Simplified Operating Reserve Demand Curve (ORDC) Enhancements

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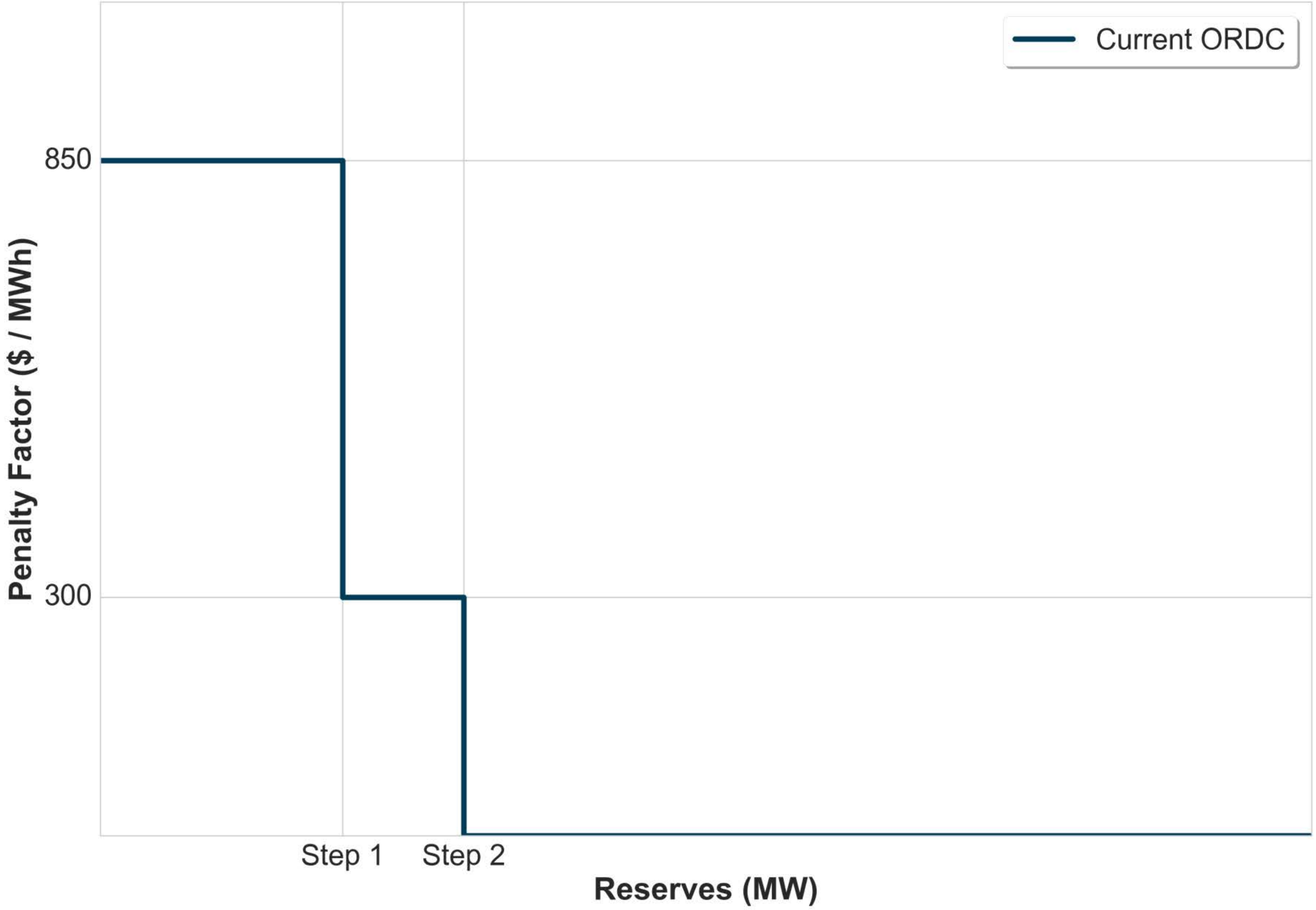
Background – Current ORDC



Step 1

- Reliability Requirement: usually output of largest unit

Step 2

- Adds 190 MW to Step 1. Also, there is an Optional Adder that can be used to capture additional reserves scheduled for reliability reasons

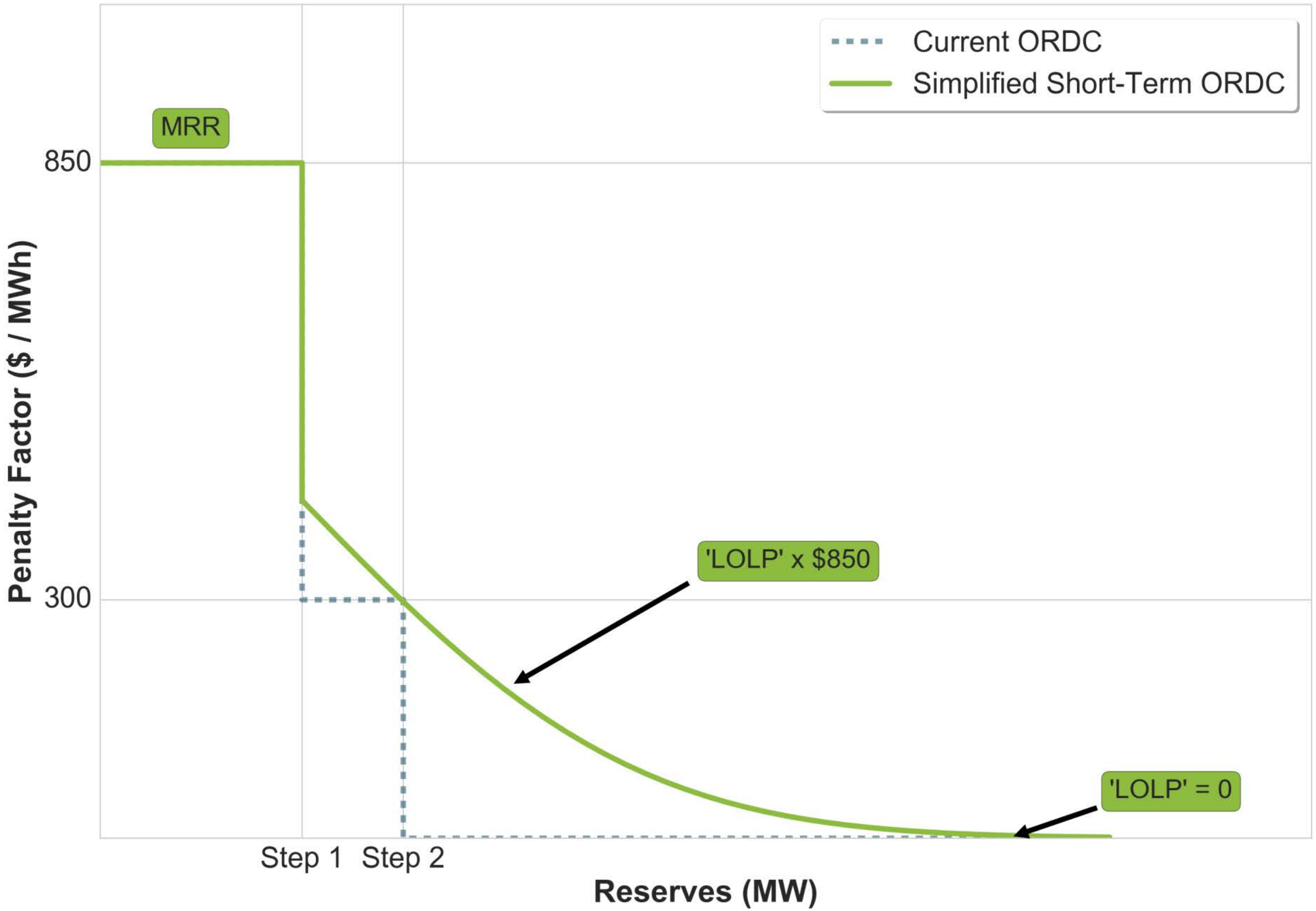
Background – Current ORDC

- Issues / Opportunities
  - Reserve price (for either Synchronized or Primary Reserves) falls to $0/MWh if the total MW reserves in the system are greater than the sum of Step 1 and Step 2 (even by 1 MW)
    - This indicates that additional reserves have no value. Additional reserves, however, provide reliability value in that they reduce the chance of falling below the minimum reserve requirement and the chance of a loss-of-load.
  - The current largest penalty factor ($850/MWh) is based on the average cost of reserves during shortage events in 2007.
  - Under certain circumstances, PJM system operators may commit additional reserves to account for uncertainties not reflected in the current ORDC or to account for other externalities.

Simplified Short-Term Enhancements

- The short-tem enhancements are expected to address
  - Reserve price (for either Synchronized or Primary Reserves) falls to $0/MWh if the total MW reserves in the system are greater than the sum of Step 1 and Step 2 (even by 1 MW)
    - This indicates that additional reserves have no value. Additional reserves, however, provide reliability value in that they reduce the chance of falling below the requirement and the chance of a loss-of-load.
  - ~~The current largest penalty factor ($850/MWh) is based on the average cost of reserves during shortage events in 2007.~~
  - Under certain circumstances, PJM system operators may commit additional reserves to account for uncertainties not reflected in the current ORDC.

Simplified Short-Term Enhancements



- Key concepts
  - "Loss of Load" Definition
    - For ORDC purposes, Loss of Load may not necessarily refer to an event in which reserves are less than 0 MW.
    - Instead, it may refer to an event in which the amount of reserves is less than a Minimum Reserve Requirement (MRR). If reserves fall below this MRR, emergency actions are triggered, which may be a precursor to load curtailment.

- Key concepts
  - "Loss of Load" Probability (LOLP) or Probability of Reserves Falling Below the Minimum Reserve Requirement (PBMRR)
    - For example, if the MRR is 2,400 MW and the difference between available capacity and load 30-minutes ahead of the target time is 2,700 MW.
    - In this example, the system has 300 MW of excess reserves 30-minutes ahead. However, this is just an estimate since things can change in the next 30 minutes. In other words, there are uncertainties.
    - If these uncertainties are quantified, then the PBMRR associated with 2,700 MW of reserves can be calculated

PBMRR (LOLP) Calculation - Uncertainties

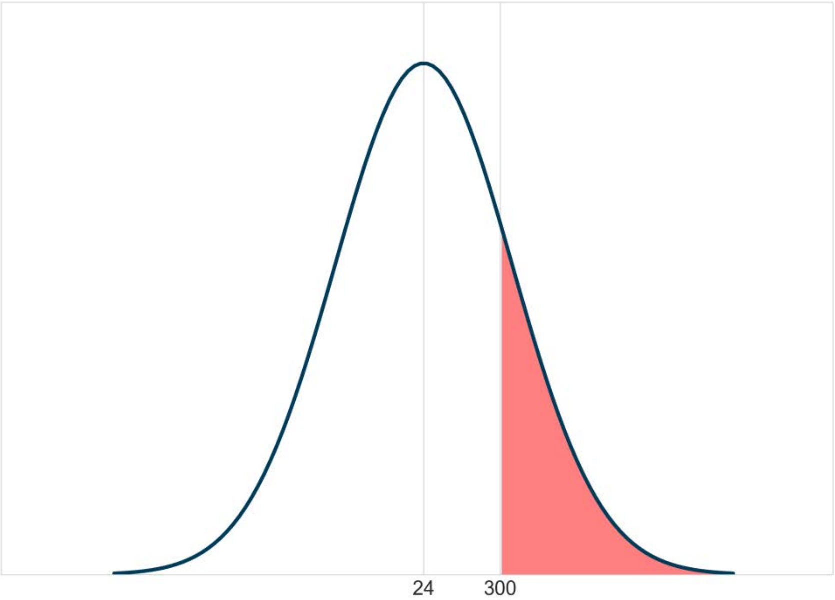
- Load
  - PJM produces a forecast for multiple look-ahead intervals (30 min, 60 min, etc.). However, the forecast is not perfect.
- Thermal generation performance
  - Thermal units can experience forced outages in the next x minutes.
- Wind/Solar generation performance
  - PJM produces a forecast for multiple look-ahead intervals (30 min, 60 min, etc.). However, the forecast is not perfect.

PBMRR (LOLP) Calculation - Example

- Going back to the previous example, if the MRR is 2,400 MW and the difference between available capacity and load (i.e. the amount of reserves) 30-minutes ahead of the target time is 2,700 MW.
  - Expected Available Capacity = 12,700 MW
  - Expected Load = 10,000 MW
- Assuming that there is only one type of uncertainty, load uncertainty.
- The PBMRR for 2,700 MW is equivalent to calculating the probability that the 30-minutes load forecast error (error is defined as actual load minus forecasted load) is greater than 300 MW.
  - Why? Because if the load at the target time is greater than 10,300 MW, say 10,400 MW, then the MRR will not be met (12,700 MW – 10,400 MW = 2,300 MW < MRR).

PBMRR (LOLP) Calculation - Example

- If the distribution of the 30-min ahead load forecast error is known (calculated from historical data, for instance)
  - Normal with mean=24 MW and standard deviation=319 MW



The probability that the load forecast error is greater than 300 MW can be easily calculated in Excel using:
1 – NORM.DIST (300, 24, 319, TRUE).

The result is 0.19.

Therefore, it can be stated that the Probability of Reserves Falling Below the Minimum Reserve Requirement (PBMRR) when the 30-min ahead difference between available capacity and load equals 2,700 MW is 19%.

ORDC Short-Term Changes

- Aimed at both Synchronized Reserves (SR) and Primary Reserves (PR) requirements
  - Both requirements are met with resources expected to respond within the next 10 minutes from the target time
- What look-ahead uncertainty interval should be used to calculate the PBMRR to build the new ORDCs?
  - Reserve assignments are made 10-minutes prior to the target time
  - A 30 minute look-ahead uncertainty interval is reasonable to account for the total time elapsed between the reserve assignment and the reserves' response time.

