Joint Market Seams Workshop

Western Electricity Coordinating Council (WECC), Salt Lake City, UT
Workshop #2

August 18, 2026

Housekeeping

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The meeting is structured to stimulate dialogue and engage different perspectives.

Please engage in a respectful and professional manner. Introduce yourself and your organization when speaking. Follow the facilitator's guidance for speaking or asking questions.

Please keep comments brief and avoid repeating points already made to ensure everyone has an opportunity to participate in a robust discussion.

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Please remember to state your name and affiliation before making your comment.

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. Start speaking a couple of seconds after you’re unmuted.

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You may also send questions via chat to all panelists.

If you need technical assistance during the meeting, please send a chat to the event producer, Intellor Events.

Welcome and Opening Remarks

Anna McKenna
Vice President
Market Design and Analysis, CAISO

California ISO

SPP
Powering Progress

WECC

Welcome and Opening Remarks

Carrie Simpson

Vice President

Markets, SPP

Meeting Objectives

Paul Dockery

Market Strategy & Governance Manager, CAISO

Casey Cadle

Director of Markets Seams Strategy, CAISO

Agenda

Please note that the below times are in Mountain Daylight Time

Time	Topic	Presenters	
9:00 – 9:10 a.m.	**Welcome and Opening Remarks**	Anna McKenna, CAISO Carrie Simpson, SPP	
9:10 – 9:20 a.m.	**Meeting Objectives**	Casey Cadle, SPP Paul Dockery, CAISO	
9:20 – 10:50 a.m.	**Transmission Operators**	**Moderator:** Raja Thappetaobula, CAISO	Yasser Bahbaz, SPP Sanman Rokade, PGE Daniel Koppes, PacifiCorp
10:50 – 11:00 a.m.	**Break**		
11:00 – 12:30 p.m.	**Congestion Management**	**Moderator:** Branden Sudduth, WECC	Kelsey Martinez, PNM Jamil Daouk, CAISO Hayden Johnson, SPP
12:30 p.m. – 1:00 p.m.	**Lunch**	Lunch provided	
1:00 – 2:15 p.m.	**Congestion Management examples**	**Moderator:** Casey Cadle, SPP	Paul Dockery, CAISO Jamil Daouk, CAISO Hayden Johnson, SPP James Lynn, CAISO Jim Gonzalez, SPP
2:15 – 2:30 p.m.	**Preview of Next Workshop and Closing Remarks**	Joanne Serina, CAISO Carrie Simpson, SPP	

Clarifying terms

- **Seams** refer to the interfaces between adjacent wholesale electric systems — such as balancing authorities, reliability coordinators, transmission service providers, and electricity markets — where neighboring entities perform essentially the same function on either side of a jurisdictional boundary within a shared network.
- **Seams issues** arise at these interfaces, impacting the ability of neighboring entities to carry out their responsibilities efficiently and effectively.
- **Market seams** refer to the interfaces between centrally cleared, structured electricity markets – such as the interface between CAISO's Western Energy Imbalance Market (WEIM) and SPP's western RTO expansion.
- **Market seams issues** arise when separate markets – with different configuration, designs, and protocols – optimize interdependent portions of a shared transmission network with limited or imperfect representation of neighboring systems. The resulting issues can include barriers to trade, inefficient congestion management, and suboptimal dispatch.

More info: [Seams | Western Energy Markets]

Seams workshop series & Joint report

- July 31st, Seattle, WA: Seams stages, expert panel, and panel of state regulators
- August 18th, Salt Lake City, UT: Reliability: Transmission constraints and congestion management
- September 16th, Denver, CO: Imports and Exports: Transactions across market boundaries
- September 30th: Joint Report on Western Seams Coordination due to FERC
- October [Date and location TBD]: [Hold for participant recommended topic], tabletop exercise, roadmap, and next steps

Comments and next meeting

- Comments: Please submit stakeholder comments on the August 18 workshop by visiting Meetings | Market Seams | California ISO and completing the comment template Word document. Upon completion of this template, please submit it to isostakeholderaffairs@caiso.com. Written comments are due by end of day Sept. 1, 2026.

- Next meeting: The California ISO and Southwest Power Pool have tentatively scheduled a September 16, 2026, hybrid Market Seams workshop in Denver, Colorado. A notice will be released soon to confirm the details.

- Seams Webpage: More information is at Seams | Western Energy Markets

TRANSMISSION OPERATORS PANEL DISCUSSION

Moderator:

Raja Thappetaobula
CAISO

Panelists:

- **Yasser Bahbaz** — SPP
- **Sanman Rokade** — PGE
- **Daniel Koppes** — PacifiCorp

Transmission Constraint Management

Raja Thappetaobula
Director of RC West Operations, CAISO

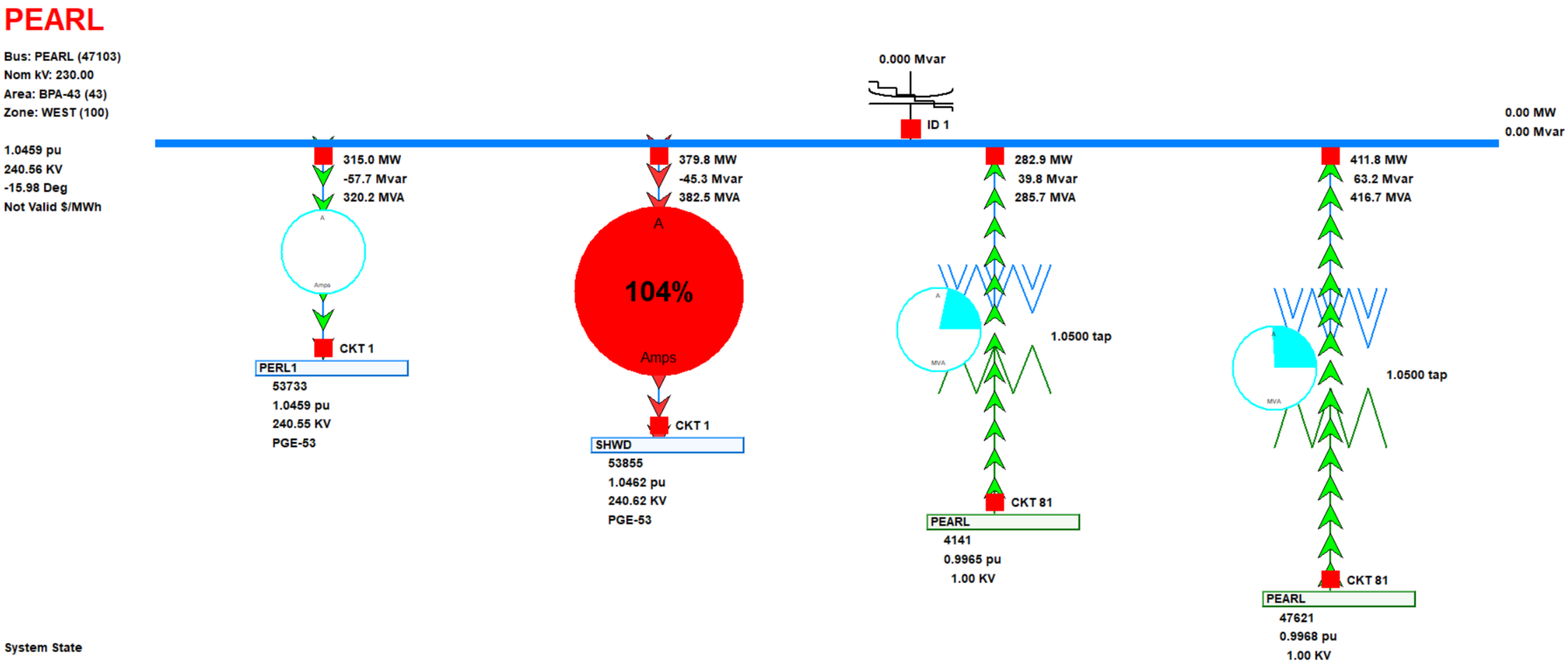
What is a Transmission Constraint?

What is a Transmission Constraint

- A transmission constraint is a limitation on how much electrical current can <u>safely flow</u> through a transmission equipment (transmission line or transformer) in the electrical grid

- Different types of safety limits that results in existence of transmission constraint
  - Thermal limits: Lines heat up as current flows and thermal limits exist to manage
  - Voltage limits: Power flows affects voltage levels and voltage limits exist to manage
  - Stability limits: Large power flows through a region can result in cascading failures due to system events and stability limits exist to manage

Transmission Constraint Due to Thermal Limit Example: (Simulated)



Stability Limit Example:

- Oregon Export Stability Limit
  - High exports from southern and eastern Oregon may result in widespread post-Contingency steady state voltage instability in the area when contingencies occur. Power flow limits are established to manage the stability
  - Operators manage the power flows so that limits are not violated in real time
  - Transmission constraint exists when power flows approach the limit

How Grid Operators Manage Transmission Constraints

- Grid operators (Transmission Operators & ISOs/RTOs) can't just let power flows beyond the established limits
    - Redispatching generation
    - Transmission reconfiguration
    - Utilize energy markets (WEIM/WEIS/RTO West)
    - Curtail transactions

Different Types of Studies to Identify Transmission Constraints

Transmission Constraint Management

- Transmission operators and Reliability Coordinators across Western Interconnect perform seasonal studies to identify transmission system issues for peak seasonal operating conditions

- RCs pre and post contingency thermal and voltage performance criteria is evaluated against stressed summer/winter operating conditions

- RCs transient performance criteria is also evaluated for stability limits

- Mitigation plans are developed and coordinated with RCs

- Updated path ratings or TTC /Transmission overloads for base case and N-1/N-2 contingency conditions

Transmission Constraint Management

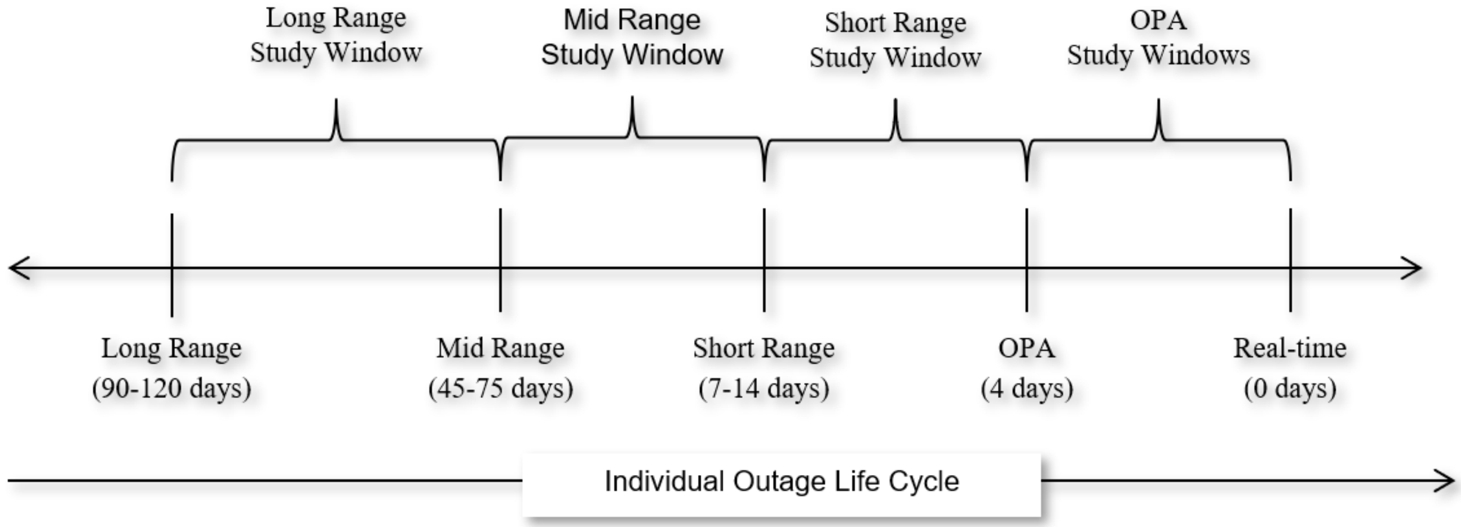
- WECC seasonal models are starting point for these studies

- Models contain most of western interconnect

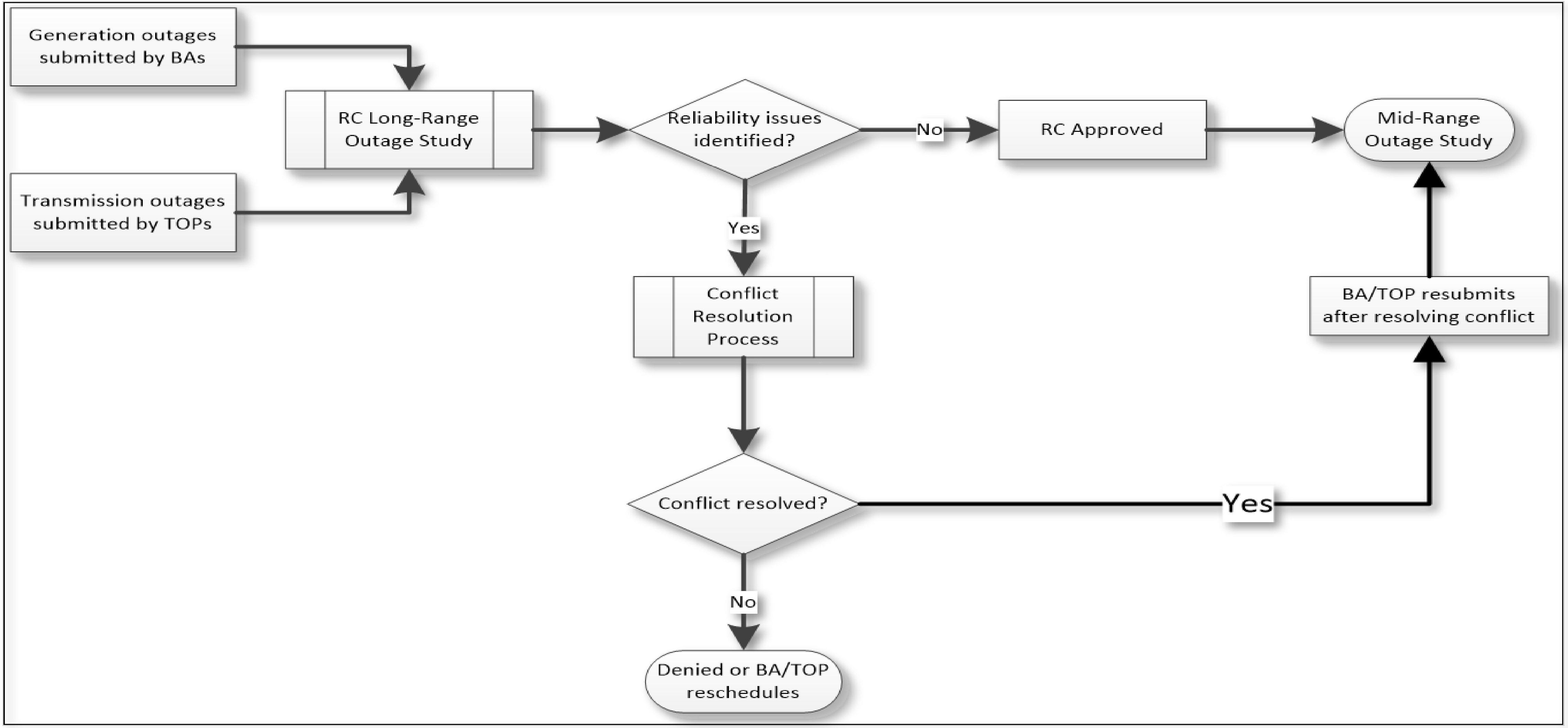
Transmission Constraint Management

- After seasonal studies TOPs and Reliability Coordinators perform outage coordination studies to determine impacts of planned transmission maintenance work and mitigations.

Outage Submission Timeline



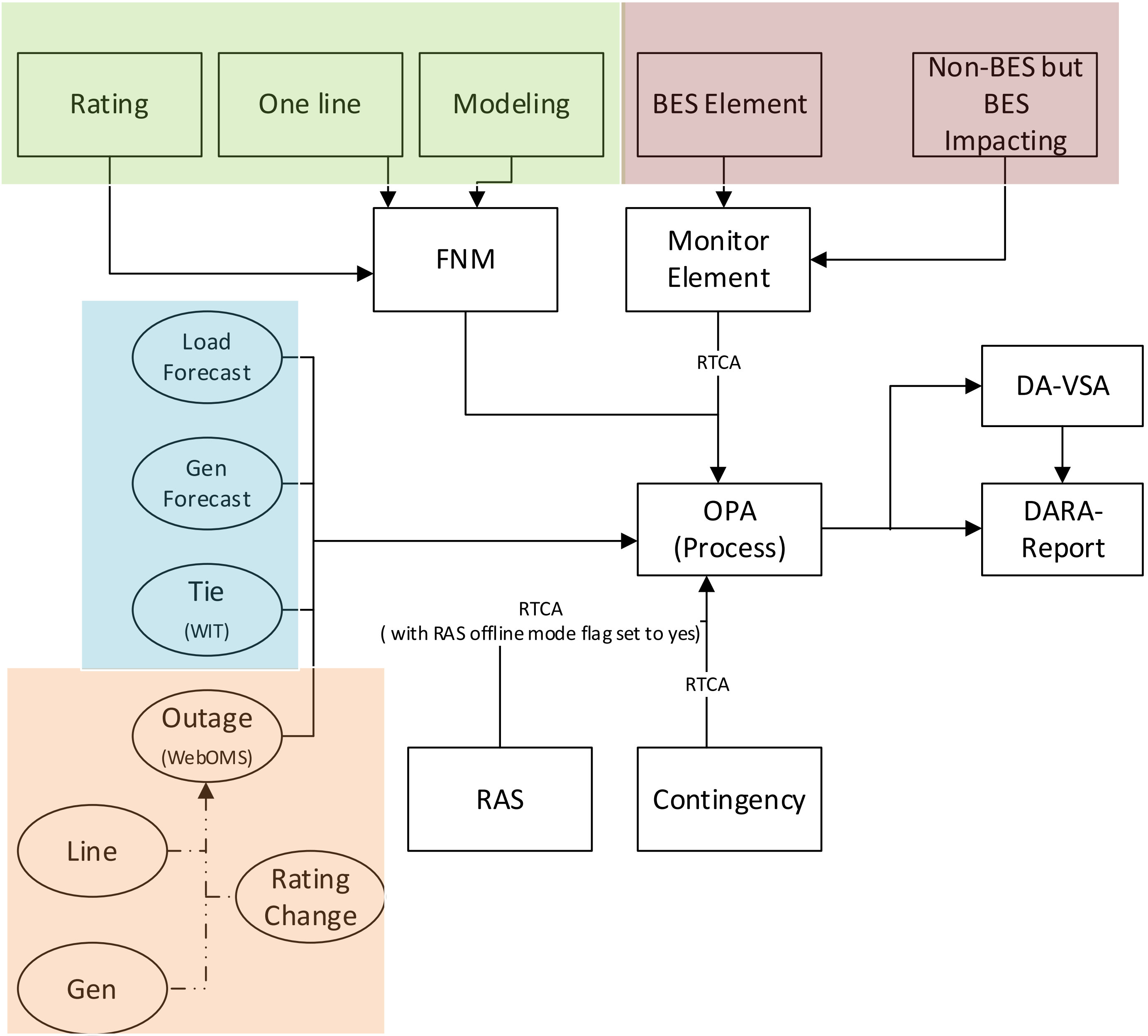
Transmission Constraint Management



Transmission Constraint Management

- Operating planning analysis study windows are the final stage of studies prior to same day and real time studies
- These studies help us to analyze more accurate real time grid operating conditions and transmission constraints that would need to be mitigated
- RCs D4/D2/D1 look ahead reliability analysis studies

OPA Process



Rating
One line
Modeling
BES Element
Non-BES but BES Impacting
FNM
Monitor Element
RTCA
DA-VSA
Load Forecast
Gen Forecast
Tie (WIT)
OPA (Process)
DARA-Report
RTCA
(with RAS offline mode flag set to yes)
RTCA
Outage (WebOMS)
RAS
Contingency
Line
Rating Change
Gen

PGE Reliability Studies Process

1 | SEASONAL ASSESSMENT

- **1.1** Develop Operational Base Case
- **1.2** Run Seasonal TTC Assessments

2 | 30-DAY OUTAGE REVIEW

- **2.1** Review PGE outages for scheduling conflicts with internal and external TOPs

3 | OUTAGE COORDINATION STUDIES

- **3.1** Import foreign TOP outages (BPA, PAC) and PGE outages to offline study cases
- **3.2** Scale basecase with historical weather, generation and load profile
- **3.3** Identify conflicts with outages and reliability impact of outages
- **3.4** Develop operating plans if needed or cancel conflicting outages

4 | D+2 & D+1 OPAs

- **4.1** Import foreign TOP outages (BPA, PAC) and PGE outages to study cases
- **4.2** Scale basecase with forecasted weather, generation and load profile
- **4.3** Change ratings to applicable AAR/DLR forecast value
- **4.4** Identify impact of system condition and outages
- **4.5** Develop operating plans if needed or cancel conflicting outages

OPERATING-PLAN ACTIONS UNDER STEP 4.5

- **4.5.1** Activate contingencies in the market
- **4.5.2** Market conformance
- **4.5.3** Topology Optimization
- **4.5.4** Manual redispatch of generation
- **4.5.5** Curtail transmission schedules
- **4.5.6** Demand Response

How to Mitigate and Manage Transmission Constraints

Transmission Constraint Management

- Mitigation actions for transmission constraints can be setup in Day ahead for optimal coordination between TOPs and RCs.

