Ramp Capability Product Cost Benefit Analysis

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The MISO is expected to require additional flexibility in dispatchable generation to address increasing volatility in the net load (load minus net interchange minus intermittent resource output) that must be met with dispatchable MISO generation. The volatility may arise from business rule changes such as shorter lead time for interchange scheduling (or more granular interchange scheduling) and/or changes in the load or generation fleet such as an increasing proportion of intermittent resources. Some of the impacts of this increasing volatility in net load on energy and ancillary service markets will include the dispatch of high cost generation resources, instances of reserve scarcity, and increased use of regulation, which will be reflected in price spikes.

Within the MISO market design, the introduction of ramp capability products can provide an attractive approach to obtaining needed operational flexibility at a lower cost than other alternatives, providing both market and reliability benefits. Benefits to the market include the following:

- Reduced frequency of reserve shortages or transmission violations,
- Less need to dispatch high cost resources;
- Avoided cost of uneconomic CT commitments to provide ramp
- Reduced need for ad hoc operator actions such as RT adjustments in the UDS Offset MW and CT commitment providing increased consistency of market results
- Transparent pricing and incentives for the supply of ramp capability
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Ramp products also provide benefits for system reliability:

- Systematic mechanism to specify and procure the ramp capability needed to respond to near real-time changes in system requirements
- Provide enhanced incentives for resources to provide ramp capability
- Avoided and/or reduced cost of reserve shortages (or potentially transmission violations)
- Reduced need for operator intervention in routine real-time market operations, freeing operator time to focus on other issues

This paper focuses on quantifying the monetary impacts of the ramp products. A series of examples and simulation cases illustrate different sources of potential savings. Some examples use small data sets to illustrate the way in which the ramp products are intended to work while others report the results of simulations carried out dispatching generation over the entire MISO footprint to simulate the operation of the ramp products over an historical operating day. The examples are designed to illustrate specific sources of the potential savings and none of them fully cover the all of the impacts in a single example. To help describe the impact investigated in the examples, the monetary impacts are broken down into six areas, each of the following three areas for the Day-Ahead Market and for real-time (RAC and RT-UDS):

- As-offered production cost – the production costs for the resource according to the resource offers for energy and reserves. As-offered production cost may be extended to include the lost value of un-served products when there are system shortages
- Product payments – product quantity times clearing price which may be measured for generation or loads.
- Revenue Sufficiency Guarantee (RSG) payments – additional payments made to eligible generators when their as-offered production costs are greater than their product payments in an operating day

Shading of the grid shown below is used to describe the scope of specific examples in these six areas of monetary impacts.

RT As-Offered Cost	RT Product Paym'ts	RT RSG
DA As-Offered Cost	DA Product Paym'ts	DA RSG

Basic Avoided Scarcity Example

This example uses four resources to illustrate how the ramp products can provide additional operational flexibility that can avoid reserve scarcity in real-time dispatch. This example examines the impact on real-time as-offered production cost of introducing the ramp capability product (including the cost of reserve or regulation shortages valued using shortage prices).

RT As-Offered Cost	RT Product Paym'ts	RT RSG
DA As-Offered Cost	DA Product Paym'ts	DA RSG

The four resources in this example have the following operating characteristics and offer data. The offer curves are flat as a function of MW output with a constant price. The startup and no-load costs are not a factor in this real-time dispatch example.

In this example, four 5-minute dispatch intervals (labeled T1, T2, T3, and T4) are dispatched sequentially as they would be over a 20 minute period in real-time. It is assumes that the resources meet their energy dispatch target for each interval such that the output of one interval becomes the initial resource output for the next interval that is used to enforce ramping constraints. The load forecast for future intervals is updated prior to each interval's dispatch as shown in the following table.

Name	Min (MW)	Max (MW)	Ramp Rate (MW/ min)	Energy Offer Price ($/MWh)	Reg Offer Price ($/MWh)	Spin Offer Price ($/MWh)	Supp Offer Price ($/MWh)	Initial Output (MW)
G0	100	400	1	25	5.0	4.0	3.0	400
G1	10	130	4	30	1.5	1.0	0.5	130
G2	10	49	1	31	2.0	1.0	0.5	30
G3	10	100	1	36	3.0	1.0	0.5	10

	T1	T2	T3	T4	T5	T6
Load Forecast @ T1 Dispatch (MW)	575	579	584			
Load Forecast @ T2 Dispatch (MW)		585	588	590		
Load Forecast @ T3 Dispatch (MW)			587	591	593	
Load Forecast @ T4 Dispatch (MW)				591	594	597

The ramp capability targets are set based on the projected change in net load over the next 10-minutes plus 12 MW of ramp capability to cover uncertainty in the up and down directions for up ramp capability (URC) and down ramp capability (DRC), respectively. The following table shows the URC requirements. The up ramp capability for the dispatch at T1 is the expected change in load from T1 to T3 (584-575) plus 12 megawatts

	T1	T2	T3	T4	T5	T6
Up Ramp Cap Req @ T1 Dispatch (MW)	21					
Up Ramp Cap Req @ T2 Dispatch (MW)		17				
Up Ramp Cap Req @ T3 Dispatch (MW)			18			
Up Ramp Cap Req @ T4 Dispatch (MW)				18		

The reserve requirements and their demand curve/penalty prices are the same in each interval.

Service	Requirement (MW)	Demand Curve/ Penalty Price ($/MWh)
Regulation	5	98
Spinning Reserve	14	98
Supplemental Reserve	6	1100

The co-optimized solution for energy, regulation, spinning reserve, supplemental reserves, and URC (for cases including URC) is shown in the table below. Although DRC was also cleared in the case, it was nonbinding and thus id not influence the dispatch and is not reported. The case without URC exhibits reserve scarcity, clearing only 5.5 MW of the required 6 MWs of supplemental reserve in interval T2. When URC is included in the optimization, reserve scarcity is avoided in this interval. The URC requirements in T1 cause G1 and G2 to be dispatched down to create additional flexibility to accommodate the change in T2. As designed, when the flexibility is used in T2 to meet the energy and reserve needs, there is not enough capacity to fulfill the URC requirement.

