

# Reliability Pricing Model Auction Supplement

RPM Training – Appendix E  
February 2012

The Auction Supplement Appendix covers:

- Coupled Sell Offers for Demand Resources
- Credit Limited Sell Offers
- Flexible Self-Scheduling
- New Unit Pricing
- Available ICAP to Offer in RPM Auctions
- Auction Clearing Examples
- Auction Results Example

- CSP can structure their coupled offer in such a manner to increase the likelihood that the more limited DR resource will clear in the case where minimum resource requirement constraints do not bind in the RPM auction.
  - The maximum MW quantity of the less limited DR product offer is no greater than the maximum MW quantity of the more limited coupled DR product offer and;
  - The minimum MW quantity of the more limited DR product offer is no greater than the minimum MW quantity of the less limited coupled DR offer.

*Please note that such an outcome cannot be guaranteed. Auction will clear less limited products associated with coupled offers, if they are economic, to meet either the minimum annual resource or minimum extended summer resource requirement. Clearing price for such less limited product(s) will be consistent with the offers for those products. However, this does not necessary mean that there will be price separation between the three products.*

- Suppose the following Pre-Registration data was submitted:

Coupled Offer	Zone Name	Annual	Extended Summer	Limited	Nominated MW
x	PECO	x	x	x	30
x	PECO	x	x	x	30
x	PECO		x	x	20
	PECO			x	10
	PECO			x	10
Max DR Mod:		60	80	100	100

RPM Hotline would model 3 resources for the Existing Registrations in PECO: One Annual, One Extended Summer, One Limited

Coupled Offers cannot clear more than 100 MWs.

- A CSP must couple Demand Resources in eRPM prior to submitting an offer into the auction:
  - Must be in the same Zone and LDA
  - Must be unique product types
- CSP will assign a unique name to identify the coupling group (i.e., Existing PECO Couple)
- Coupled Offers cannot use the Credit Limited Clearing Option

See eRPM User Guide for instructions on how to couple resources in eRPM.

- Offers are coupled by segment number
  - Offer segment 1 of Resource A, B and C is coupled
  - Offer segment 2 of Resource A, B and C is coupled
  - Etc.
- Each coupled segment can be considered as a separate coupled single-segment DR offer
  - Only one offer from each segment group may clear at most and each segment group is cleared independent of the other segment group.
- The sum of the Max MW for each Segment in a Coupled Offer cannot exceed the total MWs approved via the DR Plan or Pre-Registration process.

Couple Name	Resource		1	2	3	4	Total
Existing PECO Couple	Limited	Min	0	0	0	0	
		Max	30	30	20	20	
		Price	\$5	\$35	\$50	\$70	
Existing PECO Couple	Summer Ext	Min	0	0	0		
		Max	30	30	20		
		Price	\$30	\$70	\$80		
Existing PECO Couple	Annual	Min	0	0			
		Max	30	30			
		Price	\$60	\$90			
Max MW of each segment			30	30	20	20	<b>100</b>

- Each Segment is considered independently.
- The Sum of the Max MW of each segment is equal to the pre-registered MW total.

Couple Name	Resource		1	2	3	4	Total
Existing PECO Couple	Limited	Min	0	0	0	0	
		Max	50	20	10	20	
		Price	\$5	\$35	\$50	\$70	
Existing PECO Couple	Summer Ext	Min	0	0	0		
		Max	50	20	10		
		Price	\$30	\$70	\$80		
Existing PECO Couple	Annual	Min	0				
		Max	60				
		Price	\$60				
Max MW of each segment			60	20	10	20	110

- The Sum of the Max MW of each segment (110 MW) is higher than the pre-registered MW total (100 MW).
- PJM would notify the CSP and require the offer to be amended

## Scenario 1: No Price Separation between Limited, Extended Summer, or Annual

Resource Name	Type	Min MW	Max MW	Offer Price	Resource Clearing Price	Cleared MW
Resource A	Limited	0	100	\$5	\$65	100
Resource B	Extended Summer	0	80	\$30	\$65	0
Resource C	Annual	0	60	\$60	\$65	0

- Limited Offer will clear as it provides the most “profit”
  - Profit = (Clearing Price – Offer Price) \* MW
  - Profit<sub>Limited</sub> = (\$65 - \$5) \* 100 MW = \$6000
  - Profit<sub>Ext Sum</sub> = (\$65 - \$30) \* 80 MW = \$2800
  - Profit<sub>Annual</sub> = (\$65 - \$60) \* 60 MW = \$300

## Scenario 2: Price Separation between Limited and Annual: Limited Offer Clears

Resource Name	Type	Min MW	Max MW	Offer Price	Resource Clearing Price	Cleared MW
Resource A	Limited	0	100	\$5	\$75	100
Resource B	Extended Summer	0	80	\$30	\$75	0
Resource C	Annual	0	60	\$60	\$100	0

- Limited Offer will clear as it provides the most “profit”
  - Profit = (Clearing Price – Offer Price) \* MW
  - Profit<sub>Limited</sub> = (\$75 - \$5) \* 100 MW = \$7000
  - Profit<sub>Ext Sum</sub> = (\$75 - \$30) \* 80 MW = \$3600
  - Profit<sub>Annual</sub> = (\$100 - \$60) \* 60 MW = \$2400

Scenario 3: Price Separation between Limited , Extended Summer, and Annual: Annual Offer Clears

Resource Name	Type	Min MW	Max MW	Offer Price	Resource Clearing Price	Cleared MW
Resource A	Limited	0	100	\$5	\$10	0
Resource B	Extended Summer	0	80	\$30	\$35	0
Resource C	Annual	0	60	\$60	\$100	60

- Annual Offer will clear as it provides the most “profit”
  - Profit = (Clearing Price – Offer Price) \* MW
  - Profit<sub>Limited</sub> = (\$10 - \$5) \* 100 MW = \$500
  - Profit<sub>Ext Sum</sub> = (\$35 - \$30) \* 80 MW = \$400
  - Profit<sub>Annual</sub> = (\$100 - \$60) \* 60 MW = \$2400

- Planned Resources will have the ability to nominate a Maximum Post-Auction Credit Exposure (MPCE)
- The Auction will only clear Planned MWs up to the supplier's nominated MPCE

- A Supplier must notify PJM that they intend to utilize MPCE
- An MPCE is assigned separately to each Planned Resource
- The sum of the MPCE nominated for each Planned Resource in a party's portfolio may not exceed their total available credit
- Coupled DR Resources may not utilize the Credit Limited Offer Functionality.

- CSP wishes to offer 300 MW of Planned MW
  - Pre-Auction Credit Requirement would be:
    - $300 \text{ MW} * \$37,474 = \$11,242,200$
- CSP has \$3,000,000 of available Credit
- CSP nominates \$1,000,000 MPCE for each Offer
- Auction is run to determine initial clearing results.
  - Cleared MWs by Resource
  - Resource Clearing Price
  - Post Auction Credit Rate
  - Resulting Post-Auction Credit Exposure (PCE)
- Any resources that have a PCE greater than the specified MPCE will cause the auction to re-execute until a solution yields a PCE equal to or less than the MPCE

Resource Name	MPCE (\$/yr)	Max MW	Offer Price (\$/M W-day)	Resource Clearing Price (\$/MW-day)	Cleared MW	Post Auction Credit Rate (\$/MW-yr)	Post-Auction Credit Exposure (PCE) (\$/yr)
COMED 1	\$1,000,000	100	\$5	\$10	100	\$7,300	\$730,000
PPL 1	\$1,000,000	100	\$30	\$100	100	\$7,300	\$730,000
PECO 1	\$1,000,000	100	\$60	\$200	100	\$14,600	<b>\$1,460,000</b>

The Post Auction Credit Exposure of the EMAAC Resource (PECO 1) is greater than the MPCE.

If there are resources with PCE that did not exceed MPCE, the remaining credit availability on such resources is not applied to the resource with PCE that exceeded their MPCE.

Resource Name	MPCE (\$/yr)	Max MW	Offer Price (\$/M W-day)	Resource Clearing Price (\$/MW-day)	Cleared MW	Post Auction Credit Rate (\$/MW-yr)	Post-Auction Credit Exposure (PCE) (\$/yr)
COMED 1	\$1,000,000	100	\$5	\$10	100	\$7,300	\$730,000
PPL 1	\$1,000,000	100	\$30	\$100	100	\$7,300	\$730,000
PECO 1	\$1,000,000	100	\$60	\$220	62	\$16,060	\$995,720

The EMAAC Resource Clearing Price can increase due to unavailability of the CSP's EMAAC Resource MWs.

The final Auction Solution ensures the PCE does not exceed the MPCE.

- Flexible Self-Scheduling allows an LSE with self-supply to manage the quantity uncertainty related to the Variable Resource Requirement and a LSE's capacity obligation.
- If the **flexible self-schedule flag** is set:
  - the sell offer must specify an offer price that will be utilized in the market clearing in the event that the resource is not needed to cover the calculated capacity obligation.
  - must also submit through Self-Schedule screen in eRPM the percentage of the Preliminary Zonal Peak Load Forecast in each transmission zone the LSE wishes to cover with self-scheduled and flexible self-scheduled resources.

Flexible Self-Scheduling option is available in BRA only.

## Generation Resource (EMAACLDA)

### Base Offer Segments

EFORd:

EFORd Limit: 1.1

New Unit

Pricing:

	1	2	3	4	5	6	7	8	9	10
<b>Min MW</b>	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>Max MW</b>	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	8.9
<b>Price</b>	\$ 0.0	\$ 0.0	\$ 11.0	\$10.50	\$ 9.80	\$ 6.50	\$ 8.40	\$20.51	\$25.92	\$31.18
<b>Scheduling Option</b>	Self Schedule	Self	Flex	Flex	Flex	Flex	Flex	Regular	Regular	Regular

A participant can specify Self Schedule or Flexible Self Schedule in any offer segment.

Should the same LSE offer both self-schedule and flexible self-schedule resources to serve an Unforced Capacity Obligation within the same Zone, those resources that are self-scheduled will be used first to meet the obligation.

Company: TEST    Planning Period: 2010/2011    Zone: ALL

BASE	STATUS
BASE	OPEN
FIRST	CANCELLED
SECOND	FUTURE
THIRD	FUTURE

Pages: 1    Records: 1 - 22 of 22 matches.

Zone	Self Scheduling Factor
AECO	(null)
AEP	(null)
APS	(null)
BGE	(null)
BUCKON	(null)
BUCKFE	(null)
COMED	(null)
DAY	(null)
DOM	0.12
DPL	(null)
DUG	(null)
EXT	(null)
JCPL	(null)
METED	(null)
NCEMCCPL	(null)
PECO	(null)
PENELEC	(null)
PEPCO	(null)
PPL	(null)
PSEG	(null)
RECO	(null)
TTSCL	(null)

Enter the desired percentage of Preliminary Zonal Peak Load Forecast that wish to cover with self-scheduled and flexible self-scheduled resources.