ORDC Short-Term Changes

- What type of uncertainties should be considered in the PBMRR calculation to build the new ORDC?
  - Load, wind and solar forecast error should be included.
  - Thermal generation uncertainty due to forced outages should not be considered because,
    - Loss of a unit is already included in the MRR
    - However, if under some circumstances, the aggregate forced outage uncertainty deviates from typical values, this greater uncertainty should be captured by the ORDC. This points to the development of an Extreme Day ORDC.

- Are the uncertainties considered in the PBMRR constant throughout the year?
  - To answer this question, the 30-min error from the load, wind and solar forecasts was assessed for combinations of the following seasons and time-of-day blocks
  - Error was defined as **ACTUAL - FORECAST**

Seasons:
Summer (Jun-Aug)
Fall (Sep-Nov)
Winter (Dec-Feb)
Spring (Mar-May)

Time-of-Day Blocks:
1 (2300-0200)
2 (0300-0600)
3 (0700-1000)
4 (1100-1400)
5 (1500-1800)
6 (1900-2200)

30-min Load Forecast Error (LFE)

Season	TBlock	Mean (MW)	StDev (MW)
Fall	1	-16.5	259.6
Fall	2	20.1	464.6
Fall	3	-34.1	389.5
Fall	4	-12.5	303.3
Fall	5	55.6	539.8
Fall	6	-32.1	550.6
Spring	1	-73.1	268.1
Spring	2	-53.3	441
Spring	3	56.8	415.7
Spring	4	24.7	298.8
Spring	5	-71.2	440.6
Spring	6	108.2	611.9
Summer	1	-14.4	277.7
Summer	2	-34.1	427.2
Summer	3	-45.5	429.5
Summer	4	-59	395.1
Summer	5	55.2	463.9
Summer	6	47.6	541
Winter	1	-39.4	331.9
Winter	2	-21.9	513.5
Winter	3	70.1	482
Winter	4	22.5	375.8
Winter	5	9.1	615.7
Winter	6	10.6	380.8

Error = Actual – Forecast

Therefore,

Positive errors indicate under-forecasting
Negative errors indicate over-forecasting

(2015-2017 data)

30-min Wind Forecast Error (WFE)

Season	TBlock	Mean (MW)	StDev (MW)
Fall	1	-121.8	210
Fall	2	-129.6	202.1
Fall	3	-130.7	222.2
Fall	4	-82.6	216.9
Fall	5	-119.9	220.8
Fall	6	-76.1	234.4
Spring	1	-104.6	238.9
Spring	2	-126.7	234.6
Spring	3	-120.8	245.8
Spring	4	-101.3	261.8
Spring	5	-103.5	236.3
Spring	6	-123.3	266.8
Summer	1	-59.7	204.8
Summer	2	-71.3	180.2
Summer	3	-100.5	180.4
Summer	4	-57	190.8
Summer	5	-69.7	189.4
Summer	6	-77.3	216.3
Winter	1	-176.6	256.7
Winter	2	-177.5	247.7
Winter	3	-160	253
Winter	4	-150.8	250.8
Winter	5	-154.4	275.8
Winter	6	-130.9	279.9

Error = Actual – Forecast

Therefore,

Positive errors indicate under-forecasting
Negative errors indicate over-forecasting

(2015-2017 data)

30-min Solar Forecast Error (SFE)

Season	TBlock	Mean (MW)	StDev (MW)
Fall	2	2.8	3.7
Fall	3	0.6	39
Fall	4	-29.2	46
Fall	5	-18.4	31.2
Fall	6	3.4	6.3
Spring	1	1.3	0.6
Spring	2	1.9	5.6
Spring	3	-3.8	33.5
Spring	4	-16	39.6
Spring	5	-18	36.6
Spring	6	3.2	4.8
Summer	2	-3.6	8.8
Summer	3	-3.2	30.1
Summer	4	-26	37.2
Summer	5	-32.4	33.7
Summer	6	-2.1	10.2
Winter	2	1.3	1.1
Winter	3	11.4	46.2
Winter	4	14.6	53.7
Winter	5	4.4	23.4

Error = Actual – Forecast

Therefore,

Positive errors indicate under-forecasting
Negative errors indicate over-forecasting

(2017 data)

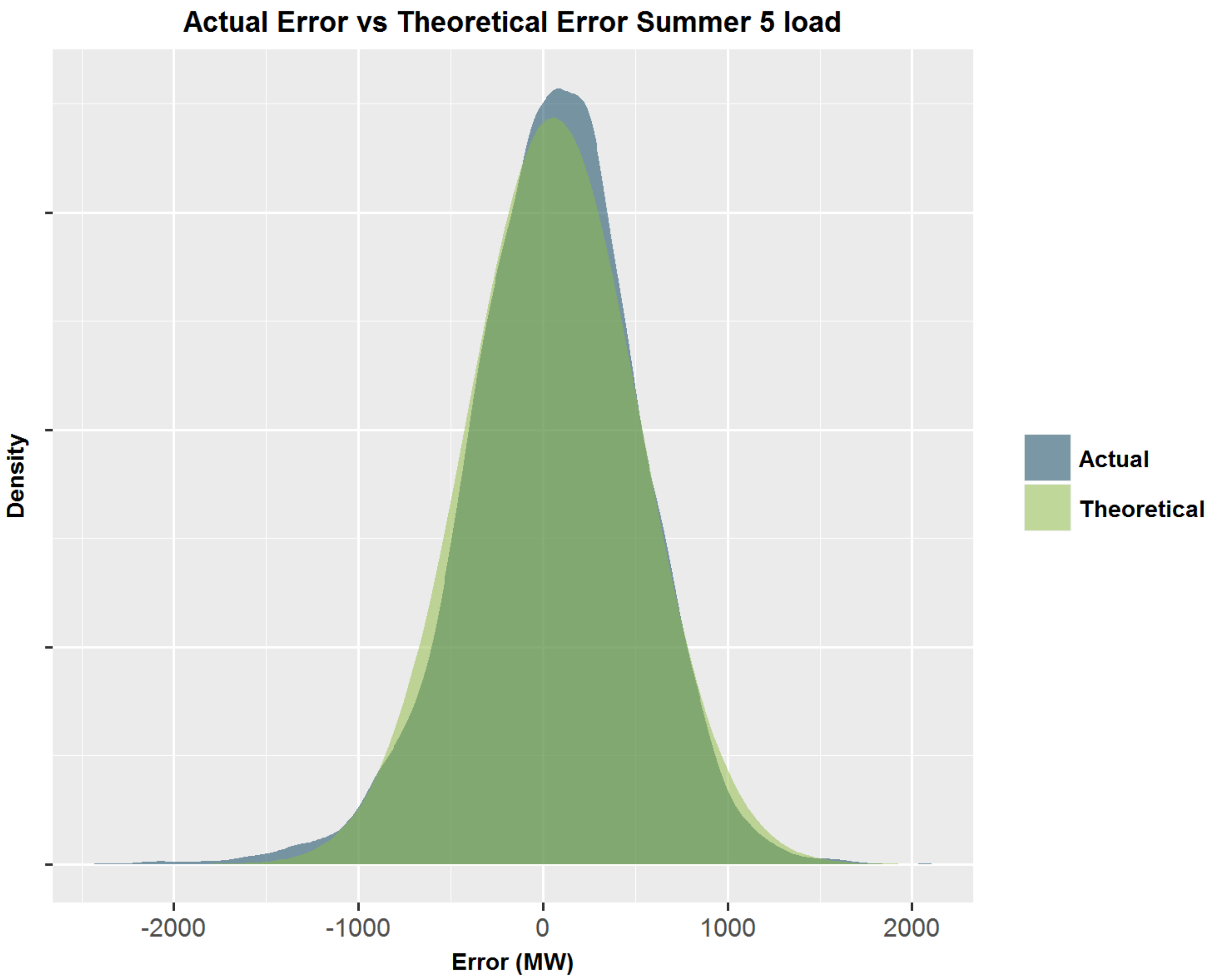
30-min Total Forecast Error (TFE)

- If the individual 30-min forecast error distributions are assumed to be normally distributed, then the 30-min Total Forecast Error (TFE) distribution is also normally distributed with,
- Mean equal to the sum of the individual mean errors (adjusting for the sign of the error depending on the type of error, e.g., load under-forecasting and wind over-forecasting makes the total error worse)
- Standard Deviation equal to the square root of the total variance. The total variance is the sum of the individual variances adjusted by the potential correlation of the errors (via the covariances)

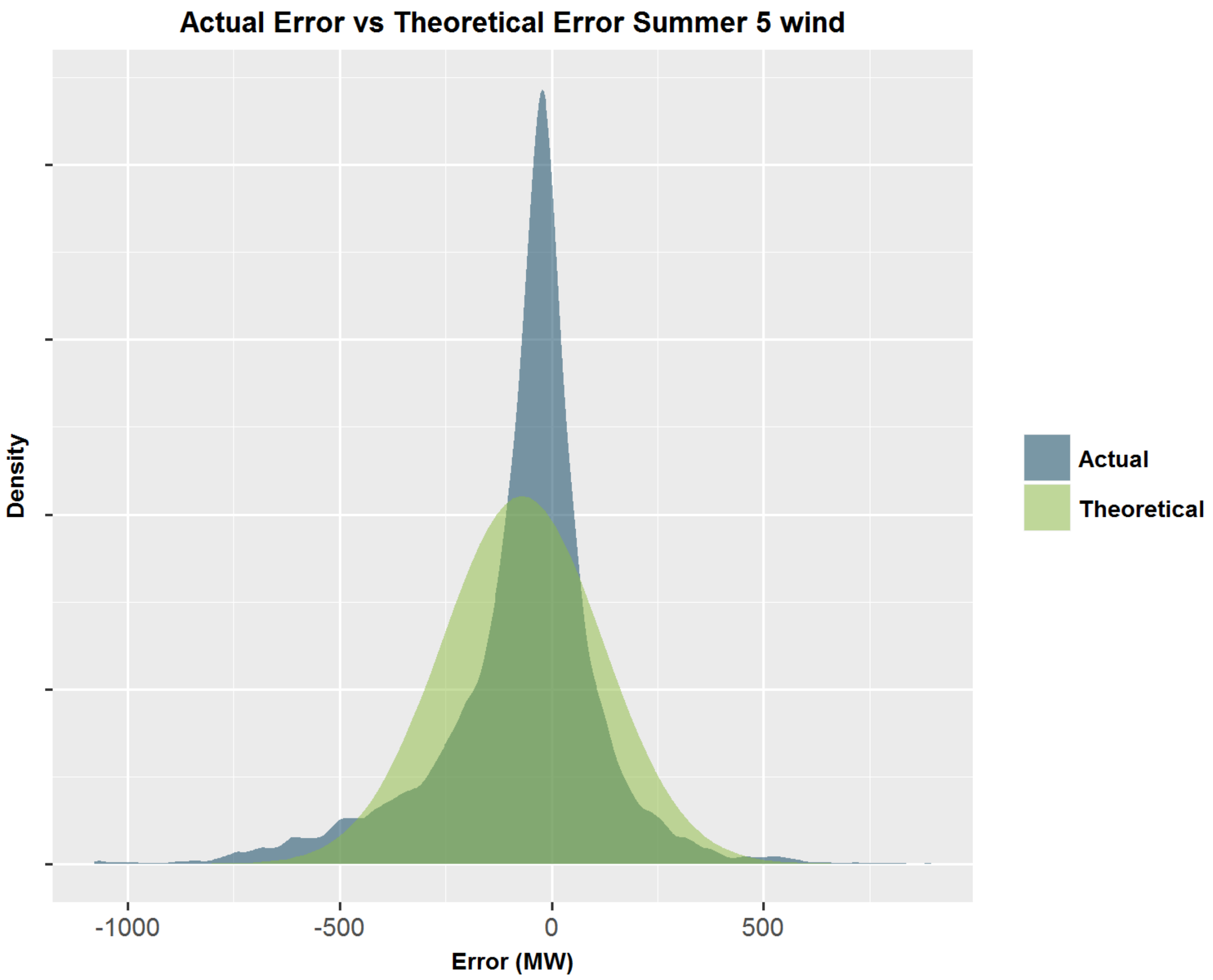
Mean = Mean LFE – Mean WFE – Mean SFE

StDev = SQRT(Variance LFE + Variance WFE + Variance SFE + 2 * Covariance(LFE, WFE) + 2 * Covariance(LFE, SFE) + 2 * Covariance(WFE, SFE))