Dispatch MWs		**T1**		**T2**		**T3**		**T4**	
		No URC	w/ URC	No URC	w/ URC	No URC	w/ URC	No URC	w/ URC
Energy	G0	400	400	400	400	400	400	400	400
	G1	130	129	130	130	130	130	130	130
	G2	34.5	29	39.5	33	39	31	39	31
	G3	10.5	17	15.5	22	18	26	22	30
Regulation	G0	0	0	0	0	0	0	0	0
	G1	0	0	0	0	0	0	0	0
	G2	4.5	0	0	0	0	0	0	0
	G3	0.5	5	5	5	5	5	5	5
Spinning	G0	0	0	0	0	0	0	0	0
	G1	0	0	0	0	0	0	0	0
	G2	4	4	4	4	4	4	4	4
	G3	10	10	10	10	10	10	10	10
Supplemental	G0	0	0	0	0	0	0	0	0
	G1	0	0	0	0	0	0	0	0
	G2	6	6	5.5	6	6	6	6	6
	G3	0	0	0	0	0	0	0	0
Up Ramp Cap.	G0	--	0	--	0	--	0	--	0
	G1	--	1	--	0	--	0	--	0
	G2	--	10	--	6	--	8	--	8
	G3	--	10	--	10	--	10	--	10

The prices of the two cases are shown in the following table. URC is able to avoid the operating reserve shortfall and the associated $1100/MWh reserve scarcity pricing. There is a shortage of upward ramp capability in this interval, but this is much less consequential from a reliability standpoint and the $10/MWh demand curve for URC has a much smaller impact on prices.

Clearing Prices	T1		T2		T3		T4	
	No URC	w/ URC	No URC	w/ URC	No URC	w/ URC	No URC	w/ URC
Energy	34	36	1130.5	41	36	36	36	36
Regulation	5	7	1101.5	12	7	7	7	7
Spinning	4	6	1100.5	11	6	6	6	6
Supplemental	3.5	5.5	1100	10.5	5.5	5.5	5.5	5.5
Up Ramp Cap.	--	6	--	10	--	5	--	0

Although the more flexible dispatch of the generation when URC costs more in terms of generator offer costs, when the cost of reserves shortages is taken into account in, the case with URC has a lower cost. By avoiding reserve scarcity with URC, the payments associated with the cleared products are reduced to just 12% of the product payments without URC when there is reserve scarcity pricing – an 88% reduction in the nominal payments for power. Large product payment changes are commonly associated with the elimination of short-term price spikes because the spike price impacts all quantities in the market. ***The focus of this study will be on production cost and shortage costs and savings associated with them. Product payment savings in Real Time does not reflect the cost of power scheduled in day Ahead process (since the shortage is not seen there). Also, it does not affect power bought and sold by vertically integrated utilities.***

	Offer Cost + Value of Un-served ($)	Product Payment ($)
No URC	5279.4	61454.6
With URC	5246.7 (-0.62%)	7351.0 (-88.0%)

Combined Day-Ahead and Real-Time Example

This example applies the ramp products in a two-settlement market where the URC and DRC products are included in both Day-Ahead and Real-Time Markets. The example simulates the participation of six resources in a 4-hour simulation of the Day-Ahead Market and real-time dispatch in one of those hours. This limited scope keeps the example relatively small while providing illustrating the interaction of URC and DRC in the market clearing and settlement processes. The example has the following features:

- A ramp capability requirement for flexibility is included in the Day-Ahead Market.
- Focus on URC interaction with energy dispatch }
- Regulation and contingency reserve are not modeled and thus savings associated with their interaction are not included.
- Virtual bids and offers are not included in the Day-Ahead Market.
- No external interchange schedules are modeled.

- Day-Ahead Market fixed demand bids are assumed to be equal to the load forecast so RAC commitments are not necessary.

This example covers all six of the monetary impact areas identified in the grid below. The Day-Ahead Market is settled based on the Day-Ahead Market clearing and prices, while the Real-Time Market is settled based on real-time prices and real-time deviations from the Day-Ahead Market schedules. Revenue sufficiency guarantees are calculated as the shortfall of generator product revenue compared to as-offered production cost.

RT As-Offered Cost	RT Product Paym'ts	RT RSG
DA As-Offered Cost	DA Product Paym'ts	DA RSG

Two scenarios are compared in this example:

- Scenario 1 (SC1) includes energy clearing and follows the current MISO approach of including Market-Wide Ramp-Up and Ramp-Down Capacity Constraints in the commitment (but not dispatch function)
- Scenario 2 (SC2) includes energy and URC and DRC in both the commitment and dispatch functions

This example has six generating resources as described in the table below. All of the resources have a single-price (flat) offer curve, $1000 startup cost offer, and $45/h no-load cost offer. G4 has higher ramp than G3 but a higher energy price. G5 is a quick start CT. The initial conditions for the 4-hour Day-Ahead Market and the single hour real-time dispatch are also included in the table. The Day-Ahead Market commitment solutions are different for the two scenarios, so the real-time dispatch initial conditions are different for scenario 1 and 2.

Name	Min (MW)	Max (MW)	Up Ramp Rate (MW/ min)	Dn Ramp Rate (MW/ min)	Offer Price ($/MWh)	DA Hr 1 Initial MW	SC1: RT Hr 3 Initial MW	SC2: RT Hr 3 Initial MW
G0	100	400	1	-1	25	400	400	400
G1	10	130	4	-4	30	115	130	130
G2	10	130	1	-1	31	60	90	90
G3	10	100	1	-1	36	Off	**10**	**Off**
G4	10	100	1.7	-1.7	37	Off	**Off**	**10**
G5	5	5	3	-3	90	Off	Off	Off

The example is designed around 660 MWs of load; the capacity of G0-G2Hour 4 requires an additional resource (G3, G4 or GG5) to be committed to meet the load energy requirements. Hour 3 load is below 660 MW at 647 MW, but the Market-Wide Ramp-Up Capacity Constraints and in scenario 2 the URC requirements cause an additional resource to be committed in hour 3. Hour 3 has a large mid-hour ramp that is a factor in the real-time dispatch simulation. The hourly average real-time hour 3 load is 646.6 MW compared to the hourly 647 MW cleared in the Day-Ahead Market. The load is increasing in the example and the ramp-down capacity and DRC are not binding or factors in the commitment or dispatch functions.

The Market-Wide Ramp-Up and Ramp-Down Capacity Constraint requirements for commitment are calculated for the Day-Ahead Market from the adjacent hour load change with a 10 MW minimum requirement. These constraints are not included in the real-time dispatch. For this example, the normal ramp minutes of 30 minutes was increased to 40 minutes to ensure commitment of an additional resource is required. For example, the Ramp-Up Capacity Requirement in hour 2 is 16.7 MW, the larger of 10 (the minimum requirement), [625-600 MW]*[40/60 minutes] (change from hour 1 to hour 2), and [647-625 MW]*[40/60 minutes] (change from hour 2 to hour 3).

