Greenhouse Gas Coordination

Working Group 10

May 29, 2024

Housekeeping reminders

- This call is being recorded for informational and convenience purposes only. Any related transcriptions should not be reprinted without ISO's permission.
- These collaborative working groups are intended to stimulate open dialogue and engage different perspectives.
- Please keep comments professional and respectful.

Instructions for raising your hand to ask a question

- If you are connected to audio through your computer or used the “call me” option, select the raise hand icon located on the bottom of your screen.
  Note: #2 only works if you dialed into the meeting.
  - Please remember to state your name and affiliation before making your comment.

- You may also send your question via chat to all panelists.

Notice to Participants

Please be reminded*, Commissioners and advisors from state public utility commissions may be in attendance.*

Agenda

Time	Topic	Presenter(s)
9:00 - 9:15	Welcome and logistics	Isabella Nicosia (CAISO)
9:15 - 9:45	Oregon perspective on emissions tracking and accounting	Commissioner Letha Tawney (OPUC)
9:45 - 10:45	Mechanics and examples of the emission constrained dispatch approach	Doug Howe (State Climate Action MOU Group)
10:45 – 11:00	Break	
11:00 – 11:30	Working group 9 feedback	Isabella Nicosia (CAISO)
11:30 – 12:30	Lunch break	
12:30 – 1:30	GHG price formation	Sylvie Spewak (CAISO)
1:30 – 2:30	EDAM GHG regulation model examples	George Angelidis (CAISO)
2:30 – 2:45	Break	
2:45 – 3:45	GHG counterfactual	Anja Gilbert (CAISO)
3:45 – 4:00	Next steps	Isabella Nicosia (CAISO)

Working group progress to date

Commissioner Letha Tawney, Oregon Public Utility Commission

OREGON PERSPECTIVE ON EMISSIONS TRACKING AND ACCOUNTING

UM 2273
Commission Workshop on Renewable Energy Certificates

June 29, 2023

Emissions Policy Approaches

Oregon
Public Utility
Commission

Points of regulation

- **Load-based (aka consumption-based)**
  - **Focus:** Regulating emissions associated with electricity consumed/delivered/sold
  - **Responsible for emissions:** Entity that buys the energy
  - **Requires:** Contractual tracking instrument outside the grid to trace energy transactions to the end use, such as RECs
- **Source-based (aka generation-based, production-based)**
  - **Focus:** Regulating emissions associated with electricity generation
  - **Responsible for emissions:** Entity that generates the energy
  - **Requires:** Tracking energy from resources owned or controlled by a supplier

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Compatibility

Questions when load-based programs and source-based programs exist simultaneously

- Can the policies complement each other by measuring different things?
  - e.g., a floor for RE generation added to the grid versus a cap for emissions from thermal resources
- Are there double counting concerns with the claims being made and by whom?
- Are voluntary buyers driving reductions BEYOND regulation – creating regulatory surplus or are they paying for covered entities' compliance?

- Oregon's Renewable Portfolio Standard is a ***load-based*** program with a long history of REC-based accounting
- Other voluntary load-based programs with RECs exist in Oregon
  - e.g., community solar, net metering, green tariff, unbundled RECs

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HB 2021
Key Provisions

Emissions reductions

ORS 469A.410 (HB 2021, Section 3)

- Subject utilities are required reduce emissions below designated targets in 2030, 2035 and 2040.
  - if OPUC has not excused compliance based on reliability (Section 9) or cost (Section 10)
- Emissions are measured based on the information reported by utilities to DEQ under ORS 468A.280 and associated administrative rules*.
- “Nothing in [HB 2021] may be construed as establishing a standard that requires a retail electricity provider to track electricity to end use retail customers.”

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*The remainder of the presentation will refer to these as “*DEQ’s Methods*”

Compliance determination

ORS 469A.420 (HB 2021, Section 5)

- Utilities provide annual emissions reports to DEQ and DEQ reports its findings to the Commission using *DEQ's methods*.
- The Commission must use the annual emissions reported from DEQ "to determine whether or not the retail electricity provider has met the clean energy targets."

Compliance determination

ORS 469A.430 (HB 2021, Section 7)

- “For the purposes of determining compliance with [HB 2021], electricity shall have the emission attributes of the underlying generating resource.”

ORS 469A.430 (HB 2021, Section 8)

- The Commission must exclude unplanned emissions that were required to meet load and emissions associated with electricity from net metering and Public Utility Regulatory Policies Act (PURPA) qualifying facilities.

- DEQ must treat specified power from Bonneville Power Administration consistent with *DEQ’s Methods*.

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Complexities

ORS 469A.400 (HB 2021, Section 1)

- DEQ establishes the baseline emissions level upon which emissions reduction targets are set. Baseline emissions are calculated based on historical emissions "associated with the electricity sold to retail electricity consumers as reported under [*DEQ's Methods*]."

ORS 469A.430 (HB 2021, Section 5)

- Direct Access providers' compliance is based on "annual greenhouse gas emissions associated with electricity sold by the electricity service supplier to retail electricity consumers".

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Complexities cont.

ORS 469A.460 (HB 2021, Section 13)

- No modification of the RPS statute.

ORS 469A.475 (HB 2021, Section 15)

- Goal of aligning accounting methodologies with markets where possible, while also ensuring market rules do not undermine state policy objectives.
- Recognition that practices may need to change as markets evolve.
- Consideration for review of DEQ's regional emissions assumptions over time.

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Interim considerations

ORS 469A.420 (HB 2021, Section 5)

- DEQ will verify projected emissions reductions in utility plans using *DEQ's Methods* and report to the Commission during the OPUC's plan review process.

ORS 469A.415(HB 2021, Section 4)

- The Commission shall ensure that utilities demonstrate continual progress in line with the projections in their plans.

Prior to 2030, utilities will continue to report their emissions to DEQ annually under *DEQ's Methods*.

Are there considerations for the UM 2273 accounting and REC issues during this interim reporting and progress monitoring period?

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DEQ’s Methods

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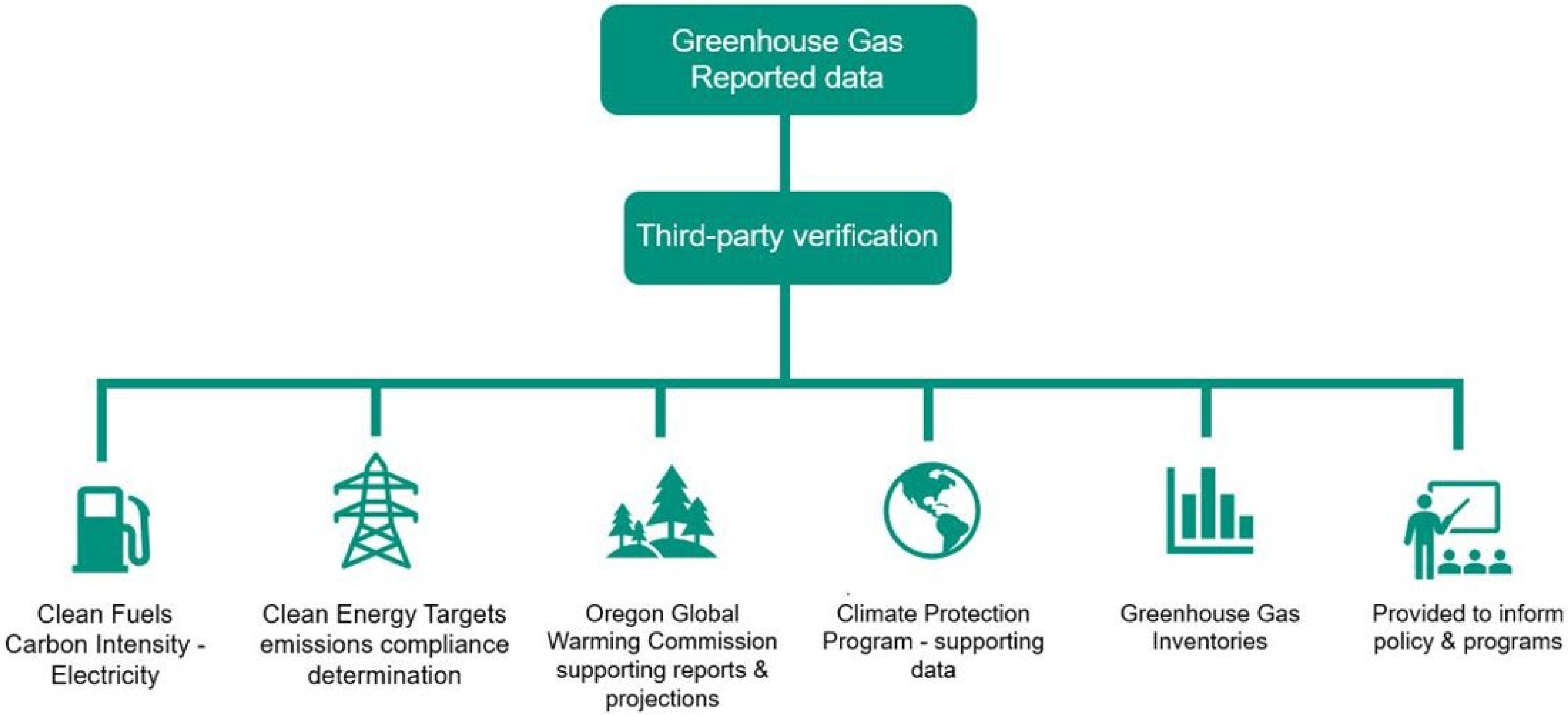
DEQ GHG Emissions Accounting

Overview of Electricity Supplier Reporting

June 29, 2023
Elizabeth Elbel,
Oregon DEQ Greenhouse Gas Reporting Program

DEQ GHG Reporting Program



Background: GHG Reporting Authority

Oregon Revised Statute 468A provides authority to the Environmental Quality Commission to require GHG reporting from certain sources:

- ORS 468A – Air Quality
- ORS 468A.050 - Classification of air contamination sources; registration and reporting of sources; rules; fees
- ORS 468A.280 – Electricity; fossil fuels; registration and reporting requirement rules

Rules adopted by the commission under this section for electricity that is imported, sold, allocated or distributed for use in this state may require reporting of information necessary to determine greenhouse gas emissions from generating facilities used to produce the electricity and related electricity transmission line losses.

Background: GHG Reporting Rules

Oregon Administrative Rules Chapter 340, Division 215 include applicability and requirements for reporting:

- Applicability for Electricity Suppliers (OAR 340-215-0030(5))

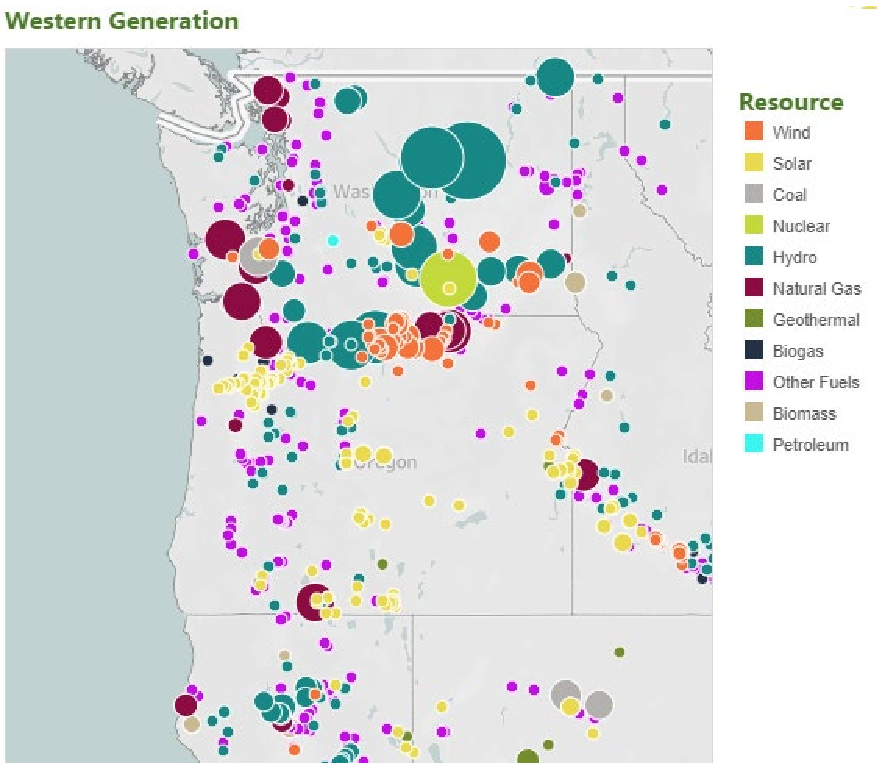
Electricity suppliers. All investor-owned utilities, multi-jurisdictional utilities, electricity service suppliers, consumer-owned utilities, and other persons that import, sell, allocate, or distribute electricity **to end users in the state** must register and report in compliance with this division.

Emission Quantification Methodology

DEQ's GHG reporting rules require electricity suppliers to report the **megawatt-hours** and **associated greenhouse gas emissions from the generation of electricity supplied** to end users in Oregon, regardless of where the electricity was generated.

They must:

- Use DEQ assigned emission factors for calculating direct GHG emissions based on generating resource.
- Separately report for each specified and unspecified source
- Apply a 2 % transmission loss correction factor for power not measured at the busbar



DEQ Assigned Emission Factors

For reporting purposes, DEQ annually calculates and assigns emission factors to specified source facilities:

- The emissions factors account for actual greenhouse gas emissions resulting from the generation of electricity occurring at each specified facility
- Separately account for anthropogenic and biogenic emissions
- Utilize 100-year time horizon Global Warming Potentials (GWP) and publicly available emissions and generation data

Greenhouse gas reporting rules prescribe a default emissions factor for unspecified power.

Unspecified Source Emission Factor

GHG RP rules require the use of the default emission factor of **0.428 (MTCO2e/MWh)** for energy originating from an unspecified source. This includes power that was not designated for delivery from a specific source at the time of entry into the transaction.

Energy Markets: The GHG RP rules also currently assign the default unspecified emission factor rate to power purchases from the energy imbalance or other centralized.

DEQ

Specified Source Emission Factors

Under Oregon's GHG RP rules, a specified source refers to a source of electricity that is either owned by the utility, purchased through a pre-existing contract or from a DEQ-approved Asset Controlling Supplier.

DEQ assigns facility-specific emission factors to each specified source annually based on facility specific data.

- **Non-emitting sources:** For non-emitting resources such as solar, wind, hydro, nuclear and closed-loop geothermal, the emission factor is zero, as no direct emissions are produced from those generation facilities.

- **GHG-emitting sources:** DEQ totals the facility-level emissions for the calendar year from electricity generation in metric tons of carbon dioxide equivalent (MTCO2e) and divides that total by the net electricity generation in MWh.

$$\frac{\textit{Source Annual GHG Emisisons MTCO2e}}{\textit{Source Annual Net Generation MWh}} = \textit{Facility Specific Emission Factor}\left(\frac{MTCO_2e}{MWh}\right)$$

Resource: Specified source emission factor methods

Multi-jurisdictional Utility Reporting

The Multi-Jurisdictional (MJ) approach applies to utilities that is an electricity retail provider to customers in Oregon and at least one other state.

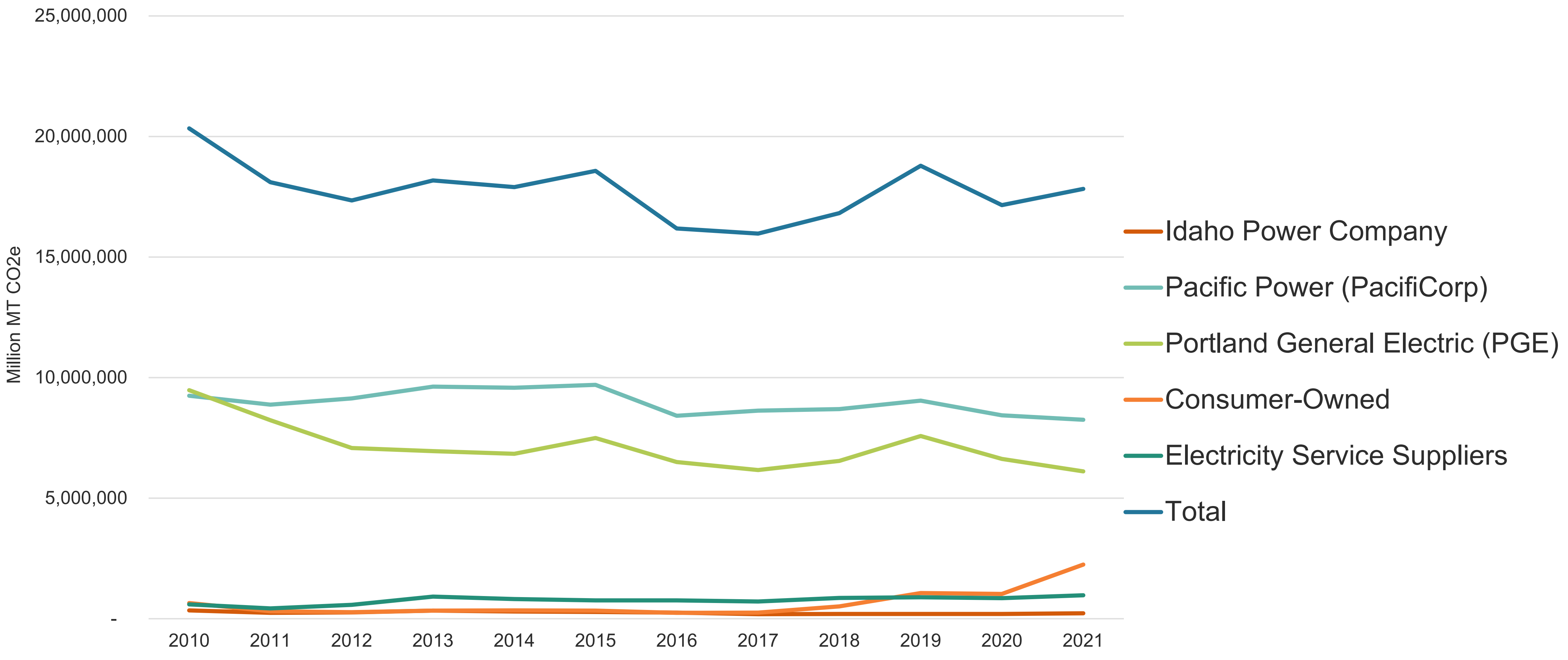
Report total MWh and greenhouse gas emissions from the generation of electricity from specified and unspecified sources in the **utility's service territory or power system** and report the following:

- (A) Wholesale electricity purchased and taken from specified sources (MWh);
- (B) Wholesale electricity purchased from unspecified sources (MWh);
- (C) Wholesale electricity sold from specified sources (MWh); and
- (D) Retail sales (MWh) to customers in Oregon's portion of the utility's service territory or power system

To calculate total emissions from a multijurisdictional entity, the DEQ calculated system emission factor is applied to the MWh delivered to end-users in Oregon.

$CO2e$ = MWh delivered in OR × TLF × system emission factor

GHG Electricity Supplier Emissions



Additional considerations for HB 2021

What modifications are made for HB 2021?

- HB 2021 excludes emissions associated with electricity from net metering or a qualifying facility.
- Targets apply specifically to anthropogenic emissions
- For the purpose of HB 2021, DEQ has also developed default emission factors for use in Clean Energy Plans.
- Assessment of compliance in a target year will be based on DEQ prescribed emission factors.

Resource: [Assigned emission factors for use in 2023 Clean Energy Plans]

Thank you!

DEQ Resources:

- DEQ Greenhouse Gas Reporting Program
- DEQ specified source emission factor methodology
- DEQ's HB 2021: Clean Energy Targets Website
- Overview of HB 2021 emissions quantification methodology
- DEQ assigned emissions factors for use in 2023 Clean Energy Plans
- Contact us: GHGreport@deq.Oregon.gov

Questions to consider

Is HB 2021 a generation-based program with a carve out for generation sold?

Or, is HB 2021 a load-based program that does not consider attributes or tracking energy to end use customers?

How does participation in centralized markets rather than controlling dispatch in each BA impact this discussion?

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Emissions Accounting in Centralized Markets

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Why join an electricity market?

- Benefits identified in HB 2021 Section 15:
  - "The Legislative Assembly finds that existing and future electricity markets will play a critical role in the transformation of the electric sector to nonemitting sources, as well as enabling load serving entities to reduce costs and serve load reliably by accessing resource and load diversity."
- Security-constrained economic dispatch
  - Optimizes dispatch of all resources in the market footprint to minimize cost while conforming to the operational and reliability constraints of the generating fleet and transmission system.

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GHG regulation varies in the West

- Western markets must manage multiple state GHG regulation regimes.
  - **GHG cap** on generation that serves load in state, including electricity imports: OR, CO, NV, NM.
  - **GHG pricing** on in-state generation and electricity imports (“cap and trade/invest”): CA and WA.
  - **No GHG regulation**: ID, MT, WY, UT, AZ.
- Pricing and non-pricing GHG regulation in the same market footprint results in different energy costs between regulated and unregulated generators.

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Markets dispatch utility resources

- Today, Oregon utilities dispatch their own resource fleets from their own control centers.
  - They can comply with an emissions cap by choosing whether to operate resources based on emission rather than economics.
- In a market, the utilities turn over dispatch control of their resources to the market operator’s dispatch algorithm.

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Challenge for GHG caps in market

- Market dispatch is optimized for economics, not emissions.
- GHG pricing affects market dispatch. GHG caps do not.
  - A state's GHG price is embedded in the price of electricity from any emitting generator located in the state or exporting to the state.
  - Clean energy will be drawn into GHG pricing states because, with a $0 GHG price, it's cheaper than emitting energy.
  - Emitting energy will be more economical to serve load in states with no GHG price than states with GHG pricing.

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Options for GHG caps in market

- Utilities subject to a GHG cap could "self-schedule" their resources during bidding.
  - Forces the resource to run and makes it ineligible for economic dispatch and export to other loads.
  - Reduces the value of market participation.
- The market could incorporate a "shadow GHG price" on generation serving load in the GHG cap state.
  - A proposal exists to allow utilities subject to a GHG cap to set emission constraints on their load bids, resulting in a shadow price that would influence the economic dispatch decisions.

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RECs don't follow market dispatch

- Today, utilities comply with Oregon's RPS 'bundled RECs' requirement by dispatching renewable energy resources to serve their load and retiring the associated RECs.
- In a market, the utilities will relinquish dispatch control, and there is no mechanism to include RECs in the market transaction, so the link between the RPS and dispatch will be severed.
- In existing organized markets in the U.S., utilities comply with state RPSs by using RECs to demonstrate they have contributed an amount of renewable energy to the market footprint.

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Challenge using RECs for HB 2021 compliance

- Imports to Oregon:
  - If the market dispatches excess solar generation from California to serve Oregon load, there is no way for the Oregon utility to acquire (and retire) RECs for that imported electricity.
    - If RECs are required, how would imports be counted toward HB 2021 requirements?
- Exports from Oregon:
  - If the market dispatches excess wind generation from Oregon to serve Washington load, the wind will be treated as emissions-free in Washington's cap-and-invest program, even without RECs.
    - Would that make the wind ineligible to count toward Oregon's RPS?

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Summary

- Centralized markets will provide significant economic and reliability benefits and cost-efficient access to a greater diversity of clean resources but will disrupt the way utilities demonstrate compliance with state RPS and GHG mandates.
- Interpreting HB 2021 as generator-based regulation, consistent with the Commission's inclination expressed in Order 23-194, will allow OR utilities to operate most effectively in a market that includes CA and/or WA GHG pricing programs.
- Western markets are still under development and many uncertainties remain.

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Participant Comments

How does today’s discussion impact consideration of the accounting and REC treatment questions in UM 2273?

What are the implications for how HB 2021 interacts with other states/programs?

