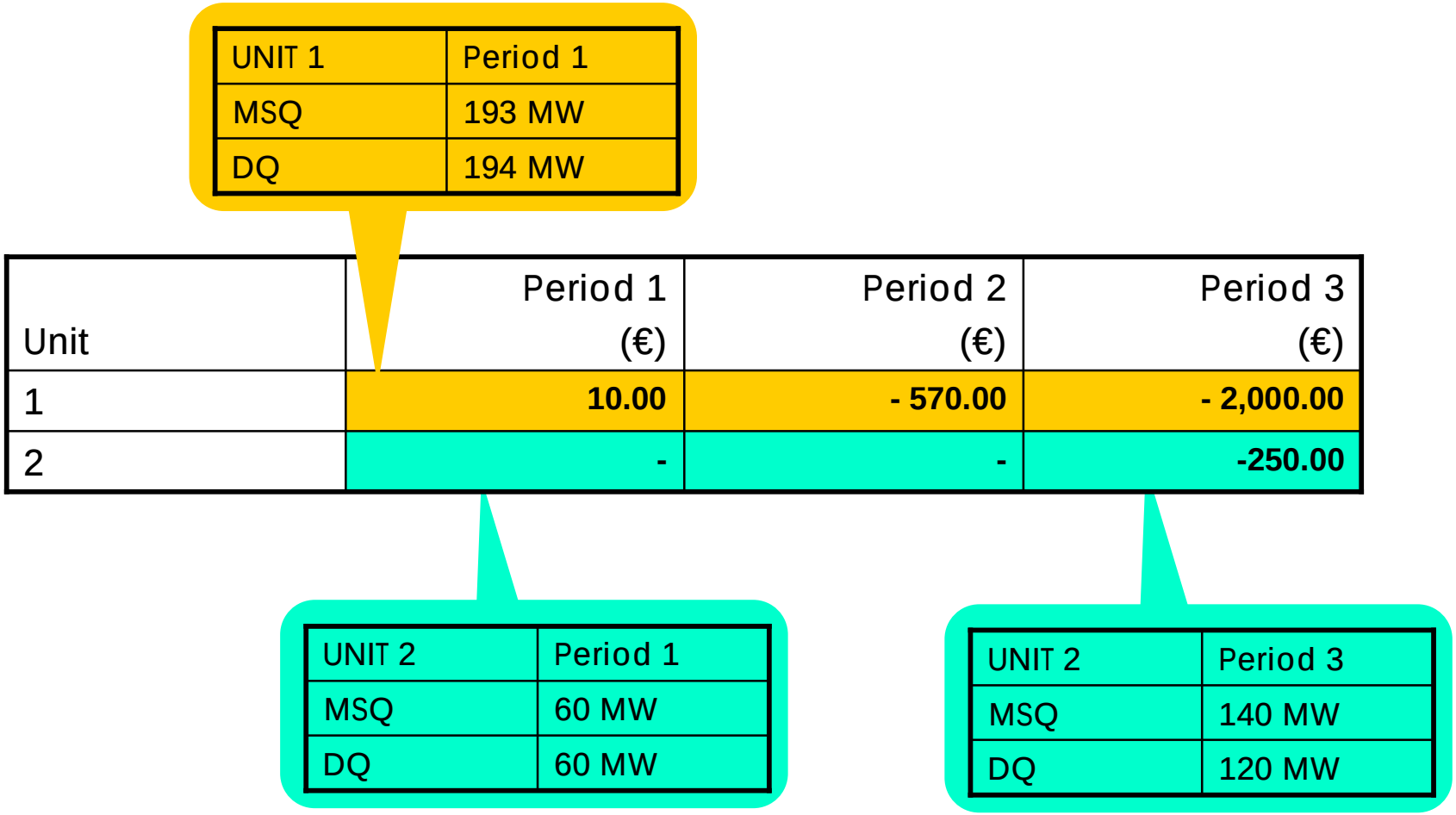
UNIT 1	Period 1
ND	-100 MWh
SMP	€20/MWh


Constraint Payments
Volume (MW Equiv)
Uninstructed Imbalance Payment
Constraint Payment
Energy Payment
Market Schedule Quantity
Dispatch Quantity
Actual Output
Unit Trading Period Data

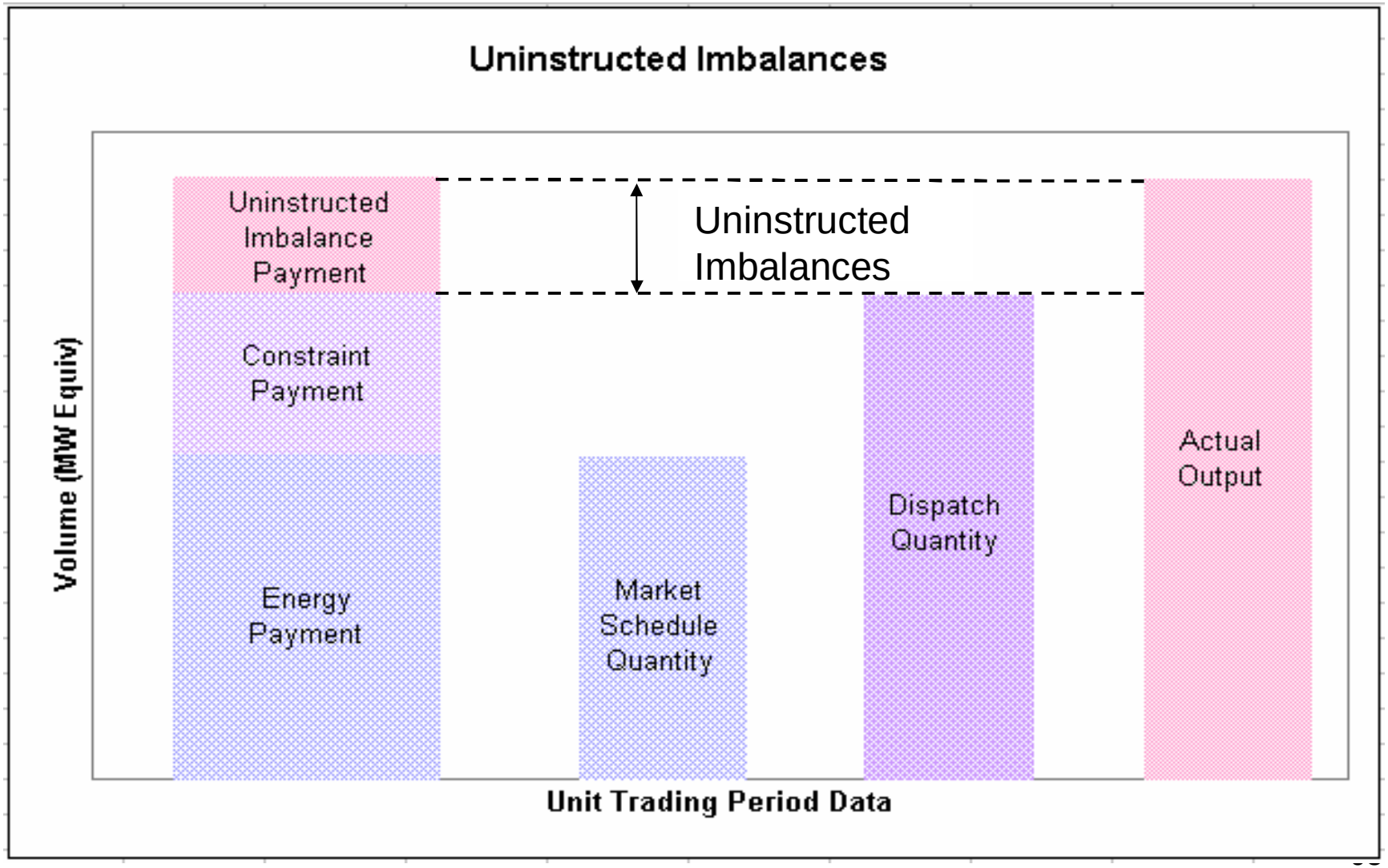
- Constraint Payment apply where the Dispatch Quantity differs from the Market Schedule Quantity in respect of a Generator Unit in a Trading Period.
- Constraint Payments compensate for additional costs incurred, or to eliminate compensation for costs not incurred.
- Constraint Payment can be positive or negative:
  - If DQ > MSQ, payment to Generator Unit
  - If DQ < MSQ, charge to Generator Unit
- Consideration for payment includes
  - Bid Price
  - Start cost
  - No load cost
- Price Takers do not get these Constraint Payments, but are compensated for constraints via Energy Payments and Uninstructed Balance Payments.
- Autonomous generators do not get Constraint Payments.



