# MARKETS+

## Development Update

November 15

# WELCOME AND OVERVIEW

BRUCE REW, SPP

# TODAY'S AGENDA – DRAFT SERVICE OFFERING

| |
|---|
| Welcome and Overview |
| Governance |
| Market Design |
| Greenhouse Gas Design |
| Transmission |
| Phase 1 Funding |

# TODAY'S AGENDA – DRAFT SERVICE OFFERING

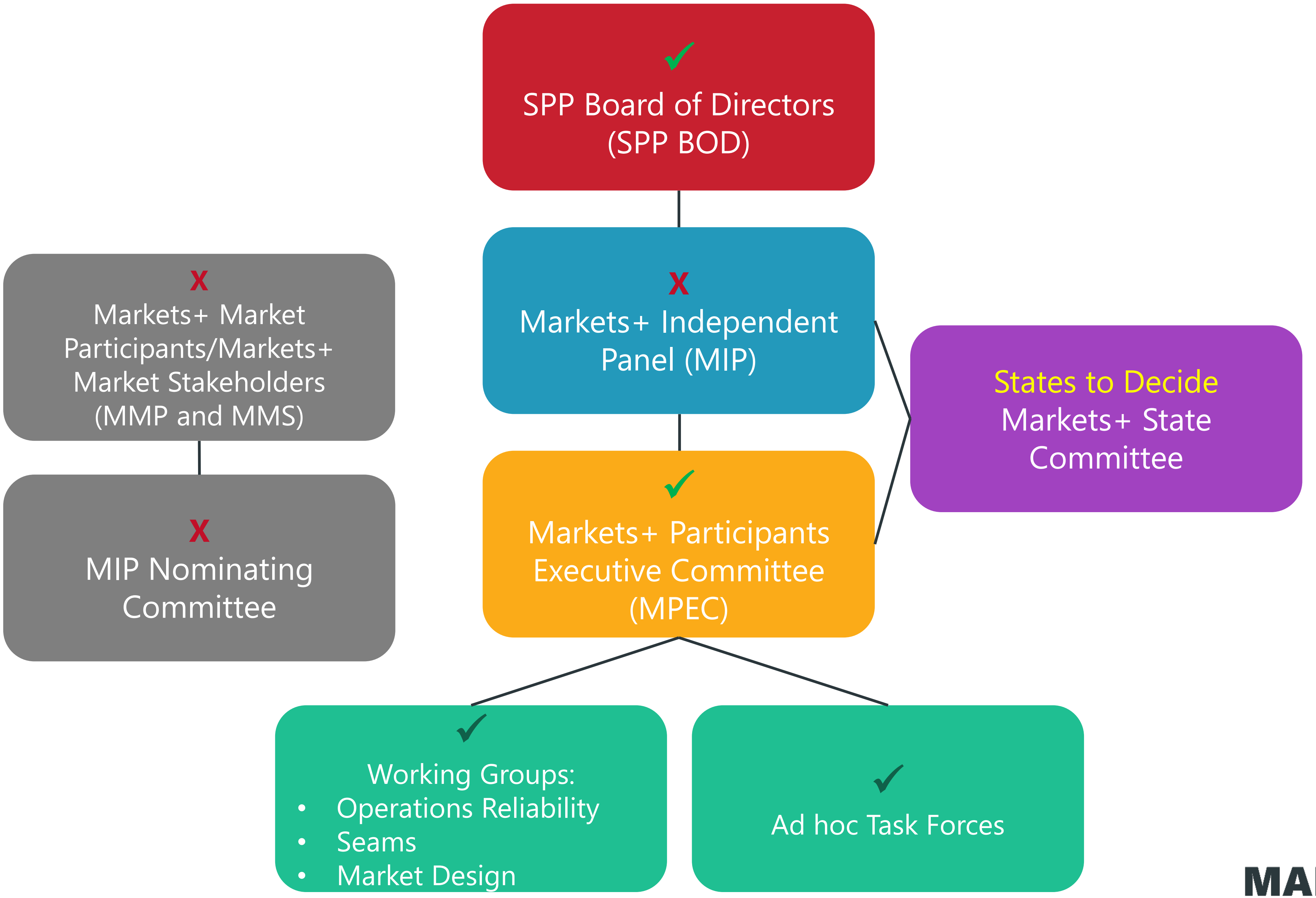
- Wireless network: Tri-State Guest
- Lunch 12-1 p.m.
- Reception at the DoubleTree Thornton 5-6:30 p.m.

Southwest Power Pool WESTERN ENERGY SERVICES

# GOVERNANCE

## COMMENTS ON GOVERNANCE STRAW PROPOSAL 3.0

# QUESTIONS AND REQUESTS FOR CLARIFICATION


✓
SPP Board of Directors (SPP BOD)
X
Markets+ Market Participants/Markets+ Market Stakeholders (MMP and MMS)
X
Markets+ Independent Panel (MIP)
States to Decide
Markets+ State Committee
X
MIP Nominating Committee
✓
Markets+ Participants Executive Committee (MPEC)
✓
Working Groups:
• Operations Reliability
• Seams
• Market Design
✓
Ad hoc Task Forces

SPP MARKETS+

# CLARIFICATION: MARKETS+ PHASE ONE FRAMEWORK

- The Markets+ service offering is the framework for Markets+ governance and market structure.
- Phase one will use the Markets+ governance structure to develop tariff language, protocols and governing documents based on the Markets+ service offering.
  - Upon approval of the tariff language, protocols and governing documents by the MPEC, the package will be submitted to the SPP board for approval to file at FERC.

# CLARIFICATION: IMPLEMENTATION OF GOVERNANCE STRUCTURE

- When will the proposed governance structure be put in place?
  - With the exception of the MIP, SPP envisions the governance structure being implemented in phase one.
- What will be the states' involvement in phase one?
  - Formation of MSC to be determined by states in phase one.

# CLARIFICATION: IMPLEMENTATION OF GOVERNANCE STRUCTURE

- Which entities will participate in phase one and how will they participate?
  - Markets+ Market Participant (MMP): Entities that are funding $9.7M cost of phase one and have executed a Markets+ phase one funding agreement. These entities have generation and/or load that they may contribute to Markets+.
  - Markets+ Market Stakeholder (MMS): Stakeholders who execute a Markets+ phase one stakeholder agreement and do not have generation and/or load. Required to pay $5,000 phase one stakeholder fee. The stakeholder fee may be waived for eligible entities that are non-profit organizations under the Internal Revenue Code.
  - Markets+ Non-Voting Stakeholder (MNVS): Interested stakeholders may provide input at all stakeholder meetings, but do not have voting rights on working groups and task forces. No phase one stakeholder fee is required.

# CLARIFICATION: WAIVER OF MMS FEE

- To be eligible for phase one stakeholder fee waiver, entities must provide the following documents:
  - Articles of Incorporation or similar documents;
  - Tax exempt status or similar documents; and
  - Most recent IRS Form 990 or similar documents.

# CLARIFICATION: WORKING GROUP COMPOSITION

- The composition of working groups will be determined in each group's scope document based on the needs of each individual group.
- The governance proposal already includes consideration of <u>geographical diversity</u> and <u>sector representation</u> when recommending and approving representation.

# CLARIFICATION: WORKING GROUP COMPOSITION

- 3.4.1.1 Composition and Terms
  - Following a solicitation of nominations by SPP staff, working group representatives shall be recommended by the MPEC chair in coordination with SPP staff to the MPEC for approval. The recommendation and approval of representatives shall consider the various types and expertise of Markets+ market participants (MMPs) and Markets+ market stakeholders (MMS), and their geographic locations, to achieve a widespread and effective representation of MMPs and MMSs.

# EXAMPLES OF SPP WORKING GROUP & TASK FORCE COMPOSITION

- Market Working Group (MWG)
  - Balanced transmission-owning member and transmission-using member representation from the Integrated Marketplace market participants.
- Supply Adequacy Working Group (SAWG)
  - Representatives should have expertise in at least one of the following areas: resource planning, load forecasting, power plant operations, transmission (operations or planning), markets or regulatory.
    - The SAWG will include representatives from, but not limited to, the following SPP membership sectors: cooperative, federal agency, investor owned utilities, independent power producer, municipal and state agency.
- Non-Jurisdictional Refund Task Force

# CLARIFICATION: TASK FORCE CREATION AND COMPOSITION

- SPP clarifies that task forces are to be proposed by the MPEC chair or working group chair and approved by the MPEC or applicable working group.
- Working group chairs may create subordinate task forces.
  - 3.2.2 Ad Hoc Task Forces
    - A temporary task force may be ~~created~~ proposed by the MPEC chair or working group chair~~.~~ and approved through an affirmative vote of the MPEC or applicable working group in accordance with the voting structure set forth in Section 3.3.1.4~~, the MPEC Chair may establish  ad hoc task forces as necessary to fulfill its mission~~.

# CLARIFICATION: TASK FORCE CREATION AND COMPOSITION

- The composition of task forces will be determined in each group's scope document based on the needs of each individual group.
- 3.4.2.2 Composition and Terms (Task Forces)
  - Task force representation will be appointed by the MPEC chair or working group chair after ~~the~~ SPP staff ~~Secretary~~ solicits nominations for task force members. The MPEC chair or working group chair in coordination with SPP staff shall consider the various types and expertise of Markets+ Market Participants (MMPs) and Markets+ Market Stakeholders (MMS) and their geographic locations to achieve a widespread and effective representation of the MMPs and MMS.

# PHASE ONE: WORKING GROUP AND TASK FORCE CREATION AND COMPOSITION

## Working Groups

1. Working group and scope document approved by MPEC
2. SPP staff solicits for nominations for working group (including chair)
3. MPEC chair in coordination with SPP staff submits a recommended slate to the working group
4. MPEC approves slate of working group members (including chair)

## Task Forces

1. Task force and scope document approved by MPEC or working group
2. SPP staff solicits for nominations for task force (including chair)
3. MPEC or working group chair in coordination with SPP staff appoints a task force
4. Task force recommendations are voted on by the creating including MPEC and/or MIP

# MARKETS+ COMMITTEE AND VOTING STRUCTURE

Markets+ Independent Panel (MIP)
(Majority Vote)

Markets+ Participants Executive Committee (MPEC)
(67% approval)

Working groups
(Majority Vote)

Ad hoc task forces
(Majority Vote)

# CLARIFICATION: MSC

- Determine if states want to form MSC during phase one.
- In phase one, work with state commissions on how to incorporate other non-market participant entities into MSC structure (e.g. state energy offices, consumer advocates, others).

# MISCELLANEOUS ITEMS

- MIP term limits
- MIP Nominating Committee
    - Committee can meet in closed session
    - Clarification to allow proxies
    - Nominating Committee will use search firm
- Appeals to MPEC and MIP
    - Clarification on timeliness
- Recommendations shall include minority positions

# OPEN ISSUES FOR DISCUSSION

# DISCUSSION: MPEC VOTING

- 1/3 investor-owned utilities, 1/3 public power, 1/3 other/independent with 67% approval threshold.
- Entities expressed need for recognition of geographical diversity.
- Several alternative options proposed.
- Future considerations: Requests to wait to finalize Markets+ MPEC voting after phase one once there is a better idea of the entities participating in Markets+.

# MPEC VOTING: ALTERNATE OPTIONS

1. **PowerEx -** IOU and public power sectors allocating their votes within the sector based on each entity's total load and generation instead of per participant OR allocate per entity within the sector but apply an additional overriding limitation that each region must be allocated a defined percentage of the vote within the sector (NW, SW and/or international). Further consideration of uniquely situated MPs that do not clearly fit within a sector.
2. **NV Energy -** Proposed MPEC approval require 67% of three sectors proposed and 50% of entities in 1) Desert SW and Intermountain West and 2) the Northwest.
3. **NIPPC, Renewable Northwest, State PUC MOU -** Allow other/independent sector to be divided into smaller groups with similar interests.

# DISCUSSION: MPEC VOTING OPTIONS

- Topic one
  - Two-tiered MPEC voting structure
    - Tier one - 1/3, 1/3, 1/3 with 67% approval threshold
    - Tier two – Regional vote with 51% approval threshold
      - Eligible regional voters?
- Topic two
  - Load ratio voting for IOU and public power sectors
  - Subdivide independent/other sector voting structure

# DISCUSSION: MIP

- When should the MIP be established?
- *Option*: Could a SPP board of directors subcommittee be used in the interim during phase one?

# DISCUSSION: GOVERNANCE REVIEW

- Should the MIP approve initiation of governance review?
  - 4.1 Governance Review
    - *Upon the MPEC's request*, but no later than three years after the Markets+ market launch, the MIP will initiate a review of the Markets+ market governance in light of accumulated experience and changed circumstances.
- Should a supermajority (4/5) vote by MIP be required to approve governance changes?
- *SPP identified issues:*
  - Determine process for revising governing documents after phase one.
  - Determine process for revising governing documents after initial governance review.

# MARKET DESIGN

JIM GONZALEZ, SPP
STEVE WHITE, SPP

# GENERAL AGREEMENT

# GENERAL AGREEMENT WITH DRAFT OFFERING

**Price Formation**

- Cooptimization
- Fast Start Pricing
- Scarcity pricing

**Products**

- Flex Reserves
- No Operating Reserves at start
- Marginal Losses

**Resources**

- Resource Participation Options
- Physical Day-Ahead Unit Commitment

# CLARIFICATION REQUESTS

# DISPATCHABLE INTERCHANGE SCHEDULES

- Dispatchable interchange schedules are physical transactions that bring energy into and/or our of the Markets+ footprint
  - Specify a bid or offer per MWh
    - 10-point curve, just like Gen and Price-sensitive load
  - SPP proposes only present in Day-Ahead process at Markets+ launch
- Expanding dispatchable interchange schedules could be investigated as a post-launch enhancement

# NITSA RESOURCE DESIGNATION & M+ DISPATCH

- Participants are not expected to re-designate NITSA resources based on expected market economic dispatch
- Congestion rents in the DAMKT will be allocated from designated resources to load regardless of how those resources are actually dispatched in the market.
- Re-designating resources could have unintended consequences to the congestion rent allocation

# WHAT TRANSMISSION WILL SUPPORT RUC

- Markets + will utilize up to the flow-based capabilities or the participating transmission facilities, less any rights not participating in Markets+.
  - Sold and unsold transmission service
  - As-available capability up to the flow-based limitation in real-time

All In minus carve outs

- RUC will rely on the remaining sold and unsold transmission service as well as the as-available capability in real-time
  - Need to work through scenarios where TSPs continue to sell service after the DA processes

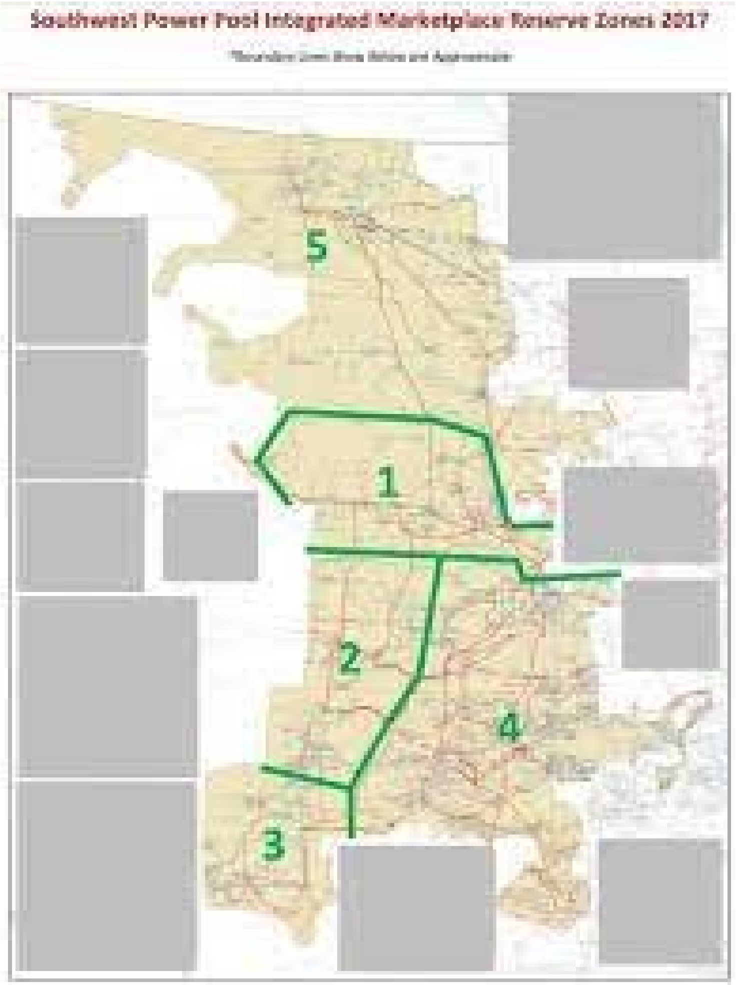
Phase 1

# DEMAND RESPONSE RESOURCE REQUIREMENTS

- Demand Response(DR) capacity participating in Markets+ must not also be participating in another program
  - For example, capacity participating in a retail DR program should not also participate in wholesale market at same time.
- DR should not be prohibited by jurisdictional authority from participating in wholesale market
- DR must have a maximum larger than Markets+ minimum participation size (100kW)
- DR can be aggregated under a single point of interconnection to the transmission system
- The responsive load must be identified in registration and telemetered to SPP in real-time
- Participants may be required to submit hourly forecasts for the responsive load prior to the DA processes and update until the operating hour
  - Depends on how the DR registers.

# RESERVE ZONES

- Reserve Zones are groupings of Pnodes where reserve min/max to carry constraints can be modeled
  - Promote geographic diversity of where reserves are procured
  - Model interface constraints to ensure reserves are reasonably deliverable if deployed
- Markets+ will only procure and price flexibility reserves at launch.
- Flexibility Reserve requirements will be calculated for market footprint, not individual BAAs
  - Recognize diversity benefit of regional market



# GROUPED HYDRO MODEL

Phase 1

- SPP will work with hydro operators to understand specific operational requirements for hydro facilities on a common river system
  - Markets + should not interfere with reliable and efficient operation of water system.
- Any design will need to maintain nodal price transparency
  - Congestion and marginal losses

# ELECTRIC STORAGE RESOURCE (ESR)

- Any resource meeting definition of ESR may register using Market Storage Resource (MSR) registration type.
  - "a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid." (FERC Order 841)
  - MSR provides additional offer parameters and clearing logic to account for unique operating characteristics of ESRs
  - Batteries, Flywheels, pump-storage, etc.

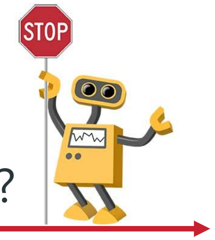
# VARIABLE ENERGY RESOURCE (VER)

- SPP proposes that VERs operate at their maximum production potential in real-time except when SPP  is actively dispatching the resource.
- Potential exemptions that would prevent SPP from actively dispatching a VER:
  - Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility
  - Run-of-the-river hydro incapable of following dispatch

# MULTI-CONFIGURATION COMBINED CYCLE RESOURCE (MCR)

- MCR registration option allows participant to register individual operating configurations.
  - Individual resource offers
  - Individual operating characteristics
  - Transition  information
- SPP proposes that this logic on be available to combined cycle resources at launch
  - Could investigate similar, but different logic to model transitions between coal mills.

Post
Go-Live ?



# RELIABILITY UNIT COMMITMENT (RUC)

- Reliability Unit Commitment assesses the operating window that has already been committed by the Day-Ahead process with hourly granularity
  - Option 1: Financial Day-Ahead Market with physical unit commitments
  - Option 2: Physical Unit Commitment
- Short-term RUC (ST-RUC) assesses the next three hours with 15-minute granularity

# FUEL-LIMITED RESOURCES

- Markets+ provides participants with tools to manage the availability of fuel-limited resources
  - Resource Offers
    - Max Daily Energy (MWH)
    - Max/Weekly Starts
  - Mitigated(cost-based) Offer
    - Opportunity Cost Calculator
      - Environmental run-hour restrictions
      - Physical Equipment Limitations
      - Non-Regulatory Opportunity Cost: Fuel Limitations
    - Default method will be defined, but participants can submit individual methodology to MMU for approval

# BEHIND-THE-METER(BTM) GENERATION

Phase 1

- SPP proposes a single, standard requirement for Markets+ footprint
- Need to strike a balance between model/forecast accuracy and administrative burden
  - SPP anticipates somewhere between five to 10 MW
- Any BTM Generator exceeding the Markets+ minimum participation threshold (100kW) capable of participating in wholesale market may register.

# MULTI-DAY ADVISORY STUDY RESULTS

- Multi-Day Advisory Study will cover the next 3-7 operating days
- Primary Outputs
  - Hourly pricing forecast by settlement location
    - SPP post publicly, available to anyone
  - Prospective, non-binding commitments
    - SPP will communicate to participant offering resource
  - Reliability-based results (infeasible deliverability, capacity issues, etc.)
    - SPP will communicate to appropriate BA/TOP/RC

# ADDITIONAL DISCUSSION

# LOAD AND RESOURCE(RENEWABLE) FORECASTS

- SPP proposes to develop load and wind/solar forecasts for both mid-term and short-term
  - Load Forecasts
    - Short-term, 5-minute granularity for next 4 hours, updates every 5 minutes
    - Mid-term, hourly granularity for next 10 days, updates at least once per hour
  - Wind/Solar Forecasts
    - Short-term, 5-minute granularity for next 4 hours, updates every 5 minutes
    - Mid-term, hourly granularity for next 72 hours, updates every hour
    - Long-term, hourly granularity for next 72-192 hours, updates periodically (8 times) throughout day.
- Discuss option for participant-provided forecasts
  - Compare Accuracy with SPP-developed forecast
  - Identify unanticipated consequences

Phase 1

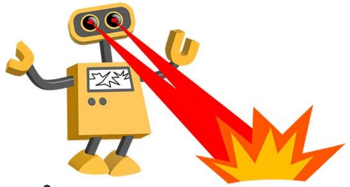
# MARKET DESIGN FEATURES FOR LONG-LEAD RESOURCES

- SPP did not propose a market design feature to accommodate long-lead resource commitments
  - Long-lead resources are resources that must be notified to start prior to the completion of the Day-Ahead process.
  - Current Markets+ design would rely on either BA instructing resource to start or participant self-committing

- Alternative designs could be investigated
  - Extend Day-Ahead commitment horizon
  - Add additional, economic long-lead commitment process
- Identify specific notification requirements of expected resources participating in Markets+ and determine next steps.

Phase 1

# CONVERGENCE BIDDING



- Most participants recommend delaying convergence bidding by at least one year
  - Allow market to mature and participants gain confidence and experience

- SPP will perform studies to identify unintended consequences related to price formation
  - Will need for filing
  - Specifically look at potential price suppression in DAMKT

Phase 1

# MINIMUM RESOURCE SIZE TO PARTICIPATE

- SPP proposes Resource must meet a minimum threshold of capacity to participate in Markets+
  - SPP proposes standard requirement for entire Market+ footprint
  - SPP proposes no smaller than 100 kW
  - Anything smaller and it is ‘noise’ to the market optimization and difficult to monitor performance
- Markets+ minimum size may differ from what is modeled in network model for reliability (BA/TOP/RC)
  - Tight coordination during registration between parties, especially related to actual load calculation

# FORMAL EXTERNAL RESOURCE PARTICIPATION MODEL

- SPP proposed a limited model for external resource participation in Markets+
  - Pseudo-tie into a participating BA
  - Imports/Exports across a Markets+ boundary
- Some participants requested a more flexible resource participation model allowing for external resources to participate in Markets+ without Pseudo-tying, but more granularly than import/export transactions.
  - SPP recommends this be investigated in Phase 1 to determine if incremental cost of external resource model provides sufficient benefit beyond what is proposed.

Phase 1

# DESIGN GOALS TO KEEP IN MIND

- Markets+ should not interfere with continued efforts to collaborate in the west
  - Allow for collaboration of BAAs
  - Allow for transition to West RTO when entities are individually ready

# QUESTIONS/DISCUSSION

# GREENHOUSE GAS DESIGN

YASSER BAHBAZ, SPP

# PROPOSAL SUMMARY

# GHG ZONES

| | |
|---|---|
| GHG Pricing Zone | For states and zones with carbon pricing programs |
| | Costs added to consumers in the GHG Zone/State are justifiable to FERC |
| GHG Non-Pricing Zone | For states without a carbon pricing program but have GHG reduction targets. |
| | Accounting, tracking and reporting efforts will be supported by SPP |

# STATES GHG TRACKING AND REPORTING

| | |
|---|---|
| GHG Pricing Zone | GHG costs will impact dispatch inside the zone |
| | The cost of emission will impact resources serving load in the zone |
| | Tracking and reporting is necessary for settlement – ***Rules are needed*** |
| Carbon Non-Pricing Zone | GHG attributes do not impact economics or dispatch inside the zone |
| | After-the-fact tracking and reporting the emission of energy consumed by the zone may be developed – ***Rules are needed*** |
| | Pursuing a rate justification to price carbon will help justify to FERC pricing in the Markets |

# TRACKING AND REPORTING FOR STATES WITH GHG TARGETS

Load MW Actual

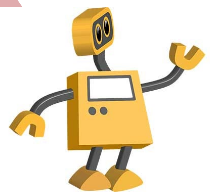
Generation MW Actuals

Location for each assets identified for each modeled zone (state)

**SPP**

Stakeholder effort to determine business rules for assigning of MWs supporting exports and imports

**SPP Facilitated Stakeholders Efforts**



**3rd Party**

**Reporting of each zone (state) MW production and consumptions by GHG attribute**

SPP

# DESIGN OVERVIEW

## Market Optimization

- The cost to serve load in states w/ GHG programs will be modeled in the market's optimization

## Zonal GHG Pricing

- A zonal approach will be used that represents the states with a GHG pricing program that requires collecting and paying GHG costs associated with carbon emission

## Resource Participation

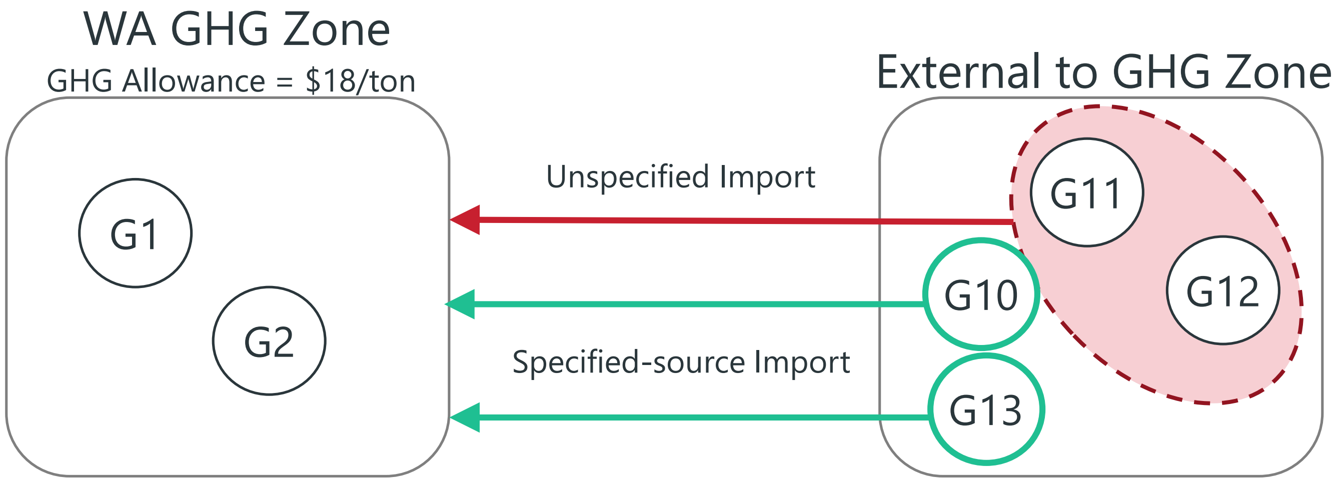
- Any M+ resource can participate in serving load in a GHG zone
  - Resources internal to the GHG zone, specified imports, and unspecified imports

## Tracking and Reporting

- SPP will facilitate the necessary data and stakeholder coordination to develop tracking and reporting requirements for states with and without a Carbon pricing program

# 3 TYPES OF RESOURCES FOR A GHG PRICING ZONE

- The 3 types are defined in the
  - ✓ *GHG Internal Resources*
  - ✓ *Specified-source Imports*
  - ✓ *Unspecified Imports*
- GHG zone imports allow resources outside the zone to participate in supplying the GHG zone. These MWs are tracked and are subject to GHG costs.