This percentage will be used to calculate the LSE's resulting capacity obligation through the auction clearing process.

- The flexible self-schedule resources will be automatically cleared in the auction if they are needed to supply the LSEs resulting capacity obligation.
- In the event that the LSE does not need all of the resources that were specified as flexible self-schedule resources to meet its resulting capacity obligation, the RPM clearing function will consider the excess as offered into the market.
- The resources that are considered excess for this LSE will be those that have the highest specified offer prices.

**On the Self-Scheduling screen, A participant Must specify the self-scheduling factor in the zone which the resource resides**

Self Scheduling	
Zone	Self Scheduling Factor
AECO	.1
AEP	(null)
APS	(null)

## Calculation of Target Self-Scheduled MWs

Target Self-Schedule MW	=	Base Zonal UCAP Obligation	*	Self-Schedule Factor
30 MW	=	3,000	*	.01

## Generation Resource (EMAACLDA)

EFORd:

EFORd Limit: 1.1

New Unit Pricing:

### Base Offer Segments

	1	2	3	4	5	6	7	8	9	10
<b>Min MW</b>	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>Max MW</b>	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	8.9
<b>Price</b>	\$ 0.0	\$ 0.0	\$ 11.0	\$ 10.50	\$ 9.80	\$ 6.50	\$ 8.40	\$ 20.51	\$ 25.92	\$ 31.18
<b>Scheduling Option</b>	Self Schedule	Self	Flex	Flex	Flex	Flex	Flex	Regular	Regular	Regular

Offer Segments 1, 2, 6  
Clear up to  
Target Self-Scheduled MW  
(rounded to .1 MW)

NOTE: All other segments clear based on price.

Segment 1	10.0 MW	\$0.00
Segment 2	10.0 MW	\$0.00
Segment 6	10.0 MW	\$6.50
<b><u>TOTAL</u></b>	<b><u>30.0</u></b>	

- Applies to **Planned Resources** where the size of the new entry is large enough such that there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped in the subsequent auctions.
- New Entry Pricing allows Planned Resources to recover the amount of its cost of entry-based offer for up to two additional consecutive years, under certain conditions.

## New Entry Pricing is applicable under the following conditions:

- (1) The new entry must select the New Entry Pricing option at the time the sell offer into the initial BRA is submitted;
- (2) The capacity cleared from a single new resource would move the total LDA resources cleared from below the LDA Reliability Requirement to a point on the VRR Curve where the price is less than or equal to 40% of the Net CONE divided by the quantity one minus pool-wide average EFORd; and
- (3) The seller submits offers into the two following BRAs to sell the entire capacity of the unit at a price equal to the lesser of: (a) The price offered in the BRA where the resource was classified as planned generation; or (b) 90% of the then-current Net CONE.

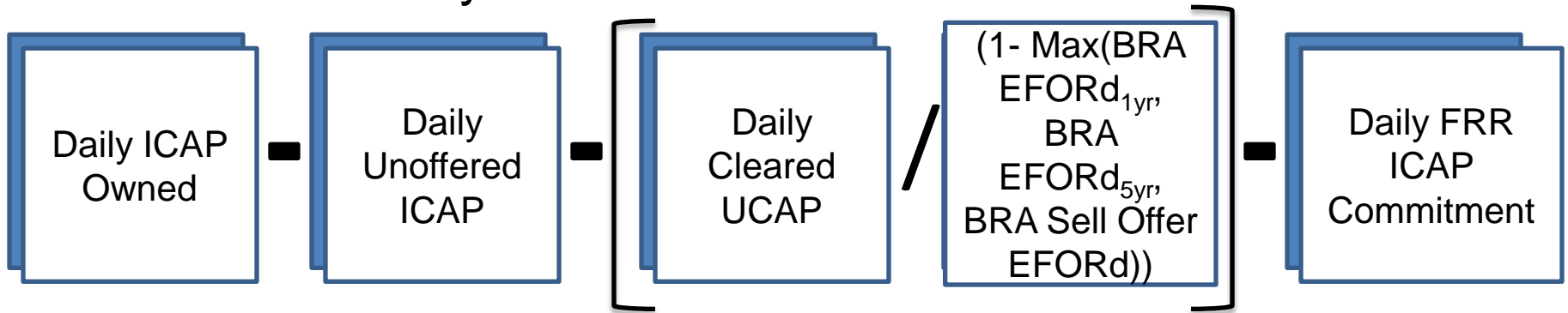
Year	Revenues Based on:
Year 1 BRA	<p>The New Entry clears: Year 1 BRA Resource Clearing Price (RCP)</p>
<p>Year 2 BRA (similar for Year 3 BRA)</p>	<p>If the New Entry Clears in Year 2:</p> <ul style="list-style-type: none"> <li>• Receives Year 2 BRA RCP</li> </ul> <p>If the New Entry does not clear in Year 2:</p> <ul style="list-style-type: none"> <li>• Offer price is adjusted down until it clears.</li> <li>• Receives Year 2 BRA Offer Price</li> <li>• The difference between the Offer Price and RCP will be paid as Resource Make-Whole payment.</li> <li>• Other resources will receive RCP.</li> </ul>

- While the New Entry Pricing is effective, the LDA in which the New Entry Pricing was initiated will be modeled as an LDA in Years 2 and 3 regardless of the amount of LDA Capacity Emergency Transfer Limit (CETL) margin over Capacity Emergency Transfer Objective (CETO) in the PJM RTEP Process.
- After the New Entry Pricing period, the LDA will be maintained only if deemed necessary in the PJM RTEP Process.

- To hedge against the risk of a changing EFORd between the Base Residual Auction and the Delivery Year, Generators can offer an ICAP value between a range of the Minimum Available ICAP and Maximum Available ICAP.

- The Minimum Available ICAP =  $\text{Min}(\text{DailyMinAvailableICAP})$

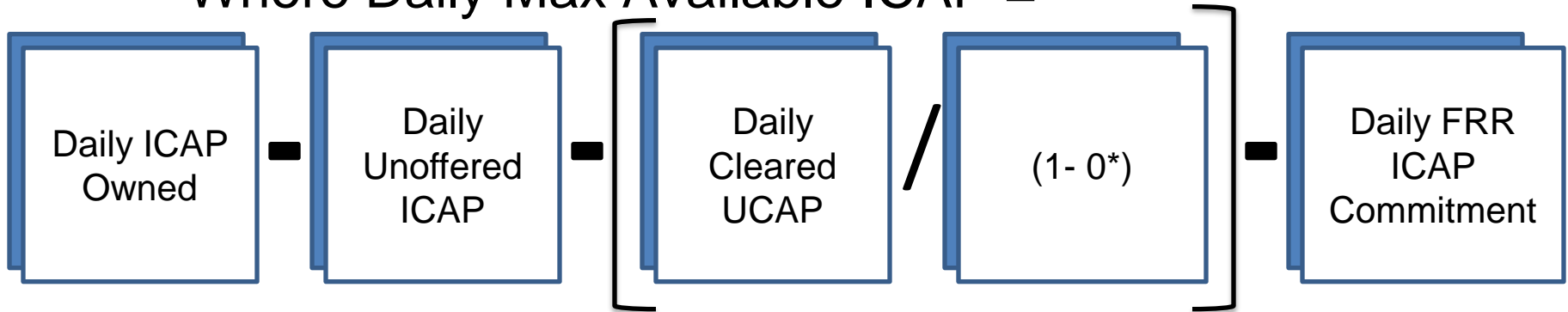
– Where Daily Min Available ICAP =



- For the BRA and 3<sup>rd</sup> IA, a party's Minimum Available ICAP Position will be equal to the party's Current Available ICAP Position for such unit.

- The Maximum Available ICAP =  $\text{Min}(\text{DailyMaxAvailableICAP})$

– Where Daily Max Available ICAP =



\*The Zero EFORD represents a UCAP Offer equal to the Available ICAP

- For the BRA and 3<sup>rd</sup> IA, a party's Maximum Available ICAP Position will be equal to the party's Current Available ICAP Position for such unit.

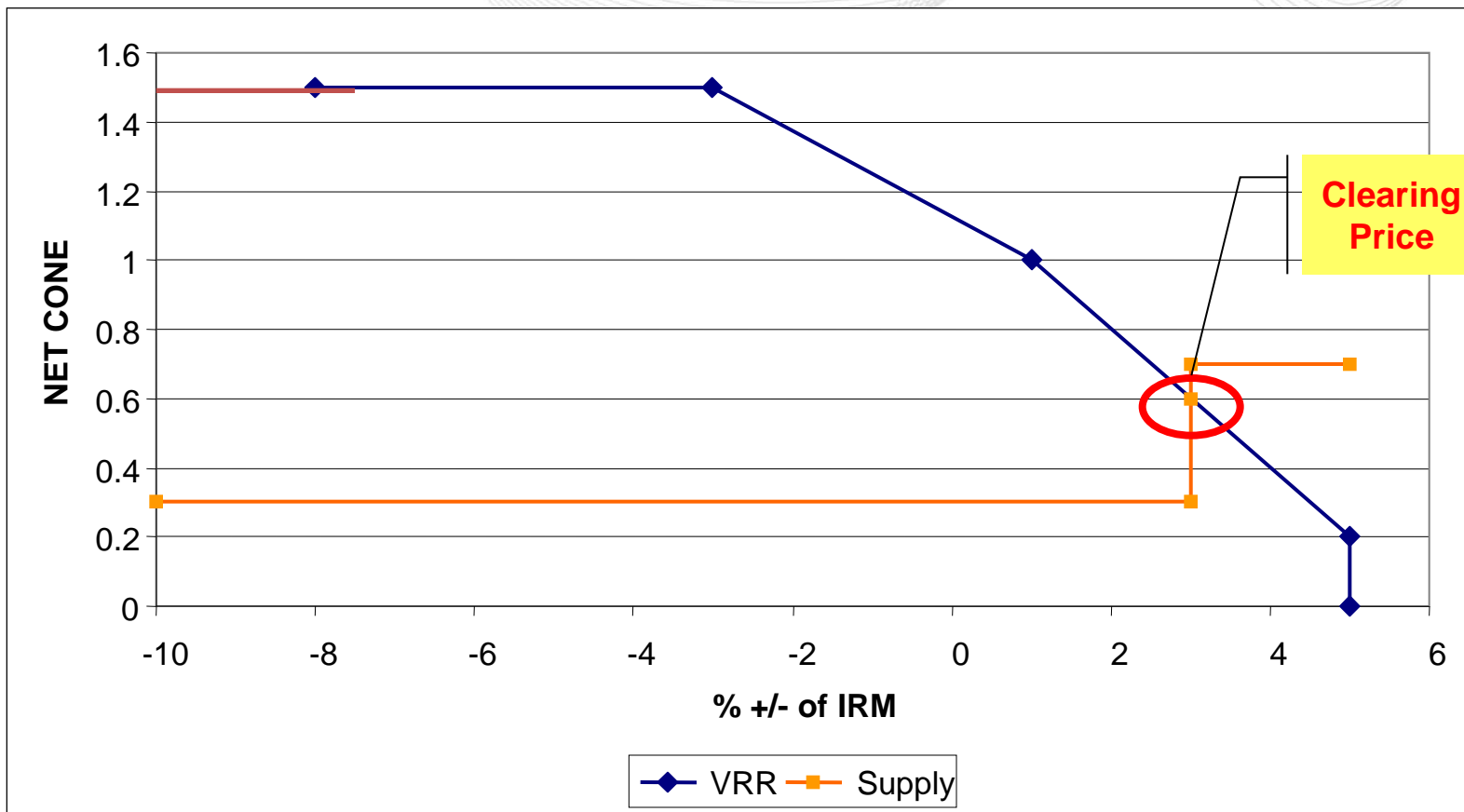
- 100 MW Generator
  - No Unit Specific Transactions
  - No FRR Commitments
- *Offering into 2012/2013 BRA*
- $BRA\ EFORd_{1yr} = \text{Effective } EFORd @ BRA = \text{Effective } EFORd \text{ when Auction is run (i.e., 09/10 DY } EFORd) = .2$
- $BRA\ EFORd_{5yr} = \text{Effective } EFORd_{5yr} @ BRA = \text{Effective } EFORd_{5yr} \text{ when Auction is run} = .1$
- Current Available ICAP = 100 MW
- Min Available ICAP = Max Available ICAP = Current Available ICAP
- Generator must offer 100 MW ICAP into BRA, with Sell Offer  $EFORd < \max(BRA\ EFORd_{1yr}, BRA\ EFORd_{5yr})$
- Offer  $EFORd @ BRA = .15$ , Offer ICAP MW = 100
- Clears: 85 MW UCAP
- Unoffered ICAP = Min Available ICAP – Offer ICAP =  $100 - 100 = 0$  MW