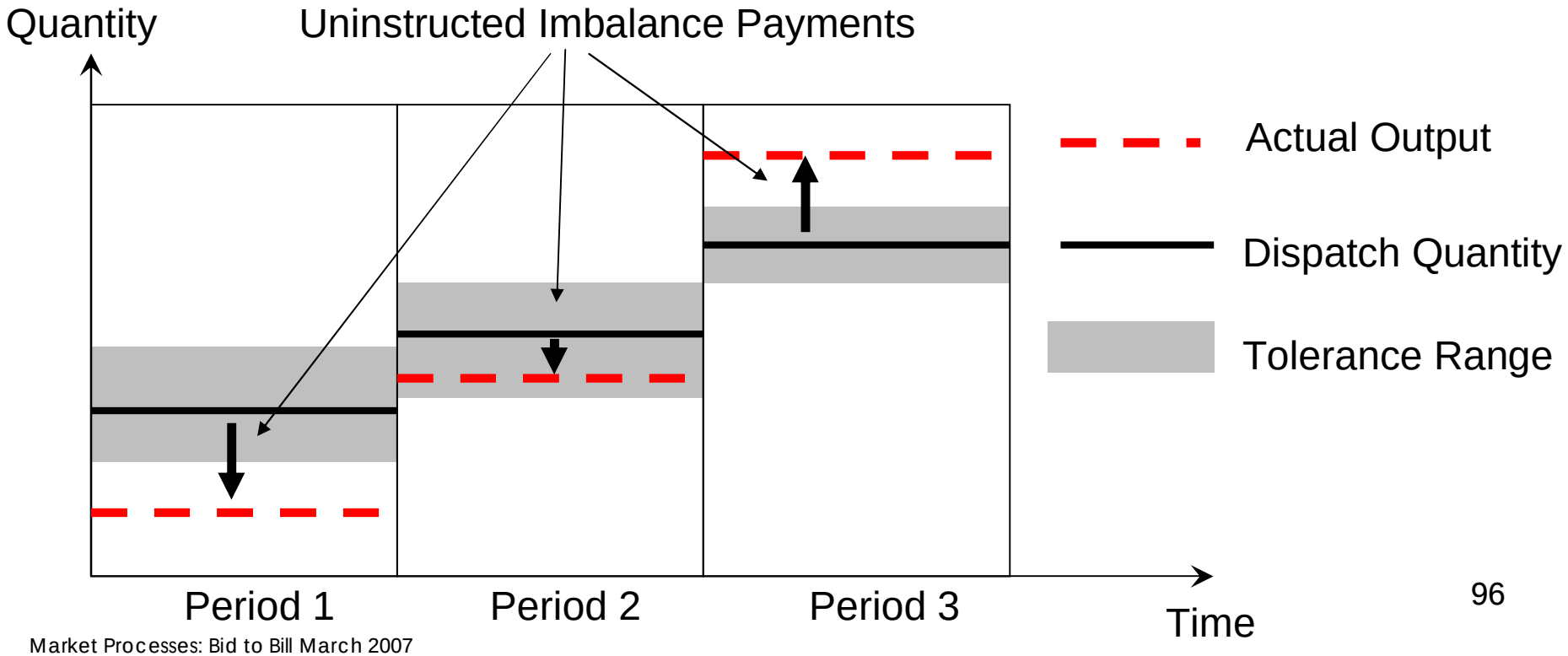
In this example, the bid curve has been modified to factor in a margin to recover no-load costs and fixed costs allocated to that Trading Period.