- Real time mitigation actions can be taken to address real time transmission constraints.

Transmission Constraint Management

- Day ahead Mitigations:
  - TTC and WECC path ratings can be adjusted
  - Transmission reconfiguration can be implemented
  - Utilize Day ahead markets by constraining overloaded transmission elements.
  - Generation schedules can be managed to mitigate
  - Cancellation of planned maintenance outages

Transmission Constraint Management

- Real Time Mitigations:
  - TTC and WECC path ratings can be adjusted
  - Transmission reconfiguration can be implemented
  - Generation schedules can be managed to mitigate
  - Recalling planned maintenance outages
  - Unscheduled Flow mitigation process
  - Utilization of real time markets

How We Manage Transmission Constraints

Objective: **reliability first, efficient congestion mitigation second with transfer limits and constraints assessed at from seasonal baselines seasonal horizon to real time.**

Seasonal Assessment

Each season, we assess transfer capability using varying levels of Load & generation and projected topology.

Thermal & Stability Constraints

Months Out

Generation assessment, outage-uncertainty analysis & transmission pre-screening, Especially for areas with transfer limitations.

7 Days Out (OD+7)

Final assessment coordinates mitigation with TOPs & defines constraints needing coordination and re-dispatch.

Thermal & Stability Constraints

Real-Time

Continuous re-assessment of mitigation plans. Market constraints monitored and activated as appropriate

On-going assessment thermal and stability

SPP updates Path and Total Transfer Capability limits so transfer limits reflect topology changes.

Congestion Management Tools

These tools are used together in any order, as needed, bringing neighboring entities into shared relief when appropriate and possible

Market (Primary)

Market re-dispatch

Manual commitment of generation, when necessary

Economic Topology Optimization (10/1 Implementation)

Other Mitigation Actions

Transmission reconfiguration

Pre- or post-contingency mitigation plans

Rescheduling or recalling outages

Coordinate relief with other entities

TOP Coordinated Action

Coordinate with TOPs, neighboring TOPs too, and RCs

Share relief and resolve the constraint together

Transmission constraints are defined consistently across all SPP systems, including the market, even when relief is shared with entities outside the market

Coordinating Along the SEAMS

- **We'll continue to prioritize open, regular communication and coordination**
  - Sharing models and projections of load, generation, and outages
  - Sharing identified transmission constraints, including potentially impacting and impacted entities and areas
  - Monitoring the impact of external outages on our footprint, and of our outages on neighboring footprints
  - Sharing key transmission elements: ratings, topology, wind and solar projections, and RAS status
  - Confirming mitigating actions and each entity's role and obligations as agreed.
- **Standardizing seams congestion management and coordination processes will make TOP coordination across the RC footprints faster and clearer on who's required to act.**

PGE Areas for Seams Consideration

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Seams Concerns

3.1 OUTAGE COORDINATION OWNERSHIP

Who owns cross-seam outage conflict mitigation: TOPs or RCs?

How are emergency outages captured ahead of market runs across seams?

4.3 AAR/DLR VISIBILITY & USE

Ensure cross-seam visibility and reliability/market use of AAR/DLR ratings.

4.5.1 CONTINGENCIES

Align cross-seam contingency activation across market operators.

4.5.2 MARKET CONFORMANCE

Ensure cross-seam market dispatch reflects accurate limits and capacity on transmission.

4.5.5 SCHEDULE CURTAILMENTS

Coordinate cross-seam transmission schedule curtailments and its impact on market dispatches.

ARE ROLES, DATA, TIMING & LIMITS ALIGNED ACROSS SEAMS?

Source: Seams Panel.xlsx, Process Flow / Process Steps tabs

PacifiCorp – Experience & Challenges

- Market to Market communication/coordination
- Lack of RC-RC procedures governing how to resolve dispute at seams
- RC Data Coordination
- Two different RC OPA's sometimes disagree
- Solutions to Transmission Constraints
  - Transmission Reconfiguration, Gen Redispatch, Market Enforcement, Maintenance Cancellation
    - But who

BREAK

CONGESTION MANAGEMENT EDUCATION PRESENTATIONS

Moderator:

Branden Sudduth
WECC

Panelists:

- **Kelsey Martinez** — PNM
- **Jamil Daouk** — CAISO
- **Hayden Johnson** — SPP

PNM | TRANSMISSION & MARKET OPERATIONS

Real-Time Congestion Management

Why market tools are needed to keep the transmission system affordable and reliable

The PNM System: Renewable-Rich, Constrained

SETTING THE STAGE

Heavy exporter of VERs

- Large variable energy resource fleet serving load well beyond our own footprint

Excess in many hours

- Carbon targets require nameplate capacity that far exceeds load in many hours

Headroom is the asset

- Maximizing transmission utilization is how more low-cost renewables connect

Constraints are not static

- Unpredictable: constraints appear with weather, outages, and flows that shift hour to hour
- Mixed duration: some bind for minutes, others persist for hours or across seasons
- The usual fix is curtailment of renewables — the most affordable energy on the system

Managing Congestion Before WEIM Tools

THE MANUAL ERA

Manual curtailment of internal resources

- Operators cut flow in one direction to relieve the constraint
- Limited economic input into the decision

Judgment over cost

- Choices relied on operator knowledge of which resources could fix the issue
- Fairness and equity drove selection more than price

Reliability coordinator role

- Could recommend solutions drawing on resources across multiple balancing authorities

Why it became less effective

- As the PNM system changed, conditions shifted far too fast to keep managing this way

The System Changed Faster Than the Process

INEFFICIENT UTILIZATION

Manual methods left transmission capacity unused — and cheap energy trapped behind it.

Capacity left on the table

- When wind output fell below Available Transmission Capacity, the process was too slow to fill the gap with cheap solar exports

Inconsistent curtailment mechanics

- Some resources respond automatically to tag adjustments
- Others need a scheduler to spot a tag change and call a control room

Uneven communication paths

- Some resources connect directly to PNM's EMS; others still require phone calls

A different fleet

- From a few large central units to many small resources with mixed communication

WEIM Tools Made Congestion Manageable

REAL IMPROVEMENT

PNM saw real improvement in congestion management through WEIM participation.

Wide visibility

- Market solutions must respect transmission constraints, so the engine sees the best system-wide dispatch

Economic dispatch

- Resources bid in, so the selected solution is the most cost-effective one available

Direct communication

- The market reaches every participating resource through the Automated Dispatch Signal

What Real-Time Congestion Actually Is

N-1 CONTINGENCY ANALYSIS

1

Power flow

Operator tools run system power flows every couple of minutes

2

N-1 test

Flag conditions where losing any element could exceed a system operating limit — thermal, stability, or voltage

3

Program limits

WEIM tools let operators and engineers load line limits and N-1 analysis into the market data set.

4

Price the fix

The market raises and lowers prices on either side of the constraint to resolve it economically

These price signals form the “location” in locational marginal pricing.

Why Market Tools Are Uniquely Capable

NO SUBSTITUTE EXISTS

One central data location

- The only tools that hold system, resource, and price data in a single place

Full resource physics

- Ramp speed and availability for every participating generator

Full price visibility

- Bid and cost information across all participating resources

Direct dispatch signals

- Communication straight to generators — not tag based

Fast cadence

- Solutions every 15 minutes; dispatch changes every 5 minutes

Hard to replicate

- No other system will have these abilities as the market breaks apart

Day 1 With New Market Seams: the ECC

WHAT IT DOES — AND DOESN'T DO

What the ECC does

- Gives widespread visibility of congestion causes and solutions to system operators and reliability coordinators
- Proven concept in the East for roughly 25 years in large RTO systems
- Allows tag-based curtailments,
- Offers an option for market dispatches to aid a solution

What it doesn't do

- Tag-based curtailments take minutes; the solution can change before it lands
- No pricing from the other market, and neither market knows the outcome of the other's dispatch
- No coordinated bi-directional fix when the solution spans market footprints

Open question: will ECC participation be voluntary?

JOAs and RC Communication

NECESSARY, BUT NOT SUFFICIENT

Congestion across seams will lean heavily on JOAs and reliability coordinator communication.

Visibility falls short

- Operator visibility stops at their own system and adjacent connection points
- Congestion needs a wider view than any single operator's tools provide

Coverage falls short

- JOAs cannot cover the range of conditions our resource and load changes now create

Speed falls short

- Not fast or dynamic enough for the constant swings of an evolving resource mix

Room for improvement in status quo

- Even 5-minute dispatch changes are often too slow to keep up with changing constraints

Potential Ways Forward

PRIORITIES

1. Move quickly to regain the real-time congestion benefits that come with market tool integration
2. Improve on Eastern market-to-market tools, which arguably do not work very well today
3. Goal should be to use every bit of the transmission system with economic, dynamic dispatch — affordability first, with clear reliability benefits
4. Advance the ECC toward sending automated dispatch signals directly to a generator

Bottom line: not capturing the economics across market seams will drive costs up until market tools are coordinated.

What We're Asking For

THE ASK

1 **Keep market tools in the congestion solution**

Real-time congestion management should sit inside a market engine that sees constraints, prices, and resource capability together.

2 **Build the seam to dispatch, not just to notify**

Advance the ECC beyond tag-based curtailment toward automated dispatch signals sent directly to generators.

3 **Judge the outcome on affordability and reliability**

Full, dynamic use of the transmission system lowers customer cost and strengthens reliability at the same time.

Coordinated market tools are how the transmission system stays affordable and reliable.

Western Energy Market Transmission Constraints

Jamil Daouk

Principal, Application Integration, CAISO

Overview

Full network model

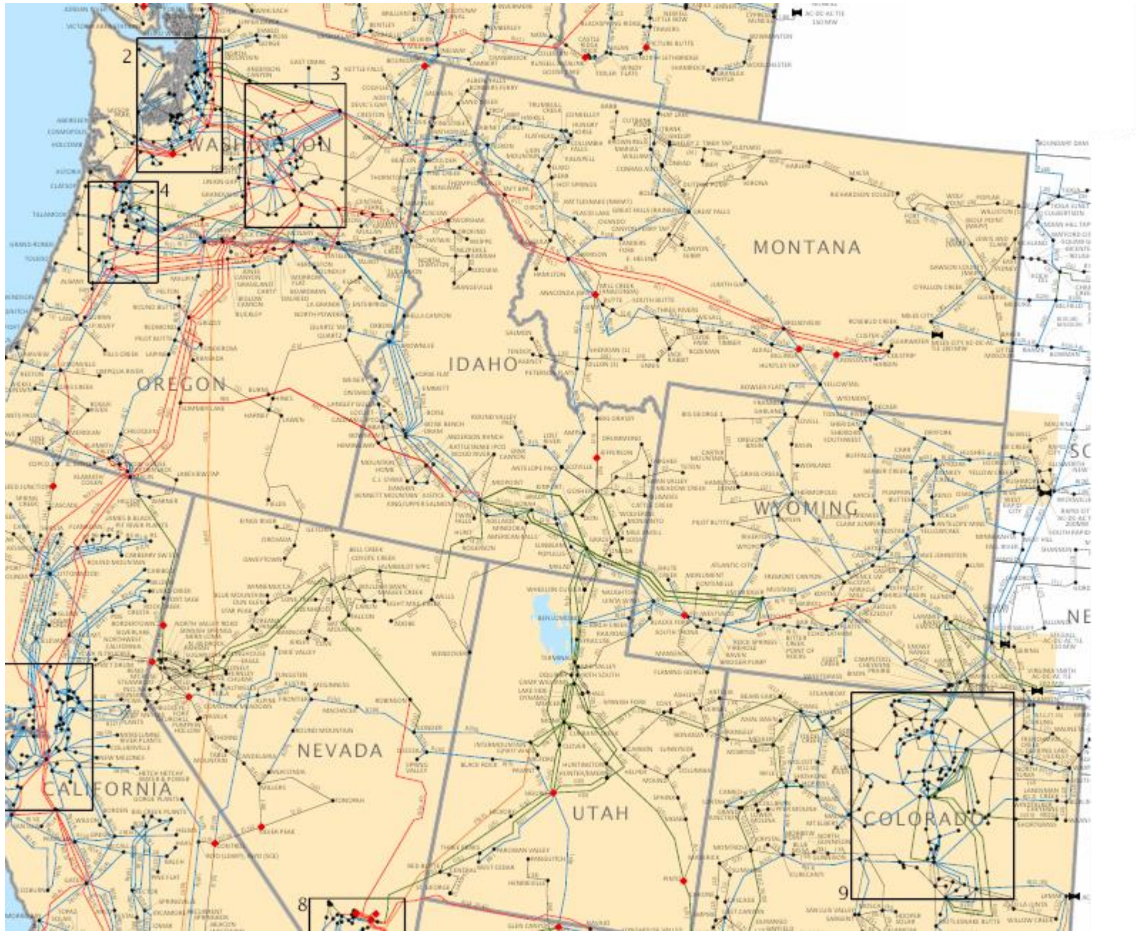
- West Wide View
- Load/Gen/Interchange Estimation
- Power flow and Calculation of Flow
- Application of Power Flow

Overview existing Market Constraint

Coordination between Markets

Full Network Model

- Western Energy Market introduced the use of WECC full network model into Western Energy Market applications
- The Full Network Model (FNM) is updated with the coordination of Onboarding WEIM entities, RC member onboarding, and RC/RC collaboration



Generation/Load/Interchange Forecast

Market Entities

- Load forecast based on CAISO Forecast Services and agreement for rolling DA, Hourly, 15-Min and 5-Min forecast.
- Interchange Forecast based on Base Schedules and Market optimized solution for Import/Export Schedules.
- Generation forecast based on Base Schedules and Market optimized solution for generation schedules

Non-Market Entities

- Entity submitted BA Load forecast in rolling DA and Hourly forecast
- Interchange forecast based on Forecasted/Submitted tags, aggregated to an Area-to-Area Net Schedule Interchange (AANSI)
- Entity submitted Generation forecast adjusted by Generation distribution factor based on Load forecast and interchange

Power flow and Calculation of Flow

- Using Market and Non-Market Generation, Load, and Interchange schedules market calculates the flow on all Network model defined transmission elements.
- Flow calculated to include all network model defined transmission element within Market footprint and outside the Market footprint.
- Enforce and mitigate transmission elements within the Market footprint deemed critically constrained

Applications of Power Flow

- Full Network Model power flow is used in
  - Day Ahead Market Runs
  - Reliability Unit Commitment Runs
  - Short Term Unit Commitment
  - Fifteen-Minute Market
  - Real Time Dispatch
  - Look Ahead Contingency Analysis (LACA)
    - Includes Day Ahead Contingency Analysis and Real Time Contingency Analysis)

Constraint Types

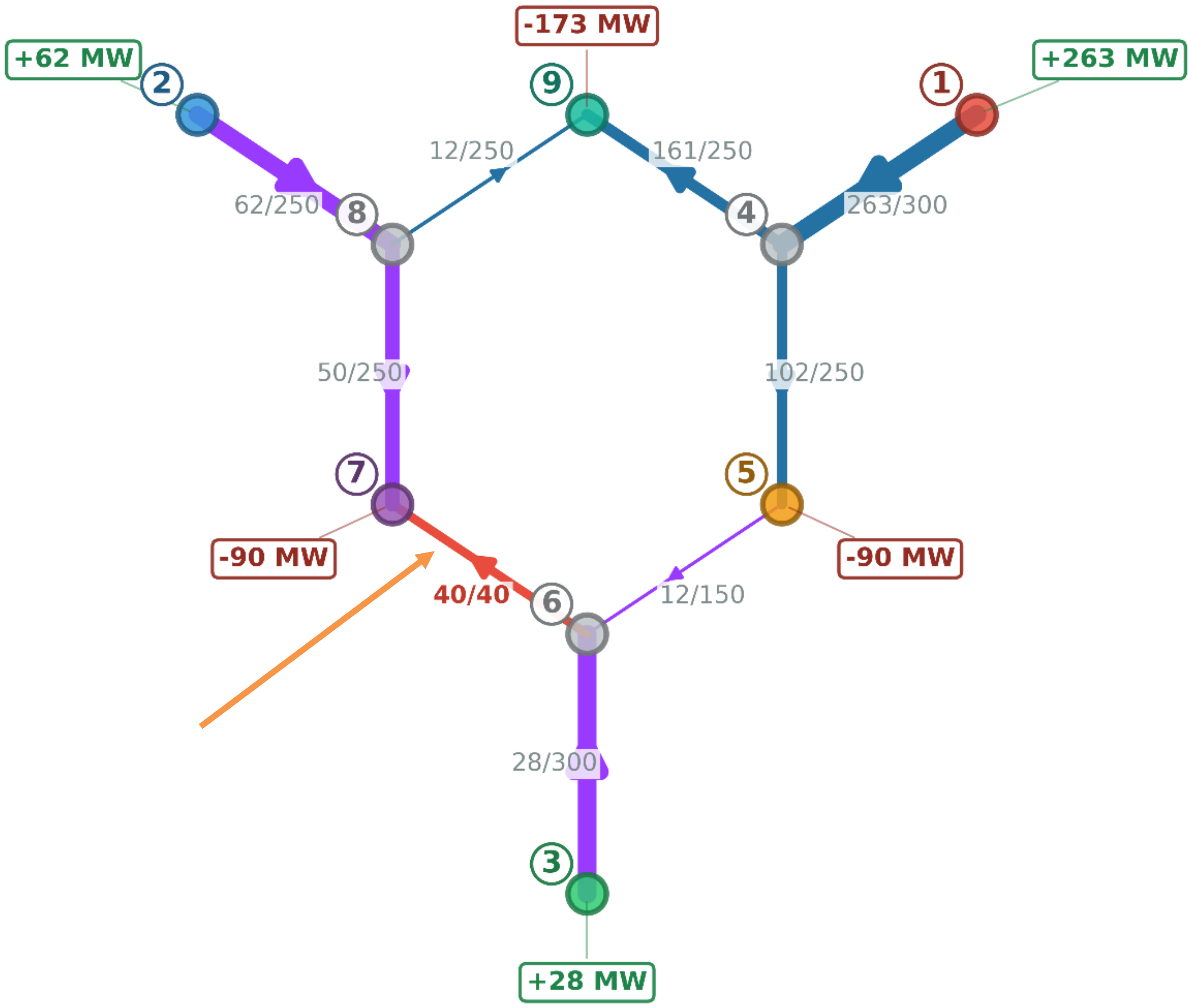
- Market Flow Constraints
- Market Contingency Flow Constraints
- Entitlement Constraints - Total Flow Constraints

Market Flow Constraints

- Market Flow Constraints are any transmission element within a Market footprint.
- Constraints are Monitored and Enforced within the Market.
- Market uses shift factors based on the optimized Market resource solution and estimated non-Market resource calculated within application power flow
- Constraint Limits are determined using the network model transmission element normal limit.
- Both Market and Non-Market schedule can impact the Market Flow Constraint, but only Market resources are used to mitigated with the Market flow constraints.