- 100 MW Generator
  - No Unit Specific Transactions
  - No FRR Commitments
- *Offering into 2012/2013 1<sup>st</sup> IA*
- New Effective EFORd = .12 (based on year ending September 2009 outage data)
- Current Available ICAP = ICAP Owned – [Cleared UCAP MW/(1-Effective EFORd)] = 100 MW – [85/(1-.12)] = 3.4 MW
- Min Available ICAP = ICAP Owned - [Cleared UCAP MW/(1-Max(BRA EFORd<sub>1yr</sub>, BRA EFORd<sub>5yr</sub>, BRA Offer EFORd))] = 100 – [85/(1-(max(.2, .1, .15)))] = -6.3
- Max Available ICAP = ICAP Owned - [Cleared UCAP MW/(1-0)] = 100 – [85/1] = 15 MW
- Generator can offer between 0 and 15 MW ICAP into the 1<sup>st</sup> IA
- Offer EFORd = .05, Offer ICAP MW = 1 MW
- Clears 1 UCAP MW, Total Cleared UCAP MW = 86 MW
- Unoffered ICAP= Min Available ICAP – Offer ICAP MW = - 6.3 – 1 = 0
- \*\*Unoffered should never be negative

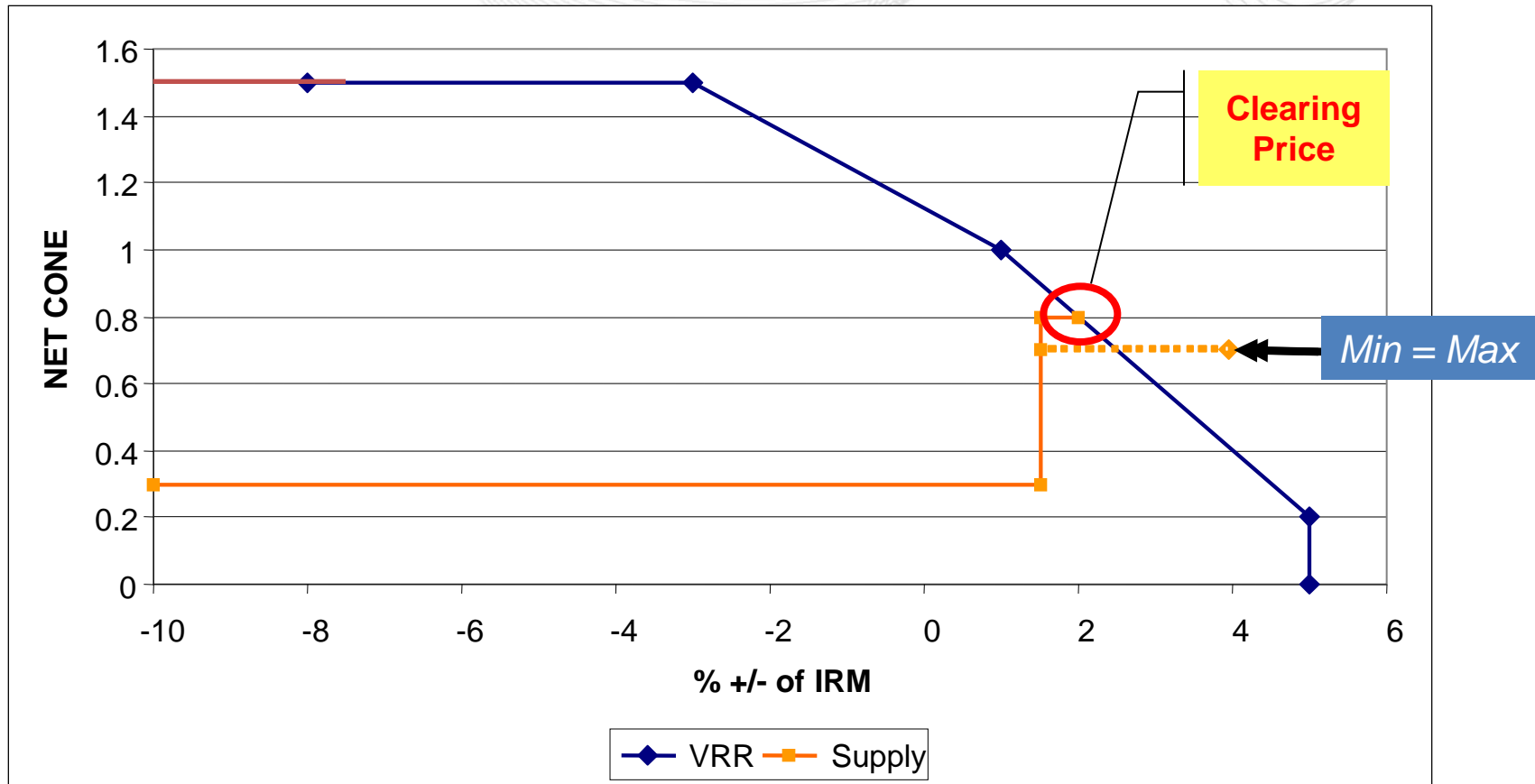
- 100 MW Generator
  - No Unit Specific Transactions
  - No FRR Commitments
- *Offering into 2012/2013 2<sup>nd</sup> IA*
- New Effective EFORd = .16 (based on year ending September 2010 outage data)
- Current Available ICAP = ICAP Owned – [Cleared UCAP MW/(1-Effective EFORd)] = 100 MW – [86/(1-.16)] = -2.4 MW
- Min Available ICAP = ICAP Owned - [Cleared UCAP MW/(1-Max(BRA EFORd<sub>1yr</sub>, BRA EFORd<sub>5yr</sub>, BRA Offer EFORd))] = 100 – [86/(1-(max(.2, .1, .15)))] = -7.5
- Max Available ICAP = ICAP Owned - [Cleared UCAP MW/(1-0)] = 100 – [86/1] = 14 MW
- Generator can offer between 0 and 14 MW of ICAP into 2<sup>nd</sup> IA
- Does not offer in 2<sup>nd</sup> IA
- Clears 0 UCAP MW
- Unoffered ICAP = Min Available ICAP – Offer ICAP MW = -7.5 – 0 = 0
- \*\*Unoffered should never be negative

- 100 MW Generator
  - No Unit Specific Transactions
  - No FRR Commitments
- *Offering into 2012/2013 3<sup>rd</sup> IA*
- New Effective EFORd = .10 (based on year ending September 2010 outage data)
- Current Available ICAP = ICAP Owned – [Cleared UCAP MW/(1-Effective EFORd)] =  
100 MW – [86/(1-.1)] = 4.4 MW
- Min Available ICAP = Current Available ICAP = 4.4 MW
- Max Available ICAP = Current Available ICAP = 4.4 MW
- Generator must offer Current Available ICAP = 4.4 MW
- Offer EFORd = .1, Offer ICAP MW = 4.4 MW
- Clears 4 MW UCAP, Total Cleared UCAP MW = 90 MW
- Unoffered = Min Available ICAP – Offered UCAP MW = 4.4 MW – 4.4 MW = 0 MW