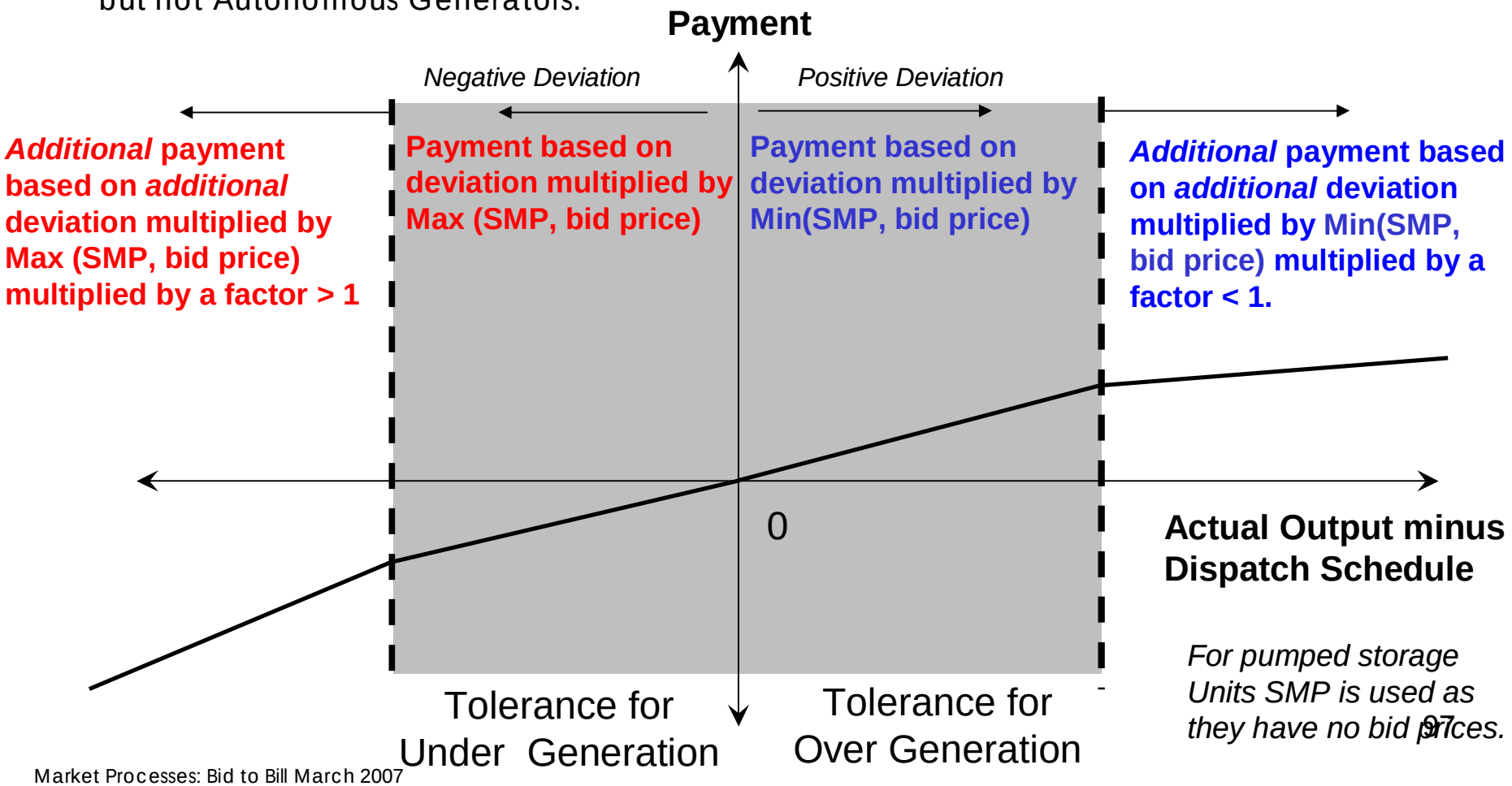
Here we just show the volume difference. To determine the results shown it is necessary to consider the bid curve relative to the quantities shown for each period.


Uninstructed Imbalances
Uninstructed Imbalance Payment
Uninstructed Imbalances
Constraint Payment
Energy Payment
Market Schedule Quantity
Dispatch Quantity
Actual Output
Volume (MW Equiv)
Unit Trading Period Data

- If the Actual Output (meter data) of a Generator Unit differs from the Dispatch Quantity then an Uninstructed Imbalance Payment (UNIMP) will be calculated.
- Value of UNIMP depends on the variation between the Actual Output and the Dispatch Quantity, and whether that variation is within the Tolerance Bands.
- The tolerance varies by Trading Period and Generating Unit based on Generating Unit characteristics and the state of the power system at that time.



- The value of the Uninstructed Imbalance Payment is determined for each Trading Period and varies depending on whether the deviation is inside or outside the tolerance, or up or down.
- Uninstructed imbalances apply to Price Makers and Price Takers (relative to their nominations) but not Autonomous Generators.



For pumped storage Units SMP is used as they have no bid prices.

	Period 1	Period 2	Period 3
Tolerance for Over Generation (TOLOG)	1.9	2.5	2.0
Tolerance for Under Generation (TOLUG)	-18.3	-18.5	-18.4
Upper Tolerance Limit	195.9	214.5	202
Dispatch Schedule Quantity	194	212	200
Lower Tolerance Limit	175.7	193.5	181.6
Actual Quantity	184	212	190
Over or Under Generation?	Under	Neither	Under
Deviation Quantity (MW)	-10 MW	0 MW	-10 MW
Deviation Quantity (MWh)	-5 MWh	0 MWh	-5 MWh
Max (SMP, Bid Price)	€20/MWh	N/A	€133.89/MWh
Payment within Tolerance Range	-€100	0	-€669.45
Payment beyond Tolerance Range (assuming a factor of 1.04)	0	0	0
Imbalance Payment	-€100	0	-€669.45

	Period 1	Period 2	Period 3
Tolerance for Over Generation (TOLOG)	1.0	1.0	1.4
Tolerance for Under Generation (TOLUG)	-11.9	-11.9	-12.1
Upper Tolerance Limit	61.0	61.0	121.4
Dispatch Schedule Quantity	60	60	120
Lower Tolerance Limit	48.1	48.1	107.9
Actual Quantity	70	60	130
Over or Under Generation?	Over	Neither	Over
Deviation Quantity (MW)	10 MW	0 MW	10 MW
Deviation Quantity (MWh)	5 MWh	0 MWh	5 MWh
Min (SMP, Bid Price)	€20/MWh	N/A	€25/MWh
Payment within Tolerance Range	€10	€0	€17.7
Payment beyond Tolerance Range (assuming a factor of 0.96)	€86.4	€0	€103.2
Imbalance Payment	€96.4	€0	€120.9

Generator Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
1	-100	-	-669.45
2	96.4	-	120.9

- What is a Make Whole Payment?
  - A payment made to a Generator if, across a Billing Period, the total Energy Payment to that generator is less than its scheduled production costs.
  - The scheduled production cost is based on:
    - The Price-Quantity Pairs,
    - Start Costs
    - No-Load Costs
    - Market Schedule Quantities
  - It is not available to Pumped Storage Generator Units (which do not bid) or to Price Taker and Autonomous Generator Units

- In this example we assume that the Generator Make Whole Payments are zero.

Generator Unit	Billing Period (€)
1	0
2	0

Imperfections Charge = Net Demand x Imperfections Price

- Charge levied on suppliers to recover Constraint Payments, Uninstructed Imbalance Payments and Make Whole Payments.
- The Imperfections Price is a charge per MWh estimated in advance of each year.

Supplier Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
Supplier Unit 1	-250.00	-350.00	-450.00
Supplier Unit 2	-87.50	-80.00	-92.50

UNIT 1	Period 1
ND	-100MWh
Imperf. Price	€2.50/MWh

From : Market Operator
42 Merrion Square

Invoice

PART 1232

To: Supplier Co
Baggot Street

Date of Issue: 23/2/07
Due Date: 1/3/07
Billing Period: 7

Invoice 12
Settlement Type - Initial
Invoice Type - Energy

1234567

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
	Energy Charge	33,100.00	4,468.50	37,568.50
	Imperfections Charge	1,050.00	141.75	1,191.75
	Total Invoice	34,150.00	4,610.25	38,760.25
	Settlement Reallocation(s)			
	Amount Due			38,760.25

A. BID SECTION

B. SETTLEMENT SECTION

1. Introduction

2. Energy Payments and Charges

3. Capacity Payments and Charges

4. Market Operator Charges

5. Payment Timeline

- Spare Capacity is required to ensure the reliable operation of the SEM.
- Capacity Payments are made to Generator Units for the supply of generation availability.
- The mechanism provides short to medium signals to existing participants so that they can optimise their availability based where it is needed most
- Capacity Payments also provide a degree of financial certainty for participants, thus encouraging and facilitating new investment.
- Capacity market is settlement is on a calendar month basis.