The real-time URC and DRC requirements are determined by the 10-minute ahead load forecast change plus 12 MW of uncertainty in each interval. The day-ahead URC and DRC requirement is based on an estimate of the real-time requirements for the operating day. The URC and DRC demand curves are priced at $10/MWh for the dispatch function.

Hourly Load and Ramp	**Hr1**	**Hr2**	**Hr3**	**Hr4**
DA Fixed Demand & Load Forecast (MW)	600	625	647	663
SC1: MW Ramp-Up Capacity Req. (MW)	16.7	16.7	14.7	10.7
SC1: MW Ramp-Down Capacity Req. (MW)	10	10	10	10
SC2: Up Ramp Capability Req. (MW)	25	21	19	23
SC2: Down Ramp Capability Req. (MW)	0	3	5	1

Interval Ending	**2:05**	**2:10**	**2:15**	**2:20**	**2:25**	**2:30**	**2:35**	**2:40**	**2:45**	**2:50**	**2:55**	**3:00**
Load Forecast (MW)	632	633	634	637	648	649	650	652	653	655	657	659
SC1: MW Ramp-Up Req	--	--	--	--	--	--	--	--	--	--	--	--
SC1: MW Ramp-Dn Req	--	--	--	--	--	--	--	--	--	--	--	--
SC2: UpRamp Req (MW)	14	16	26	24	14	15	15	15	16	16	15	14
SC2: DnRamp Req (MW)	10	8	0	0	10	9	9	9	8	8	9	10

Day-Ahead Market Results

The Day-Ahead Market results are different for scenarios 1 and 2. Scenario 1 commits the less expensive and less flexible G3 in hours 3 and 4. Results in the following table show the energy and URC dispatch for each generator in each hour.

(MW/Up Ramp Capability MW)	Hr1	Hr2	Hr3	Hr4
G0	400 / -	400 / -	400 / -	400 / -
G1	130 / -	130 / -	130 / -	130 / -
G2	70 / -	95 / -	107 / -	123 / -
G3	-	-	10 / -	10 / -
G4	-	-	-	-
G5	-	-	-	-

Scenario 2 commits the more expensive and more flexible G4 instead. Scenario 2 also moves MWs from the less expensive G1 to G2 in hours 1 and 2 to meet the URC requirements.

(MW/Up Ramp Capability MW)	Hr1	Hr2	Hr3	Hr4
G0	400 / 0	400 / 0	400 / 0	400 / 0
G1	115 / 15	119 / 11	130 / 0	130 / 0
G2	85 / 10	106 / 10	107 / 10	123 / 7
G3	-	-	-	-
G4	-	-	10 / 9	10 /16
G5	-	-	-	-

The energy clearing prices are the same both scenarios. Scenario 1 energy clearing prices are $31/MWh in each interval.

Price ($/MWh)	Hr1	Hr2	Hr3	Hr4
Energy	31	31	31	31

The scenario 2 energy price is the same. The URC price is $1/MWh in the first two hours representing the redispatch cost between G1 and G2 ($31/MWh - $30/MWh).

Price ($/MWh)	Hr1	Hr2	Hr3	Hr4
Energy	31	31	31	31
Up Ramp Capability	1	1	0	0
Down Ramp Capability	0	0	0	0

Real-Time Market Results

The Real-Time Market 5-minute dispatch is simulated for only hour 3 in this example. It is assumed that the resources committed in hour 3 from the Day-Ahead Market are online and dispatchable for the whole hour in real time.

The resources in scenario 1 do not have sufficient flexibility to meet the load change at 2:25. In this example, it is assumed that the operators foresee the upcoming ramp challenge and commit the G5 CT to come online at 2:25 to meet the real-time load requirements rather than not meeting the load in that interval. The dispatch results for scenario 1 are shown in the following table.

Scenario 1 Dispatch	2:05	2:10	2:15	2:20	2:25	2:30	2:35	2:40	2:45	2:50	2:55	3:00
G0	400	400	400	400	400	400	400	400	400	400	400	400
G1	130	130	130	130	130	130	130	130	130	130	130	130
G2	92	93	94	97	102	104	105	107	108	110	112	114
G3	10	10	10	10	11	10	10	10	10	10	10	10
G4	--	--	--	--	--	--	--	--	--	--	--	--
G5	--	--	--	--	5	5	5	5	5	5	5	5

Scenario 2 with the additional flexibility of G4 rather than G3 is able to meet the load change without needing to incur the additional costs of calling on a CT as shown in the energy dispatch in following table.

Scenario 2 Dispatch	2:05	2:10	2:15	2:20	2:25	2:30	2:35	2:40	2:45	2:50	2:55	3:00
G0	400	400	400	400	400	400	400	400	400	400	400	400
G1	130	130	130	130	130	130	130	130	130	130	130	130
G2	92	93	94	97	102	107	110	112	113	115	117	119
G3	--	--	--	--	--	--	--	--	--	--	--	--
G4	10	10	10	10	16	12	10	10	10	10	10	10
G5	--	--	--	--	--	--	--	--	--	--	--	--

In scenario 2, the URC constraints are met by G2 and G4.

Scenario 2 URC	2:05	2:10	2:15	2:20	2:25	2:30	2:35	2:40	2:45	2:50	2:55	3:00
G2	10	10	10	10	10	10	10	10	10	10	10	10
G4	4	6	16	14	4	5	5	5	6	6	5	4

During the mid-hour ramp up, G3 sets the price at $36/MWh in scenario 1. In all other intervals in scenario 1, the price is set by G2 at $31/MWh.

Scenario 1 Prices	2:05	2:10	2:15	2:20	2:25	2:30	2:35	2:40	2:45	2:50	2:55	3:00
Energy	31	31	31	31	36	31	31	31	31	31	31	31

In scenario 2, the energy price is higher in both the 2:25 and 2:30 intervals with G4 setting the price at $37/MWh. G2 and G4 are able to provide the required URC without redispatch so the URC price is $0/MWh in each interval.