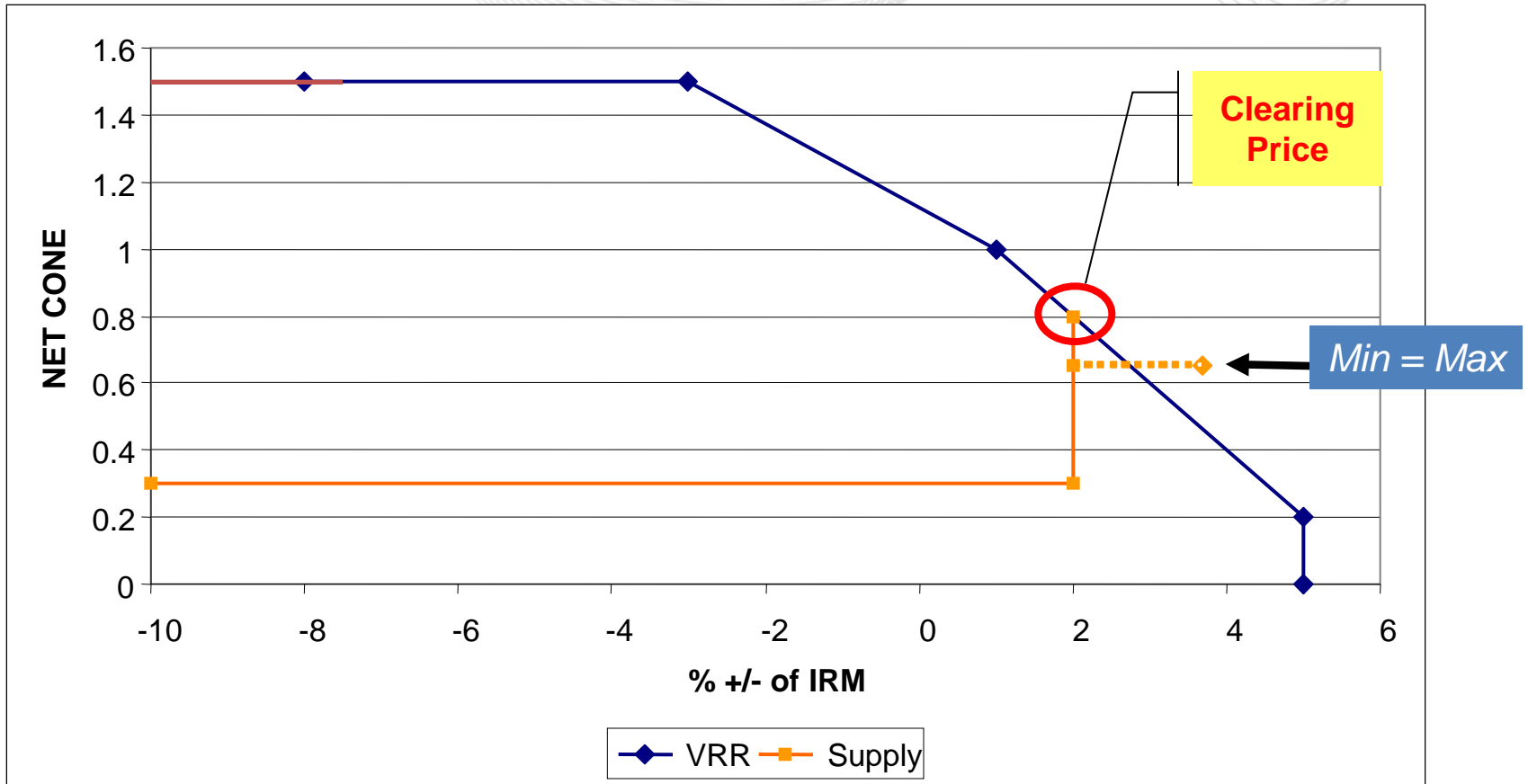
- The following slides illustrate Auction Clearing Examples where:
  - Intersection of supply and demand curves occur at the vertical portion of the supply curve
  - A higher priced, flexible segment is cleared before a lower priced, inflexible segment
  - The supply curve is extended vertically to intersect with the demand curve
  - A make-whole payment is awarded to the marginal bid
  - Intersection of supply and demand curves occur at the vertical portion of the VRR curve



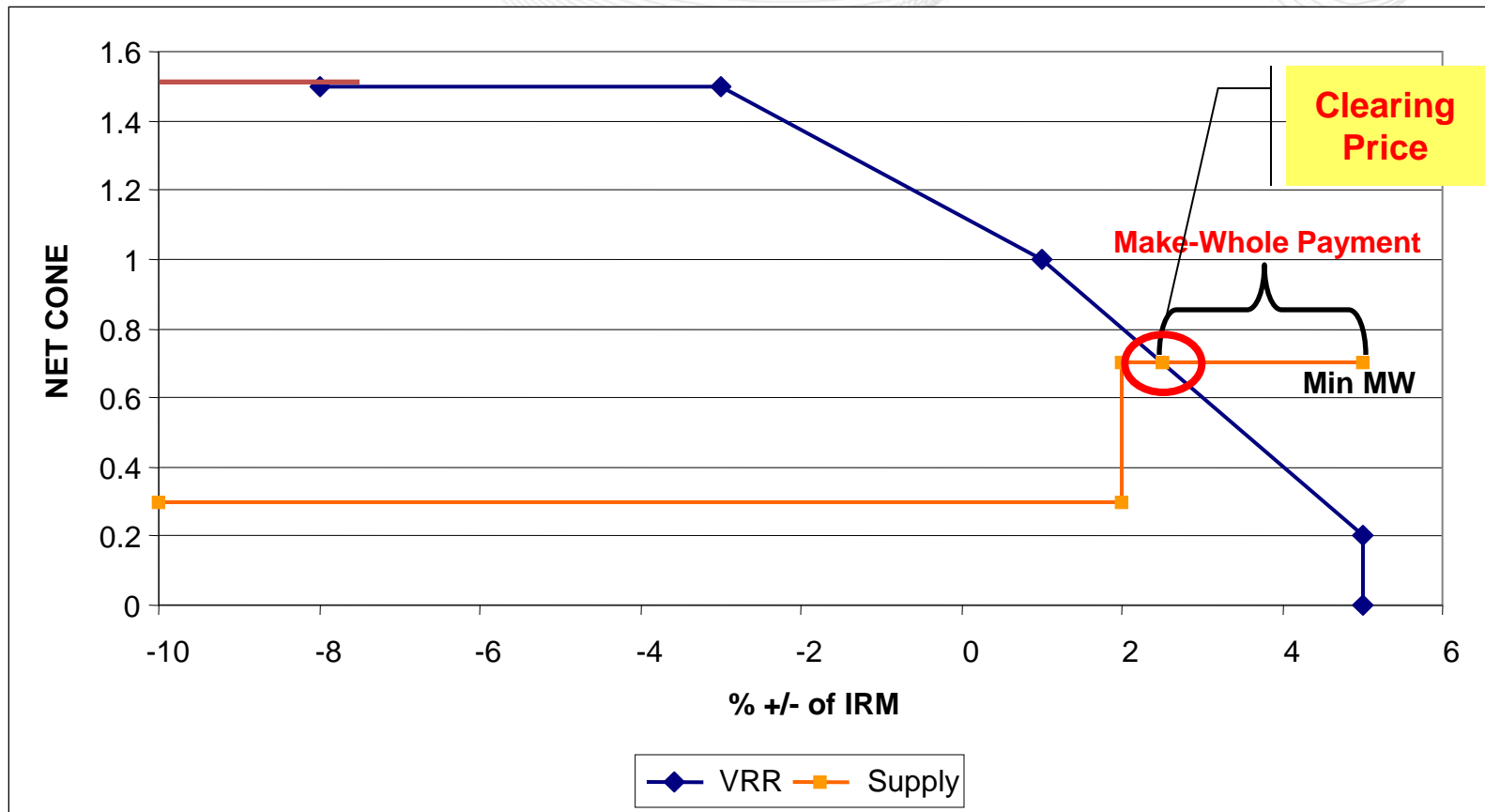
- All Sell Offers create a Supply Curve that is a block curve
- Intersection occurs at vertical portion of Supply curve, VRR sets clearing price
- In this example Clearing Price is 0.6 Net CONE at IRM+3%



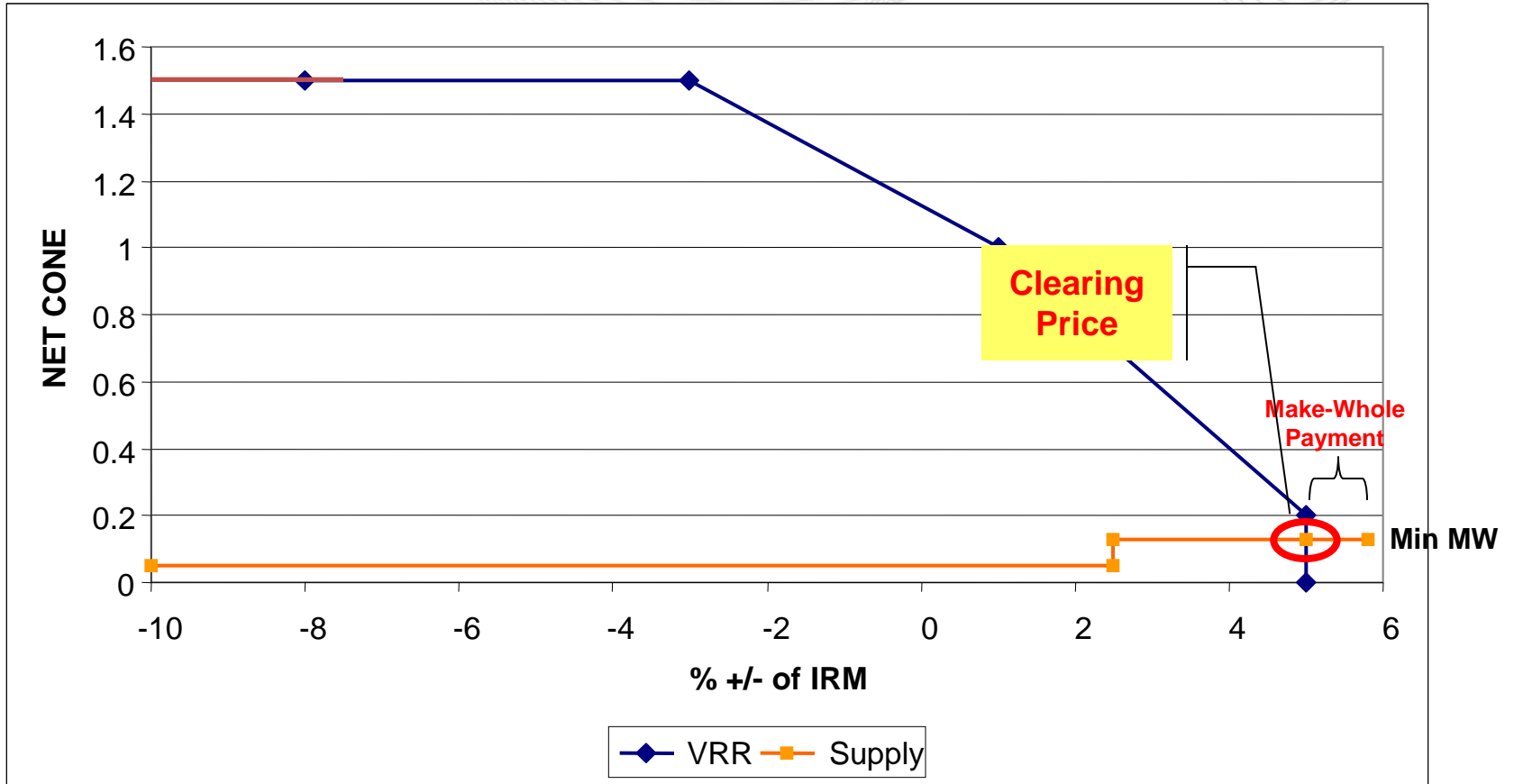
- All Sell Offers create a Supply Curve that is a block curve
- Optimization will clear the lowest overall cost to LDA
- Substitutes the higher priced offer in for the lower priced offer with no flexibility
- Clearing Price is 0.8 Net CONE at IRM+2%
- Offer with dotted line does not clear because of lack of flexibility



- All Sell Offers create a Supply Curve that is a block curve
- Continuing vertical portion of supply curve to intersection of VRR curve in some cases results in lower overall cost to LDA than clearing a lower priced inflexible offer
- Since intersection occurs at vertical portion of **Supply** curve, VRR sets clearing price
- Clearing Price is 0.8 Net CONE at IRM+2%
- Offer with dotted line does not clear because of lack of flexibility



