

Comparison of RTOW, WestConnect, and Proposed CAISO Market Designs To FERC's Standard Market Design NOPR of July 31, 2002

October 1, 2002

The comparison matrix shown on following pages has been prepared to provide a comparison of the market design proposals of the three Western RTOs currently under development to the Standard Market Design (SMD) described in the Notice of Proposed Rule Making (NOPR) released by the Federal Energy Regulatory Commission (FERC) on July 31, 2002. This matrix is based on an earlier comparison dated April 26, 2002 which has been updated to recognize the issuance of the NOPR and the issuance of an order on the RTO West by the FERC on September 18, 2002.

It is not possible to fully capture the details of any of these proposed market design in the brief statements provided in this matrix. While the entries in this matrix are believed to be reasonable summaries for comparing features, the actual filings, statements and orders of the RTOs and FERC should be consulted to obtain a full understanding of any particular market design feature. Any difference in position between the original documents and this comparison matrix is unintentional; however, to the extent that they exist, the original documents of course prevail.

For all columns of this comparison, a blank entry indicates that no position was articulated on that issue in the source materials. The term ITP used in the FERC column refers to an Independent Transmission Provider, which may be an RTO or another organization which meets the independence requirements of the proposed rule. The basis for the entries in each of the columns is as follows:

- FERC STANDARD MARKET DESIGN NOPR – Order issued July 31, 2002
- WESTCONNECT PROPOSED – FERC filing made October 2001
- RTO WEST – FERC Order issued September 18, 2002
- CAISO PROPOSED – A description of the current status of work in progress
- CAISO PROPOSED (long term) – A description of the current status of work in progress

Note: To compress the information into a tabular form, the following acronyms are used throughout: DA = day-ahead, HA = hour-ahead, RT = real-time, and CM = congestion management.

**Comparison of RTOW, WestConnect, and CAISO Proposed Market Designs
with FERC's Standard Market Design – October 1, 2002**

□	FERC STANDARD MARKET DESIGN NOPR	WESTCONNECT PROPOSED	RTO West	CAISO PROPOSED (Phase 1a: 10/30/02 Phase 1b: 01/31/03)	CAISO PROPOSED (long- term)
	<i>NOTE: Based on SMD NOPR issued July 31, 2002. Blanks indicate those issues not addressed in the NOPR.</i>	<i>NOTE: The elements below describe the WestConnect proposals as contained in their October 2001 FERC filing.</i>	<i>Note: Based on 3/29/02 Filing. Blanks indicate those that no position was taking in the filing.</i>	<i>NOTE: The elements described below reflect phase 1a implementation and the current status of a work in progress for Phase 1b.</i>	<i>NOTE: The elements described below reflect the current status of a work in progress.</i>
MARKET DESIGN					
Prior to Day Ahead					

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<u>Capacity Obligation &/or Market</u>	ITPs forecast future demand, facilitate the determination of an adequate level of future regional resources by a Regional State Committee and assign each LSE a share of the needed resource. LSEs may meet share of future resources through self-supply, purchase contracts, or demand response programs. ITP checks to see that resources are not double counted, and inform the state regulatory authority when an LSEs fails to submit a satisfactory plan for meeting the adequacy requirement. If a power shortage occurs and the ITP cannot satisfy demand in the spot market and meet minimum operating reserves, the ITP adds a per-MWh penalty during the shortage for an LSE not meeting its share of regional resource for that year. If the ITP must curtail load in such an emergency, the load of non-compliant LSEs will be curtailed before that of LSEs that are compliant with the resource adequacy standard	No capacity obligation as such. However, the requirement to submit Balanced Schedules and the penalties associated with under-scheduling and leaning on the Balancing Energy market should encourage the Scheduling Coordinators (SCs) to have sufficient capacity available to meet demand plus reserve obligations.	No capacity obligation proposed as filed. Each LSE is required to submit balanced schedules to meet load/resource balance. Penalties may apply for failure to supply adequate resources. RTO West is encouraged in the order to consider developing a resource adequacy plan and to consider the effect of RTO West procedures to implement reliability requirements in the development of a resource adequacy plan.		Available Capacity (ACAP) Obligation: Monthly "Available Capacity" or "ACAP" obligations on Load Serving Entities (LSEs) based on monthly peak load; daily obligations based on daily load duration curve. Deficient LSEs must curtail first if load shedding is necessary, based on pre-identified Demand Resources that may qualify as ACAP. ACAP supplier is responsible for availability of resource on a daily basis. Eligible resources are: self-owned and contracted generation; firm bilateral contracts backed by specific generating units; and demand response The ISO verifies ACAP compliance on the month-ahead basis; A ISO, as part of the day-ahead scheduling process, the ISO verifies that load-serving entities indeed meet their capacity obligations. NOTE: Neither SMD nor MD02 suggests ISO/ITP must run a capacity mkt.