Example Flow Constraint

- Market flow and estimated non-market flow are used by the power flow to determine constraint impact on Market flow



Market Contingency Flow Constraints

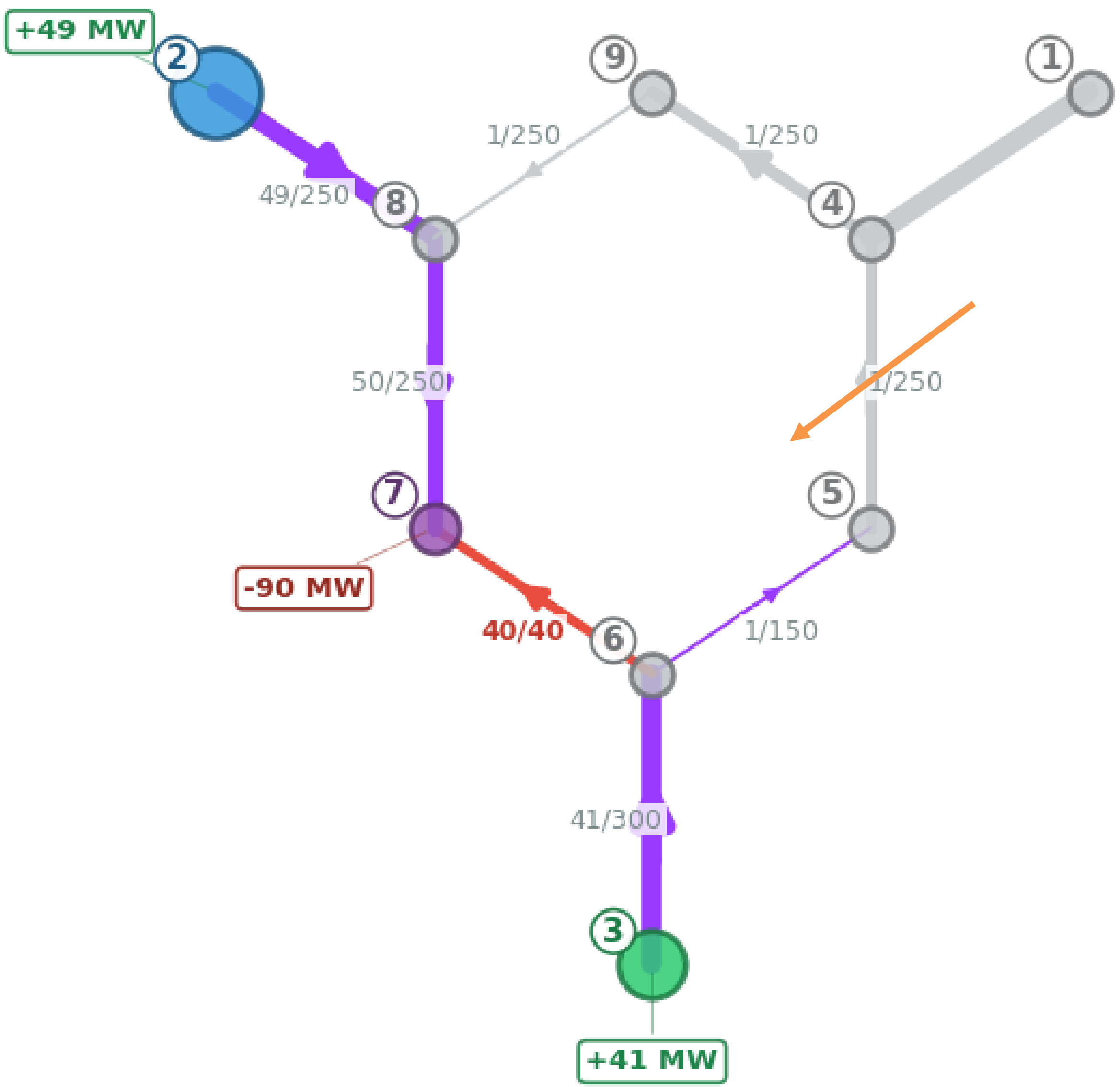
- Similarly to Market flow constraints, Market Contingency Flow Constraint are market constraints identified within a contingency run on any transmission element within a Market footprint.
- A Subset of contingencies, determine by a process, between the Entity and the Market Operator contingencies are run within each market run.
- Constraints are Monitors and Enforces Market Constraints while activating an N+1 contingency.
- Market uses shift factors based on the optimized Market resource solution and estimated non-Market resource calculated within application power flow.
- Line
- Mitigates constraint market resource impact to constraint.

Entitlement Constraints

- Based on a predefined external constraint
- Calculates total flow, based on Market resources only
- Calculates shift factors based on Market run, to calculate Market resource impact to external flow constraint.
- Limits Market flow on the external constraint

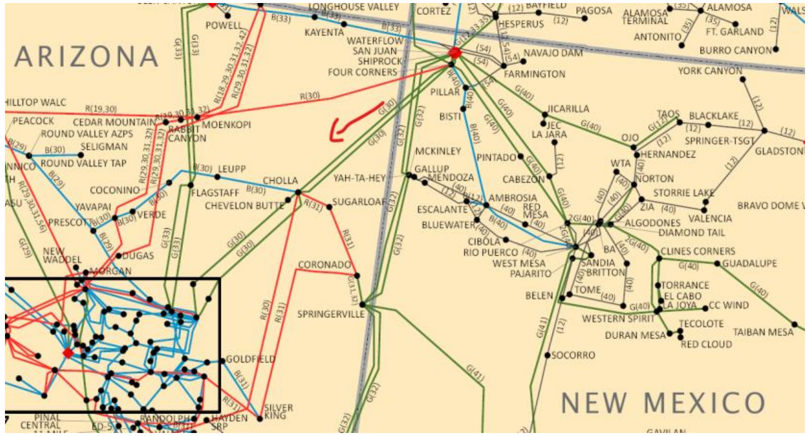
Example Entitlement Flow Constraint

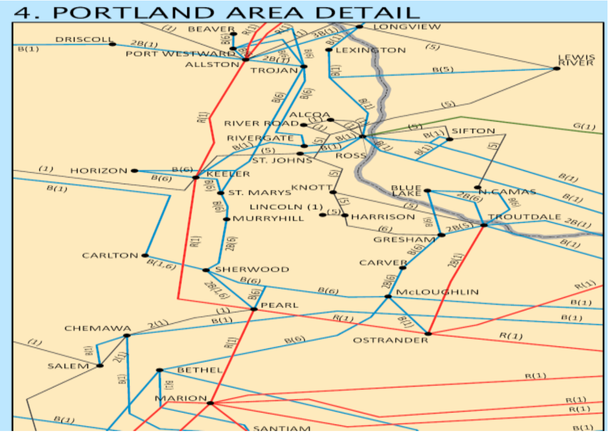
- Market Flow used by the power flow to determine constraint impact on non market constraint

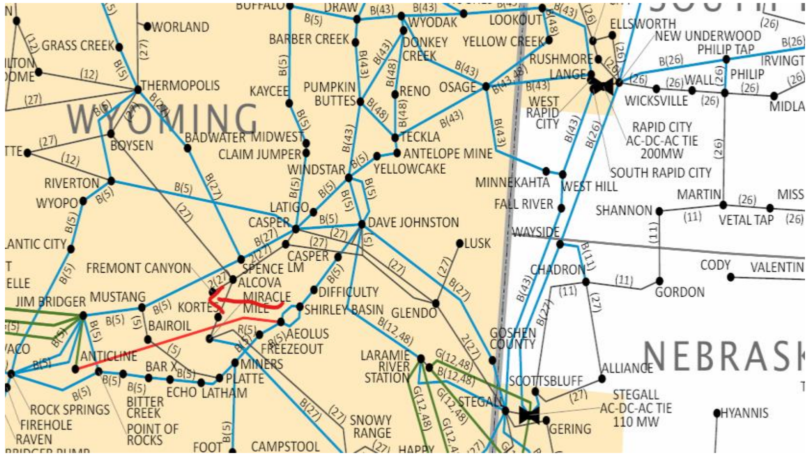


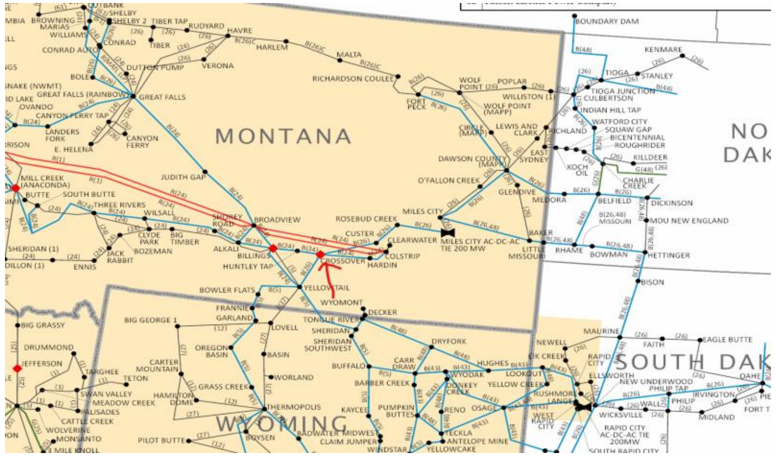
Coordination between entities

- How are the constraints being used in existing Seams constraint mitigation









Process between Entities

- Using Market Flow Constraints entities identify constraints within their control area that are impacted by external resources and adjust the Market Flow Constraint limits to ensure the market accommodates external flow.

- Total flow Constraint are market tool used between CAISO Market and BPA, in which CAISO calculates market flow impact on BPA defined constraints, and allowing BPA to provide Real time update total flow limit allowing Market mitigation of flow

SPP West RC Congestion Methodology and Mitigation

SPP Congestion Management Methodology

Purpose:

- SPP Congestion Management Methodology provides procedures for mitigating System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances in real-time operations.

- This ensures the safe and reliable operation of the Bulk Electric System (BES) in the Western Interconnection.

Monitoring & Managing SOLs

Congestion Management Using Markets

- **Markets provide relief on a constraint when an effective limit is observed in reference to flow on an identified facility.**
  - When flow is expected to reach or exceed that limit, the solution creates a price separation around that constraint to incentivize re-dispatch.
- **Physical Flow Control is used when the market controls the total net flow on the facility in reference to the SOL regardless of the contribution.**
  - This will evaluate both market and non-market flow and re-dispatch market generation to mitigate any projected exceedance of the observed limit.
  - The observed limit is representative of a system operating limit when a constraint is activated in physical flow.
- **Market Flow Control is used when the market controls the contribution of market generation serving market load.**
  - The observed limitation for Market flow control is set by evaluating the current contribution to a constraint minus the requested relief.
  - Market Flow targets can be more or less than the SOL, and the market flow does not observe the change in non-market contribution to the constraint.

Monitoring & Managing SOLs

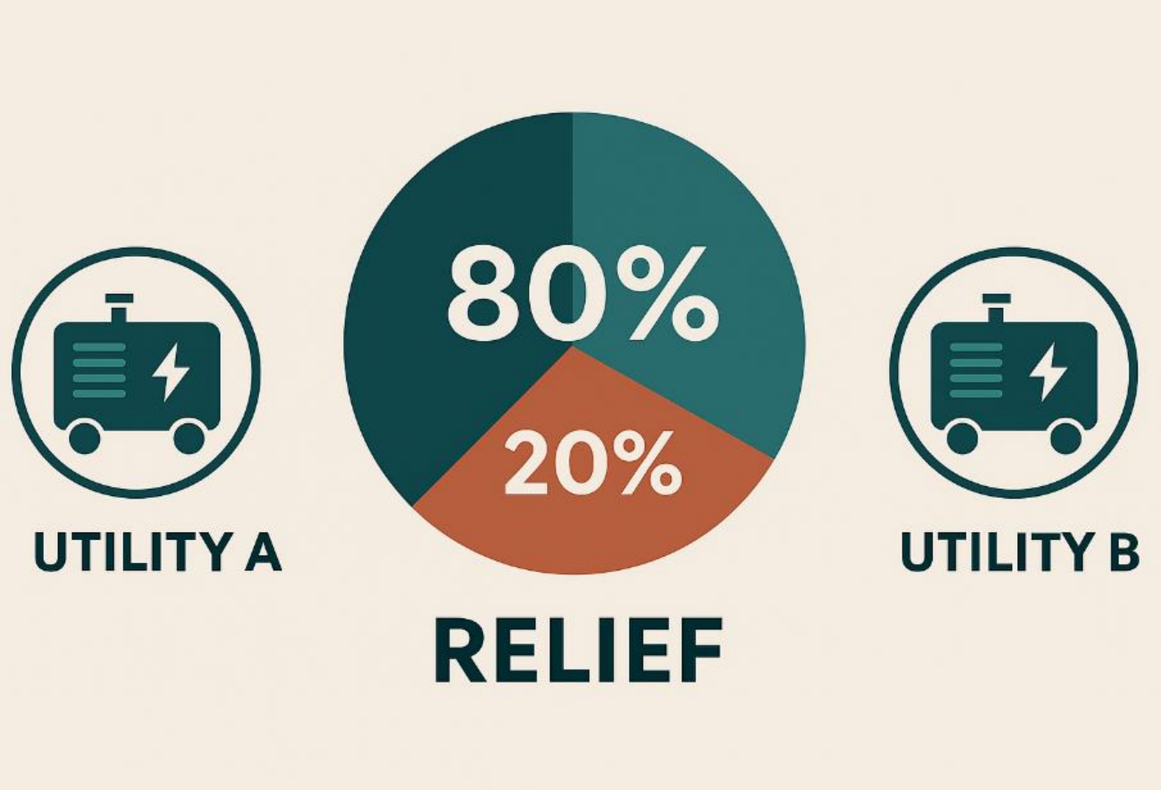
- Tools used: EMS alarm summary, Real-Time Contingency Analysis (RTCA), custom applications
- SOL exceedance criteria:
  - Flow above normal/emergency limits
  - Voltage outside normal/emergency limits
  - Instability risk from contingencies
- RC coordinates mitigation actions with impacted entities.
- Corrective actions are dictated and administered in accordance with the SOL methodology and the SPP West RC Congestion Management Methodology.

SPP West RC Congestion Management Methodology (CMM)

- Agreed upon method of mitigating SOL exceedances in the SPP West RC area
- Owned and maintained by Western Reliability Working Group (WRWG)
- Development and maintenance driven through SPP's stakeholder process.

Congestion Management Steps

1. Validate SOL exceedance and system conditions.
2. Apply OP-guides, agreements, mitigation plans, or Unscheduled Flow Mitigation Plan (UFMP).
3. Coordinate with BAs for unscheduled flows.
4. Evaluate Phase Shifting Transformers (PST) for mitigation.
5. Assess outages and recall actions.
6. Reconfigure transmission as needed.
7. Redispatch generation on a pro-rata basis:
   - Individual Resource Operating instruction
   - Total Net Relief Obligation: Relief targets can be achieved using a fleet of generators.
8. Initiate emergency operations with neighboring RCs.
9. Evaluate and coordinate load shedding.
10. Notify impacted parties when exceedance is mitigated.

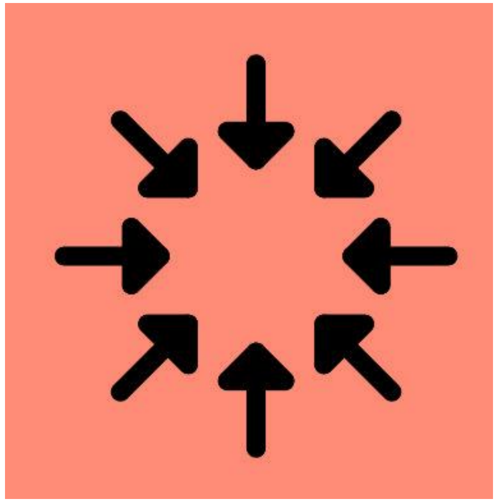


Generation Re-Dispatch

- Resources Ranked by GLDF Impact.

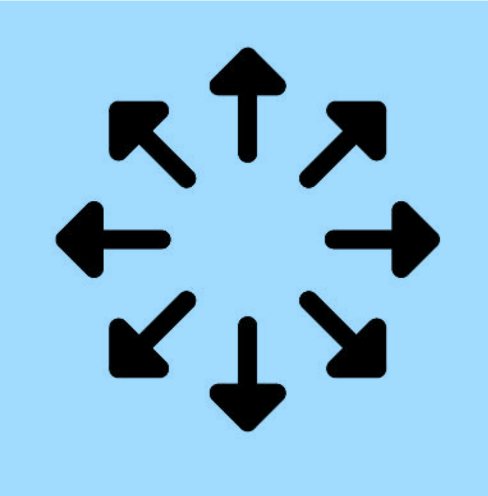
Group	Percent GLDF	Minimum Available Relief in MW	Maximum Number of Units
1	75%	10	5
2	25%	10	5
3	10%	10	5
4	7%	10	5
5	5%	10	5

- SPP assigns relief based on pro-rata distribution, and on impact and relief available.
- Electronically equivalent generators are considered a single resource.
- Resources that reside in a common dispatch group have the option to meet the aggregate of the resource's relief obligations.



Internal Participation in Total Net Relief Obligation

- BAs/Market Operators must designate participating generators.
- Participation changes require 45-day notice to ensure modeling reflects the participating load and generation.
- RC calculates relief based on GLDF (GSF-LSF) and MW impact
- If the RC determines that a BA or Market Operator is ineffective, their designation may be terminated.



Coordinating Total Net Relief Obligation **w/External Parties**

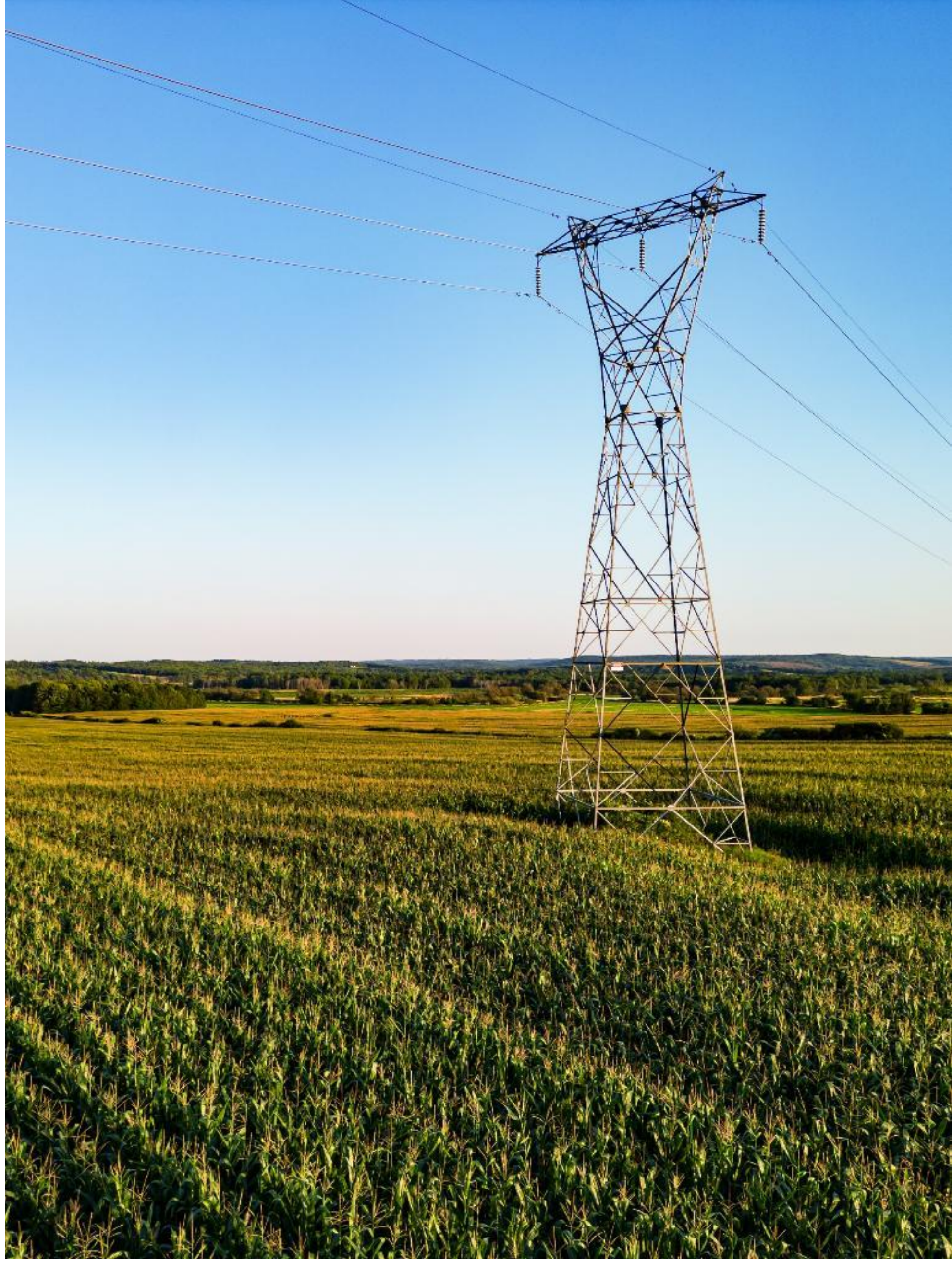
- Relief targets can be determined using the methodology described in the CMM or consistent with a mutually agreed upon operating agreement.
- SPP calculates its generation-to-load impact using market generation and load on constraints defined as flowgates.
  - This calculation is also done by third party applications like ECC.
- Market activation can be implemented in Market Flow mode to provide relief using a fleet of generators.