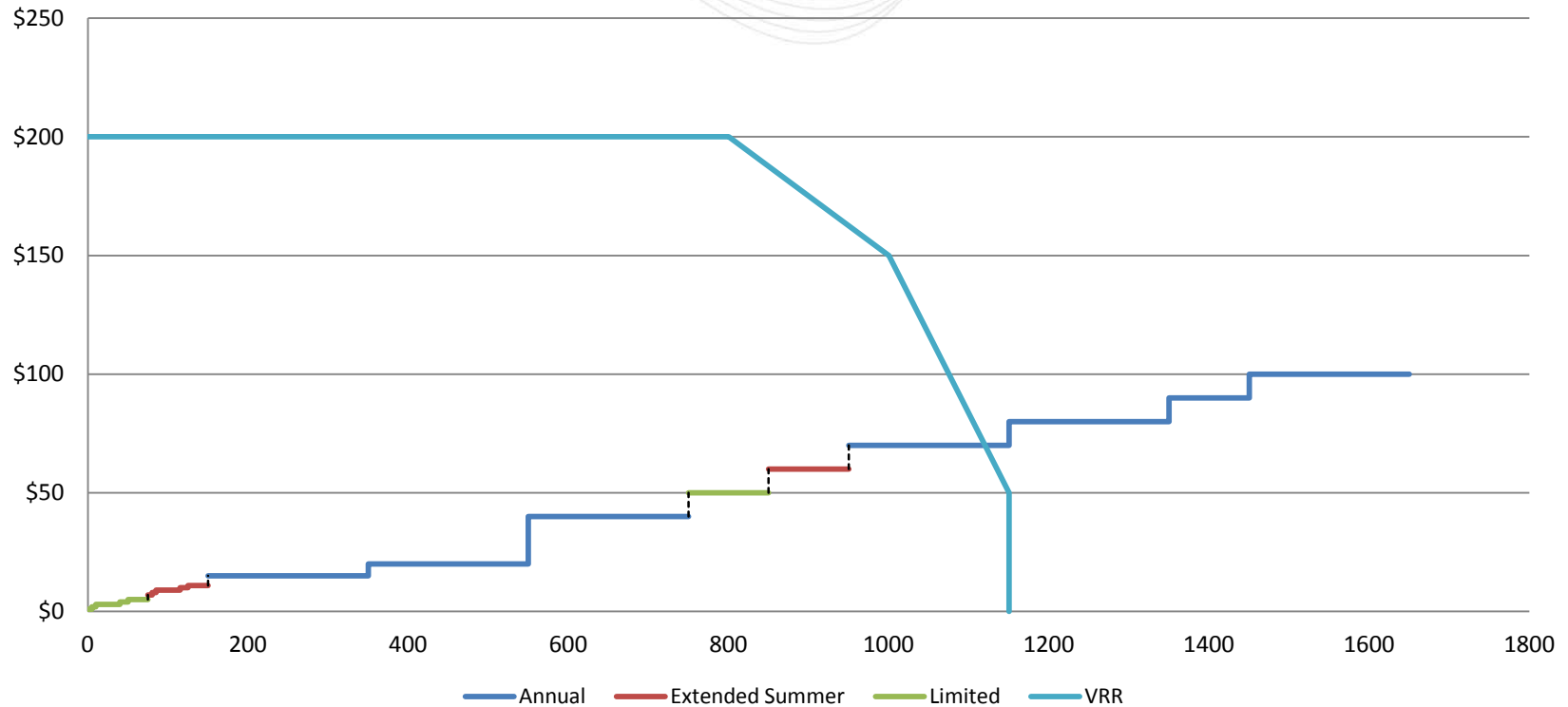
- All Sell Offers create a Supply Curve that is a block curve
- Optimization only needs to clear portion of last sell offer. Lower overall costs to LDA results if provide make-whole payment to last offer as opposed to extending vertically the supply curve
- Clearing Price is 0.7 Net CONE at IRM+2.5%
- Make Whole payments are for the MW portion of block bid beyond VRR curve



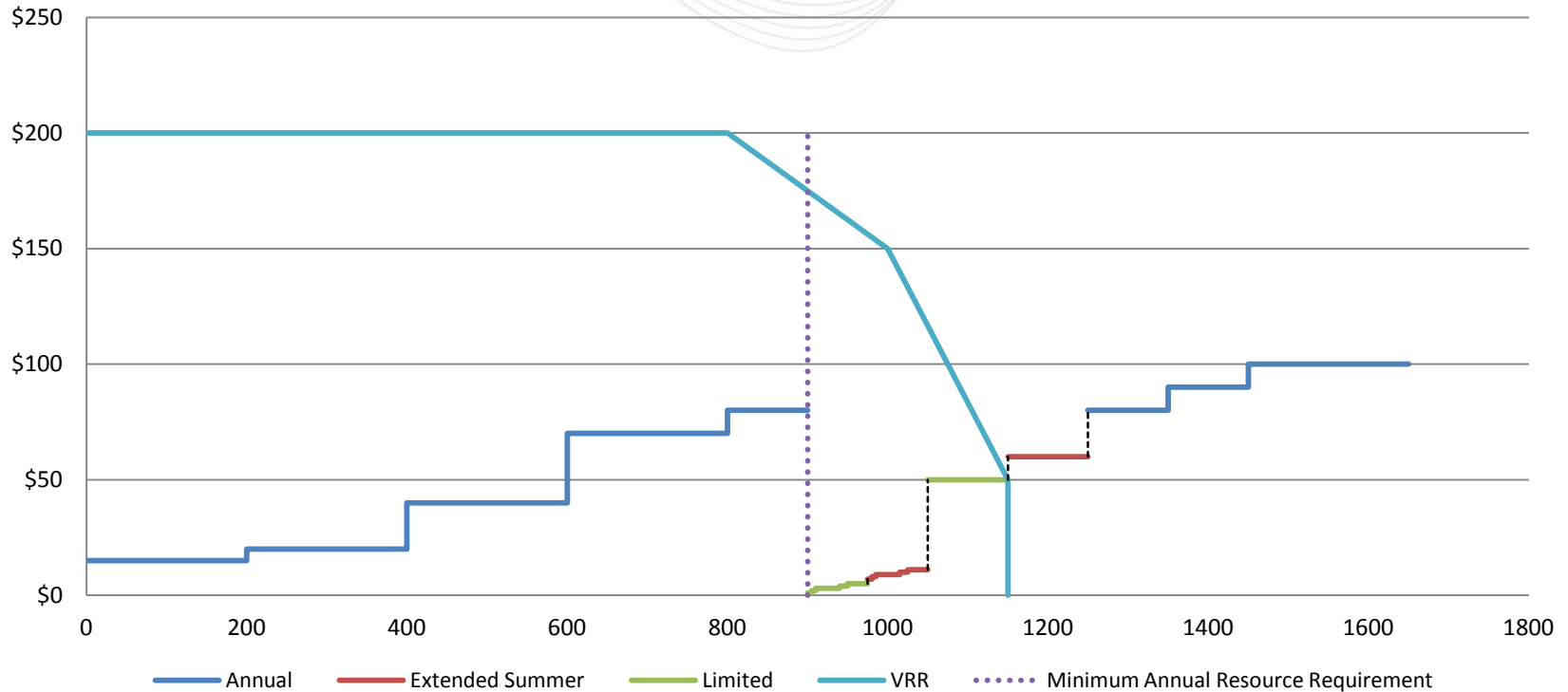
- All Sell Offers create a Supply Curve that is a block curve
- Since intersection occurs at vertical portion of VRR curve, Supply sets clearing price
- Clearing Price is 0.13 Net CONE at IRM+5%
- Make Whole payments are for the MW portion of block bid beyond VRR curve

Resource Type	Capacity of the Resource, MW	Offer Price
Limited DR 14	5	\$1
Limited DR 15	5	\$2
Limited DR 16	30	\$3
Limited DR 17	10	\$4
Limited DR 18	25	\$5
Extended Summer DR 8	5	\$7
Extended Summer DR 9	5	\$8
Extended Summer DR 10	30	\$9
Extended Summer DR 11	10	\$10
Extended Summer DR 12	25	\$11
Annual Resource 1	200	\$15
Annual Resource 2	200	\$20
Annual Resource 3	200	\$40
Limited DR 19	100	\$50
Extended Summer DR 13	100	\$60
Annual Resource 4	200	\$70
Annual Resource 5	200	\$80
Annual Resource 6	100	\$90
Annual Resource 7	200	\$100

- Multiple Offers of each Product Type
- Assume One LDA
- The following examples illustrate the clearing results considering three cases:
  - No Minimum Requirements
  - Annual Requirement Only
  - Annual and Extended Summer Requirements



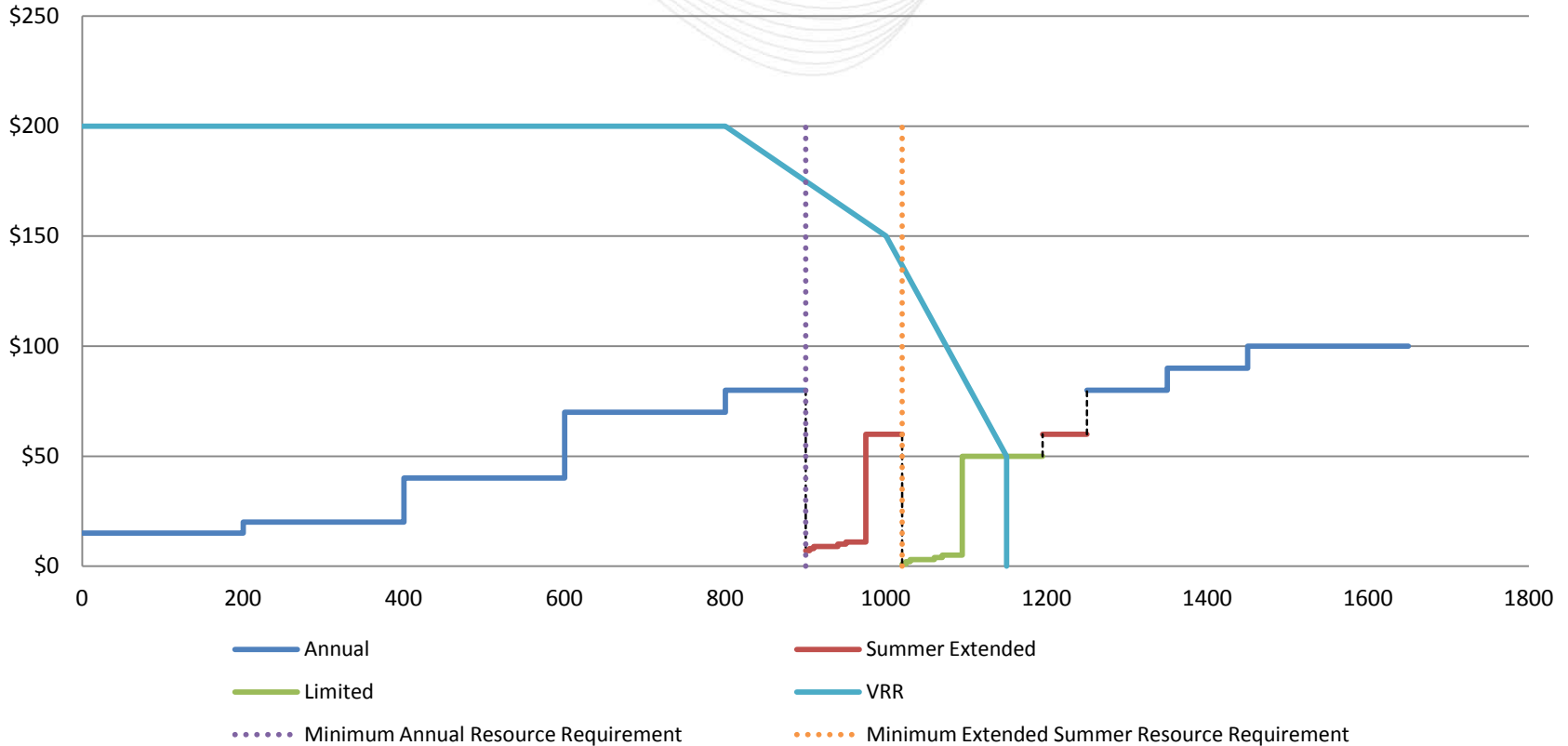
Marginal Value Of System Capacity = \$70  
 Annual Resource Price Adder = \$0  
 Extended Summer Price Adder = \$0