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Doug Howe, State Climate Action MOU Group

MECHANICS AND EXAMPLES OF THE EMISSION CONSTRAINED DISPATCH APPROACH

May 29, 2024

Emission Constraint Dispatch:
Technical Discussion

On Behalf of the State Climate Action MOU group

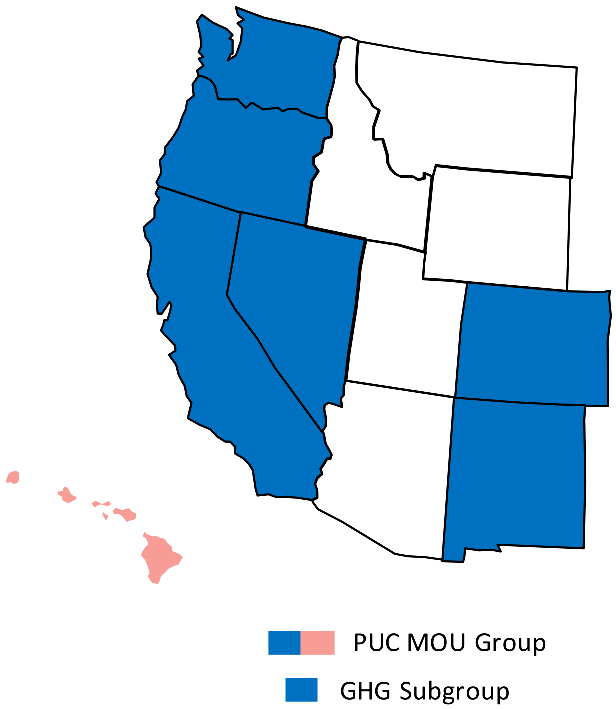
Doug Howe, Ph.D.

CAISO GHG CG

May 2024

The State Climate Action MOU Group

- Western Public Utility Commissions' Joint Action Framework on Climate Change.
- Organized in 2003 by founding members California PUC, Oregon PUC and Washington UTC.
- The GHG Subgroup consists of a commissioner from each member commission, except Hawaii, to engage in the treatment of state GHG standards in Day-Ahead Markets under development.



US map provided by yourfreetemplate.com

Disclaimer

This presentation endeavors to provide an objective view of the ongoing developments of electricity markets in the Western U.S.

However, opinions are solely those of the author and speaker.

Emission Constrained Dispatch

- There is a non-priced GHG Zone within the market.
- The non-priced GHG Zone specified a target maximum emissions for a particular dispatch interval.
- The objective is to dispatch market resources so the GHG allocated to the non-priced GHG Zone is less than or equal to the target maximum emissions.
- “No Leaning”: the non-priced GHG Zone must offer into the market a portfolio of generation that can meet the target maximum emissions on a standalone basis. This ensures a feasible dispatch solution.

Example Set Up

BAA A
Non-Price GHG Zone
Load: 350

	Emission Factor	MWH Offer	Price
G1	0.46	200	$30
G2	0.00	120	$64
G3	0.70	55	$60

99,999 MW

99,999 MW

BAA B
Load: 750

	Emission Factor	MWH Offer	Price
G4	0.92	380	$38
G5	0.51	380	$40
G6	0.46	135	$42
G7	0.00	145	$50
G8	0.39	180	$48

BAA-A Is Not Leaning

BAA-A has set a target maximum emission rate of <u>0.38 = 133 tonnes</u>

	Emission Factor	MWH Offer	Full Dispatch Emissions
G1	0.46	200	92
G2	0.00	120	0
G3	0.70	55	38.5
	0.348	375	130.5

Emission Constrained Dispatch

- Builds off the Resource Specific approach for priced GHG zones
- Internal resource dispatch and emissions are allocated to the non-priced GHG zone
- External resources can be “deemed” to be serving the non-priced GHG zone. Deemed resource dispatch and emissions are allocated to the non-priced GHG zone.
- Total of internal emissions and deemed emissions cannot exceed the target maximum emissions.

Objective Function

- Same as Resource Specific, but there is no GHG Adder, so we assign a cost of $0.001 to resources being assigned to the GHG reduction zone.

$$\Sigma_i D_i * p_i + \Sigma_i A_i * 0.001 + \Sigma_{k,l} T_{k,l} * t_{k,l}$$

D_i = dispatch of generator G_i

p_i = offer price of generator G_i

A_i = Amount of dispatch of G_i assigned to GHG reduction zone

$T_{k,l}$ = transfer from BAA B_k to B_l

$t_{k,l}$ = cost of transfer from BAA B_k to B_l

Constraints Same as Resource Specific Plus One More

- Internal generation is assigned to A.
- External generator amount deemed to A must not exceed generator's dispatch
- Total deemed dispatch must not exceed net transfers B to A
- Load of A must not exceed the sum of internal and deemed energy to A (shadow price is the GHG marginal price)
- Power Balance equality constraint for both A and B (shadow prices are the respective energy marginal prices)
- Total of internal emission and deemed emissions must not exceed the maximum emission target (emission constraint). If this constraint does not bind then the GHG marginal price is zero.

Dispatch Results

- The maximum emission target was 133 tonnes, which was exactly met, so the emission constraint was binding.
- Because of the “no leaning” rule, the emission constraint would most likely not bind often.

	EMISSION FACTOR	DISPATCH	DEEMED TO A	EMISSIONS TO A
G1	0.46	200	200	92.0
G2	0.00	0	0	
G3	0.70	0	0	
G4	0.92	380	0	
G5	0.51	380	10	5.1
G6	0.46	78	78	35.9
G7	0.00	62	62	0.0
G8	0/39	0	0	
TOTALS		1100	350	133

Financial Settlement

LMP- A = $41.13 LMP-B = $41.13 GHG MP = $8.87

Generator	Energy Pay	GHG Pay	Total Pay	Cost	Profit
G1	$ 8,226	$ 1,774	$ 10,000	$ 6,000	$ 4,000
G2	$ -	$ -	$ -	$ -	$ -
G3	$ -	$ -	$ -	$ -	$ -
G4	$ 15,630	$ -	$ 15,630	$ 14,440	$ 1,190
G5	$ 15,630	$ 89	$ 15,718	$ 15,200	$ 518
G6	$ 3,210	$ 692	$ 3,902	$ 3,278	$ 624
G7	$ 2,548	$ 550	$ 3,098	$ 3,098	$ 0
G8	$ -	$ -	$ -	$ -	$ -

Total generator payments are $48,349

Load A pays: $14,396 ($41.13 x 350) in energy plus $3,105 (350*$8.87)in GHG cost for total of $17,500
Load B pays: $30,848 ($41,13 x 750)
Total load payments are: $48,349

What Happens If Dispatched on Price Alone?

	EMISSION FACTOR	DISPATCH
G1	0.46	200
G2	0.00	0
G3	0.70	0
G4	0.92	380
G5	0.51	380
G6	0.46	135
G7	0.00	0
G8	0.39	5
TOTALS		1100

Dispatch in B	900
Load in B	750
Excess from B	150
System Average Emission Factor for B	0.675
Excess Emissions allocated to A	101.2
Internal Emissions	92
Total Allocated to A	**193.2**
Percent Over Target	**45%**

Thank you

Questions?

Isabella Nicosia, Associate Account Manager, Stakeholder Engagement

WORKING GROUP 9 FEEDBACK

Stakeholder Feedback: PG&E Presentation on Problem Statement 1

Entity	Comment
PGE	Seeks additional data from the ISO on the extent and value of emissions leakage in the WEIM
SRP, Six Cities	Support PG&E's recommendation for the ISO to conduct a cost-benefit analysis of optimization constraints limiting secondary dispatch
SRP	Request feedback from the ISO on feasibility and accuracy of performing a detailed cost-benefit analysis
SRP	Encourages exploration of different baselines for measuring secondary dispatch and its cost implications

Stakeholder Feedback: WPTF Presentation on Problem Statement 4

Entity	Comment
PacifiCorp	Seeks clarity on what advantages would be gained through enhanced transparency
SRP	Supports further discussions on the interpretation of the marginal GHG component and options to enhance transparency

Stakeholder Feedback: Vistra Presentation on Problem Statements 1-3

Entity	Comment
PacifiCorp	Supports Vistra's data request for the ISO to show how the GHG shadow price is calculated when GHG bids are exhausted
PGE	Stresses importance of not disadvantaging market participants in non-priced GHG capped states
SRP	Supports exploring examples for pricing impacts using a counterfactual that treats BAAs individually
SRP	In scenarios with insufficient GHG bids, requests the ISO disclose the optimization model's logic and penalty prices associated with relaxing a GHG constraint, and suggests this information be included in a BPM
SRP	Supports discussions on solutions for resources not fully awarded in the IFM
Six Cities	Supports further evaluation of GHG counterfactual runs based on aggregated non-GHG areas

Stakeholder Feedback: Data Requests

Entity	Comment
CRS	Echoed November working group comments and request for data from WREGIS, states, and the ISO that would identify instances of double counting
PGE	Encourages continued engagement with EDAM participants subject to non-priced GHG reduction policies
SRP	Requests the ISO provide a list of metrics requested by stakeholders with a progress status indicator and explanations/use cases for each metric provided detailing how it can be effectively utilized by stakeholders to manage GHG compliance and market operations

Stakeholder Feedback: WPTF Presentation on its After-the-Fact Accounting Approach Examples

Entity	Comment
CRS, PacifiCorp, PGE SRP, Six Cities	Supports further consideration of approach
CRS	Support including a residual mix adjusted for null power and prefer removing null power generation rather than assigning emissions to it
CRS	Emphasize need for coordination with WREGIS to avoid double counting
CRS	Support treating storage committed to specific load as load and assigning generation attributes to storage if there's a contract and including associated RECs to avoid double counting
PacifiCorp	Difficulties exist for multijurisdictional utilities with an hourly accounting framework due to multi-state operations
PacifiCorp	Requests additional discussion on how excess solar would be treated
PacifiCorp	Suggests avoiding multiple emission factors unless required by regulators
SRP	Suggests emissions from self-scheduled resources be attributed directly to the corresponding LSE
SRP	Supports dual residual emission rate calculations, with one adjusted for null power
SRP	Requests comprehensive review of methodology for storage to avoid conflicts with CARB's methodology and potential double counting
SRP	Requests flexibility in determining whether RECs should accompany energy transactions to California LSEs due to varying environmental policies in the West

Stakeholder Feedback: PNM Presentation on Problem Statement 7

Entity	Comment
PGE	Notes differences in Oregon and New Mexico’s policies; conclusions about PNM’s position should not be generalized to other non-priced participants
SRP	Concerned that environmental policy changes across the West could lead to price impacts as entities adjust their bidding strategies to meet new goals or requirements

Work streams

1 **ISO Market Operations & GHG Design – Current Approach to GHG Pricing Programs in WEIM**

- Problem statements 1-4, 6e
- Sponsors: PG&E, Vistra, WPTF

2 **Addressing Non-Pricing and Clean Energy Policies, and Voluntary Goals**

- Problem statements 7a-c
- Sponsors: PGE, PNM, WRA

3 **GHG and Related Metrics**

- Problem statements 5, 6a-d, 6f

LUNCH BREAK

Sylvie Spewak, Senior Policy Developer, Policy Development

GHG PRICE FORMATION

Overview of concepts in today's examples

- Separable **GHG bid adders** allow the market to dispatch at least cost, consistent with separate jurisdictional preferences
  - Prevents the cost of one jurisdiction's GHG policy from impacting costs in the rest of the market
- The **GHG export allocation** tells the market how many MW of capacity to attribute to a GHG area
- The **marginal GHG cost**, a value produced by the market optimization, is a shadow price for allocating an additional MW to the GHG area
  - Ensures the efficiency of price formation and market outcomes

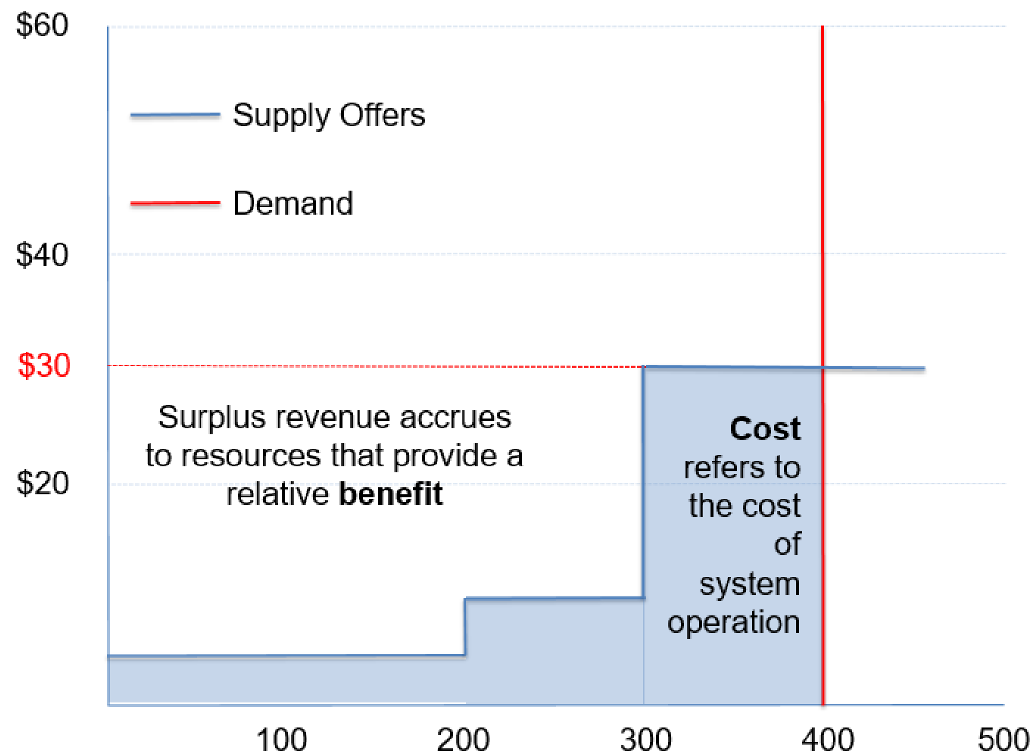
The simplified steps in these examples are a way for us to conceptualize how optimization works

- Optimization is an iterative process, so the order in which you think through these steps does not matter
- What we actually see in market prices, or from a solver, may look different due to increased complexity
- These concepts will build toward our understand of examples in the Business Practice Manuals (BPM) for the Energy Imbalance Market
- The ISO Learning Center has more resources : https://www.caiso.com/CBT/market-pricing/MarketPricing.html

Optimization has two simultaneous functions

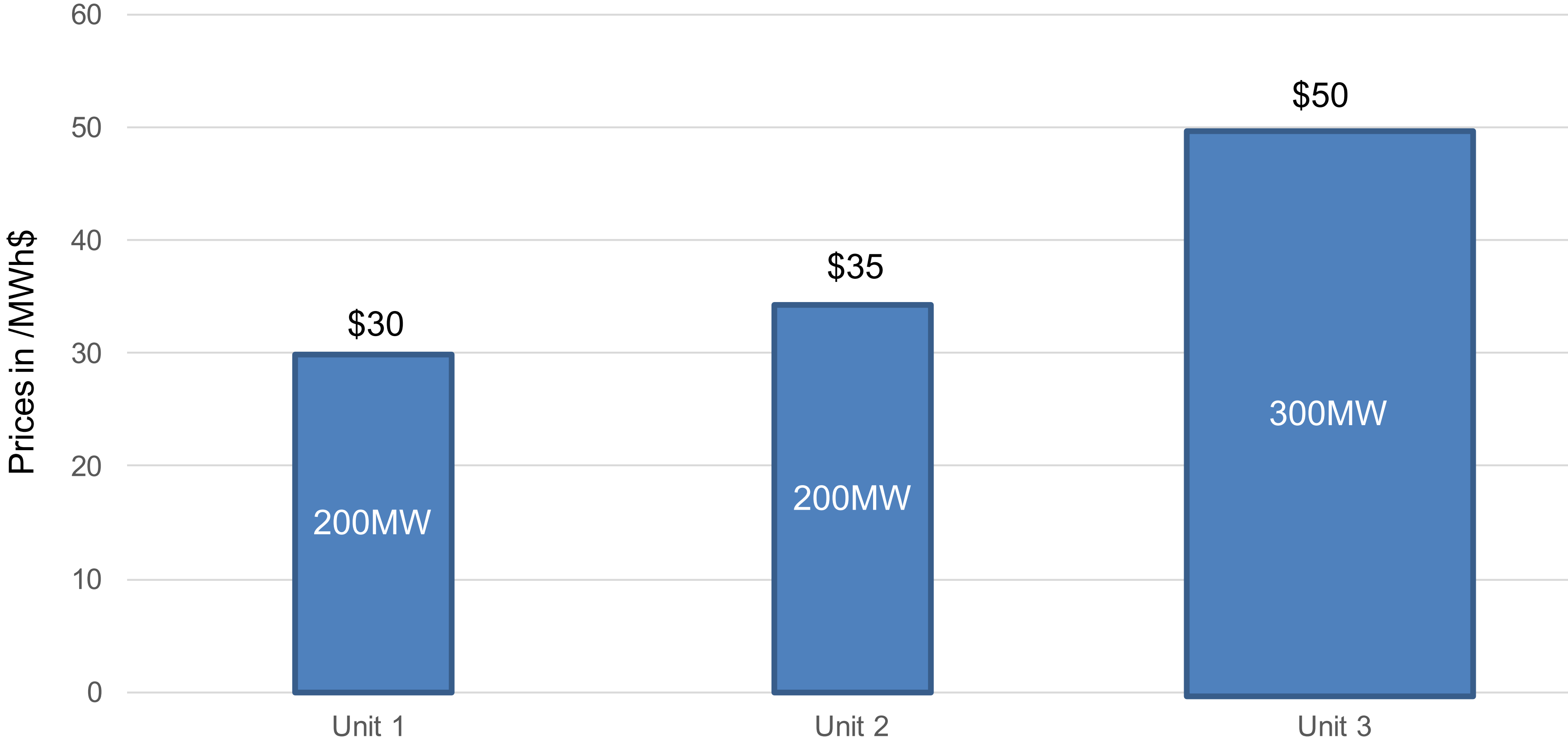
The objective of **optimization** is to find a solution that minimizes costs and maximizes benefits.

- Prices incentivize the targeted dispatch
- Cost is minimized through least cost dispatch



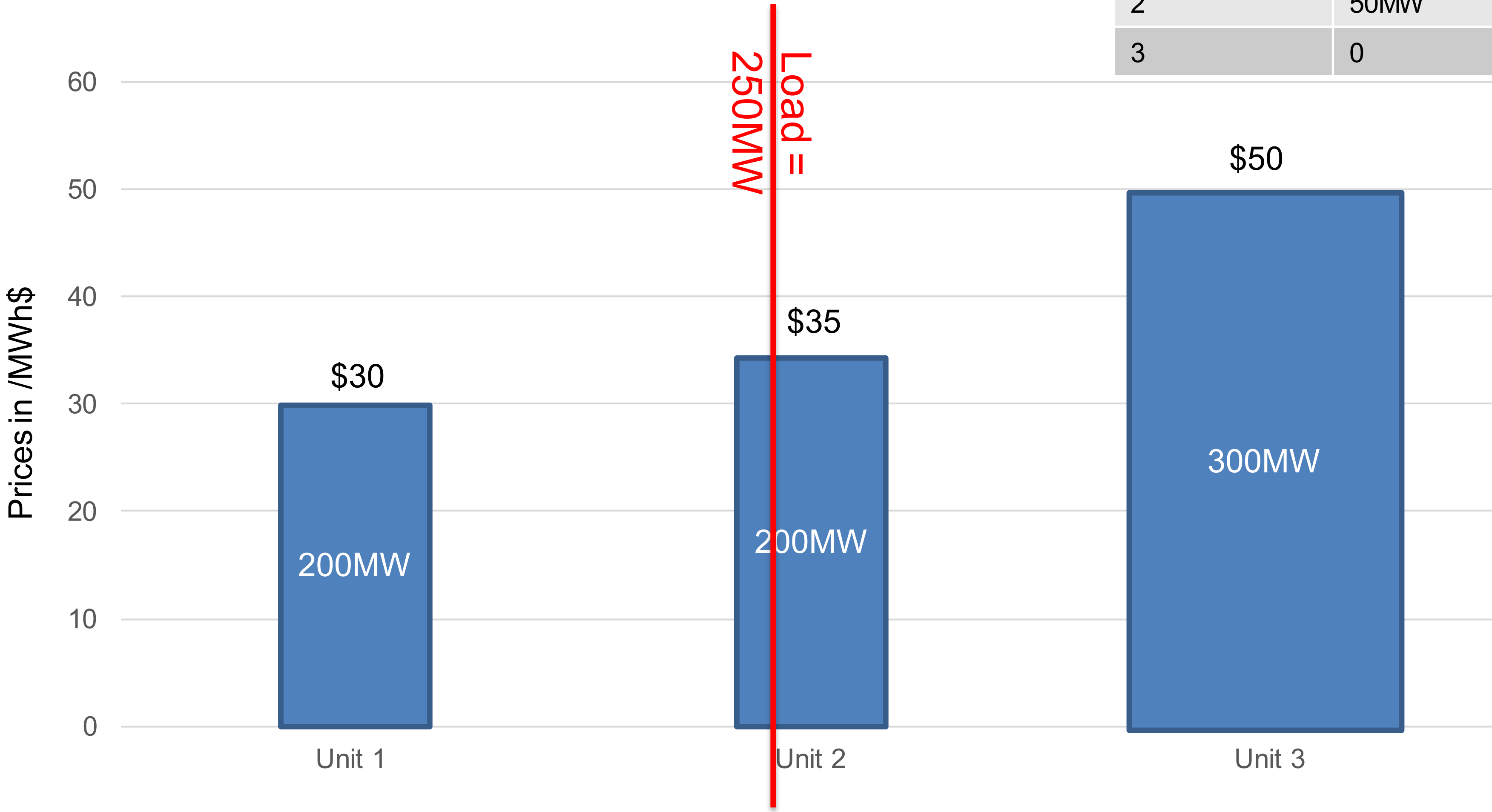
Prices should signal for each resource what their optimal dispatch is that would minimize system costs.

How do we dispatch these resources to meet 250MW of load?



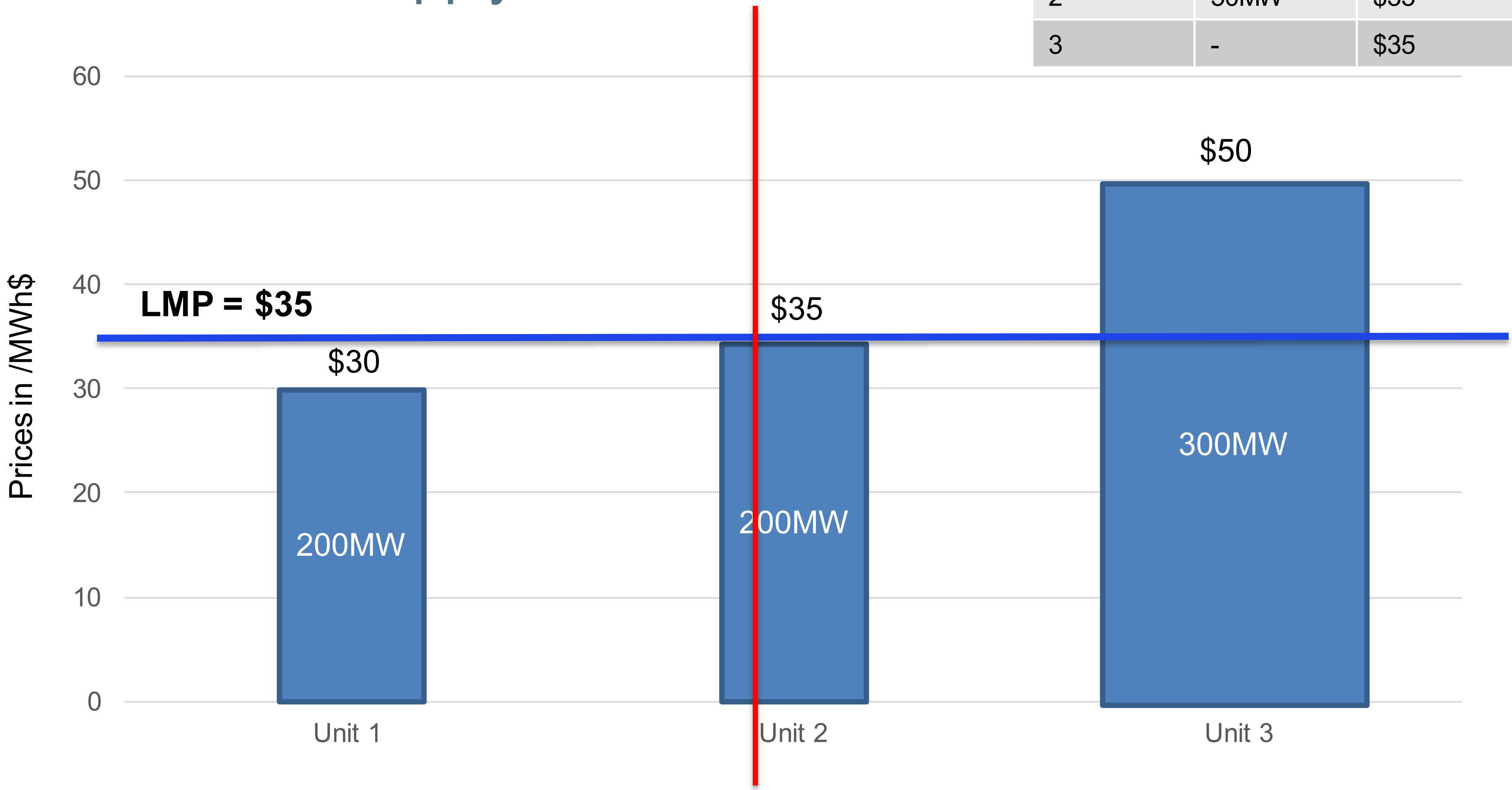
How do we dispatch these resources to meet 250MW of load?