From : Power Station Co
Baggot Street

Self Billing Invoice

PART 1232

To: Single Market Operator
42 Merrion Square

Date of Issue: 5/3/07
Due Date: 9/3/07
Capacity Period:2

Invoice 2
Settlement Type - Initial
Invoice Type - Capacity

7654321

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
	Capacity Payments	- 428.50	- 57.85	- 486.35
	Total Invoice	- 428.50	- 57.85	- 486.35
	Settlement Reallocation(s)			
	Amount Due			- 486.35

From : Market Operator
42 Merrion Square

Invoice

PART 1232

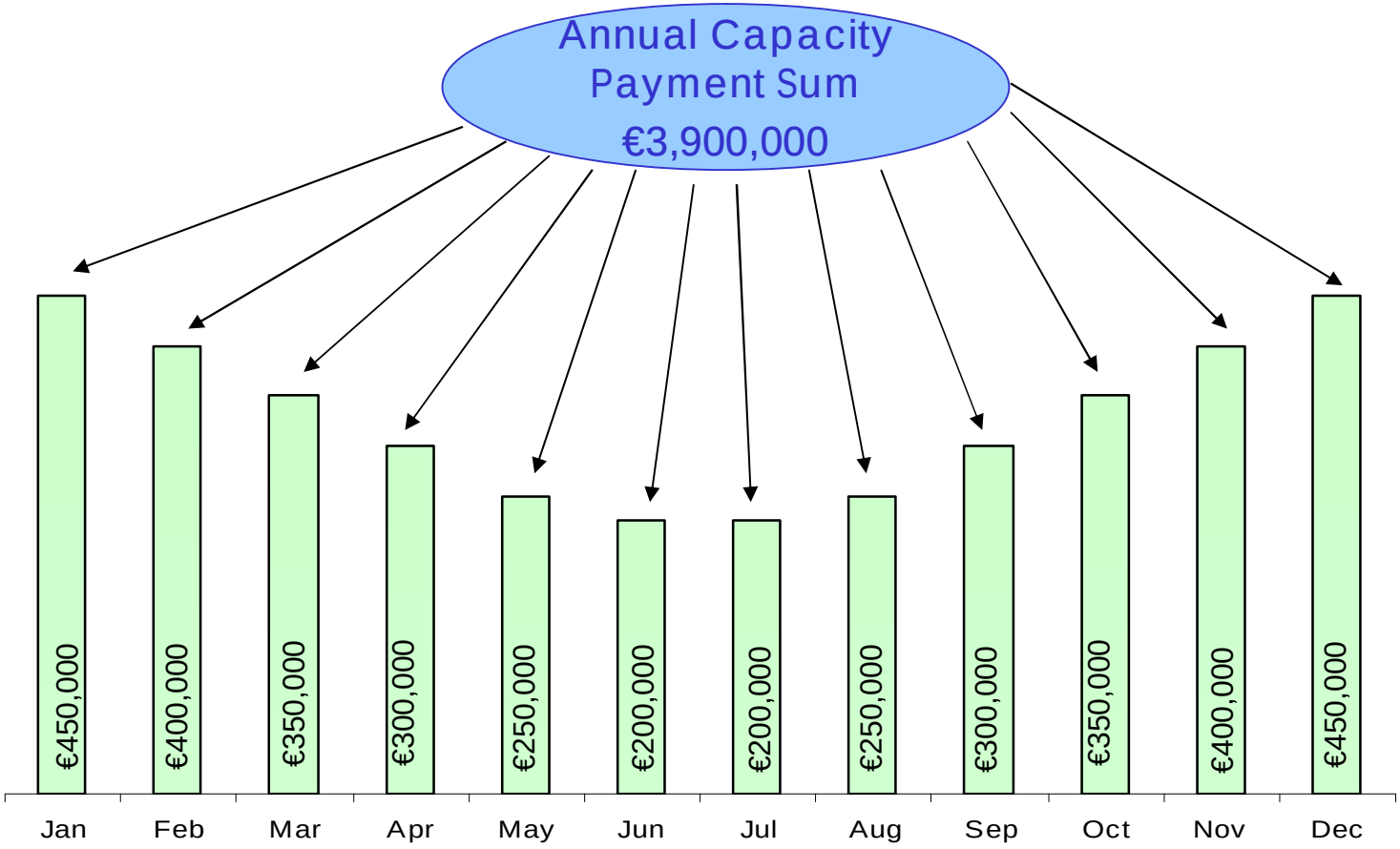
To: Supplier Co
Baggot Street

Date of Issue: 5/3/07
Due Date: 9/3/07
Capacity Period: 2

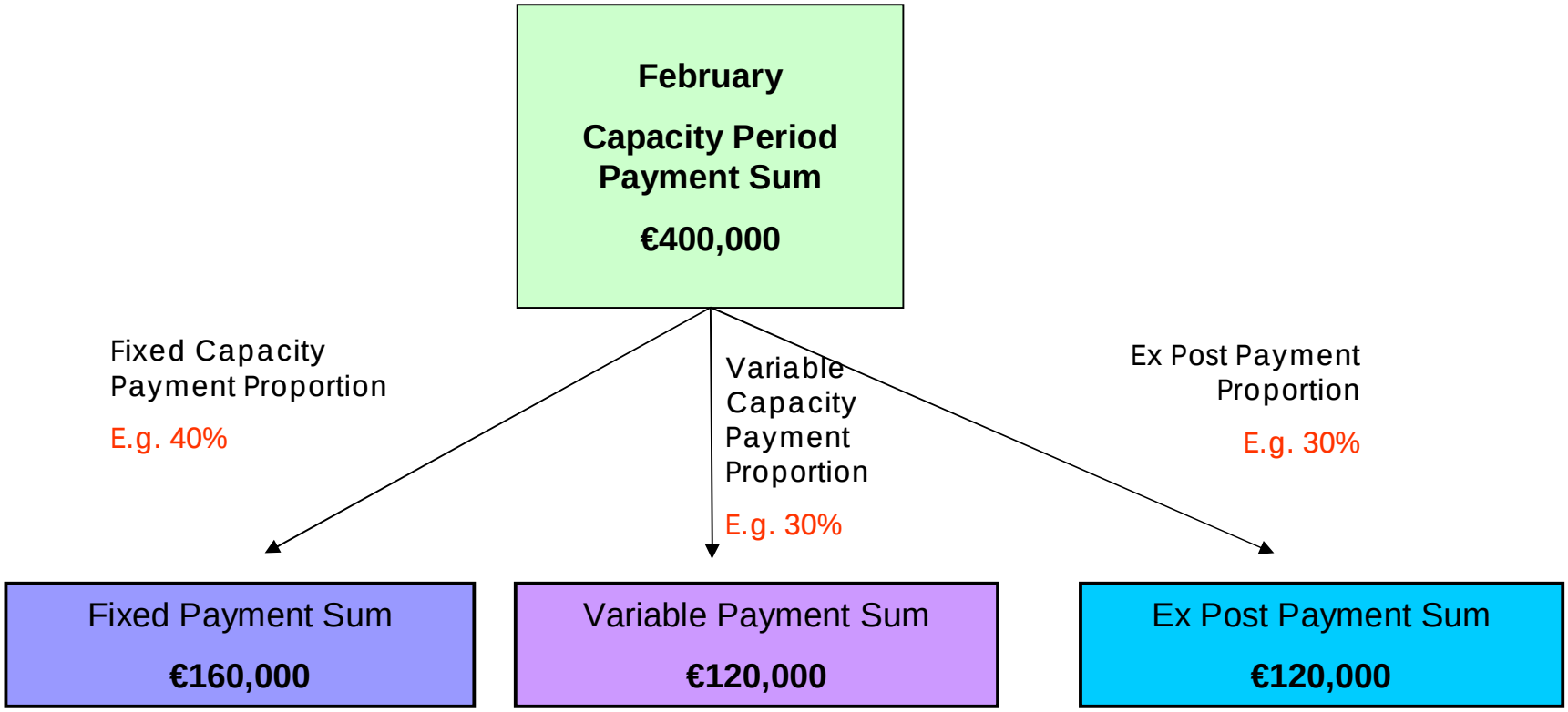
Invoice 2
Settlement Type - Initial
Invoice Type - Capacity