Marginal Value Of System Capacity = \$50  
 Annual Resource Price Adder = \$30  
 Extended Summer Price Adder = \$0

# Clearing Example 3

## Minimum Annual and Extended Summer Resource Requirements



Marginal Value Of System Capacity = \$50  
 Annual Resource Price Adder = \$20  
 Extended Summer Price Adder = \$10

	Example 1	Example 2	Example 3
Minimum Annual Resource Requirement	0 MW	900 MW	900 MW
Minimum Extended Summer Resource Requirement	0 MW	0 MW	1020 MW
Limited DR Cleared	175 MW	175 MW	130 MW
Extended Summer DR Cleared	175 MW	75 MW	120 MW
Annual Resources Cleared	775 MW	900 MW	900 MW
Total Resources Cleared	1125 MW	1150 MW	1150 MW
Marginal Value of System Capacity	\$70	\$50	\$50
Extended Summer Price Adder	\$0	\$0	\$10
Annual Price Adder	\$0	\$30	\$20

All BRA Auction Results are posted on the RPM Auction User Information page under the applicable Delivery Year

### 2009/2010 Base Residual Auction Results

\*\* Results for the EMAAC LDA are not calculated in this document as it did not bind in the 2009/2010 Base Residual Auction. For

#### RPM Parameters

IRM	15.00%				
Pool Average EFORd	6.13%	LDA		Cleared Qualifying Transmission Upgrade [MW]	ILR Forecast Obligation [MW]
FPR	1.0795	MAAC+APS	392.0	0.0	1,055.7
Obligation Peak Load Scaling Factor	1.01409	SWMAAC	0.0	0.0	345.7
DR Factor	95.70%				

#### Auction Clearing Results

LDA	System Marginal Price [\$ /MW-day]	Locational Price Adder* [\$ /MW-day]	2009 Prelim Zonal Peak Load Forecast [MW]	Base UCAP Obligation [MW]	Cleared Internal Capacity Including Cleared Demand Resources	Cleared Demand Resources [MW]	Make Whole [MW]	Make Whole Costs [\$ /day]	CTRs Allocated To LSEs [MW]	Incremental CTRs [MW]	Cleared Qualifying Transmission Upgrades [MW]	Economic Value of CTRs Allocated to Load [\$ /day]	Resource Credits [\$ /day]	Resource Clearing Price [\$ /MW-day]
RTO	\$102.04	\$0.00	120,792.2	133,886.9	132,231.8	892.9	0.0	0.0					\$6,090,165.56	\$102.04
MAAC+APS	\$102.04	\$89.28	68,795.0	76,366.0	72,547.8	813.9	0.0	0.0	2,370.5	392.0	0.0	\$211,647.17	\$11,982,964.69	\$191.32
SWMAAC	\$102.04	\$46.01	14,269.0	15,966.1	9,914.6	356.3	0.0	0.0	5,705.8	0.0	0.0	\$262,523.86	\$2,353,032.02	\$237.33
										\$34,997.76	\$0.00	\$474,171.03	\$20,426,162.27	

\* Locational Price Adder is with respect to the immediate higher level LDA.

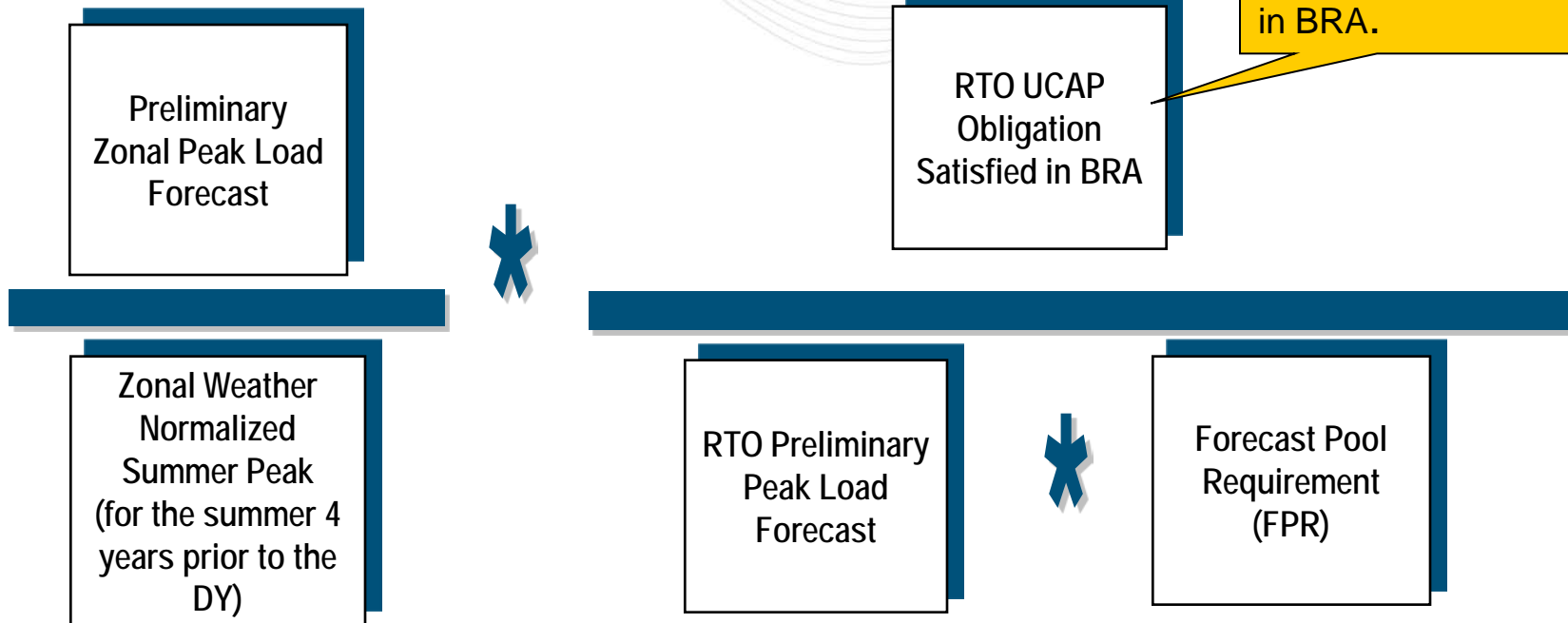
#### Zonal Results

Zone	LDA1	LDA2	MAAC+APS Obligation Ratio Share	MAAC+APS CTR Allocation [MW]	MAAC + APS CTR Allocation [\$ /day]	SWMAAC Obligation Ratio Share	SWMAAC CTR Allocation [MW]	SWMAAC CTR Allocation [\$ /day]	TOTAL CTRs Allocated to Load	TOTAL CTR Allocation [\$ /day]	Preliminary Zonal Capacity Price [\$ /MW-day]	base Zonal CTR Credit Rate [\$ /MW-day of UCAP oblig.]	Zonal CTR Settlement Rate [\$ /MW-day of CTRs]	Preliminary Zonal ILR Price [\$ /MW-day]	Final Zonal CTR Rate [\$ /MW-day of CTRs]	Final Zonal Capacity Price [\$ /MW-day]	Net Load Price [\$ /MW-day]
AE	MAAC+APS		4.01%	95.0	\$8,479.91		0.0	\$0.00	95.0	\$8,479.91	\$191.32	\$2.77	\$89.26	\$188.55	\$2.83	\$196.53	\$193.70
AEP *				0.0	\$0.00		0.0	\$0.00	0.0	\$0.00	\$102.04	\$0.00	\$102.04	\$0.00	\$0.00	\$104.82	\$104.82
APS	MAAC+APS		12.25%	290.4	\$25,925.30		0.0	\$0.00	290.4	\$25,925.30	\$191.32	\$2.77	\$89.27	\$188.55	\$2.73	\$196.53	\$193.80
BGE	MAAC+APS	SWMAAC	10.75%	254.8	\$22,746.96	51.41%	2933.1	\$134,951.93	2,933.1	\$157,698.89	\$237.33	\$19.21	\$53.77	\$218.12	\$18.86	\$243.79	\$224.93
COMED				0.0	\$0.00		0.0	\$0.00	0.0	\$0.00	\$102.04	\$0.00	\$0.00	\$102.04	\$0.00	\$104.82	\$104.82
DAYTON				0.0	\$0.00		0.0	\$0.00	0.0	\$0.00	\$102.04	\$0.00	\$0.00	\$102.04	\$0.00	\$104.82	\$104.82
DOM *				0.0	\$0.00		0.0	\$0.00	0.0	\$0.00	\$102.04	\$0.00	\$0.00	\$102.04	\$0.00	\$104.82	\$104.82
DPL	MAAC+APS		5.98%	141.8	\$12,863.47		0.0	\$0.00	141.8	\$12,863.47	\$191.32	\$2.77	\$89.31	\$188.55	\$2.52	\$196.53	\$193.71
DUQ				0.0	\$0.00		0.0	\$0.00	0.0	\$0.00	\$102.04	\$0.00	\$0.00	\$102.04	\$0.00	\$104.82	\$104.82
JCLP	MAAC+APS		9.21%	218.3	\$19,491.57		0.0	\$0.00	218.3	\$19,491.57	\$191.32	\$2.77	\$89.29	\$188.55	\$2.74	\$196.53	\$193.79
METED	MAAC+APS		4.12%	97.6	\$8,715.21		0.0	\$0.00	97.6	\$8,715.21	\$191.32	\$2.77	\$89.30	\$188.55	\$2.72	\$196.53	\$193.81
PECO	MAAC+APS		12.34%	292.6	\$26,126.51		0.0	\$0.00	292.6	\$26,126.51	\$191.32	\$2.77	\$89.29	\$188.55	\$2.75	\$196.53	\$193.78
PENLC	MAAC+APS		4.03%	95.5	\$8,527.30		0.0	\$0.00	95.5	\$8,527.30	\$191.32	\$2.77	\$89.29	\$188.55	\$2.77	\$196.53	\$193.76
PEPCO	MAAC+APS	SWMAAC	10.16%	240.8	\$21,502.84	48.59%	2772.7	\$127,571.93	2,772.7	\$149,074.77	\$237.33	\$19.21	\$53.77	\$218.12	\$19.01	\$243.79	\$224.78
PL	MAAC+APS		10.92%	258.8	\$23,103.65		0.0	\$0.00	258.8	\$23,103.65	\$191.32	\$2.77	\$89.27	\$188.55	\$2.76	\$196.53	\$193.77
PS	MAAC+APS		15.64%	370.8	\$33,102.33		0.0	\$0.00	370.8	\$33,102.33	\$191.32	\$2.77	\$89.27	\$188.55	\$2.70	\$196.53	\$193.83
RECO	MAAC+APS		0.60%	14.1	\$1,262.13		0.0	\$0.00	14.1	\$1,262.13	\$191.32	\$2.77	\$89.51	\$188.55	\$2.62	\$196.53	\$193.91