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<u>Congestion Revenue Rights (CRRs) [Firm Transmission Rights (FTRs) in MD02]</u> Financial or Physical	Financial – Congestion Revenue Rights (CRRs)	Physical. Firm Transmission Rights (FTRs), Recallable Transmission Rights (RTRs), Non-firm Transmission Rights (NTRs) or Non-Converted Rights (NCRs – rights associated with Existing Contracts not converted to WestConnect service) (together simply referred to as FTRs or Transmission Rights) required to schedule use of FTR Interfaces (internal congested interfaces) and Scheduling Points (connections to other control areas).	Financial	Financial with a day-ahead physical scheduling priority	Financial with day-ahead physical scheduling priority on point-to-point FTRs
Option or Obligation	Obligations are required but options rights or flowgate rights may be issued upon request of market participants and when technically feasible.	N.A., as there is no revenue stream associated with holding an FTR.	Options either as Financial Transmission Options (FTOs) or for Catalogued Transmission Rights (CTRs) to honor pre-existing agreements and obligations.	Option – Continuation of today's FTR product.	Point-to-point obligations initially, adding point-to-point options and flowgate rights depending on need and technical feasibility. NOTE: In both the initial and final implementation FTR Options will be offered to Existing Contract Rights (ETC) holders who convert to FTRs.
Revenue Stream/ or Offset CM Cost	Revenue stream for price difference between a names source and sink to hedge for congestion cost but not required for scheduling.	Not applicable, as limiting the scheduling of the use of FTR Interfaces and Scheduling Points to those holding FTRs is designed to minimize congestion. Intra-zonal congestion socialized.	Offset to congestion costs incurred by right holder	Revenue stream as well as hedging on specific contract path	Allowing purchase for revenue stream as well as hedging for scheduling (point-to-point or network service)

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Duration	Variety of terms: NOPR does not specify terms or quantities; suggests regional variation will be allowed.	Each FTR is for one hour. Annual auction of annual blocks of FTRs, based on minimum number of FTRs available in any month. Monthly, sub-monthly and daily auctions of any additional blocks of FTRs available.	Those from contract conversion, for the life of the contract. Those from auction, term to be specified when auction designed. Long term for those obtained by constructing new facilities.	Annual (individual hours can be traded in secondary market)	Three-year (30% of minimum ATC), Annual (45% of minimum ATC), and Monthly (the rest of ATC) ; allowing unbundling to shorter time periods in secondary trades (down to individual hours).
Definition	<p>Source-to-sink, direction specific, rights. Financial only. ITP may offer both:</p> <ul style="list-style-type: none"> ➤ point-to-point (e.g. TCCS or NY/PJM FTRs) and "flowgate" or path-specific rights (closed loop) <p>Standard CRRS are direction specific between a point of delivery to a point of receipt. Flowgate CRRS provide value (shadow price) for a specific system element.</p>	A Transmission Right is the right to schedule the delivery of one (1) MW of Energy or Ancillary Services in a specific direction across an FTR Interface or Scheduling Point for one (1) hour	From specified injection Points to Withdrawal Points in a specific direction.	Direction and path specific (open loop/contract path)	<p>Source-to-sink, direction specific rights. Primarily Financial, but can be used for day-ahead priority against curtailment with point-to-point balanced schedules. Provisions for:</p> <ul style="list-style-type: none"> ➤ point-to-point ➤ point-to-hub ➤ hub-to-hub ➤ hub-to-point and ➤ Considering additional "flowgate" or path-specific rights (closed loop)
Primary Release Mechanism	Auctions with an initial allocation of CRRs to current users of the system with pre-existing rights. After four years, current users receiver the auction revenues (Note: The effect of this provision is that by bidding in the auction for the rights for which they are entitled to receive revenues, current users set a value that must be exceeded by another bidder to obtain the rights. Otherwise the current user will	Auction	<p>Either by (1) conversion of rights in existing contracts and obligations or (2) purchase at auction from RTO West.</p> <p>Rights pooled in Cataloged Transmission Rights (CTRS) for unconverted contracts and obligations which settle in the same manner as FTOs. Parties with CTRs may exercise optionality and release capacity to RTO West auctions</p>	Auction	CAISO would first reserve capacity for ETC rights holders, then allocate FTRs to converted ETCs, then to Loads (LSEs), followed by auction for the remaining capacity.