Scenario 2 Prices	2:05	2:10	2:15	2:20	2:25	2:30	2:35	2:40	2:45	2:50	2:55	3:00
Energy	31	31	31	31	37	37	31	31	31	31	31	31
Up Ramp Capability	0	0	0	0	0	0	0	0	0	0	0	0
Dn Ramp Capability	0	0	0	0	0	0	0	0	0	0	0	0

Example Settlement Calculations

Calculations to settle the day-ahead and real-time clearing described above are described in this section. Using a two-market settlement approach, the Day-Ahead Market is settled first using its clearing results to calculate Day-Ahead Market product payments and revenue sufficiency guarantees (if the generator product payments do not exceed the as-offered costs).

The Day-Ahead Market settlement calculations for G2 in scenario 1 are the following:

- As-offered production cost = $12,425
    - $0 Startup (G2 was initially on-line so no startup cost is incurred)
    - $45/h No-load * 4 Hours
    - $31/MWh Energy * (70 MWh + 95 MWh + 107 MWh +123 MWh)
- Market product payments = $12,245
    - $31/MWh Energy * (70 MWh + 95 MWh + 107 MWh +123 MWh)
- Revenue Sufficiency Guarantee = $180
    - Larger of 0 and as-offered production cost – market product payments
    - Maximum (0, $12,425 - $12,245)

For scenario 2, the G2 Day-Ahead Market calculations are

- As-offered production cost = $13,231
    - $0 Startup
    - $45/h No-load * 4 Hours
    - $31/MWh Energy * (85 MWh + 106 MWh + 107 MWh +123 MWh)
    - Availability offer for URC is supported so $0 cost for URC
- Market product payments = $13,071
    - $31/MWh Energy * (85 MWh + 106 MWh + 107 MWh +123 MWh)
    - $10/MWh URC * (10 MWh + 10 MWh) + $0/MWh URC * (10 MWh + 7 MWh)
- Revenue Sufficiency Guarantee = $160
    - Larger of 0 and as-offered production cost – market product payments
    - Maximum (0, $13,231 - $13,071)

The complete Day-Ahead Market settlement calculations are summarized for all resources in the table below. With URC in scenario 2, the commitment of the more flexible but slightly more expensive G4 results in $46 higher as-offered costs and product payments.

	Scenario 1			Scenario 2		
	DA Offered Costs	DA Product Payment	DA RSG Payment	DA Offered Costs	DA Product Payment	DA RSG Payment
G0	40,180	49,600	0	40,180	49,600	0
G1	15,780	16,120	0	15,000	15,340	0
G2	12,425	12,245	180	13,231	13,071	160
G3	1,810	620	1,190	0	0	0
G4	0	0	0	1,830	620	1,210
G5	0	0	0	0	0	0
Total	70,195	78,585	1,370	70,241	78,631	1,370

In the two-market settlement approach, real-time prices are used to settle the differences between the Day-Ahead Market cleared quantities and real-time actual quantity data. All resources are assumed to follow their dispatch instructions in real-time so the real-time dispatch is equal to the real-time actual generation in this example.

Continuing the sample calculations using G2, with hourly average real-time output for hour 3 of scenario 2 below its Day-Ahead Market clearing, G2 buys back the difference at the real-time price with a charge of $34.60, which in MISO may be subject to reduction based on the Day-Ahead Margin Assurance Payment (DAMAP) if G2 is eligible.

	Hr3			
	RT MW	DA MW	MW Diff.	Avg. RT Price
Average Energy	105.92	107	-1.08	32
Average Up Ramp	10	10	0	0
Average Down Ramp	0	0	0	0
Market Payments ($)			-34.7	

The real-time settlement calculations for all resources show that scenario 1 without the ramp products results in $1225 additional payments for the Real-Time Market. In the following summary of the calculation of real-time settlements (product payments and RSG), the real-time offered costs are not reported if the resource is not eligible for real-time revenue sufficiency guarantees because it was committed for the hour in the Day-Ahead Market**.**

From these results, we see that the real-time G5 commitment lead to higher real-time RSG which could be avoided by redispatching to increasing the level of generation ramp capability. In scenario 1, the G5 commitment reduces the energy output of other generators and G2 is also ramp rate constrained during the hour.

	Scenario 1			Scenario 2		
	RT Offered Costs	RT Product Payment	RT RSG Payment	RT Offered Costs	RT Product Payment	RT RSG Payment
G0	-	0	0	-	0	0
G1	-	0	0	-	0	0
G2	-	-120.4	0	-	-34.7	0
G3	-	2.6	0	-	0	0
G4	-	0	0	-	21.3	0
G5	1,330	104.7	1225.3	-	0	0
Total	1,330	-13.1	1225.3	0	-13.3	0

In terms of production cost, the real-time dispatch in scenario 2 avoids the CT commitment and has a smaller production cost.

	Scenario 1 Hr 3 Production Cost	Scenario 2 Hr 3 Production Cost
G0	10,045.0	10,045.0
G1	3,945.0	3,945.0
G2	3,243.2	3,328.4
G3	408.0	--
G4	--	439.7
G5	1,330.0	--
Total	18,971.2	17,758.1

Combined Day-Ahead and Real-Time Summary

Ramp products are expected to cause modest production cost increases when additional ramping flexibility is committed and to provide larger savings when it is used to reduce the cost of meeting load by avoiding the dispatch of high cost generation, the commitment of uneconomic CTs and reserve shortages, and the associated short-term prices spikes. As in this example where there is sufficient DRC and it is not factor, the ramp products only have non-zero prices and receive payments when out-or-merit dispatch of generation is necessary to create additional URC/DRC.

This example showed savings from committing for more flexibility in the Day-Ahead Market and dispatching to use that flexibility in real-time. Changing the committed resource mix had a cost of $46 at the time of commitment, but saved $1225 in one hour of operations by avoiding the need to commit an additional CT.

In production, the savings of avoiding one CT commitment for one hour by re-dispatching using ramp products might be in the range of $2,000 to $10,000 based on rough approximations of MISO data including

- Startup cost: $1,000 to $4,000 (50 to 100 MW unit)
- No-Load cost: $0 to $3,000
- Incremental cost: $50/MWh to $150/MWh

Net Load Volatility Cost-Benefit Estimate

To estimate the costs-benefit analysis of the ramp products being used to manage volatility in net load and reducing the associated short-term price spikes, a series of RT-UDS simulations were performed using MISO system data from 4 sample days. Although this analysis examines only a subset of the cost impacts related to price volatility, it uses MISO system data from the selected days for the estimate rather than illustrating the concepts on a small hypothetical example.