- 2009/2010 Auction Results
  - LDA level UCAP Obligation
  - CTRs
    - Quantity
    - Economic Value
    - Final Zonal CTR Credit Rate
  - Preliminary Zonal Capacity Price
  - Final Zonal ILR Price
  - Final Zonal Capacity Price

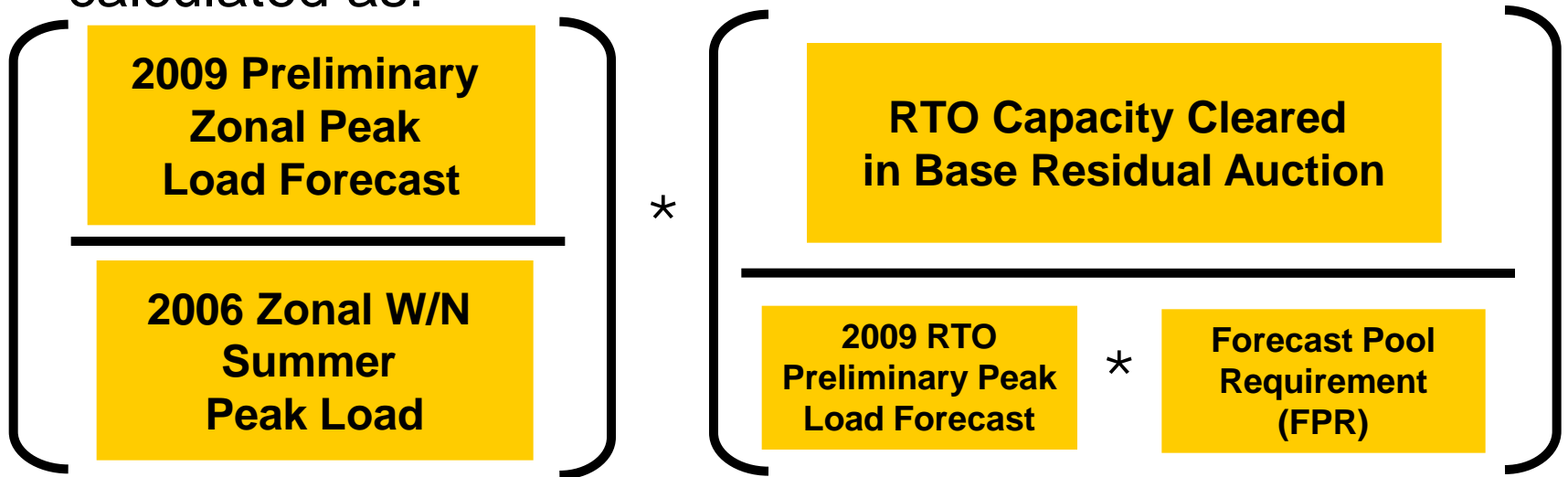
- Zonal UCAP Obligations are calculated using the Zonal RPM Scaling Factors
- The LDA UCAP Obligation for MAAC+APS is a sum of the obligations for all zones within MAAC+APS
- This quantity is critical to the amount of CTRs allocated to the load within the LDA
- The example will show those calculations for the zones within MAAC+APS

Base Zonal RPM Scaling Factor =



- Base Zonal RPM Scaling Factor accounts for (1) load growth from the summer 4 yrs prior to the Delivery Year to the Delivery Year and (2) any excess resources procured in Base Residual Auction above those required to exactly meet the FPR.
- For 2007/08 -2010/11 DYs, the Zonal Weather Normalized Peak for summer 2006 will be used to establish the Base Zonal RPM Scaling Factors.

For 2009/10, the **Base Zonal RPM Scaling Factor** is calculated as:



For the PS Zone, this value is:

$$\left[ \frac{10763.0 \text{ MW}}{10330.0 \text{ MW}} \right] * \left[ \frac{132231.8 \text{ MW}}{120792.2 * 1.0795} \right]$$

**Base Zonal RPM  
Scaling Factor [PS] = 1.05660**

- The first parenthetical relates the known 2006 Zonal W/N Summer Peak Load to the 2009 Preliminary Peak Load Forecast
- The second is a ratio that scales the UCAP requirement for the load to the amount of capacity cleared in the BRA

- Using the Base Zonal RPM Scaling Factor and 2006 Zonal W/N Summer Peak Load for the PS Zone, we can calculate the Base Zonal UCAP Obligation (less the Zonal Forecast ILR Obligation) of that Zone

<b>PS Zonal Base UCAP Obligation (less ILR)</b>	<b>=</b>	<b>2006 Zonal W/N Summer Peak Load</b>	<b>*</b>	<b>Forecast Pool Requirement (FPR)</b>	<b>*</b>	<b>Base Zonal RPM Scaling Factor</b>
<b>PS Zonal Base UCAP Obligation (less ILR)</b>	<b>=</b>	<b>10,330.0</b>	<b>*</b>	<b>1.0795</b>	<b>*</b>	<b>1.05660</b>
		<b>PS Zonal Base UCAP Obligation (less ILR)</b>	<b>=</b>	<b>11,782.4 MW</b>		

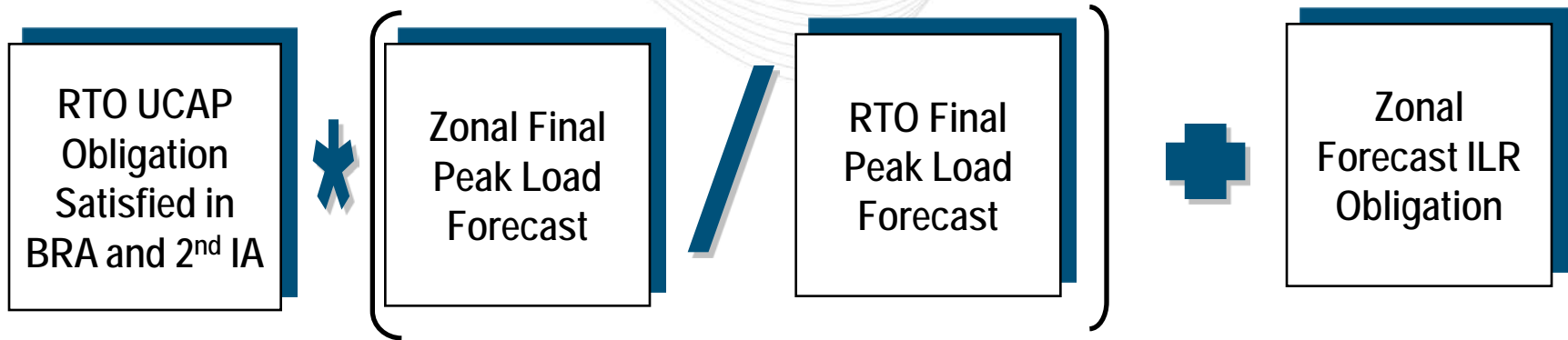
- Because ILR is not cleared in the BRA but is forecasted zonally, the Zonal Forecast ILR Obligation is added to come up with the Base Zonal UCAP Obligation for the PS Zone

<b>PS Zonal Forecast ILR Obligation</b>	=	<b>Zonal ILR Forecast</b>	*	<b>Forecast Pool Reserve (FPR)</b>	*	<b>Demand Resource (DR) Factor</b>
---	---	-------------------------------	---	--	---	--

<b>161.6 MW</b>	=	<b>156.4 MW</b>	*	<b>1.0795</b>	*	<b>.957</b>
-----------------	---	-----------------	---	---------------	---	-------------

<b>PS Zonal Base UCAP Obligation</b>	=	<b>11,782.4 MW</b>	+	<b>161.6 MW</b>	=	<b>11,943.9 MW</b>
--	---	--------------------	---	-----------------	---	--------------------

Final Zonal UCAP Obligation =



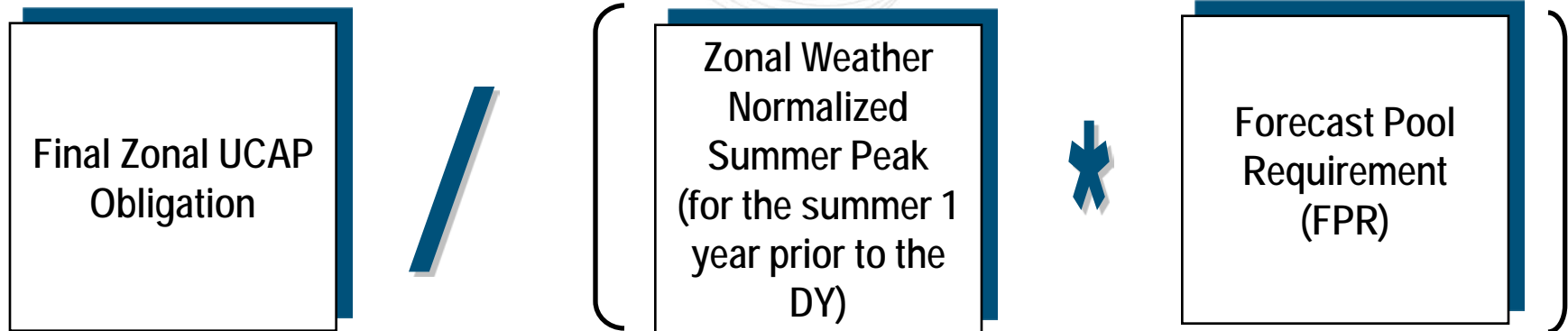
- The Final UCAP Obligation is determined after the clearing of the Third Incremental Auction for the Delivery Year
- The RTO UCAP obligation satisfied in the BRA and 2<sup>nd</sup> IA is equal to the total unforced capacity committed (cleared MWs and make-whole MWs) as a result of the BRA and 2<sup>nd</sup> IA.
- The Final Preliminary Zonal and Final Zonal Peak Load Forecasts in the above equation are reduced by the Preliminary and Final Peak Load Forecasts of the FRR Entities in the Zone, respectively.