# GHG PRICING RESOURCE CATEGORIES

| | |
|---|---|
| **GHG zone internal resources** | Generators that reside within the geographical boundary of the zone, each has its own GHG rate |
| **Specified Source Imports** | Imports that are supported by designated generators with specified GHG rates |
| **Unspecified Source Imports** | Imports from system generation outside the GHG zone. This import is expected to have a default and pre-determined GHG rate |

# GHG PRICING ZONES

## GHG Zone Internal Generation

Is subject to GHG costs

Dispatched Gen within the zone Satisfies GHG zone load first.

## GHG Rates

resources within GHG zone resources

source for Specified-source imports

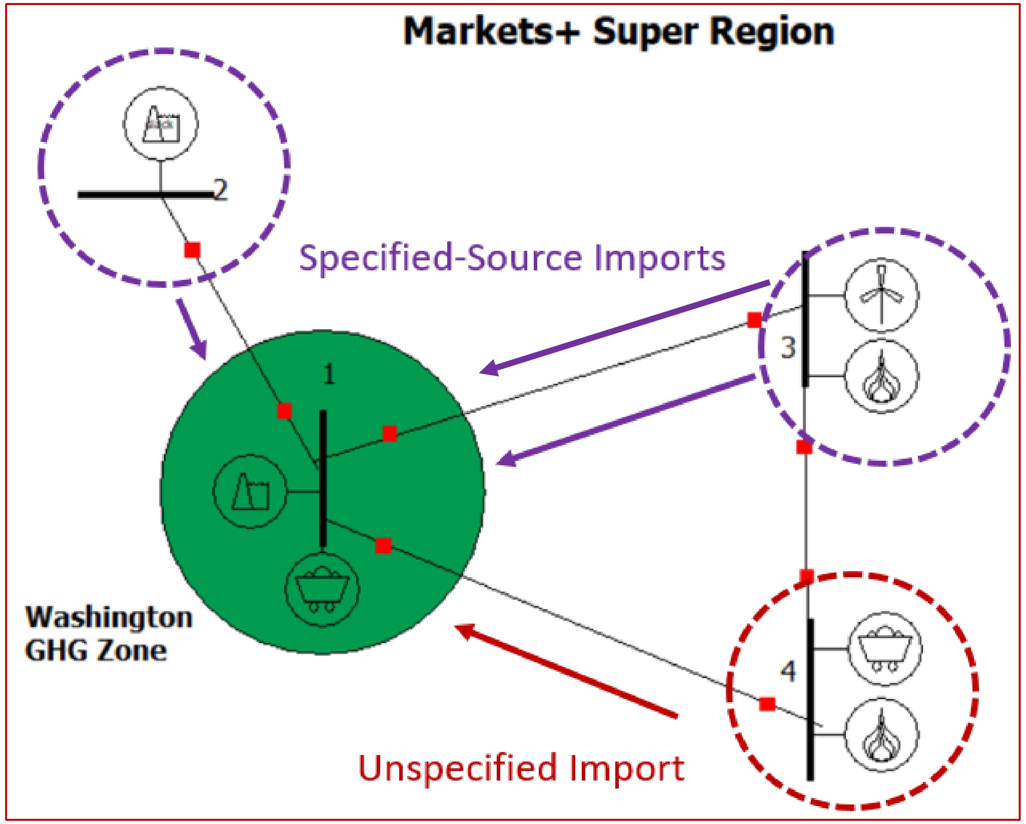
A pre-determined rate for unspecified-source imports

## Tracking GHG Zone MW

MWs serving load in the zone from external or internal resource/fleet are accounted for

# GHG ZONE DEFINITION FOR PRICING CONSIDERATIONS

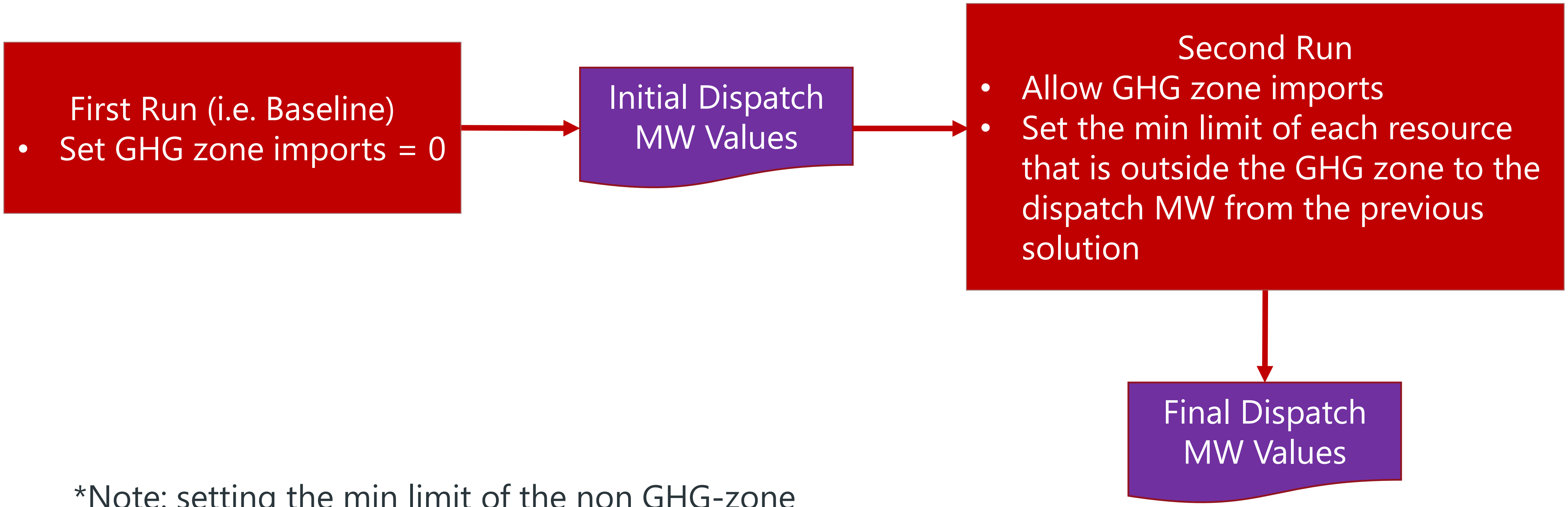
- Typically, a state-bordered region that has applied a GHG pricing program, Cap and Trade, or Cap-and-Invest program
- The zone would consist of resources and loads that reside within the boundary of the GHG zone with a pricing program
- Two or more states could have "linked" programs with a single GHG zone acting in unison



# MW RE-DESIGNATION ISSUE

- An economic resource external to a GHG pricing zone may have produced the same energy amount to serve load in the M+ footprint regardless of the existence of the GHG zone and its costs depending on the relative impact of GHG pricing
- If the energy from the resource is then assigned to a GHG zone (i.e., re-designated) due to a specified source import designation
- If the energy designated to the GHG zone is replaced by GHG-emitting resources, the overall reduction calculated by the GHG zone only exists as reported.

# BASELINE APPROACH




*Note: setting the min limit of the non GHG-zone resources in the second run constrains resources outside the GHG zone to prevent emissions and MW Re-designation issue based on the previous solution

# COMMENTS AND QUESTIONS

# IMPORT LIMIT ADJUSTMENT IN THE BASE-RUN

Why Zero-out the import limits in the base-run

Business objective is to identify the resource output level for resources not in the GHG Pricing zone before these resources consider imports into the zone

To keep the least emitting generation from being assigned to the GHG Pricing zone in the dispatch solve, we need to know how much of this low emitting generation would be used to serve load outside the zone as if there were not the GHG Pricing zone and its load

# IMPORT LIMITATION FOR ALL STATES AND BAS

| | |
|---|---|
| Disallow other states/BAs from imports in the base-run | This might make sense if all states had GHG programs, but that is not the case at this time |
| | Limiting other states or zones' imports and exports in the initial run is not necessary and may not be desirable because there is not a similar pricing impact to import for other states; thus not an import limitation between the non-GHG states/BAs |

# REMOVE GHG PRICING IN THE BASE RUN

| | |
|---|---|
| Where would the resources operate if the GHG Pricing zone rules were not in place? | Allowing the GHG Pricing zone to import in the base-run does not seem like the appropriate incremental approach assessment considering all MWs consumed by the GHG Pricing zone are subject to GHG costs. |
| | The GHG Pricing zone load must only exists with the GHG program for appropriate assessment to meet the program intent and policies. |

# MARGINAL PRICING OF GHG COSTS

| Observations of the Marginal Pricing for the GHG Costs | Marginal pricing does not necessarily reflect the costs associated with GHG emission observed in the model. |
| --- | --- |
| | GHG constraint for each GHG Pricing zone produces a shadow price representing the incremental cost to an incremental load moving to the GHG zone |

# MARGINAL PRICING OF GHG COSTS - CON'T

Observations of the Marginal Pricing for the GHG Costs

When resource cost + GHG is below the LMP, the resource would be ***dispatched*** to its ***maximum*** whether GHG was modeled or not. This resource will <u>not set price</u>, so its GHG costs will not be visible to the market

When resource cost without GHG costs is above incremental costs, the resource would be ***dispatched*** to its ***minimum*** with or without GHG cost model; this resource will <u>not set price</u>; its GHG costs will not be visible to the market

# NEXT STEPS – PHASE 1


- Establish a working group to develop a design that is consistent with the intent of programs and state policies.
- Close coordination with states and program-responsible agencies will be key to this effort.
- Evaluate the marginal Pricing approach of GHG costs – Shadow price and GHG constraint formulation
- Assess proper criteria for Specified-Source Imports and continue to investigate addressing the MW Re-designation concerns.

# NEXT STEPS – PHASE 1


- Work with the stakeholders on the approach to incorporate the needs for GHG Non-Pricing zones.
- Determine the entity that may take on the compliance obligation unspecified imports procure.
- Facilitate the development of tracking and reporting for any state with GHG reduction targets or programs (GHG Non-Pricing zones)

# QUESTIONS/DISCUSSION

# TRANSMISSION

STEVE JOHNSON, SPP
MICHA BAILEY, SPP

# MARKET TRANSMISSION SERVICE

STEVE JOHNSON, SPP

# MARKET TRANSMISSION SERVICE

- Recognizes market use of transmission and provides revenue to mitigate loss of short-term firm and non-firm sales due to market activity
- Five concepts defined in service offering:
  - TSP Qualified Recovery Amount
  - TSP Qualified Revenue Ratio
  - MTS Recovery Scaling Factor
  - MTS Revenue Recovery Amount
  - MTS Revenue Distribution

# TSP QUALIFIED RECOVERY AMOUNT

- Based on an TSP's short-term firm and non-firm revenue only, not total ATRR
- Initial TSP QRA based on average of previous three years of short-term firm and non-firm revenue
- Used to determine initial TSP Qualified Recovery Ratio
- Markets+ Transmission Working Group will determine future QRA determination process

# TSP QUALIFIED REVENUE RATIO

- A ratio of a TSP's short-term firm and non-firm (Initial QRA) vs. total ATRR will be calculated
- Applied to current and future year ATRR
- Update process to be determined by Markets+ Transmission Working Group

$$TSP\ QRR = \frac{Avg(TSP's\ previous\ 3\ years\ STF + NF\ Revenue)}{Avg(\text{ Previous 3 years TSP's total ATRR})}$$

# MTS RECOVERY SCALING FACTOR

- TSP QRR = ratio of STF+NF (QRA) vs. ATRR (e.g. 10%)
- Determine Recovery Scaling Factor (MTS RSF) to apply to ratio (50% used in this example)
- Apply TSP QRR to future year to account for changes in ATRR
- M+ Transmission Working Group to set MTS RSF

Example RSF calculation:

Year 1
ATRR=$120M
QRA=$12M; QRR=10%
Recovery Scaling Factor is .5
.5*(ATRR*QRR)=$6M

Year 2
ATRR=$130M
10% QRR is maintained from initial baseline
Recovery Scaling Factor is .5
.5*($130M*QRR)=$6.5M

$$\textbf{\textit{Recovery Scaling Factor (RSF) = Factor between 0 and 100\%}}$$

# MTS REVENUE RECOVERY AMOUNT AND DISTRIBUTION

- MTS Revenue Recovery Amount is calculated based on the following formula:

$$\boldsymbol{MTS\ Revenue\ Recovery\ Amount\ (RRA) = (ATRR * QRR) * RSF}$$

- The MTS Recovery Amount is distributed based on a ratio of TSP RRA vs. total RRA

$$\boldsymbol{MTS\ Revenue\ Distribution = \frac{TSP\ MTS\ RRA}{Total\ MTS\ RRA}}$$

# MTS RATE AND REVENUE RECOVERY DISCUSSION

- Draft service offering proposed a fixed collection amount with a variable hourly rate based on total gen/load MW cleared in the market.
  - Some commenters would like a fixed rate with a true-up
  - True up would be offset to future MTS rate
    - 1 year in arrears (e.g. 2024 results would be used in 2025 to calculate the 2026 MTS rate).
    - TSPs would apply revenue in similar fashion to non-firm revenue
- Received comments for and against billing all load and generation vs. load only

# MARKET TRANSMISSION SERVICE RECOVERY PRIORITY

- Market Transmission Service Recovery is being established as a market charge to acknowledge market transmission use and provide offsetting revenue to loss of short term firm and non-firm sales
  - Based on underlying firm transmission provided by TSR owners and TSPs
- MTS will be treated as firm service given the nexus to underlying firm network and point-to-point

# OATT SALES AFTER MARKET RUN

- In draft service offering –
  - Short-term transmission sales continue up to and after day-ahead market run
  - Transmission requests made during market run will be placed in a TSP's OASIS queue to be processed after market run and associated transmission use is determined and communicated to TSP
  - Transmission** not obligated by the DAMKT can continue to be offered through real-time window

**SPP proposes an uncertainty factor*DAMKT transmission to ensure confidence in future commitments and real time dispatch

# OATT SALES AFTER MARKET RUN

- Concerns around transmission sales after market run
  - Two camps
    - Ensure sales through real-time
    - Restrict sales after market run to ensure deliverability of market solution
- Option proposed:
  - Allow sales of transmission based on cleared market award
    - Ensures feasibility
    - Ensures transmission availability through real-time

# OATT RIGHTS USE AFTER MARKET RUN

- Some comments regarding use of transmission rights after DA market run and exposure to congestion
- Two solutions proposed
  - Hold harmless payments
    - Would result in market uplift
  - Opt out provision
    - Would need to set opt-in/opt out interval to avoid gaming
    - Associated impacts would result in market uplift

# CONDITIONAL FIRM – 6CF

- Transmission in Markets+ will continue to be administered by individual TSPs like today
- Markets+ will receive firm rights used and available for market dispatch from the TSP prior to the DA market run
- 6CF is firm until conditions are experienced that cause the non-firm condition
- TSPs will report 6CF as 7F firm to the market operator
  - Evaluated for the appropriate conditions and determined by the TSPs

# IMPORTS, EXPORTS, WHEELS

DANIEL BAKER, SPP

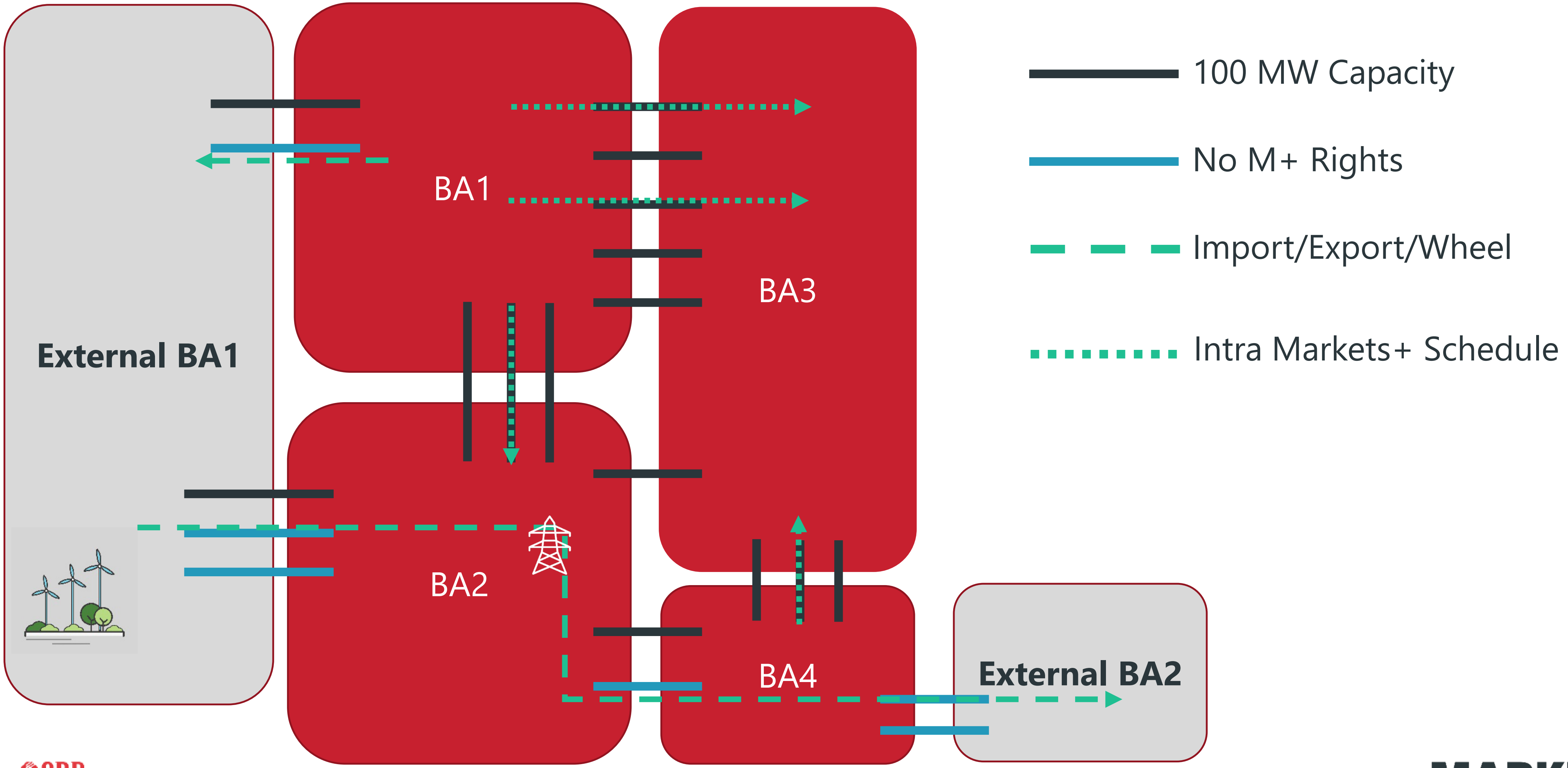
# THE MARKET PROCESS

## SUMMARY OF MARKETS+ SCHEDULING

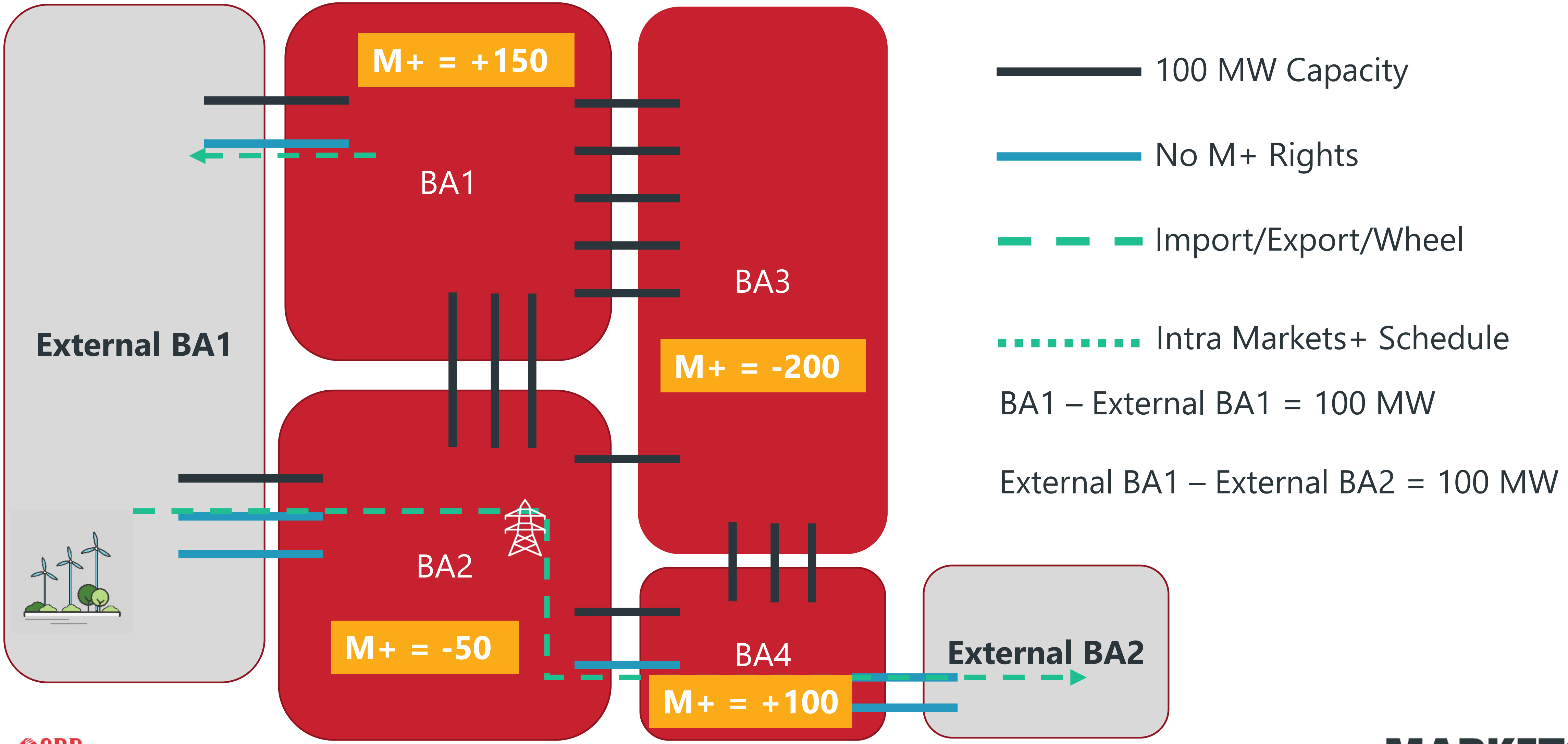
# BEFORE DAY AHEAD MARKET

- Markets+ models all lines and elements with corresponding limits
- Markets+ Operational Analysis identifies N-1 constraints
- All in Transmission concept
- Participants identify transmission not available for M+ (sold outside the market)