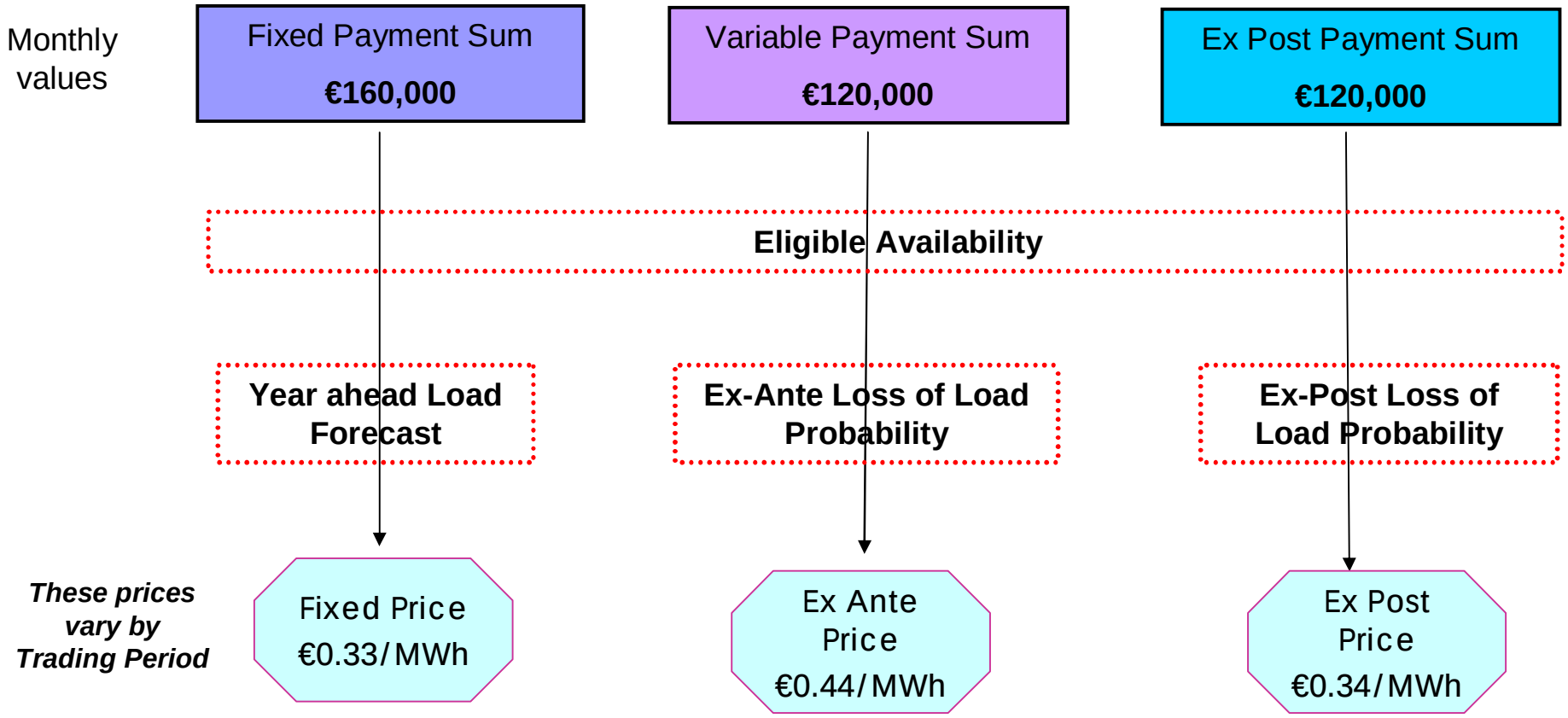
1234567

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
	Capacity Charge	1,116.82	150.77	1,267.59
	Total Invoice	1,116.82	150.77	1,267.59
	Settlement Reallocation(s)			
	Amount Due			1,267.59