RC – RC Unplanned Coordination

RC – RC Coordination

- SPP West RC coordinates with neighboring RCs to resolve disputes involving multiple RC areas.
- When entities disagree on reliability actions, the most conservative action is taken until the issue is resolved.
- The RC – RC Agreement requires RC-to-RC communication during emergencies, disputes, and operational disagreements.
- These real-time system events are reviewed by both parties to determine the need for more document operational actions.

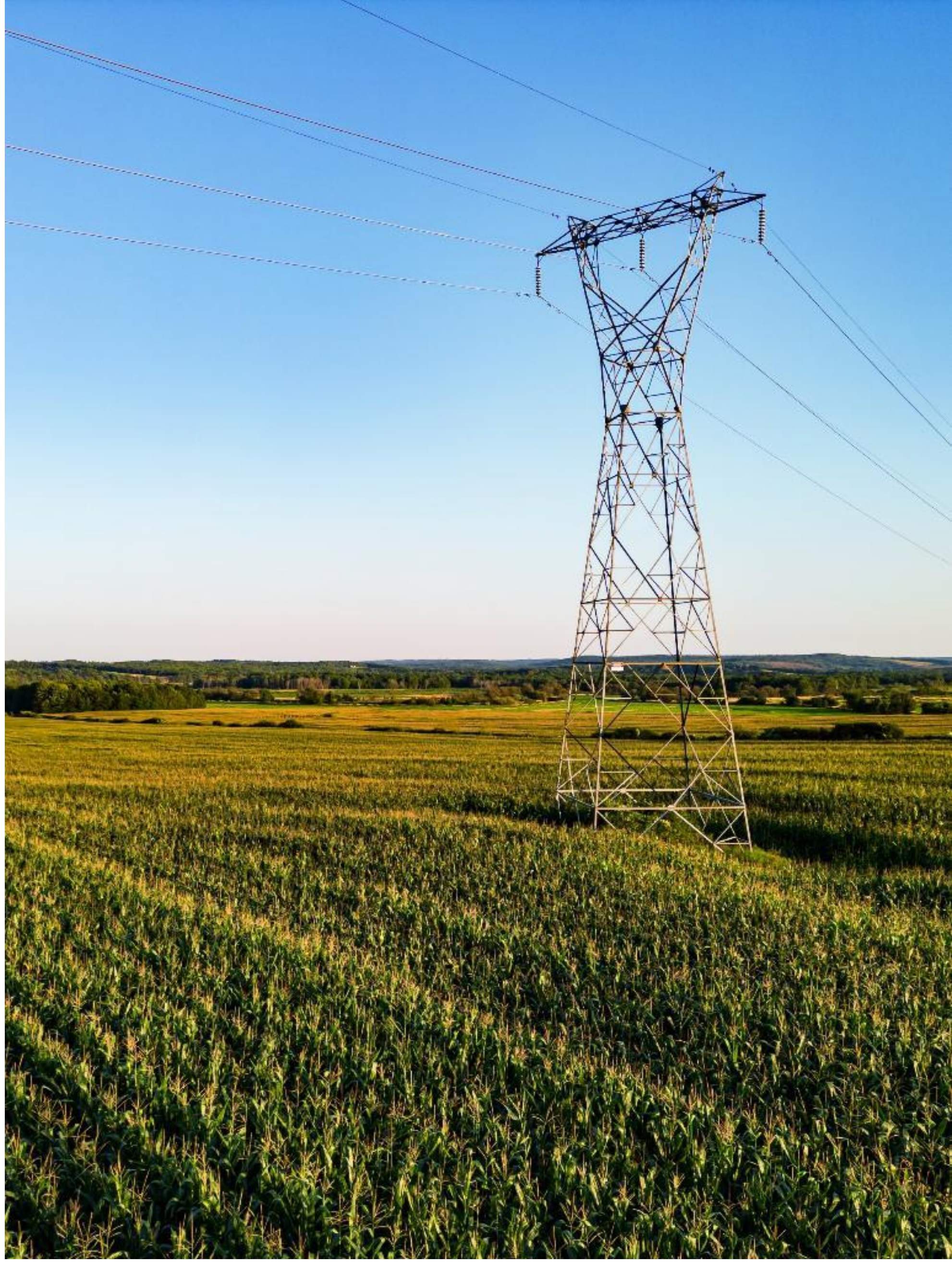
Emergency Coordination w/ Neighboring RCs



- Initiation of Emergency Operations
  - When a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance cannot be mitigated with internal actions, the SPP RC initiates emergency operations with neighboring RCs.
  - Done in accordance with NERC Reliability Standards to ensure system reliability across RC boundaries.
- Communication and Coordination
  - The SPP RC communicates the nature of the emergency, affected facilities, and required actions to the neighboring RCs.
  - Coordination may involve sharing real-time system conditions, contingency analysis results, and mitigation plans.

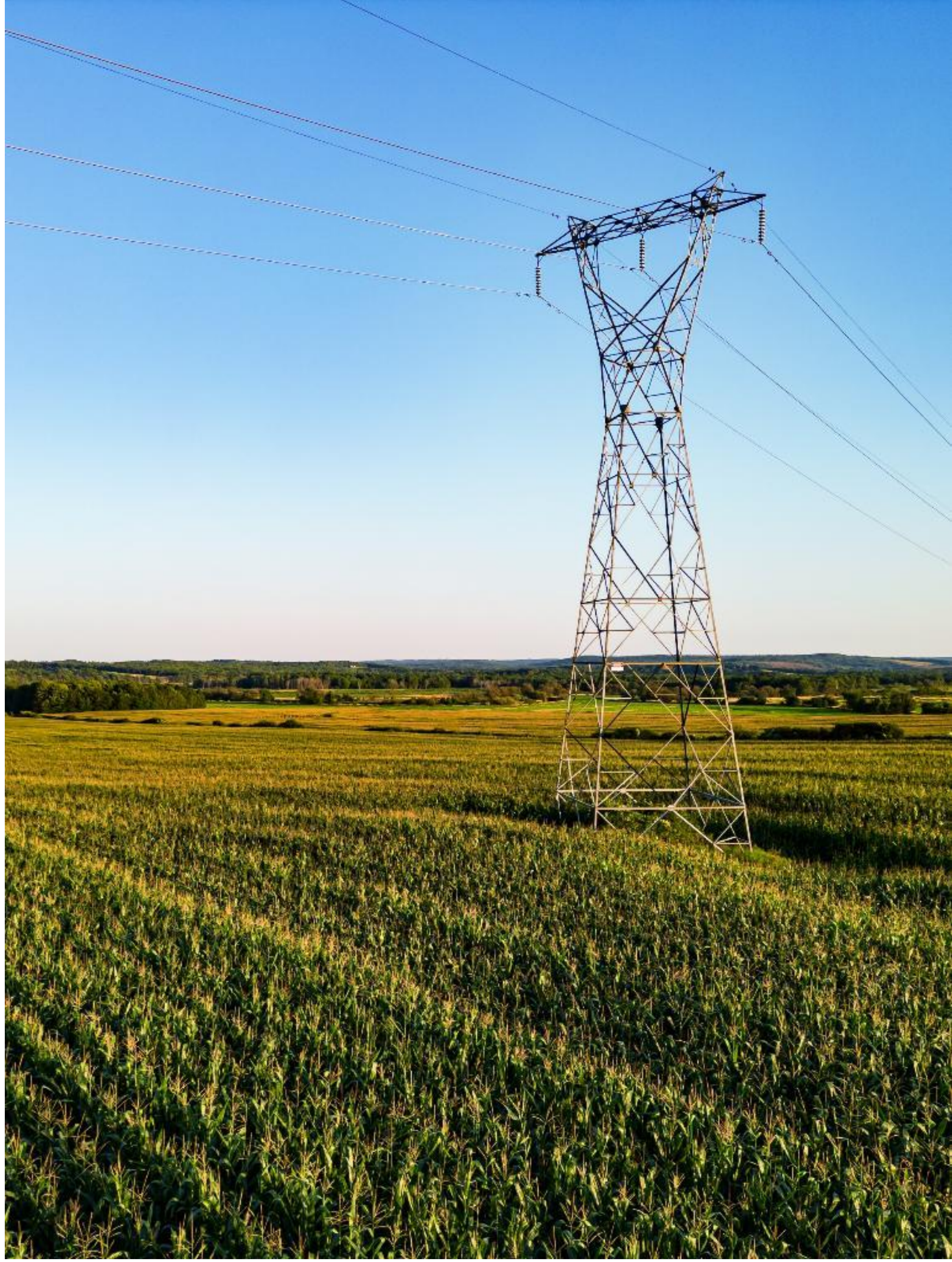
Emergency Coordination w/ Neighboring RCs

- Joint Mitigation Actions
  - Neighboring RCs may be asked to participate in redispatching generation, reconfiguring transmission, or implementing load shedding as needed.
  - Actions are coordinated to ensure that relief is achieved efficiently and reliably, minimizing risk to the Bulk Electric System (BES).
- Notification and Follow-Up
  - Impacted Transmission Operators (TOP), Balancing Authorities (BA), and RCs are notified when the exceedance has been mitigated.
  - The SPP RC ensures that all parties are informed of the resolution and any ongoing risks.



Emergency Coordination w/ Neighboring RCs

- Dispute Resolution
  - If disagreements arise regarding mitigation actions, the SPP RC coordinates with neighboring RCs to resolve disputes.
  - The most conservative operating approach is implemented until consensus or further evidence is available.

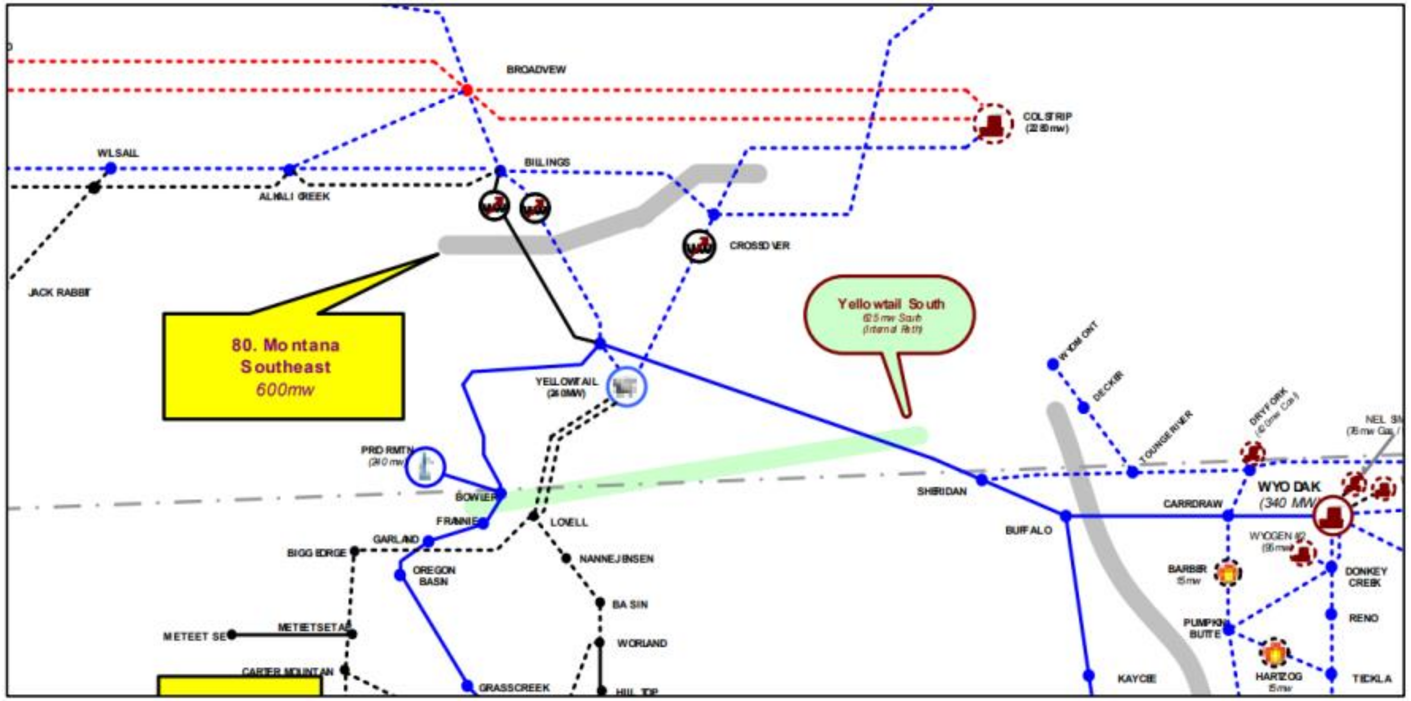


Common Constraint Coordination

Non-Emergency RC-to-RC Coordination

When looking to mitigate regularly seen contingencies along an RC-to-RC seam, SPP RC will work with that neighboring RC to develop an OP-Guide/Operating Plan.

Example: RC 9330 (NWMT Path 80 Operating Agreement)



Line	Metering Point
Billings-Yellowtail 230 kV Line	Yellowtail (PACE)
Hardin-Crossover 230 kV Line	Crossover (WACM)
Huntley-Crossover 230 kV Line	Crossover (WACM)
Rimrock-Yellowtail 161 kV Line	Rimrock (NWMT)

Path 80 Common Constraint Coordination

NWMT Path 80: Outage & Mitigation Overview

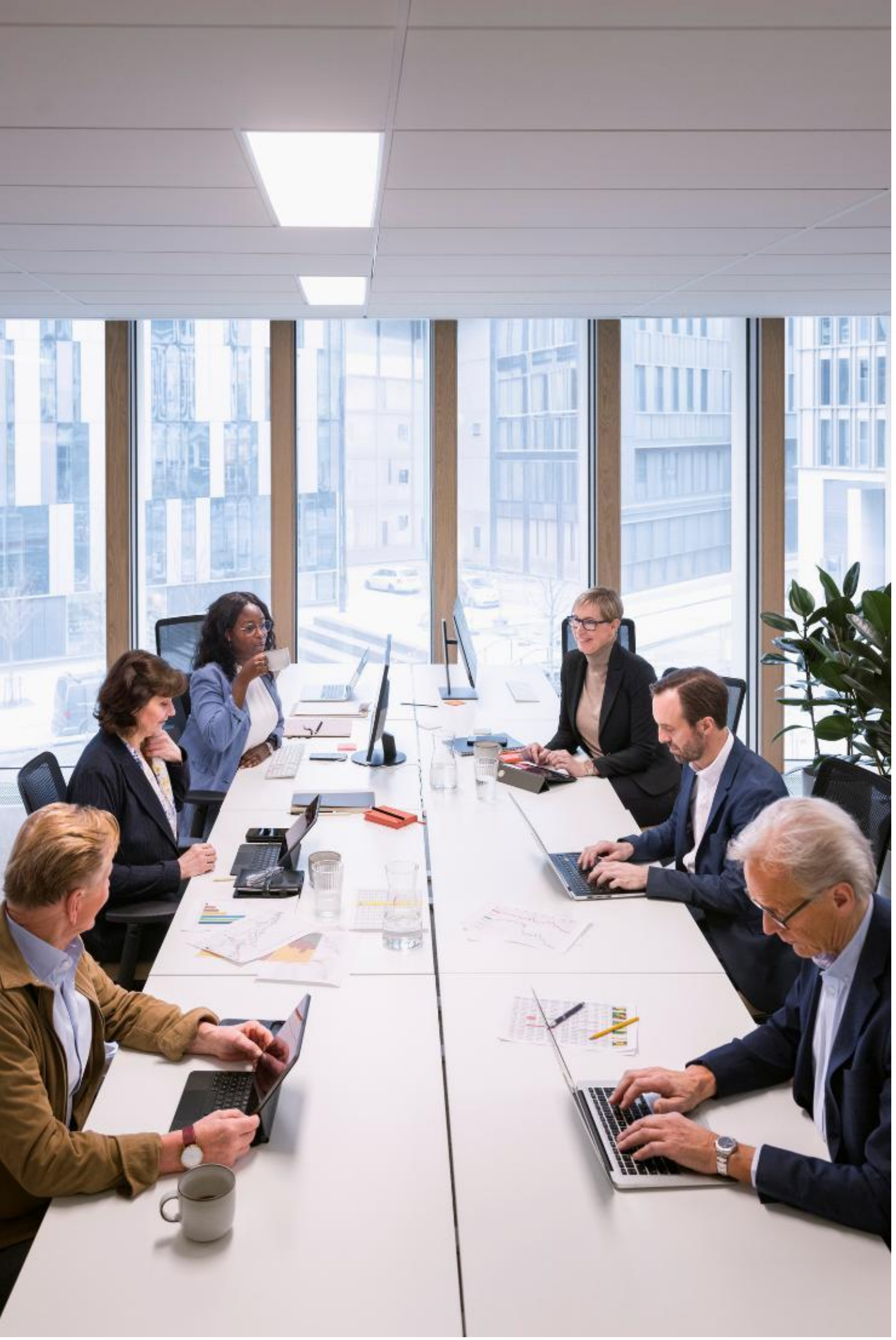
- Unscheduled South-to-North flows during outages can cause RTCA post-contingent overloads on BES lines in Path 80 interface.
- Mitigation requires coordinated action among multiple TOPs and RCs.

Joint RC Operating Guide Development

- Due to the area's location, ownership, and operational importance, SPP West RC and RC West collaborated on a unified Operating Guide.
- RCs ensured consistent participation across entities and evaluated each mitigation step to confirm equitable relief among all owners.

Ongoing Maintenance

- As topology changes, generation re-evaluation, and rating updates occur, RCs continue to refine the Operating Guide for accuracy.
- Regular updates support alignment on processes and ensure effective mitigation as system conditions evolve.



Development, Approval, and Maintenance

Initial Development of the Operating Procedure

- RCs met with all impacted parties to solicit feedback and design a mutually agreed upon operational plan.
- After all parties agree on language, they meet to approve the final document and determine its effective date.

Review period and incremental updates

- Following implementation, system changes may change the nature of the mitigation. Ongoing discussions effectuate process changes related to:
    - Remedial actions schemes
    - Markets integrations or footprint
    - Qualification of Path 80
    - System Topology that effects limiting elements
    - Operating restrictions on impactful generation
- Even if no changes are identified in a calendar year, impacted parties review the document annually to ensure actions align with current operating conditions.

Operating Guide Concepts

1. Validate Common Exceedance
2. Evaluate BA Performance
3. Coordinate PST Adjustment
4. Schedule Curtailment (UFMP)
5. Recall outages
6. RAS Adjustments / Impacts
7. Transmission Re-configuration
8. Manual Schedule Curtailment
9. Manual Generation Re-dispatch
    - Target Relief Obligation based on historical contribution
10. Load Shed

Congestion Horizons

Outage Coordination Window

Multi-Day Reliability Assessment (MDRA)

Nightly study identifies congestion and capacity concerns with available operational data.

- Load
- Outages
- Generation
- Interchange
- Constraints

Operational Planning

Study results inform the outage coordination studies for planning maintenance.

- Develop temporary operating guides
- Identify re-configuration options
- Manual generation commitment
- Cancel or reschedule outages
- Stakeholder engagement
- Applicable constraints

Day-Ahead Horizon

Day-Ahead Market

Day Ahead Market Operators use a combination of market and operational planning data to predict future operational conditions.

- Implement identified mitigations
- Common constraints
- Previously identified operating conditions
- Manual generation commitments
- Updated system topology

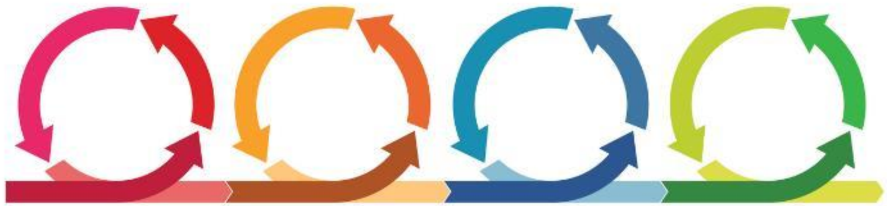
Operational Planning Analysis

Offline study identifies potential congestion and confirms whether planned mitigations are adequate.