# EXAMPLE – TRANSMISSION SYSTEM OVERVIEW



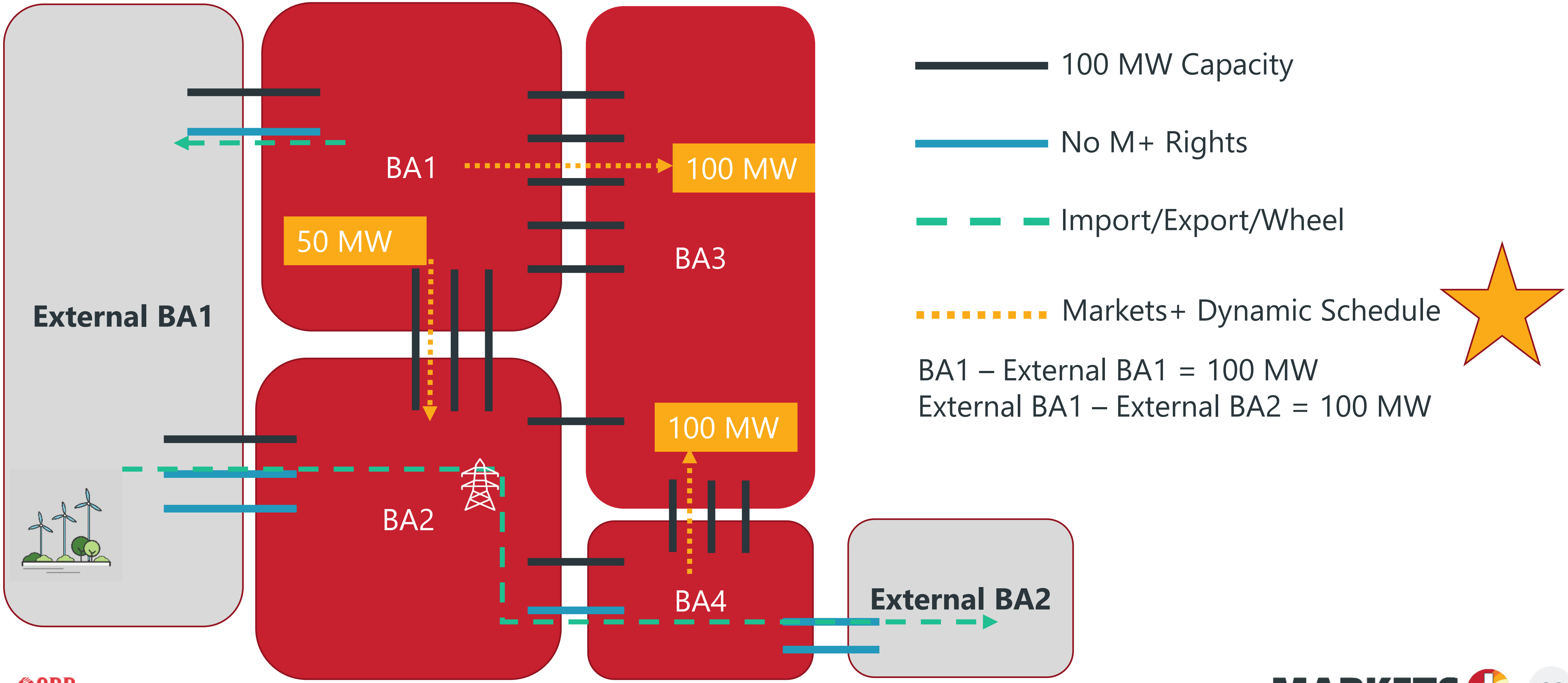
# EXAMPLE – DAY AHEAD MARKET RESULTS




BA1 – External BA1 = 100 MW

External BA1 – External BA2 = 100 MW

# EXAMPLE – DAY AHEAD MARKET RESULTS

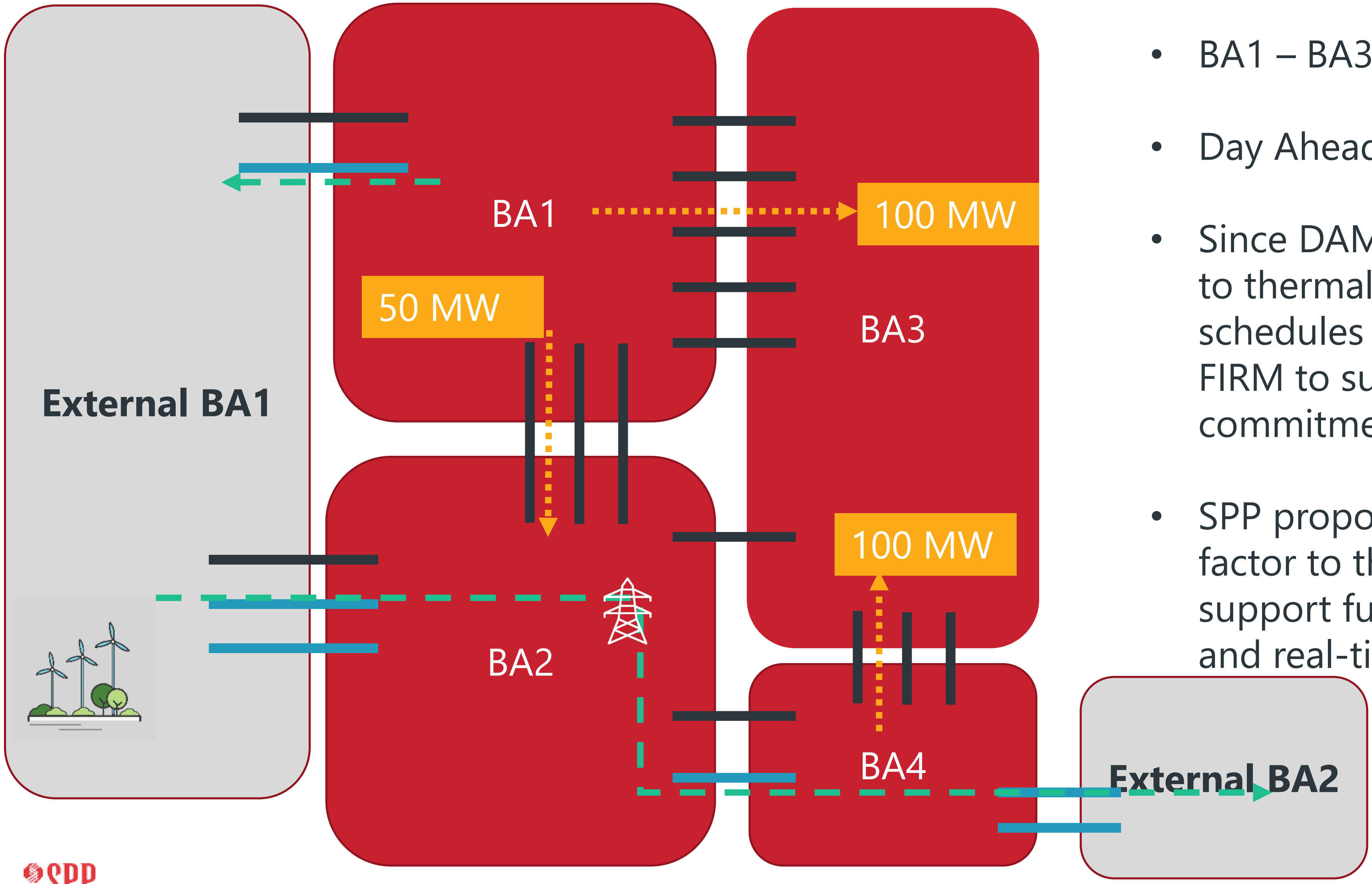



BA1 – External BA1 = 100 MW
External BA1 – External BA2 = 100 MW

# MARKETS+ DESIGN ACTION ITEM

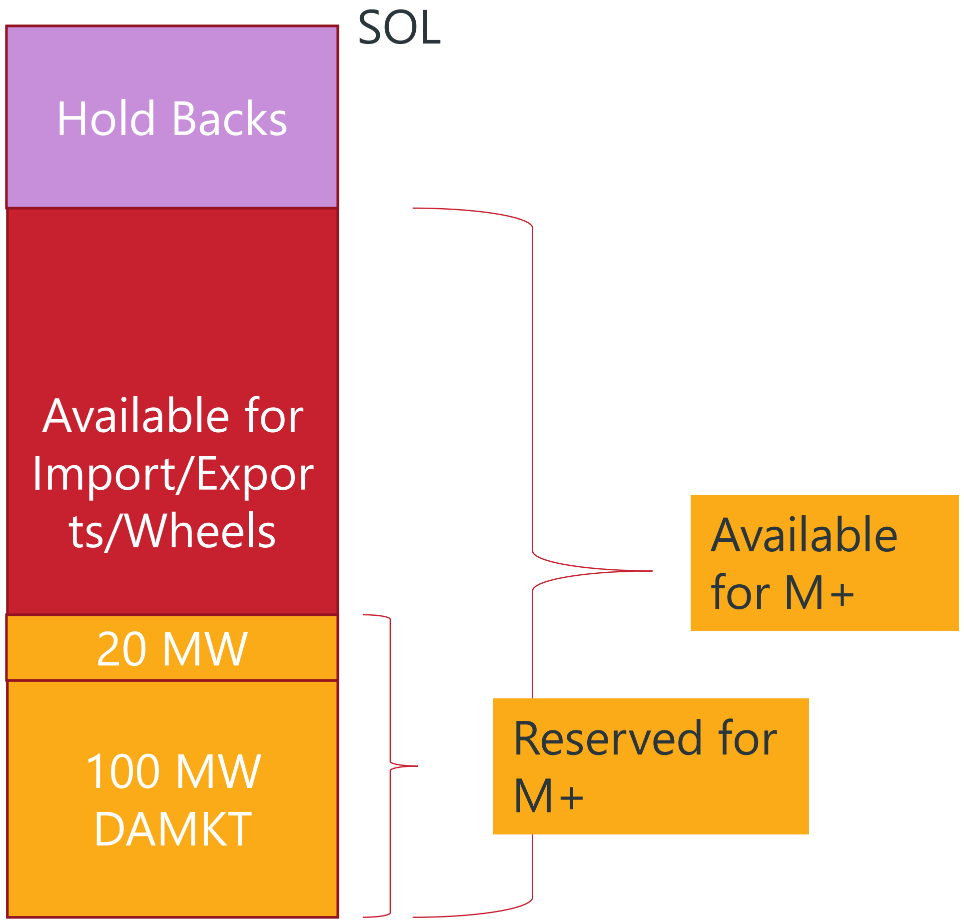
- Allocate M+ dynamic schedule to paths and/or elements
- SPP proposal is create centroid buses in each BA and calculate shift factor based flows
- This would also support calculation and reporting and market flow for coordinated congestion management

# EXAMPLE – DAY AHEAD TRANSMISSION RIGHTS



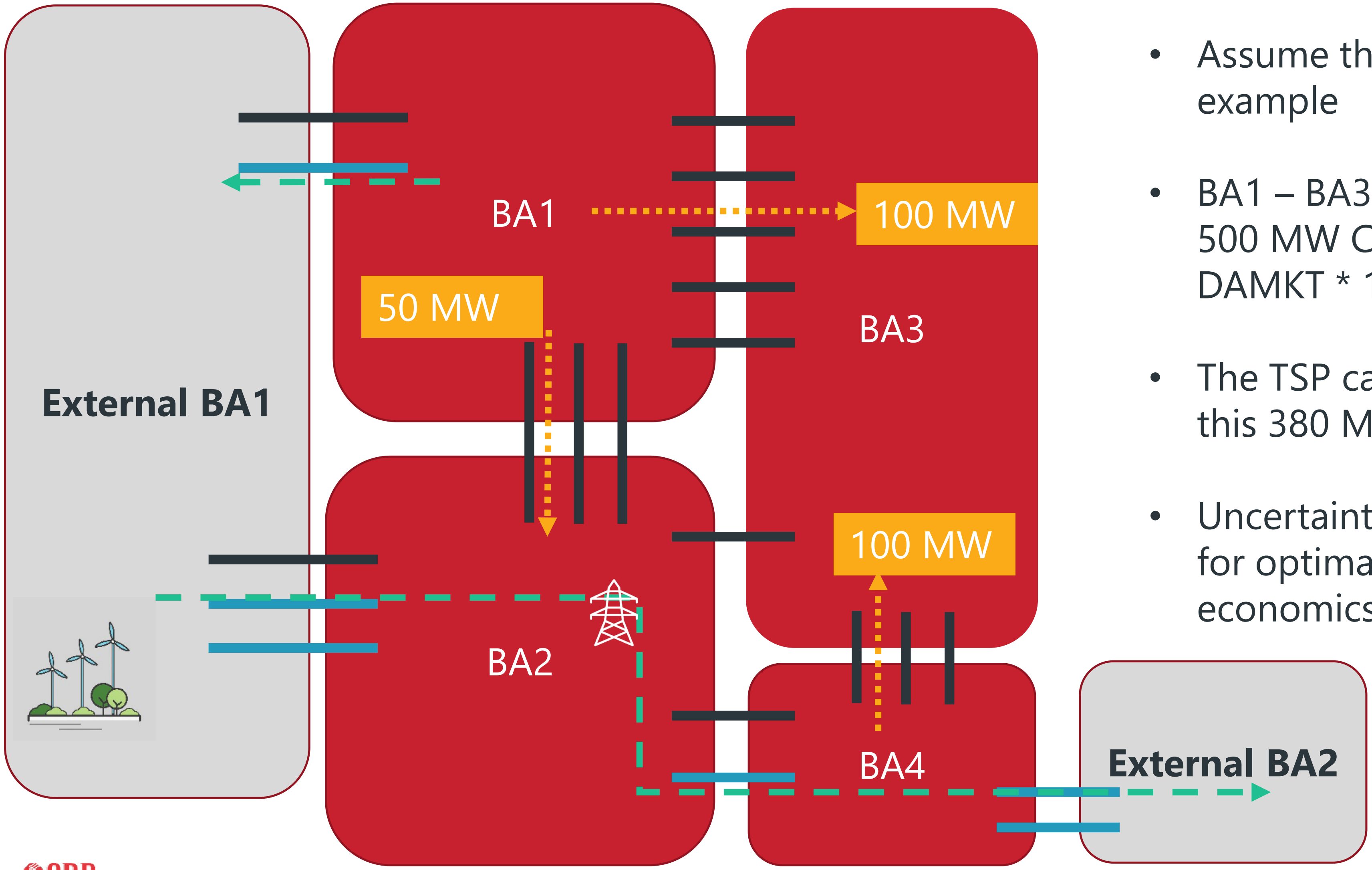

- BA1 – BA3 = 500 MW Capacity
- Day Ahead Market used 100 MW
- Since DAMKT uses all M+ rights up to thermal capacity, these DAMKT schedules should be counted as FIRM to support reliable unit commitment
- SPP proposed adding a uncertainty factor to this DAMKT result to support future unit commitments and real-time.

# MARKETS+ DESIGN ACTION ITEM



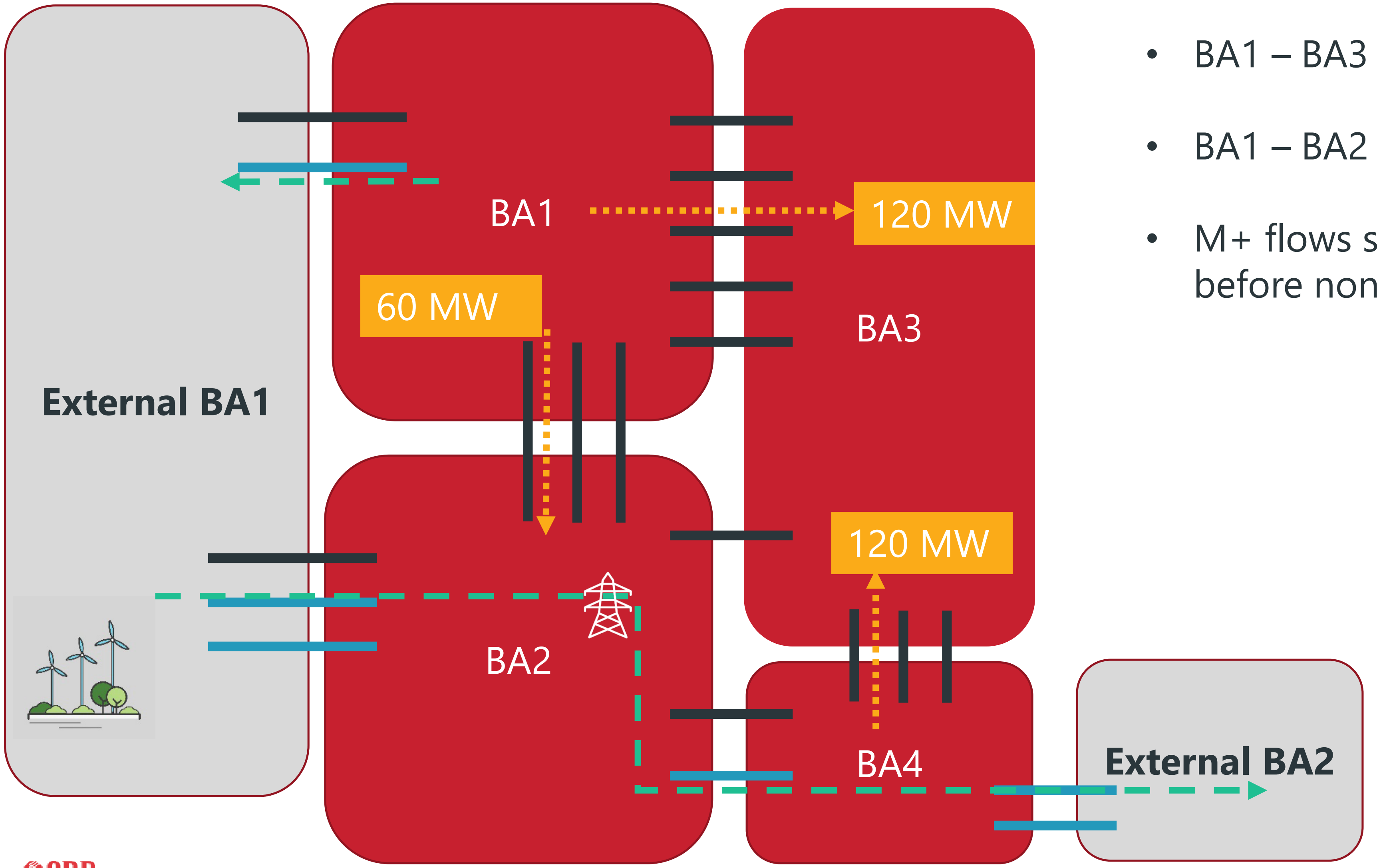

- BA1 – BA3 has 500 MW Capacity
- Day Ahead transmission usage should be considered firm to support market assurance.
- An uncertainty factor (20% in this example) is proposed to ensure market dispatch assurance
- DAMKT + uncertainty should be counted as firm transmission
- Market will re-dispatch automatically for congestion, this is just for accounting for transmission sales

# EXAMPLE – DAY AHEAD TRANSMISSION RIGHTS



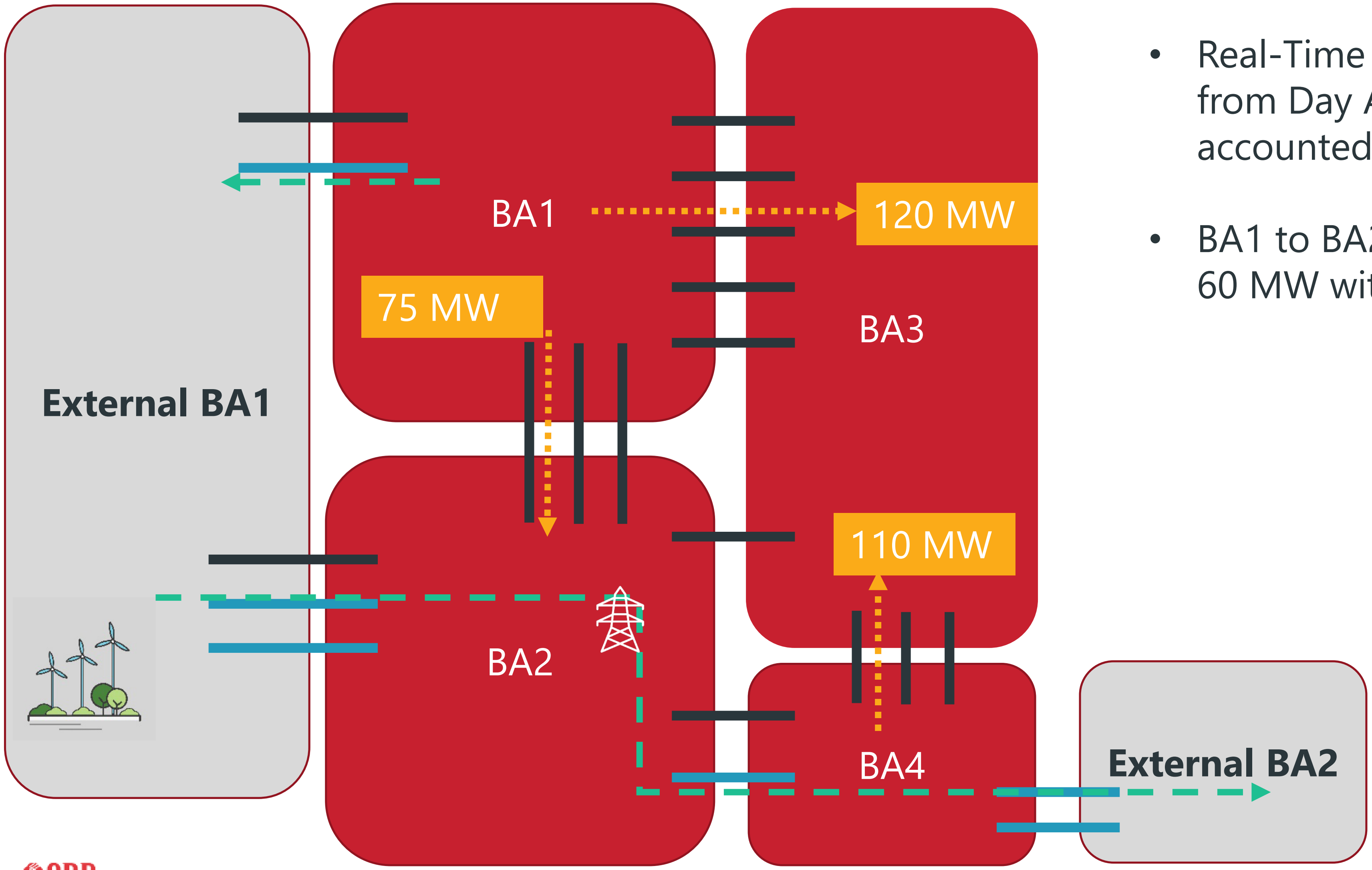

- Assume this factor is 20% for this example
- BA1 – BA3
  500 MW Capacity – (100 MW DAMKT * 1.2) = 380 MW
- The TSP can continue to sell from this 380 MW if desired
- Uncertainty Factor will be studied for optimal reliability and economics

# EXAMPLE – DAY AHEAD TRANSMISSION RIGHTS



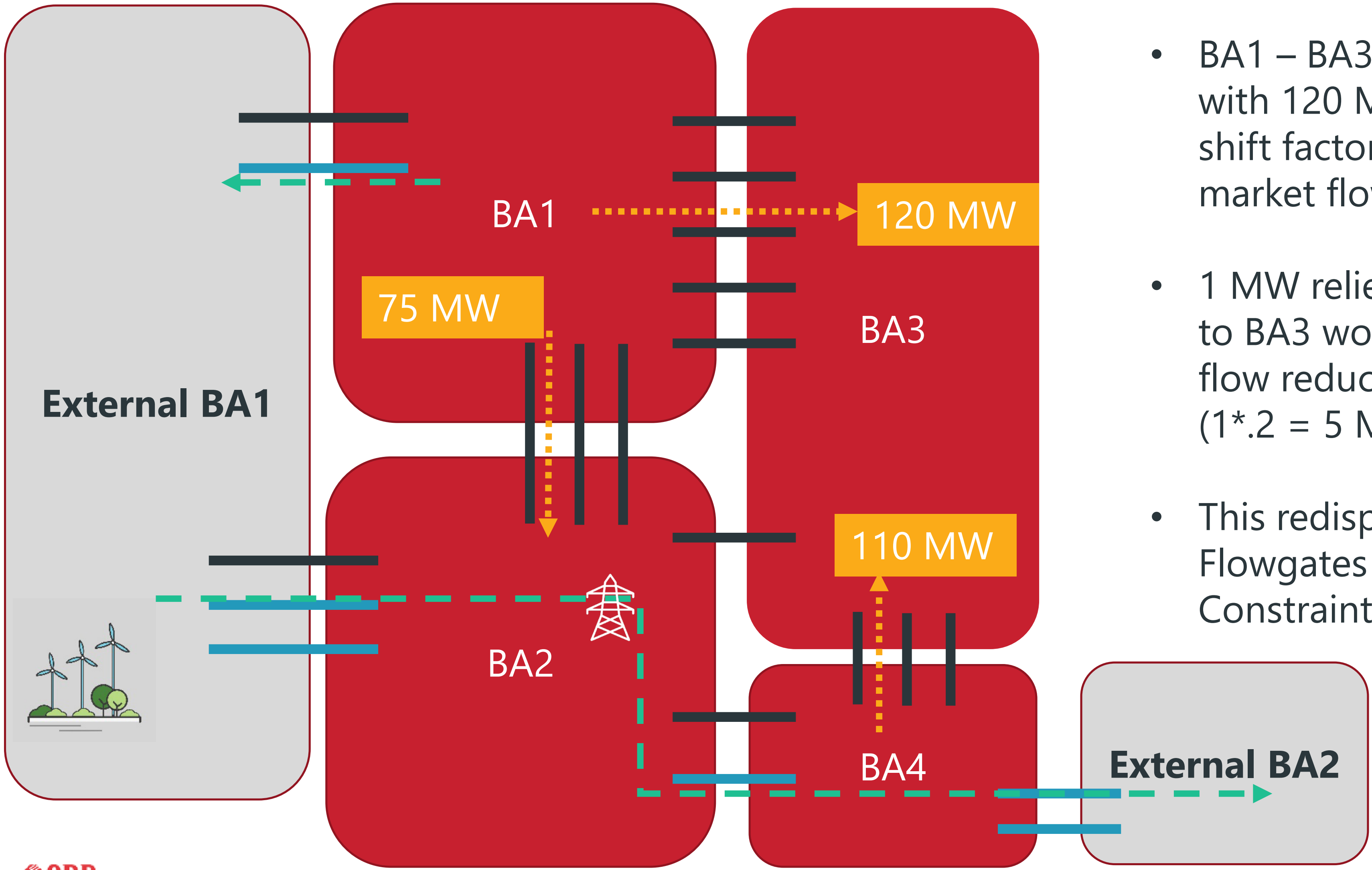

- BA1 – BA3 Reservation is 120 MW
- BA1 – BA2 Reservation is 60 MW
- M+ flows should be stacked as firm before non-firm sales