Unit	Dispatch
1	200MW
2	50MW
3	0

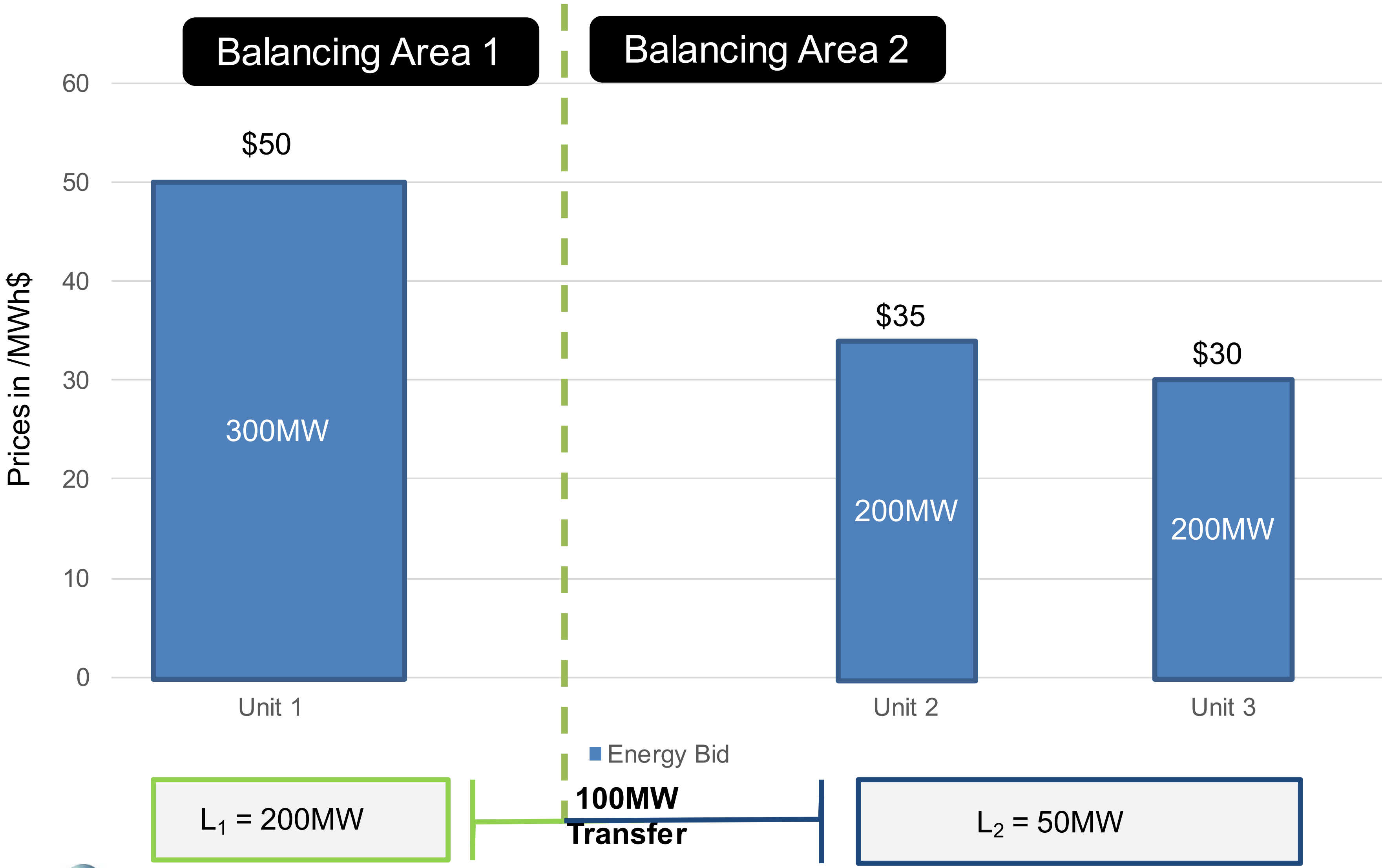


How do we set prices to incentivize 250MW of supply at least cost?

Unit	Dispatch	LMP
1	200MW	$35
2	50MW	$35
3	-	$35



Accounting for a physical transmission constraint



Minimizing costs with a transfer constraint

Unit	Dispatch (MW)	Energy Cost ($)	Cost of serving L_1 ($)	Cost of serving L_2($)	Cost to the system ($)
1	100	50	5,000	-	5,000
2	-	-	-		**-**
3	150	30	3,000	1,500	1,500
Total	**250**		**8,000**	**1,500**	**10,000**

The cost of serving L_1 comes from Units 1 and 3:

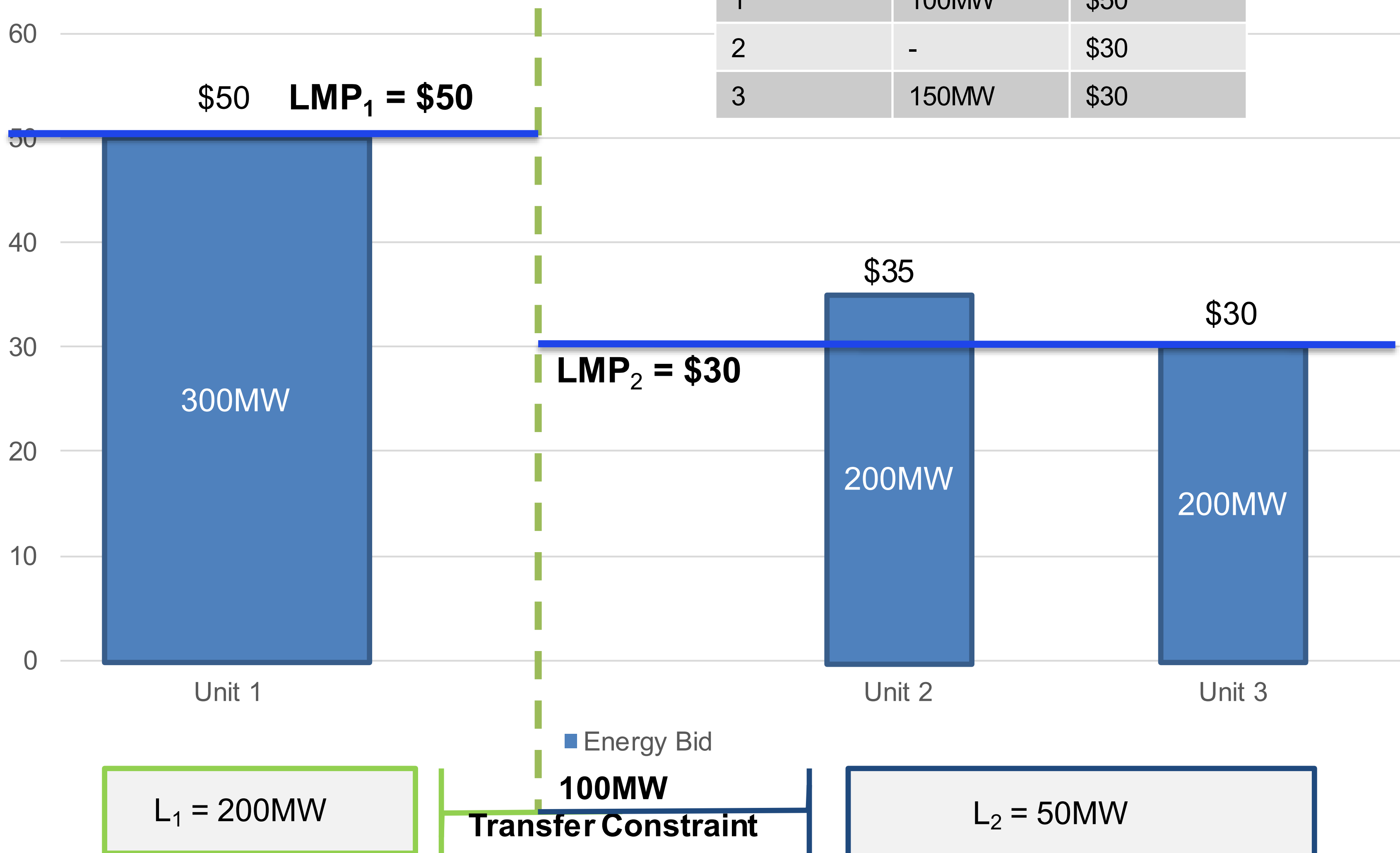
- Unit 1 costs $50 * 100MW = $5,000/MWh, and
- Unit 3 costs $30 * 100MW = $3,000/MWh to produce supply for L_1.

The cost of serving L_2 comes from Unit 3:

- Unit 3 cots $30 * 50MW = $1,500/MWh to produce supply for L_2.

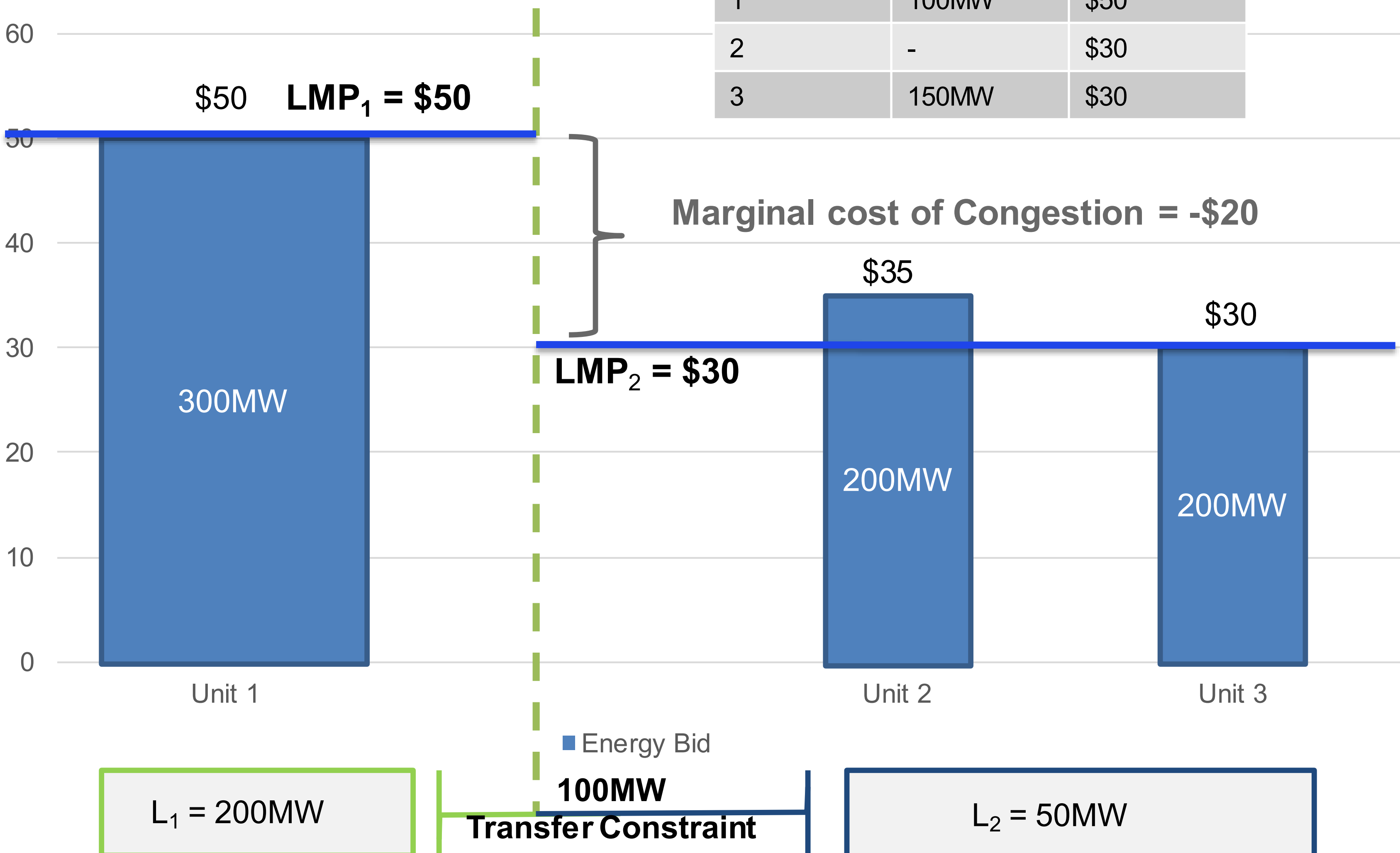
Accounting for a physical transmission constraint

Unit	Dispatch	LMP
1	100MW	$50
2	-	$30
3	150MW	$30



Accounting for a physical transmission constraint

Unit	Dispatch	LMP
1	100MW	$50
2	-	$30
3	150MW	$30



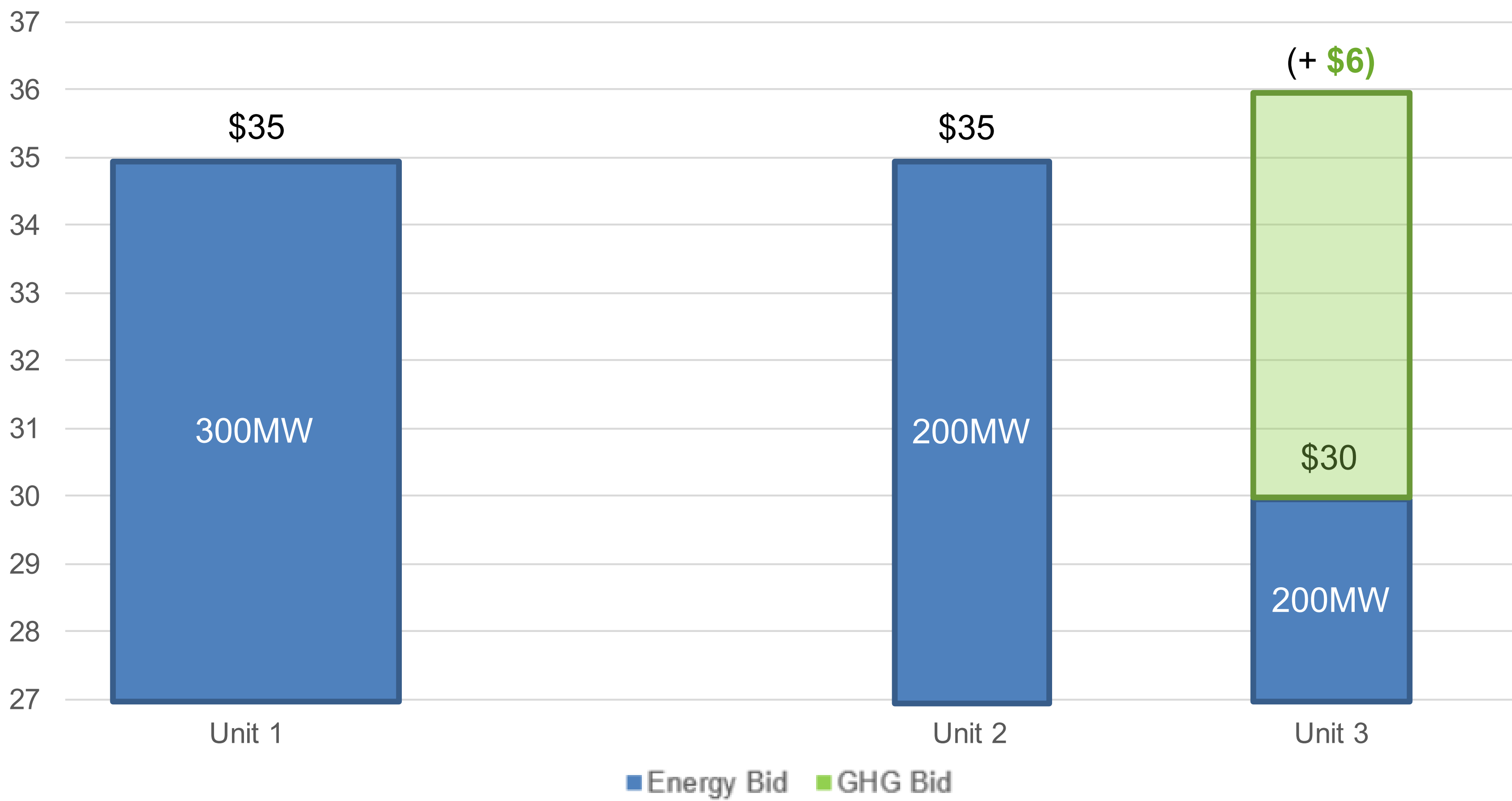
GHG Accounting with GHG bid adders

- A resource can submit a two part GHG bid adder for each GHG area:
  - MWh quantity the resources is willing to offer to the GHG area
  - $/MWh cost associated with the resources expected compliance obligation in the GHG area
- A resource does not need a bid adder for it's own jurisdiction

Model Assumptions

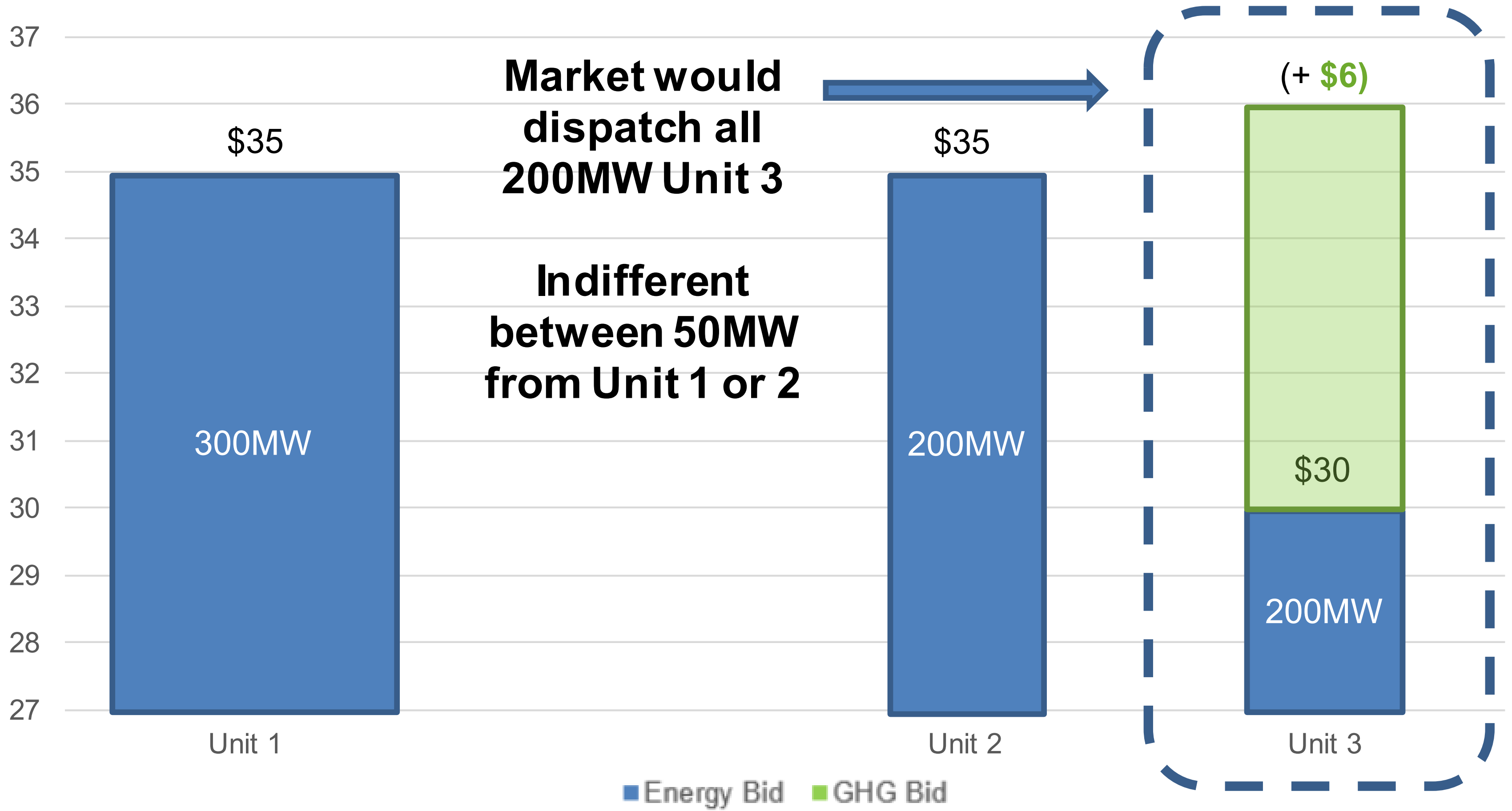
- Assume all jurisdictions have sufficient supply to meet their load
- Assume all resources in the non-GHG area submit a bid adder for the full capacity of resources shown
- These examples leave out the counterfactual approach for now

Ignoring bid adders, dispatch minimizes system costs consistent with non-GHG area preferences