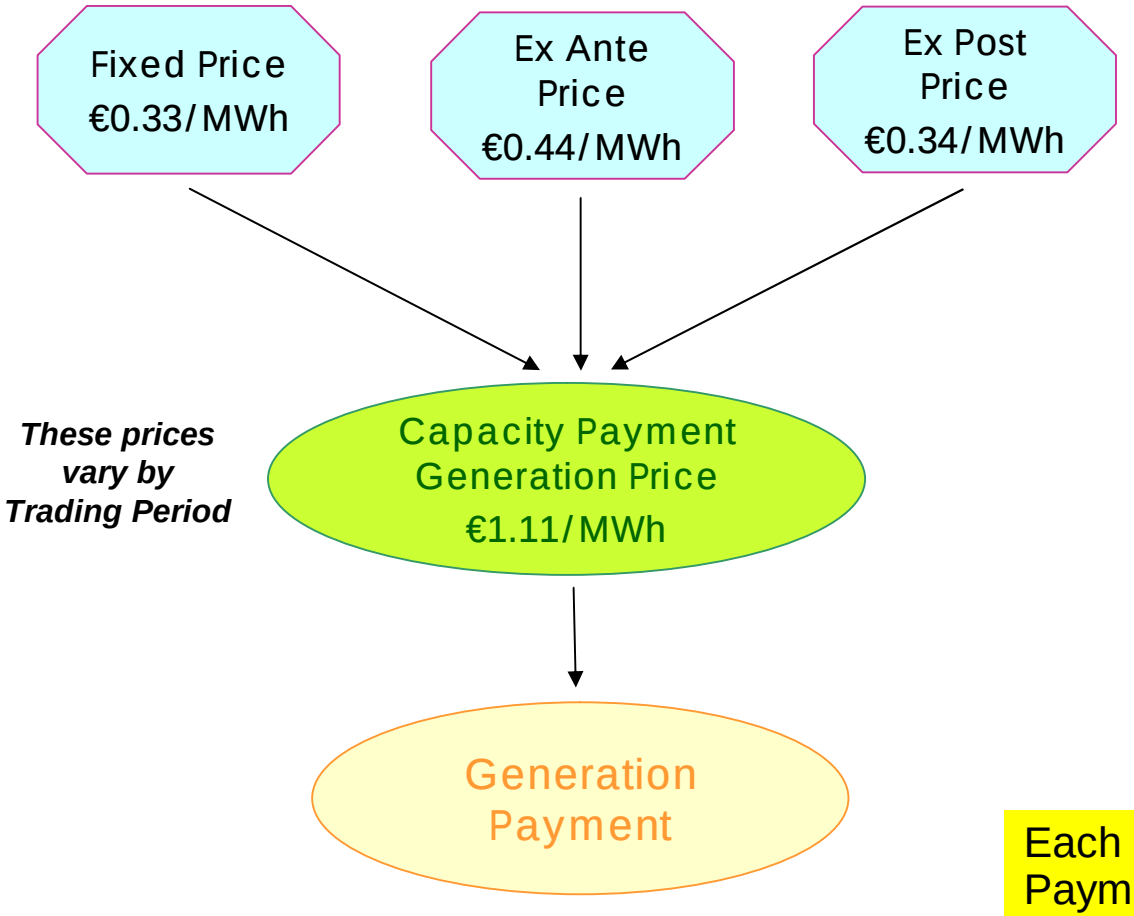


Ä Annual Capacity Payment Sum is broken down into 12 Capacity Period Payment Sums


February
Capacity Period Payment Sum
€400,000
Fixed Capacity Payment Proportion
E.g. 40%
Variable Capacity Payment Proportion
E.g. 30%
Ex Post Payment Proportion
E.g. 30%
Fixed Payment Sum
€160,000
Variable Payment Sum
€120,000
Ex Post Payment Sum
€120,000



Conceptually, each component is determined in the same way - the fixed amount for the month is converted into a per MWh payment based on the Eligible Availability in the system and the "factor" for each Trading Period relative to the sum over the month of those "factors". The three approaches use different "factors" – year ahead forecast Trading Period demand or loss of load probabilities.



- For each Trading Period
  - Ø Aggregate the component prices to the Capacity Payment Generation Price (CPGP).
  - Ø Apply the Price to the Eligible Availability for each Generator Unit to calculate the Capacity Payment.

Each month the sum of the Capacity Payments equals the Capacity Period Payment Sum for that month.

- Methodology
  - For most units (e.g. Unit 1)
    - Eligible Availability equals its ex post availability, i.e. its Availability Profile used in the Ex Post UUC Calculation
  - Special rules for Energy Limited Generator Units (e.g. Unit 2)
    - Simplistically, the lesser of the Market Schedule Quantity and its Availability Profile is used.
    - The actual methodology is more complicated.

	Period 1 (MW)	Period 2 (MW)	Period 3 (MW)
Availability Profile (Unit 1)	**250**	**250**	**200**
Eligible Availability (Unit 1)	**250**	**250**	**200**
Availability Profile (Unit 2)	**200**	**200**	**200**
Market Schedule Quantity (Unit 2)	**60**	**60**	**140**
Eligible Availability (Unit 2)	**60**	**60**	**140**

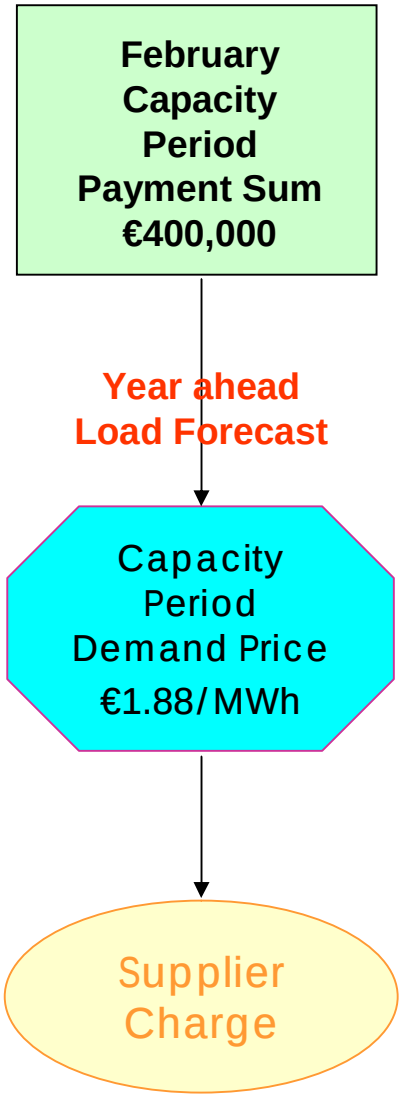
Capacity Payment = 0.5 x Eligible Availability x Capacity Payment Generation Price

UNIT 1	Period 1
EA	**250 MW**
CPGP	€1.11/MWh

The factor of 0.5 converts the Eligible Availability from MW to MWh

Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
1	**138.67**	**143.29**	**146.54**
2	**33.29**	**34.39**	**102.58**

UNIT 2	Period 3
EA	140 MW
CPGP	€1.47 /MWh



- Capacity Charges are levied on Supplier Units to fund Capacity Payments made to Generator Units.
- The Capacity Charge amount per Trading Period is based on the Annual Forecast Demand