# EXAMPLE – REAL-TIME TRANSMISSION RIGHTS



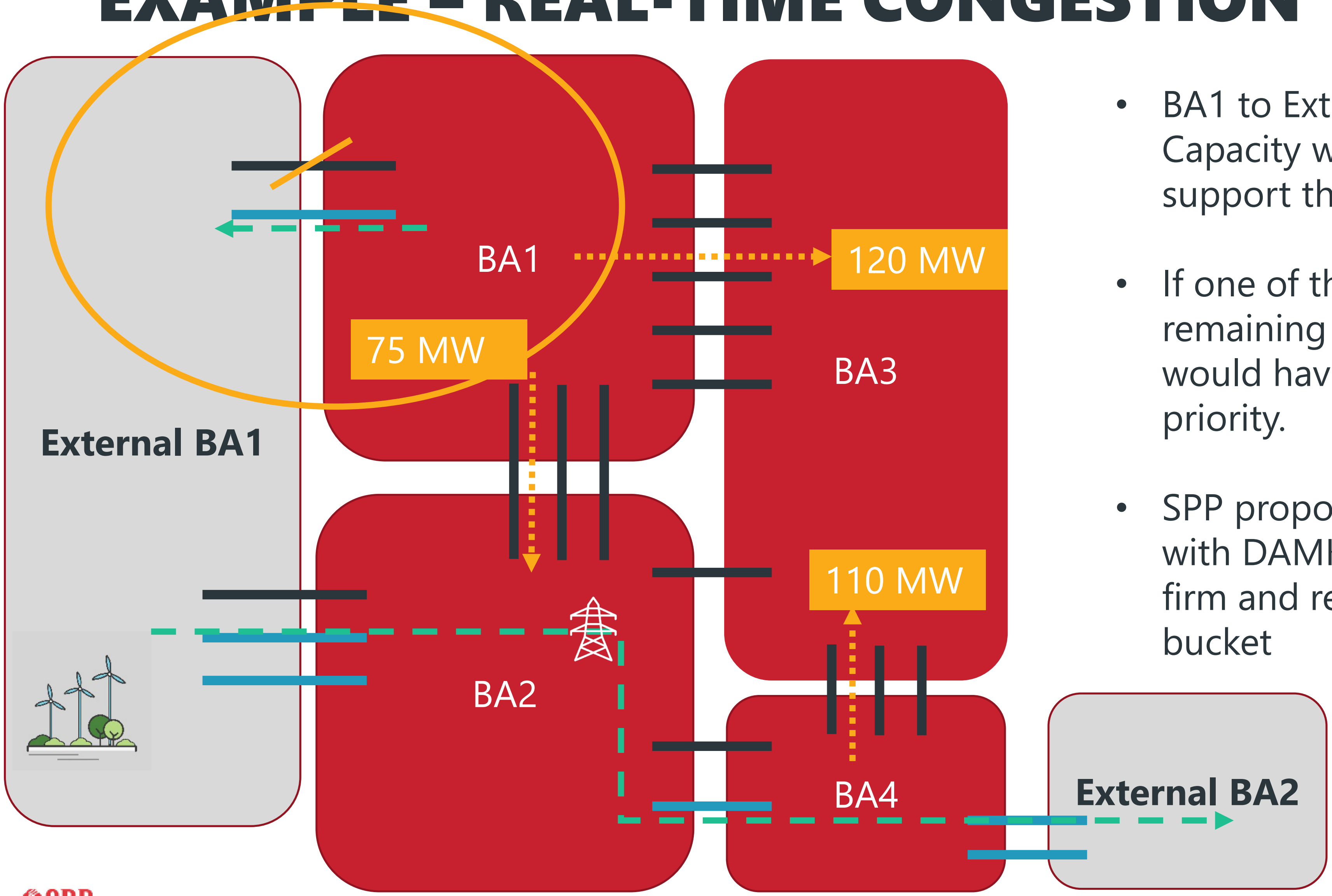

- Real-Time Market Flow difference from Day Ahead should be accounted as firm if available
- BA1 to BA2 DAMKT reservation was 60 MW with 75 MW in real time

# EXAMPLE – REAL-TIME CONGESTION




- BA1 – BA3 had 500 MW Capacity with 120 MW Flow. Assume equal shift factor to each line for 24 MW market flow
- 1 MW relief on elements from BA1 to BA3 would require 5 MW market flow reduction (1*.2 = 5 MW)
- This redispatch is controlled by N-1 Flowgates and Service Flow Constraints

# EXAMPLE – REAL-TIME CONGESTION



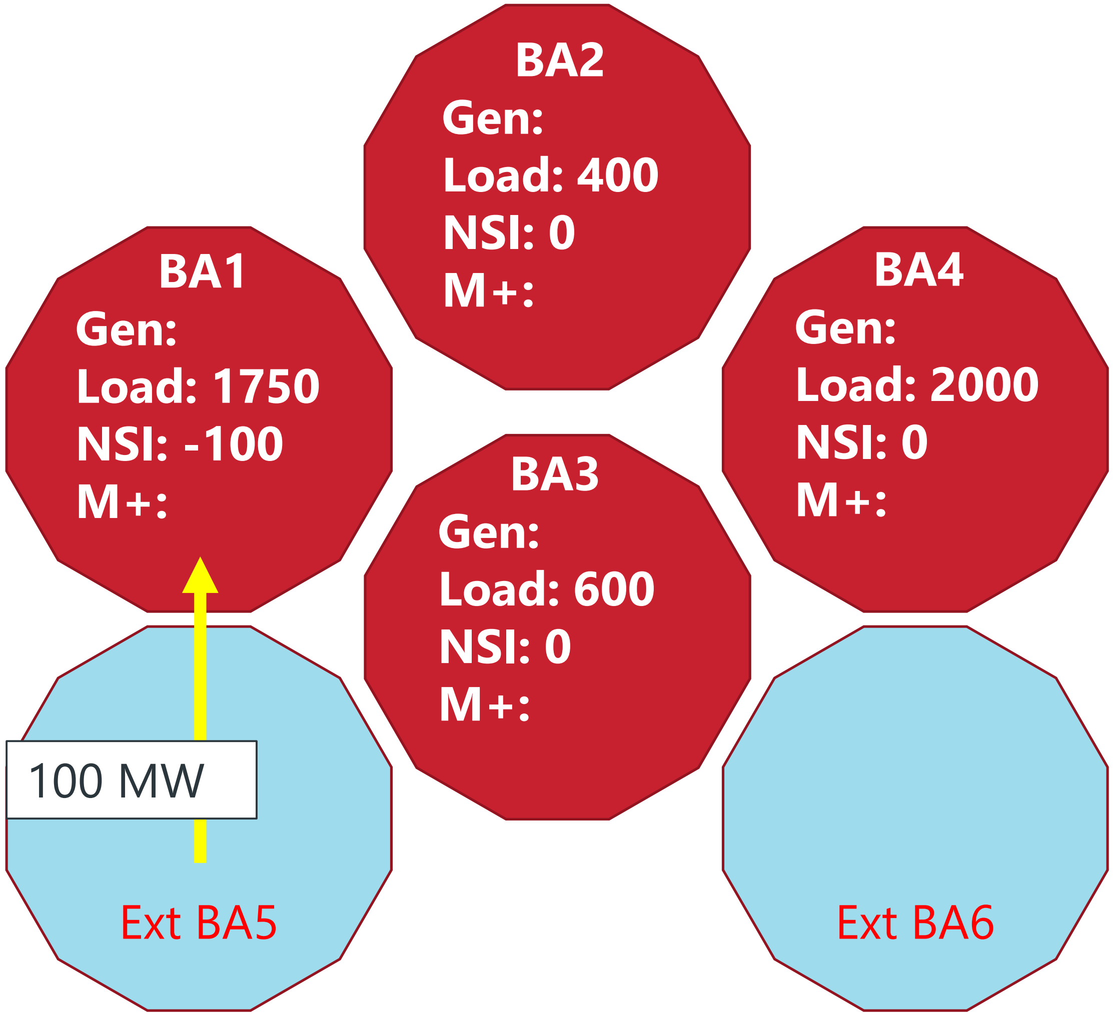

- BA1 to External BA1 had 200 Capacity with 100 MW sold to support the Export
- If one of the elements trip and the remaining capacity is 0, Markets+ would have to redispatch based on priority.
- SPP proposes TSR based allocation with DAMKT transfers considered firm and real-time in the non-firm bucket

# IMPORTS

SCHEDULES INTO THE MARKETS+ BOUNDARY

# IMPORT EXAMPLE 1

- Import Schedule from Ext BA5 to BA1 for 100 MW at $30 / MWH
- Markets+ views this as a total decrement to the total obligation.
- Obligation = Load + NSI
  =(1750+400+2000+600-100)
  =4,650 MW
- Markets+ determines the most economic generation to meet this obligation



# IMPORT EXAMPLE 1

- Import Schedule from Ext BA5 to BA1 for 100 MW
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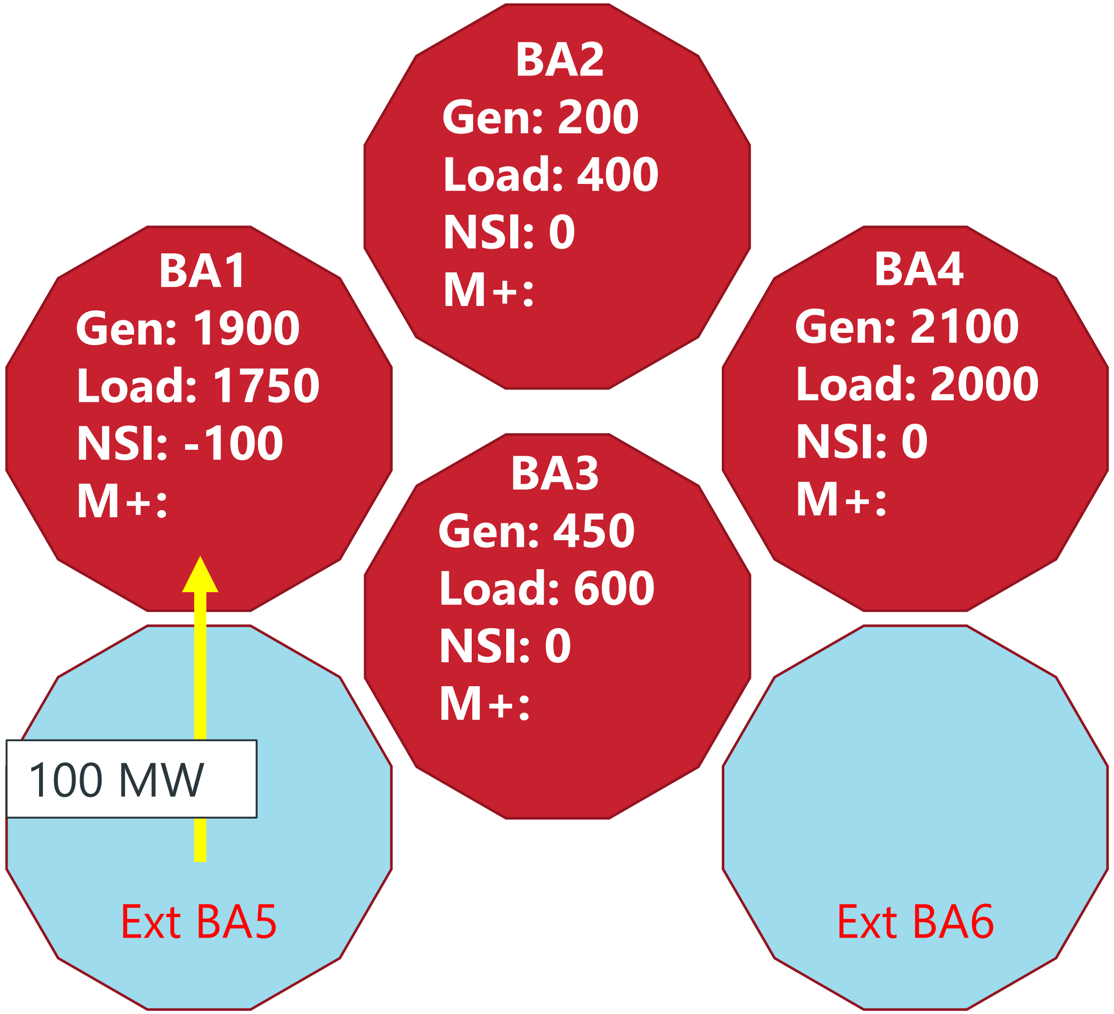
  =4,650 MW
- Markets+ determines the most economic generation to meet this obligation
- Generation = Obligation

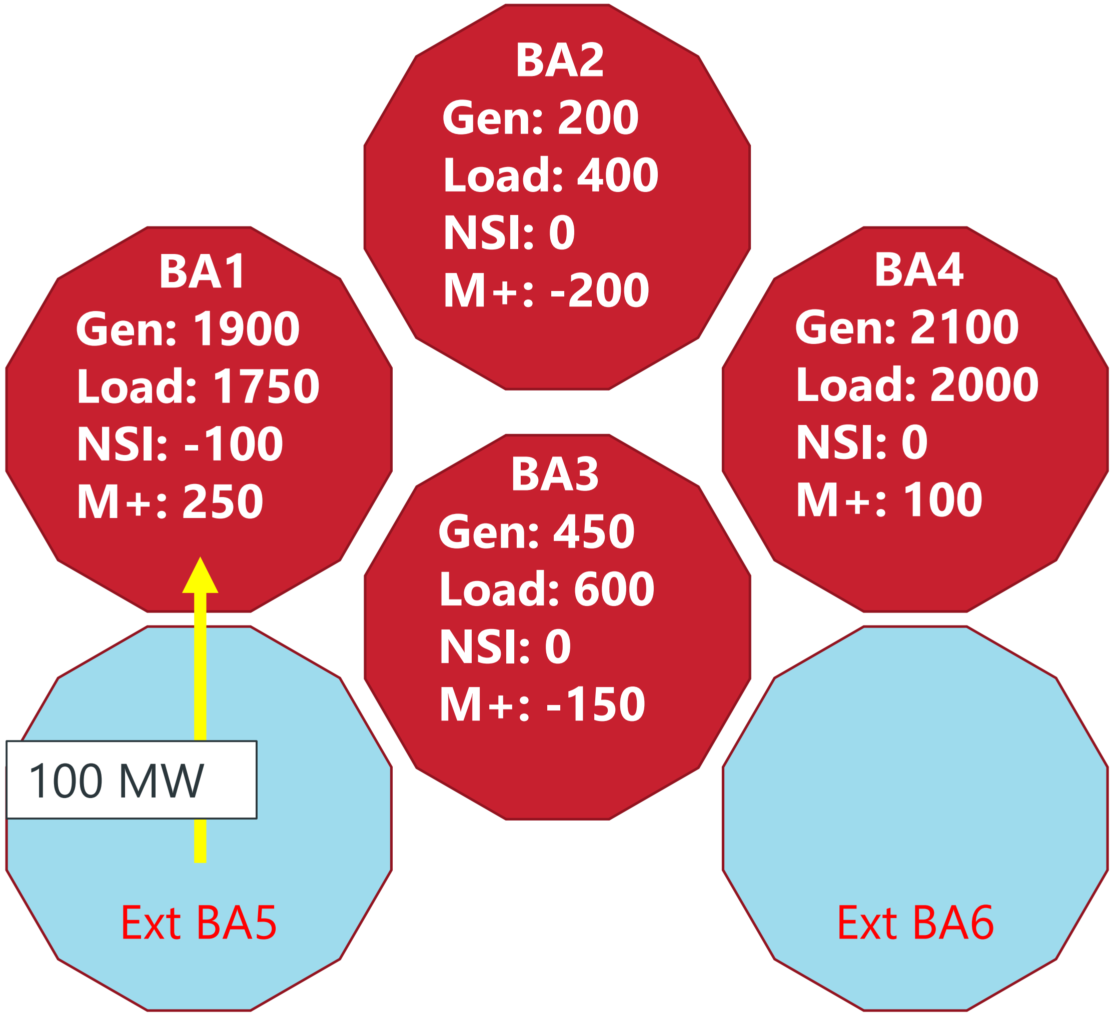


# IMPORT EXAMPLE 1

- Markets+ Energy (M+) accounts for the energy transferred between participating BAs for market activity.

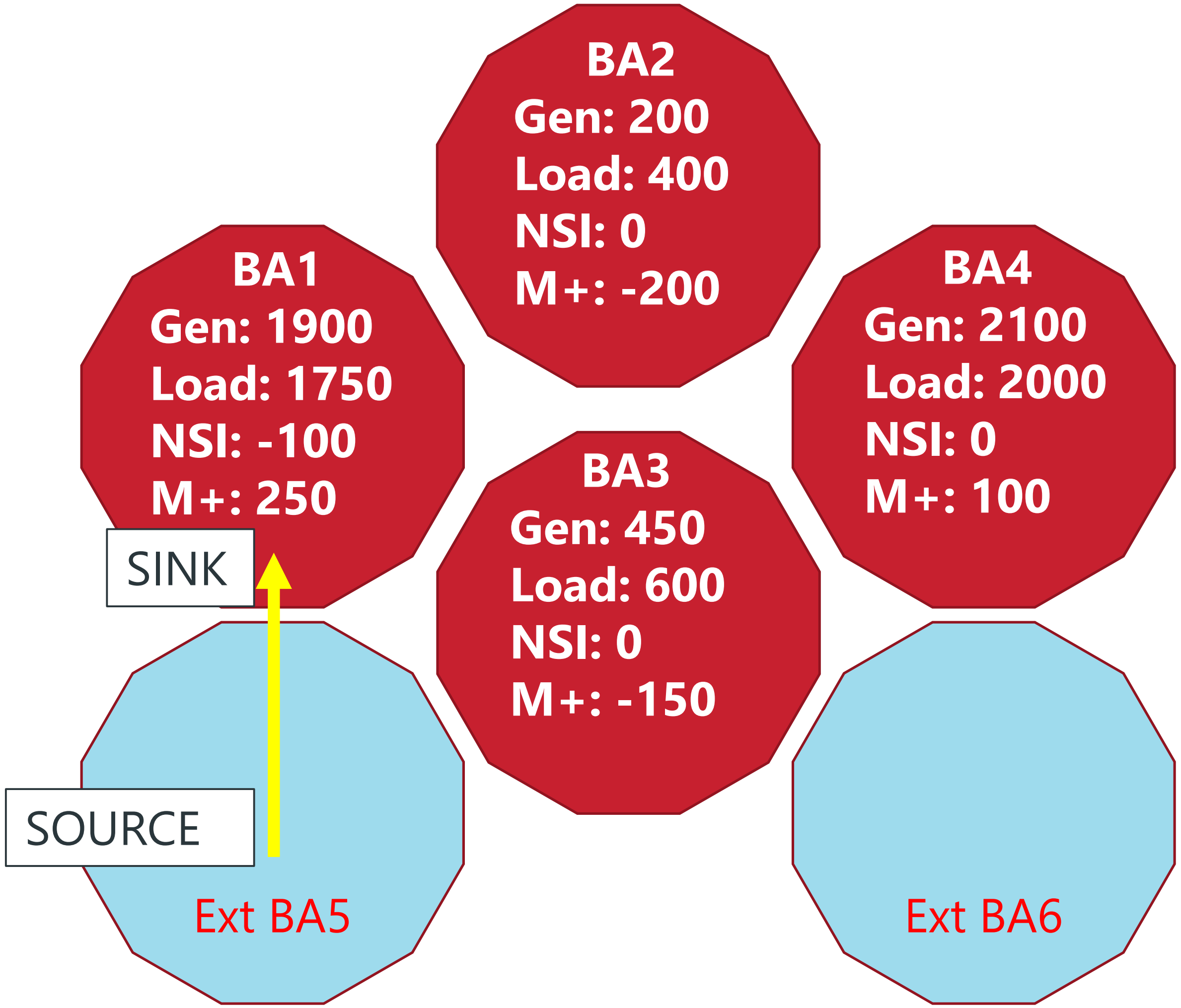
- M+ is a dynamic schedule

- Calculated after economic dispatch
  For BA1
  M+ = Gen-(Load+NSI)
  = 1900-(1750-100)
  = 250 MW



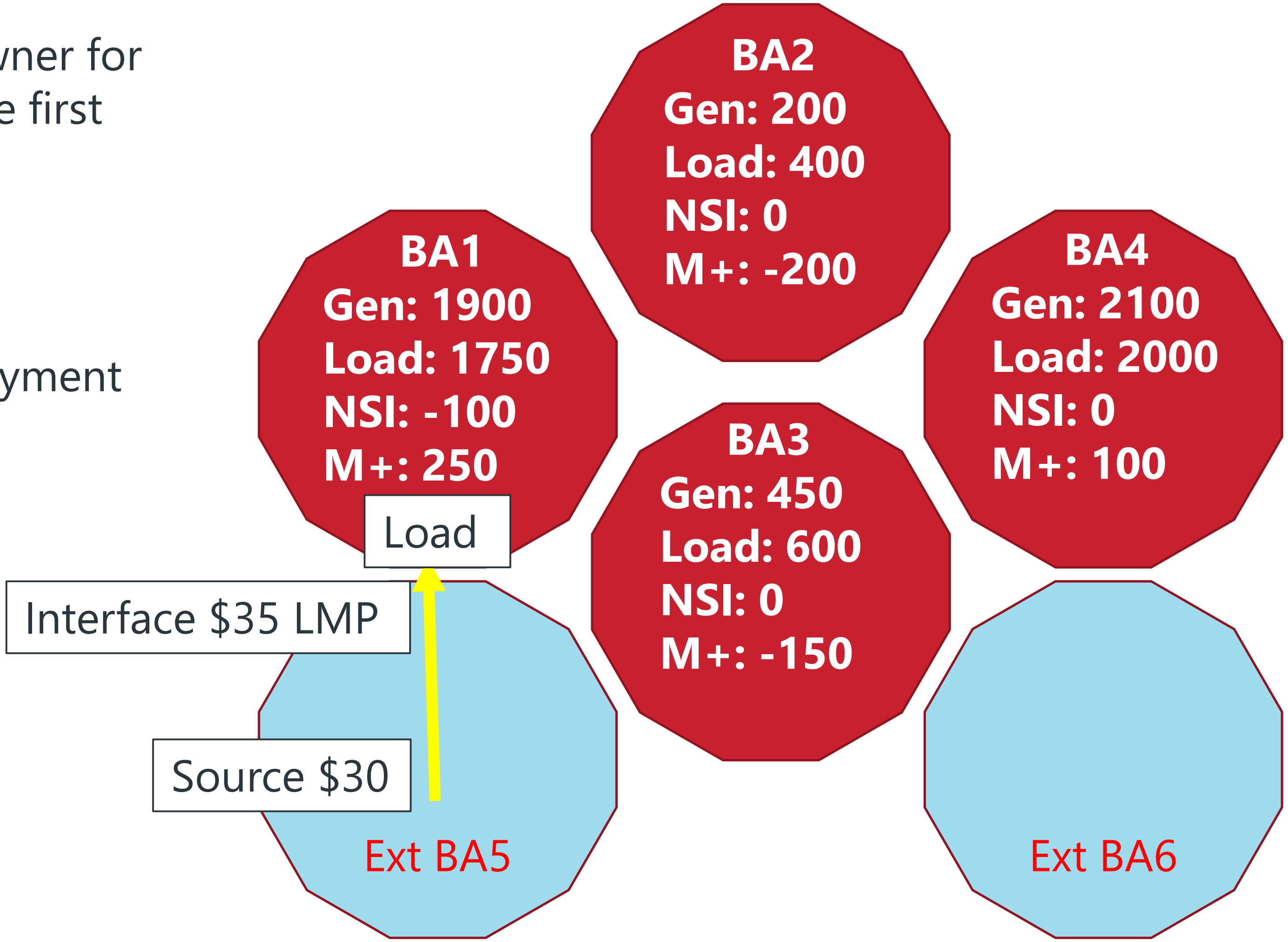
# IMPORT EXAMPLE 1 - TRANSMISSION

- Market Transmission Service (MTS) compensates for transmission usage
- The PSE of the import from Ext BA5 to BA1 is responsible for procuring transmission service all the way from source to sink.



# IMPORT EXAMPLE 1 – SETTLEMENTS

- SPP pays $35 / MWH to the Asset Owner for import based on interface price of the first POR that is in a Markets+ BA.
- SPP calculates the interface price
- PSE is responsible for the contract payment of $30 / MWH



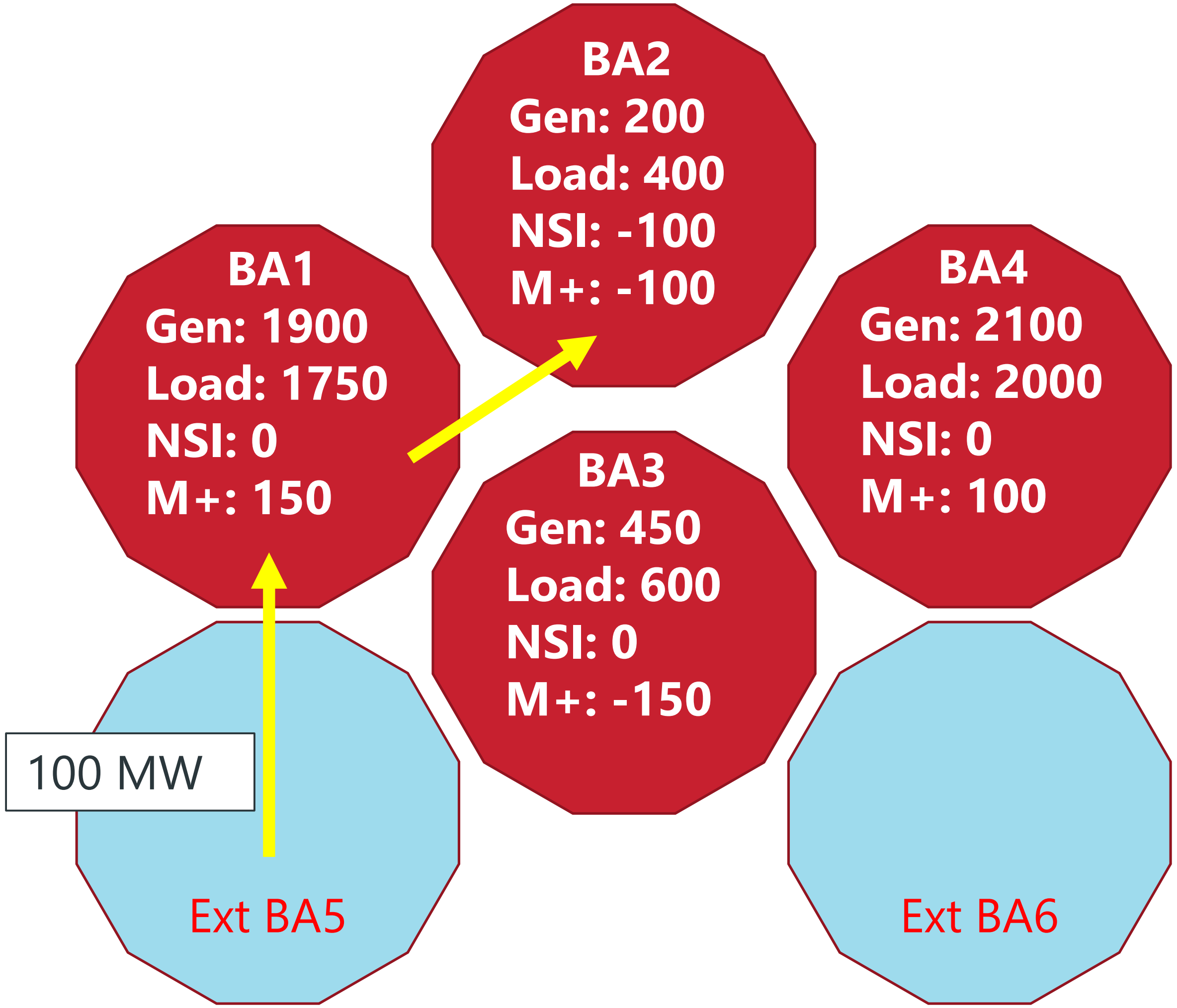
# IMPORT EXAMPLE 2

- Import Schedule from Ext BA5 to BA2 for 100 MW

- Markets+ views this as a total decrement to the total obligation.