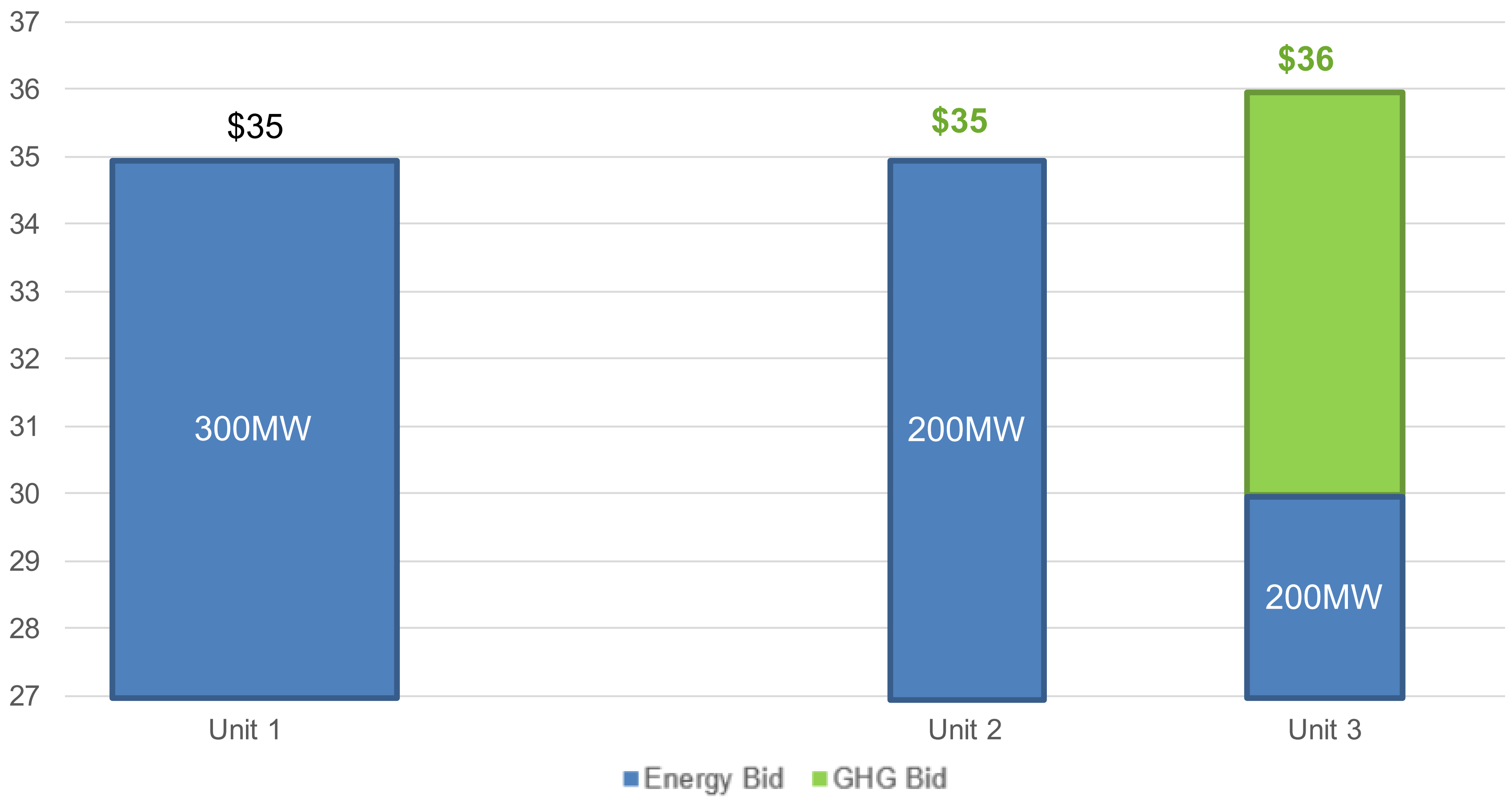
L_{GHG+N} = 250MW

Ignoring bid adders, dispatch minimizes system costs consistent with non-GHG area preferences



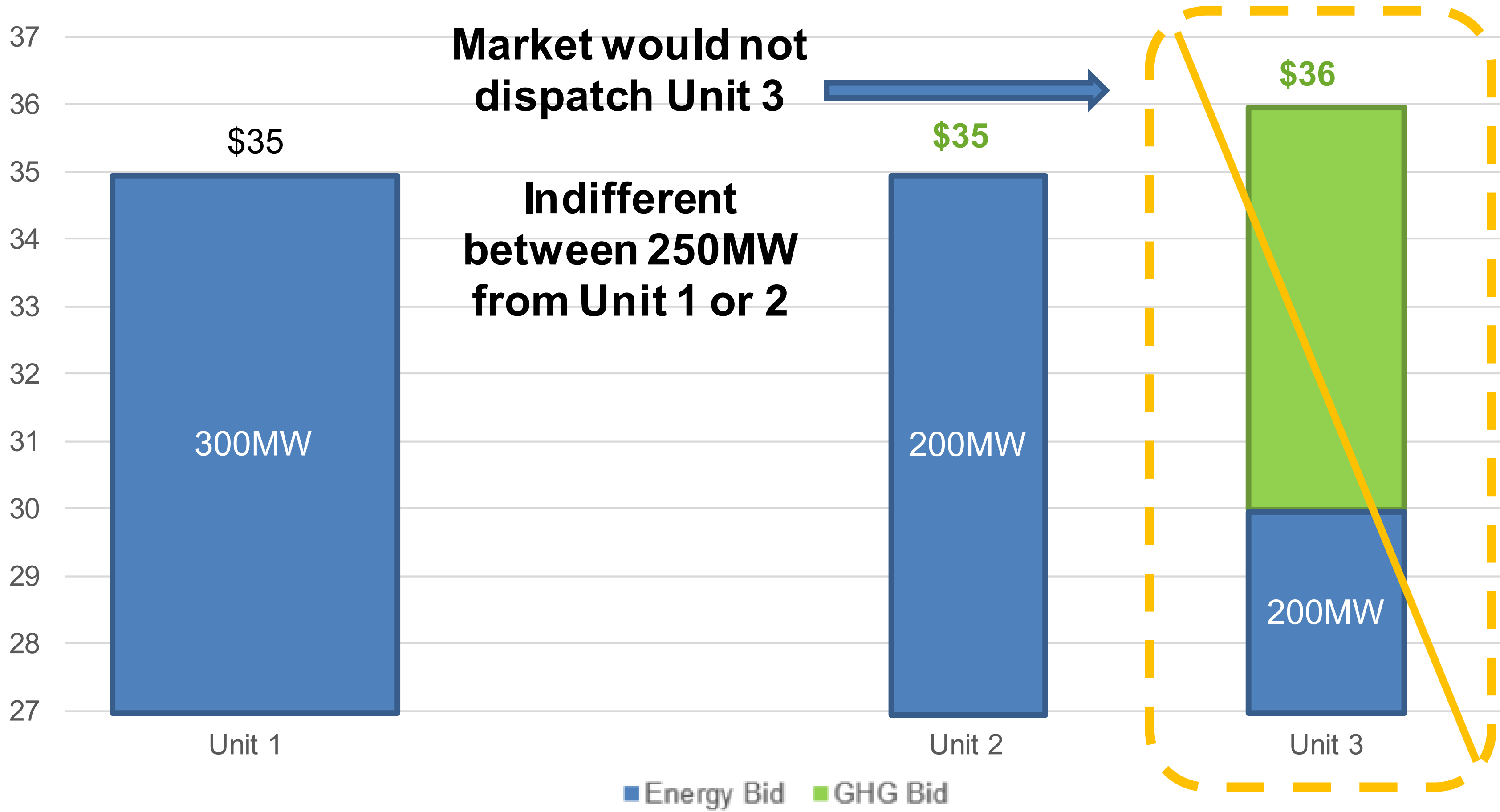
L_{GHG+N} = 250MW

With bid adders, dispatch minimizes costs as if the whole market were similarly regulated



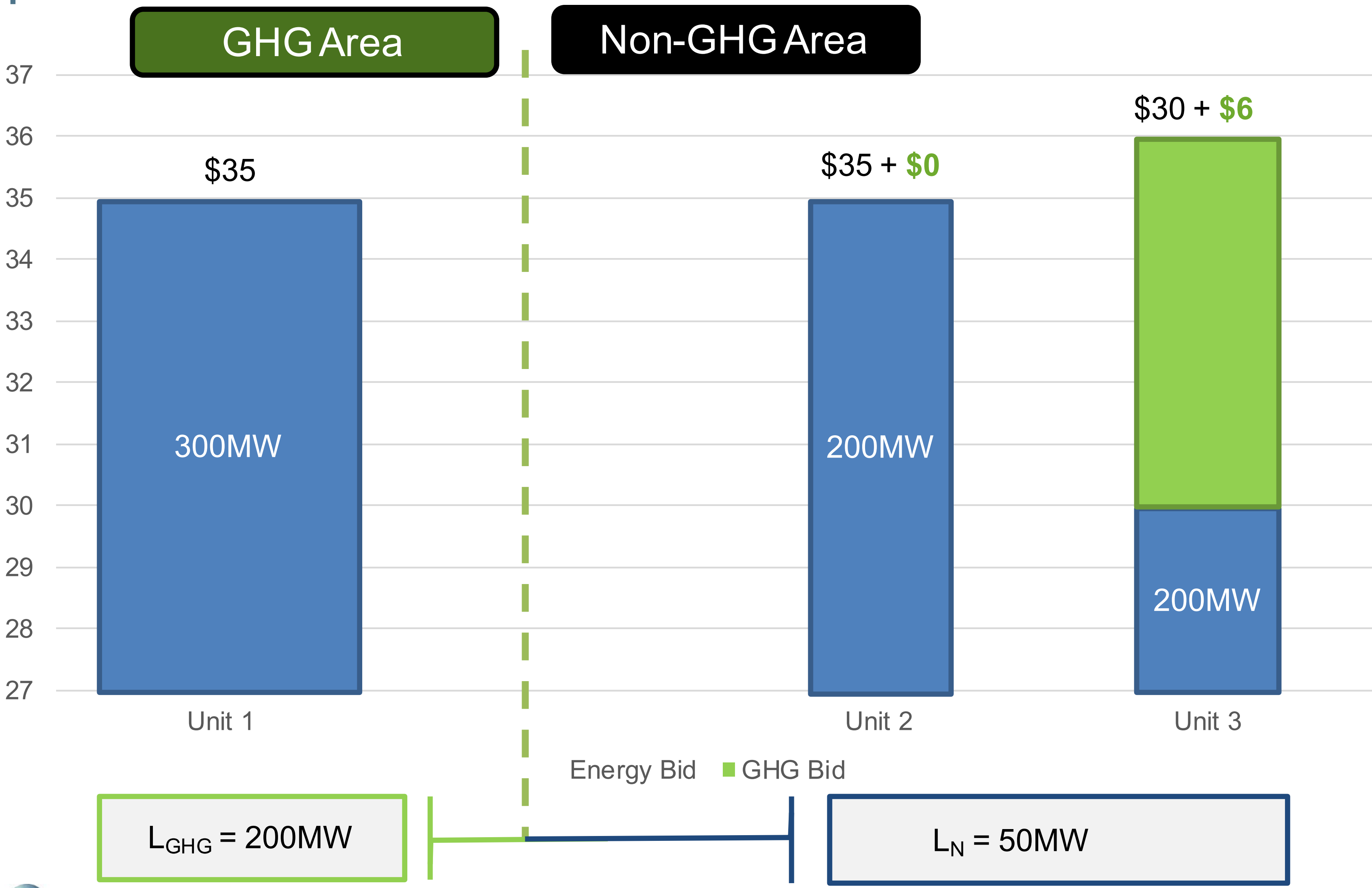
L_{GHG+N} = 250MW

With bid adders, dispatch minimizes costs as if the whole market were similarly regulated



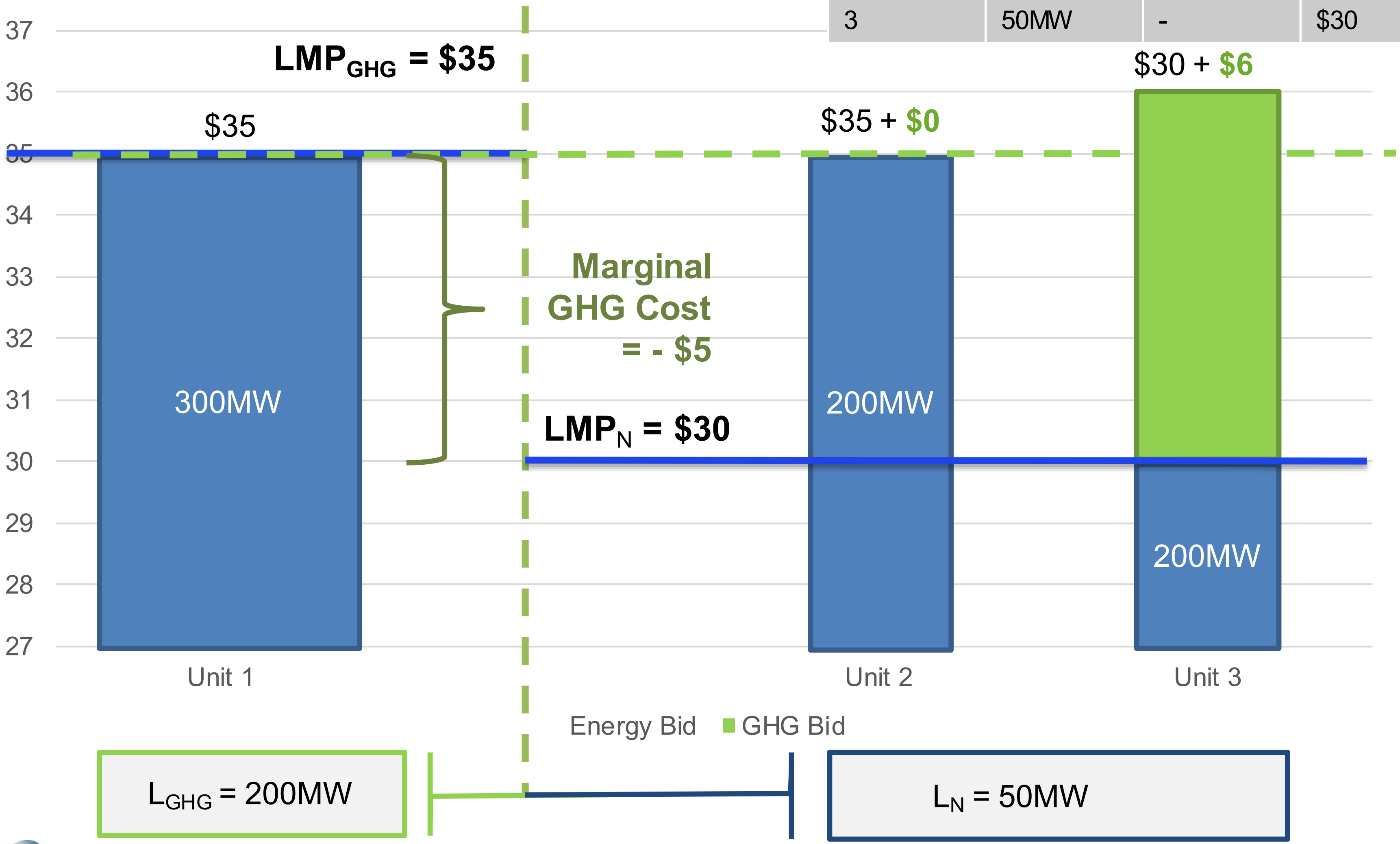
L_{GHG+N} = 250MW

The market tries to satisfy GHG and non-GHG preferences at the same time



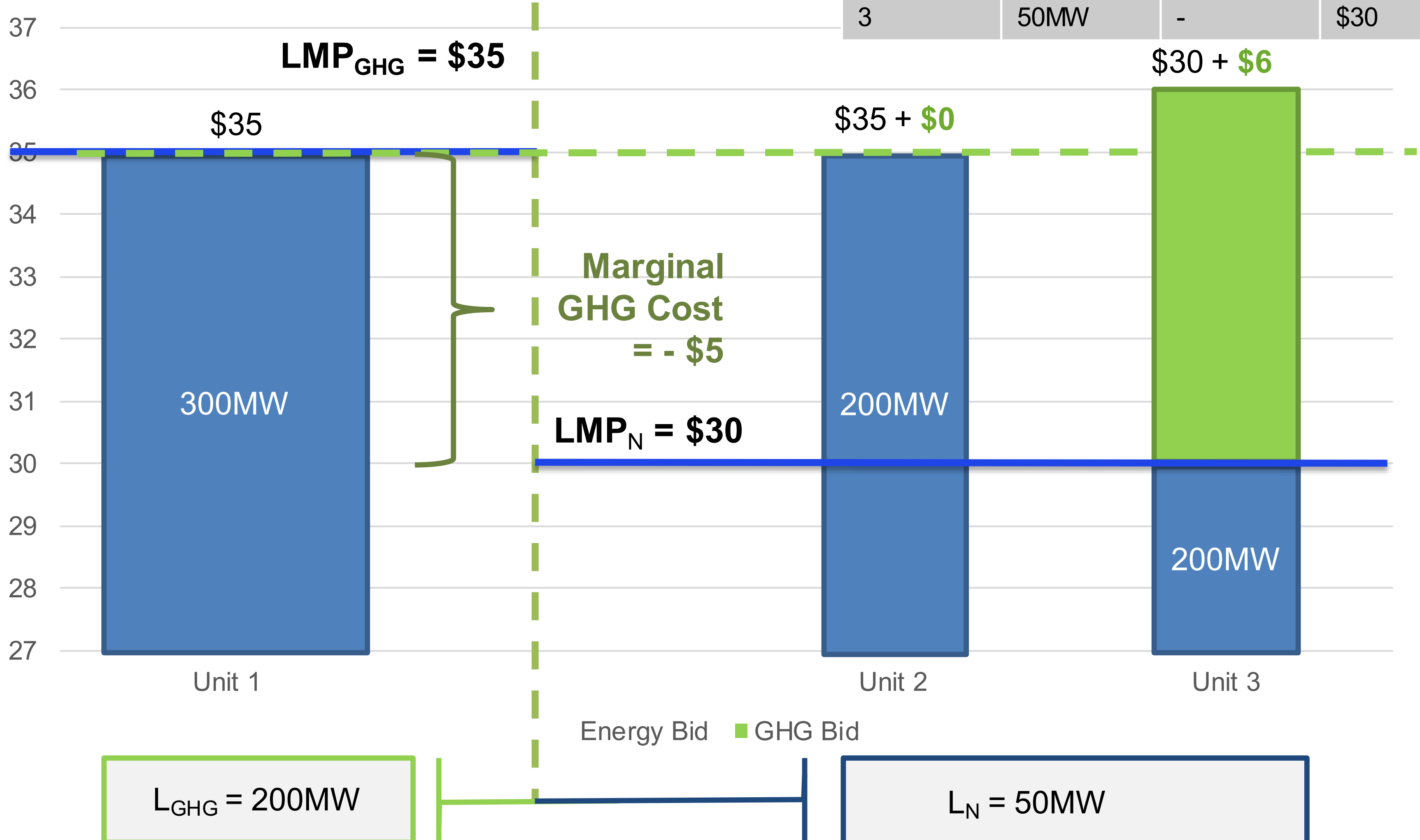
The difference in total cost due to GHG area demand is $5/MWh

Unit	Dispatch	Export Allocation	LMP
1	100MW	-	$50
2	100MW	100MW	$30
3	50MW	-	$30



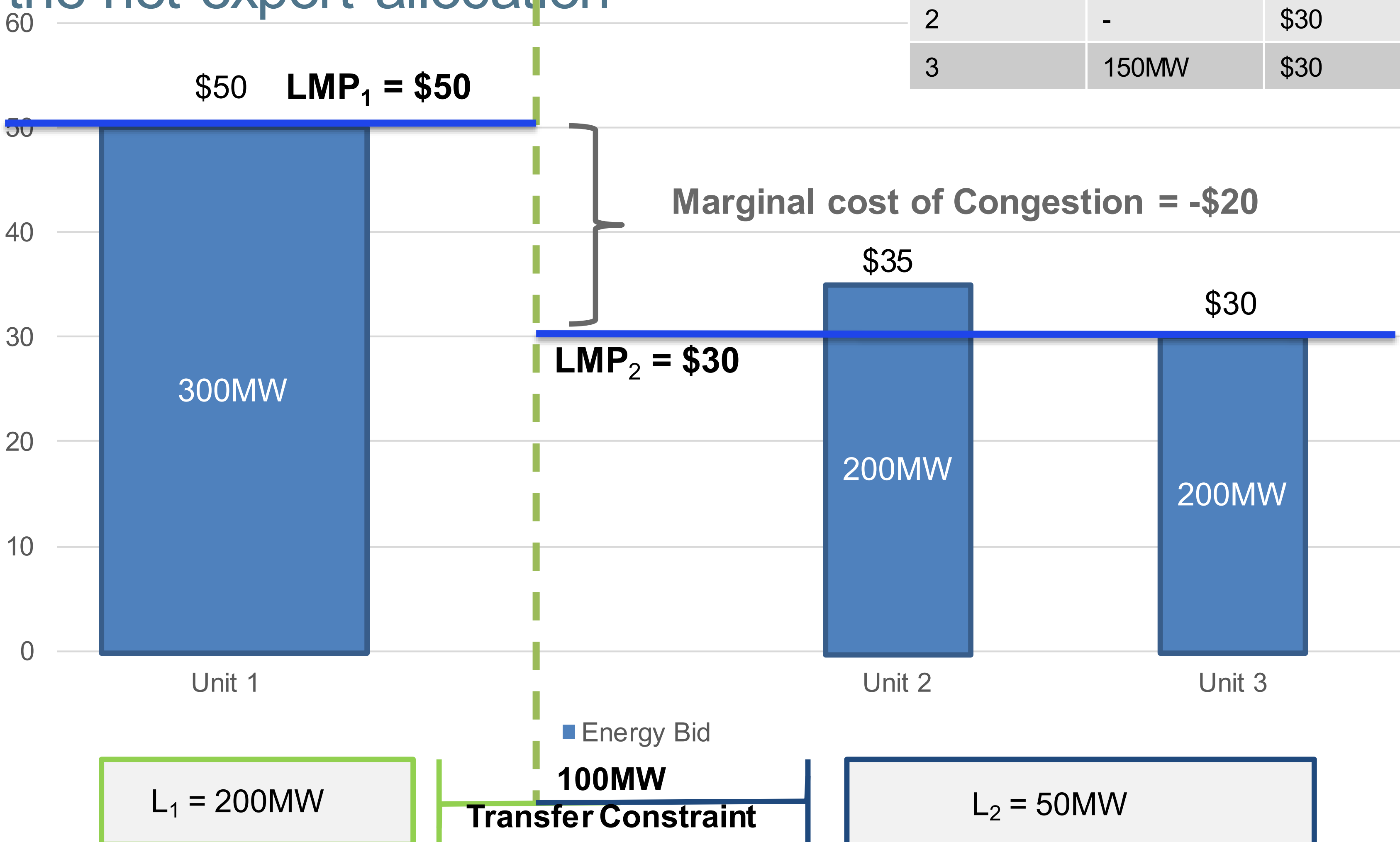
How do we know to attribute a 100MW GHG export allocation?