The results of the 4 days of simulations are aggregated over two types of periods: those associated with short-term price spikes (either up or down) and non-price spike periods. The non-spike intervals provide an estimate of the cost-benefit of operational production cost savings (or costs) resulting from the ramp products during the non-spike time periods. The short-term price spike data gathered for the 4 sample days estimates the cost-benefit provided per short-term price spike. The annual duration and frequency of non-spike and spike time periods were determined using historical MISO data and annual cost-benefit estimated by projecting the cost-benefit analysis calculated for the corresponding time periods for the selected days over the year. The results provide an estimated annual cost-benefit of the ramp products in terms of reduced as –offered production cost, avoided reserve violations, avoided transmission constraint violations price spikes, and associated reductions in price volatility from reduced frequency and/or intensity of price spikes and the associated generation redispatch.

These RT-UDS simulations were also used to investigate appropriate values for the following ramp product parameters:

- Demand curve cost – Both $5/MWh or $10/MWh penalty values were investigated in the study. The value of the demand curve penalty value determines the tradeoff between using dispatchable capacity for energy now versus saving flexibility for future intervals. The value of the demand curve penalty value is low compared to scarcity prices.
- Uncertainty component of the URC/DRC requirements – In addition to forecast changes in net load, the ramp product requirement includes an amount to cover uncertainty in net load. The uncertainty component can be adjusted by varying the number of standard deviations of the net load used to set this parameter.

Since this analysis was limited to the simulation of RT-UDS, the scope of the benefits estimated with the approach is focused on real-time as-offered production costs and product payments. If the scope of the study was extended to incorporate the impacts such as commitment changes or changes in the use of the RT-UDS offset, the benefits would be likely to increase.

RT As-Offered Cost	RT Product Paym'ts	RT RSG
DA As-Offered Cost	DA Product Paym'ts	DA RSG

Sample Day Simulation

The following days were selected for analysis to provide a reasonable sample of operating scenarios to act as a basis for estimating the costs and benefits of the ramp products:

- A high load day - 7/6/2012
  - Peak load of around 97,000 MW. Reserve scarcity occurred frequently, with 23 intervals exhibiting OR scarcity in the production RT-UDS.
- A medium load day - 7/28/2012
  - This day had peak loads of around 72,000 MW. Reserve scarcity occurred in only a small number of intervals.
- A low load day - 9/15/2012
  - Peak load was around 55,000 MW. No reserve scarcity occurred on this day.
- Wind generation drop day - 10/14/2012
  - Load level was low. There were price spikes on this day but no reserve scarcity was observed.

The sample days were analyzed by simulating a series of 288 RT-UDS dispatches for each operating day where the dispatch of one period is used to set the initial generator conditions for the next 5 minute period. The resource offers, dispatch status and online status; interchange transactions; load forecast; and activated transmission constraints were input from the actual RT-UDS cases from the selected operating day. The Up Ramp Capability and Down Ramp Capability target requirements were calculated for each period of the operating day. The requirements are determined as the expected change in net load plus a margin for uncertainty. The margin to cover uncertainty was defined by the following:

- Expected variability (change) in the net load (load, wind generation, and NSI) was calculated for the current interval as the change in their schedule/forecast between the current interval and the target ramp minutes (e.g., 10 minutes as in this study) in the future
- Uncertainty margin was determined based on the standard deviations of load, wind generation, NSI, and off-dispatch generation. The following components were used to define the uncertainty margin in the sample day simulations:
  - Load: 0.15% of the hourly average load
  - Wind forecast: uncertainty is modeled as a function of output
    - When wind generation is between 1% and 99% of the in-service wind generation capacity, the URC margin for wind is 1% of the in-service wind generation capacity

        - When wind generation is close to zero (< 1% of in-service wind generating capacity), the URC margin for wind is limited to wind generation output because it will primarily be in the upward direction; the standard deviation is equal to the expected wind generation.
        - When the wind generation is near its maximum (in-service level), the upward uncertainty is smaller because changes in output will primarily be in the downward direction. In this case, the uncertainty margin for wind is equal to the difference between the in-service capacity and the expected wind generation
    - NSI: has known variability and associated ramping needs defined by the approved interchange schedules but is assumed to have no uncertainty (0 standard deviation) 10 minutes prior to real time since interchange must be scheduled 20 minutes ahead of real time
    - Resources not following dispatch instructions: constant standard deviation of 80 MW in each time interval

The deliverability of the ancillary services and ramp products within zonal reserve transmission capabilities was constrained using MISO's "reserve procurement" transmission limit constraints. These constraints would be enforced in the simulations in the periods in which they were binding in RT-UDS. The reserve procurement constraints do not bind often and were not binding on the simulated days, so no locational constraint on ramp capability were enforced in the simulations.

The following analysis was performed for each of the four operating days studied:

- Base RT-UDS dispatch simulation without ramp products – this 288-interval series of 5-minute market clearing dispatch solutions provides a starting point for the cost benefit analysis. The base RT-UDS simulation is compared with the actual RT-UDS solutions to confirm that they are similar.
- Simulation runs with ramp products – these runs simulated 288 intervals of RT-UDS optimizing energy, regulation, contingency reserves, and the ramp products. These runs provide a cost-benefit comparison with the base RT-UDS.
    - This analysis is repeated for variations in the number of standard deviations used to determine the uncertainty margin for the ramp product requirement and the ramp product demand curve prices. The results for the different input ramp product input parameters were analyzed separately so that the overall results could be reported for these variations and the best levels determined.
        - URC and DRC demand curve prices were tested for values of $5/MWh and $10/MWh.
        - URD and DRC requirements were determined as the sum of an expected change in net load and an uncertainty margin to cover net load variability. The number of standard deviations used to define the uncertainty margin is reported for the sample days.

For each 5-minute interval in each simulation run, the following data is collected:

- As-Offered (Offer) Cost – includes startup, no load, energy, and AS offer costs to produce at the dispatched output. This cost includes the costs of redispatch which may be required to provide URC or DRC
- Value of un-served products – estimate value of reductions in ancillary service and ramp product deficits based on shortage/violation prices. The shortage/violations prices in these examples are as follows:
  - Power Balance = $3500/MWh
  - Operating Reserve = $1100/MWh
  - Reg-Spin Reserve = $98/MWh
  - Regulation = $98 - 300/MWh (changes periodically)
  - Transmission constraint violations = $2000/MWh (upper value)
- Value of transmission constraint violation – estimated value of reduction in transmission constraint violations based on penalty prices
- Combined costs – the sum of As-Offered Cost + Value of un-served products + Value of transmission constraint violation
- Load payments – payments by loads (quantity times real-time clearing price) for energy, ancillary services, and the ramp products (URC and DRC)
- URC/DRC payments and number of binding intervals – the cost is the ramp capability price times cleared quantity. Only binding intervals will have a non-zero URC or DRC clearing prices. This value is a component of the load payments item, but is reported separately for additional information. The load payment and the URC/DRC payment terms should not be added together.