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	retain the rights.)		by early submit early schedules and accepting any resulting added congestion cost.		
Secondary Market	Possibility for secondary trading with no ITP involvement. NOPR proposed that ITP periodically conduct auctions to facilitate secondary trading.	Will not operate a secondary market. Requires FTR holders to register final trades in secondary markets if they are to be recognized in the Balanced Schedule validation process.	Tradable for use by other Scheduling Coordinators	ISO does not operate a secondary market, but requires FTR holders to register secondary trades.	Will not operate a secondary market, require FTR holders to register secondary trades.
Day Ahead					
<u>Energy Spot Market</u>	Nodal pricing; i.e., Locational Marginal Pricing (LMP) at the nodal level. Integrated Congestion Management; simultaneous forward Energy, Congestion and Ancillary Service markets. Energy bid curves serve for energy trading and congestion management adjustments.	None.	None, Day-Ahead Congestion Clearing Market only. Order encourages RTPO West to consider whether a day-ahead market would provide additional efficiencies to participants.	No forward energy market facilitated by the ISO for the September 30, 2002 implementation (Phase 1a). Considering relaxation of market separation (thus forward energy market) for Phase 1b.	Nodal pricing. Integrated Congestion Management: Simultaneous forward energy, Congestion and Ancillary Service markets. Energy bid curves serve for energy trading and congestion management adjustments.
<u>Congestion Management Market</u> Model spatial granularity	Nodal pricing - Congestion charge between any two nodes is defined as difference between nodal energy prices.	Full network model used to define and manage inter- and intra-zonal congestion.	Nodal pricing	Zonal; radial model. Any congestion within zones is ignored in forward CM and mitigated in real time.	Nodal pricing, using full network model of CAISO grid plus reduced external equivalent for the rest of WECC. - Congestion charge between any two nodes is defined as difference between nodal energy prices.

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Model objective function	Integrated with DA energy market (optimized simultaneously); bid cost minimization	Security constrained economic dispatch of balancing energy market, including dispatch to manage inter- and intra-zonal congestion and minimization of deviations from SC schedules. Resources designated to provide operating reserves normally not dispatched unless there is a contingency.	Minimize cost of congestion clearing	DC optimal power flow with market separation	Optimal power flow (tending towards AC OPF with transmission losses accounted for implicitly) without market separation (considering provisions for voluntary market separation)
Schedule Components	<p>Bid-based scheduler may specify schedule to be eliminated if congestion cost exceed given value.</p> <p>Settlement based on nodal prices; possibility to define trading hubs</p>	<p>Requires a Balanced Schedule, including:</p> <ul style="list-style-type: none"> - Generation; - Demand; - Imports/exports; - Inter-SC trades of energy and Ancillary Services; - Transmission & Distribution Losses; - Ancillary Services, self-provision and offers; and - Required Transmission Rights 	<p>Inc/Dec bids for congestion clearing from supply and demand-side.</p> <p>Schedules may indicate party's desire to have schedule eliminated if congestion cost exceeds a threshold price.</p> <p>Day-Ahead Settlement on congestion clearing nodal prices when Day-Ahead schedules become firm commitments.</p>	<p>Generation schedule at nodes at hourly intervals;</p> <p>Loads schedule at Demand Zones at hourly intervals</p> <p>Optional inc/dec bids on generation and loads used for CM</p>	<p>Generation schedule (and settle) at nodes at hourly intervals; LPAs act as trading hubs;</p> <p>Loads schedule (and settle) at demand zone, load group, node, or LPA level at hourly intervals;</p> <p>Optional inc/dec bids on generation and loads used for both CM and energy trades</p> <p>Provision for 3-part bids (cost-based start-up and minimum-load; bid-based energy)</p>
Other Scheduling Requirements	<p>Submit receipt point (generation or import), delivery point (load or export), MW quantity, time period.</p> <p>Accepts balanced or unbalanced SC schedules. (No balanced schedule requirement)</p> <p>Settlement based on nodal prices; possibility for ITP to define trading hubs.</p> <p>Supply bids must distinguish financial only (virtual) bids from ones tied to a physical resource.</p>	<p>There are Day-Ahead auctions of unused FTRs as RTRs, release of NTRs, and a scheduling process for provision of Local Generation Resource (LGR) service.</p>	<p>Schedules must be balanced when submitted.</p>	<p>Requires balanced schedule</p>	<p>Supply resources schedule and settle at nodes at hourly intervals.</p> <p>Accepts balanced or unbalanced SC schedules.</p> <p>Require generation feasibility. Inter-hour schedule changes must be consistent with ramping capabilities of resources.</p> <p>Proxy prices to be on file</p>