- Obligation = Load + NSI
  =(1750+400+2000+600-100)
  =4,650 MW

- Markets+ determines the most economic generation to meet this obligation

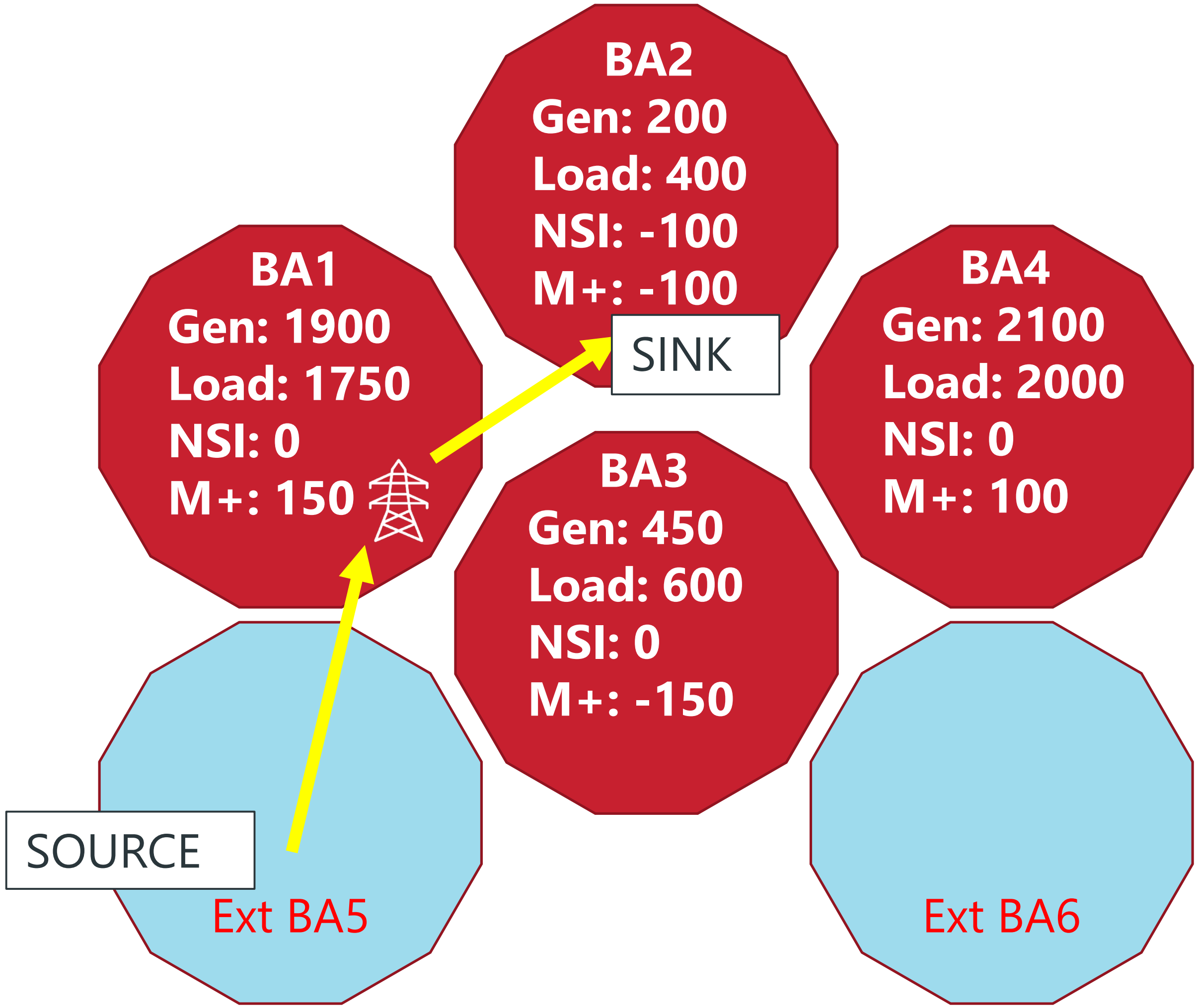


# IMPORT EXAMPLE 2 - TRANSMISSION

- Import Schedule from Ext BA5 to BA2 for 100 MW

- Market Transmission Service (MTS) compensates for transmission usage

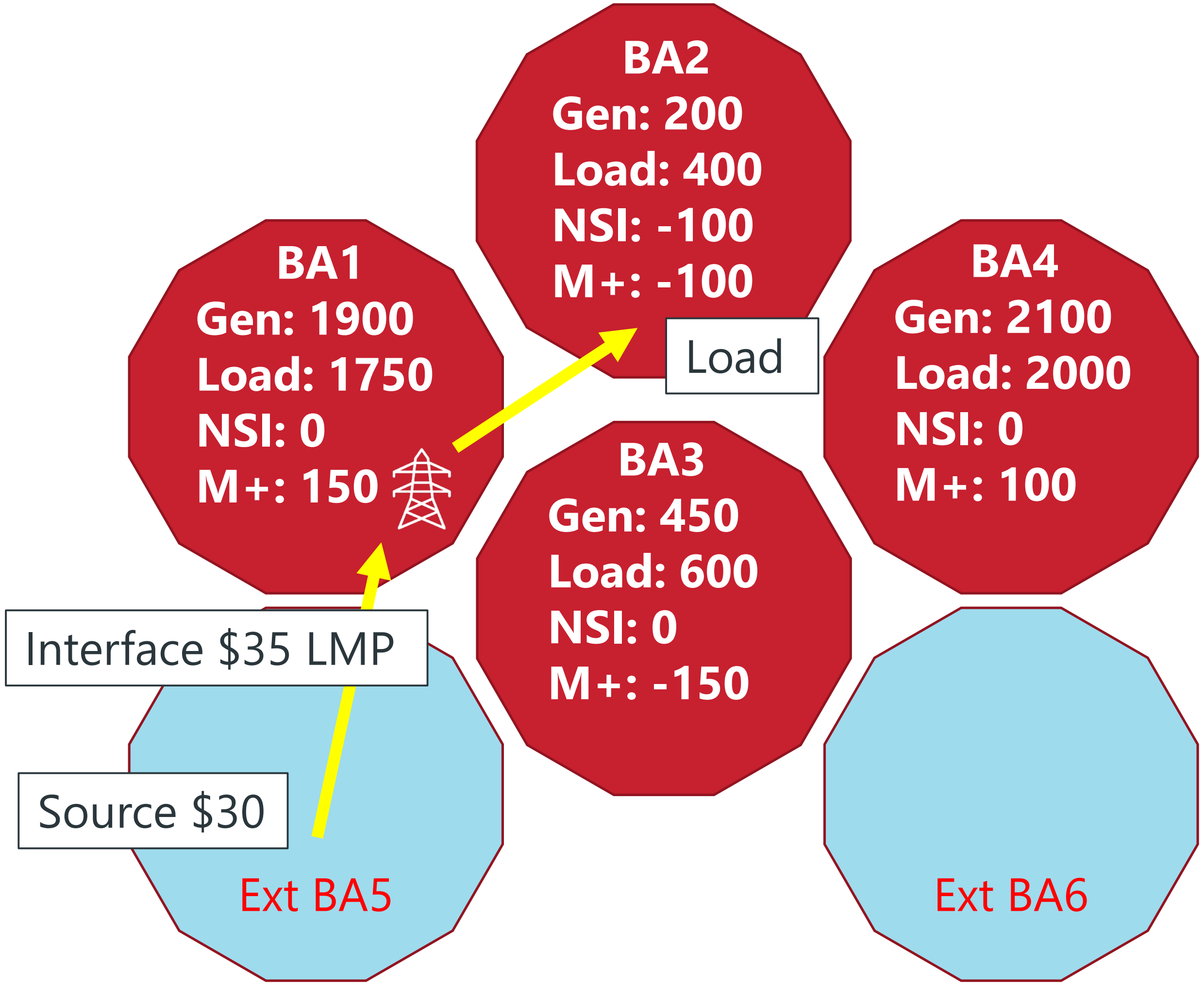
- The PSE of the import from Ext BA1 to BA2 is responsible for procuring transmission service all the way from source to sink.



# IMPORT EXAMPLE 2

- Import Schedule from Ext BA5 to BA2 for 100 MW

- There is only 1 Markets+ settlement at the interface where the first POR is a Markets+ participant.

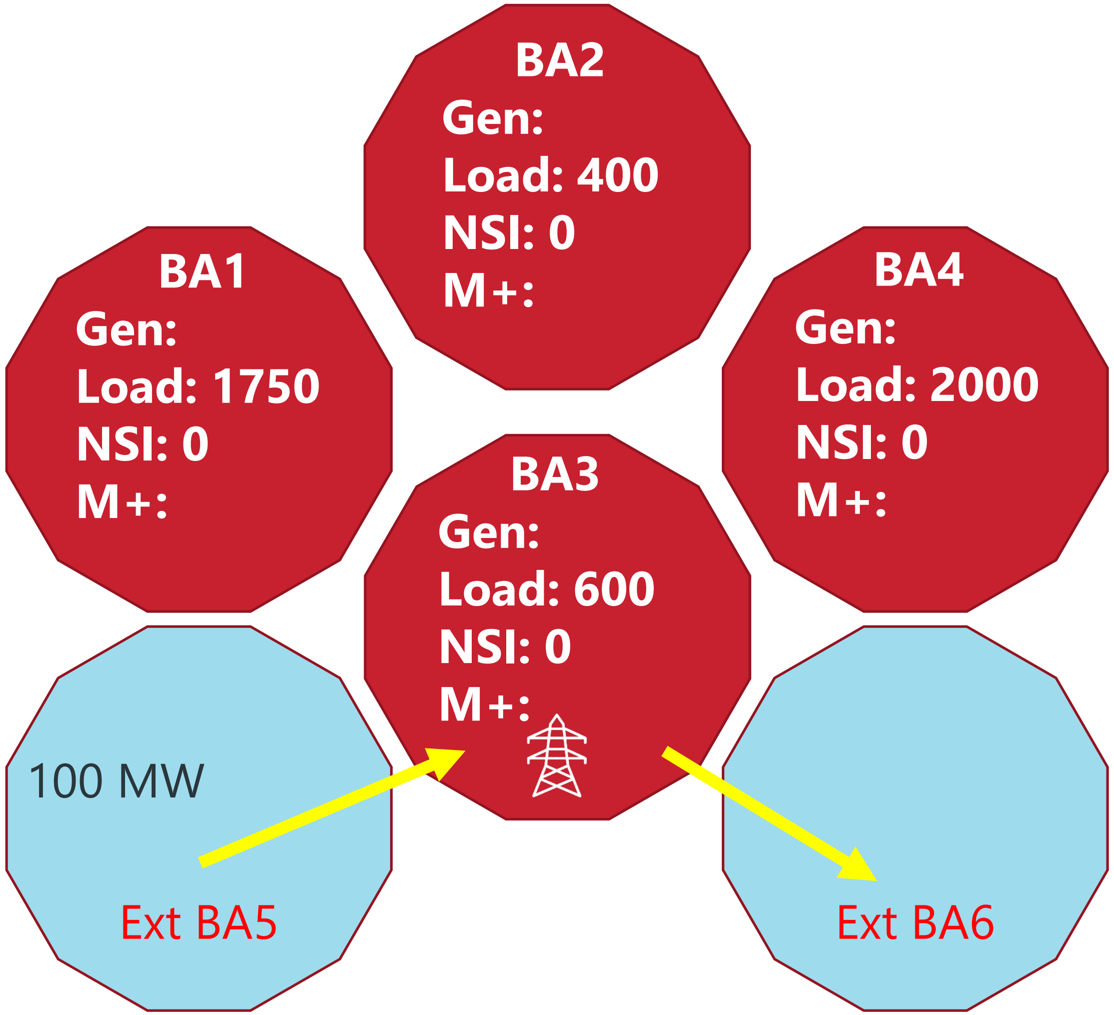


# WHEELS

SCHEDULES THROUGH THE MARKETS+ BOUNDARY

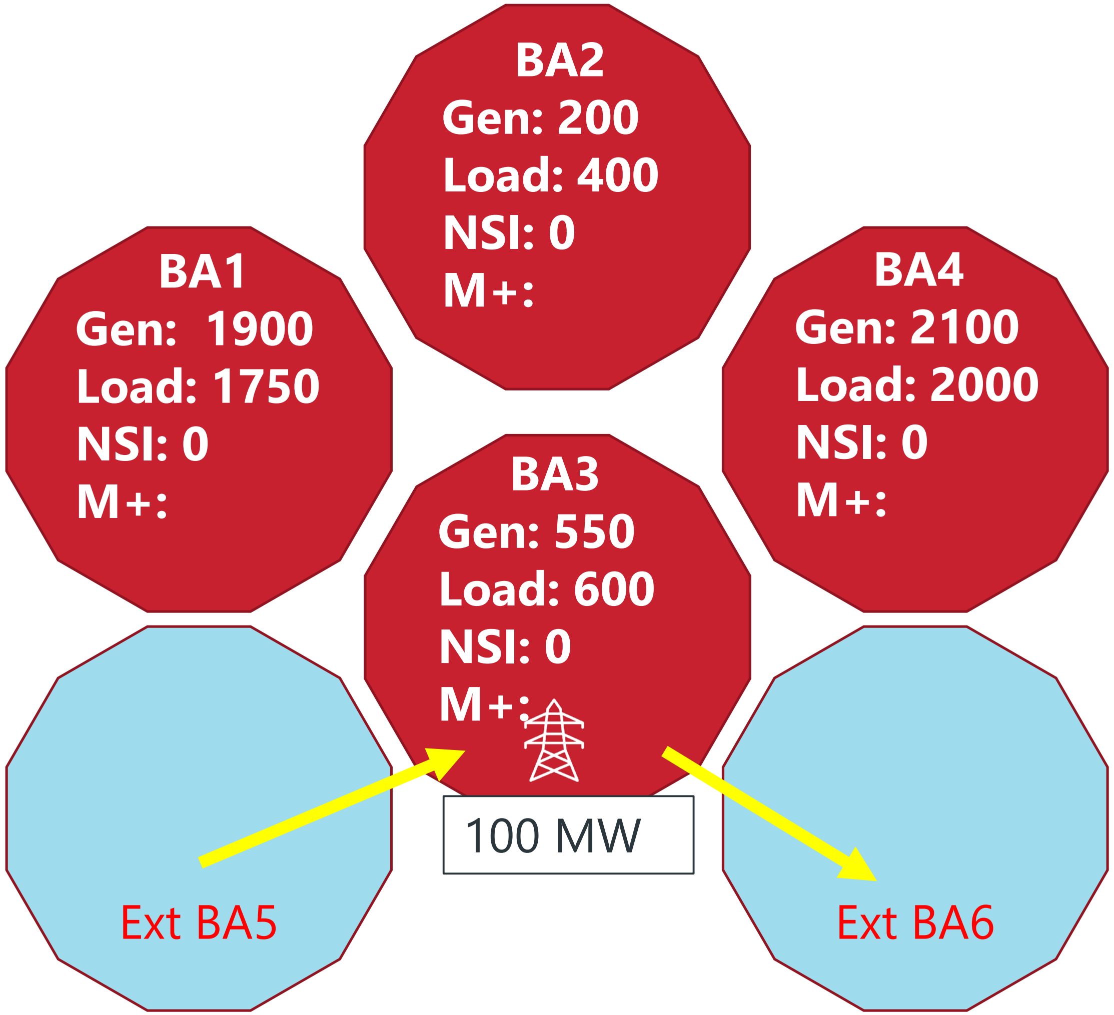
# WHEELS THROUGH MARKETS+ EXAMPLE

- Ext BA5 schedule to Ext BA6 for 100 MW
- Markets+ views this as two separate schedules. This has no net impact to the total obligation.
- Obligation = Load + NSI
  =(1750+400+2000+600)
  =4,750 MW
- Markets+ determines the most economic generation to meet this obligation



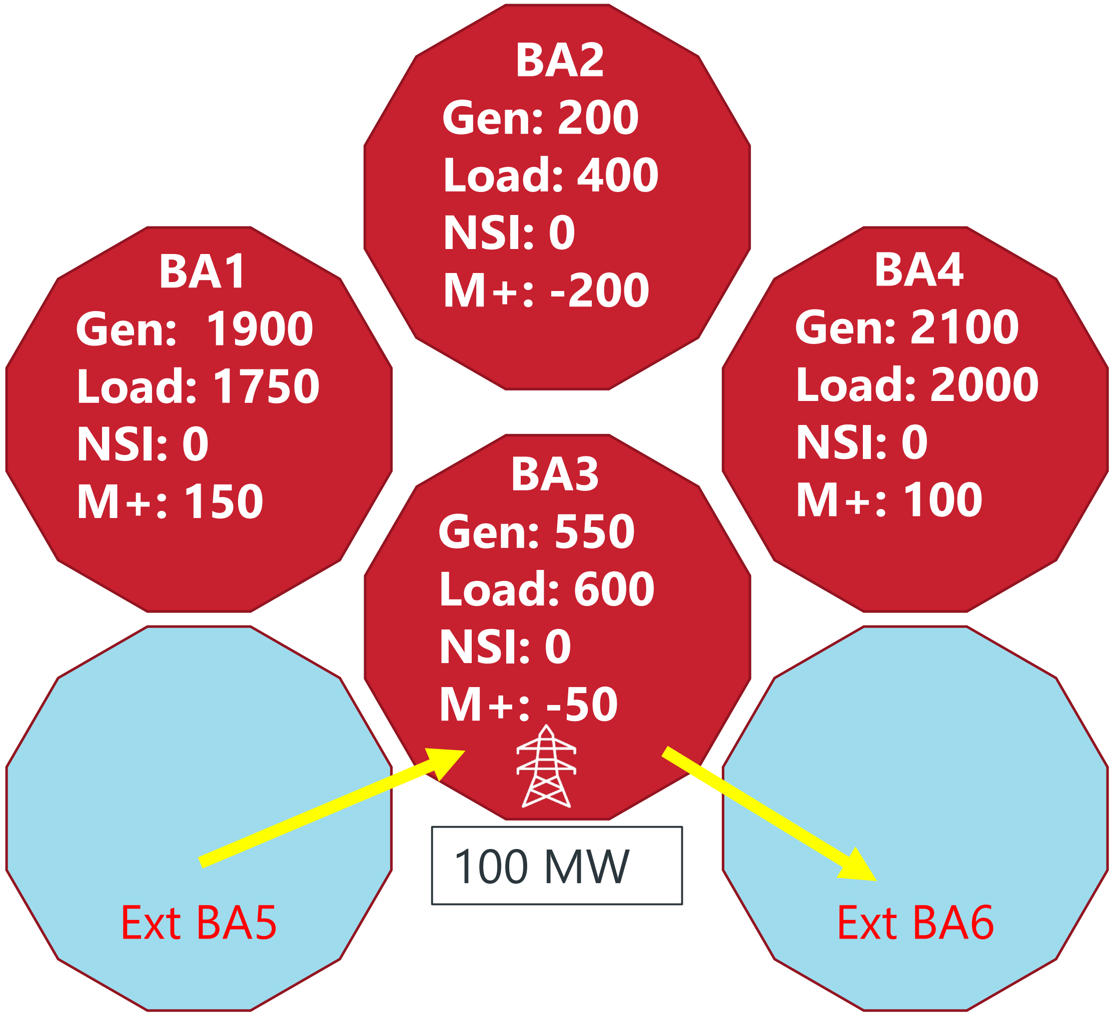
# WHEELS THROUGH MARKETS+ EXAMPLE

- Ext BA5 schedule to Ext BA6 for 100 MW
- Markets+ views this as two separate schedules. This has no net impact to the total obligation.
- Obligation = Load + NSI
  =(1750+400+2000+600)
  =4,750 MW
- Markets+ determines the most economic generation to meet this obligation
- Generation = Obligation



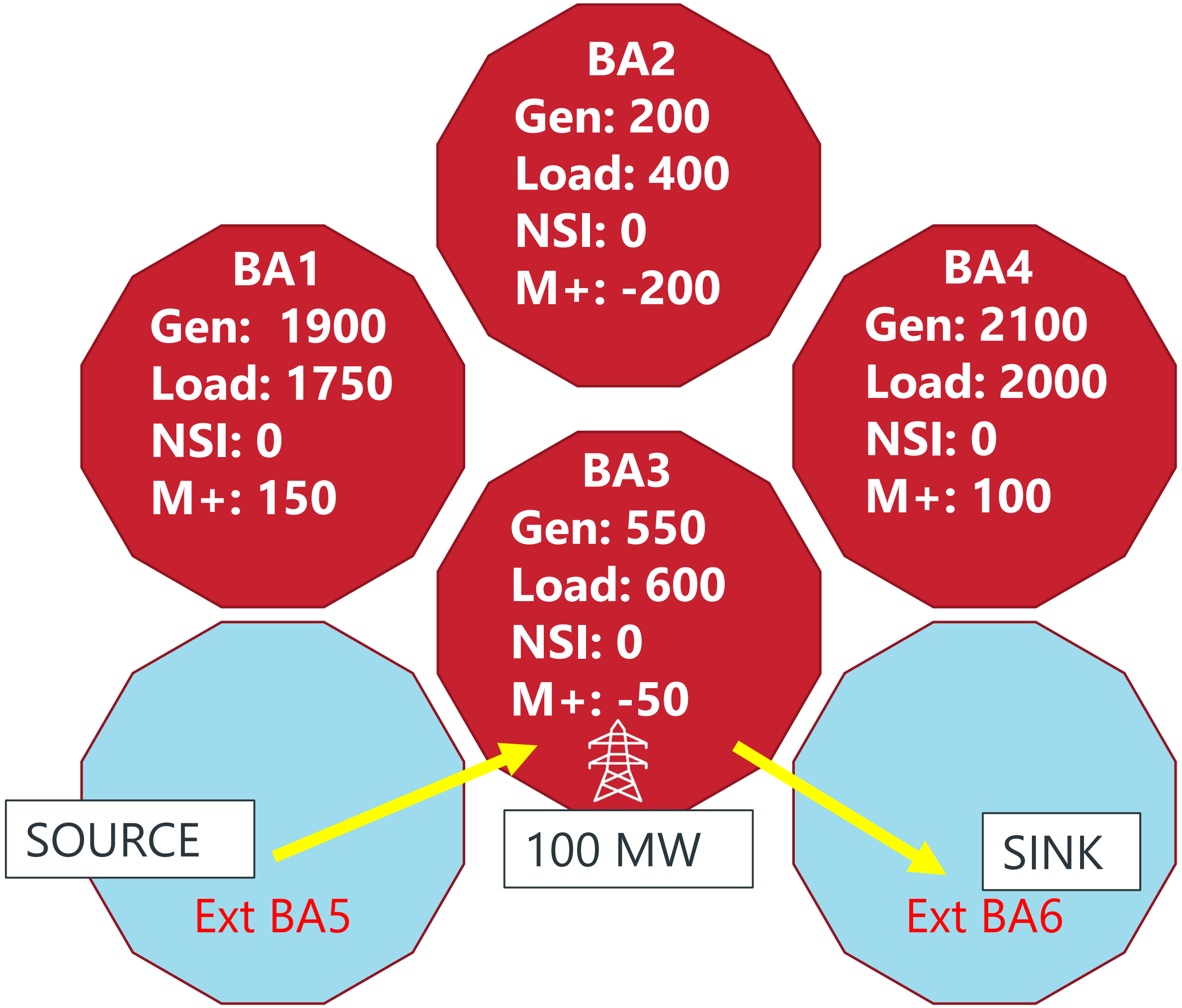
# WHEELS THROUGH MARKETS+ EXAMPLE

- Ext BA5 schedule to Ext BA6 for 100 MW
- Market Energy (M+) is calculated for each BA as Gen - (Load+NSI)
- This is the value used to update the dynamic schedule for each Markets+ BA



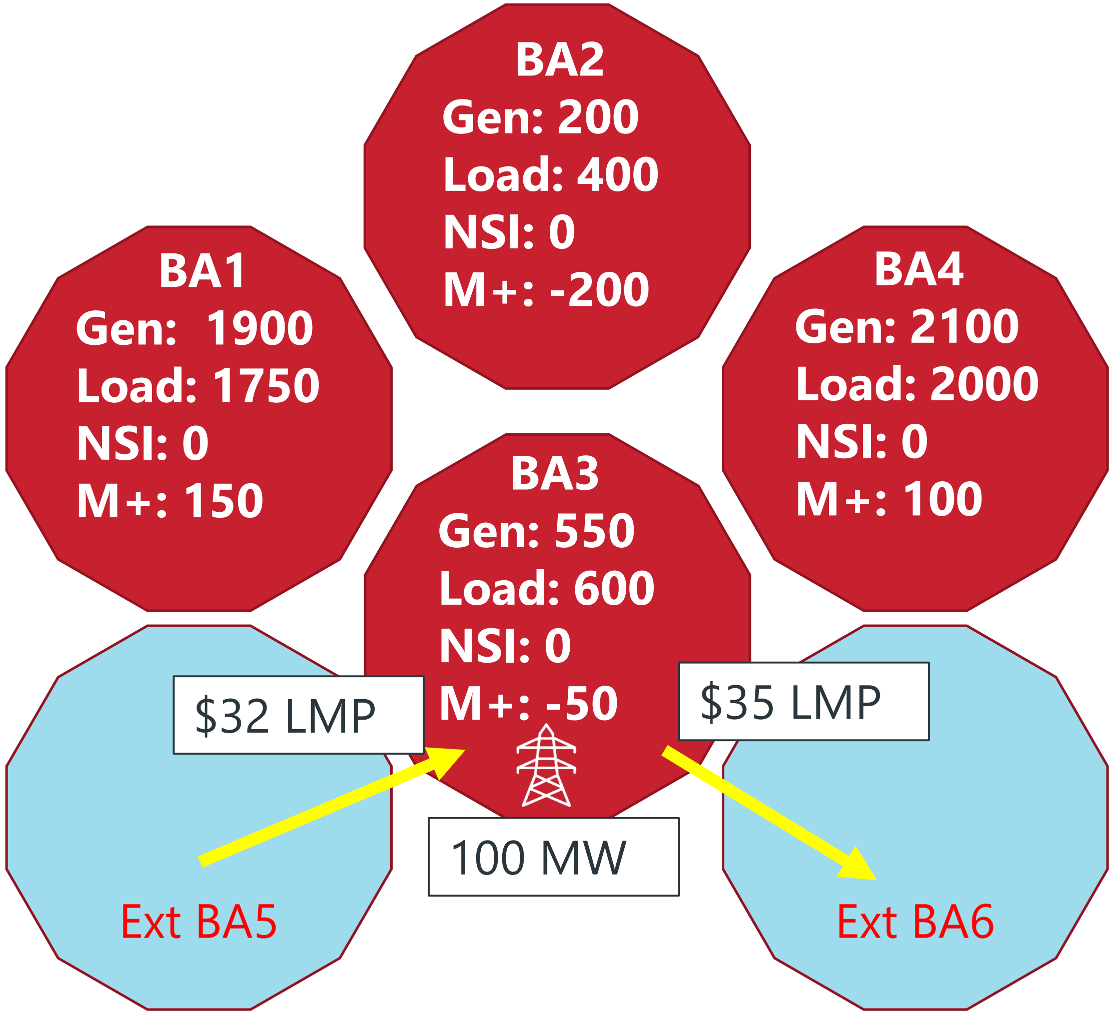
# WHEELS THROUGH MARKETS+ TRANSMISSION

- Ext BA5 schedule to Ext BA6 for 100 MW
- PSE must procure transmission service from source to sink
- Market Transmission Service (MTS) pays for the M+ Energy Transfers to compensate for transmission usage