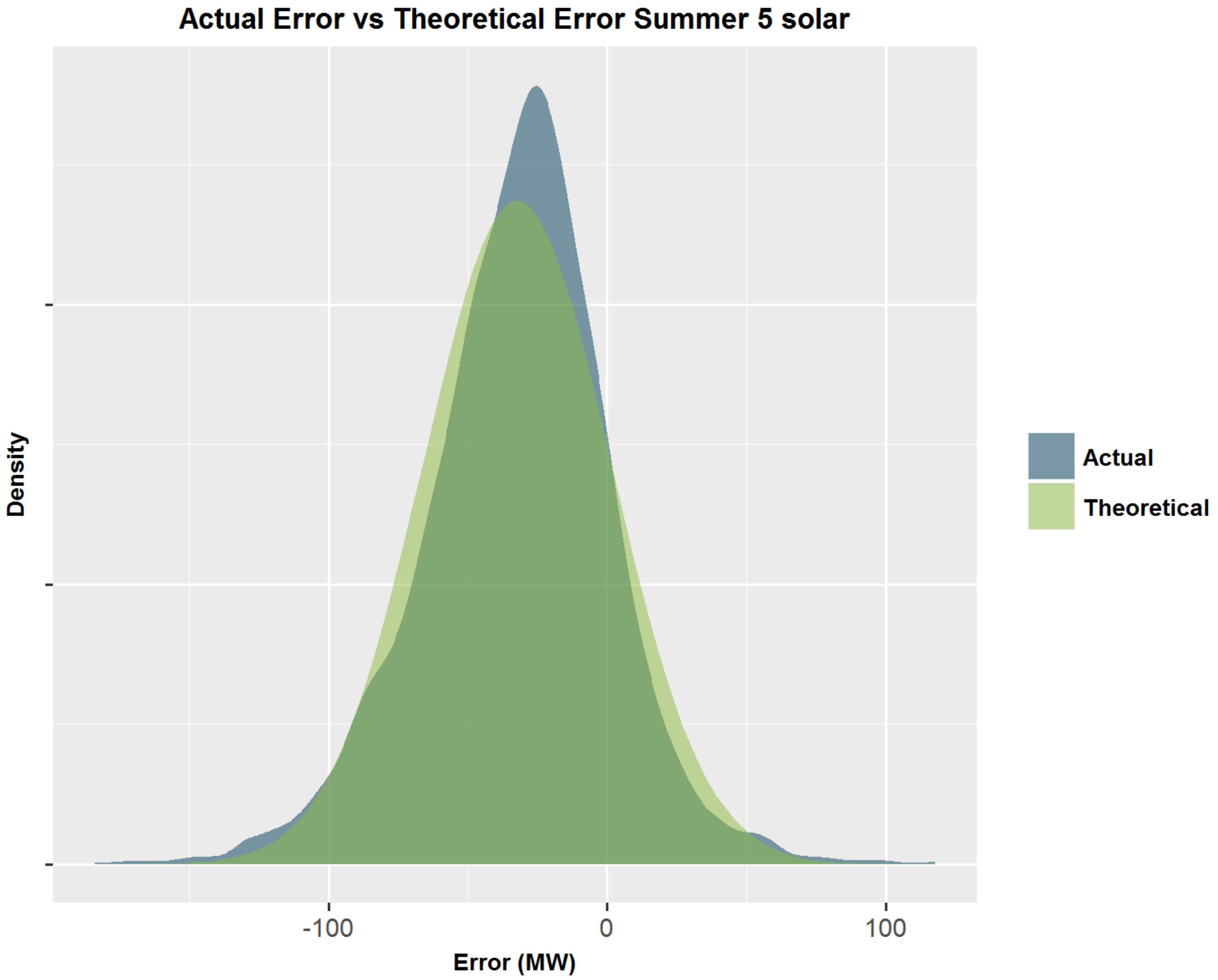
30-min LFE – Summer 1500-1800 (TBlock 5)



30-min WFE – Summer 1500-1800 (TBlock 5)



30-min SFE – Summer 1500-1800 (TBlock 5)



PBMRR Calculation for Summer 1500-1800 (TBlock 5)

- MRR = 1400 MW (for Synchronized Reserves)

- LFE: Mean = 55.2 MW, StDev = 463.9 MW (Var = 215,203 MW^2)
- WFE: Mean = -69.7 MW, StDev = 189.4 MW (Var = 35,872 MW^2)
- SFE: Mean = -32.4 MW, StDev = 33.7 MW (Var = 1,136 MW^2)
- Covariance (LFE, WFE) = 1,178 MW^2
- Covariance (LFE, SFE) = -597 MW^2
- Covariance (WFE, SFE) = 68 MW^2
- Thus, the 30-min Total Forecast Error (TFE) normal distribution has

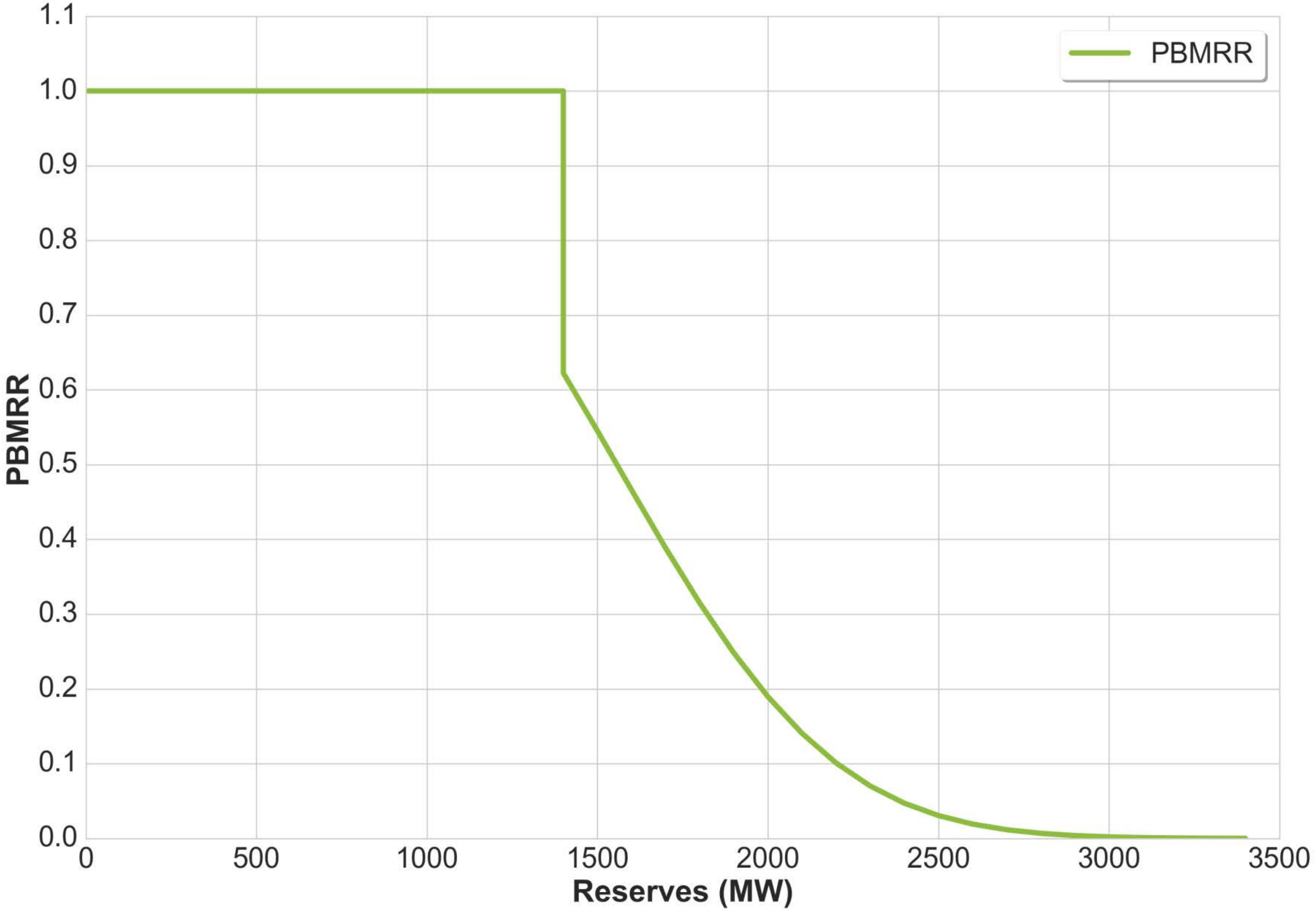
Mean = 55.2 – (-69.7) – (-32.4) = 157.3 MW

StDev = SQRT (215,203 + 35,872 + 1,136 + 2 * 1,178 + 2 * (-597) + 2 * 68) = 503.5 MW

PBMRR Calculation - Summer 1500-1800 (TBlock 5)

Reserves (MW)	Excess Above MRR (MW)	PBMRR or Prob(TFE > Excess Above MRR)
0	-1400	1
100	-1300	1
200	-1200	1
300	-1100	1
400	-1000	1
500	-900	1
600	-800	1
700	-700	1
800	-600	1
900	-500	1
1000	-400	1
1100	-300	1
1200	-200	1
1300	-100	1
1400	0	1
1500	100	0.5453
1600	200	0.4662
1700	300	0.3884
1800	400	0.3149
1900	500	0.2481
2000	600	0.1896
2100	700	0.1405
2200	800	0.1009
2300	900	0.0701
2400	1000	0.0471
2500	1100	0.0306
2600	1200	0.0192
2700	1300	0.0116
2800	1400	0.0068
2900	1500	0.0038
3000	1600	0.0021
3100	1700	0.0011
3200	1800	0.0006
3300	1900	0.0003
3400	2000	0.0001

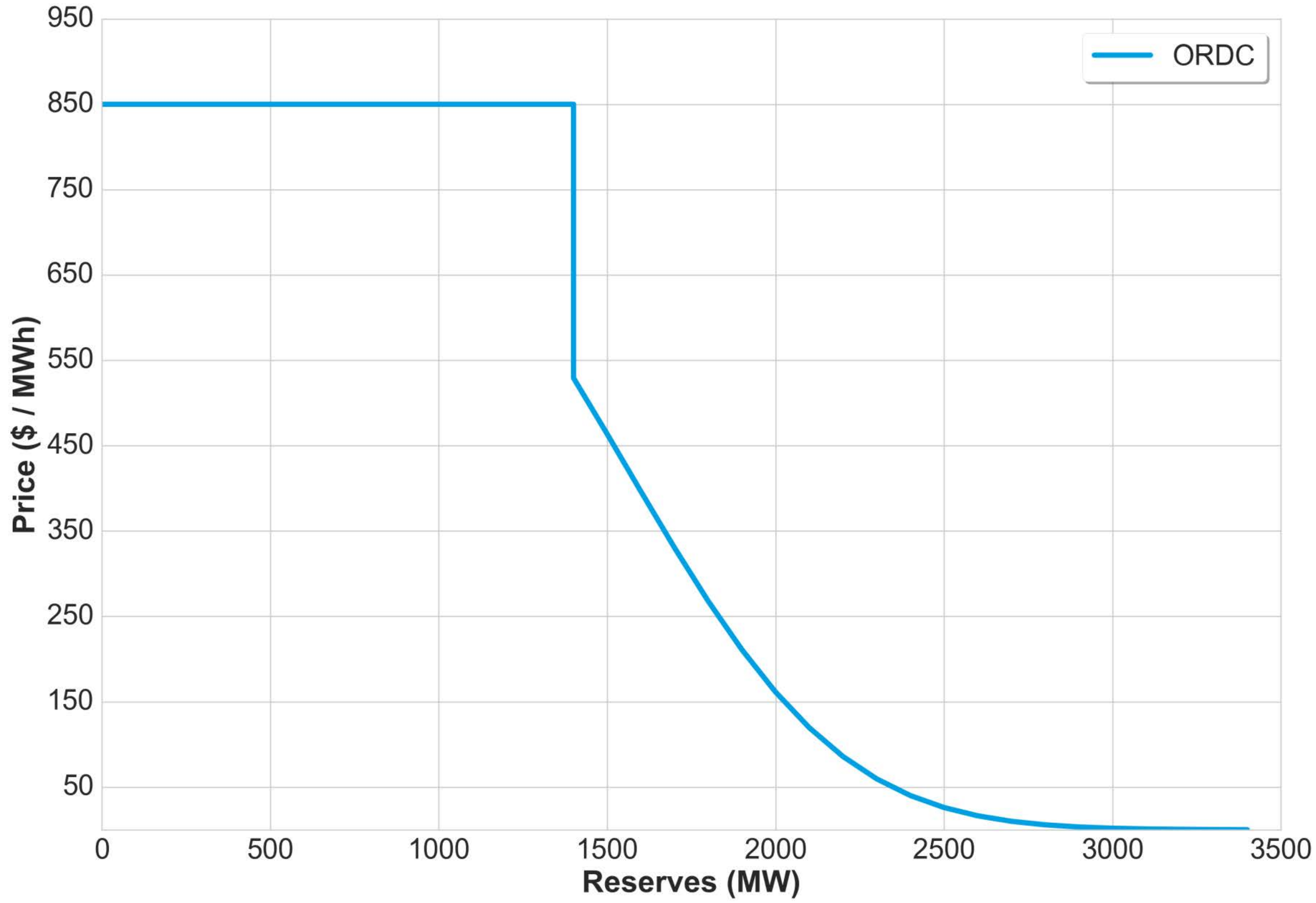
PBMRR Curve - Summer 1500-1800 (TBlock 5)



ORDC Values - Summer 1500-1800 (TBlock 5)

Reserves (MW)	Excess Above MRR (MW)	PBMRR or Prob(TFE > Excess Above MRR)	Price (PBMRR x $850)
0	-1400	1	850
100	-1300	1	850
200	-1200	1	850
300	-1100	1	850
400	-1000	1	850
500	-900	1	850
600	-800	1	850
700	-700	1	850
800	-600	1	850
900	-500	1	850
1000	-400	1	850
1100	-300	1	850
1200	-200	1	850
1300	-100	1	850
1400	0	1	850
1500	100	0.5453	464
1600	200	0.4662	396
1700	300	0.3884	330
1800	400	0.3149	268
1900	500	0.2481	211
2000	600	0.1896	161
2100	700	0.1405	119
2200	800	0.1009	86
2300	900	0.0701	60
2400	1000	0.0471	40
2500	1100	0.0306	26
2600	1200	0.0192	16
2700	1300	0.0116	10
2800	1400	0.0068	6
2900	1500	0.0038	3
3000	1600	0.0021	2
3100	1700	0.0011	1
3200	1800	0.0006	0
3300	1900	0.0003	0
3400	2000	0.0001	0

ORDC Curve - Summer 1500-1800 (TBlock 5)