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	Provides for local (out of merit order) market power mitigation				for mitigating congestion with no competitive inc/dec bids. Loads may schedule and settle at specified aggregation areas, at hourly intervals. Trading hubs will be created to facilitate trading. NOTE: Virtual bidding under MDO2 is still under discussion. To prevent adverse operational impacts, virtual supply bids must be designated as such by the bidder.
Congestion Prices	Congestion Price (including losses) is calculated as difference between 2 locational prices; Acceptance of schedule is physical transmission right – right to physically inject energy at a location and simultaneously physically withdraw energy at another location. No congestion costs are socialized	The prices (through auctions or secondary markets) of the various types of FTRs required for scheduling, plus any socialized intra-zonal congestion.	Price difference between Injection Point and Withdrawal Point. RTO West loss methodology for new and converted service yet to be determined. All balanced schedules accepted subject to RTO West's ability to clear congestion.	Congestion prices in forward market are the difference between marginal INC and DEC bids (of the marginal SC) accepted for redispatch to clear congestion across the interface	Congestion prices (including the cost of losses) in forward market are the difference between hourly nodal energy prices. Flowgate prices are computable directly as the dual variable of the relevant flowgate constraints
<u>Ancillary Service Market Services</u>	Operating Reserves Market required, including at least AGC (Regulation) and 10-minute operating reserves.	Regulation, Load Following Up, Load Following Down, Spinning Reserves, Non-spinning Reserves, Balancing Energy, Supplemental Energy, Voltage Support, Scheduling & Dispatch, Black Start, Congestion Redispatch, and LGR.	Markets for Regulation and Frequency Response, Load Following Up, Load Following Down, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Congestion Redispatch, Supplemental Energy, Balancing Energy, Voltage Support and Black Start	Spinning Reserves, Non-Spinning Reserves, Replacement Reserves, Regulation Up, and Regulation Down	Spinning Reserves, Non-Spinning Reserves, and Regulation