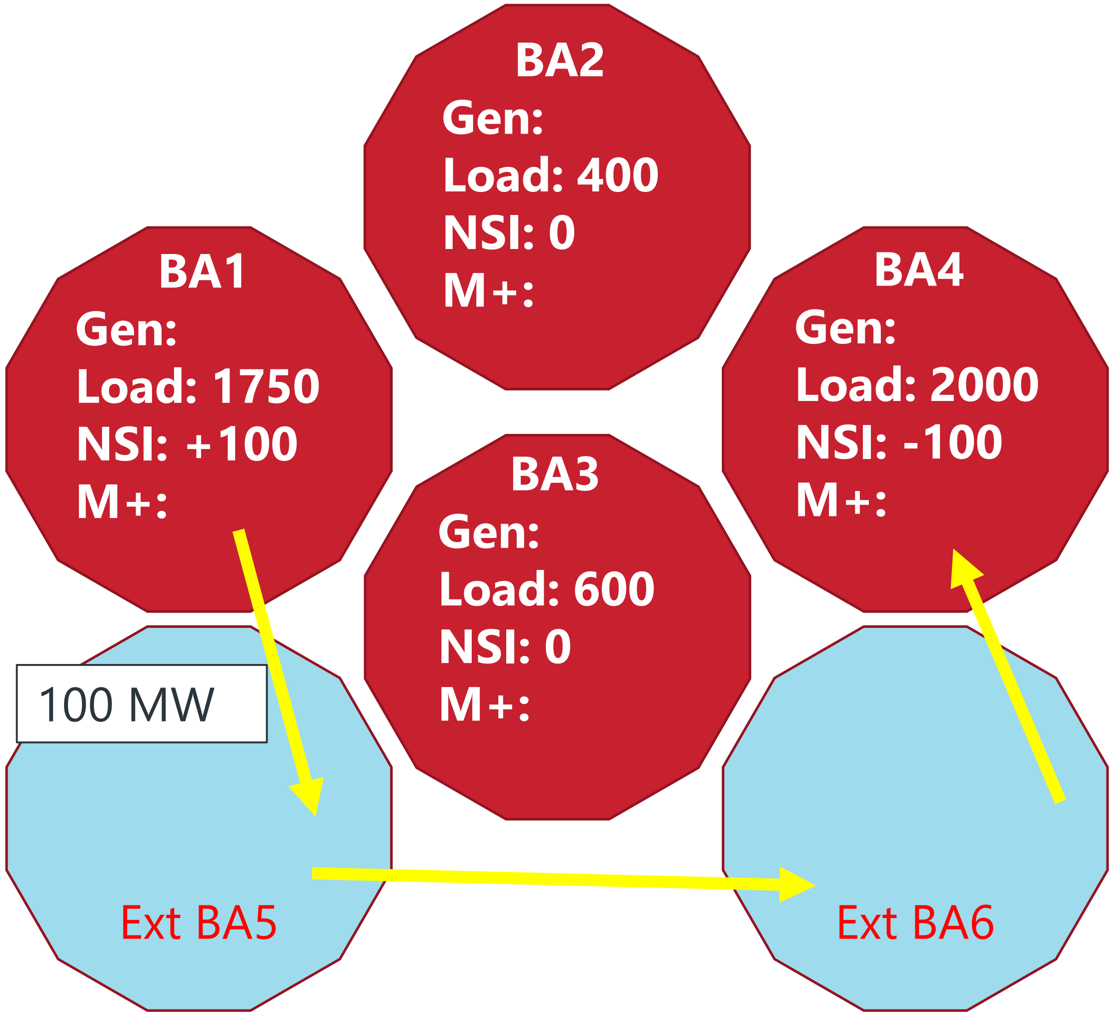
# WHEELS THROUGH MARKETS+ - SETTLEMENTS

- Ext BA5 schedule to Ext BA6 for 100 MW
- SPP Pays Asset Owner $32 / MWH for the import side of the wheel and SPP Charges Asset Owner $35 / MWH for the export based on the calculated interface prices
- PSE settles contract outside of the market with counterparty



# EXTERNAL WHEEL EXAMPLE

- BA1 schedule to BA4 for 100 MW
- Markets+ views this as two separate schedules. An export for BA1 and import for BA4. This has no net impact to the total obligation.
- Obligation = Load + NSI
  =(1750+400+2000+600 +100 - 100)
  =4,750 MW
- Markets+ determines the most economic generation to meet this obligation



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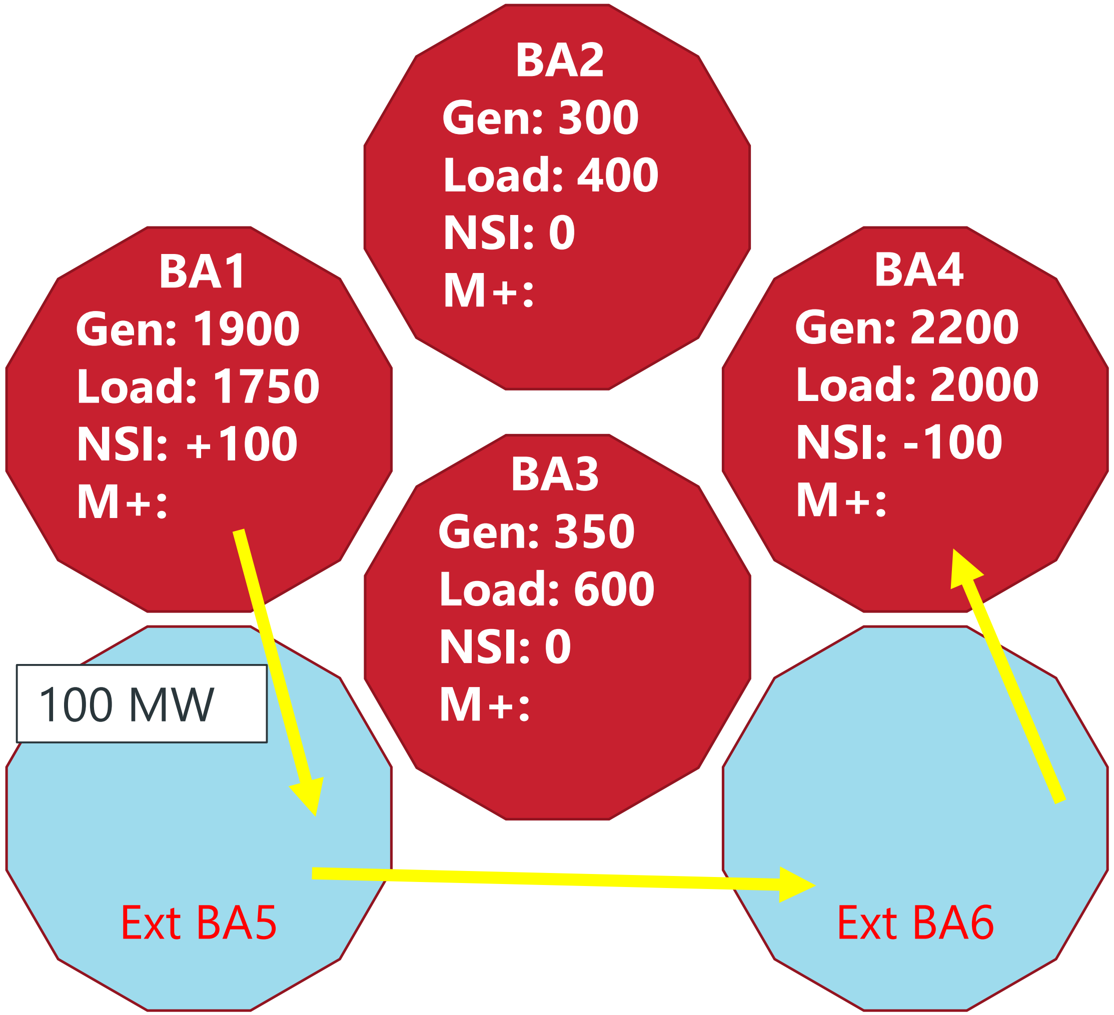
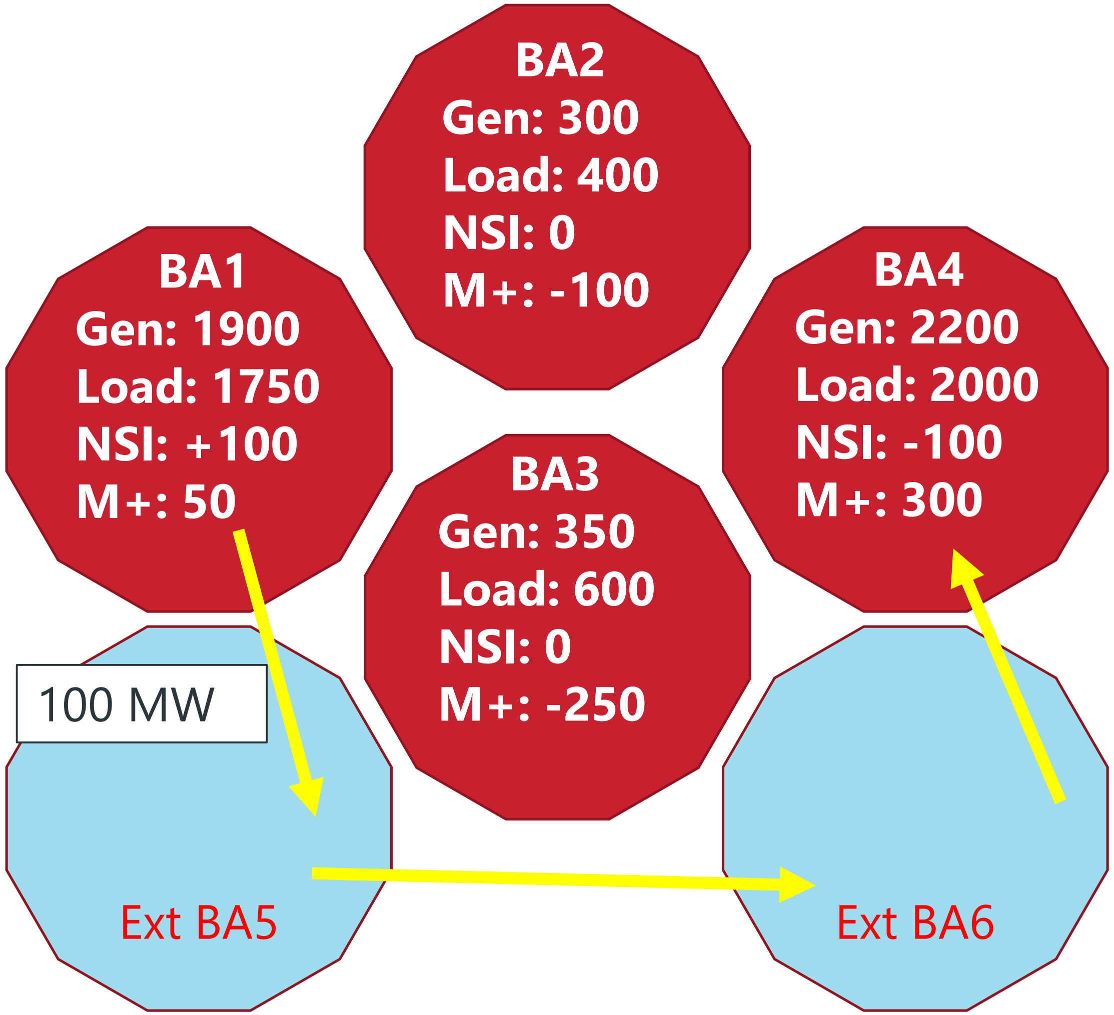
- Obligation = Load + NSI
  =(1750+400+2000+600 +100 - 100)
  =4,750 MW
- Generation = Obligation



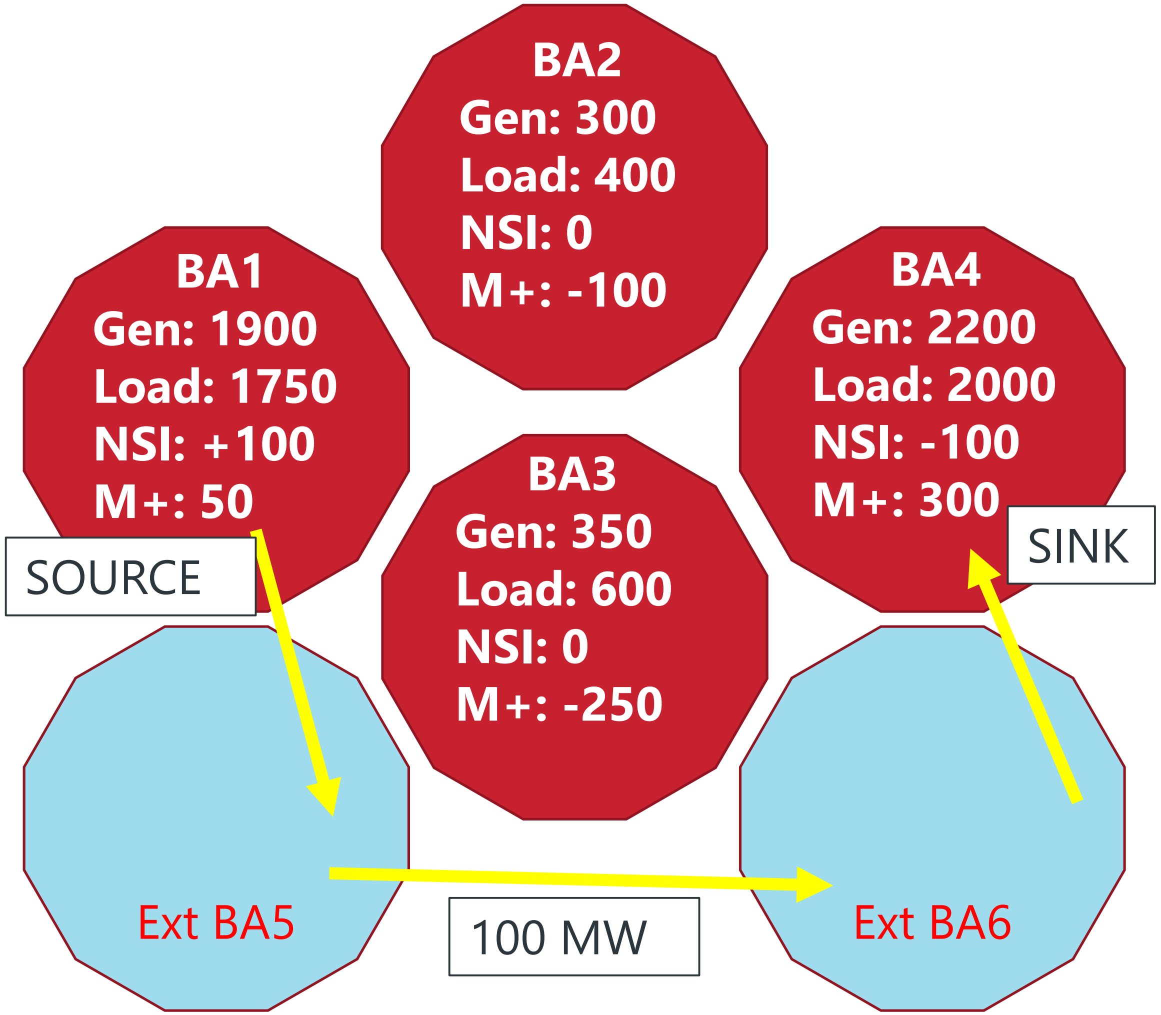
# EXTERNAL WHEEL EXAMPLE

- BA1 schedule to BA4 for 100 MW
- Markets+ Energy is calculated as Gen-(Load+NSI) for each BA
- This is the value used to update the dynamic schedule for each Markets+ BA



# EXTERNAL WHEEL EXAMPLE - TRANSMISSION

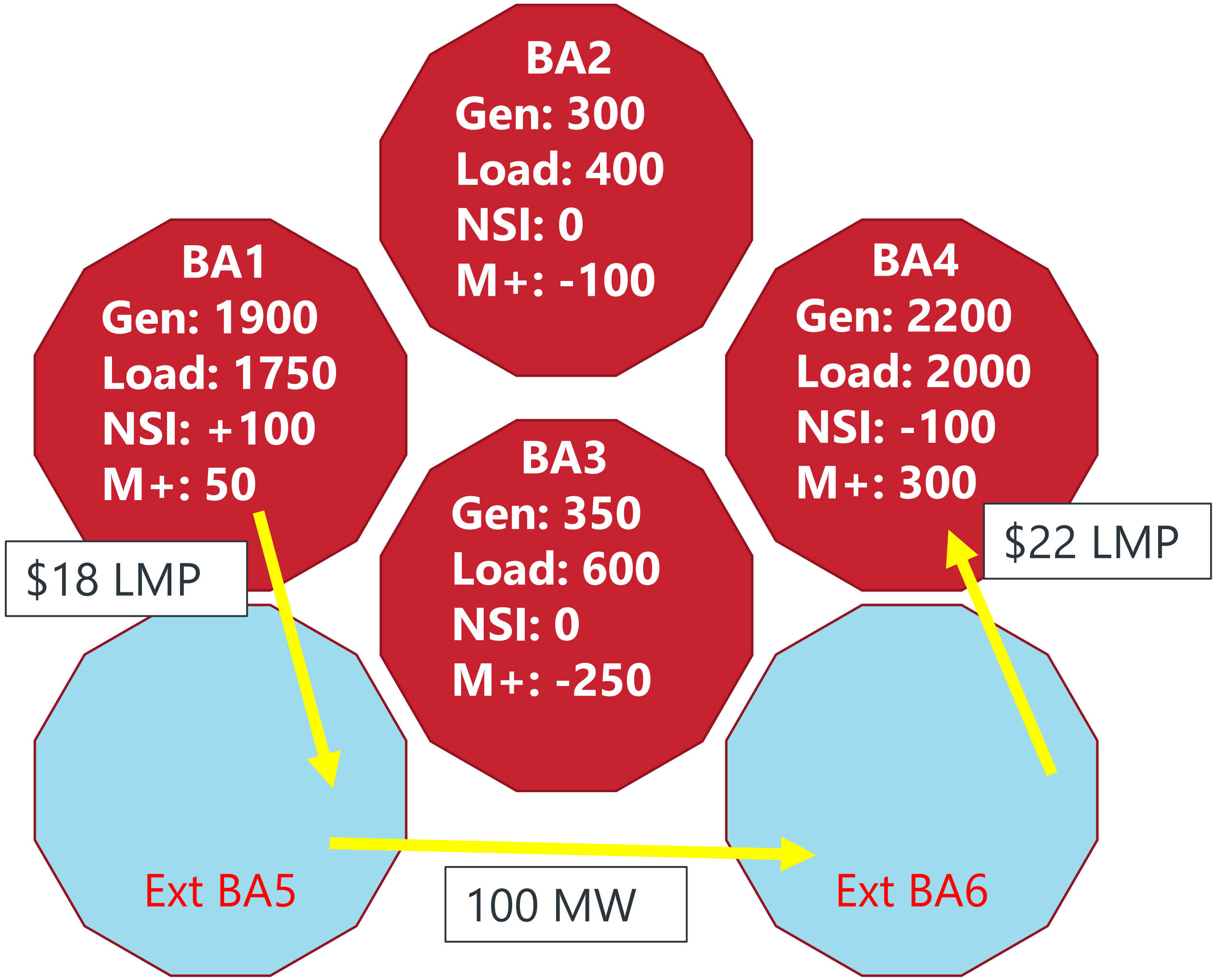
- BA1 schedule to BA4 for 100 MW
- PSE must procure transmission service from source to sink
- Market Transmission Service (MTS) pays for the M+ Energy Transfers to compensate for transmission usage



# EXTERNAL WHEEL EXAMPLE - SETTLEMENTS

- BA1 schedule to BA4 for 100 MW

- SPP Charges Asset Owner $18 / MWH for the export side of the wheel and SPP Pays Asset Owner $22 / MWH for the export based on the calculated interface prices



# EXPORTS

SCHEDULES OUT OF THE MARKETS+ BOUNDARY

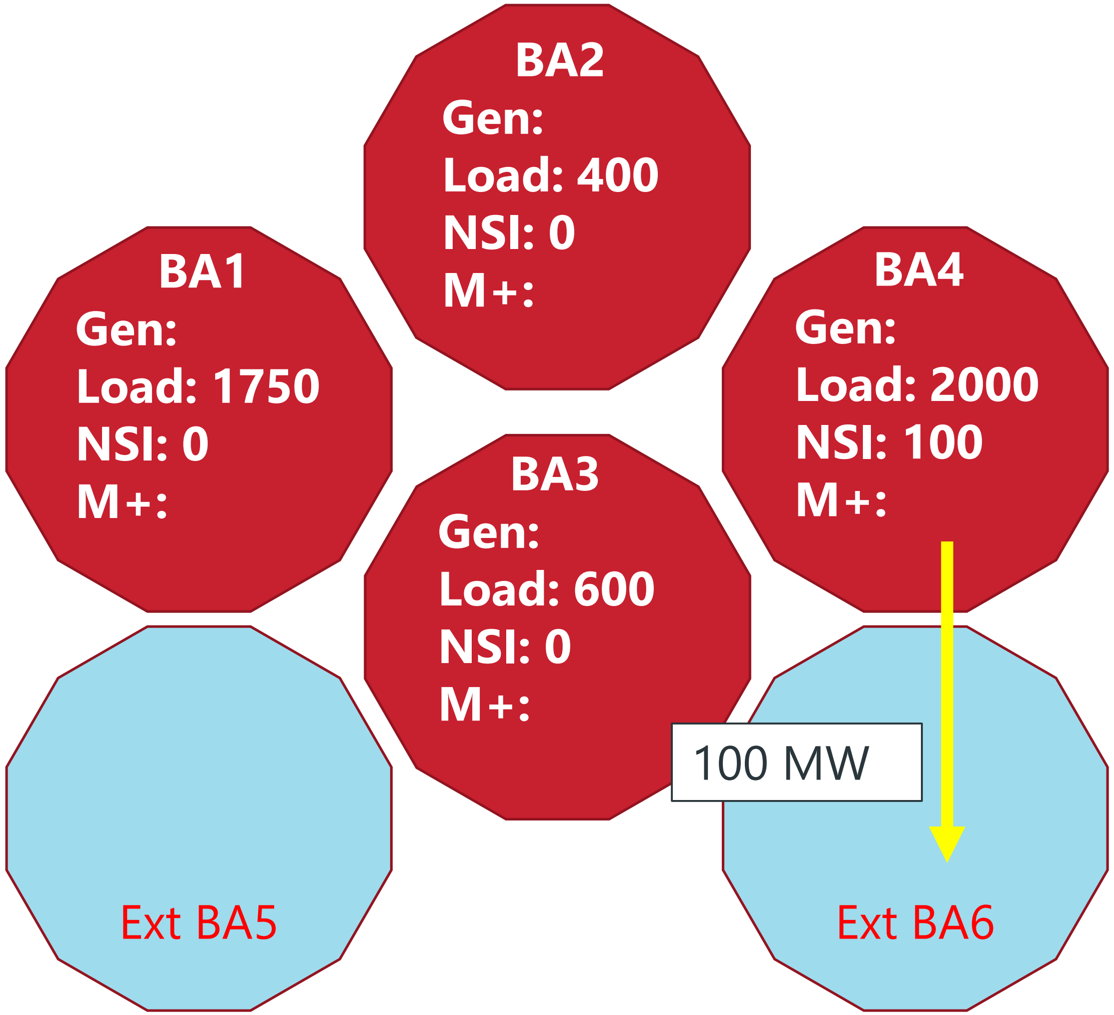
# EXPORT EXAMPLE 1

- Export Schedule from BA4 to Ext BA6 for 100 MW

- Markets+ views this as a total increment to the total obligation.