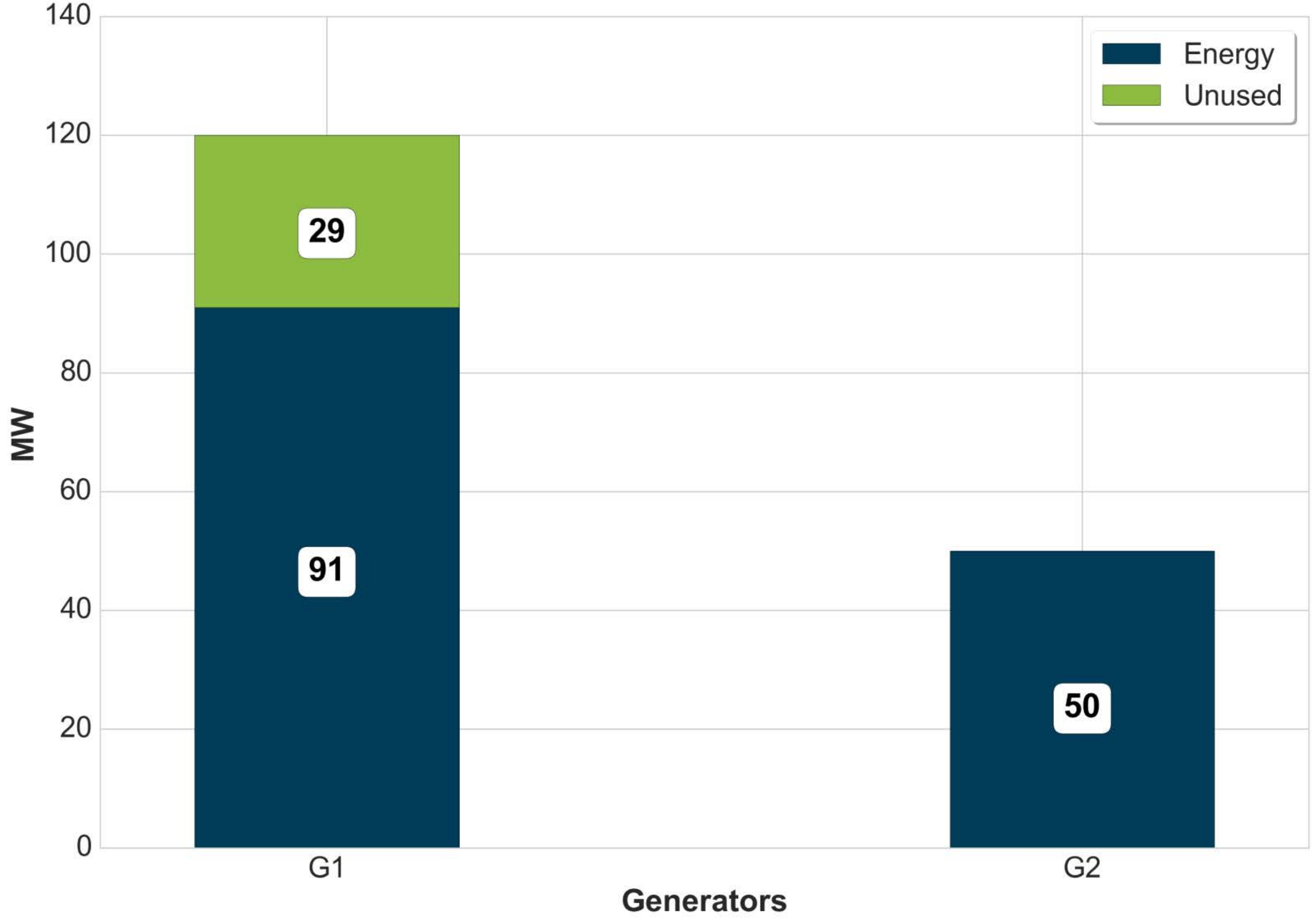
- ORDC adjustment due to operators' actions
  - Case 1: operators take actions due to greater-than-normal uncertainty (specifically, forced outages uncertainty)
    - If greater-than-normal uncertainty can be quantified, then ORDC can be adjusted following procedure described in previous slides (Extreme Day Curve)
  - Case 2: operators take actions due to externalities not accounted for in SCED
    - ORDC can be extended by MW impact on reserves amount.
  - In either of the two cases, decisions need to be made as to when the adjusted ORDC is triggered and for how long.

Further Considerations

- MRR is a variable quantity
  - This should not pose a challenge to the implementation of the short-term simplified ORDC since the PBMRR does not depend on the MRR, only on the excess above the MRR.
- Reserve Zone ORDCs
  - Reserve Zone ORDCs can be derived following the same methodology described in previous slides using data from zonal forecasts.

Co-Optimization of Energy and Reserves Basic Concepts and Examples

Single Period Example



Energy Offers:

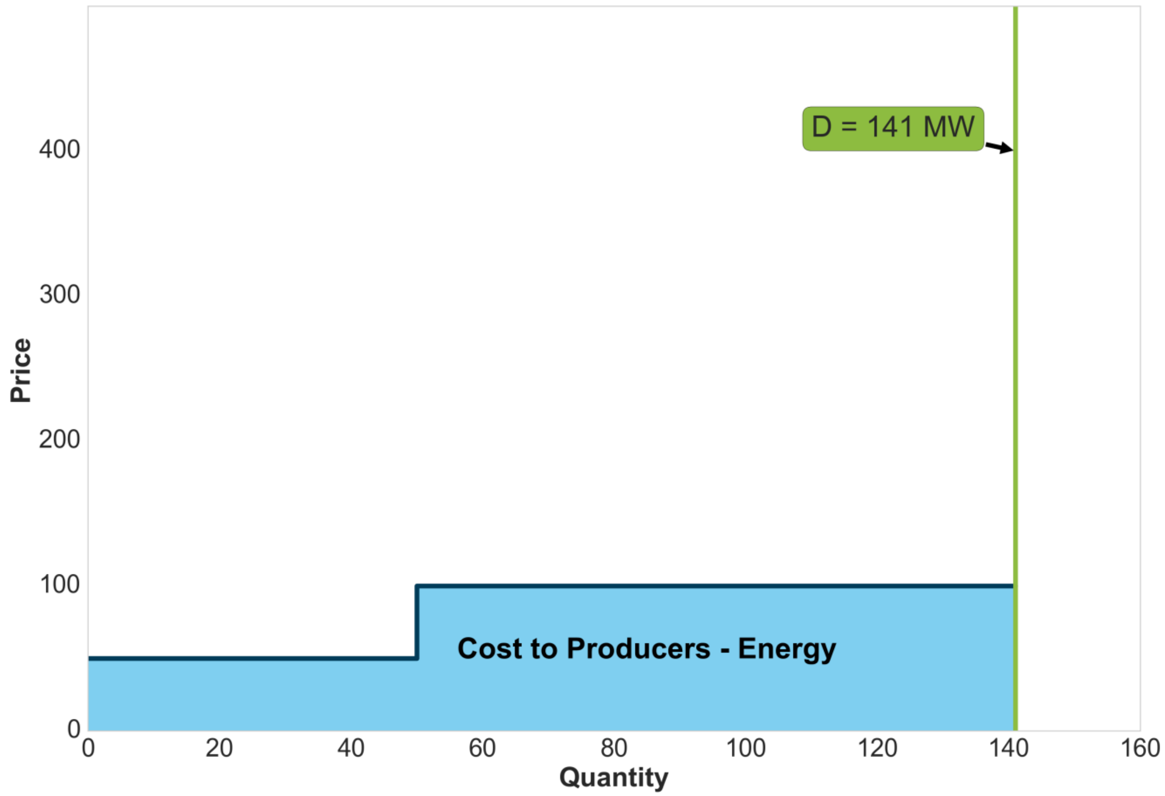
G1: $100 / MWh
G2: $50 / MWh

Demand = 141 MW

Chart reflects optimal Energy allocations

Energy Market Optimization – Objective Function

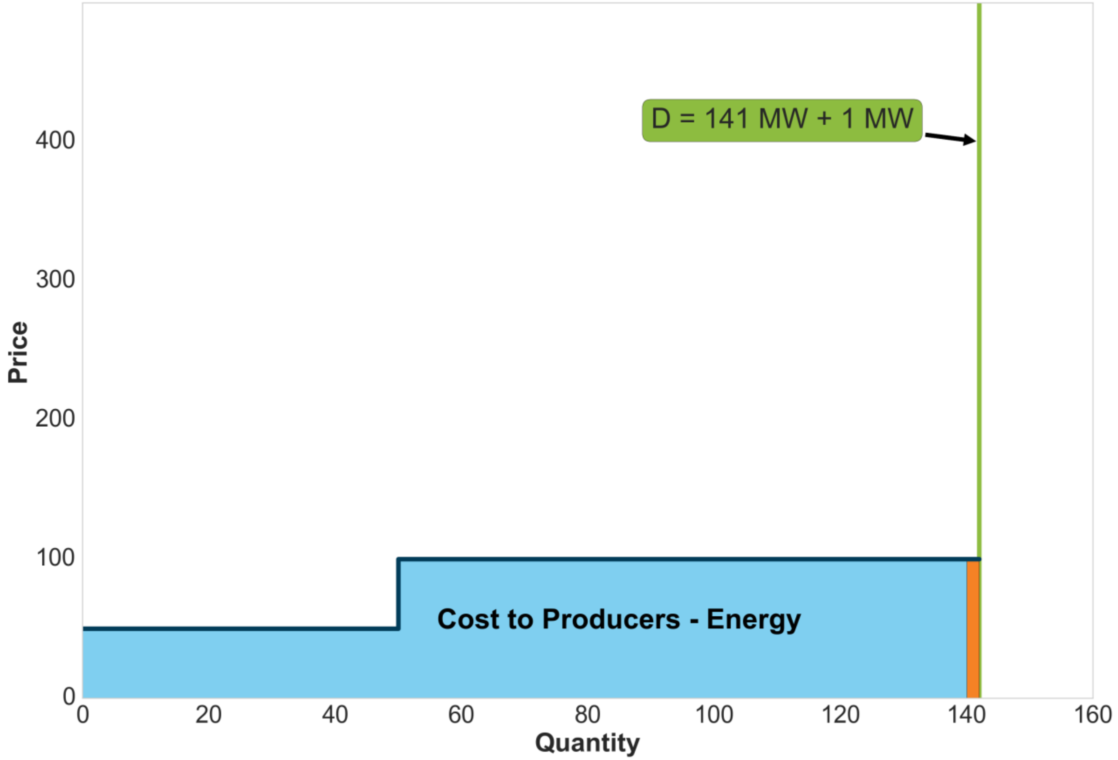
- Objective Function (E): Minimize Cost to Producers



E = \$50/MW x 50 MW + \$100/MW x 91 MW

E = \$11,600

- Clearing Price is the change in the objective function if we need to serve 1 MW of additional energy



E(1MW) = $50/MW x 50 MW + $100/MW x 92 MW

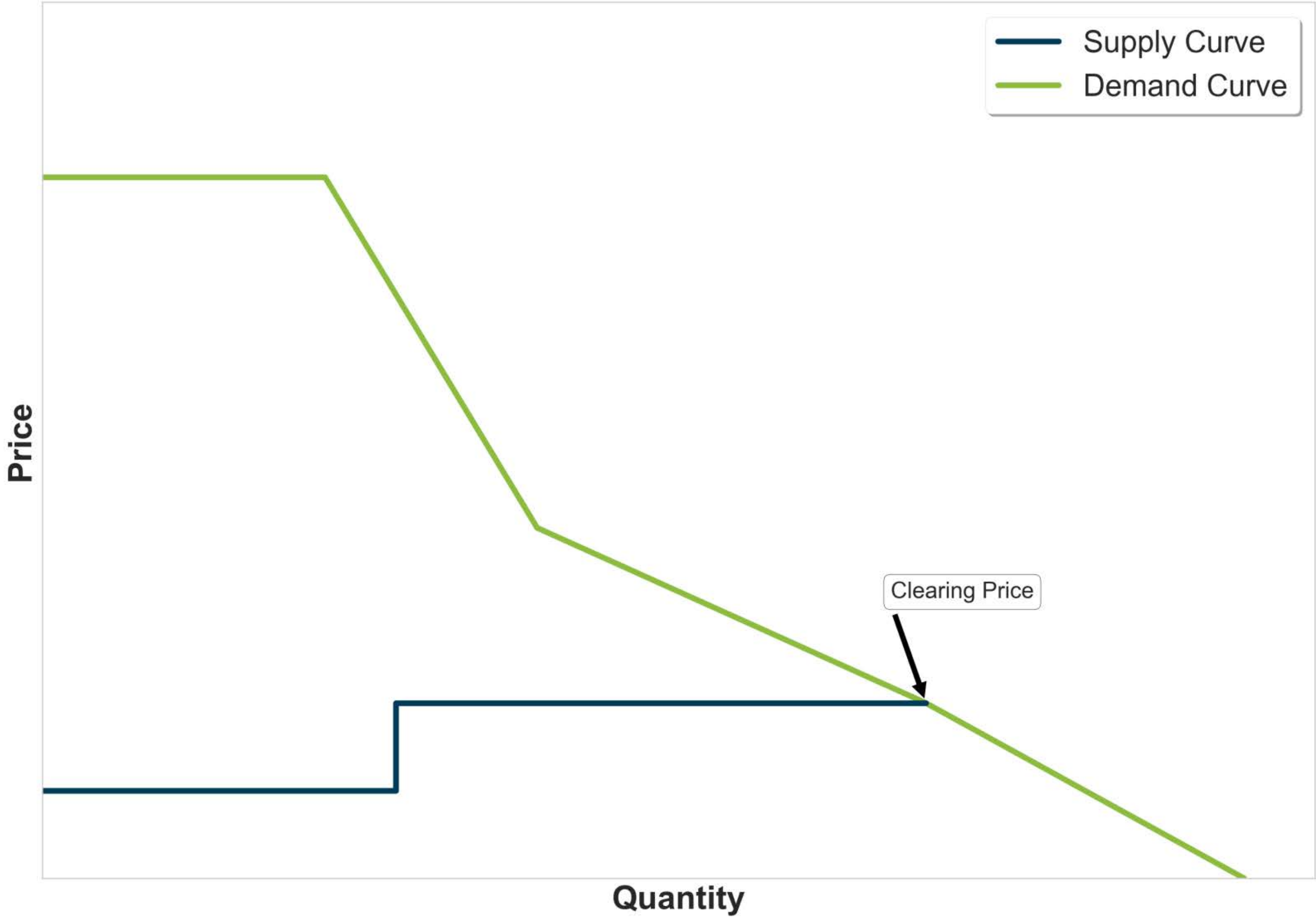
E(1MW) = $11,700

Change in Objective Function:

E(1MW) – E = $11,700 - $11,600 = $100

Therefore,
Clearing Price is $100 / MWh

What if Demand is not fixed (not a vertical demand curve)



The new Operating Reserves Demand Curve (ORDC) has this downward-sloping shape.
Also, this type of shape is used in RPM.