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ISO Acquisition or Self-provision	Both ITP procurement and self provision	Both for the first five above, at the SC's discretion. WestConnect provides the last seven (which it acquires on a competitive basis).	Both	Both, SC's option	Both, ISO procurement and self provision (at SC's option)
Acquisition Mechanism	Simultaneously auction with DA energy and CM markets.	Bids. Primarily Day-Ahead, but longer term for Voltage Support and Black Start.	Competitive bid submitted with schedules.	Auction after CM market closes; award based on capacity bids only; markets for Regulation (Up an Down), Spin, Non-spin, and Replacement cleared sequentially in that order; Rational Buyer procurement allows demand substitution, i.e., procurement of higher quality A/S in the sequence to substitute for the lower quality A/S when doing so reduces total A/S procurement cost.	Simultaneous auction with energy based on bid-cost minimization (rather than the Rational Buyer type payment minimization objective function)
Bid Components	Both generators and demand-side participants to offer products that meet requisite technical requirements Permit submission of both capacity availability and energy bids	Daily capacity bids for Regulation, both Load Following and both Operating Reserves. Daily energy bid curves for those five (5) Ancillary Services plus Supplemental Energy, Congestion Redispatch and, as applicable, LGR service. To be developed for Voltage Support and Black Start.	Both generators and loads may bid; however, details are yet to be determined.	Regulation and Reserves: Bidders submit capacity and energy bids; energy bids are not used in the A/S capacity auction; energy bids are provided for use in the real-time market (after the capacity auction); a single energy bid curve will be used for all ancillary services and supplemental energy in each hour (can change from hour to hour). Multiple ramp rates allowed for different output levels on the energy bid curve.	Energy and capacity bids will both be considered in the simultaneous auction; once selected, energy bids associated with the selected A/S capacity would not be allowed to be modified. Multiple ramp rates allowed for different output levels on the energy bid curve.
<u>Centralized Unit Commitment.</u>	Bidders submit multi-part energy bids, start-up, and minimum loads, and various operating constraints in conjunction with integrated Energy/Congestion Management market. Although not specifically called "unit commitment" the ITPs reliability	None.	None; voluntary self-commitment based on balanced schedules. RTO will make its own load forecast to insure the adequate capacity is on line to meet load in Real-time.	Must-offer waiver request/denial process for Long-start-time (LST) resources; guaranteed cost recovery for units committed by the ISO (waiver request denied) including: guaranteed start-up cost compensation; guaranteed	Day-ahead Unit Commitment Service (UCS); Resources submit 3-part bids (cost-based start-up and minimum-load; bid-based energy), along with technical and

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	<p>responsibilities and multi-part bids suggest that ITP provides unit commitment services.</p> <p>NOPR does not mention simultaneous UCS integrated with DA market..</p> <p>Unit commitment for reliability purposes, after the day ahead market, is expected of ITP.</p>			<p>minimum load cost compensation for each hour net of market revenues in that hour provided that the resource does not undergo uninstructed deviation outside a band in that hour. Waivers issued based on first come first served (no bid cost minimization).</p>	<p>inter-temporal constraints (start-up time, minimum run time, minimum down time, all based on technical parameters filed with the ISO). ISO day-ahead market optimization makes optimal commitment decisions using a cost minimization objective. Resources committed by the CAISO will be guaranteed recovery of relevant start-up and minimum load cost net-of-market-revenues.</p> <p>Residual Unit Commitment (RUC): [Under Discussion]Following the day-ahead market, ISO runs the <i>Residual</i> Unit Commitment "market". If submitted schedules (final schedules clearing the day-ahead market) do not fully reflect ISO load forecast, ISO may commit additional ACAP resources to ensure adequate capacity on-line. ACAP resources are required to be available for unit commitment.</p> <p>Resources committed by the CAISO will be guaranteed recovery of appropriate start-up and minimum load cost, using a net-of-market-revenues</p>

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					<p>approach. Non-ACAP resources and imports (other than ACAP imports) may not participate in the RUC,. Competitive ACAP imports selected in RUC will be pre-dispatched for the real-time market operation; they will not be allowed to set the real-time price, but will be paid the bid price based on which they were selected in the RUC. To limit the impact of RUC import pre-dispatch on the real-time market operation, commitment to import energy in RUC will be limited such that the total supply clearing the day-ahead market plus the resource-specific minimum load and the RUC import energy do not exceed 95% of ISO's load forecast.</p>
<p><u>Release of Un-used Transmission Capacity after Close of DA Markets</u></p>	<p>Transmission capacity sold in DA that is not used by DA purchaser in RT should be made available for FT energy market Transmission owner must procure capacity under the SMD tariff to reserve capacity for ETCs that do not convert to SMD tariff service.</p>	<p>RTRs (i.e., unused NCRs, as allowed by the associated Existing Contract (EC) and FTRs sold Day-Ahead on a recallable basis) can be recalled until two (2) hours prior to the start of the Settlement Period (hour) for use by the original FTR holder. NTRs can be recalled at anytime.</p>	<p>Rights are only congestion hedges and are not required to submit schedules. FTOs and CTRs settle against Day-Ahead Market. CTRs provide protection against RT congestion as current rights do.</p>	<p>None (all transmission allocated in congestion management is firm)</p>	<p>Recallable Transmission Service: Following allocation of firm transmission in CM, ISO runs recallable transmission service (RTS) using unscheduled ETC capacity.¹</p>

¹ Preferred option is for ETC holders to agree to ISO scheduling time line (i.e., ETC rights expire after DA, like FTRs).