Unit	Dispatch	Export Allocation	LMP
1	100MW	-	$50
2	100MW	100MW	$30
3	50MW	-	$30



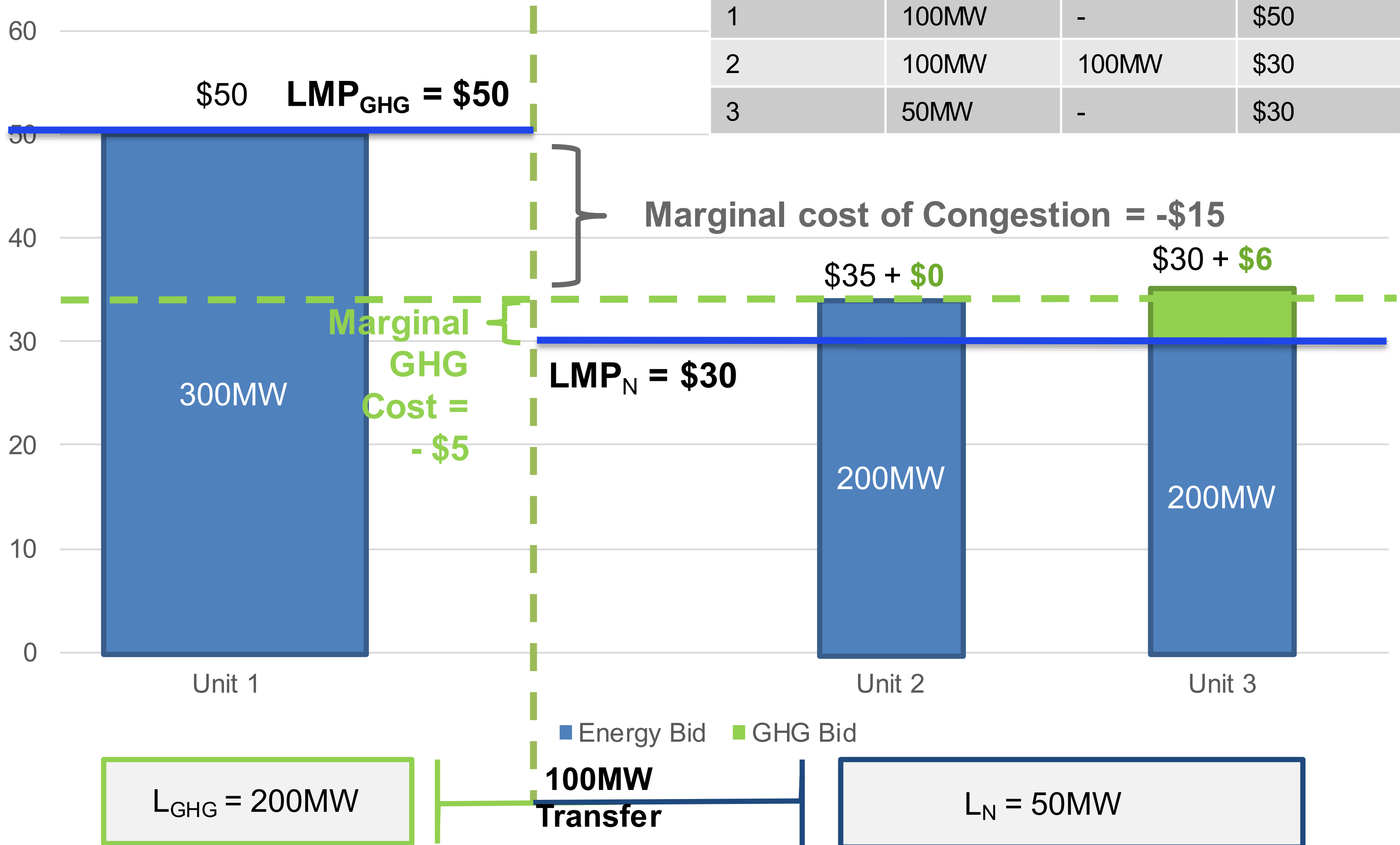
A physical transmission constraint can provide sufficient information to determine the net export allocation

Unit	Dispatch	LMP
1	100MW	$50
2	-	$30
3	150MW	$30



Putting it all together

Unit	Dispatch	Export Allocation	LMP
1	100MW	-	$50
2	100MW	100MW	$30
3	50MW	-	$30



LMP decomposition: what’s the sign?

- In this presentation and in the WEIM today, LMP component parts are represented as negative components of the LMP in the GHG area
- In EDAM, the LMP component parts will be represented as positive components of the LMP in the non-GHG area
- There will be no difference in the values, just the signs.

Some takeaways

- The marginal GHG cost is non-zero when transfers into the GHG area increase the total cost to load compared to a transfer absent GHG policy
  - A transfer that does not impose a cost due to GHG policy is just congestion

- The marginal GHG cost is non-zero when
  - The market would dispatch different resources for the GHG and non-GHG areas (there's a shadow cost) and
  - The GHG area is net importing (there is a positive GHG export allocation)

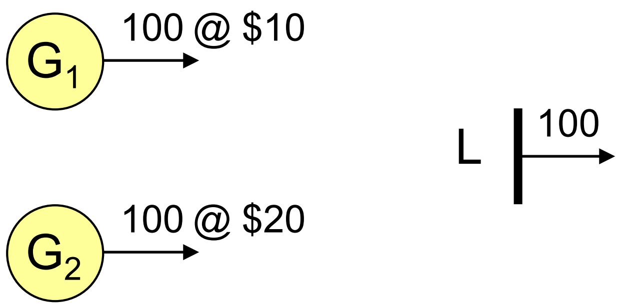
George Angelidis, Ph.D., Executive Principal, Power Systems and Market Technology

EDAM GHG REGULATION MODEL EXAMPLES

Answers to questions on the GHG regulation cost model

- What is the marginal GHG cost component of the LMP in a GHG regulation area?
  - The marginal GHG regulation cost for <u>net import</u> into that area
  - It is not related to any GHG regulation costs of internal resources
- What is the marginal GHG regulation cost from resources inside a GHG regulation area?
  - It does not exist! The GHG regulation cost is only a component of the energy bid; the latter may be marginal, but no component of it is
    - The GHG regulation cost of an accepted bid can be higher than the one in the marginal energy bid

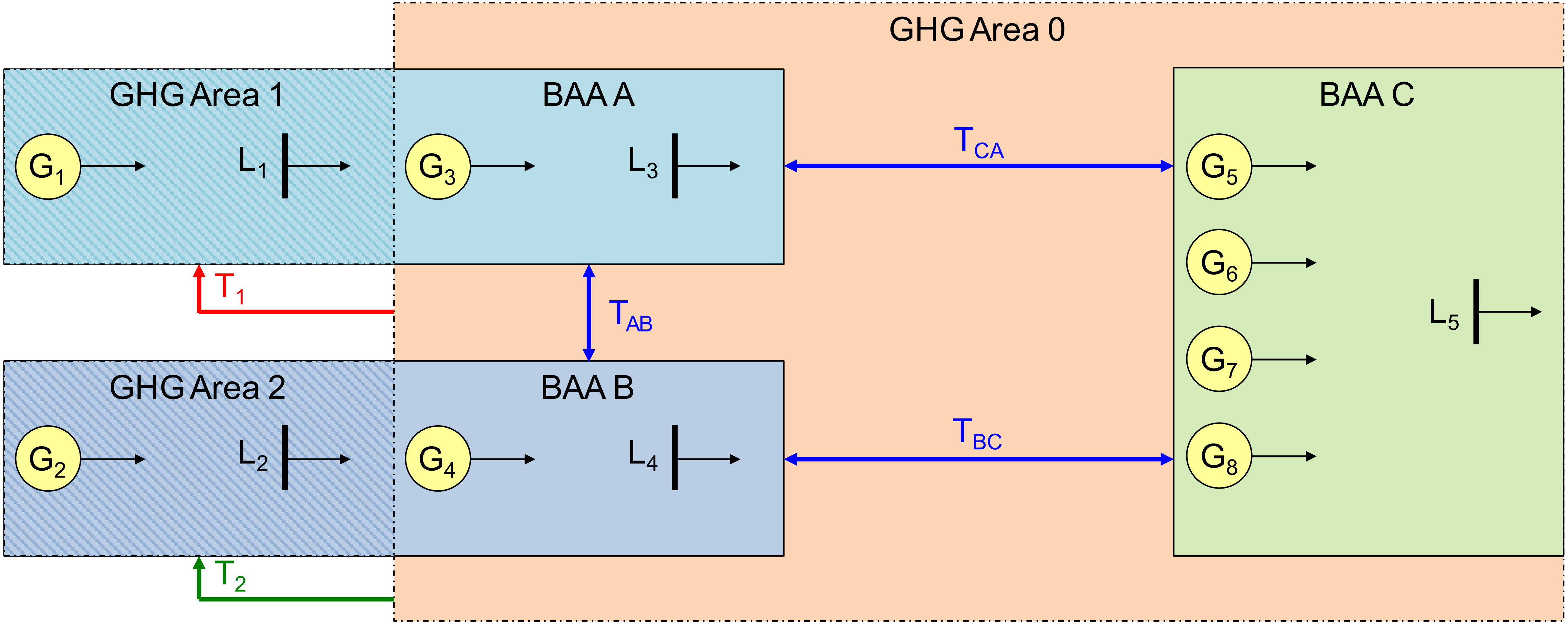
Prices at discontinuities



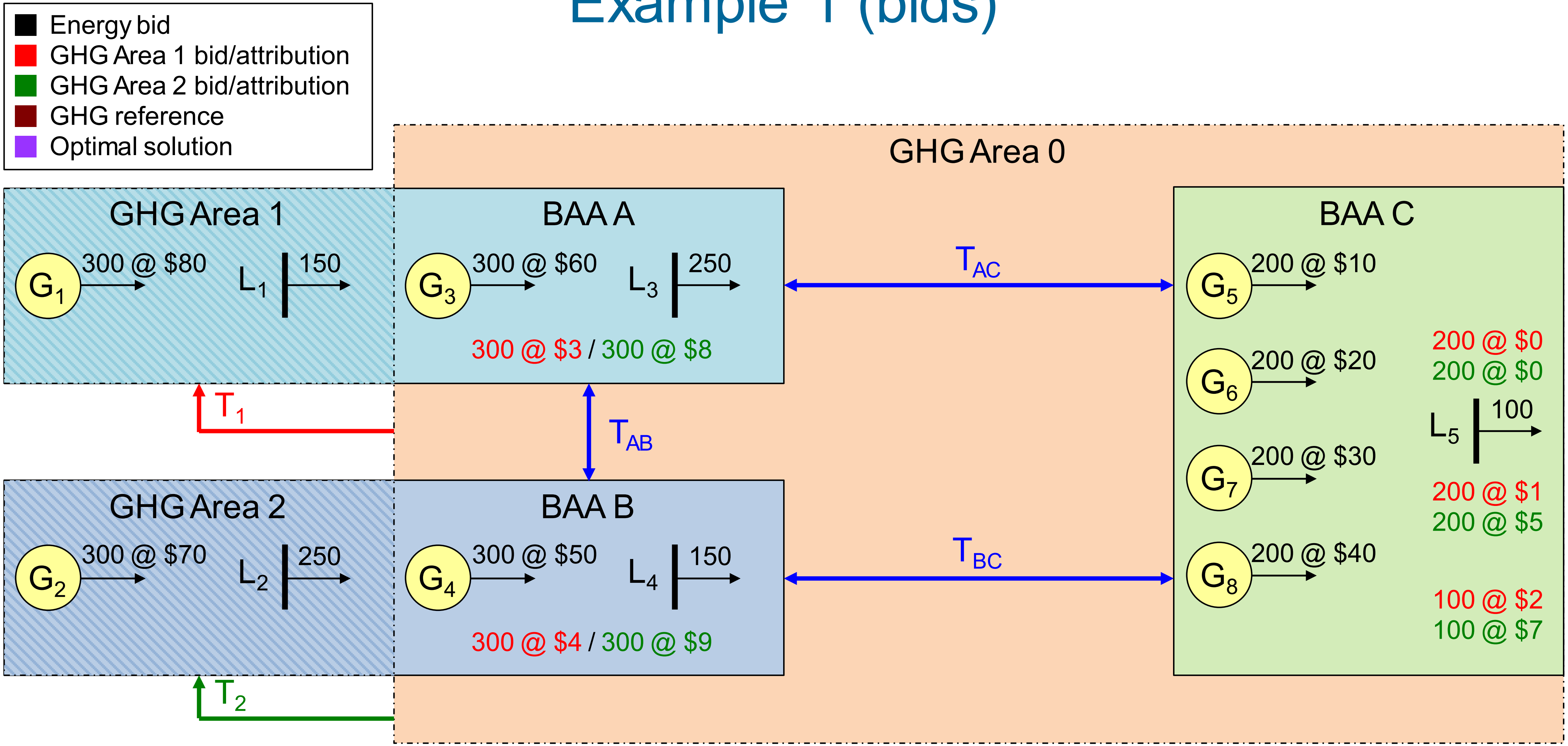
$$
\left.\begin{array}{c}
\min(10\,G_1 + 20\,G_2) \\
G_1 + G_2 = 100 \\
0 \le G_1 \le 100 \\
0 \le G_2 \le 100
\end{array}\right\} \Longrightarrow \begin{cases} G_1 = 100 \\ G_2 = 0 \end{cases}
$$

- What is the MEC?
  - The partial derivative of the objective function with respect to an algebraic injection
  - The partial derivative is not defined at a discontinuity
    - Different for positive and negative injection
      - L = 100 + ε → MEC = $20
      - L = 100 − ε → MEC = $10
  - Convention: last accepted bid price in merit order

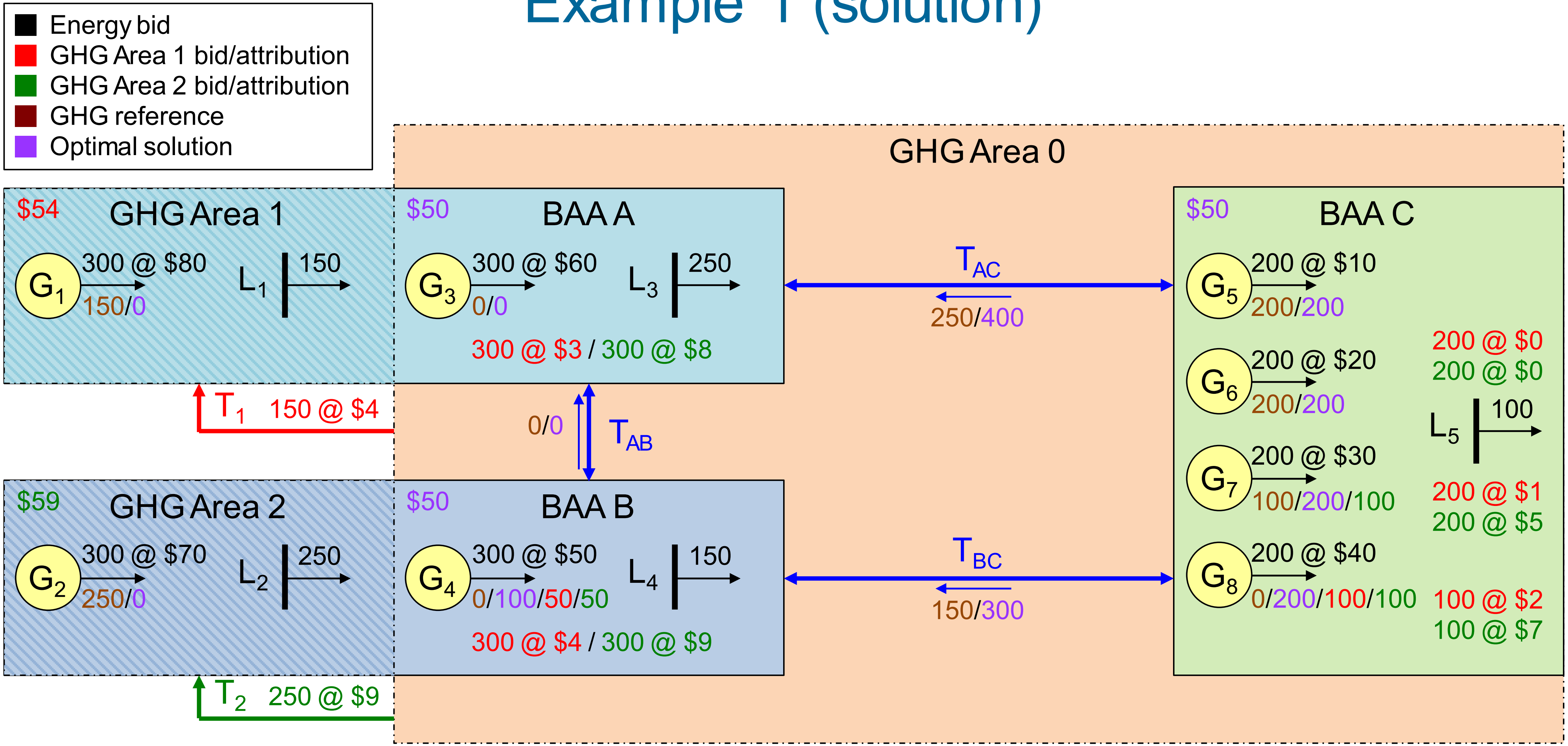
Example (network)



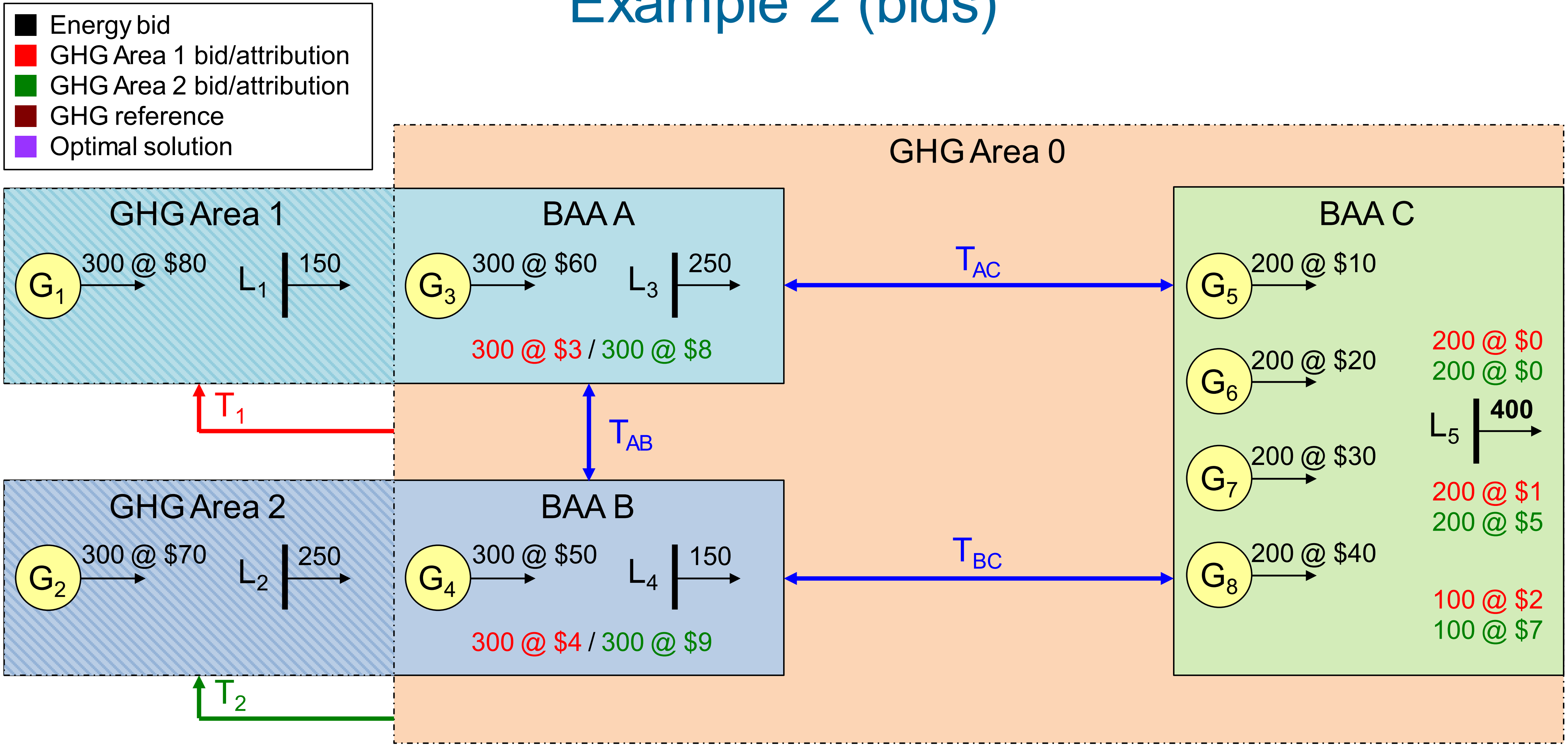
Example 1 (bids)



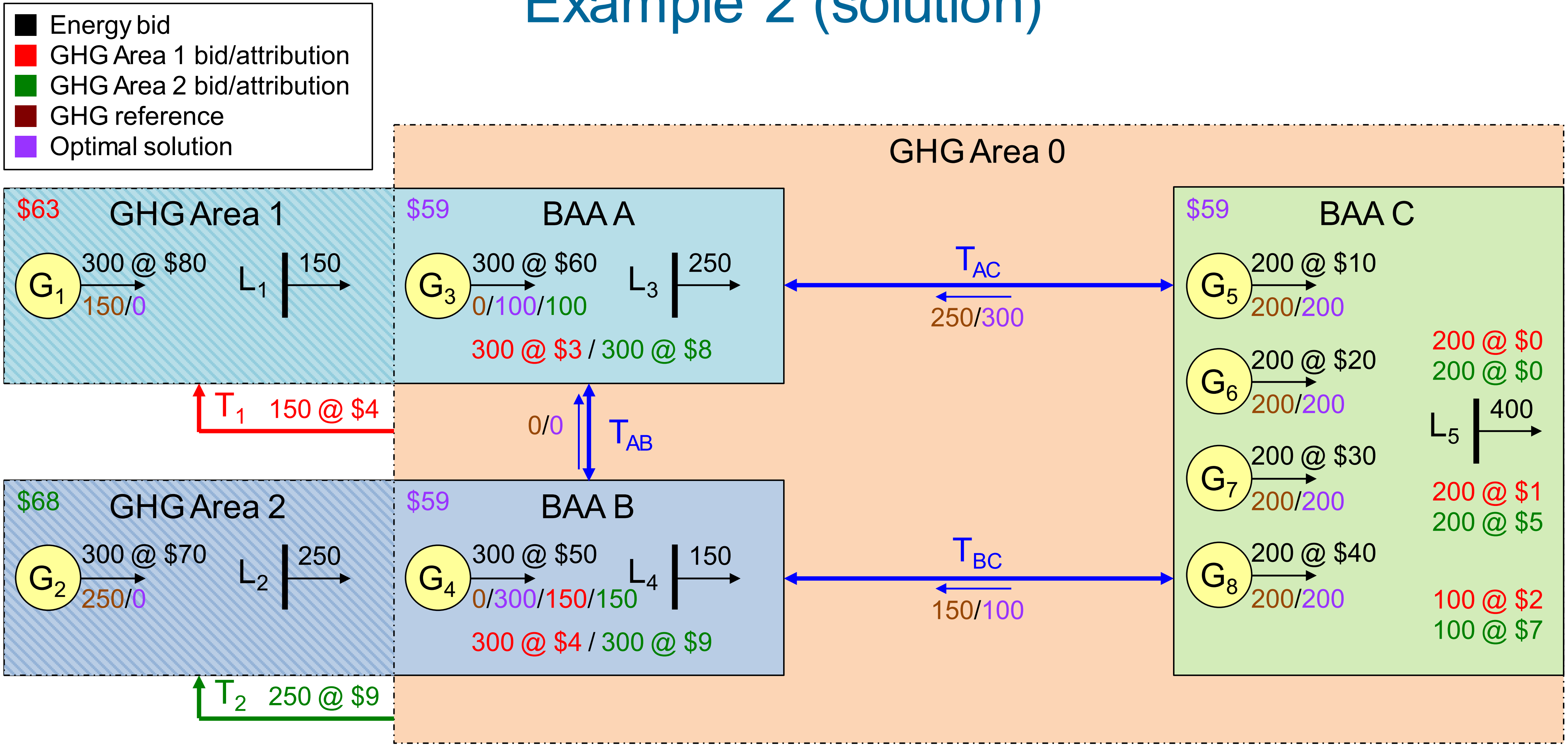
Example 1 (solution)