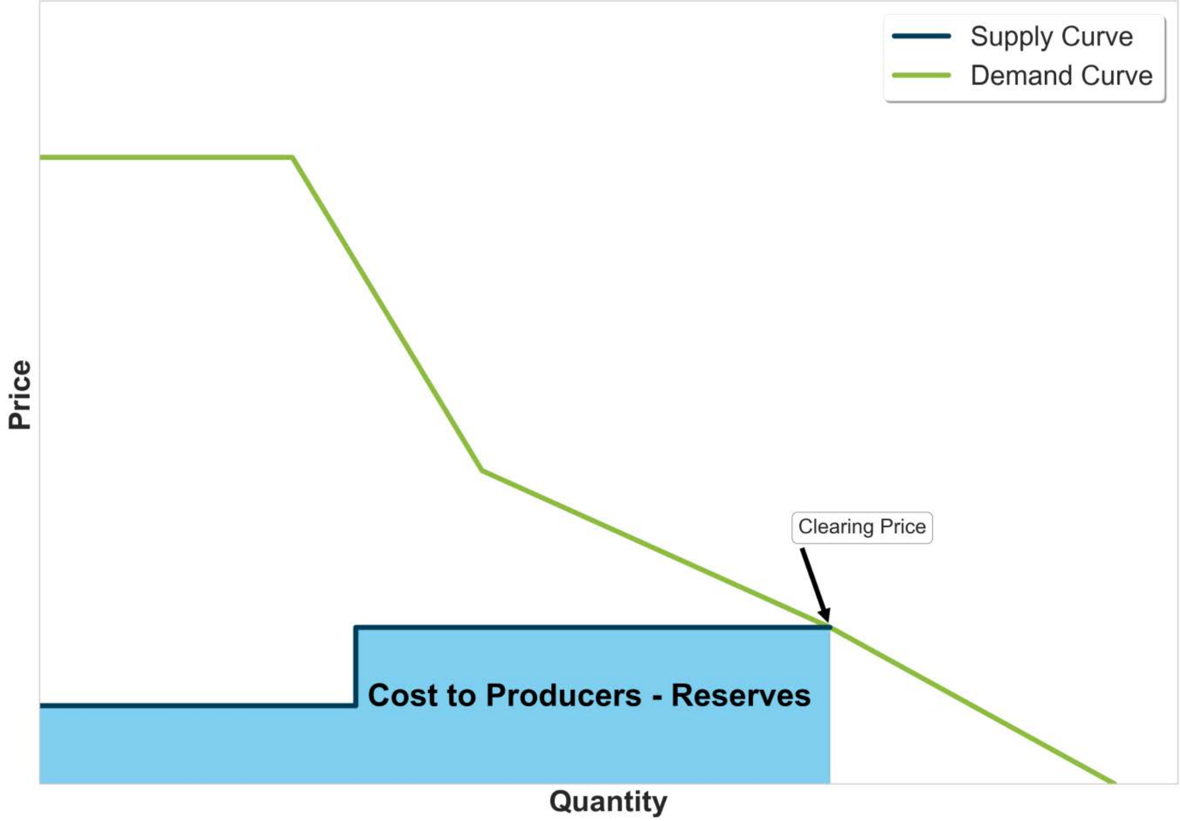
Reserve Market Optimization with ORDC – Objective Function

- Objective Function (R): Maximize Social Welfare

- Social Welfare is defined as Benefit to Consumers minus Cost to Producers

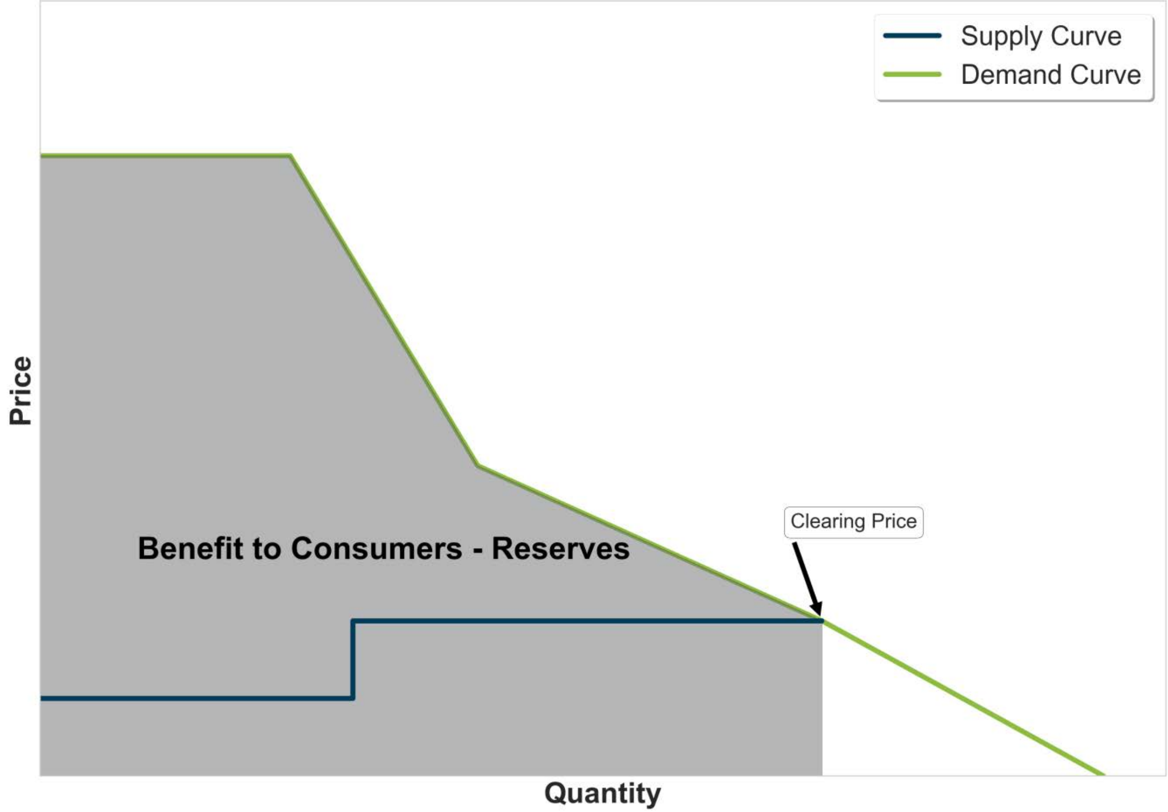
- R = Maximize (Benefit to Consumers minus Cost to Producers)

- Cost to Producers



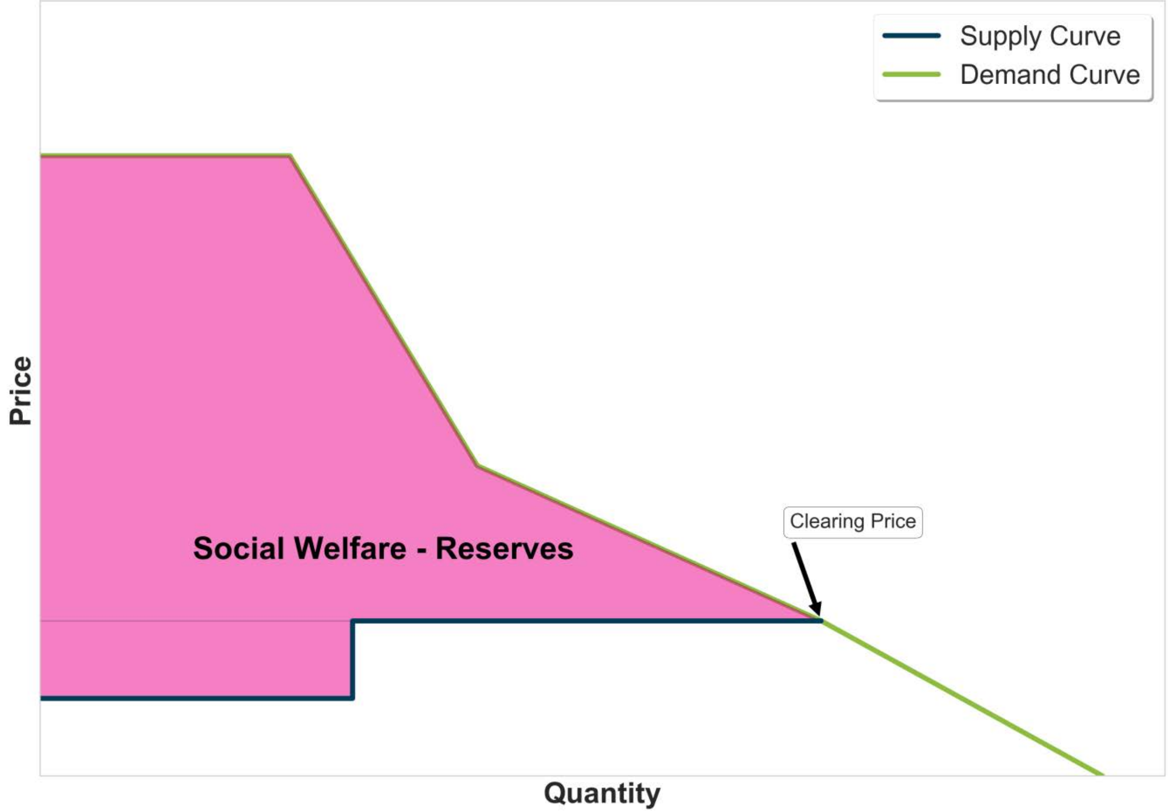
Reserve Market Optimization with ORDC – Objective Function