These data will show different aspects of the impact the ramp products:

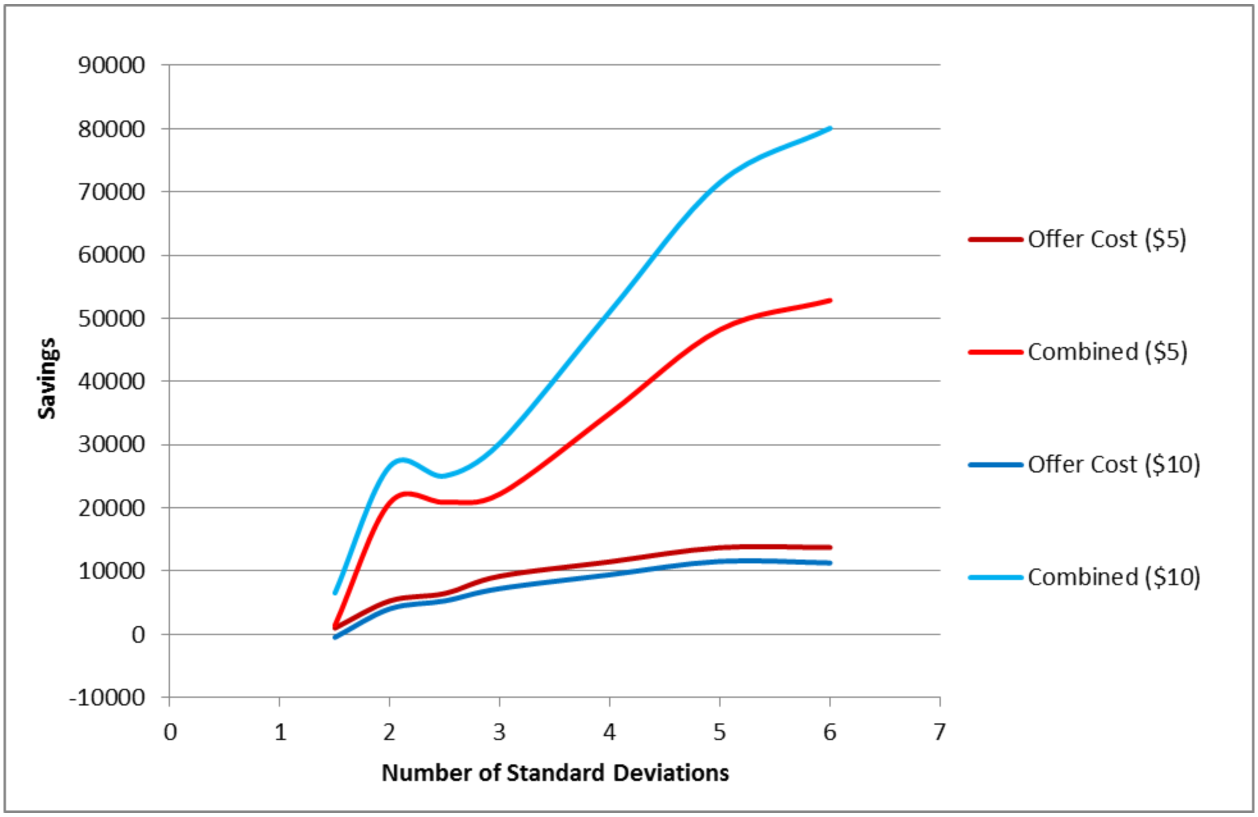
- As-offered production cost impacts are smaller than the nominal impact on generator and/or load payments, since the resulting changes in prices are applied to all injections and withdrawals in the market
- Combined costs provide insight into the impact of the product on optimized costs and production efficiency
- Load payments reflect the impact on total product payments, price times quantity, for energy, ancillary services and URC/DRC
- The impact on generator revenue sufficiency guarantees and price volatility make whole payments were not quantified in these simulation results
  - Example: a reduction in price spikes would be expected to reduce price volatility make whole payments, reducing out of market settlement actions and increasing market transparency

For each day, the actual RT-UDS price variations were compared with the study's base RT-UDS simulation without ramp products to confirm that the starting point for the analysis of that day is similar to what was observed in production. As an example, the following chart compares the marginal energy component (MEC) of the energy prices for RT-UDS and the simulation for July 6, 2012. The relationships on the other 3 days are similar.

The following series of tables and charts summarize the daily simulation data for the base RT-UDS simulation and for a number of variations of demand curve price and standard deviations used in the URC and DRC requirement calculations. Note that in these results, it is common for the URC and DRC results to provide an overall cost savings which is reported as a positive savings value.

July 6, 2012 Simulation Results

	Offer Cost	Un-served Products	Tx. Violation	Combined Costs	Total Load Payment	
Base Case	**34495101**	**4111418**	**290763**	**38897282**	**305605155**	--
# std dev	**Offer Cost Savings**	**Un-served Products Savings**	**Tx. Violation Savings**	**Combined Savings**	**URC/DRC Payment**	**# Periods URC/DRC Bind**
$5 URC/DRC Demand Curve						
1.5	1001	836	-413	1424	-11049	55
2	5308	13885	1675	20868	-14124	66
2.5	6490	12588	1831	20908	-19090	88
3	9216	10930	2067	22213	-25782	94
4	11497	17470	6033	35000	-42028	113
5	13739	23850	10633	48222	-53934	153
6	13754	26972	12123	52849	-71926	172
$10 URC/DRC Demand Curve						
1.5	-463	7249	-238	6548	-21321	55
2	4057	20625	1936	26618	-25656	66
2.5	5311	18122	1650	25083	-34673	88
3	7261	21565	1459	30285	-42953	95
4	9449	34595	7062	51106	-73837	113
5	11562	42943	17007	71513	-102503	154
6	11312	52969	15808	80089	-131295	173