- Use inputs from previous study horizons
- Implement agreed upon mitigation
- Identify constraints that have not been identified and ensure they are included in all relevant studies
- Communicate mitigations to real-time staff

Iterative Study Process

Aligning Study Assumptions



- MDRA informs outage coordination process, day-ahead market, and OPA.
  - Data source stays consistent, and coordination ensures mitigation is consistently applied.
- As mitigations change, processes are updated daily to ensure the most accurate information is included in all horizons.
- West CMM applied to implemented mitigation.
  - MDRA
  - Outage coordination
  - OPA
  - Day-ahead and real-time markets
- Meant to ensure that mitigations in day-ahead market align with real-time operator actions, reducing day-ahead/real-time price separation.

LUNCH BREAK

DAY-ONE CONGESTION MANAGEMENT EXAMPLES

Moderator:

Casey Cadle
SPP

Panelists:

- **Jamil Daouk** — CAISO
- **Paul Dockery** — CAISO
- **Hayden Johnson** — SPP
- **James Lynn** — CAISO
- **Jim Gonzalez** — SPP

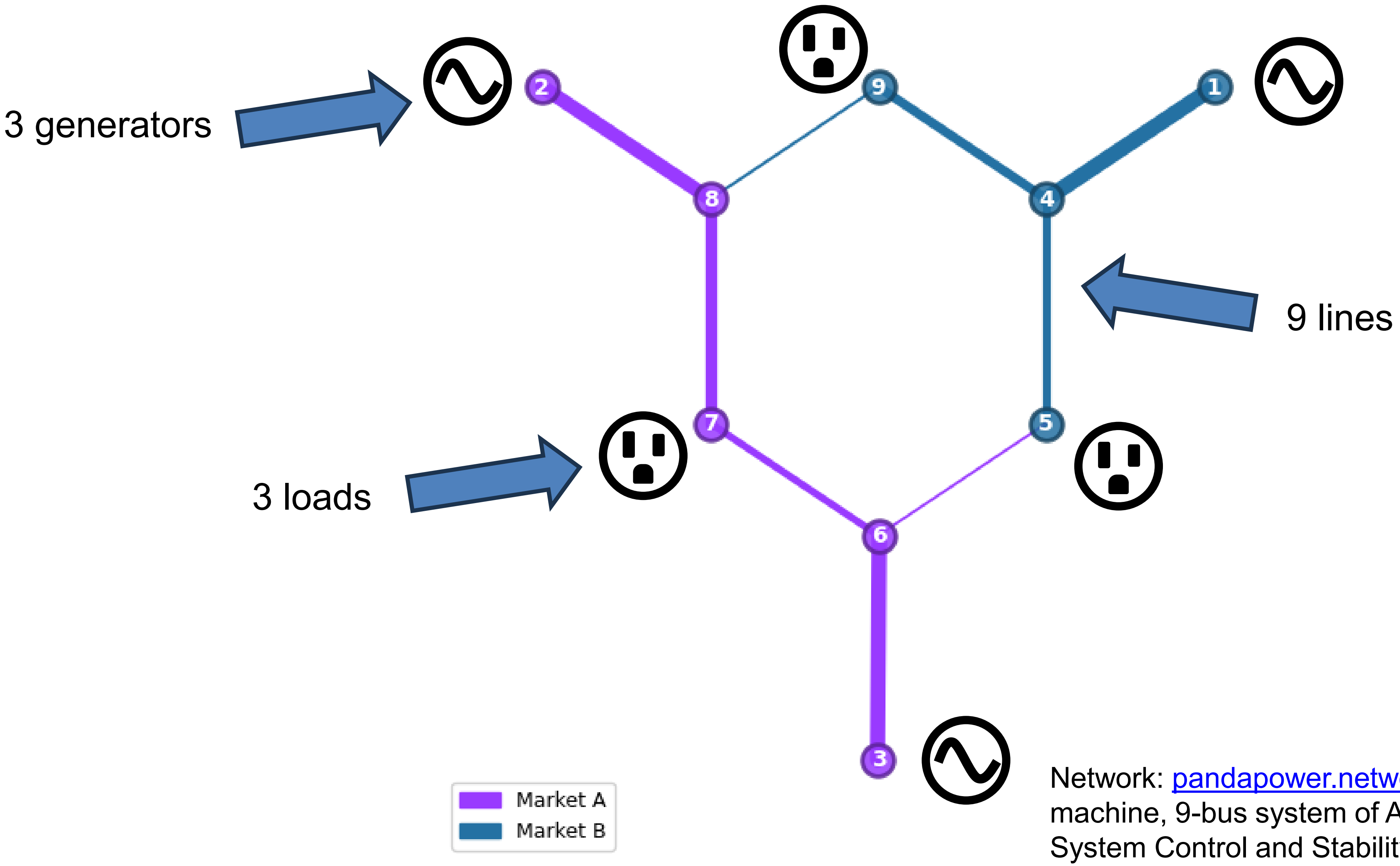
Seams Workshop – Congestion Management Examples

Paul Dockery
Market Strategy & Governance Manager

Congestion management examples using an illustrative model

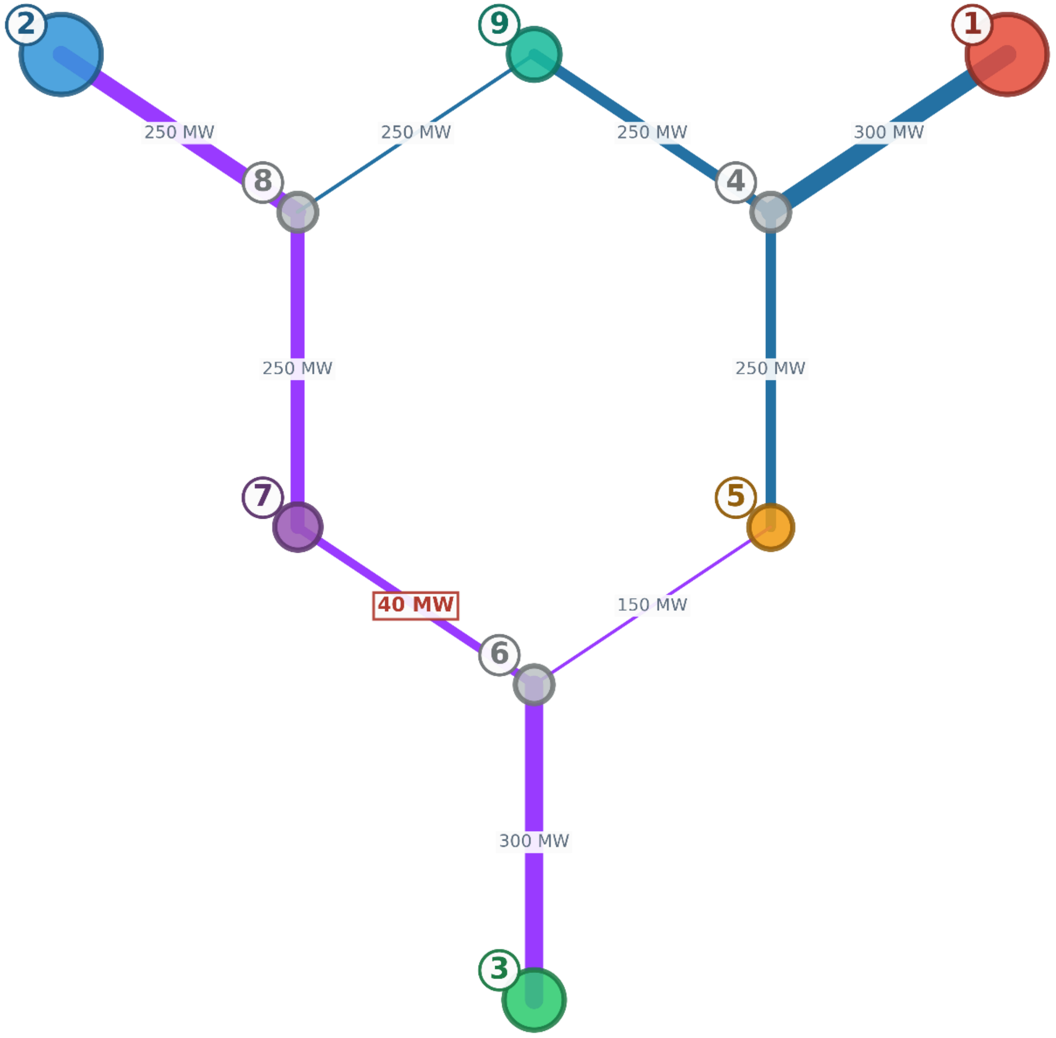
- Forecasts for nodes outside a market footprint
- Dispatch on an illustrative network with a single binding constraint under two examples
  - Ignoring flow contribution from outside the market area
  - Over-forecasting flow contribution from outside the market area
- Production cost and dispatch changes

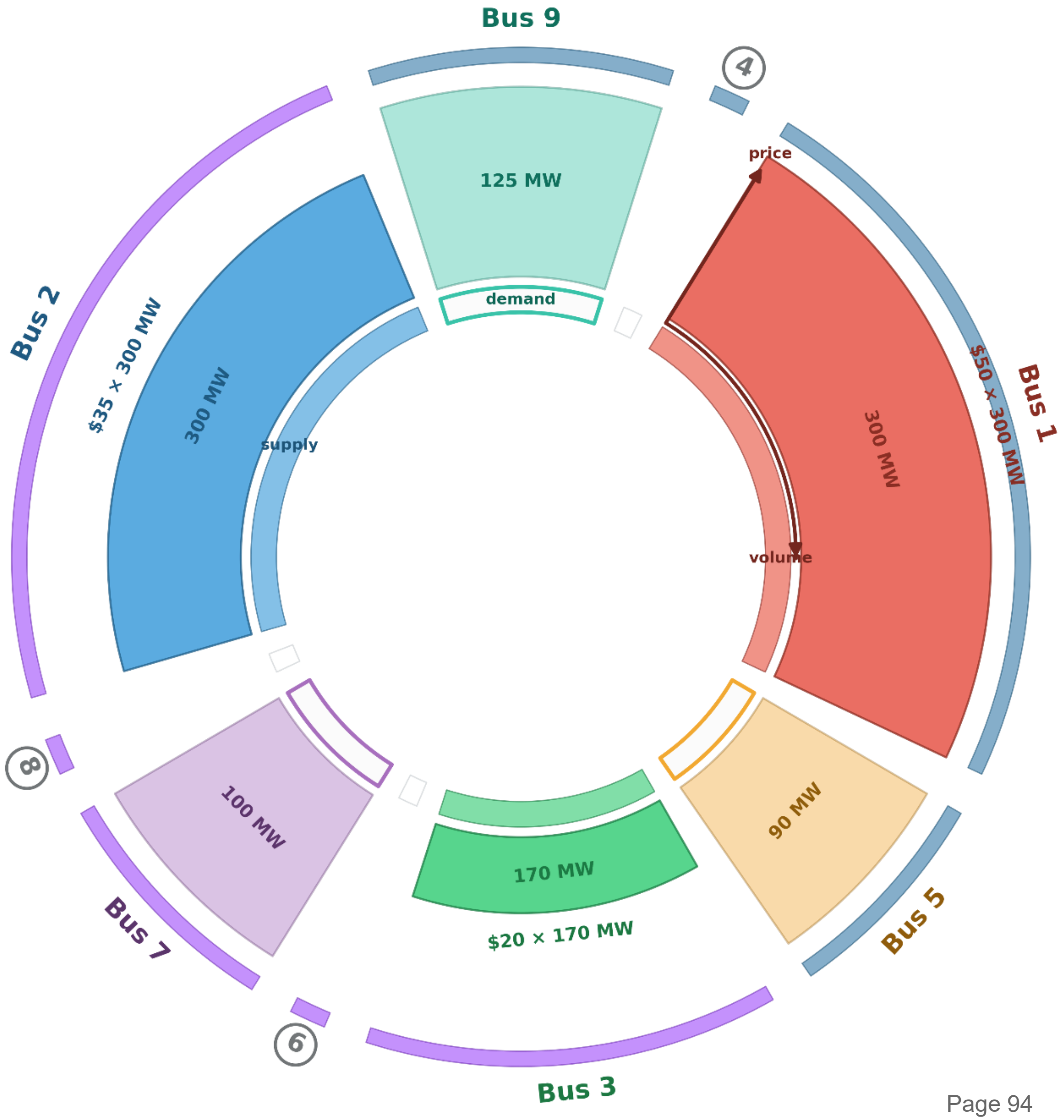
WSCC 9 Bus Test Case – Seams Example



Network: pandapower.networks.case9 after the WSCC 3-machine, 9-bus system of Anderson & Fouad, Power System Control and Stability (1977).

WSCC 9 Bus Test Case – Seams Example

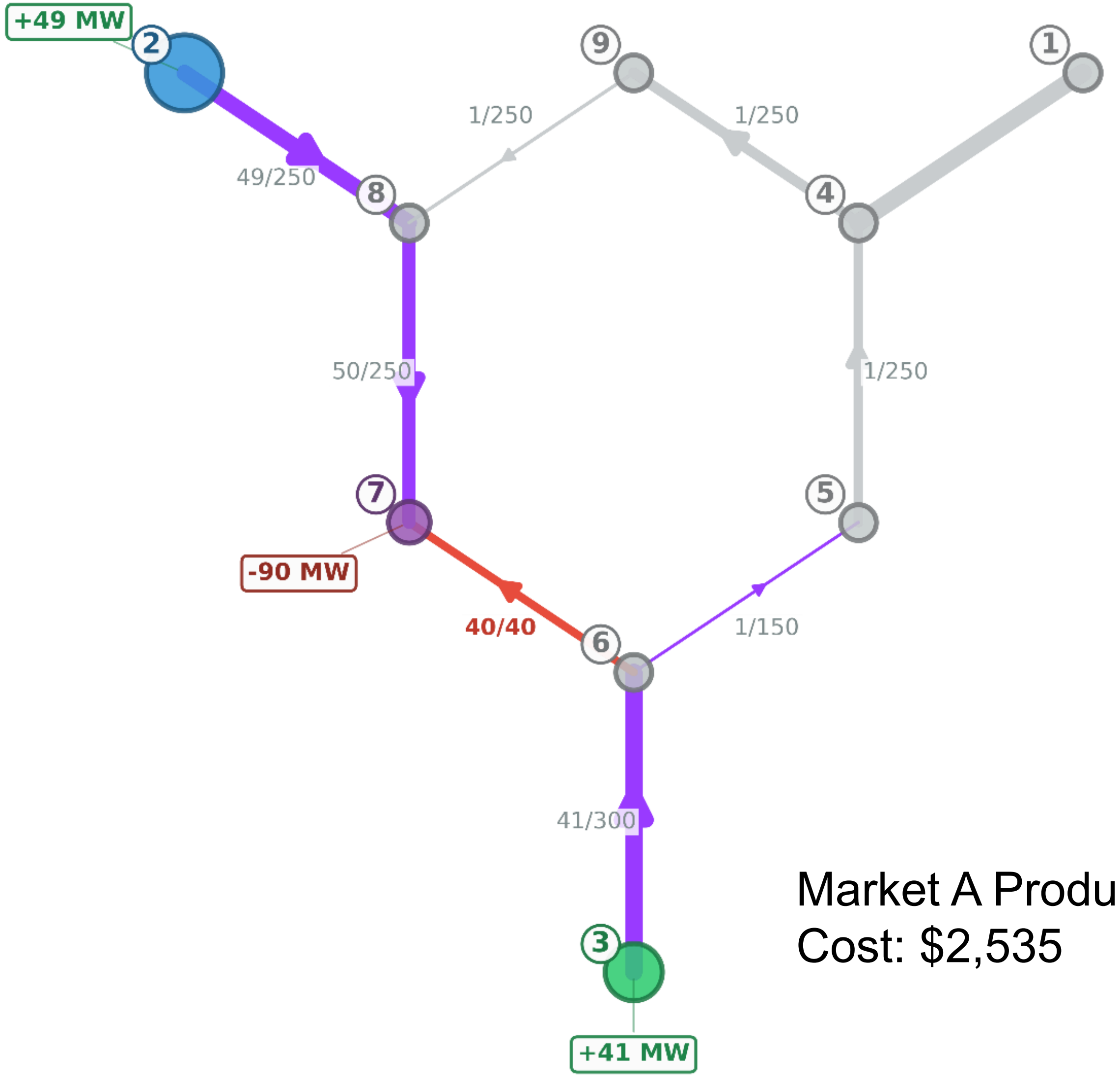




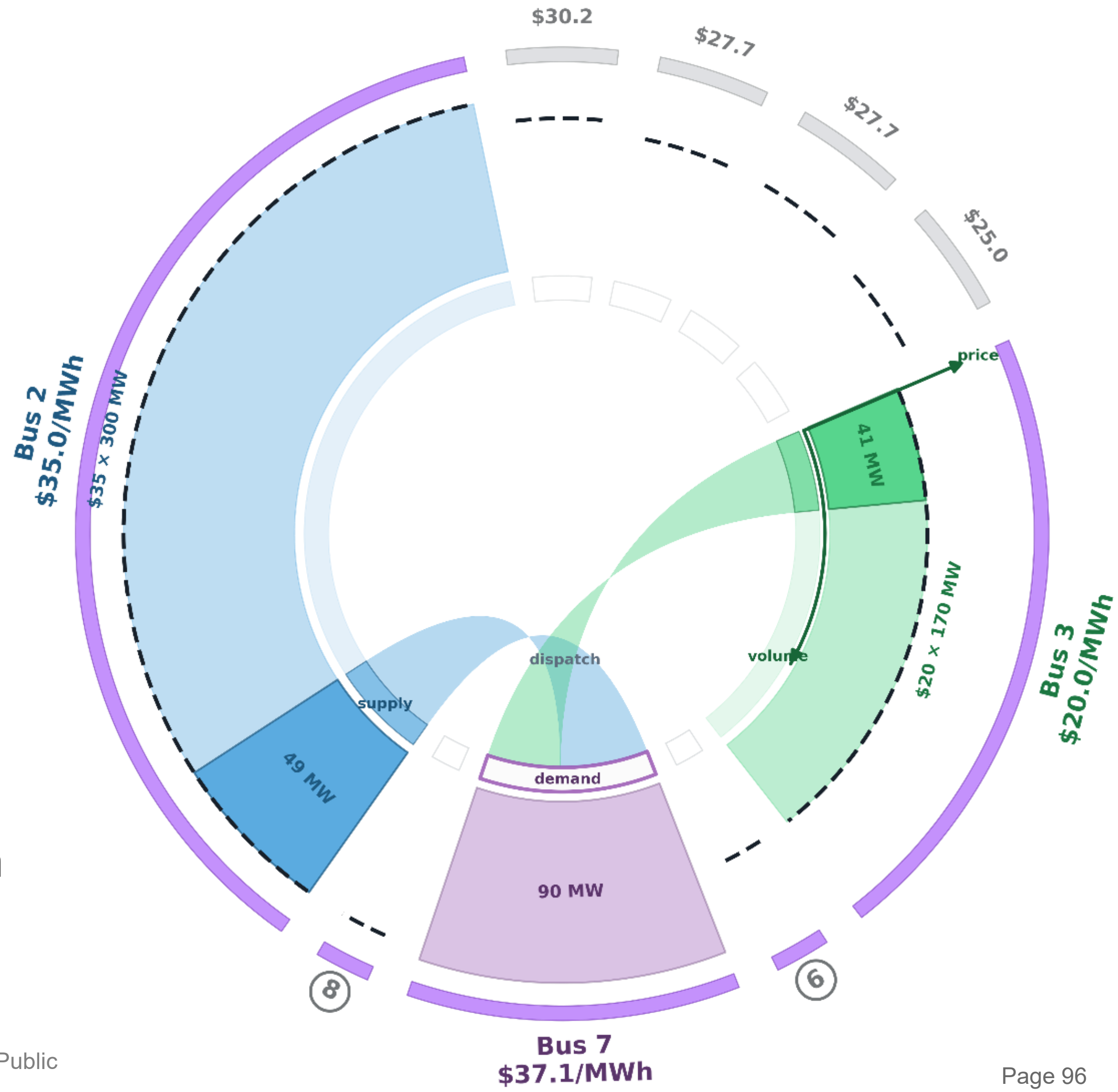
Example #1 – no forecast of neighbor's flow contribution