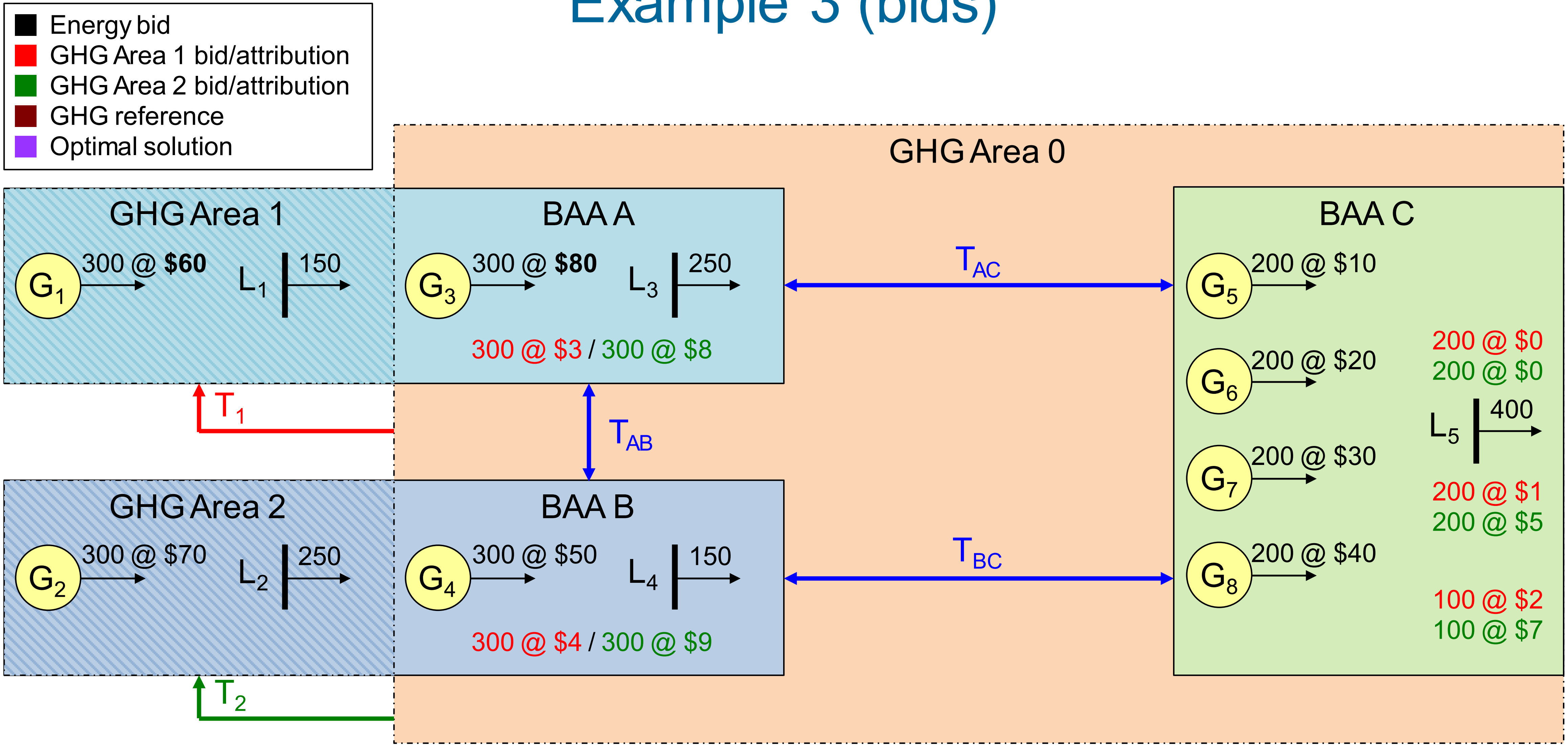
Example 2 (bids)



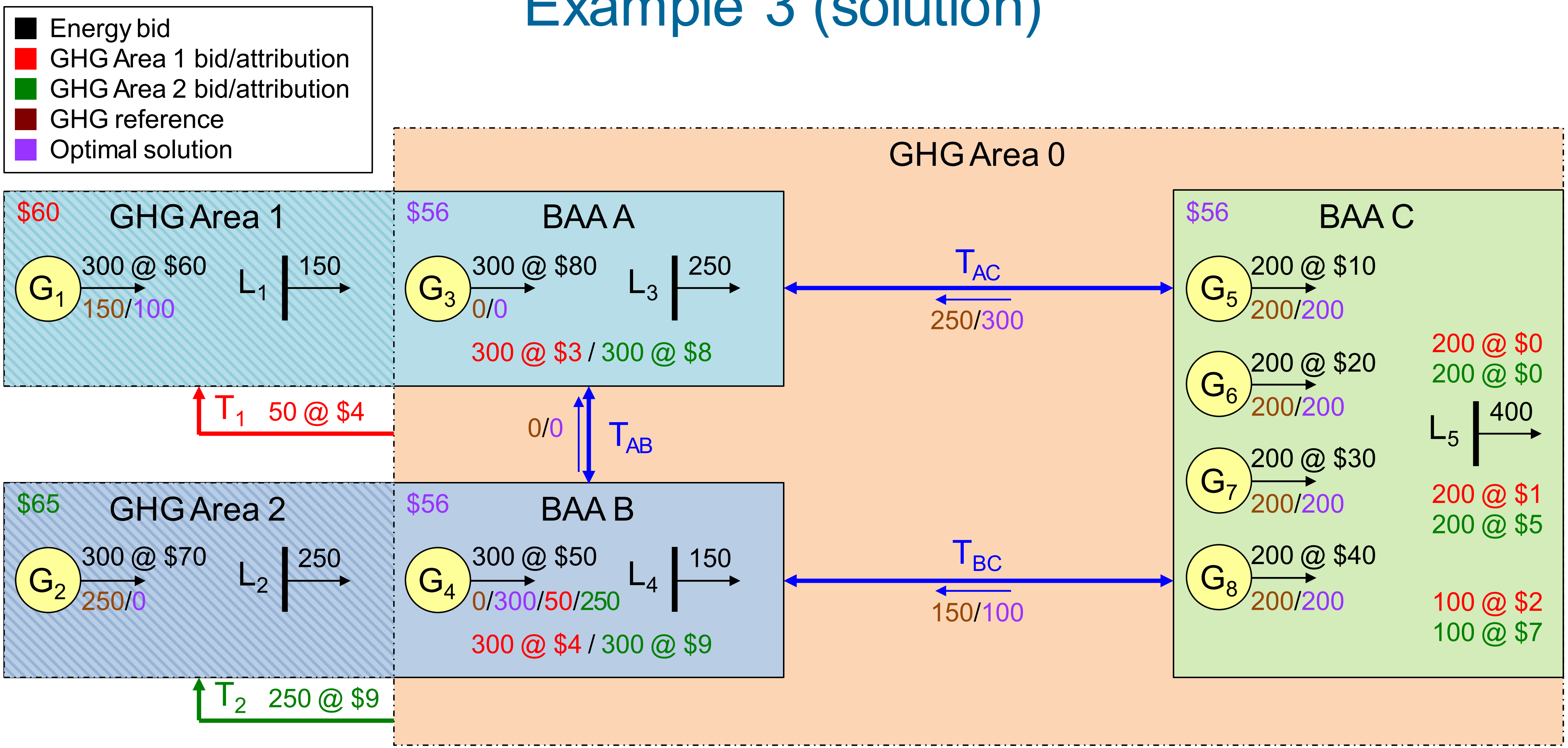
Example 2 (solution)



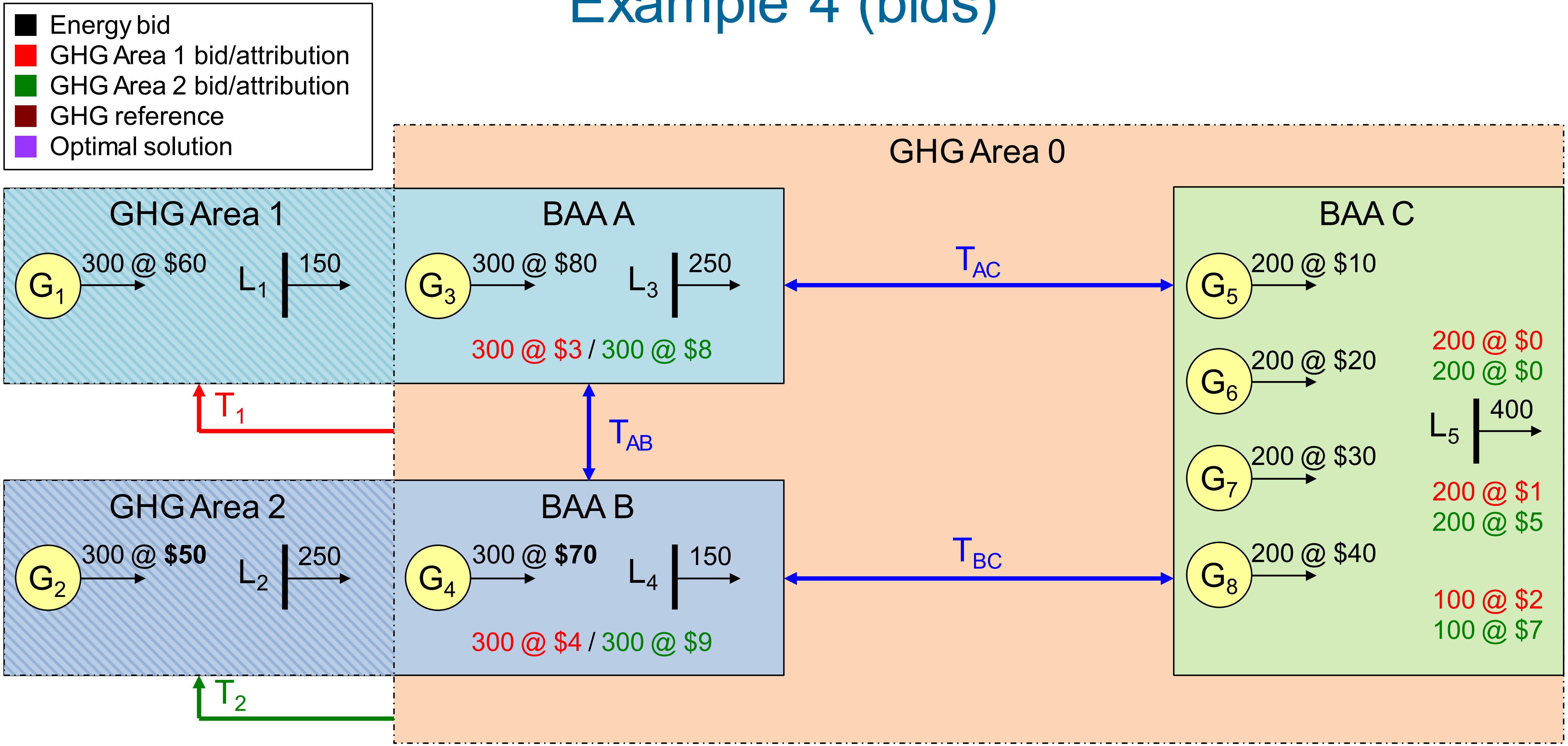
Example 3 (bids)



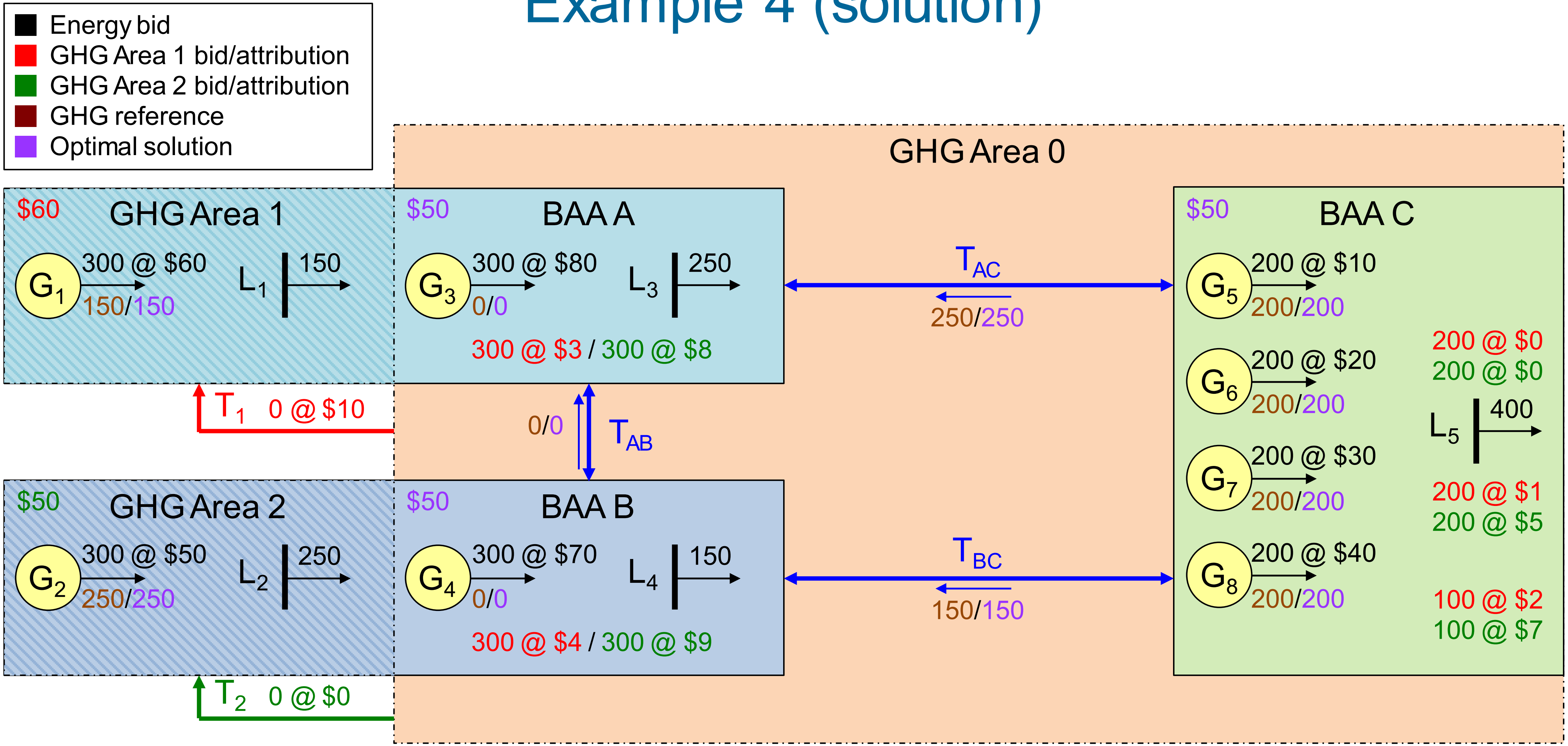
Example 3 (solution)



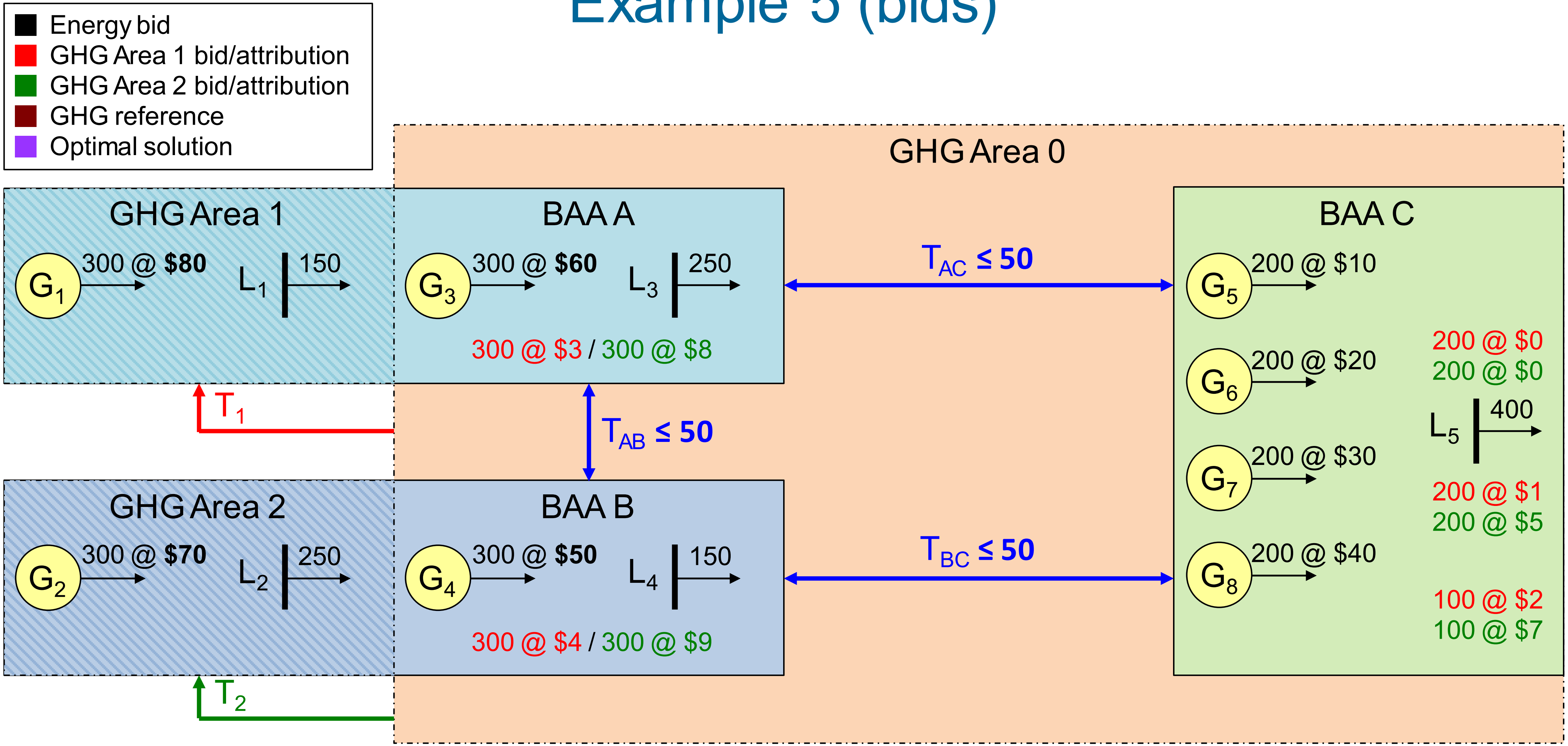
Example 4 (bids)



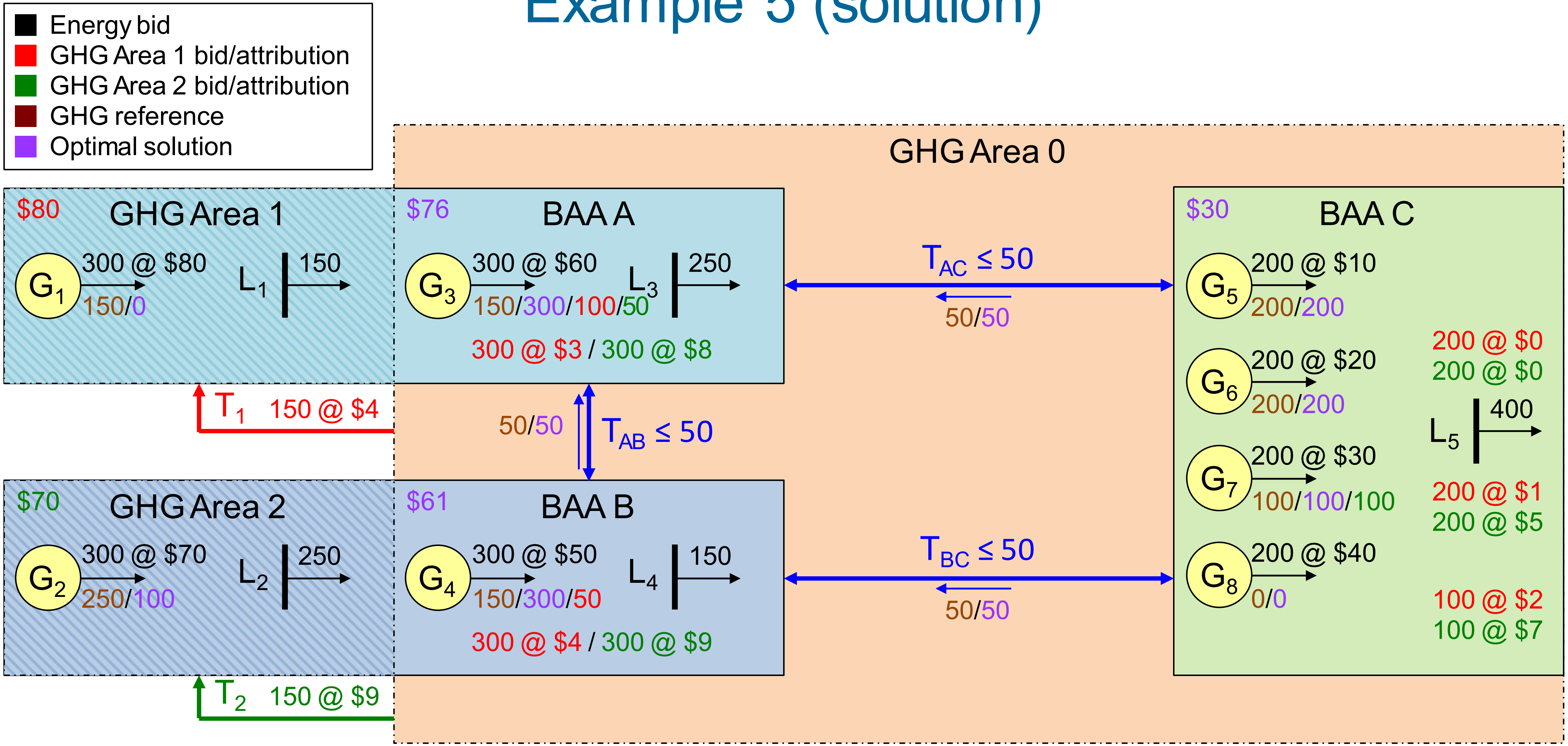
Example 4 (solution)



Example 5 (bids)



Example 5 (solution)



BREAK

Anja Gilbert, Lead Policy Developer, Policy Development

GHG COUNTERFACTUAL

Objectives for today's discussion

After today's session, stakeholders should be able to:

1. Understand what the counterfactual is and why it exists
2. Explain how the counterfactual has been implemented for WEIM-only entities versus EDAM-entities
3. Explain why a BAA level counterfactual is not optimal as compared to a counterfactual that looks at the non-GHG regulation area as a whole

Part 1: What is the GHG counterfactual and why does it exist?