- Obligation = Load + NSI
=(1750+400+2000+600+100)
=4,850 MW

- Markets+ determines the most economic generation to meet this obligation



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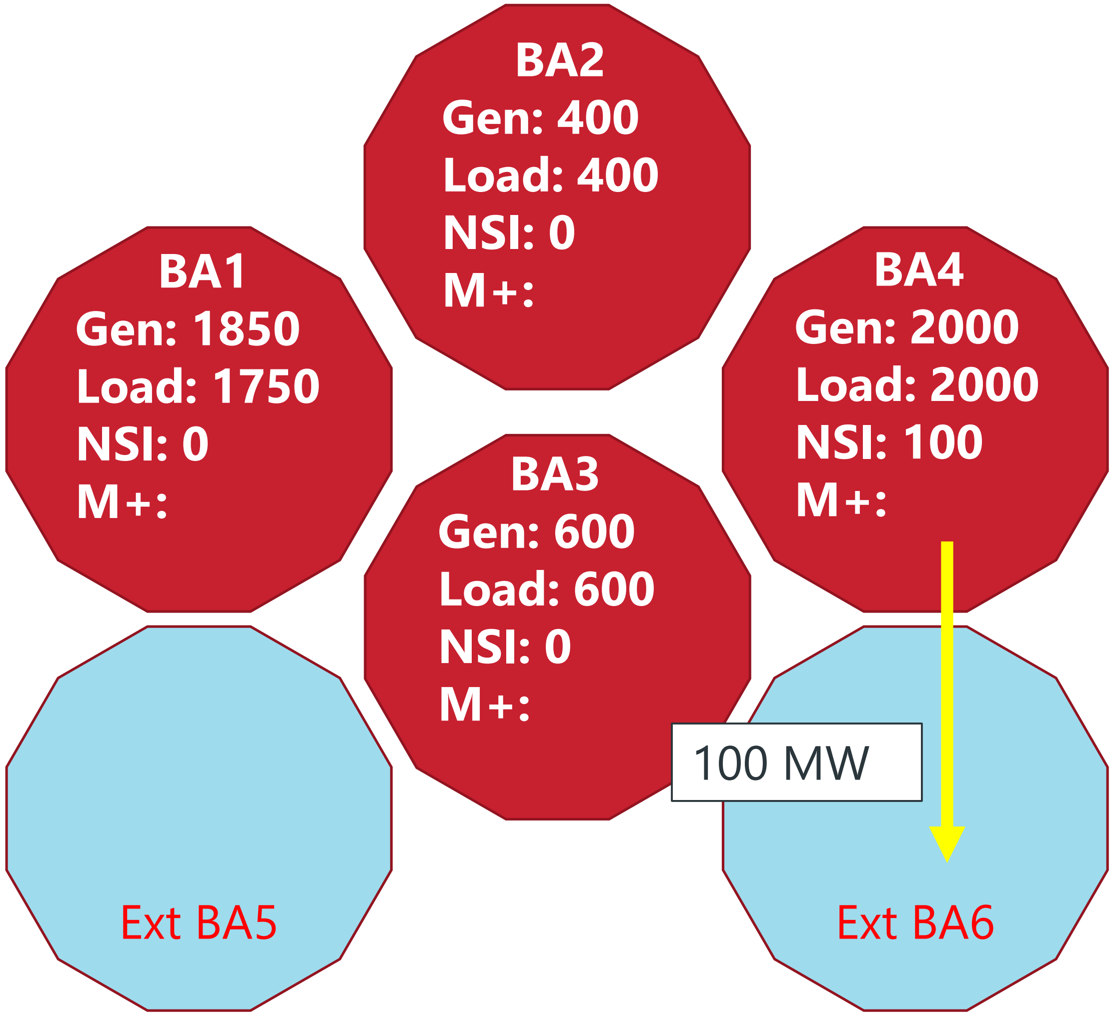
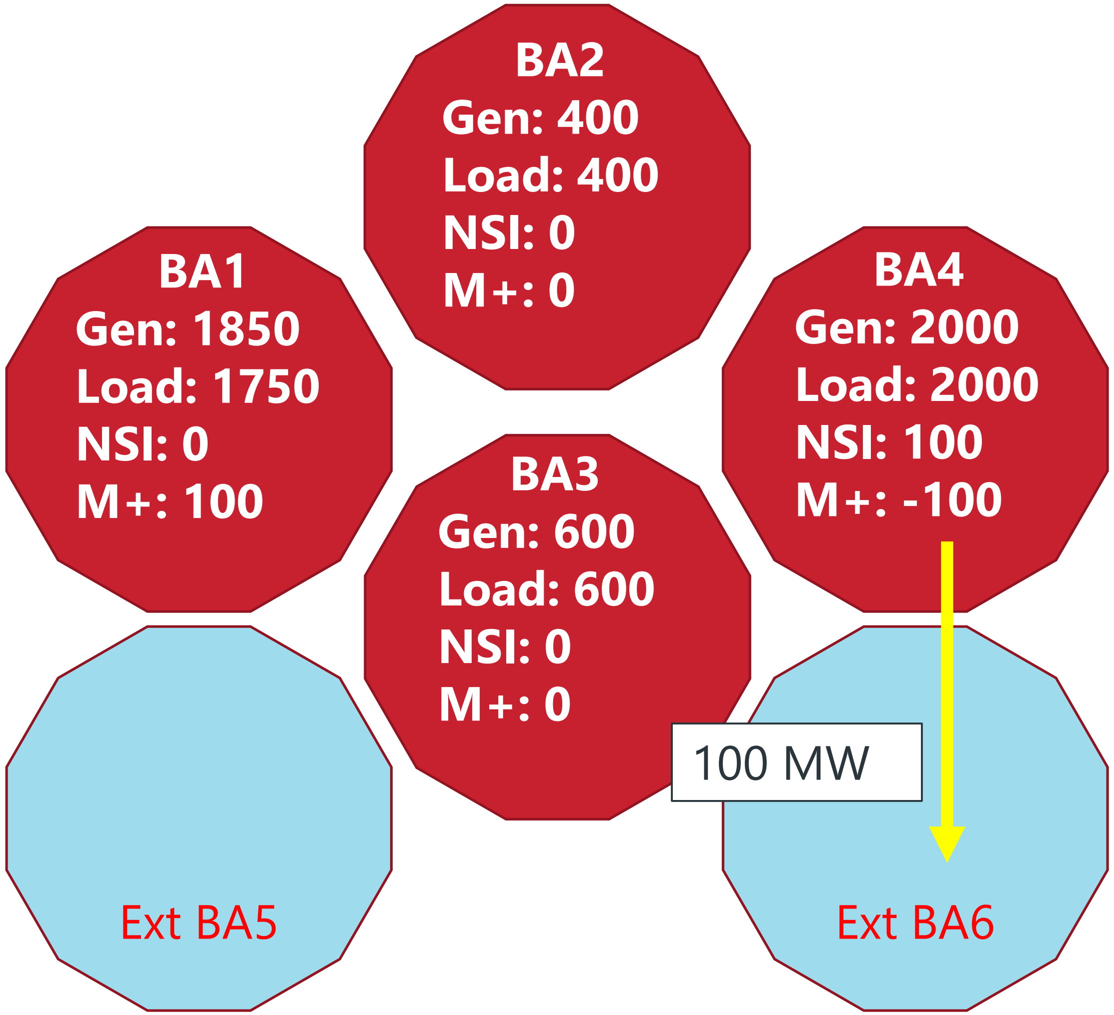


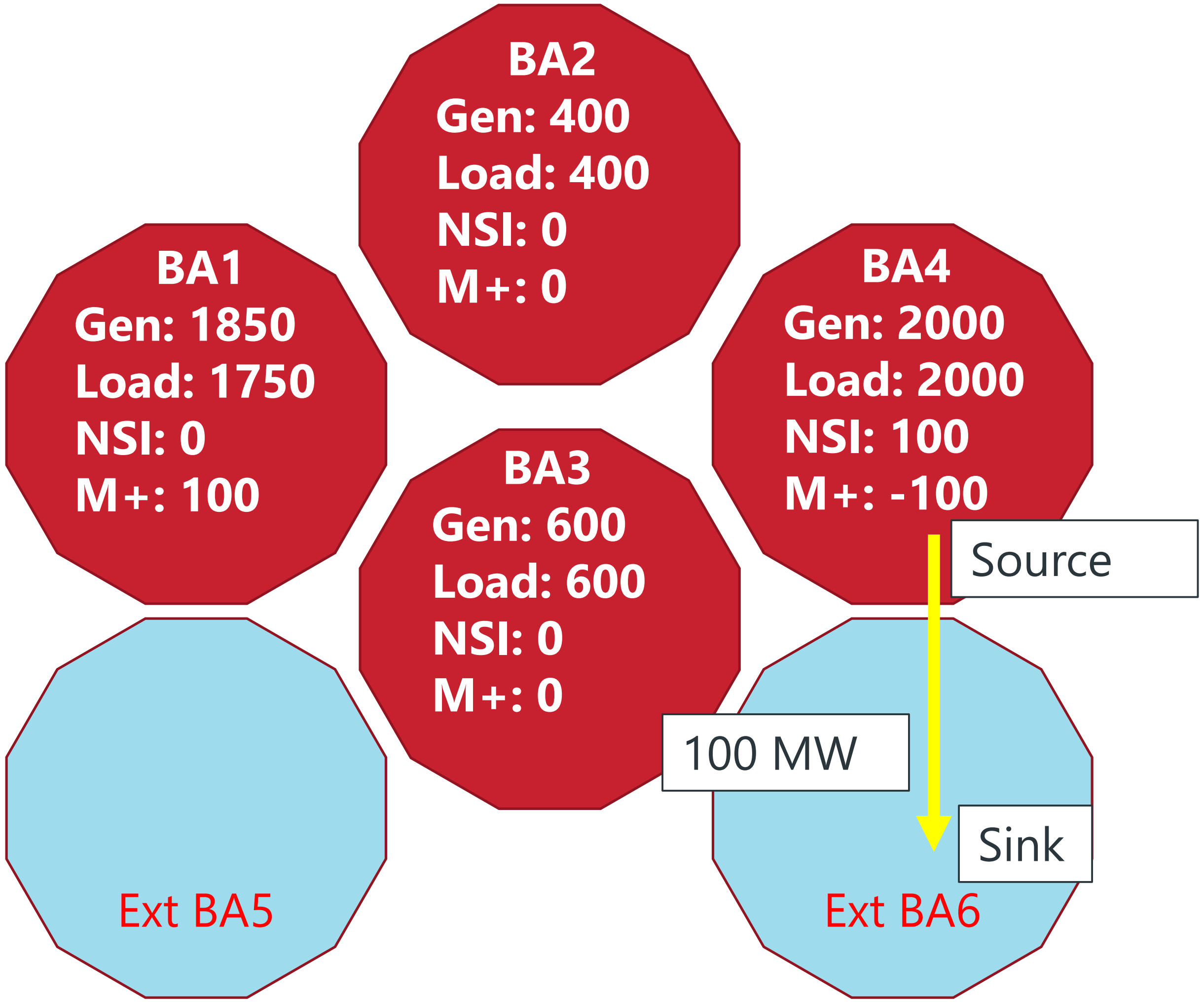
# EXPORT EXAMPLE 1

- Markets+ Energy (M+) accounts for the energy transferred between participating BAs for market activity.
- M+ is a dynamic schedule
- Calculated after economic dispatch
  For BA1
  M+ = Gen-(Load+NSI)
  = 1850-(1750+0)
  = 100 MW



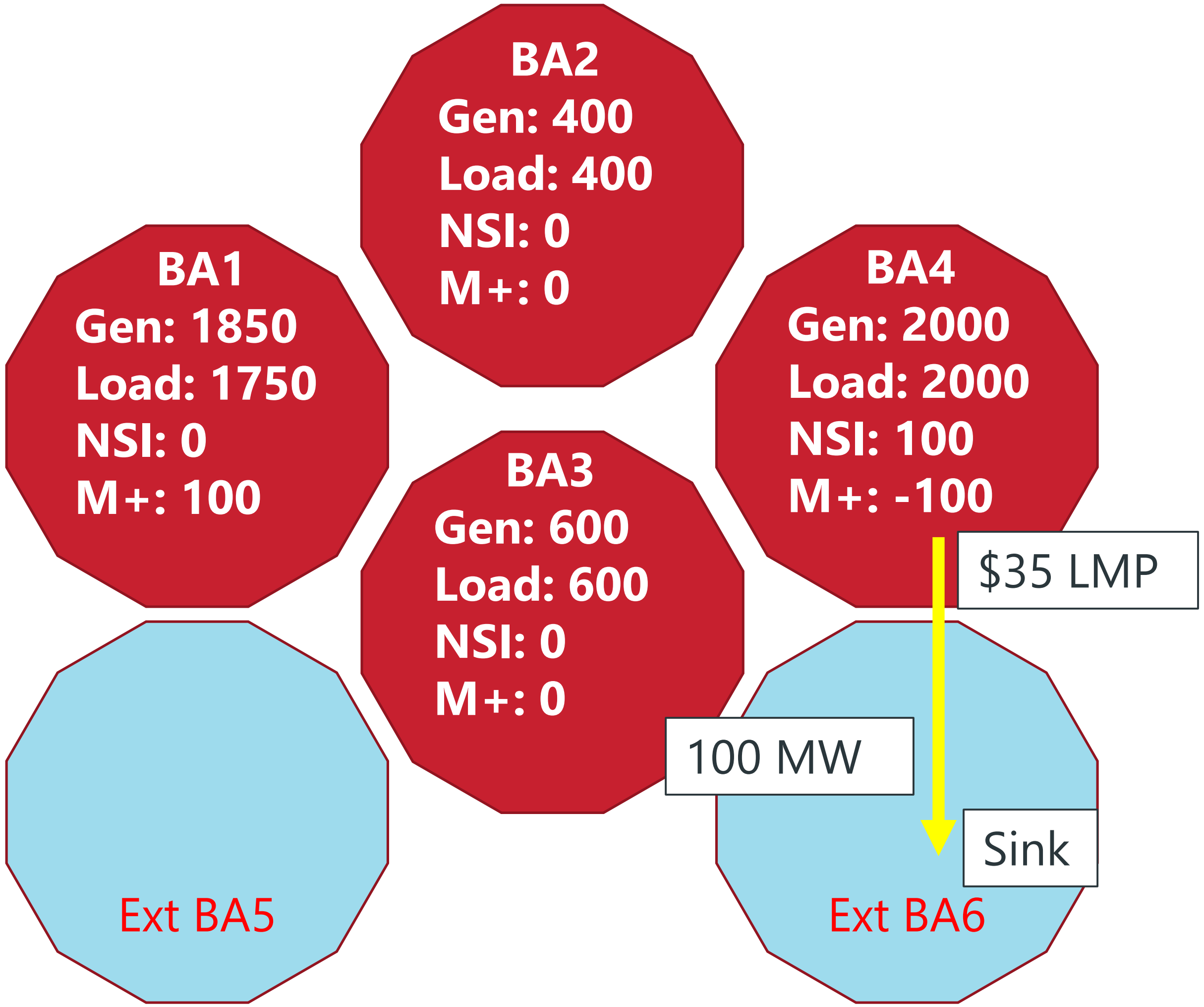
# EXPORT EXAMPLE 1 - TRANSMISSION

- Market Transmission Service (MTS) pays for the M+ Energy Transfers to compensate for transmission usage
- The PSE of the export from BA4 to Ext BA6 is responsible for procuring transmission service all the way from source to sink.



# EXPORT EXAMPLE 1 – SIMPLE SETTLEMENTS

- SPP charges $35 / MWH to the Asset Owner for export based on interface price of the last POD that is in a Markets+ BA.
- SPP calculates the interface price
- PSE is responsible for any contract payment outside market to BA4

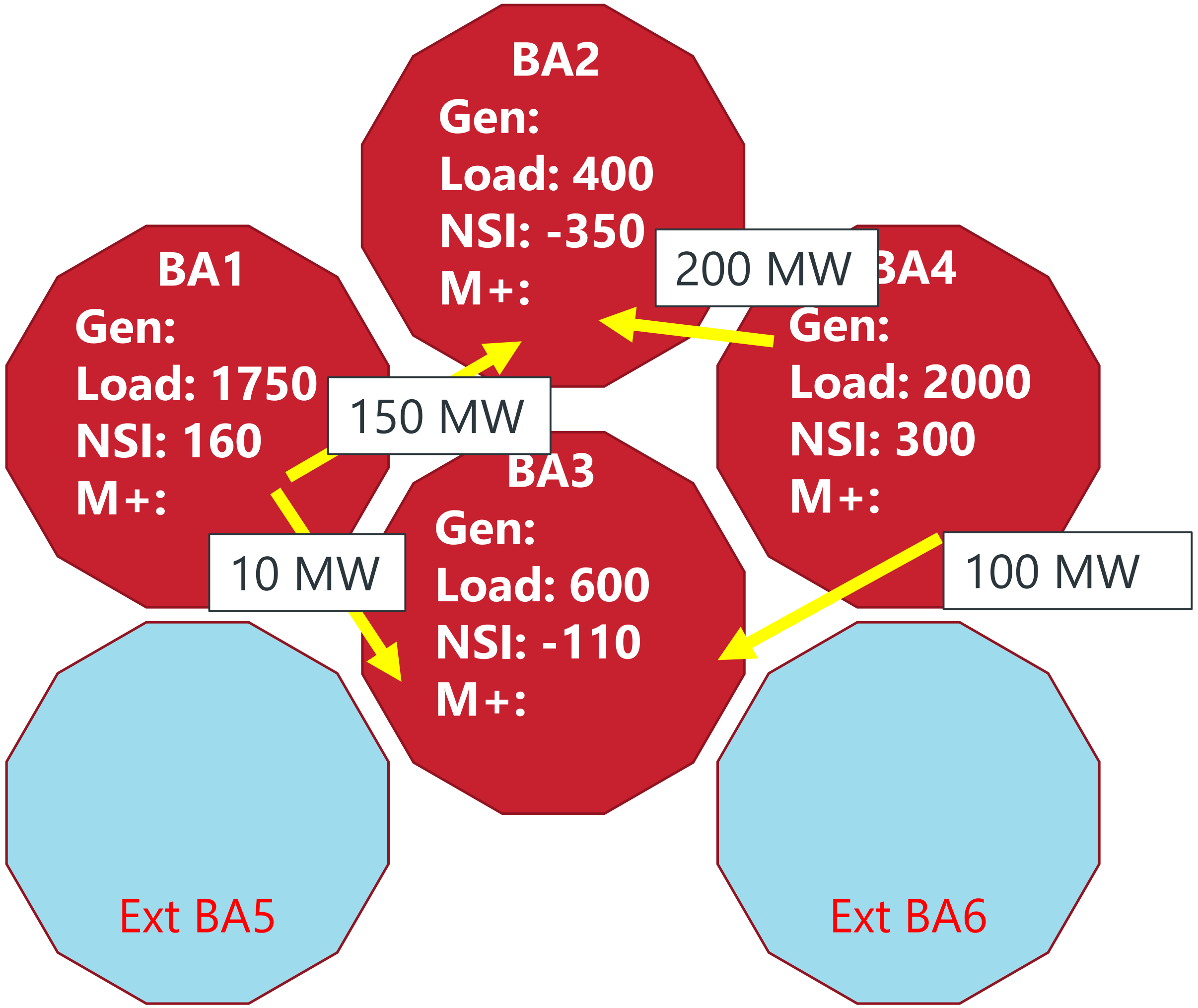


# INTRA MARKETS+ SCHEDULES

SCHEDULES INSIDE OF THE MARKETS+ BOUNDARY

# INTRA MARKETS+ SCHEDULES EXAMPLE

- Schedules between Markets+ Participants are not used for overall dispatch.
- Obligation = Load + NSI
  =(1750+400+2000+600+150+10-150-200-10-100+200+100)
  =4,750 MW
- Markets+ determines the most economic generation to meet this obligation



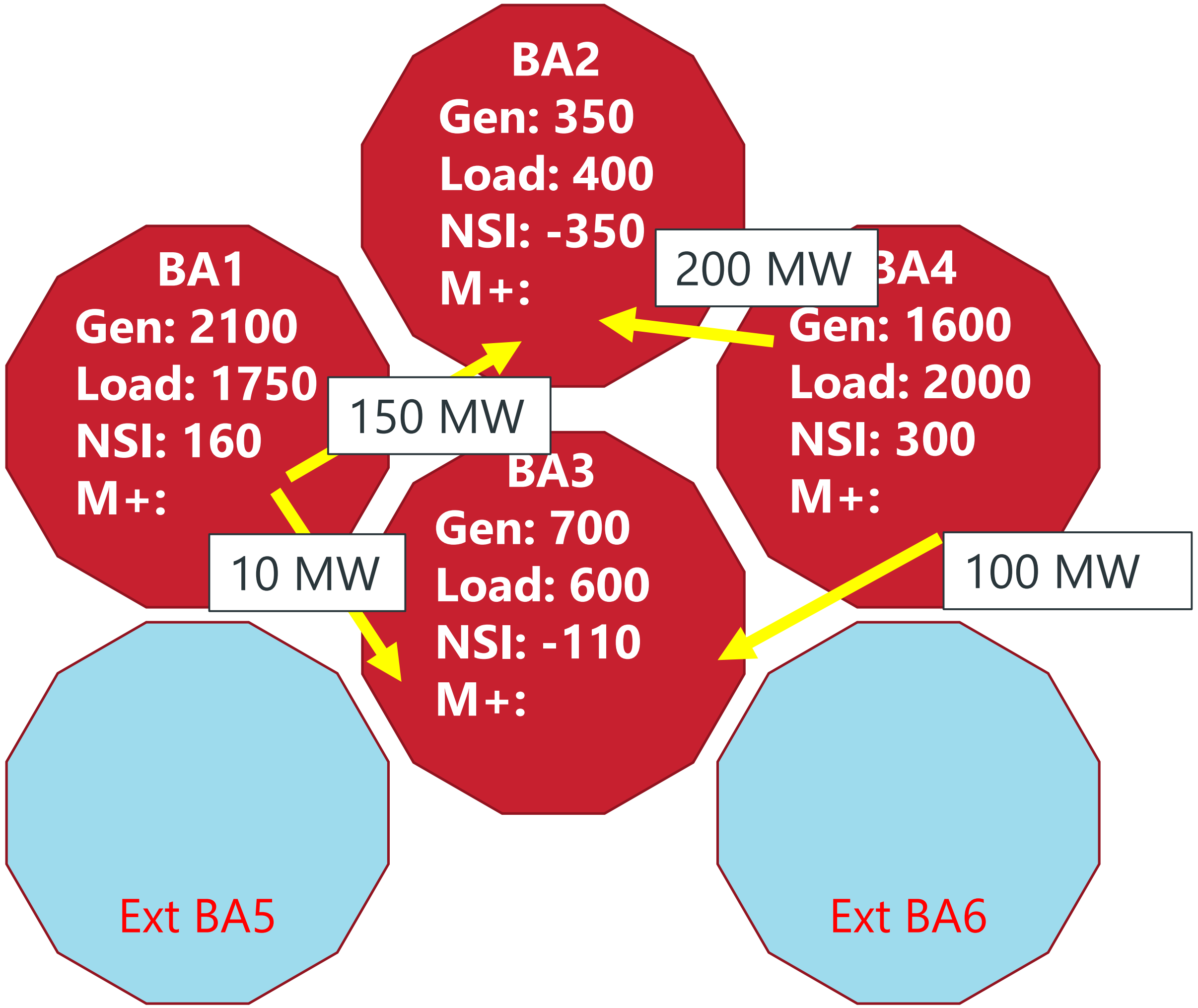
# INTRA MARKETS+ SCHEDULES EXAMPLE

- Schedules between Markets+ Participants are not used for overall dispatch.

- Obligation = Load + NSI
  =(1750+400+2000+600+150+10-150-200-10-100+200+100)
  =4,750 MW

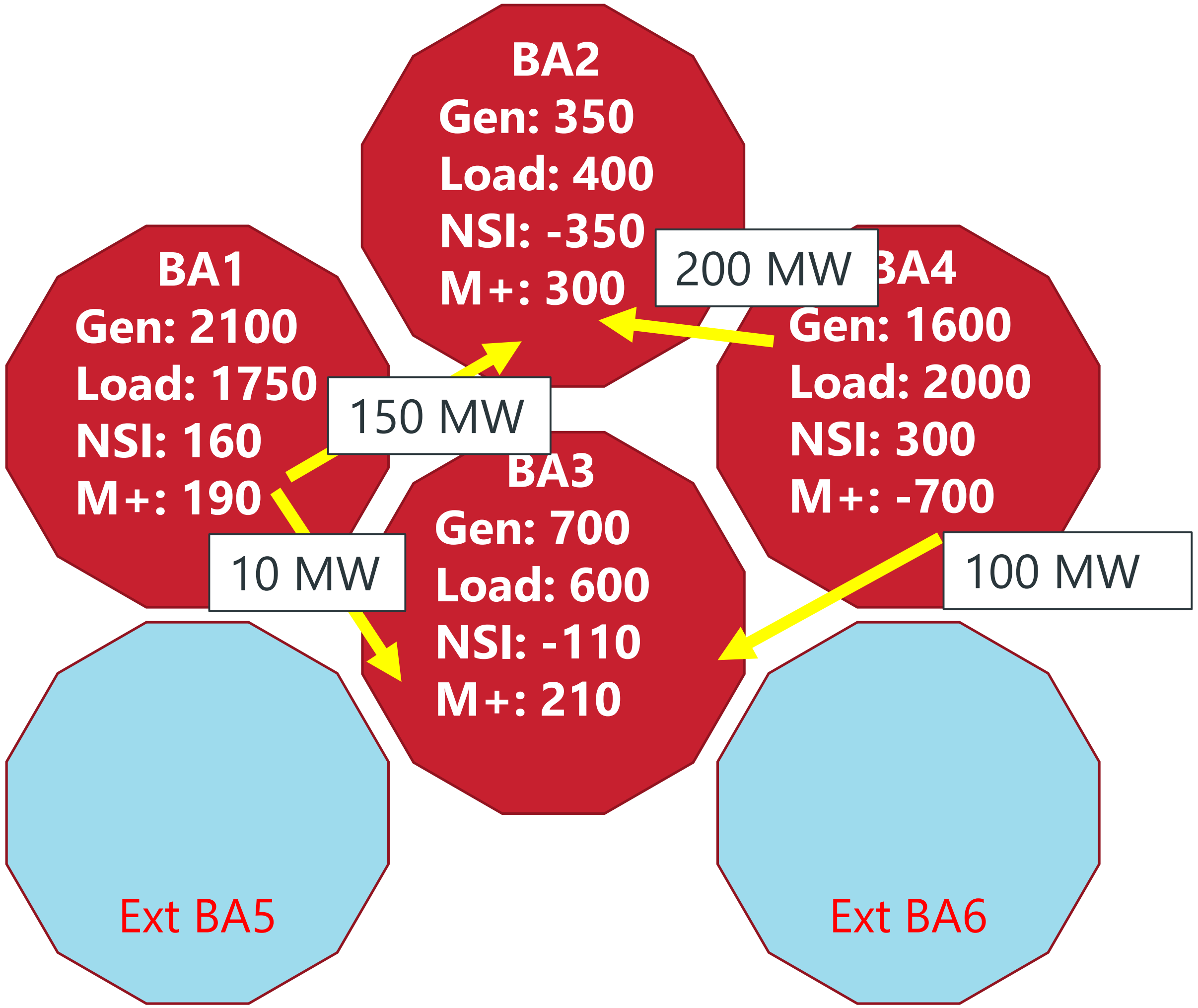
- Markets+ determines the most economic generation to meet this obligation

- Generation = Obligation



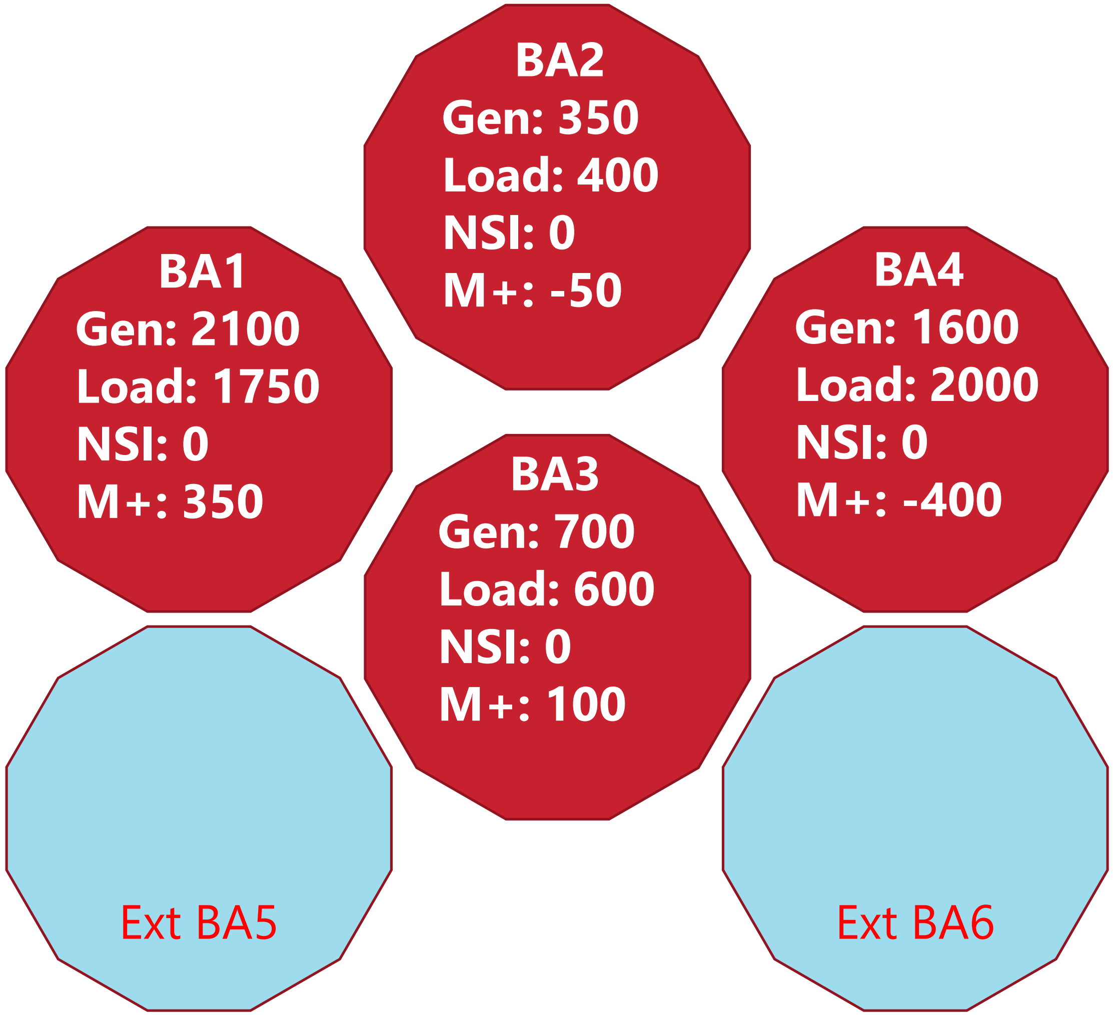
# INTRA MARKETS+ SCHEDULES EXAMPLE

- Schedules between Markets+ Participants are not used for overall dispatch.
- Markets+ Energy (M+) is calculated for each BA as Gen-(Load+NSI). This value is used to adjust the dynamic schedules between participating BAs
- Markets Transmission Service is used to compensate for transmission usage supporting M+ Energy.