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	Transmission capacity use for DA transactions does not constrain RT operations. Changes after DA process face congestion cost without a hedge.				MD02 provides incentives for ETC rights holders to convert, and will honor those ETCs that do not convert, but ISO has described to FERC how this can severely complicate the reform of congestion management and compromise the effectiveness of LMP price signals.
Hour Ahead					
Timing	SMD does not mention an Hour Ahead market (considers Day Ahead and Real Time markets only). It does not preclude Hour Ahead market.	The Schedule Adjustment Process ends one (1) hour prior to the start of the Settlement Period.	Schedule changes are permitted after Day-Ahead, but there is not formal Hour-Ahead process defined.	Two hours before real-time.	Hour Ahead market to move closer (close 60 minutes before) real time.
Energy Market	N/A	SCs can adjust their energy schedules so long as the overall schedule remains balanced and includes any required Transmission Rights.		None	See DA
Congestion Management Market	N/A	None, per se. Continue required use of Transmission Rights to manage congestion on FTR Interfaces and Scheduling Points and use of Congestion Redispatch bids to manage intra-zonal congestion.		See DA	See DA
Ancillary Services Market	N/A	WestConnect will conduct an on-going Ancillary Services procurement process, as necessary, to meet additional requirements, including replacement of previously committed Ancillary Services		See DA	See DA

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Real Time					
Model spatial granularity	Nodal	Full network model	Nodal	Existing three-zone model	Nodal, using full network model of CAISO grid plus reduced external equivalent network for the rest of WECC.
Model objective function	Security -constrained Economic Dispatch	Security -constrained economic dispatch, which accounts for all transmission constraints, loop flows, and generator performance parameters and constraints, and imbalance needs.	Minimize costs of balancing energy and congestion clearing.	Phase 1b: Security -Constrained Economic Dispatch (including clearing of overlapping inc and dec bids in every 10 minute interval) using the current radial network model with the existing zones and scheduling points.	Security -constrained economic dispatch (SCED), which accounts for all transmission constraints, loop flows, transmission losses, and generator performance parameters and constraints, and imbalance needs [plan to use State Estimator (SE) results as input to SCED if/when SE is implemented]
Energy/CM Market bids	Inc/dec bids	Energy bid curves associated with various Ancillary Services.	Inc/Dec bids from supply and demand-side.	inc/dec bids	inc/dec bids
Ancillary Services bids	Nothing Specific about A/S procurement in real-time	Capacity bids and associated energy bid curves.	Details yet to be determined.	Out-of-Market Transaction if bids are insufficient	Nothing specific [considering real-time purchase of A/S if the hour-ahead market is made advisory]
Market Power Mitigation	(see market power mitigation section below)	Appendix H, Market Monitoring, provides overall market monitoring provisions, with additional details to be developed prior to operation. LGR service	Details not yet developed, however order encourages RTO West to include appropriate market mitigation measures to prevent	Mitigation against economic withholding (pre-dispatch AMP) and local market power in real time (based on proxy bids) [see market power mitigation below]	Mitigation against economic withholding (pre-dispatch AMP) and local market power in real time (based on proxy bids) [see market power

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		addresses market power concerns during Load Pocket Conditions.	participants from exercising market power due to structural flaws in the market (e.g., lack of price-responsive demand or load pockets) or unusual market conditions.		mitigation below]
Dispatch interval	Every 5 minutes	WestConnect will operate a single control area with real-time dispatch as necessary to meet NERC and WSCC control performance criteria. Balancing Energy prices will be determined on a 10-minute interval basis.	Details yet to be determined	Every 10 minutes	Every 10 minutes
Imbalance Price	Each locational price reflects redispatch costs for congestion, loop flow, & imbalance needs; Difference between 2 locational prices reflect costs of congestion and losses.	Separate 10-minute Balancing Energy Clearing Prices for each Congestion Zone.	Nodal prices based on least cost acquisition; congestion cost is price between nodes.	Single 10-minute Real-time Price in each zone reflects redispatch costs for imbalance needs taking into account inter-zonal congestion. Phase 1b: Considering ex-post pricing (based on unit performance rather than acknowledged dispatch instruction)	Single 10-minute Real-time Price at each location reflects redispatch costs for congestion, loop flow, transmission losses, and imbalance needs. Considering ex-post pricing (based on unit performance rather than acknowledged dispatch instruction)
Penalties	Considers 3 options: No Penalty Penalty for uninstructed generation & load for reliability threat only Penalty for uninstructed generation & load	Penalties for under-scheduling Demand during the Day-Ahead Scheduling process and for leaning on the Real-Time Balancing Energy market.	Potential penalties for "over reliance" on balancing energy market.	Phase 1b: System of penalties for uninstructed deviation beyond specified band. [No payment for uninstructed generation above the band; 25% MCP penalty for uninstructed undergeneration outside the band]	System of penalties for uninstructed deviation beyond specified band. [No payment for uninstructed generation above the band; 25% MCP penalty for uninstructed undergeneration outside the band.