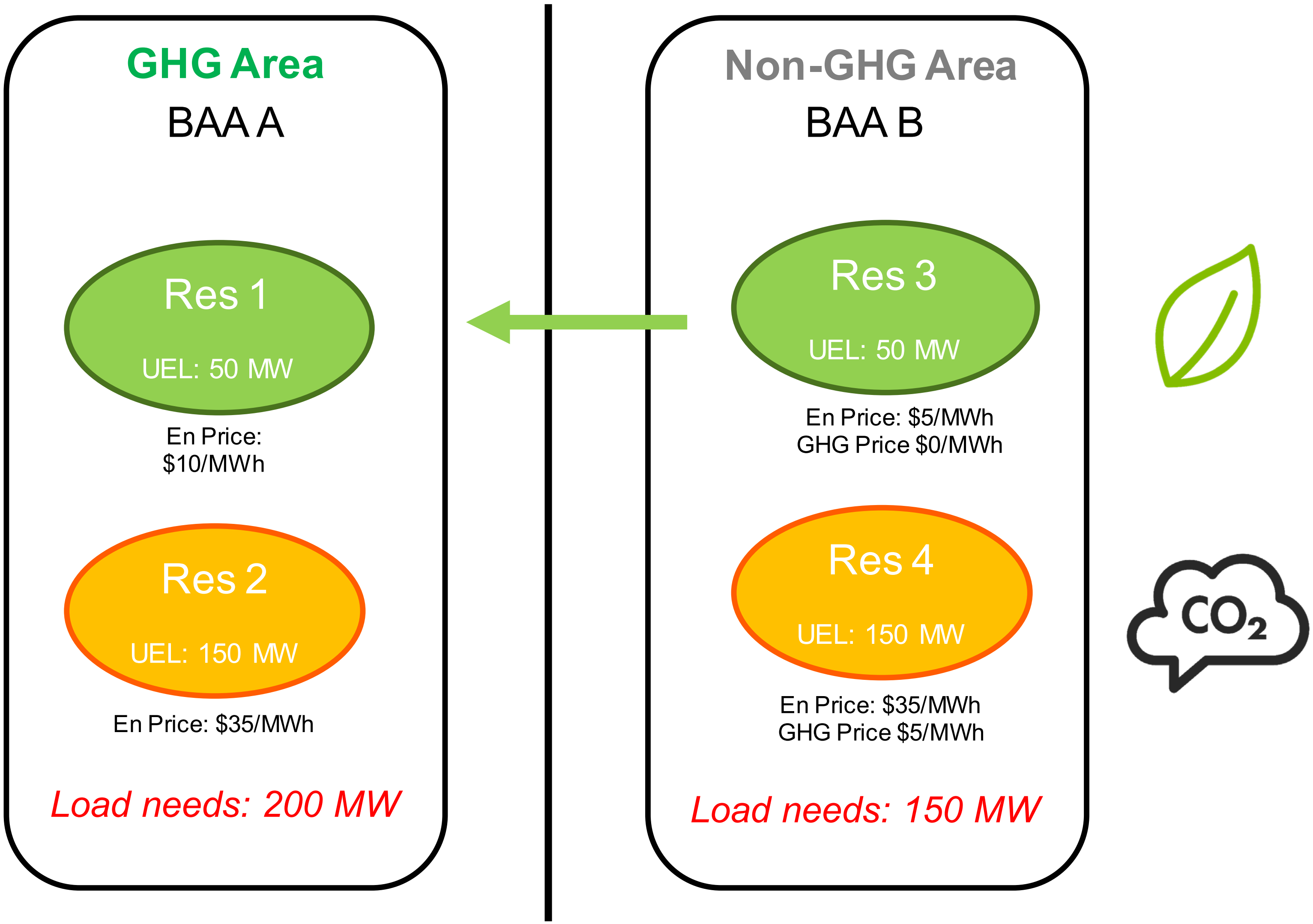
The counterfactual represents what generation would serve the non-GHG area, absent GHG policy

It allows states to calculate what could be considered secondary dispatch

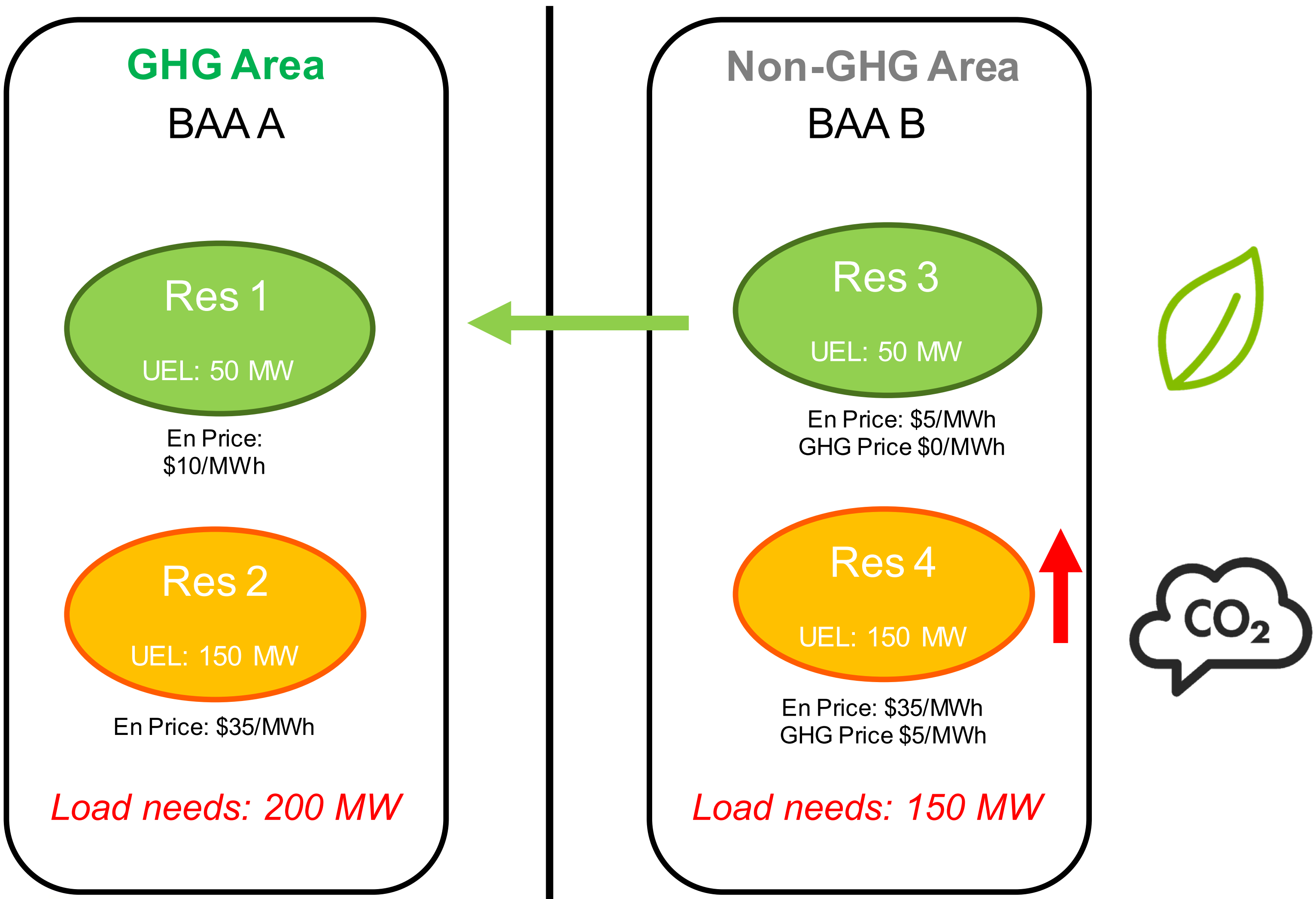
Electricity markets and carbon policies

- When GHG pricing is reflected in the market optimization, lower emitting resources are relatively economic to serve a region that has a price on carbon
  - This is because low emitting resources face fewer/no costs to comply with regulation whereas high emitting resources face greater costs to comply with the regulation
  - This is the outcome of policies which place a price of carbon on electricity production
- In some instances, higher emitting resources will need to "backfill" to serve load in a non-GHG region—when clean dispatch is attributed to serve load in a GHG region. This is called "secondary dispatch."

EDAM non-counterfactual scenario: 50 MW attributed from Res 3 from BAA B to GHG Area / BAA A



EDAM non-counterfactual scenario: As 50 MW is attributed from Res 3 in BAA B to serve to serve the GHG Area, 50 MW is incremented from Res 4 to serve the non-GHG area resulting in secondary dispatch



Secondary dispatch & the role of the counterfactual

- Secondary dispatch occurs if:
  - The attributed resource would **not** have generated in the absence of serving GHG regulation area demand,
  - If the attributed resource is below the counterfactual – meaning it overlaps with what was assumed to serve the non-GHG area

- The counterfactual helps Stakeholders understand:
  - What generation would serve the non-GHG area, absent GHG policy
  - What dispatch is likely incremental, once GHG policy is considered

Measures to Reduce Secondary Dispatch for WEIM and EDAM Entities

	WEIM Entities	EDAM Entities
Counterfactual	Base Schedules are the self-assessment of scheduled generation and transfers	An Optimized Reference Pass reduces the delta between the assumptions made in base scheduling vs. optimal dispatch
Bidding Constraints	Limiting the GHG attribution to the volume of difference between upper economic limit and counterfactual reduces the potential for secondary dispatch	
Net Export Constraint	N/A	The net export constraint limits attribution by not allowing attribution from a net importing BAA, except in cases of committed capacity

How California Accounts for Secondary Dispatch

- Since potential secondary dispatch is not eliminated, the California Air Resources Board (CARB) calculates the emission intensity of WEIM outstanding emissions at the unspecified source emission rate less any resource-specific emissions attributed to WEIM participating resources by the CAISO's market optimization

$$
\begin{aligned}
&EIM\ Oustanding\ Emissions \\
&= Total\ CA\ EIM\ Emissions\ - Deemed\ Delivered\ EIM\ Emissions \\
&= \left(Total\ EIM\ MWh\ * TL\ * EF_{unsp}\right) - \sum Deemed\ MWh_{sp}\ * TL\ *\ EF_{sp}
\end{aligned}
$$

§95111(h)(1)(A)

Where:

TL	– Transmission Loss Factor (1 or 1.02)
EF_{sp}	– Specified Emission Factor
EF_{unsp}	– Unspecified Emission Factor (0.428)

- CARB assigns outstanding WEIM Emissions to Electric Distribution Utilities pro-rata on retail load by reducing their freely allocated allowances

Part 2: What is the counterfactual for WEIM-only Entities versus EDAM Entities?

WEIM-only Entity counterfactual *= base schedules*

EDAM Entity counterfactual

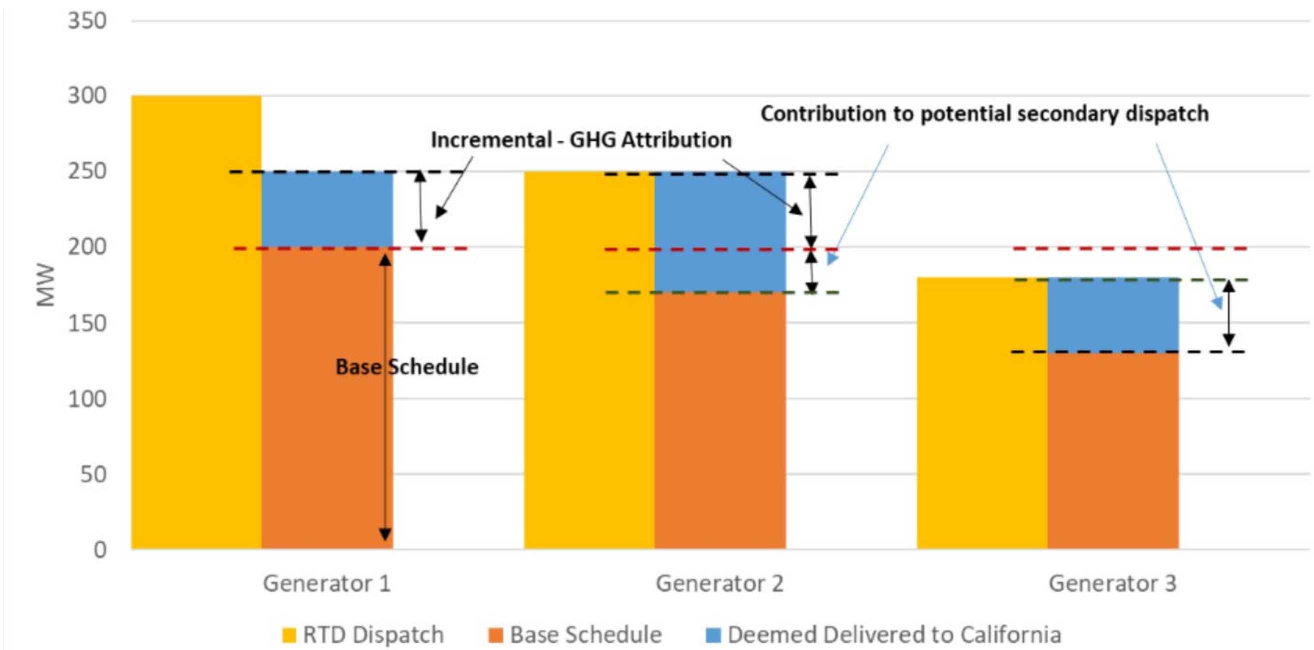
- *Day Ahead= GHG Reference Pass*
- *Real Time= DAM Energy Award – DAM GHG Award*

Reference: counterfactual design in WEIM and EDAM

Attribute	WEIM-only Entities Today and with EDAM Go-Live	EDAM Entities
Counterfactual	Base Schedules	Day Ahead= GHG Reference Pass Real Time= DAM Energy Award – DAM GHG Award
Committed Capacity	WEIM entities may include contracts in base transfers	Removed from GHG Reference Pass in DA so that it can be attributed
Attribution Constraints	The GHG attribution is limited to the lower of: (1) the GHG bid capacity, (2) the positive difference between the upper economic limit and the counterfactual (3) the optimal energy schedule.	
Eligible for Attribution	Upper Economic Limit (UEL) – Counterfactual	
Secondary Dispatch	Secondary Dispatch = (0, GHG award - max(0, energy award - counterfactual))	

Counterfactual in the WEIM and secondary dispatch

Gen in WEIM Area	Type	Base Schedule (MW)	RTD Dispatch (MW)	GHG Attribution - Attributed to CA (MW)	Contribution to Potential Secondary Dispatch (MW)
Gen 1	Hydro	200	300	50	0
Gen 2	Gas	200	250	80	30
Gen 3	Hydro	200	180	50	50



Why would a WEIM or EDAM entity resource be dispatched below its counterfactual ?

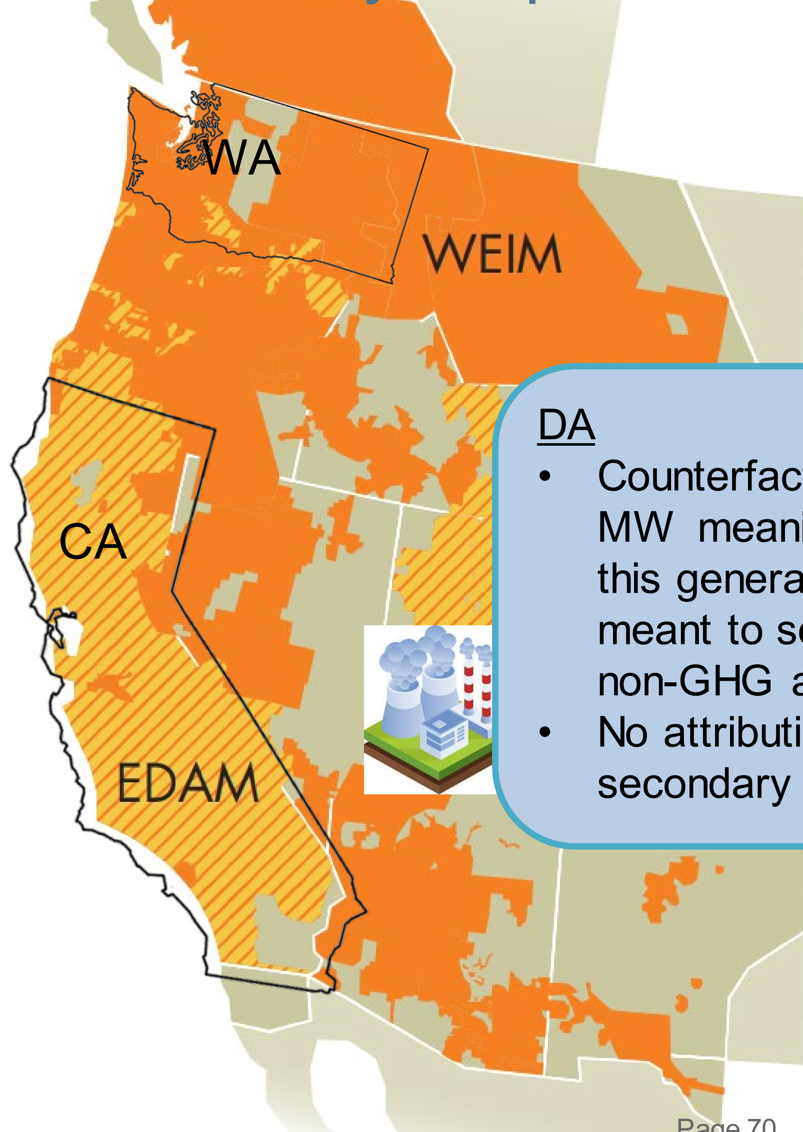
Resources can be dispatched below their counterfactual for a variety of reasons. For example:

1. **Economic displacement:** Another resource is relatively less expensive (i.e. lower energy bid price), so the optimization dispatches the other resource upwards and the current resource downwards
2. **Decreases in load forecast:** When the actual load (technically, the market clears against forecasted load) needs of the EDAM or WEIM area is lower than expected, less output is required from the resource
3. **Other resource is "backfilling"** Another resource is relatively more expensive (i.e. a higher energy-only bid price) but has a lower "total bid" price (i.e. energy bid price plus GHG bid price), that resource may be dispatched upwards but the current resource receives a GHG attribution

While reason 3 may be considered to be leakage due to potential secondary dispatch, reasons 1 and 2 are not.

Counterfactual in EDAM & Secondary Dispatch Day Ahead

EDAM Entity DA	MW
Energy Bid	100
GHG Bid	100
UEL	100
Counterfactual	100
Eligible for Attribution	0
Energy Award	100
DA GHG Award / Attribution	0
Secondary Dispatch	0

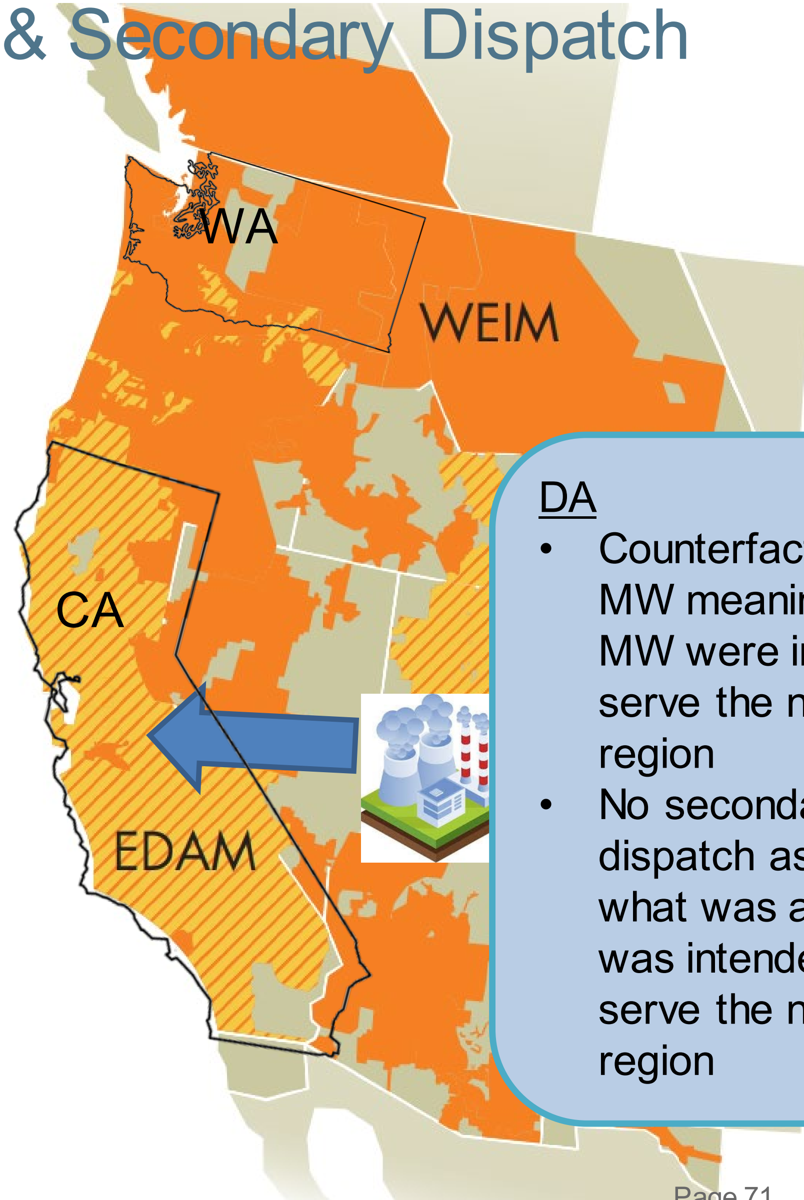


DA

- Counterfactual = 100 MW meaning all of this generation is meant to serve the non-GHG area
- No attribution and no secondary dispatch

Counterfactual in EDAM & Secondary Dispatch Day Ahead

EDAM Entity DA	MW
Energy Bid	100
GHG Bid	100
UEL	100
Counterfactual	20
Eligible for Attribution	100-20= 80
Energy Award	80
DA GHG Award / Attribution	40
Secondary Dispatch	0

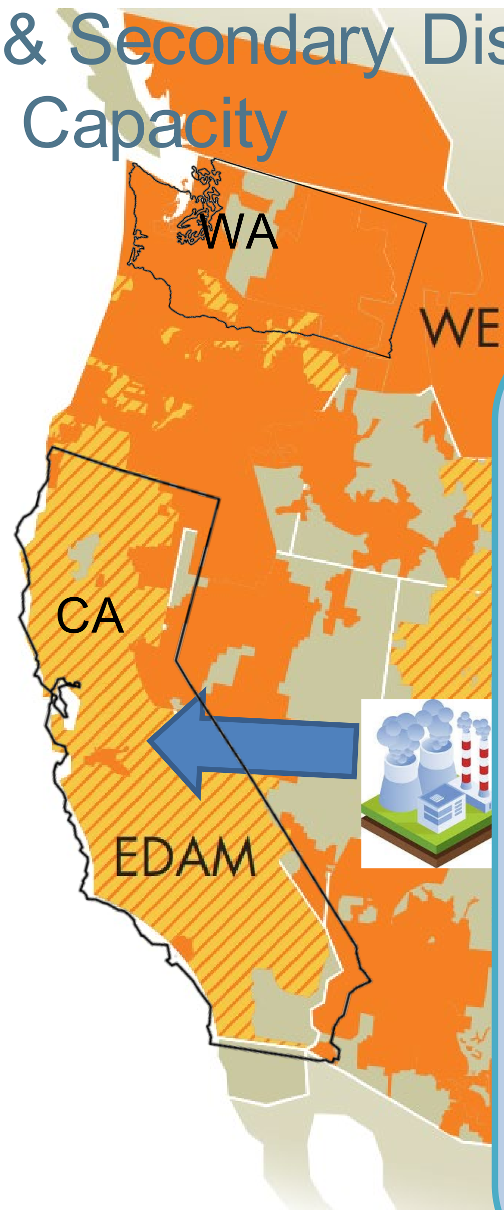


DA

- Counterfactual = 20 MW meaning those MW were intended to serve the non-GHG region
- No secondary dispatch as none of what was attributed was intended to serve the non-GHG region

Counterfactual in EDAM & Secondary Dispatch Day Ahead w/Committed Capacity

EDAM Entity DA	MW
Energy Bid	100
GHG Bid	100
UEL	100
Committed Capacity	60
Counterfactual	40
Eligible for Attribution	100-40=60
Energy Award	100
GHG Award / Attribution	60
Secondary Dispatch	0

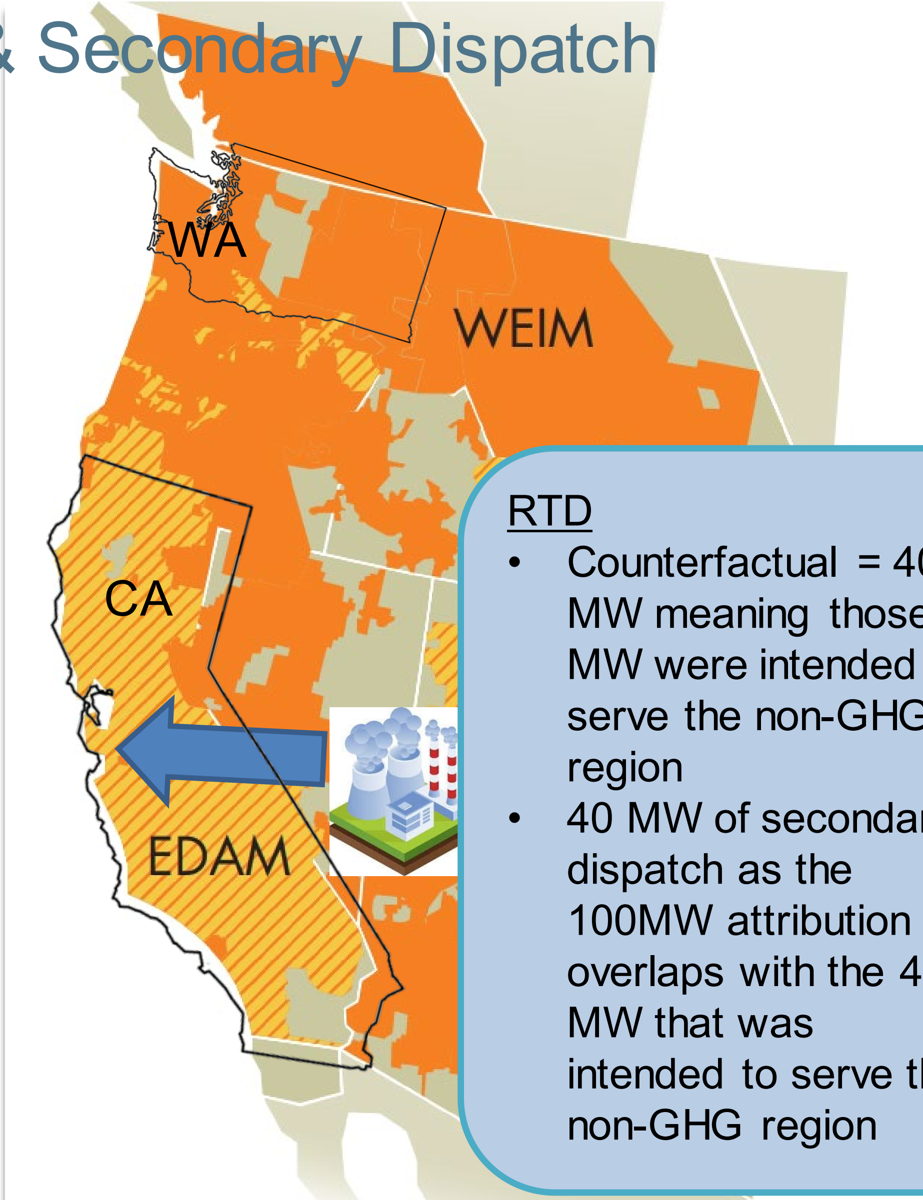


<u>DA with Comm. Cap</u>

- 60MW excluded from the counterfactual
- Counterfactual = 40MW meaning 40 MW is intended to serve the non-GHG region
- When 60 MW is attributed there is 0MW of secondary dispatch as there was not overlap between what was intended to serve the non-GHG region and GHG region