- Benefit to Consumers

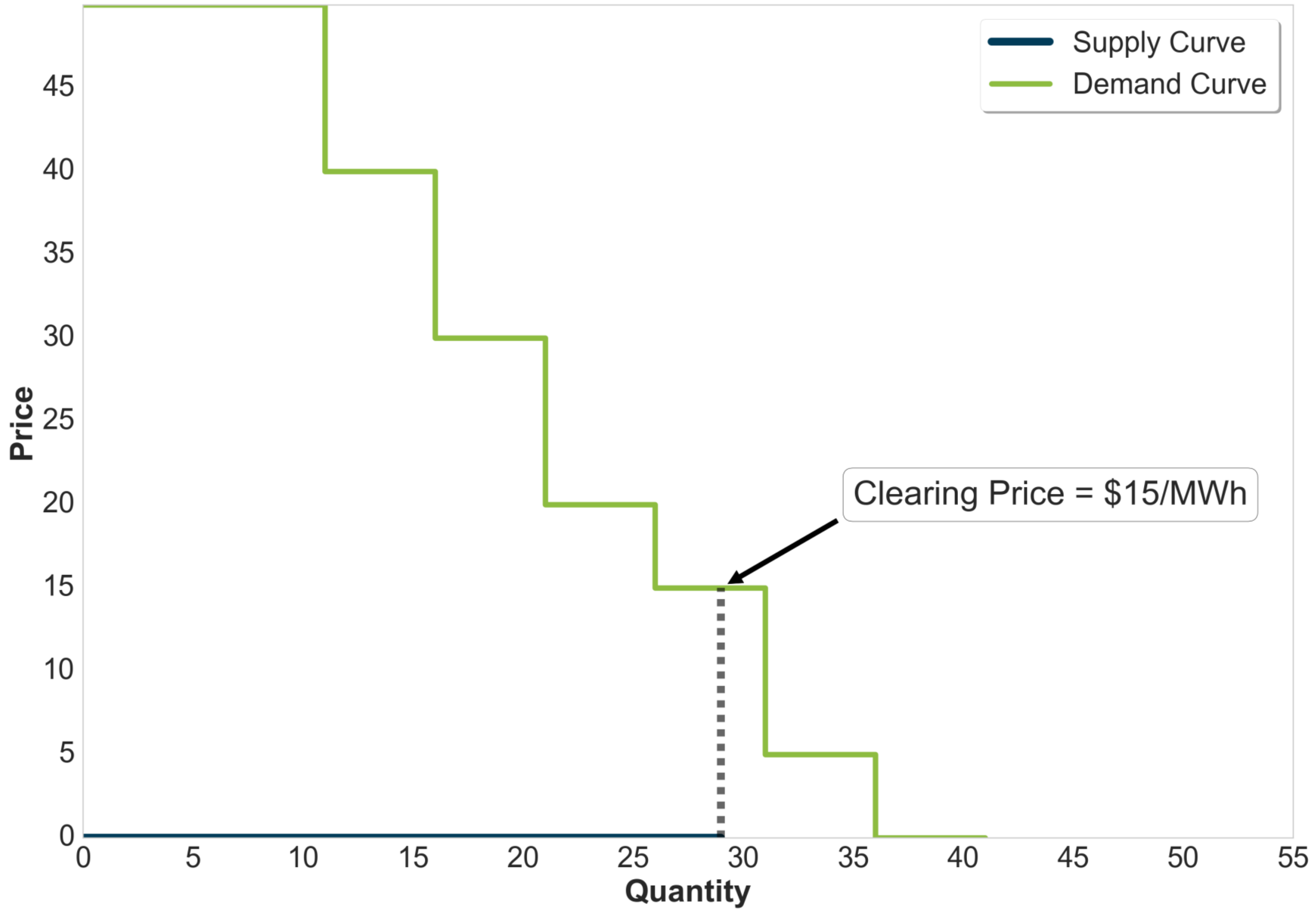


Reserve Market Optimization with ORDC – Objective Function

- Social Welfare = Benefit to Consumers minus Cost to Producers



Reserve Market Optimization with ORDC – Example



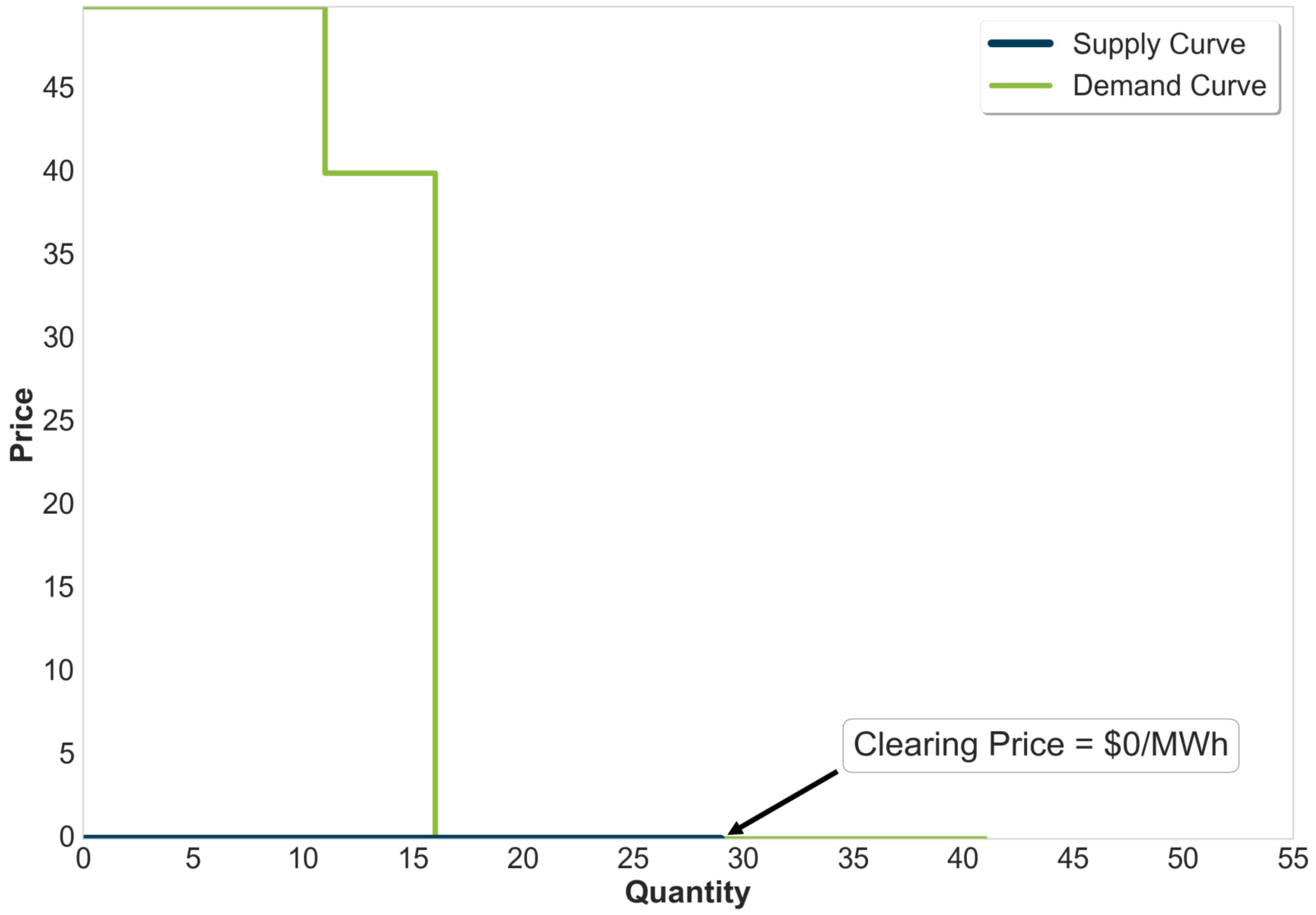
After serving a given demand, there are 29 MW available for reserves at $0/MWh.

We clear 29 MW of reserves.

The supply curve of reserves is at the $0/MWh level

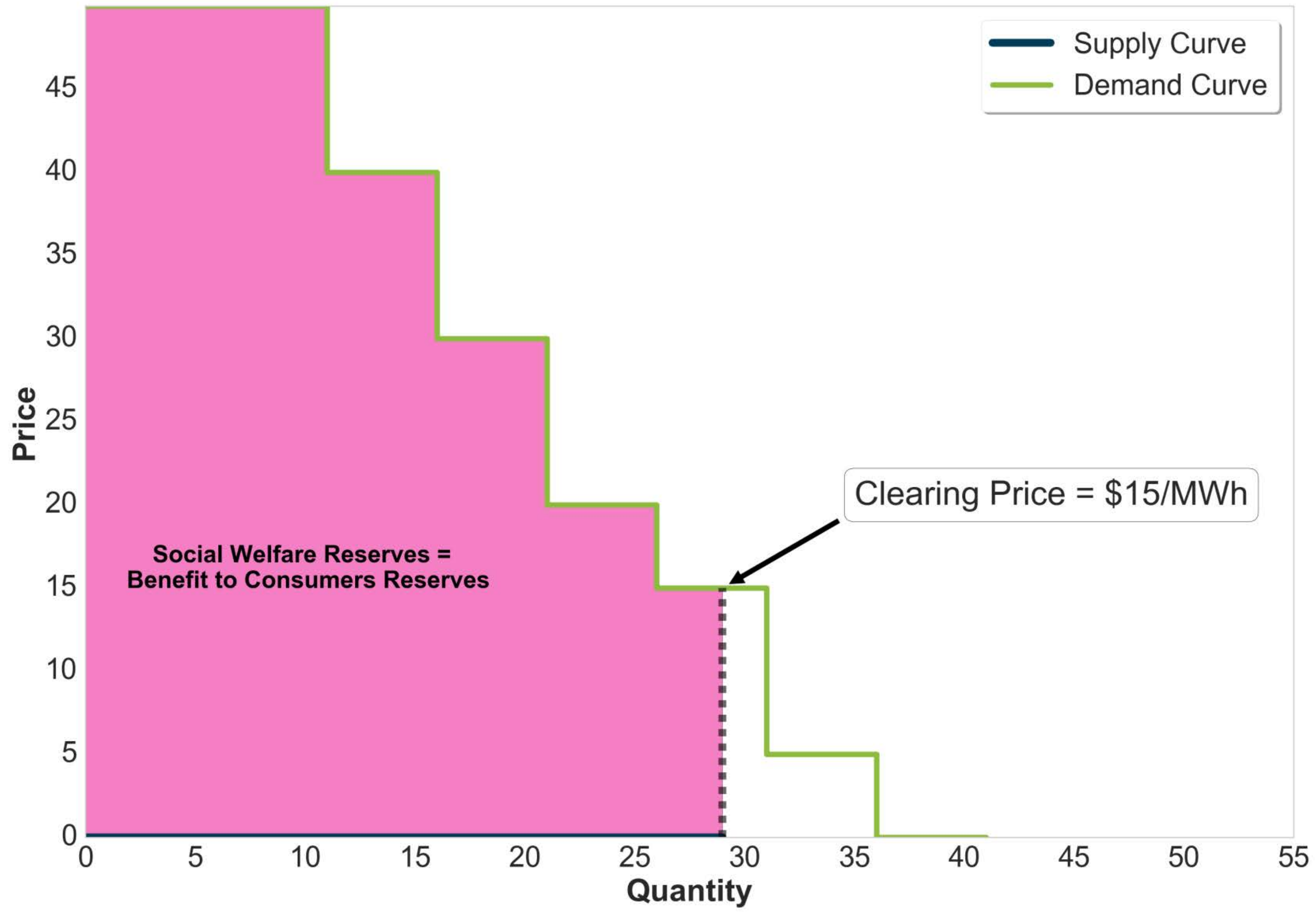
Clearing price is dictated by the Demand Curve

Reserve Market Optimization with ORDC – Example



Had the ORDC included only the first two steps (similar to PJM's current ORDC), the quantity cleared is also 29 MW but the clearing price would have been $0/MW.

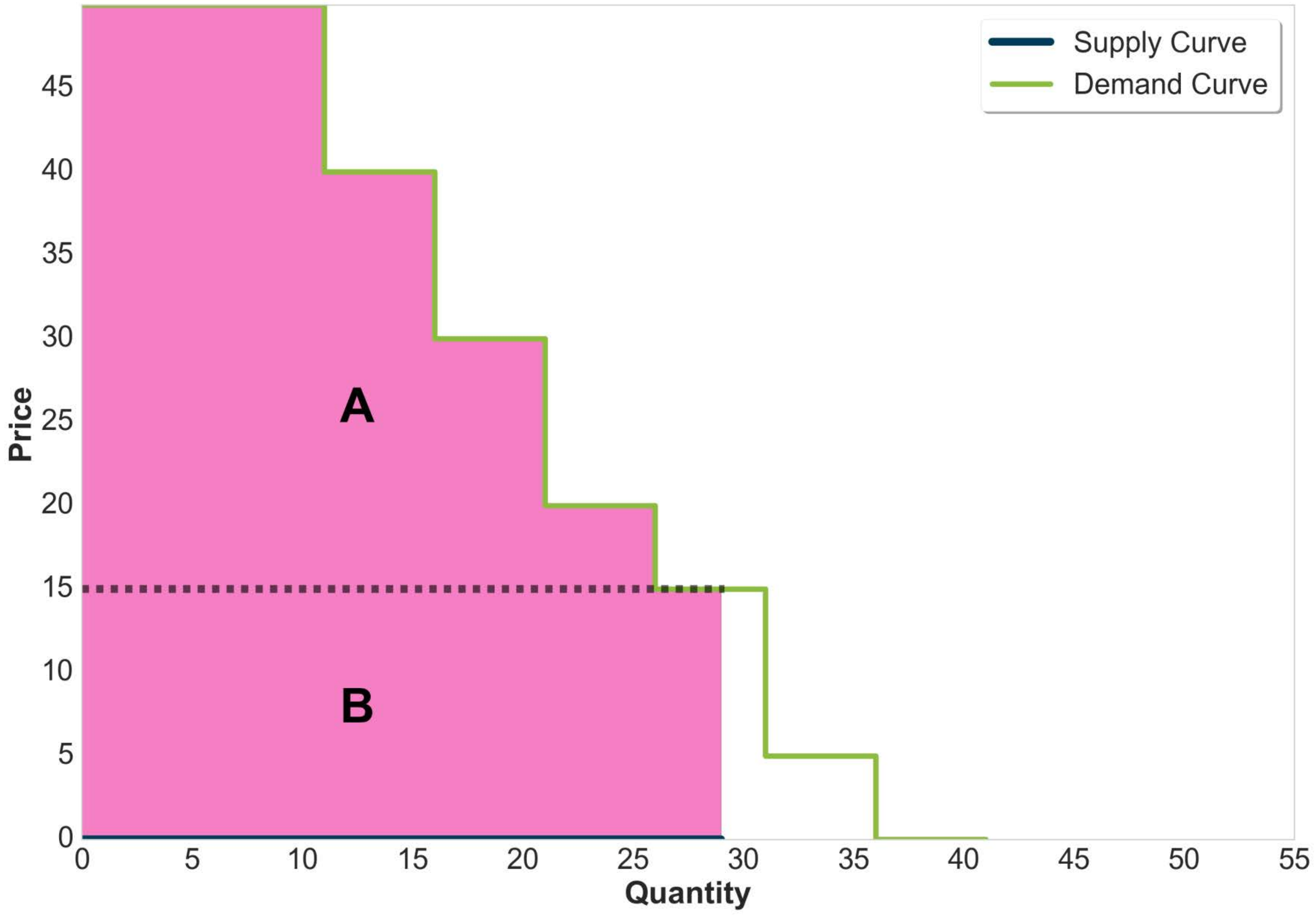
Reserve Market Optimization with ORDC – Example



Since the supply curve is at the $0/MWh level, the Cost to Producers is 0 (area under the Supply curve).