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Post Real-Time					
Settlement Stages	2-stage settlement recommended: DA and RT	Preliminary Monthly Invoices issued approximately twenty (20) days after the end of the month. Final Monthly invoices issued approximately sixty (60) days after the end of the month.	2-stage settlement for DA congestion clearing and RT congestion clearing and balancing energy.	3-stage settlement: DA, HA, RT. RUC compensation based on unrecovered start-up and min-load.	3-stage settlement: DA, HA, RT. (CAISO participants rely on HA settlement to minimize exposure to RT prices and congestion risks.) RUC compensation based on unrecovered start-up and min-load.
Pricing/Payment: Spatial Granularity	Nodal	Payments and credits for Transmission Services, FTR auctions, and Ancillary Services Same as the granularity of the service being billed.	Nodal	Real-time zonal prices for both load and generation (System-wide when there is no congestion between ISO zones).	Generators will earn nodal prices; loads may pay based on an aggregation of nodal prices as relevant (node, load group, demand zone, LPA.)
Temporal Granularity	Hourly for both pricing and settlement in forward market; sub-hourly pricing in RT with hourly settlement	Same as the granularity of the service being billed.	Hourly envisioned with details of settlement process yet to be determined.	Hourly in Forward Markets (CM/AS) Every 10-minutes in Real-time (Energy)	Hourly in forward markets (Energy/CM/AS); Every 10-minutes in Real-time (Energy; possibly also residual CM and AS under consideration)
Price Caps	Damage control bid caps	None, at this time	FERC encourages RTO West to consider inclusion of market mitigation provisions.	Damage-control price cap on ISO markets. The level is currently \$250/MWh. Negative bids capped at negative \$30/MWh.	Damage-control price cap on ISO markets. The level is currently \$250/MWh. Negative bids capped at -\$30/MWh.
DEMAND RESPONSE PARTICIPATION	"Demand resources ... should be able to participate fully in energy, ancillary services and capacity markets" "Market rules ... must not unduly bias the choice between demand or supply resources"		Demand-side bidding in DA and RT envisioned.	Loads can participate in the Non-spinning Reserve and Supplemental Energy markets through Participating Load Program.	MD02 adds capability for load to participate in the day-ahead and hour ahead energy markets; load will be allowed to submit three-part market-based bid blocks