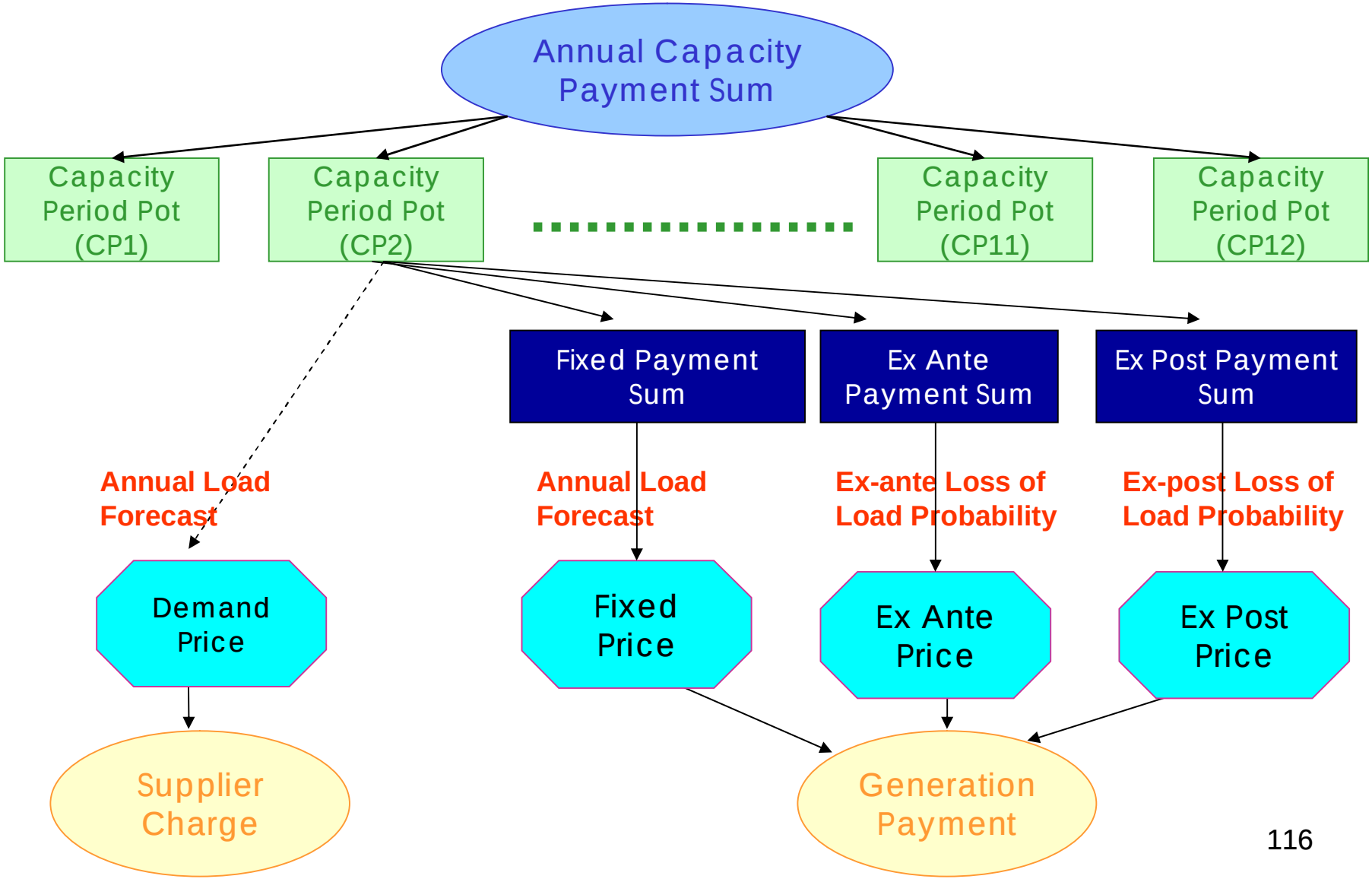
Each month the sum of the Capacity Charges equals the Capacity Period Payment Sum for that month.

Capacity Charge = Net Demand x Capacity Period Demand Price

UNIT 1	Period 1
ND	-100 MWh
CPDP	€1.88/MWh

Supplier Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
Supplier Unit 1	**-188.87**	**-278.77**	**-649.18**
Supplier Unit 2	**-66.11**	**-63.72**	**-133.44**

UNIT 2	Period
ND	-37 MWh
CPDP	€3.60/MWh


Annual Capacity Payment Sum
Capacity Period Pot (CP1)
Capacity Period Pot (CP2)
Capacity Period Pot (CP11)
Capacity Period Pot (CP12)
Fixed Payment Sum
Ex Ante Payment Sum
Ex Post Payment Sum
Annual Load Forecast
Annual Load Forecast
Ex-ante Loss of Load Probability
Ex-post Loss of Load Probability
Demand Price
Fixed Price
Ex Ante Price
Ex Post Price
Supplier Charge
Generation Payment

From : Power Station Co
Baggot Street

Self Billing Invoice

PART 1232

To: Single Market Operator
42 Merrion Square

Date of Issue: 5/3/07
Due Date: 9/3/07
Capacity Period:2

Invoice 2
Settlement Type - Initial
Invoice Type - Capacity

7654321

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
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	Total Invoice	- 428.50	- 57.85	- 486.35
	Settlement Reallocation(s)			
	Amount Due			- 486.35

aime All Island Market for Electricity

From : Market Operator
42 Merrion Square

Invoice

PART 1232

To: Supplier Co
Baggot Street

Date of Issue: 5/3/07
Due Date: 9/3/07
Capacity Period:2

Invoice 2
Settlement Type - Initial
Invoice Type - Capacity

1234567

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
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	Settlement Reallocation(s)			
	Amount Due			1,267.59

A. BID SECTION

B. SETTLEMENT SECTION

1. Introduction

2. Energy Payments and Charges

3. Capacity Payments and Charges

4. Market Operator Charges

5. Payment Timeline

aime All Island Market for Electricity

From : Market Operator
42 Merrion Square

Invoice

PART 1232

To: Supplier Co
Baggot Street

Date of Issue: 23/2/07
Due Date: 1/3/07
Billing Period: 7

Invoice 12
Settlement Type - Initial
Invoice Type - Market Operator Charge

1234567

Charge_ID	Charge_Type	Net Amt	VAT	Gross Amt
	Variable Market Operator Charge	126.00	17.01	143.01
	Total Invoice	126.00	17.01	143.01
	Settlement Reallocation(s)			
	Amount Due			143.01

- Market Operator Charges recover the costs of operating the SMO.
- The Fixed Market Operator Charge is levied as an annual fee for all Generating Units and all Supplier Units.
  - It is effectively a membership fee.
  - This fee is ignored in this example.
- The Variable Market Operator Charge is a rate per MWh that is fixed annually.
- The Variable Market Operator Charge is prepared weekly and billed only to Supplier Units.