- Each market clears independently without accounting for each other's use of the transmission network
- Market A has a binding constraint and finds the least cost dispatch of its system resources while respecting the limit
- Market B has no binding constraints and does not monitor binding constraint in Market A
- Power flow on the network based on combined dispatch overloads a line
- Market A redispatches to bring the line back into its limits

Example #1 – no forecast of neighbor's flow contribution – Market A



Market A Production
Cost: $2,535



Example #1 – no forecast of neighbor's flow contribution – Market A

Marginal cost of serving load at bus 7

+ Bus 2 Gen

↑ 1.14 MW @ \$35/MWh

= \$39.90

- Bus 3 Gen

↓ 0.14 MW @ \$20/MWh

= \$2.80

△ Bus 7: \$39.90 - \$2.80 = \$37.10

Example #1 – no forecast of neighbor's flow contribution – Market A

Marginal cost of flowing on the line from 6 to 7

+ Bus 2 Gen

↑ 1.34 MW @ $35/MWh

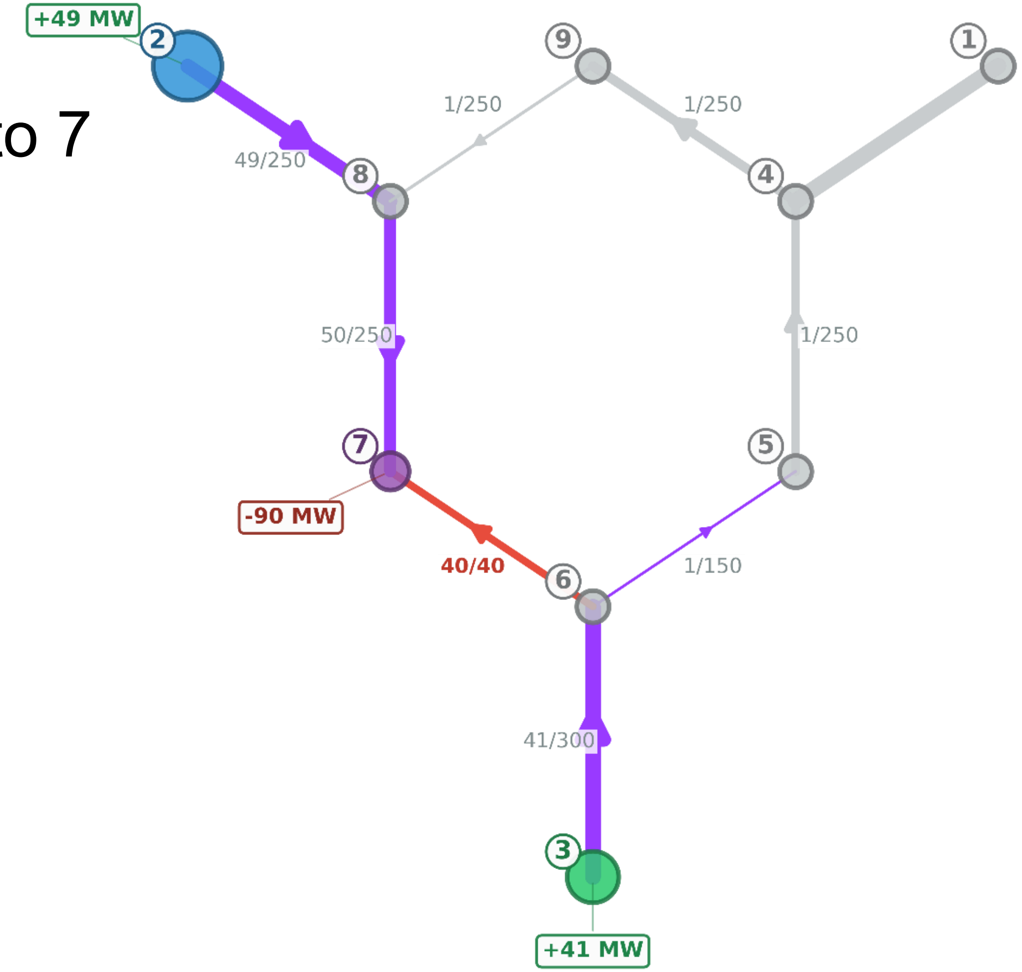
= $46.90

- Bus 3 Gen

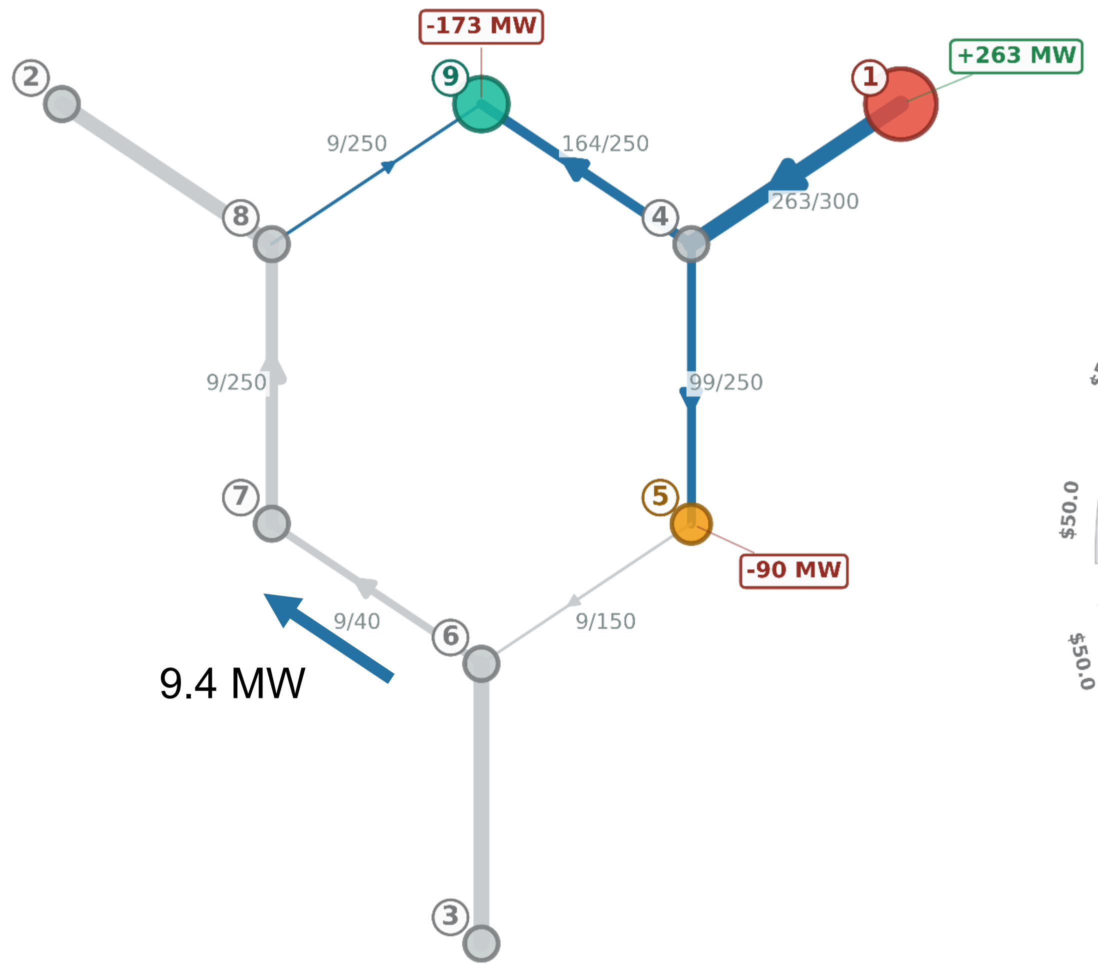
↓ 1.34 MW @ $20/MWh

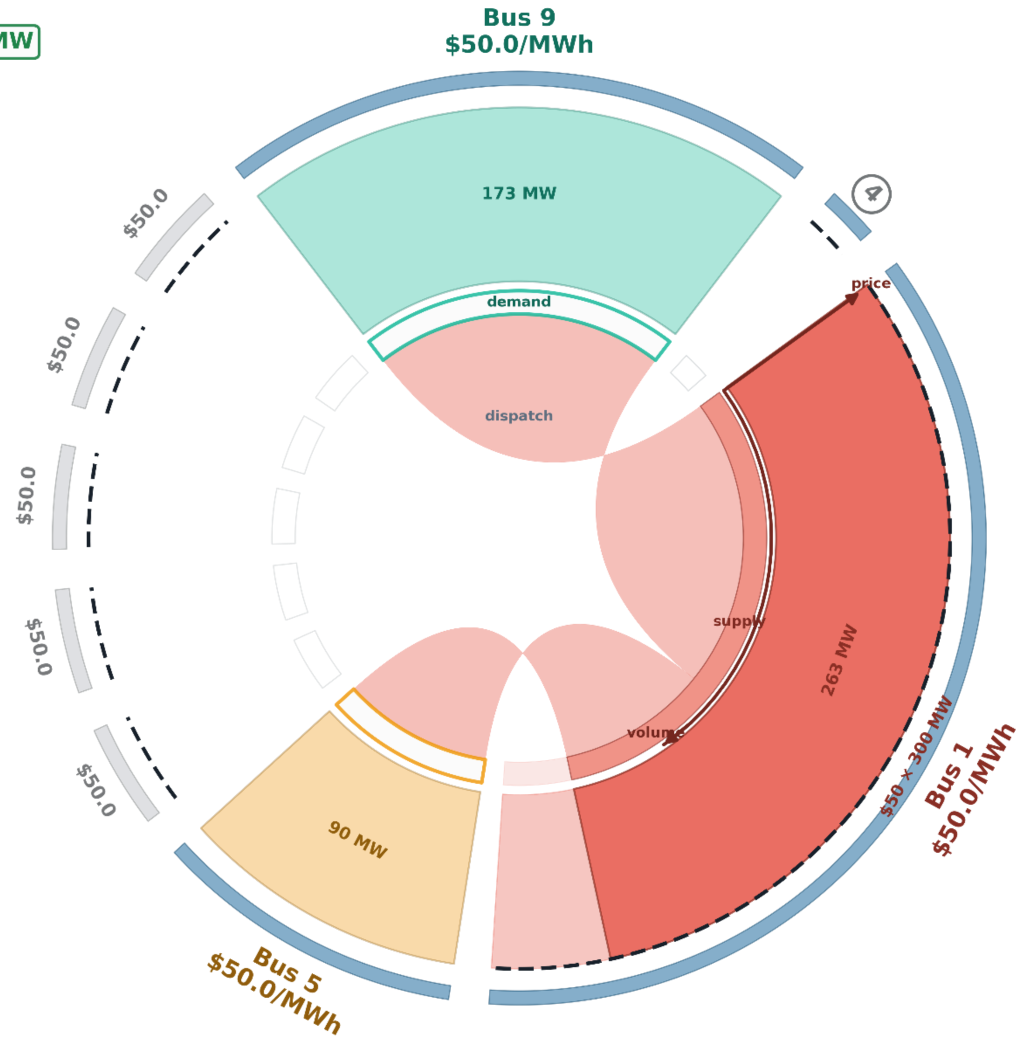
= $26.80

△ Line 6-7: $46.90 - $26.80 = $20.10

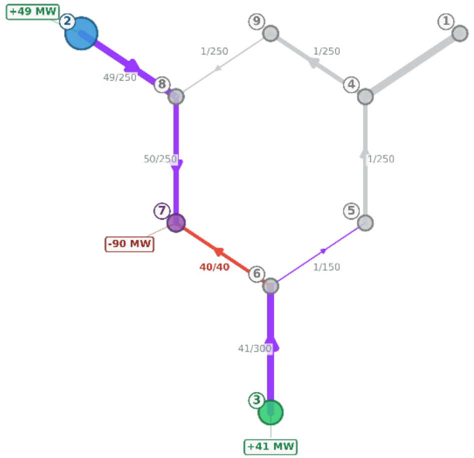


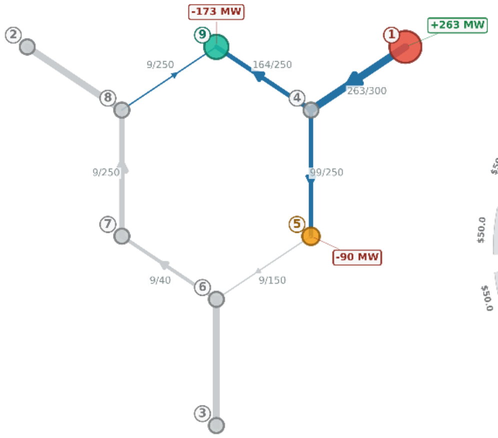
Example #1 – no forecast of neighbor's flow contribution – Market B