# INTRA MARKETS+ NO SCHEDULES EXAMPLE

- Schedules between Markets+ Participants are not used for overall dispatch.
- Alternatively, if Markets+ load isn't scheduled and just lets the Market solve the overall dispatch is exactly the same
- Load and Resources are settled the same with no impact to LMP
- The only difference is changes to M+ energy transfers



# CONGESTION RENT ALLOCATION

MICHA BAILEY, SPP

# CONGESTION RENTS

DA Congestion Rents
- Sum up all Generators
- Sum up all Loads
- Net out losses

Allocation of DA Congestion Rents

# ALLOCATION OF CONGESTION RENT IN OFFERING

- Allocation, no market functions
  - No Simultaneous Feasibility Testing (SFT) in allocation
  - SFT occurs in Transmission Service process
- Allocation cap
  - Network = 103% * (Average last three years of peak load)
  - PTP = MWs on PTP reservation
- No uplift calculations
  - What is collected, allocate back
- All positions will be options not obligations
  - Counter flow positions will have a value of $0

# CLARIFICATIONS

- Include detail from discussion in offering
  - SPP will include additional information in the service offering
- Using TSR to allocate Real-Time Congestion
  - Proposal is to leave Real-Time congestion as a determinate in Revenue Neutrality Uplift
    - Aggregation of market wide (Real-Time MWs minus Day-Ahead MWs) * Real-Time Locational Marginal Price
    - TSRs are not used for the differential between the prices of the Day-Ahead and Real-Time markets
  - Other markets have biddable Real-Time hedge instruments
    - Virtual position in Day-Ahead Market

# CLARIFICATIONS

Clarify how redirects will work with congestion rents allocation

TSRs change to a new source/sink

How Redirects are used will be tied to Phase 1 decisions

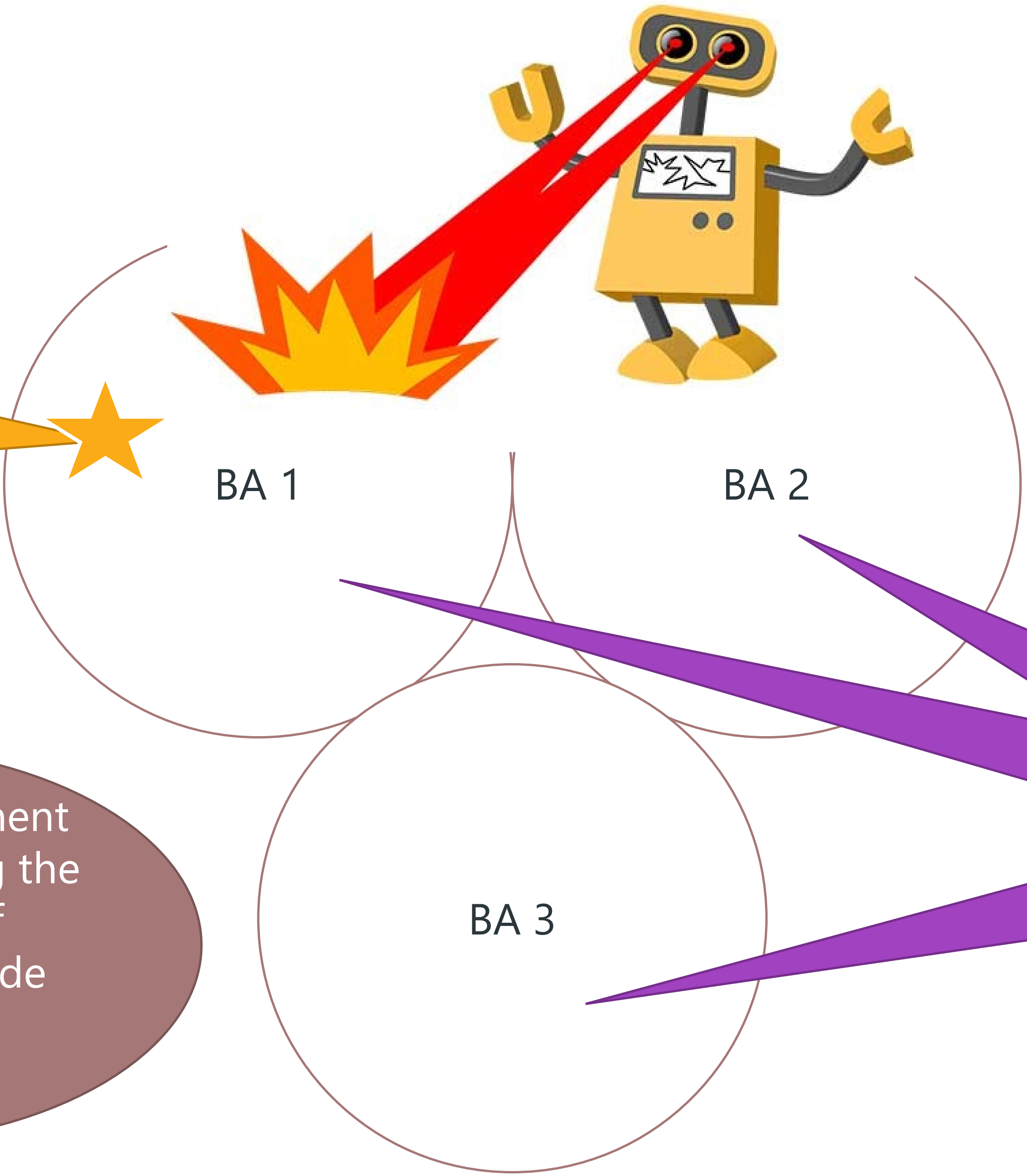
- Frequency of submittal needs to be determined
- Monthly, Weekly, or Daily

# PHASE 1 TOPICS FOR DECISIONS

- Include Conditional Firm in congestion rent allocation
- Consideration for short-term firm
- Move the yearly allocation cap to a monthly allocation cap
- TSR submission either monthly, weekly or daily
- Allow option to distribute congestion rent to BAs rather than transmission customers
- Tiered approach for distribution of congestion rents
- Zonal distribution of congestion rents
- Derates in congestion rent allocation

# DERATES

Suppose that there is an element that has a Derate



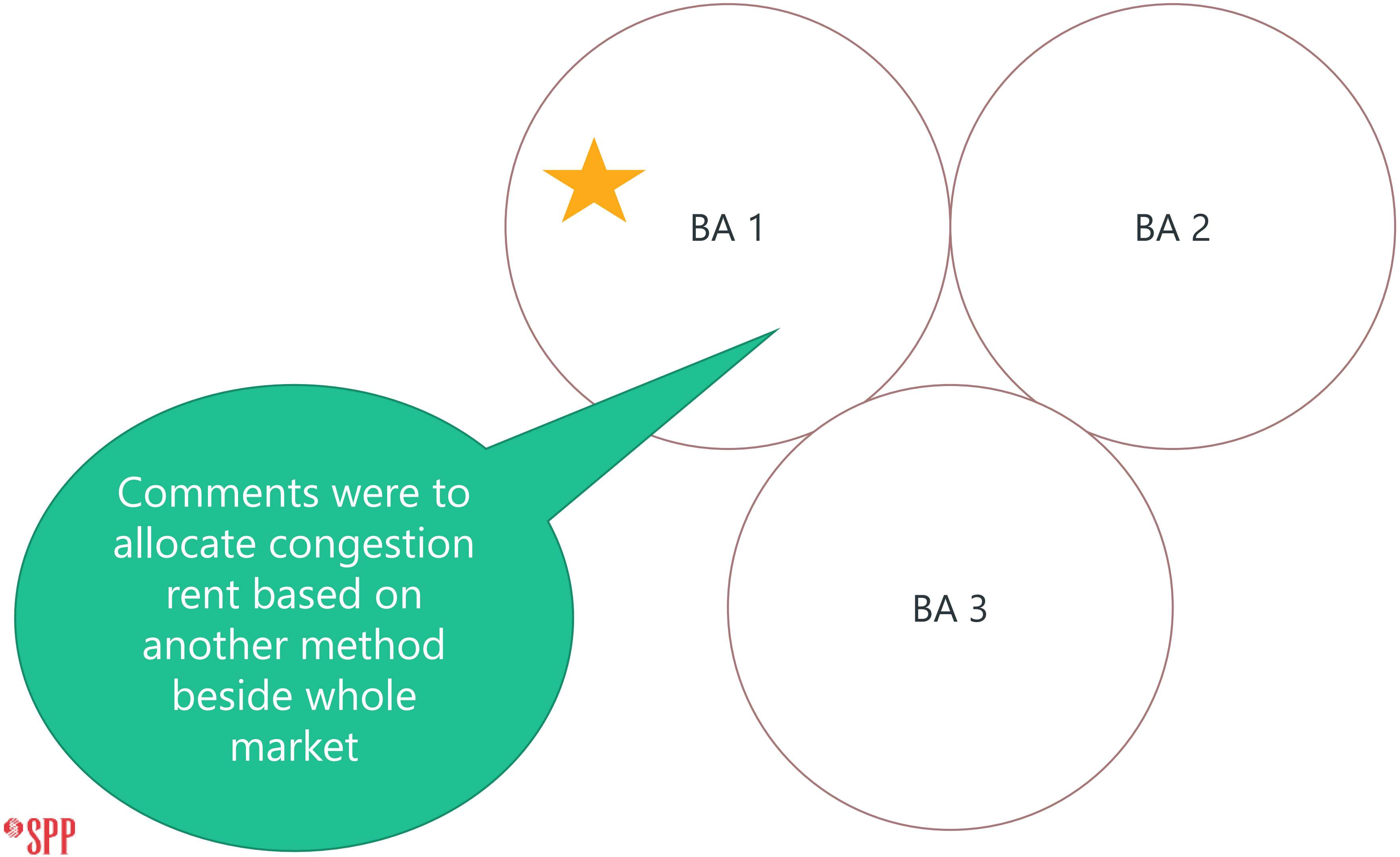

The LMPs will reflect the Derate because there will be one reference bus

MCC is the component of LMP representing the marginal cost of congestion at Enode relative to the Reference Bus

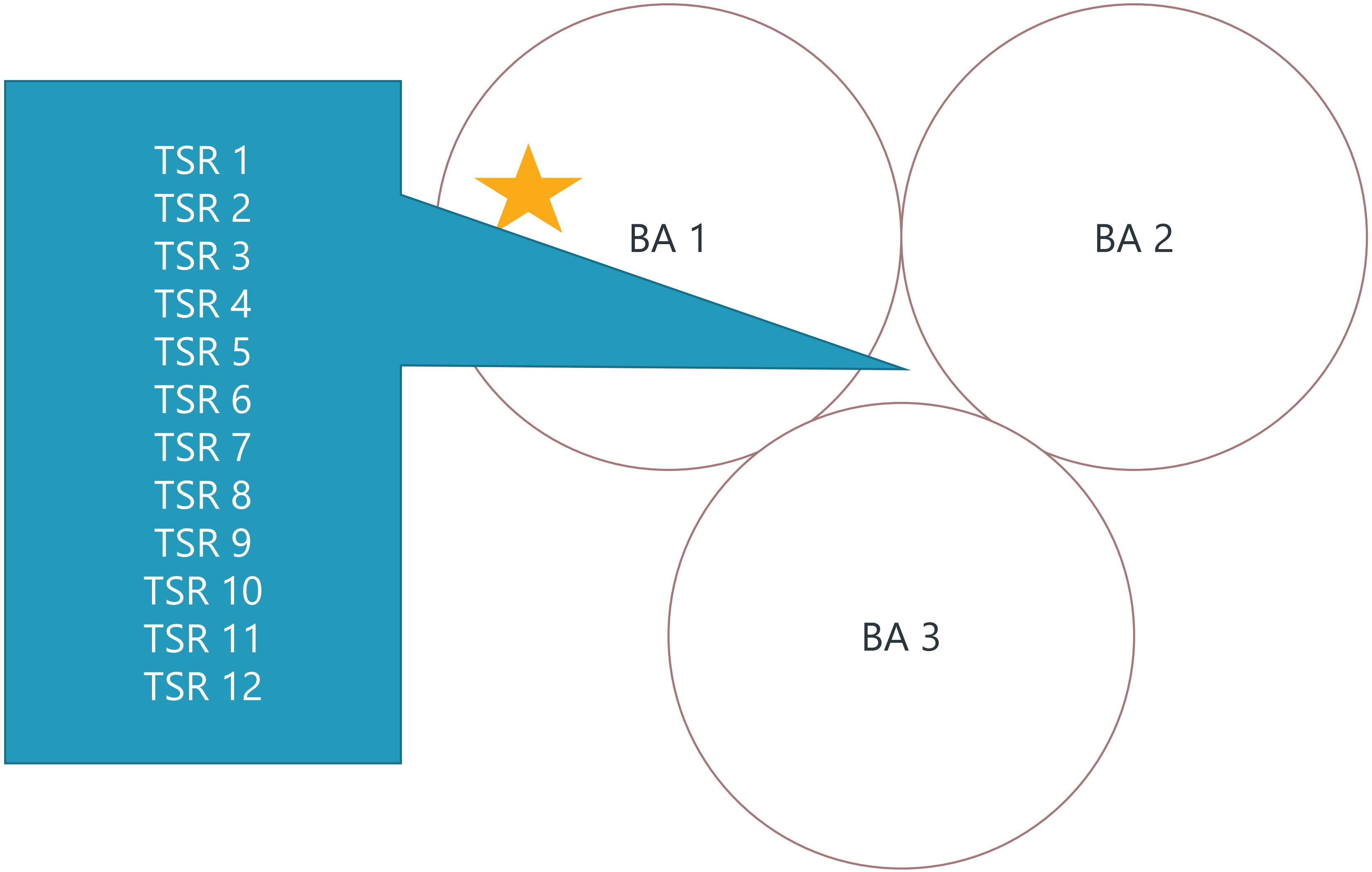
# DERATES

**The amount of money in the bucket of dollars will change accordingly**

# DERATES

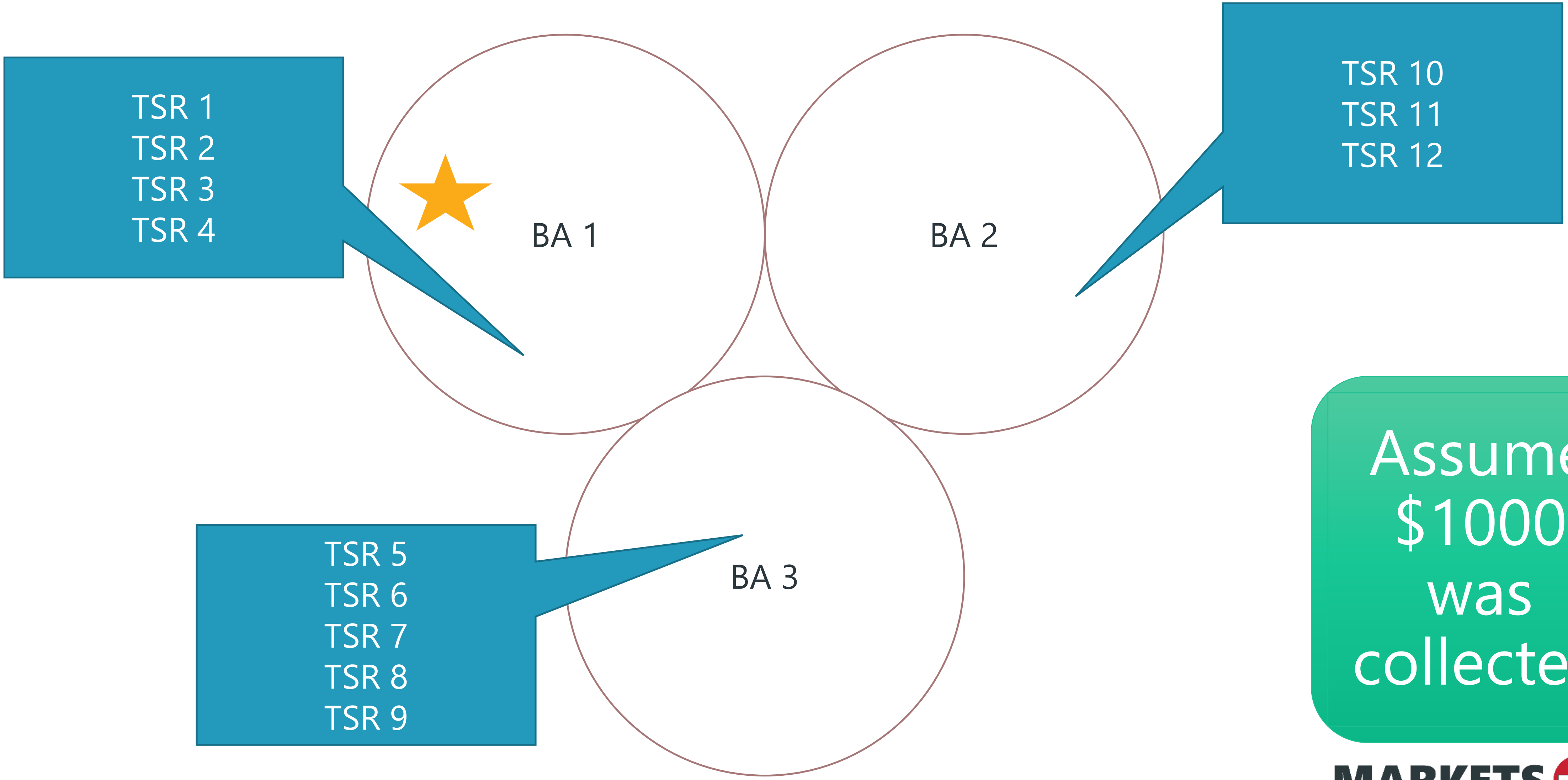

BA 1
BA 2
BA 3
Comments were to allocate congestion rent based on another method beside whole market

# DERATES




Assume $1000 was collected

# DERATES




Assume $1000 was collected

# QUESTIONS/DISCUSSION

# IMPLEMENTATION PHASE I – TARIFF DEVELOPMENT

BRUCE REW, SPP

# MARKETS+ PHASE 1

| Deliverables | Cost | Other Considerations |
|---|---|---|
| Draft tariff, protocols and filing letter | $9.7M, 21 months | Free ridership |
| Establish business practices and operational criteria | Additional run beyond 21 months billed at $500k monthly | PIO desired participation & states advisory role |

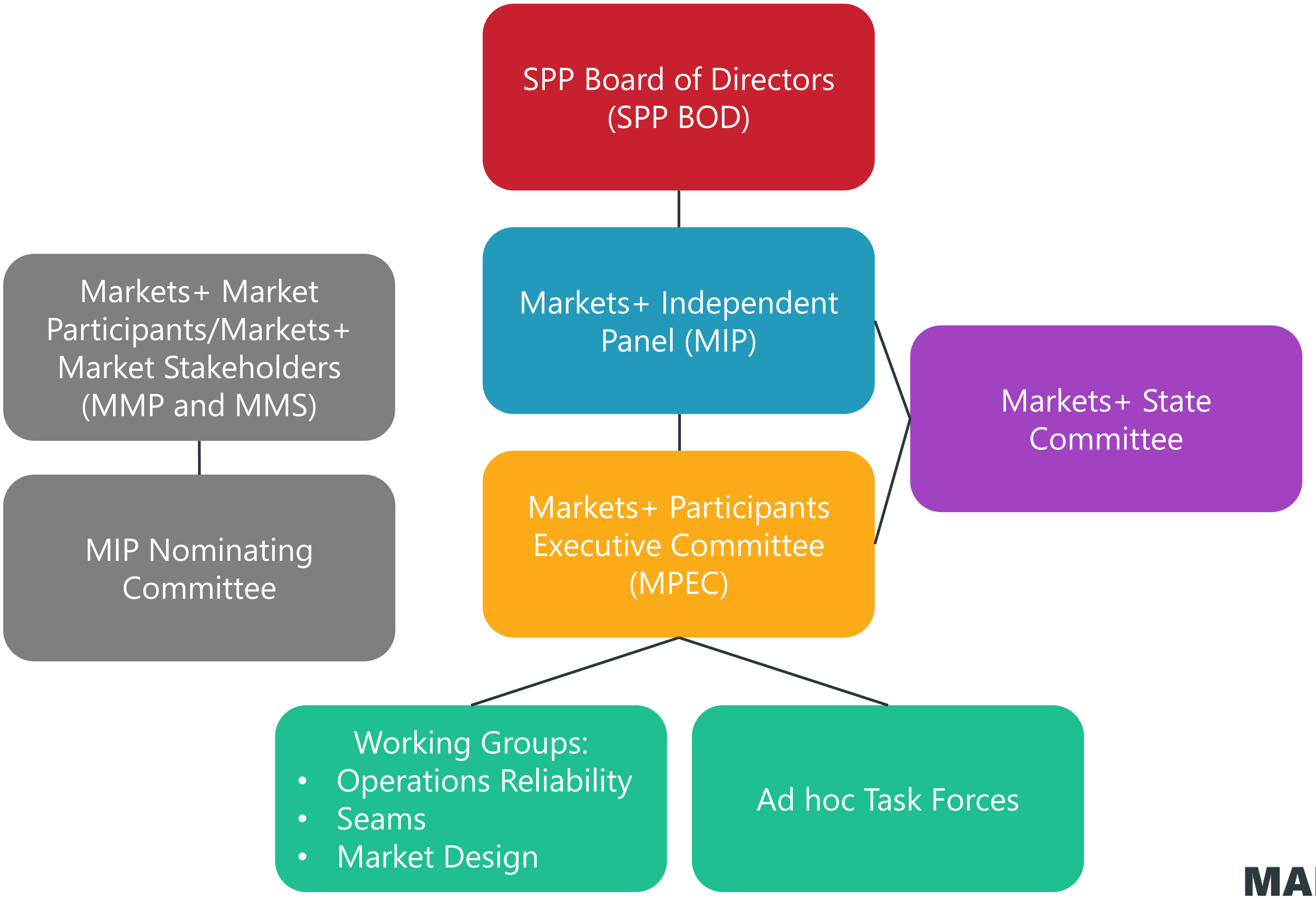
# FUNDING METHODOLOGY

- Incentive to fund
  - Eligible to vote on design decisions
  - Ensure Markets+ moves forward
- Free ridership mitigation
  - Include phase 1 costs in phase 2 funding
  - Credit entities that funded phase 1 down to their proportionate costs based on phase 2 participation

# PROPOSAL

# METHODOLOGY OBJECTIVES

- Consistency with SPP's governance proposal
- Partial deployment of the Markets+ governance
  - establish the Markets+ Participants Executive Committee (MPEC) offered by SPP in the service offering
- Ensure funding is reflective of the size of committing entities
- Address free-ridership concerns


SPP Board of Directors (SPP BOD)
Markets+ Independent Panel (MIP)
Markets+ Market Participants/Markets+ Market Stakeholders (MMP and MMS)
MIP Nominating Committee
Markets+ Participants Executive Committee (MPEC)
Markets+ State Committee
Working Groups:
• Operations Reliability
• Seams
• Market Design
Ad hoc Task Forces

# MPEC VOTING STRUCTURE

3 sectors each represent 33 1/3% of the vote:

- Investor-owned Utilities
- Public Power
- Independents

Markets+ Participants Executive Committee (MPEC)

Advisory Role

Markets+ State Committee

Working Groups:

- Operations Reliability
- Seams
- Market Design

Ad hoc Task Forces

Simple Majority

# PHASE 1 FUNDING METHODOLOGY

Funding entities

- **Ratio share allocation on NEL + total participating gen**

PIOs

*Considered in the independent sector*

- **$5000 fee**
  - **Maybe waved for eligible entities that are nonprofit organizations under the Internal Revenue Code.**

States involvement

*Advisory role*

- **Advisory role on design elements at the MPEC**

# ADDRESSING FREE-RIDERSHIP


- Ensuring the total implementation cost is allocated to all participating parties, including those who will join during or later in the process.
- The cost of phase 1 will be added to phase 2 project cost, facilitating phase 1 cost allocation to all participating entities.
  - Entities that funded phase 1 will be credited back any difference due to the reallocation of costs to all phase 2 participants.

# QUESTIONS/DISCUSSION