For the PS Zone, this value is:

$$\begin{aligned}
 &= \text{RTO UCAP Obligation Satisfied in BRA and 2<sup>nd</sup> IA} \times \frac{\text{Zonal Peak Load Forecast}}{\text{RTO Final Peak Load Forecast}} + \text{Zonal Forecast ILR Obligation} \\
 &= 132231.8 \text{ MW} \times \frac{10446.0 \text{ MW}}{114414.1} + 172.6^* \\
 &= 12245.4
 \end{aligned}$$

\*Includes AEP ILR Reallocation of 11 MW  
 161.6 + 11 = 172.6 MW

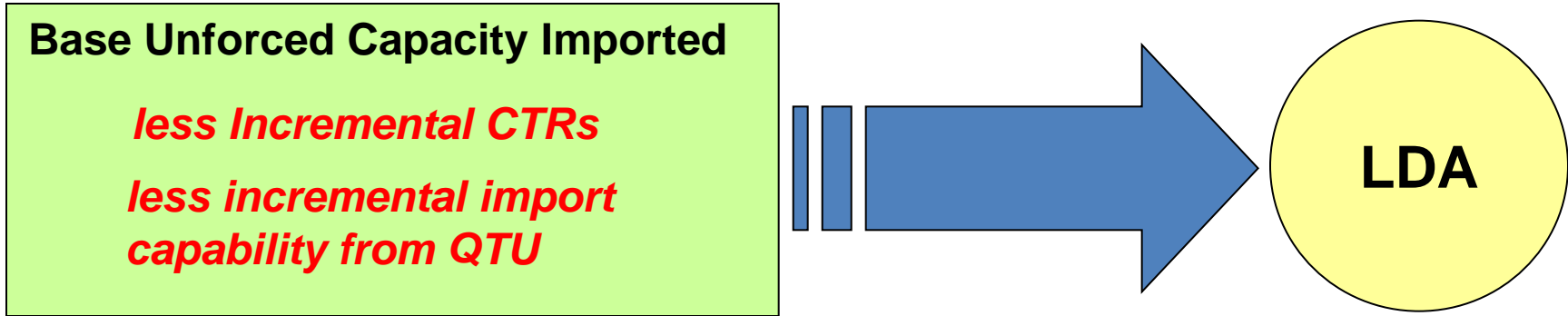
Final Zonal RPM Scaling Factor =



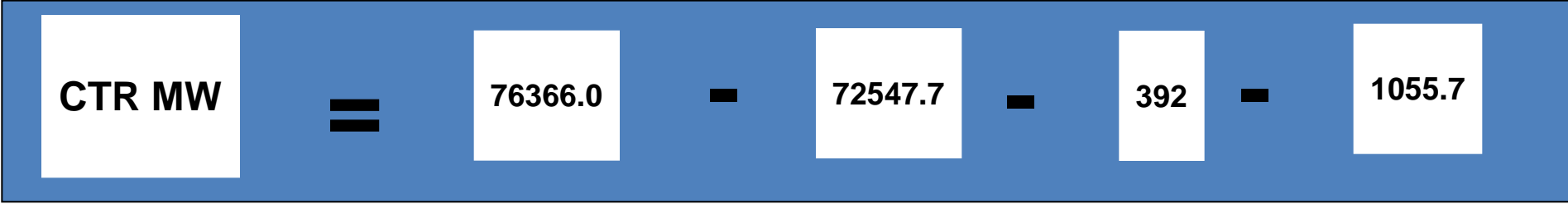
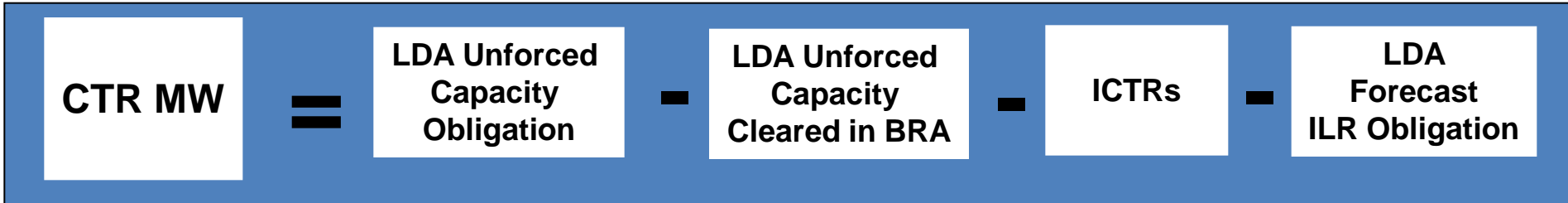
- Final Zonal RPM Scaling Factors are used in determining an LSE's Daily UCAP Obligation.
- Final Zonal RPM Scaling Factor accounts for (1) load growth from the prior-year summer to the Delivery year; (2) any excess resources procured in Base Residual Auction above those required to exactly meet the FPR; and (3) ILR Forecast Obligation Values.
- Final Zonal RPM Scaling Factors are posted with the Final UCAP Obligation

For the PS Zone, this value is:

$$\frac{\text{Zonal UCAP Obligation}}{\text{2006 Zonal W/N Summer Peak} * \text{Forecast Pool Requirement (FPR)}} = \frac{12245.7 \text{ MW}}{10440 \text{ MW} * 1.0795}$$
$$\text{Final Zonal RPM Scaling Factor [PS]} = 1.08658$$



- In 2008/2009, MAAC+APS had 392 MW of ICTRs and no cleared QTUs sinking in the LDA, so



**CTR MW = 2370.6 MW**

- The **TOTAL Economic Value** of these CTRs can be calculated:

$$\text{TOTAL Economic Value of CTRs} = \text{CTR MW} * \text{EMAAC Locational Price Adder}$$

$$\text{\$211,647.17/day} = 2370.6 \text{ MW} * \text{\$89.28/MW-day}$$

The Final Zonal CTR Credit Rate (\$/MW-day) is equal to:

$$\text{Final Zonal CTR Credit Rate} = \frac{\text{TOTAL Economic Value of CTRs}}{\text{LDA Unforced Capacity Obligation}}$$

$$\frac{\$211,647.17/\text{day}}{76,366 \text{ MW}} = \$2.80/\text{MW-day}^*$$

\*Specific Zonal CTR Credit Rates may vary

The **CTR Settlement Rate (\$/MW-day)** is equal to:

$$\text{CTR Settlement Rate} = \frac{\text{TOTAL Economic Value of CTRs}}{\text{CTR MW}}$$

$$\frac{\$211,647.17/\text{day}}{2,370.6 \text{ MW}} = \$89.28/\text{MW-day}$$

**NOTE:** This is the same value as the Locational Price Adder for EMAAC. This will not be the case if one LDA is nested within another (ie, SWMAAC in MAAC+APS in 2009/2010).

- If a make-whole scenario exists in any LDA, the costs associated with that make-whole are socialized across the LDA that the scenario exists in.
- The Preliminary Zonal Capacity Price includes this adjustment when applicable.
- In the 2009/2010 BRA, there were no make-whole scenarios, thus, the Preliminary Zonal Capacity Price and the Resource Clearing Price are the same.

## Final Zonal ILR Prices are calculated:

<b>Final Zonal ILR Price</b>	<b>=</b>	<b>Adjusted Zonal Capacity Prices</b>	<b>-</b>	<b>Final Zonal CTR Credit Rate</b>
<b>\$188.55/MW-day</b>	<b>=</b>	<b>\$191.32/MW-day</b>	<b>-</b>	<b>\$2.77/MW-day</b>

Because there is no 2<sup>nd</sup> IA for 2009/2010, the Preliminary Zonal Capacity Price can be substituted for the Adjusted in the equation above.

- The Final Zonal Capacity Price (FZCP) is the price at which LSEs will pay load charges for each MW of UCAP obligation for a day
- The FZCP is calculated such that the total credits to supply equals the total charges to load
- The FZCP takes into account the fact that ILR may be paid less than resources that clear in an auction and any difference in the ILR Forecast versus what actually certifies

- Based on the LDA obligations calculated using the ILR Forecast Obligation and the BRA results, the LDA UCAP obligations and charges are

LDA	Final Zonal UCAP Obligation [MW]	Preliminary Zonal Capacity Price [\$/MW-day]	Preliminary Locational Reliability Charge [\$/day]
RTO	56,696.9	\$102.04	\$ 5,785,351.52
MAAC+APS	60,984.3	\$191.32	\$ 11,667,524.18
SWMAAC	16,205.7	\$237.33	\$ 3,846,108.11
Total	133,887.0		\$ 21,298,983.81

- The charge calculations on the previous slide make 2 assumptions that need to be rectified via the FZCP
  1. The amount of ILR forecasted is what actually certifies.
    - Actual ILR certified may differ from the forecast.
  2. Certified ILR is paid the same amount as a resource that clears in an auction.
    - Certified ILR in a constrained LDA is paid a lower rate than a cleared resource in the LDA (i.e., Final Zonal ILR Price)
- To accommodate for these assumptions, a scaling factor is calculated to scale the load charges to meet the resource credits

- This scaling factor is a simple ratio of the total credits paid to cleared resources, certified ILR, CTRs, ICTRs, and cleared QTUs over the total preliminary charges calculated in the previous table.
- This factor is then used to scale up or down the total charges in each zone.
- The resulting amount of charges is then used to calculate the FZCP.

- The FZCP Scaling Factor is equal to the Total Resource Credits over Total Preliminary Charges calculated to load using the ILR Forecast and Preliminary Zonal Capacity Price:

$$\text{FZCP Scaling Factor} = \frac{\text{TOTAL Resource Credits}}{\text{TOTAL Preliminary Locational Reliability Charges}}$$

$$\frac{\$ 21,878,594.17 \text{ /day}}{\$ 21,298,983.81 \text{ /day}} = 1.0272$$

- Using the FZCP Scaling Factor, we can calculate the Final Locational Reliability Charge (\$/day)
- The FZCP is calculated by taking the ratio of the Final Locational Reliability Charge and the Final UCAP Obligation of each LDA.
- Each zone within the LDA will pay the applicable FZCP

LDA	Preliminary Locational Reliability Charge [\$/day]	FZCP Scaling Factor	Final Locational Reliability Charge [\$/day]	Final UCAP Obligation [MW]	FZCP [\$/MW-day]
RTO	\$5,785,351.52	1.0272	\$5,942,788.59	56,696.9	\$104.82
MAAC+APS	\$11,667,524.18	1.0272	\$11,985,033.12	60,984.3	\$196.53
SWMAAC	\$3,846,108.11	1.0272	\$3,950,772.45	16,205.8	\$243.79
Total	\$21,298,983.81	1.0272	\$21,878,594.16	133,887.0	