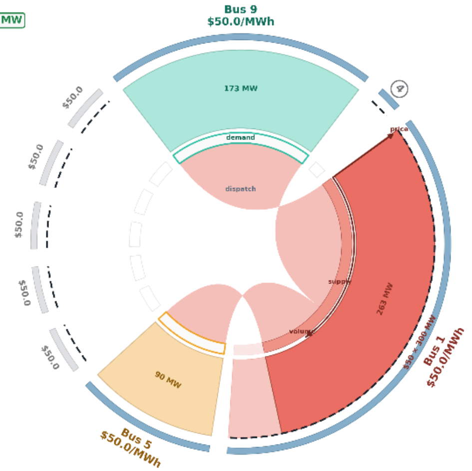


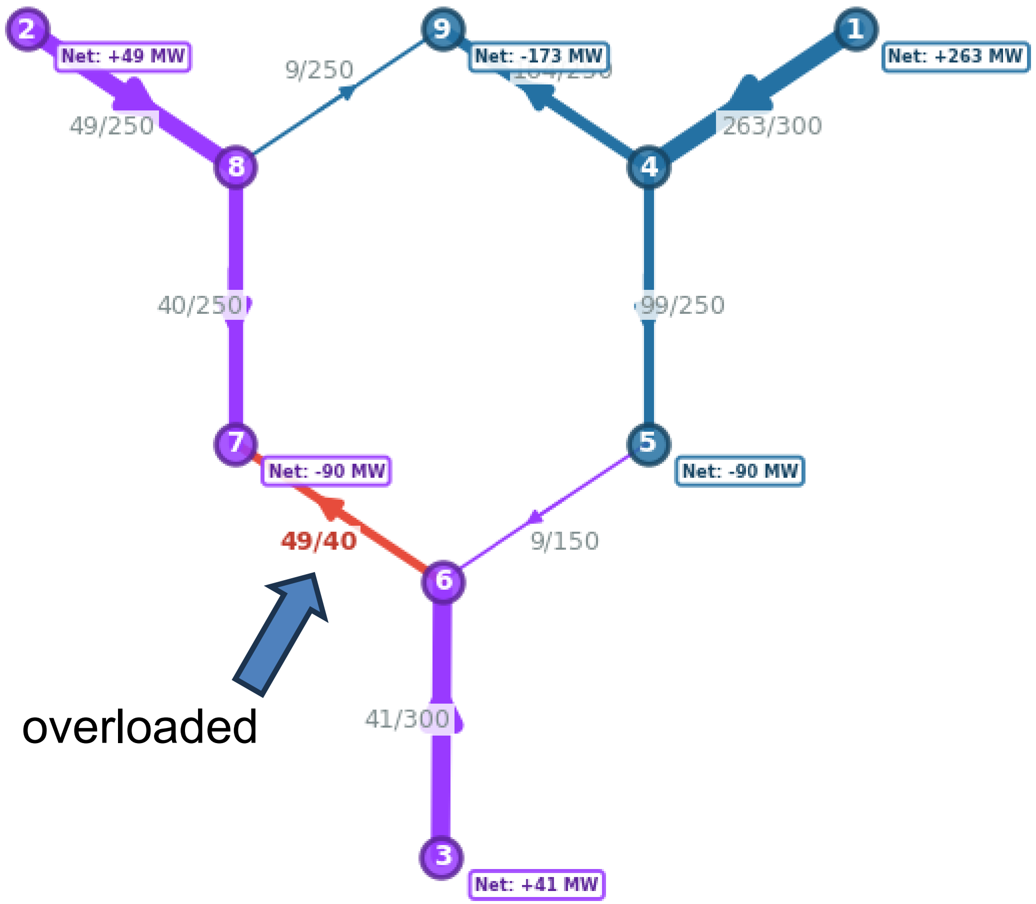


Example #1 – no forecast of neighbor’s flow contribution - combined









Example #1 – no forecast of neighbor's flow contribution – redispatch

Market A Production
Cost: $2,725

Independent run: $2,535

+ Bus 2 Gen

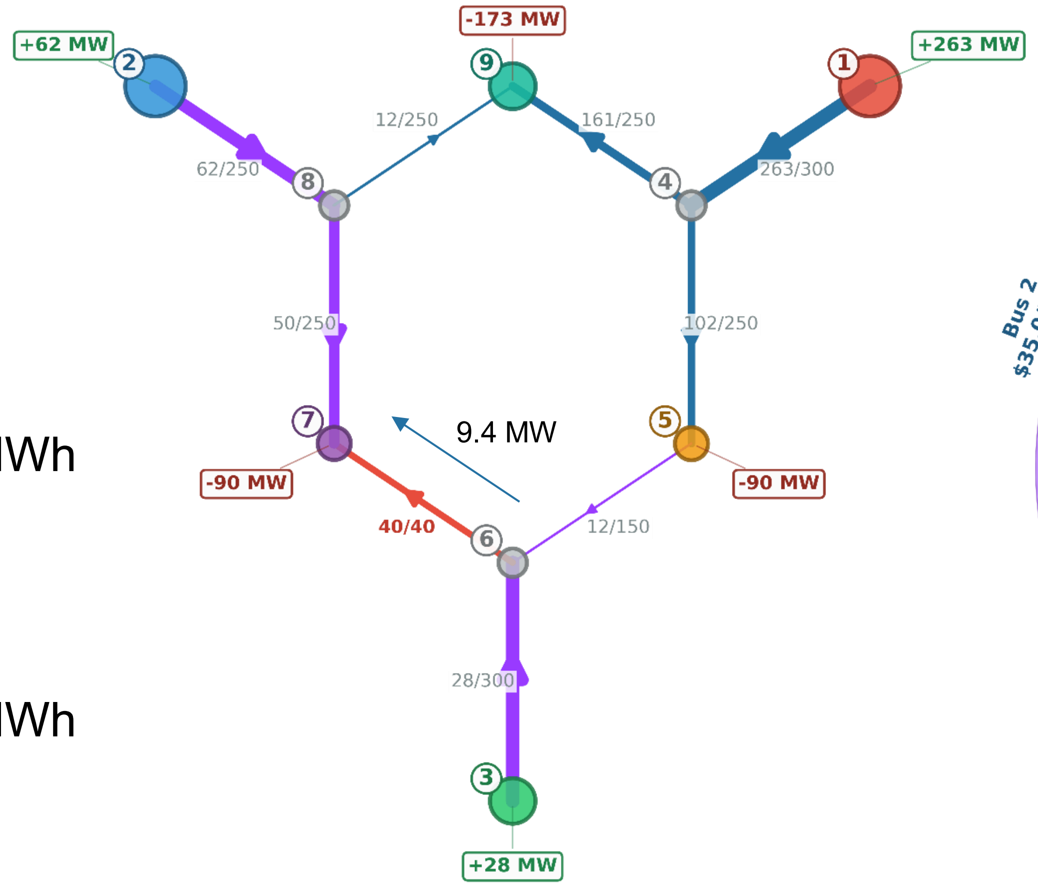
↑ 12.66 MW @ $35/MWh

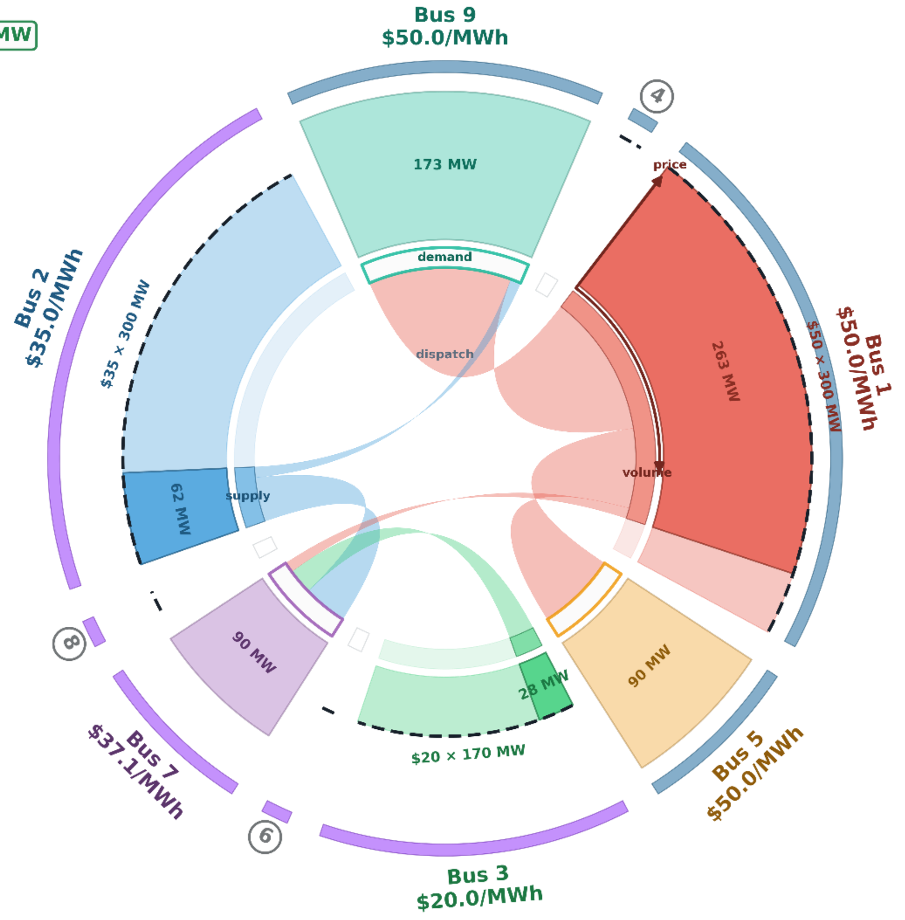
= $443

- Bus 3 Gen

↓ 12.66 MW @ $20/MWh

= $253





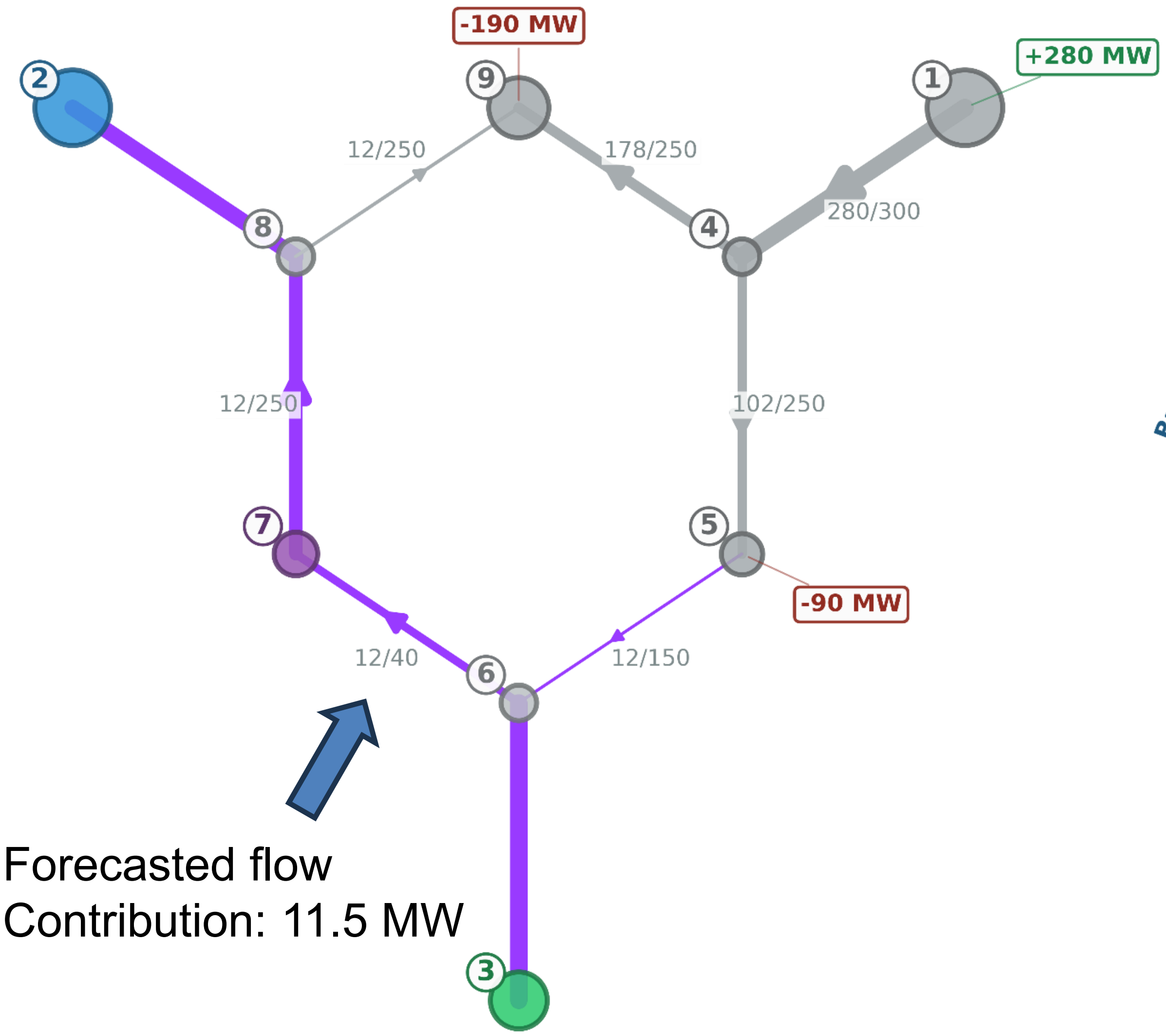
△ Market A production cost: $443 - $253 = $190

= 9.4 MW @ $20.10/MWh = $190

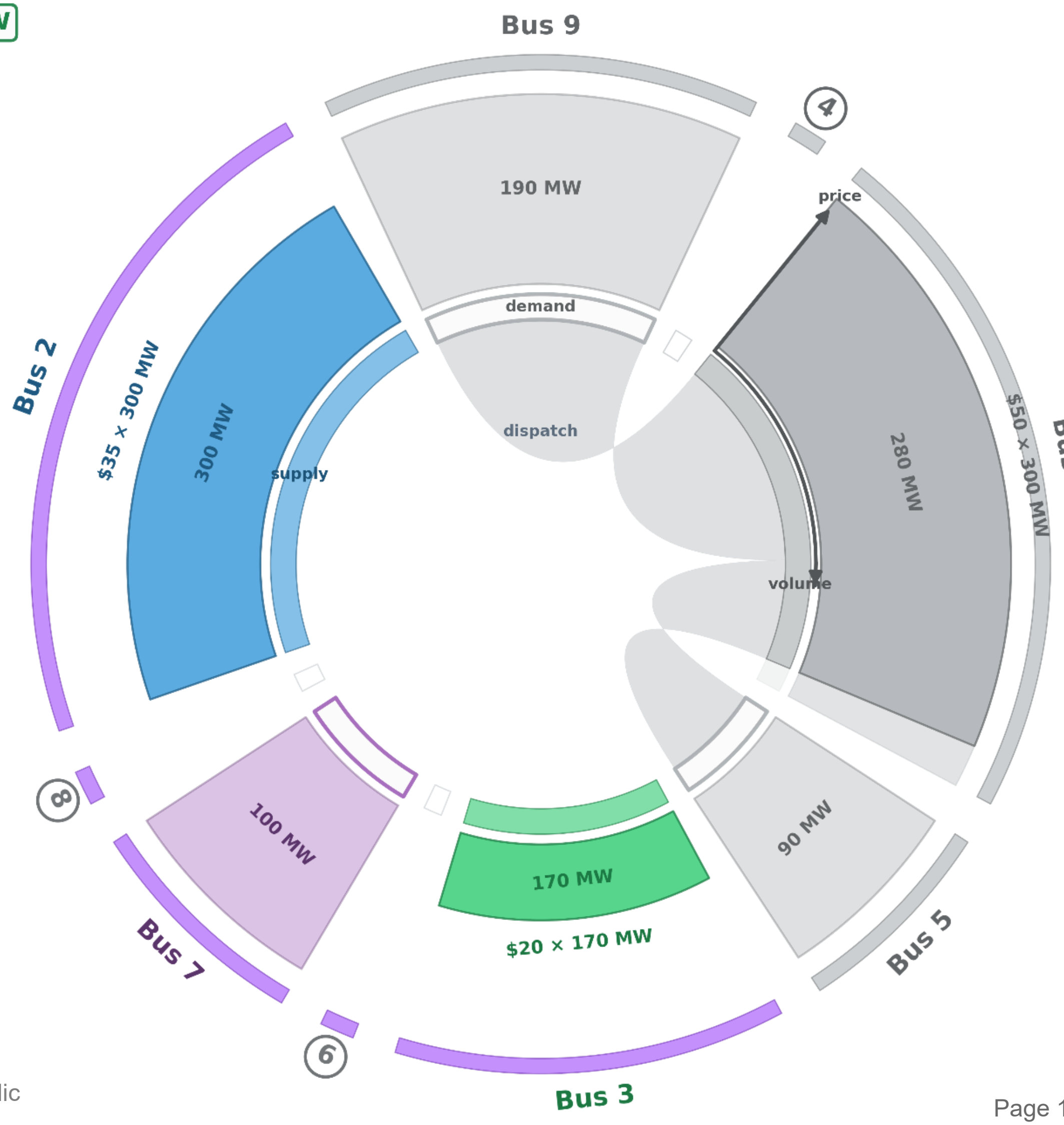
Example #2 – over-forecast neighbor’s flow contribution

- Each market forecasts the other’s use of the transmission network
- Market A has a binding constraint and finds the least cost dispatch of its system resources while respecting the limit and accounting for Market B’s expected flows
- Market B has no binding constraints and does not monitor binding constraint in Market A
- Power flow on the network based on combined dispatch leaves space on the line
- Market A bears the cost of phantom congestion