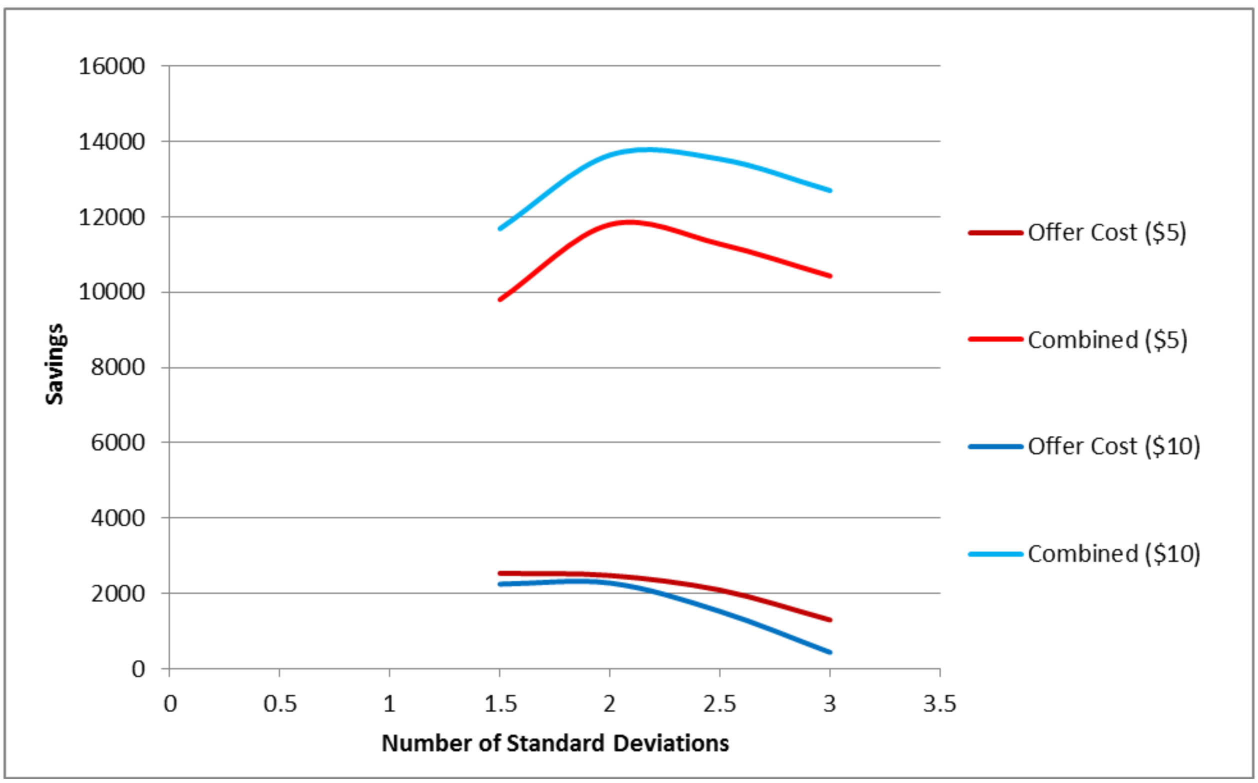
The result for July 6, 2012 is unique due to theist day's large number of scarcity intervals and tight capacity. Increasing the URC / DRC requirements to larger values continues to provide additional production cost savings and in general causes

- Increase in as-offered cost savings
- Reduction in un-served reserves
- Reduction in transmission constraint violations
- Increase in combined savings (including items above)
- Increase in product payments for URC and/or DRC
- Increase in number of periods that URC / DRC are binding
- Increase in Load Payment savings

Increasing the URC / DRC demand curve price has an impact similar to increasing URC / DRC requirements in that more URC / DRC is cleared.

July 28, 2012 Simulation Results

	Offer Cost	Un-served Products	Tx. Violation	Combined Costs	Total Load Payment	
Base Case	**21395096**	**14947**	**4348**	**21414391**	**52207728**	
# std dev	**Offer Cost Savings**	**Un-served Products Savings**	**Tx. Violation Savings**	**Combined Savings**	**URC/DRC Payment**	**# Periods URC/DRC Bind**
$5 URC/DRC Demand Curve						
1.5	2535	7269	0	9804	-3257	19
2	2475	9376	-54	11797	-6082	31
2.5	2088	9251	-61	11278	-9456	42
3	1295	9197	-61	10431	-15013	65
$10 URC/DRC Demand Curve						
1.5	2246	9440	0	11686	-5871	19
2	2276	11422	-54	13644	-9512	31
2.5	1522	12087	-75	13534	-14722	42
3	433	12329	-62	12700	-22364	65



The simulation results for July 28, 2012 were more typical than those for July 6, 2012. URC/DRC requirements including an uncertainty margin of 2 to 2.5 standard deviations maximizes as-offered cost savings, reduction in un-served reserves, reduction in transmission violation costs, and increases the net savings.

September 15, 2012 Simulation Results

	Offer Cost	Un-served Products	Tx. Violation	Combined Costs	Total Load Payment	
Base Case	**13998370**	**336**	**90422**	**14089127**	**29815321**	
# std dev	**Offer Cost Savings**	**Un-served Products Savings**	**Tx. Violation Savings**	**Combined Savings**	**URC/DRC Payment**	**# Periods URC/DRC Bind**
$5 URC/DRC Demand Curve						
2	435	-8	283	710	-89	1
2.5	341	62	-141	262	-472	3
3	381	65	1595	2041	-1095	7
$10 URC/DRC Demand Curve						
2	435	-8	283	710	-89	1
2.5	341	62	-141	262	-472	3
3	897	65	2126	3087	-1564	8

Since there was limited reserve scarcity on this day, the economic impacts of URC / DRC were also limited. Reduction in un-served reserves, net cost savings, and load payment reduction are all low and URC / DRC constraints are binding in very few intervals.

October 14, 2012 Simulation Results

	Offer Cost	Un-served Products	Tx. Violation	Combined Costs	Total Load Payment	
Base Case	**11123233**	**0**	**31278**	**11154511**	**22797482**	
# std dev	**Offer Cost Savings**	**Un-served Products Savings**	**Tx. Violation Savings**	**Combined Savings**	**URC/DRC Payment**	**# Periods URC/DRC Bind**
$5 URC/DRC Demand Curve						
2	18	0	3	21	-1778	5
2.5	88	0	68	156	-2889	7
3	234	0	2	236	-4140	9
$10 URC/DRC Demand Curve						
2	-20	0	3	-17	-2457	5
2.5	31	0	68	98	-3593	7
3	84	0	3	87	-5194	9

There is no interval with reserve scarcity and the price spikes were local price spikes caused by transmission constraints. With no overall reserve scarcity, there were no savings in the value of un-served reserves. The net production cost impact was also small and there were very few intervals in which URC/DRC constraints bind. The benefits from reduced transmission violations were also small; indicating the most of the additional ramp capability was created in locations in which it could not be dispatched to reduce the transmission constraint violations.