Counterfactual in EDAM & Secondary Dispatch Real Time

EDAM Entity RTD	MW
Energy Bid	100
GHG Bid	100
UEL	100
Counterfactual	40
Eligible for Attribution	100-40=60
Energy Award	100
GHG Award / Attribution	100
Secondary Dispatch	40



RTD

- Counterfactual = 40 MW meaning those MW were intended to serve the non-GHG region
- 40 MW of secondary dispatch as the 100MW attribution overlaps with the 40 MW that was intended to serve the non-GHG region

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Part 3: Addressing stakeholder concerns about EDAM GHG counterfactual

Stakeholders have voiced concerns that the EDAM counterfactual approach of looking at the full non-GHG area as opposed to at a BAA-by-BAA level is flawed

Calculating the Counterfactual at the Full Non-GHG Area versus BAA-by-BAA

Full Non-GHG Area Counterfactual:

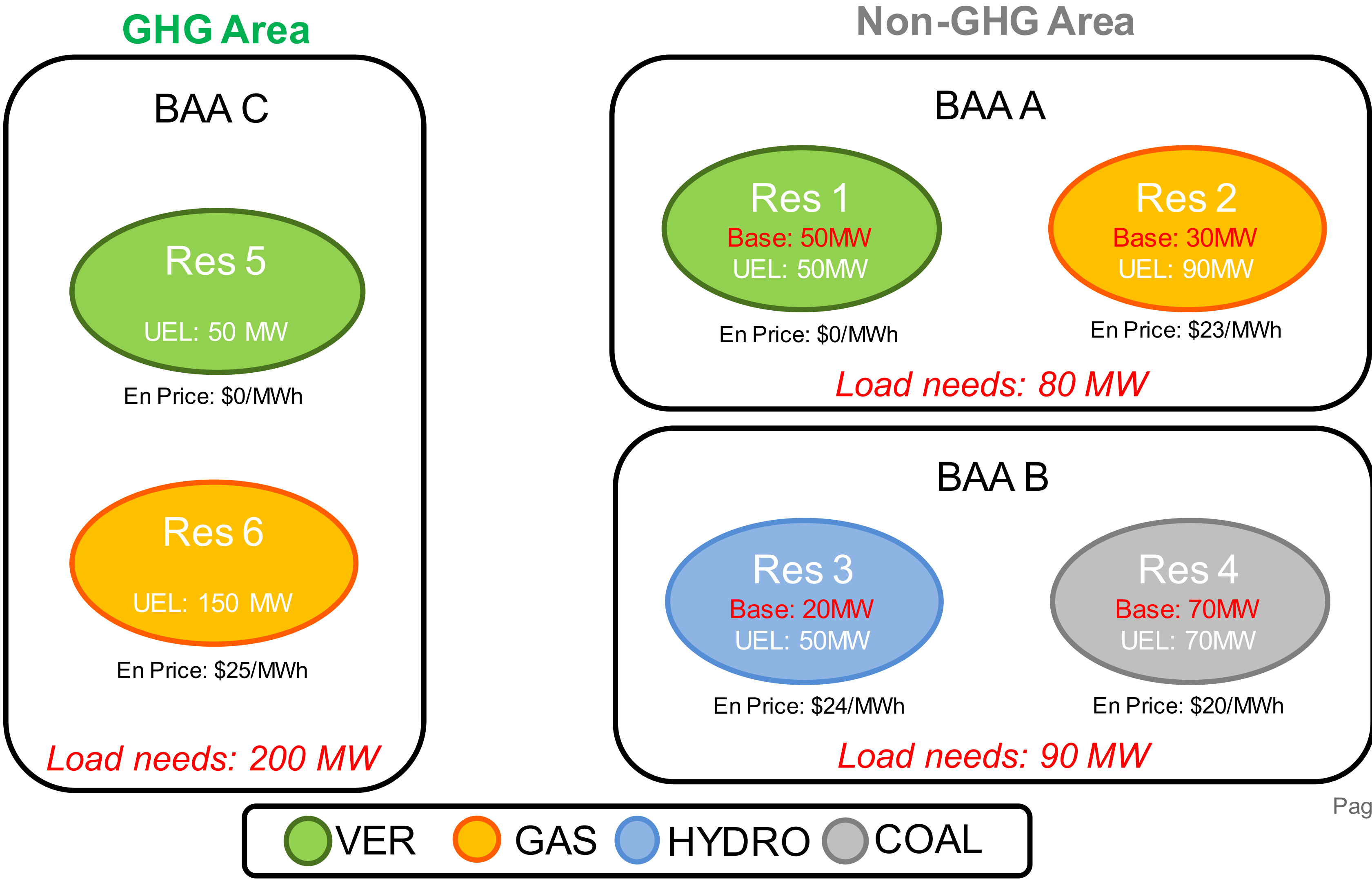
- Accounts for economic displacement across the non-GHG area for an optimized counterfactual
- Mirrors the approach in the WEIM
- Allows contracted resources to: 1.) serve the GHG region and, 2.) be attributed, if economic

BAA-by-BAA Counterfactual

- Does not account for economic displacement across the non-GHG area (negating the benefits of the WEIM and EDAM)
- Inaccurate perception that low cost clean resources will only serve the non-GHG area instead of the GHG region

WEIM Scenario 1: BAAs meet native load with native gen

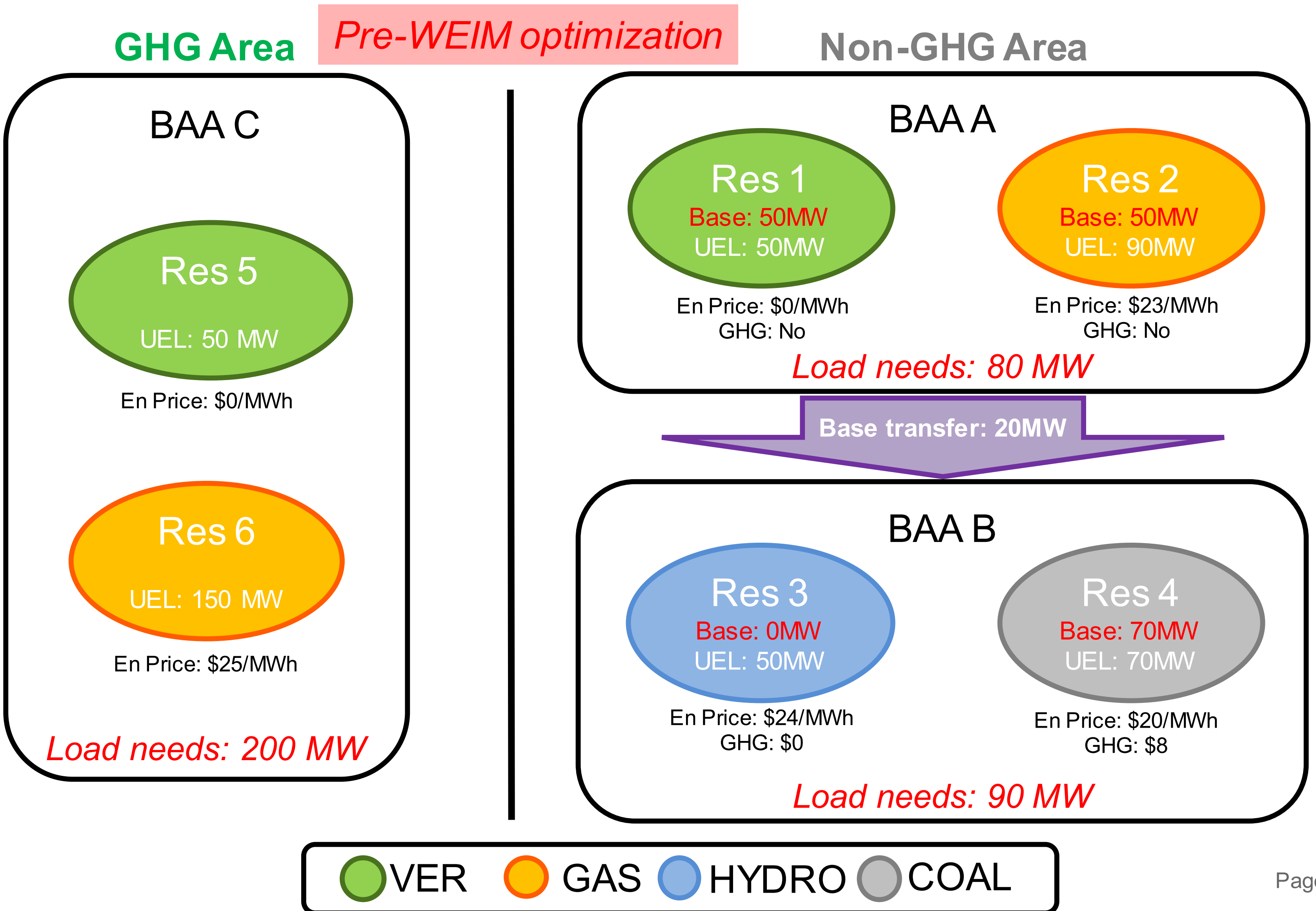
Pre-WEIM optimization



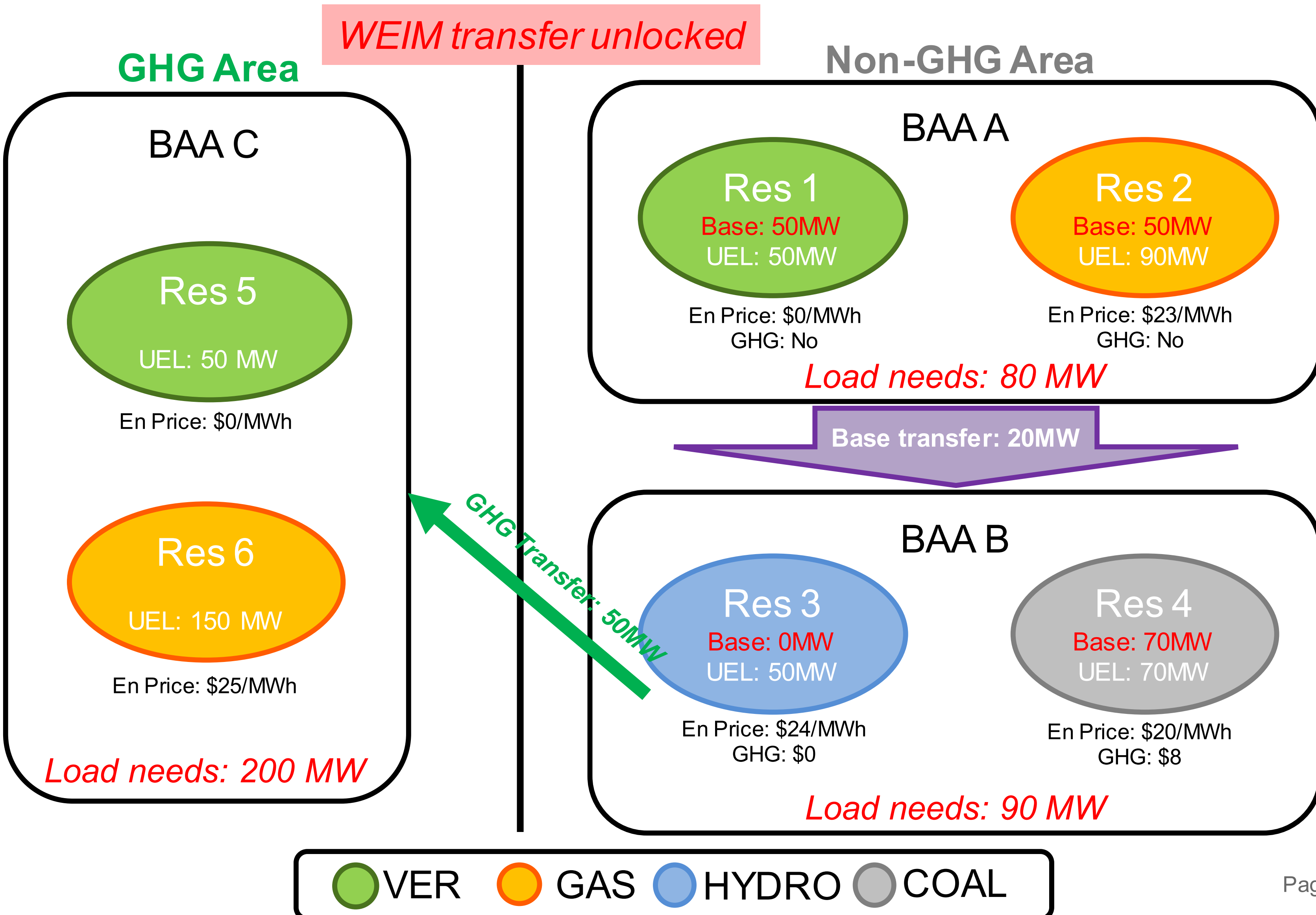
Why the BAA level counterfactual is flawed

- If BAA B had to meet its load needs with only native generation, it would base schedule Res 3 upwards, despite it being more expensive than Res 2
- However, <u>neither the WEIM nor EDAM requires BAAs to solely rely on native generation</u>:
  - The balancing and bid-range capacity tests of the RSE ensure that BAAs have sufficient supply to meet demand
  - Both tests account for bilateral transactions, including between WEIM BAAs (“base transfers”)
- **WEIM Scenario 2** depicts a more plausible situation for how BAA B might meet its load needs if it had better information of costs elsewhere

WEIM Scenario 2: BAAs meet native load with gen and base transfers



WEIM Scenario 2: BAAs meet native load with gen and base transfers

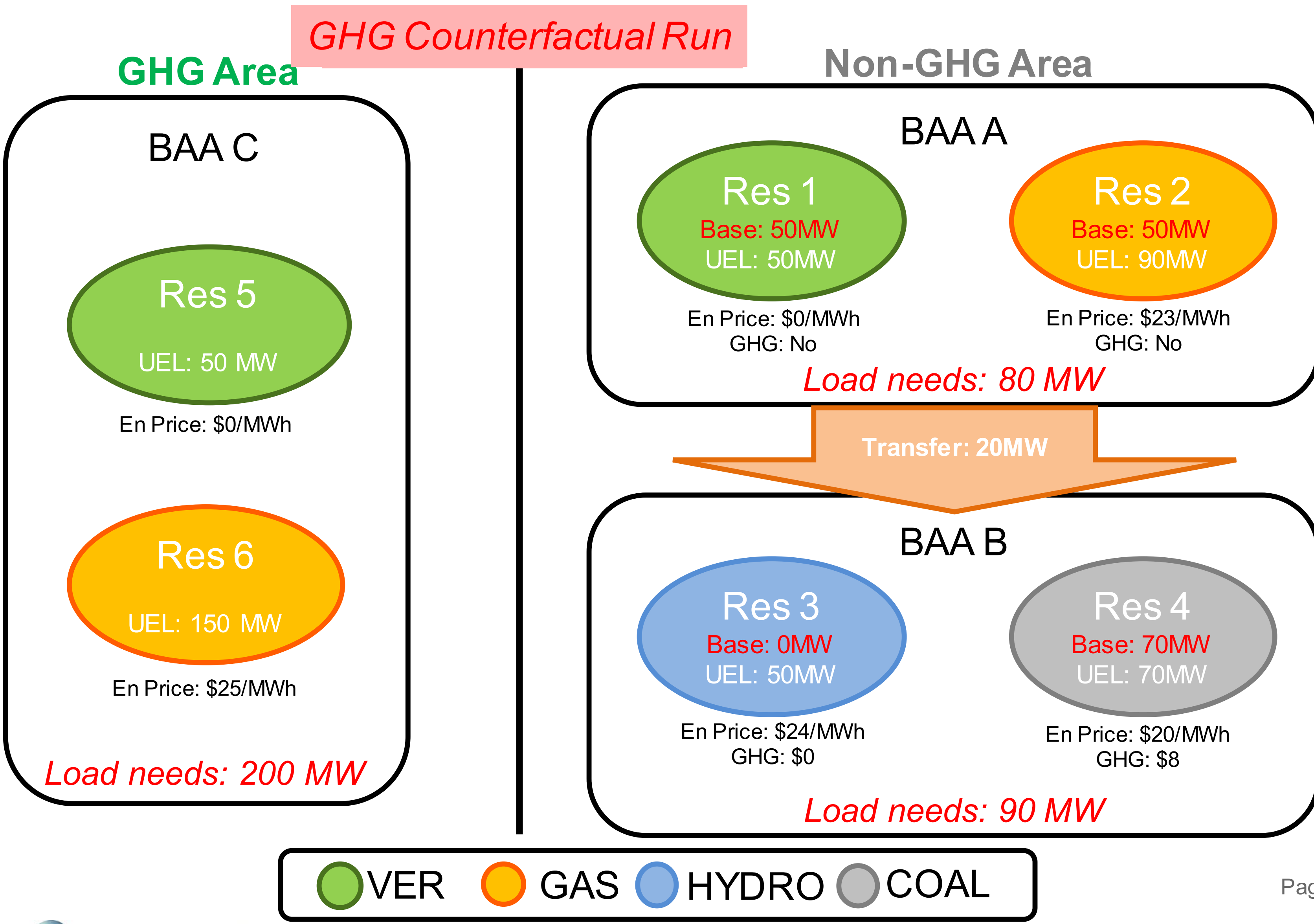


California ISO

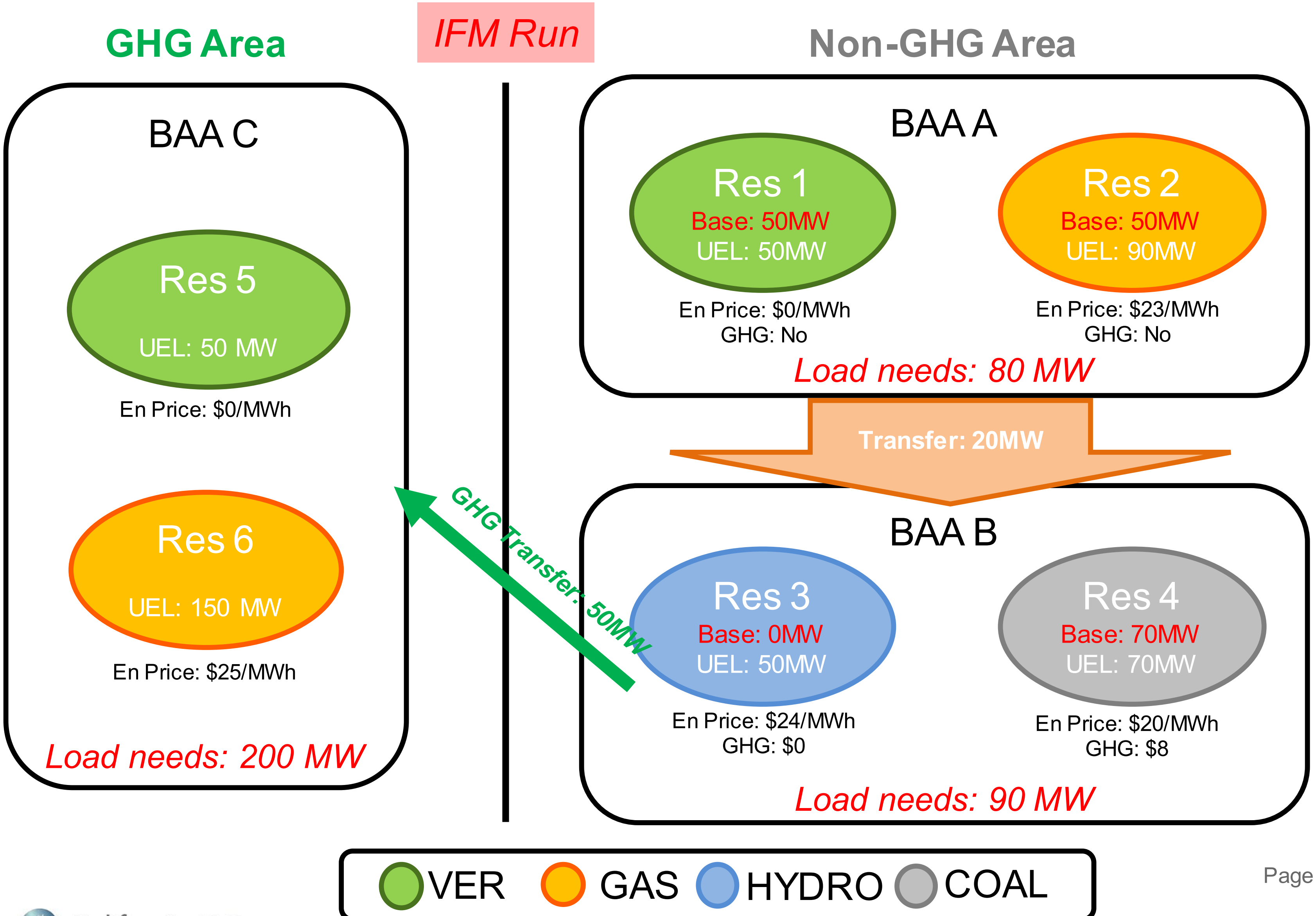
WEIM design is consistent with the EDAM design

- BAA B was able to procure less expensive energy bilaterally prior to participating in the WEIM by receiving a base transfer from BAA A
- This is exactly what would happen in EDAM:
  - In the GHG Counterfactual Run, the market would schedule a “transfer” from BAA A to BAA B
  - Then, in IFM, the market results would be the same as **WEIM Scenario 2**
- The EDAM GHG Counterfactual Run simply avoids what happened in **WEIM Scenario 1** because it has a complete picture of the relative energy bid prices in both BAA A and BAA B

EDAM Scenario (Actual): BAAs meet native load with gen and transfers



EDAM Scenario (Actual): BAAs meet native load with gen and transfers



Isabella Nicosia, Associate Account Manager, Stakeholder Engagement

NEXT STEPS

Next steps

- Comments due by end of day June 12.
  - Submit using the template provided on the working group webpage

- Next working group:
  - Date: June 26, 2024
  - Time: 9 a.m. – 4 p.m.
  - Location: Attendees may choose to participate in-person at the ISO, or virtually.

- Submit requests to present to ISOStakeholderAffairs@caiso.com

- Relevant information: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group

A new **caiso.com**
is coming May 30, 2024

The California ISO Stakeholder Symposium will be held on Oct. 30, 2024 at the Safe Credit Union Convention Center in Sacramento, California.

A welcome reception for all attendees will be held the evening of Oct. 29.

Additional information, including event registration and sponsorship opportunities, will be provided in a future notice and on the ISO’s website.

Please contact Symposium Registration at **symposiumreg@caiso.com** with any questions.