□	FERC STANDARD MARKET DESIGN NOPR	WESTCONNECT PROPOSED	RTO West	CAISO PROPOSED (Phase 1a: 10/30/02 Phase 1b: 01/31/03)	CAISO PROPOSED (long-term)
	<p>or supply resources"</p> <p>"Demand can best respond by participation in the day-ahead market"</p> <p>"Sellers (including demand side) must have the option of submitting multi-part bids"</p>				(minimum curtailment duration); also demand response can fulfill ACAP obligation. Demand response designated ACAP can participate in Residual Unit Commitment..
MARKET POWER MITIGATION	<p>Structural Solutions preferred over behavioral rules, mitigation measures and penalties.</p> <p>Local market power mitigation:</p> <ul style="list-style-type: none"> • Must offer requirement and mitigated pricing under noncompetitive conditions should be defined as part of PGAs • ITP to identify generating units that must run for reliability and have them subjected to mitigation • Local market power bid caps are cost-based. <p>Safety net bid cap as a proxy for demand bidding</p> <p>Resource adequacy requirement.</p> <p>Transmission provider to identify generating units that must run for reliability and have them subjected to mitigation</p> <p>Limitations on flexibility to change</p>	<p>To be developed and approved by the FERC.</p>	<p>Market monitoring described, but details of mitigation strategies left for implementation phase.</p> <p>FERC encourages RTO West to include market power mitigation provisions.</p>	<p>To mitigate physical withholding:</p> <ul style="list-style-type: none"> • Must Offer Obligation • Penalties for uninstructed deviations (not following dispatch instructions is s form of physical withholding) <p>To mitigate economic withholding:</p> <ul style="list-style-type: none"> • Resource specific bid caps for locational market power mitigation • Damage control bid/price cap • Automated Mitigation Procedure (action & impact thresholds similar to the NYISO AMP) • Market Competitiveness Index : 12-month rolling average price cost markup to be used as ongoing assessment of "just and reasonable" market outcome . <p>To mitigate local market power:</p> <ul style="list-style-type: none"> • Limit generation schedule out of 	<p>To mitigate physical withholding:</p> <ul style="list-style-type: none"> • ACAP • RUC • Penalties for uninstructed deviations (not following dispatch instructions is s form of physical withholding) <p>To mitigate economic withholding:</p> <ul style="list-style-type: none"> • Resource specific bid caps for locational market power mitigation • Damage control bid/price cap • Automated Mitigation Procedure (action & impact thresholds similar to the NYISO AMP)

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	<p>bids</p> <p>AMP is voluntary – triggered by market conditions to be defined.</p>			<p>constrained areas in the forward market</p> <ul style="list-style-type: none"> • Mitigate out-of-merit Order INC bids needed for locational requirements in real-time • Mitigate out-of-merit Order DEC bids needed for locational requirements in real-time 	<ul style="list-style-type: none"> • Market Competitiveness Index: 12-month rolling average price cost markup to be used as ongoing assessment of “just and reasonable” market outcome. <p>To mitigate local market power: Mitigate out-of-merit Order INC bids needed for locational requirements in the forward market and in real-time</p>
<u>Market Monitoring</u>	<p>Market monitoring should be autonomous from ITP management and report directly to FERC and to ITP Board. It should also share its reports with ITP management and with the Regional State Advisory Committee.</p> <p>Proposes extensive detail regarding the objectives and contents of market monitoring activities, as well as specific rules governing market participant behavior.</p>				<p>MD02 does not contemplate changes to structure of ISO market monitoring function (Department of Market Analysis).</p> <p>Separate activity, the “Oversight and Investigations Review,” to evaluate and revise rules and procedures regarding oversight, investigations and enforcement.</p>
<u>State Participation in RTO Operations</u>	<p>SMD proposes Regional State Advisory Committee to work with the RTO to seek regional solutions to issues that may fall under Federal, State or shared jurisdiction, which may include</p>				<p>Not addressed by MD02.</p>

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	but not limited to: <ul style="list-style-type: none"> • Resource adequacy standards • Transmission planning, expansion • Rate design and revenue requirements • Market Power and Market Monitoring • Demand response and load management • Distributed generation and inter-connection policies • Energy efficiency and environmental issues • RTO management & budget review. 				
<u>ITP Governance</u>	Board of Directors <ul style="list-style-type: none"> • Between five and nine members • The board should be composed of members that are not part of the management of ITP. (Commission requests comment on whether the CEO should be a non-voting member; newer ISO Boards do not include the CEO.) • Fully independent of any market participants. Responsibilities of Board of Directors <ul style="list-style-type: none"> • Oversee ITP's administration of tariff and market rules 				Not addressed by MD02.

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	<p>approved by FERC</p> <ul style="list-style-type: none"> • Monitor operations of market within region • Ensure system reliability and operating efficiency • Ensure efficiently functioning markets, and • Short and long-term planning objectives. <p>Stakeholder Advisory Committee</p> <p>Comprised of representatives of six Stakeholder classes:</p> <ul style="list-style-type: none"> • Generators and marketers • Transmission owners (including vertically integrated utilities) • Transmission dependent utilities • Public interest groups • Alternative energy providers • End-users and retail energy providers (load serving entities that do not own transmission or distribution assets) <p>A company (including all of its affiliates) may have a representative in only one stakeholder sector.</p>				