Example #2 – over-forecast neighbor's flow contribution – Market A input



Forecasted flow
Contribution: 11.5 MW



Example #2 – over-forecast neighbor's flow contribution – Market A

Market A Production Cost: $2,767

Independent run: $2,535

+ Bus 2 Gen

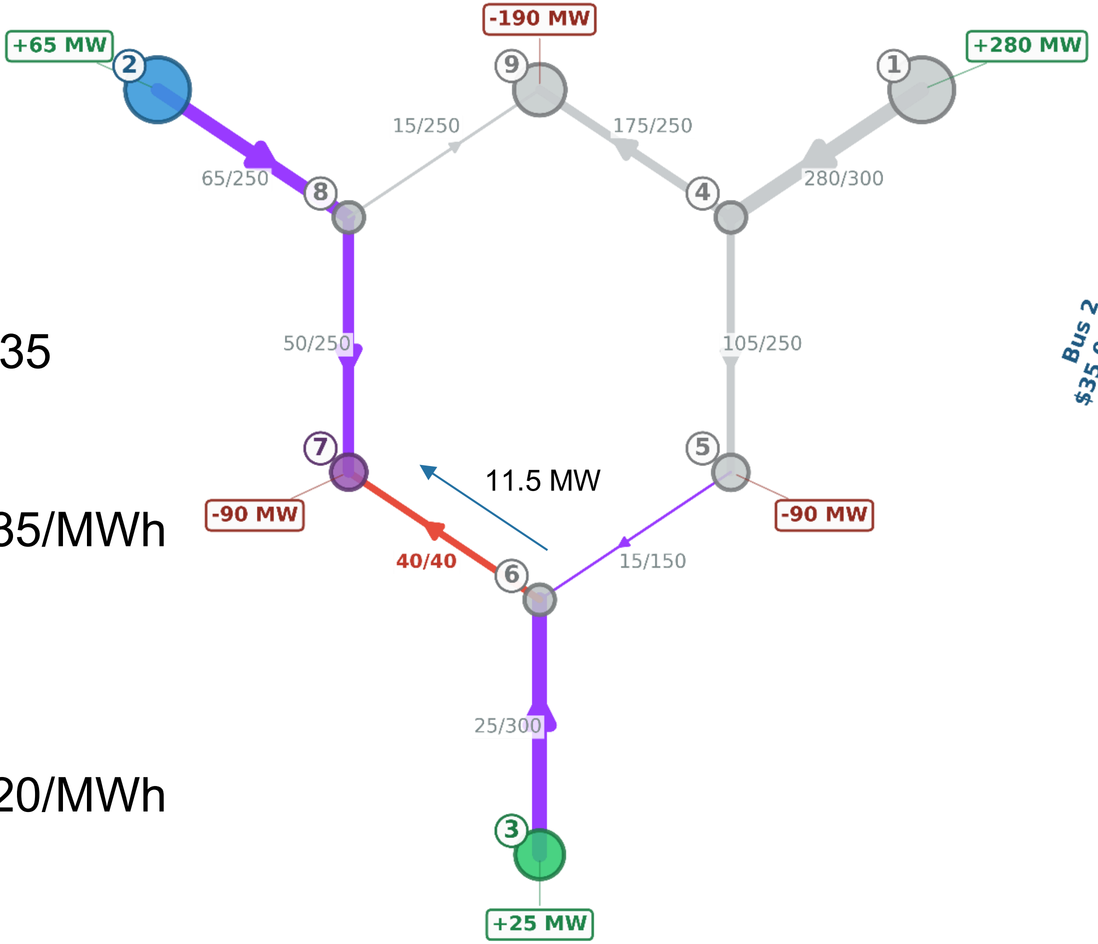
↑ 15.45 MW @ $35/MWh

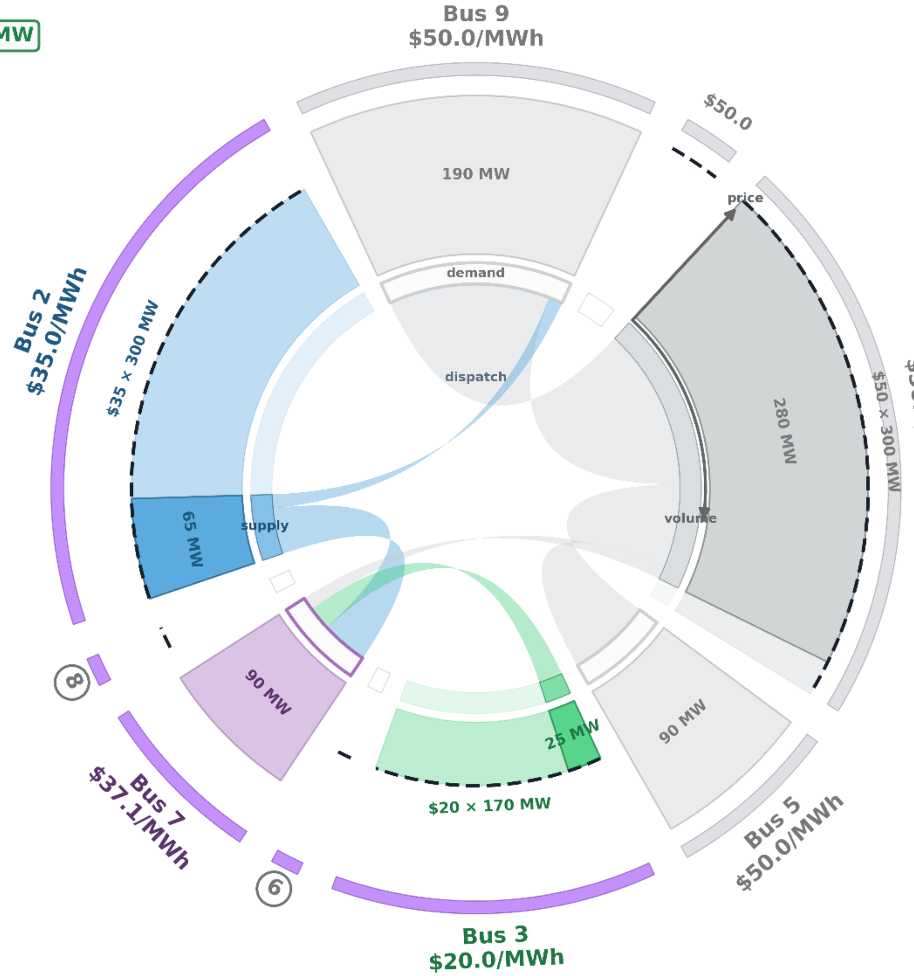
= $541

- Bus 3 Gen

↓ 15.45 MW @ $20/MWh

= $309

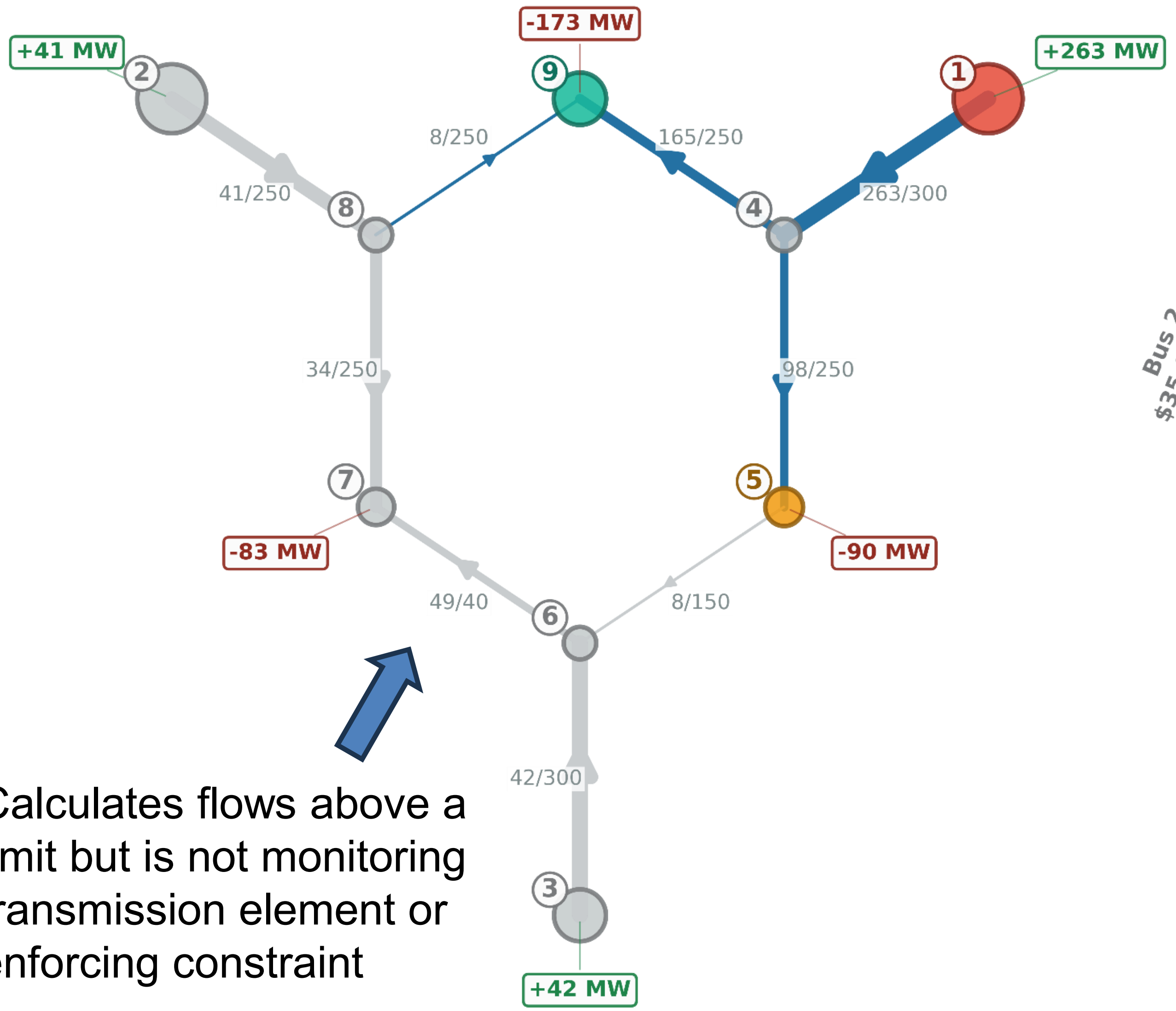




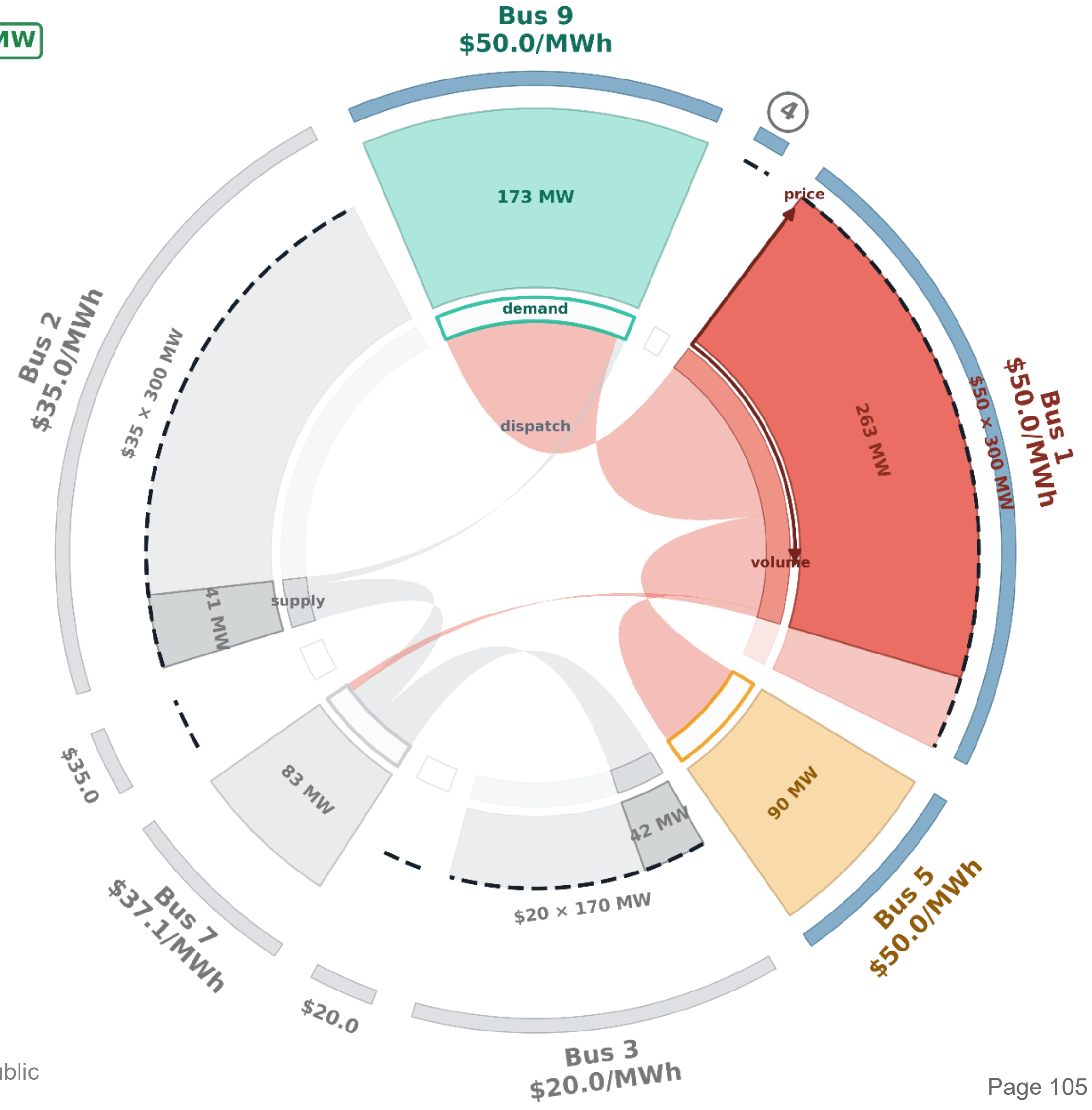
△ Market A production cost: $541 - $309 = $232

= 11.5 MW @ $20.10/MWh = $232

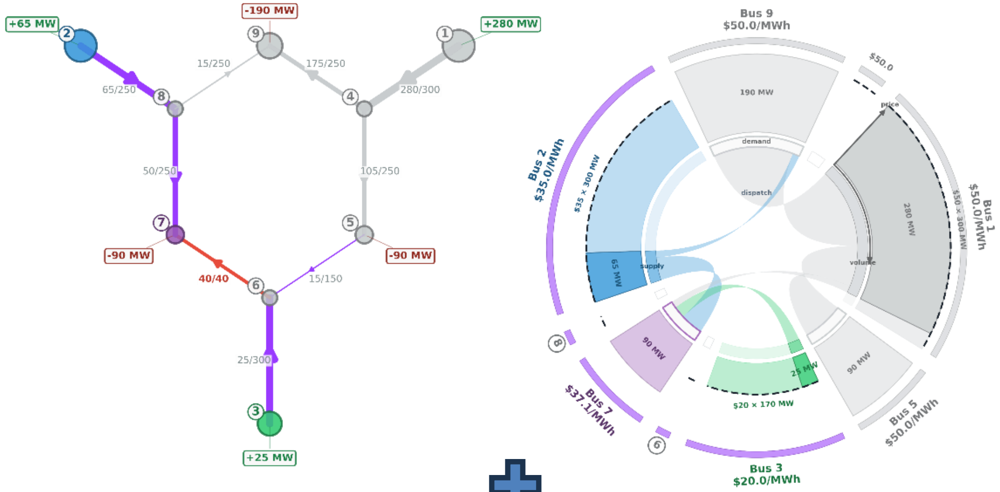
Example #2 – over-forecast neighbor's flow contribution – Market B

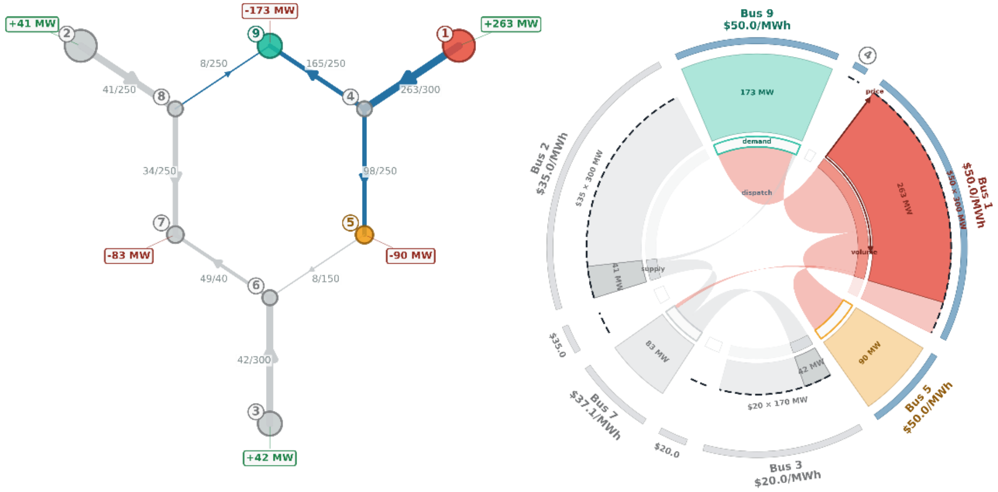


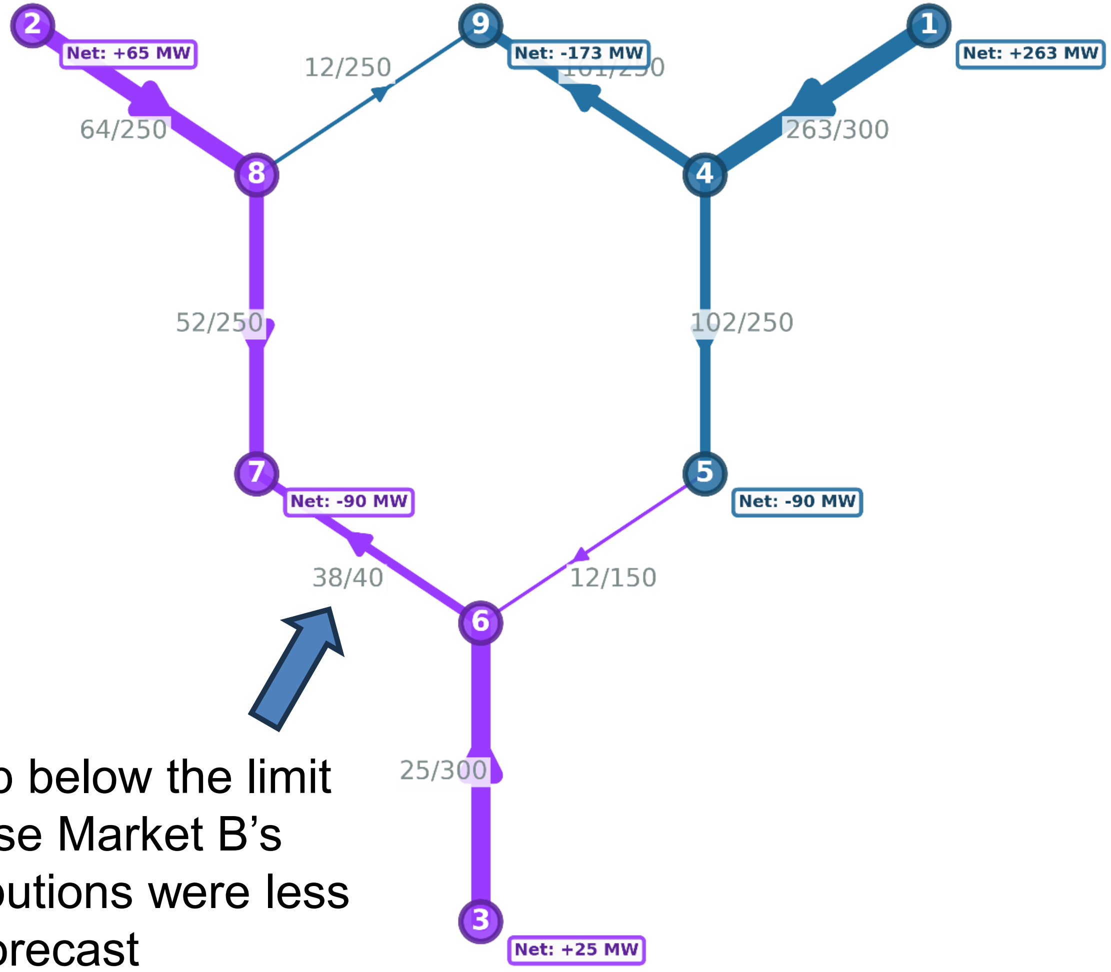
Calculates flows above a limit but is not monitoring transmission element or enforcing constraint



Example #2 – over-forecast neighbor's flow contribution







End up below the limit because Market B's contributions were less than forecast

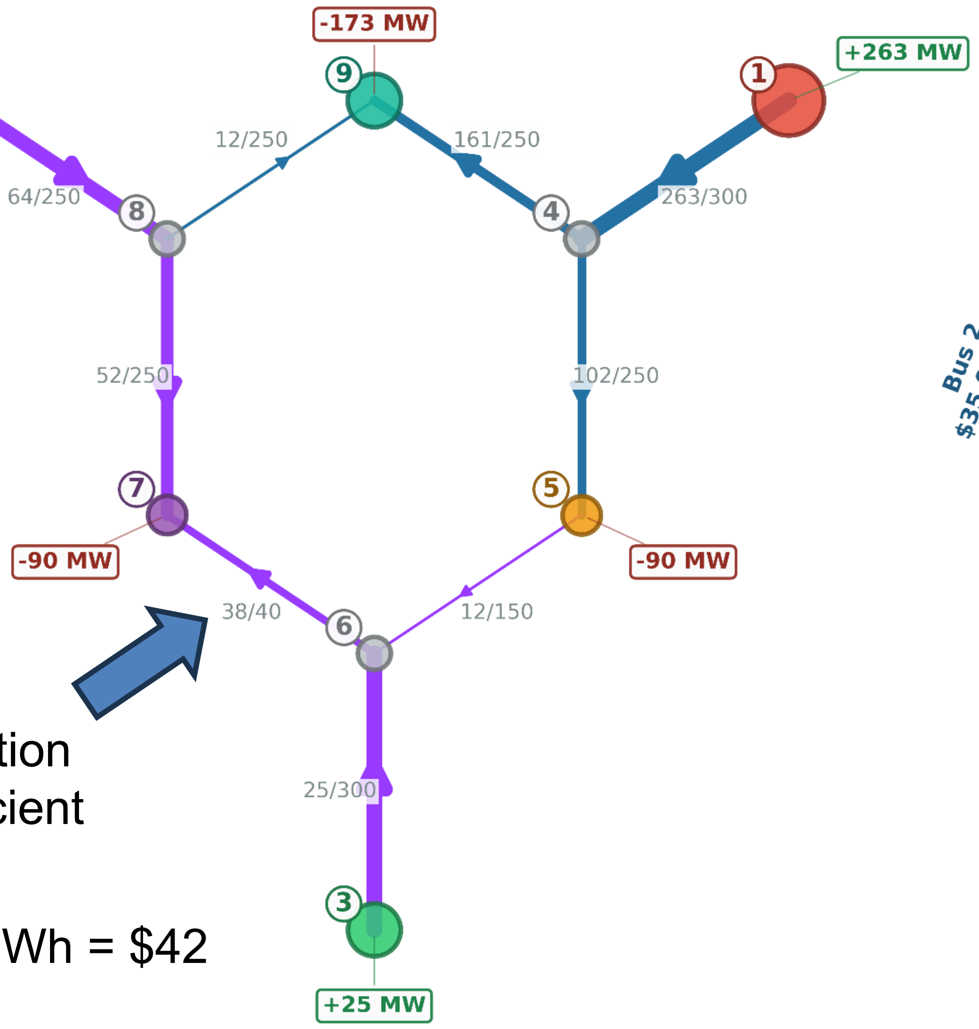
Example #2 – over-forecast neighbor's flow contribution

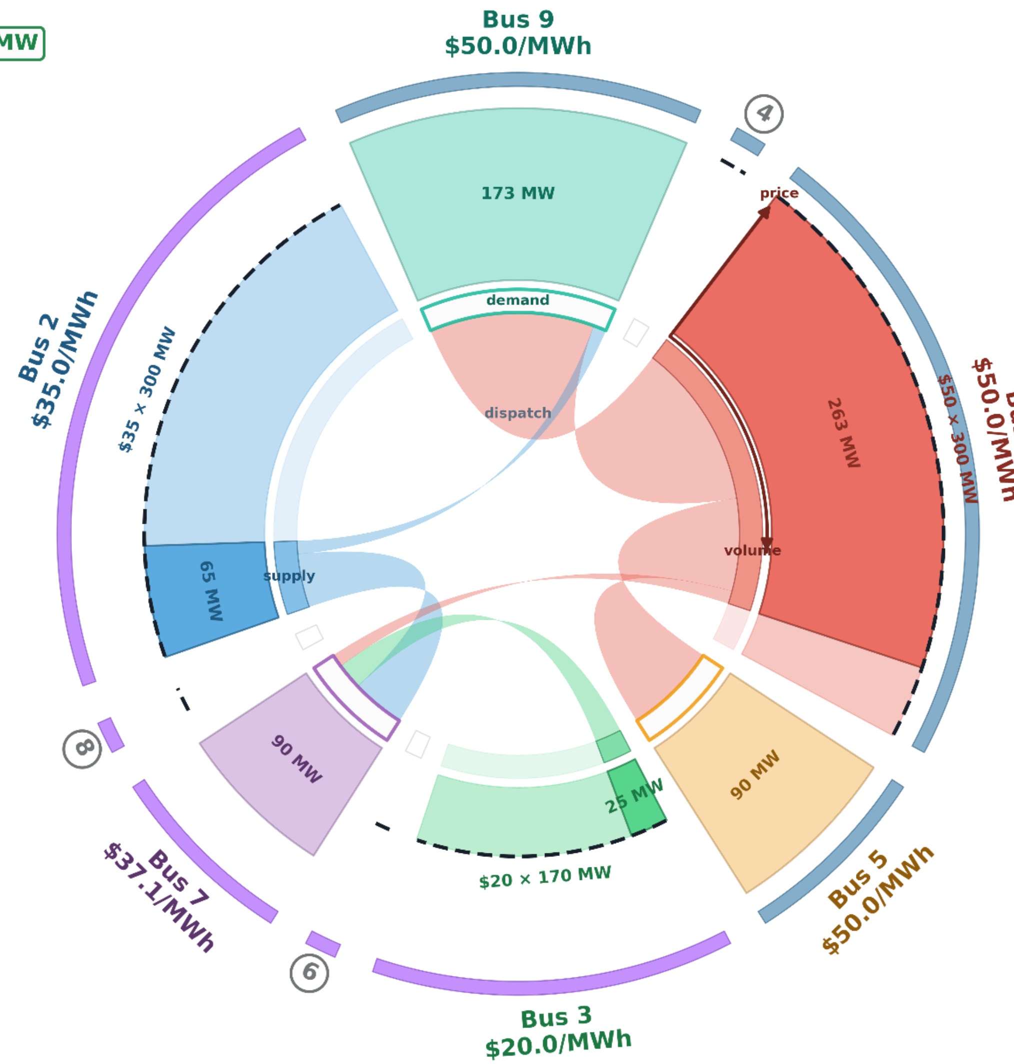
Market A Production Cost with headroom on the constraint: $2,767

Market A Production Cost at limit: $2,725

↑ $42 increased production cost because of inefficient use of system

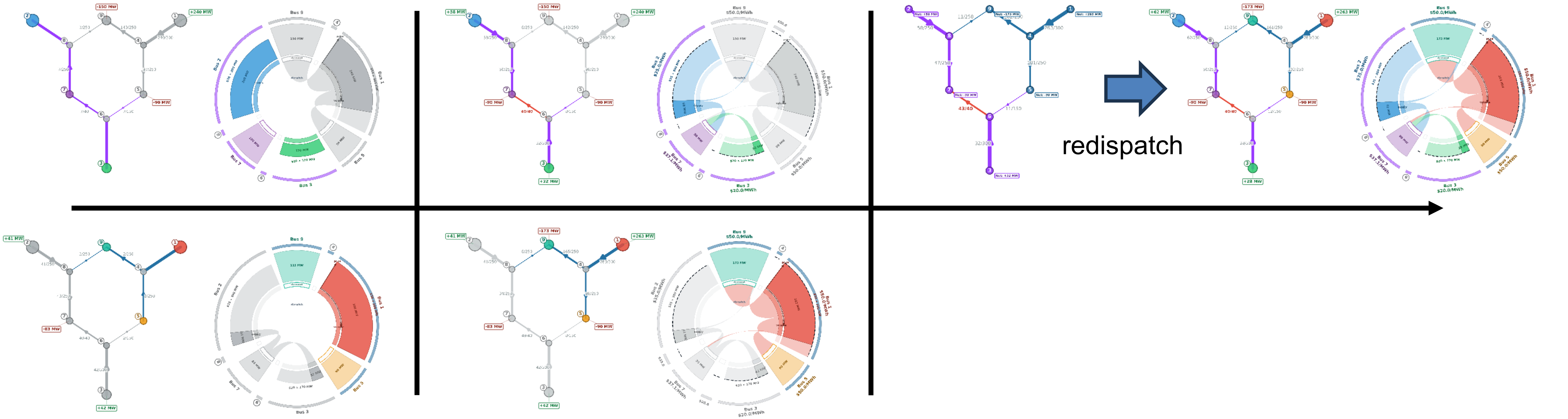
= 2.1 MW @ $20.10/MWh = $42





Parallel process considerations

Inputs Optimization Reconciliation



Key considerations

- Data sharing
- Modeling
- Methodology for managing jointly impacted constraints

Closing Remarks

Joanne Serina

Vice President

Stakeholder Engagement and Customer Experience, CAISO

Closing Remarks

Carrie Simpson
Vice President
Markets, SPP

Comments and next meeting

- Comments: Please submit stakeholder comments on the August 18 workshop by visiting Meetings | Market Seams | California ISO and completing the comment template Word document. Upon completion of this template, please submit it to isostakeholderaffairs@caiso.com. Written comments are due by end of day Sept. 1, 2026.

- Next meeting: The California ISO and Southwest Power Pool have tentatively scheduled a September 16, 2026, hybrid Market Seams workshop in Denver, Colorado. A notice will be released soon to confirm the details.

- Seams Webpage: More information is at Seams | Western Energy Markets

Welcome and Opening Remarks

Carrie Simpson
Vice President
Markets, SPP