Variable Market Operator Charge = Net Demand x Variable Market Operator Price

Supplier Unit	Period 1 (€)	Period 2 (€)	Period 3 (€)
Supplier Unit 1	-30.00	-42.00	-54.00
Supplier Unit 2	-10.50	-9.60	-11.10

Unit 1	Period 1
ND	-100MWh
VMOP	€0.30/MWh

From : Market Operator
42 Merrion Square

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A. BID SECTION

B. SETTLEMENT SECTION

1. Introduction

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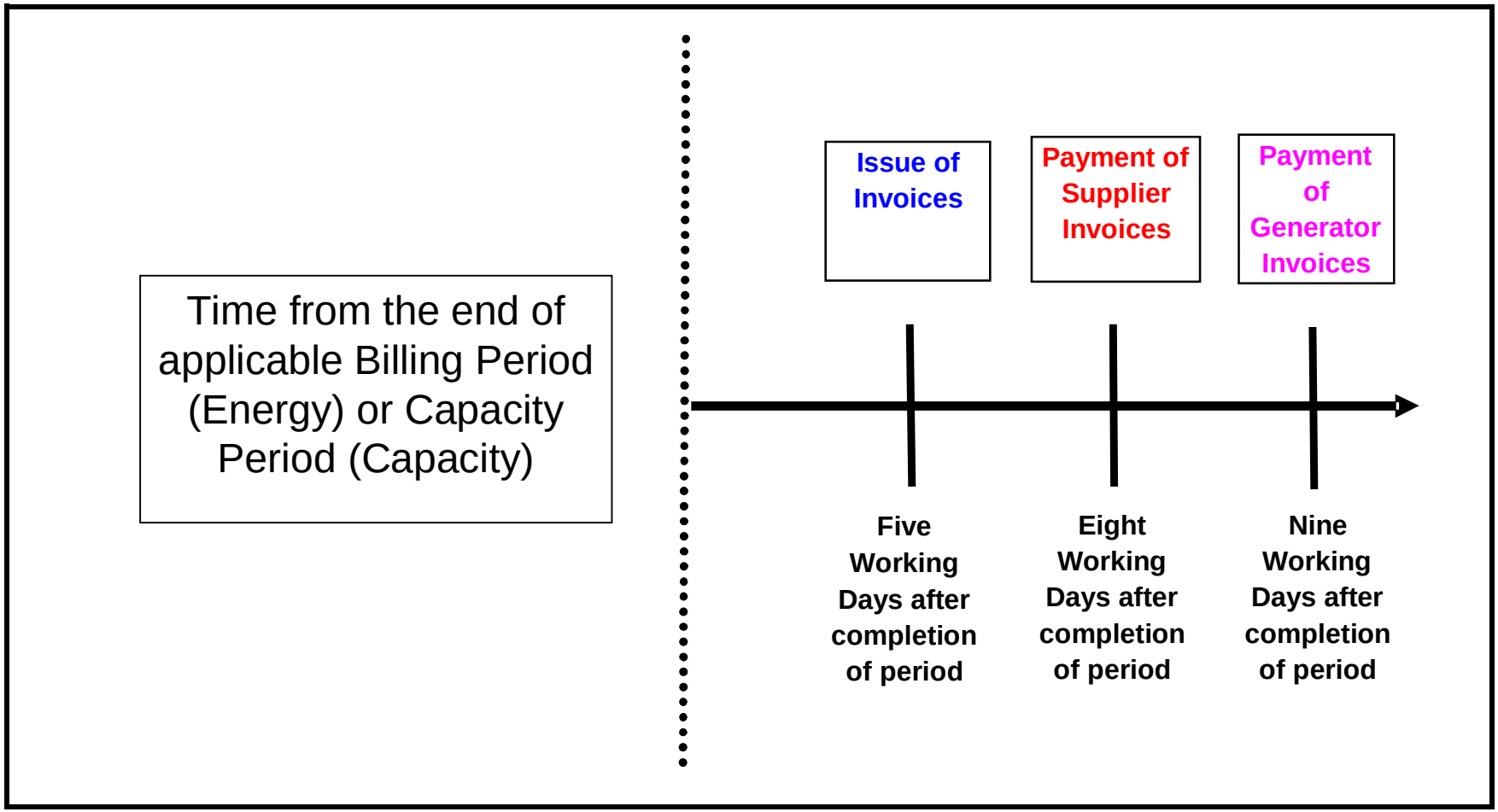
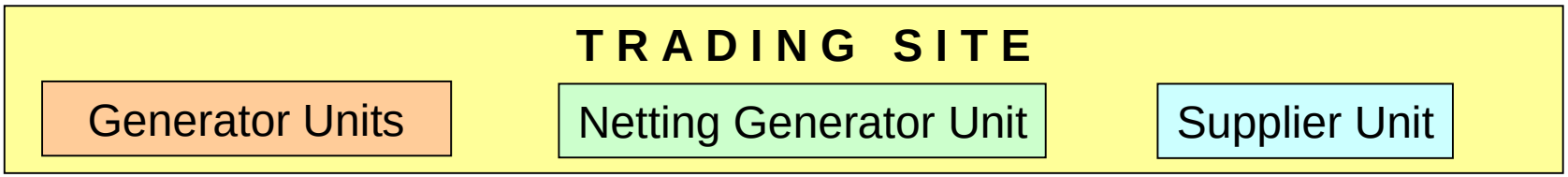
3. Capacity Payments and Charges

4. Market Operator Charges

5. Payment Timeline


Time from the end of applicable Billing Period (Energy) or Capacity Period (Capacity)
Issue of Invoices
Payment of Supplier Invoices
Payment of Generator Invoices
Five Working Days after completion of period
Eight Working Days after completion of period
Nine Working Days after completion of period



- A "Trading Site" is a device for correctly netting energy and capacity payments when there are both generation and load at the same site.
- With generation & load at the same site then the final settlement position will be:
  - Energy payments are based on the NET generation.
  - Constraint payments and uninstructed imbalances are based on the GROSS generation while Imperfection Charge are on GROSS LOAD.
  - Capacity payments are based on the NET generation.
  - Variable Operators Charge on GROSS load.
- The Generator Units are registered by the Market Participant at that Trading Site.
- There can be only one Supplier Unit at a Trading Site:
  - The example on the next slide assumes this is registered to the registered participant for the Trading Site (i.e. A Trading Site Supplier Unit)
  - Alternatively, it could be registered to another participant (an Associated Supplier Unit) in which case the Netting Generator Unit has a zero quantity for the Trading Site participant.
- The Netting Generator Unit is a virtual unit, registered by the SMO on behalf of the Market Participant at that Trading Site.

TRADING SITE

Generator Units | Netting Generator Unit | Supplier Units

- Meter Data and MSQ for the Netting Generator Unit is negative of the lesser of:
  - The absolute value of the total metered values for the Generator Units.
  - The absolute value of the total metered values for the Supplier Units.
- Energy and Capacity Payments are based on Generator Unit MSQ's and the Netting Generator (which is a negative number)
- Energy and Capacity Charges are based on Supplier Unit MSQ's less Netting Generator Unit output (which is a negative number)
- Other settlement terms are still settled on a gross basis.

Generator Unit MW (A)	+100	+50	+40
Supplier Unit MW (B)	-60	-80	-40
Netting Generator Unit MW (C = -Min(¦A¦,¦B¦))	-60	-50	-40
Generator Unit Energy/Capacity Payment MW (A)	+100	+50	+40
Netting Generator Unit Energy/Capacity Payment MW (C)	-60	-50	-40
Net Energy/Capacity Payment MW (A+ C)	+40	0	0
Supplier Unit Energy/Capacity Charge MW (B – C)	0	-30	0