Therefore,
Social Welfare = Benefit to Consumers

Reserve Market Optimization with ORDC – Example



R = Social Welfare = Benefit to Consumers

R = A + B

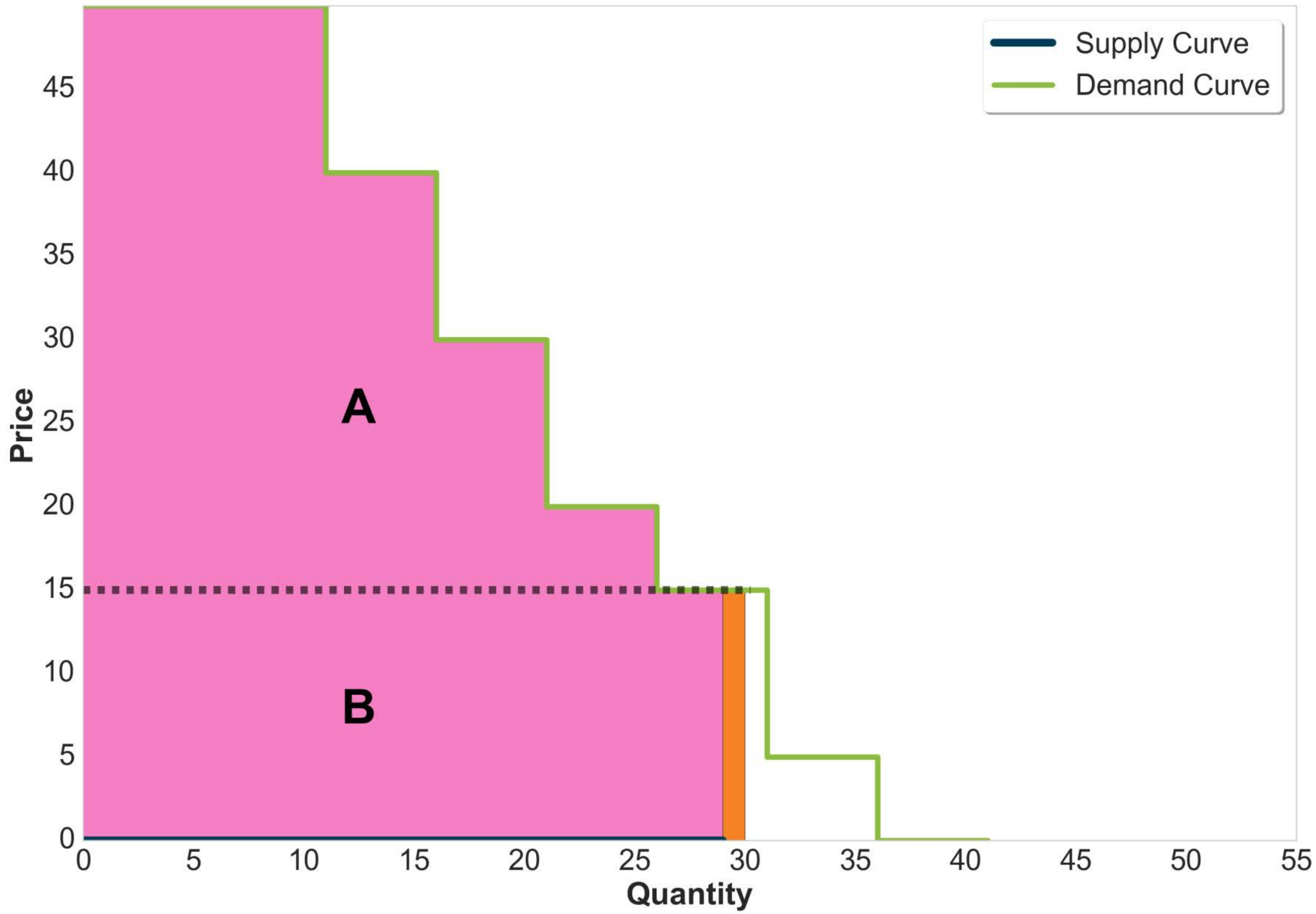
R = $610 + $15/MWh x 29 MW

R = $610 + $435

R = $1,045

Note that A = $610

Reserve Market Optimization with ORDC – Example



Clearing Price is the change in the objective function if we need to serve 1 MW of additional reserves

R(1MW) = A + B
R(1MW) = A + $15/MWh x 30 MW

R(1MW) = $610 + $450 = $1,060

Change in Objective Function:

R(1MW) – R = $1,060 – $1,045

R(1MW) – R = $15

Therefore,
Clearing Price is $15 / MWh

- Objective Function: Maximizing Social Welfare

Max (Social Welfare) =

Assuming vertical demand curve for energy and downward-sloping demand curve for reserves

Max (Social Welfare Energy + Social Welfare Reserves) =

Max (Benefit Consumers Energy – Cost Producers Energy) +
(Benefit Consumers Reserves – Cost Producers Reserves) =

Max (~~Benefit Consumers Energy~~ – Cost Producers Energy) +
(Benefit Consumers Reserves – Cost Producers Reserves) =

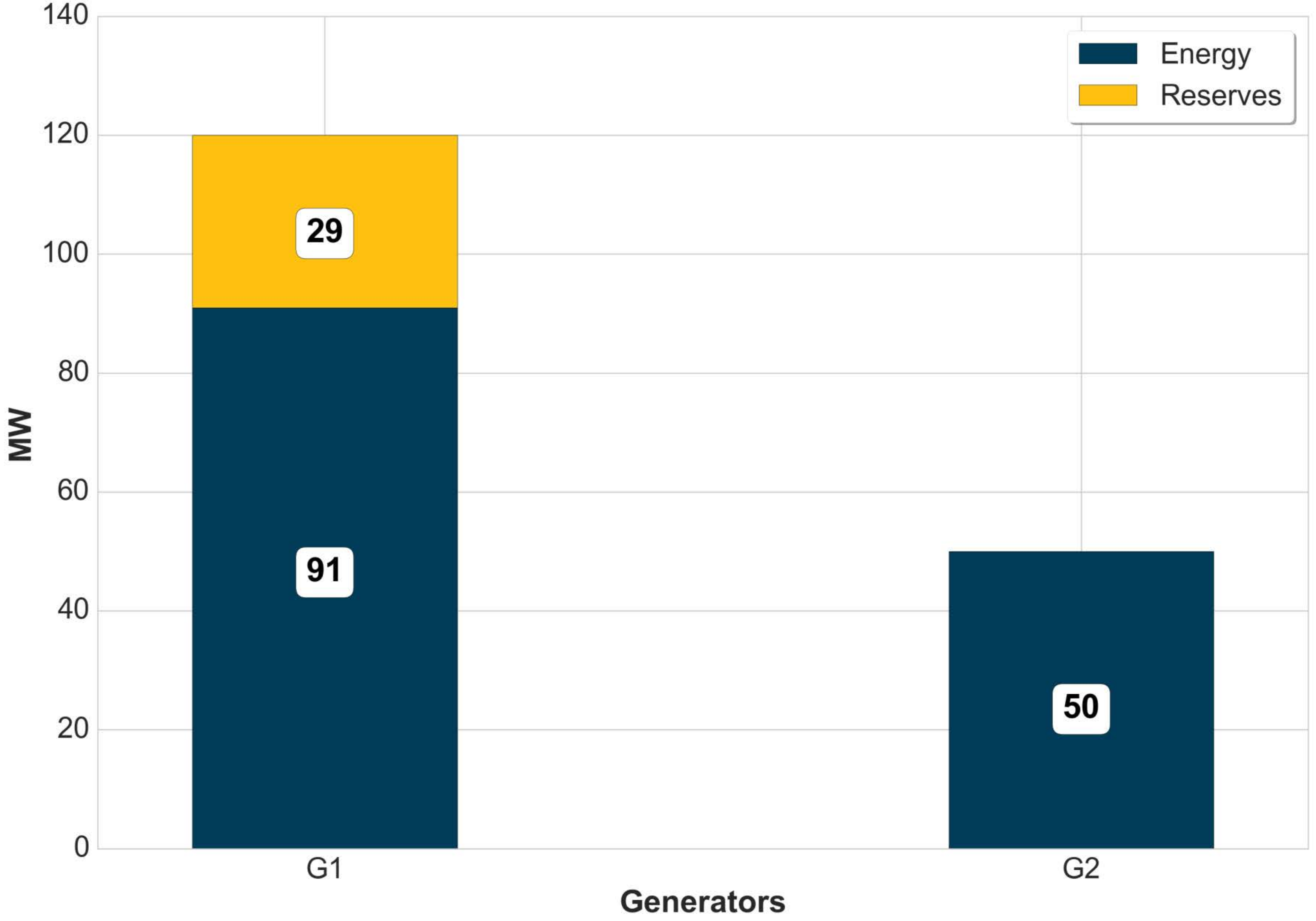
Multiplying by -1

Min (Cost Producers Energy - (Benefit Consumers Reserves – Cost Producers Reserves)) =

Min (Cost Producers Energy – Social Welfare Reserves)

- Benefit to Consumers Energy does not impact the objective function because it is a constant (which, in turn, it is due to the fact that for energy we assume a vertical demand curve). Constants do not matter in optimization problems.
- Multiplying a Maximization objective function by -1 alters the signs of the objective function and turns the problem into a Minimization problem

Co-Optimizing Energy and Reserves - Example



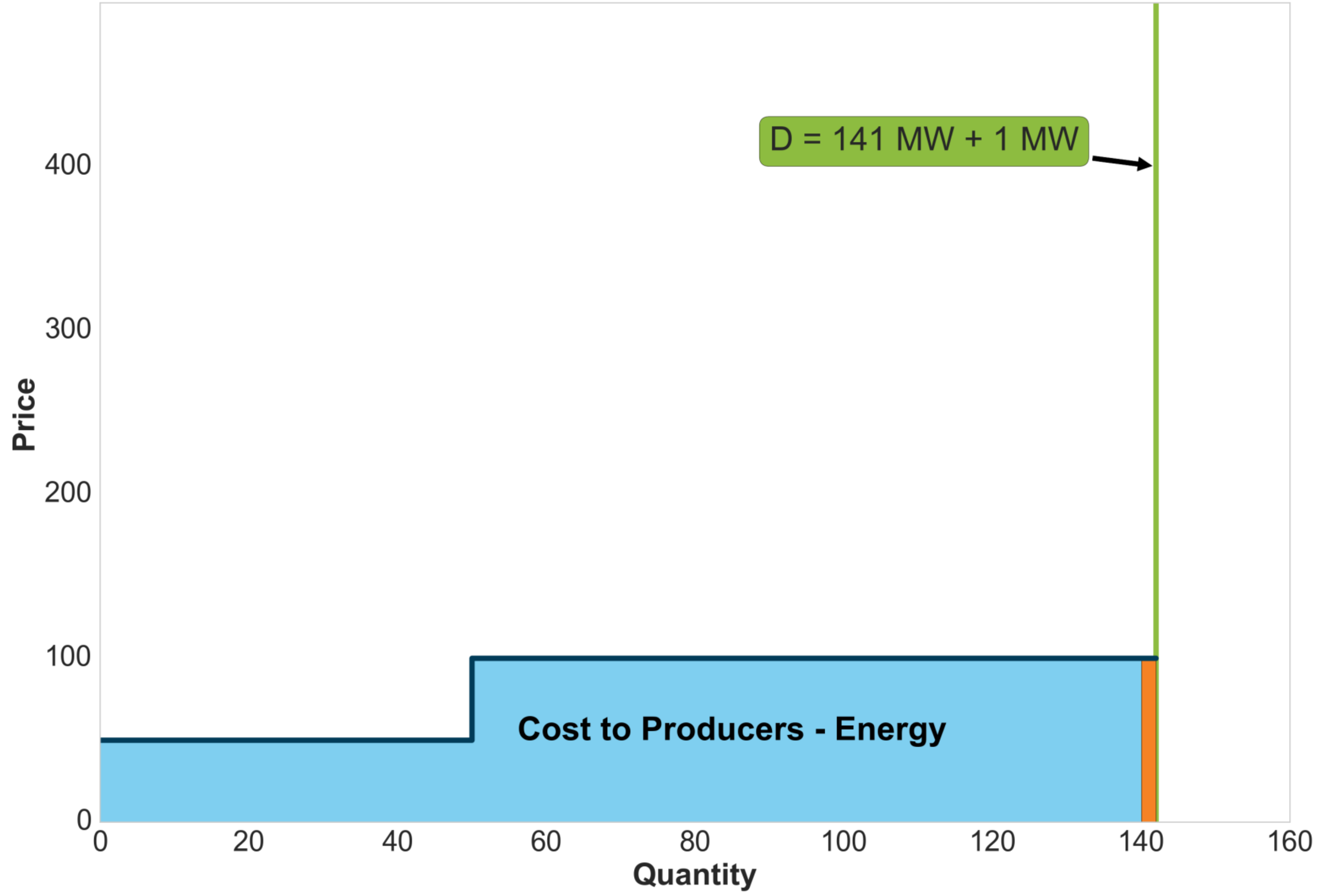
Energy Offers:

G1: $100 / MWh
G2: $50 / MWh

Demand = 141 MW

Chart reflects optimal Energy and Reserve allocations

Co-Optimizing Energy and Reserves - Example

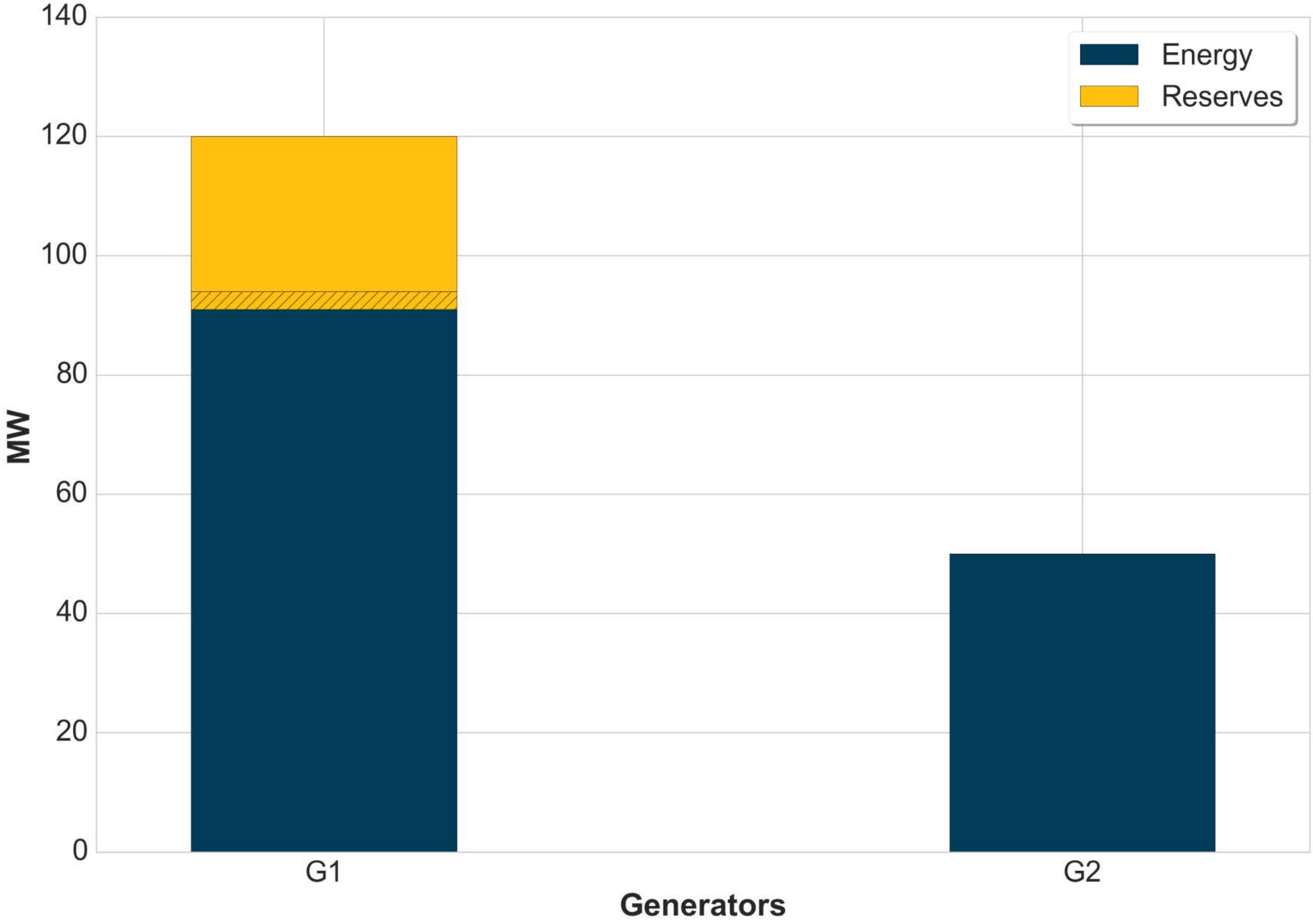


What is the clearing price for energy?

The clearing price for Energy is not as straightforward as in Slide 4 because we are co-optimizing energy and reserves.

We need to consider the implications for reserves, if we clear 1 MW of additional energy.

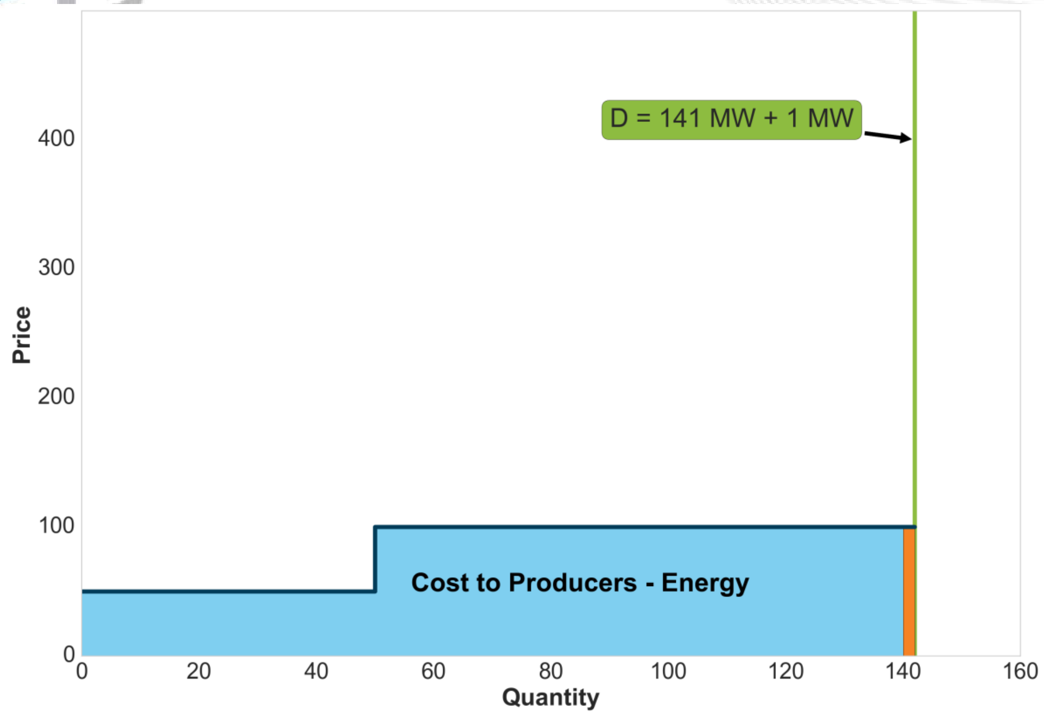
Co-Optimizing Energy and Reserves - Example

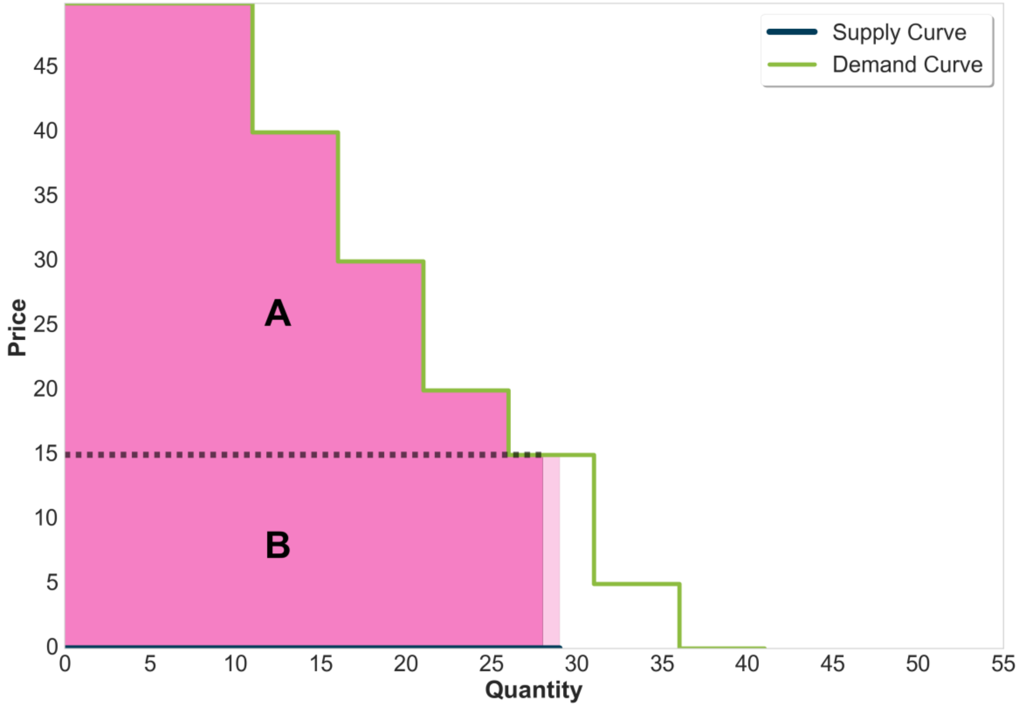


Clearing Price for Energy is the change in the objective function if we need to serve 1 MW of additional energy.

If we serve 1 MW additional energy, we increase the energy cost and we reduce the social welfare from reserves (because we increase energy by 1 MW and have to reduce reserves by 1 MW)

Co-Optimizing Energy and Reserves - Example



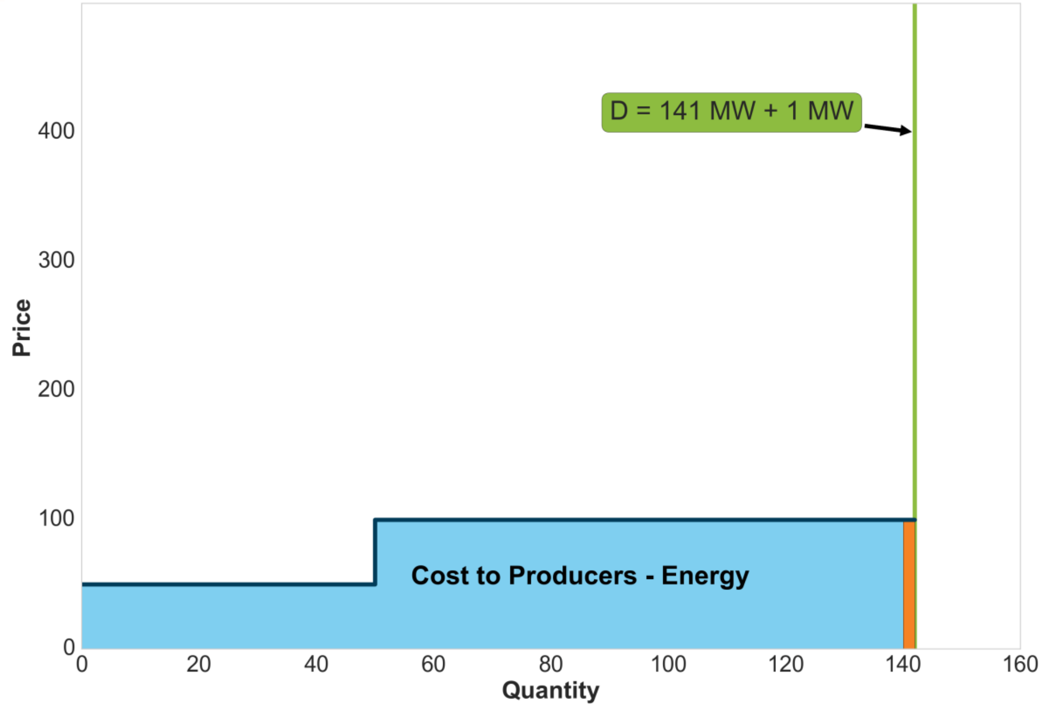


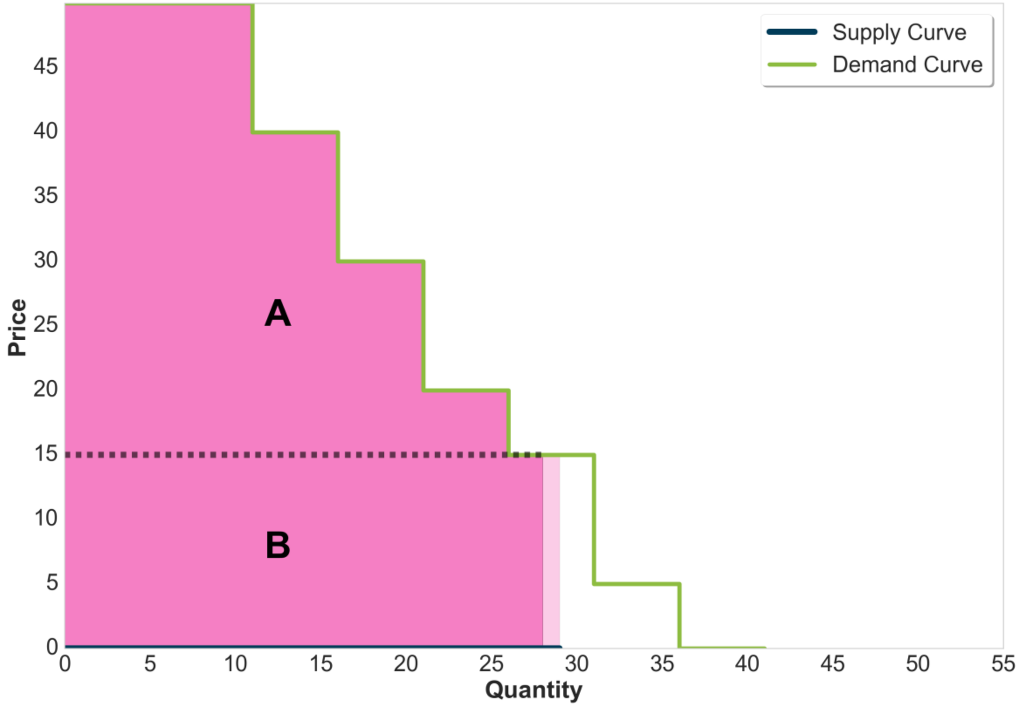
Optimal Social Welfare = Cost to Producers Energy - Social Welfare Reserves
= \$50/MW x 50 MW + \$100/MW x 91 MW – (\$610 + \$15/MWh x 29 MW)
= **\$10,555**

If we need to serve 1 MW of additional energy:

Social Welfare (1MW) = \$50/MW x 50 MW + \$100/MW x **92 MW** – (\$610 + \$15/MWh x **28** MW)
= **\$10,670**

Co-Optimizing Energy and Reserves - Example





The change in the social welfare function to serve 1 MW of additional energy is:

Change in Social Welfare = \$10,670 – \$10,555
= \$115

Therefore, the energy clearing price is \$115/MWh. Note that, **for this particular example**, the reserve price (\$15/MWh) ends up being added to the original energy-only price (\$100/MWh)