Price Spike Identification Process

To identify price spikes in historical RT-UDS data, we first defined what constitutes a price spike in either the up or down direction. Historical data was analyzed to identify whether each 5-minute interval is part of an up price spike, a down price spike or a non-price spike interval. Spike intervals were also identified as being due to scarcity pricing (which may also include transmission constraints) or only transmission constraints (without scarcity). Up and down price spike intervals were identified for regional or system-wide price changes and were identified by the following characteristics while non-price spike intervals are those not meeting these criteria. Up and down price spikes must have the following characteristics:

- Duration of the price spike: A price “spike” must be for a limited duration and have a significant change in price.
  - The 27 MISO load zones are used to identify price spikes at a local level. A load zone LMP must increase by at least $100/MWh for up spikes (decrease by at least $100/MWh for down spikes) within three 5-minute intervals
  - The regional measure of LMP must then return to normal (give back by 90% of the deviation) within eight 5-minute intervals of the peak (or trough for down spikes)
  - The peak (tough) is the highest (lowest) regional measure of LMP in the time intervals from the initial $100/MWh change in price until the earlier of eight 5-minute intervals or the interval in which the LMP gives up 90% of the variation
- Start of the price spike: The start of a price spike is the interval in which the price starts to deviate from pre-spike pricing levels.
  - If the $100/MWh increase (decrease) occurs over 3 intervals, the first interval is the beginning of the spike
  - If the $100/MWh increase (decrease) occurs in less than 3 intervals the first interval of the spike is the first interval with the smaller of a $20/MWh or 50% increase (decrease) in price, although the interval will not be included if the prices decreases (increases) in the next interval to within $20/MWh of the pre-spike price or returns over half of the change from the previous interval
  - Up price spikes cannot have a pre-spike price of less than -$50/MWh
  - Down price spikes cannot have a trough price greater than -$10/MWh
- End of the price spike: The end of the price spike is the interval prior to the price returning toward pre-spike levels

- To qualify as a price spike, the regional measure of LMP must return at least 90% of the change between pre-spike price and the peak (trough) within eight intervals after the peak.

These criteria define price spikes within an electrical sub-region of the market footprint. A spike in a region may be isolated (e.g., related to transmission constraints) or may coincide or overlap with spikes in other regions. System price spikes are determined from the regional prices spikes using the following process where price spikes associated with capacity shortages (in each load zone, less than 10 MW of capacity beyond requirements within the price spike region):

- Repeat the following process separately for up and down spikes
- Repeat the following steps until all spikes (up and down spikes) have been grouped:
    - Identify the longest spike at any location and all of the spikes at any location that overlap with it in time
    - Group the overlapping spikes as a single spike event
    - Exclude the grouped spike and its members from future iterations and repeat from the identification of the longest remaining spike until no local spikes remain

Price spikes were identified for the 2012 calendar year including the 4 sample days that were the subject of simulations of the ramp products. Price spikes associated with capacity shortages have been excluded from this analysis because ramp capability products will not be able to impact these spikes. The results for 2012 are shown in the table below.

	Up Price Spikes	Down Price Spikes
Number of Spikes	1496	196
Number of Intervals with Spikes	5332	623
Average intervals per Spike	3.56	3.18

One could envision a detailed analysis where the price spikes are grouped based on attributes such as the presence of transmission congestion, coincidence with capacity shortages, or number of regions experiencing the spike. For the granularity of data in this study, it was deemed appropriate to treat all spikes equally both in the sample days and in the application of their results to the entire year.

Price Volatility Annual Cost-Benefit Estimates

The estimates resulting from this study are impacted by the assumptions made in performing the study. The following are some examples of the assumptions that may be relaxed to explore additional impacts of the ramp products:

- The study is limited to the analysis of redispatch in RT-UDS. The commitments from the original operating day made in the day-ahead market, reliability assessment commitments (RAC), and look-ahead commitment (LAC) limited by the assumptions made in the study. When the ramp products are included in these commitment decisions, they will reflect RT-UDS ramp capability requirements and consequently commitment is expected to be more cost effective as was demonstrated in the combined day-ahead and real-time example.

- The realization of uncertainty is limited in the study. The simulations feed forward one dispatch solution to the next assuming target dispatches are met in each interval. When conditions and forecasts are dynamically changing in real time and uncertainties have a larger impact, URC/DRC is expected to provide additional benefits for these near-term uncertainties.
- Estimated RT dispatch savings would increase if account were taken of
    - Reduction in UDS-Offset and/or Market-Wide Ramp-Up and Ramp-Down Capacity Constraint (also known as headroom) requirements
    - DA and RT RSG payments
    - Impacts of URC / DRC on DA and RAC commitments
    - Reduction in CT commitments close to Real Time

Within the scope of these studies, the following table summarizes the production cost savings and annual savings by spike and non-spike intervals. The spike interval savings were estimated by projecting the 4-day savings to the annual time frame in two ways: (1) by the ratio of spike counts in the study days to the 2012 total spike count and (2) by the ratio of the number of spike intervals in the study days to the number of spike intervals in 2012. The non-spike interval savings was estimated by multiplying the average non-spike interval daily savings for 365 days.

Demand Curve	Annual Comb. Cost Savings
$5	1.2 - 2.1 M$
$10	1.3 - 2.4 M$

The range of combined cost savings from this analysis for different days is between 0% and 0.15% and the yearly value is estimated to be less than 0.1%. The range of load payment savings for different days is between 0% and 20% and the yearly value is approximated by 5%.

Overall Tangible Savings

The following points summarize the overall savings that can be provided by ramp products:

- Day-Ahead Market and RUC processes
    - Cost increases associated with additional competition for resource capacity – In the DA process, as offered costs and product payments will be increased slightly due to the URC / DRC pricing and choosing more flexible resources. However, the DA RSG will be reduced since URC / DRC is substituting the headroom requirements (in part or as a whole Assuming headroom constraints have similar requirement levels as URC / DRC, day ahead as-offered costs and product payments will be slightly increased as shown in the combined Day-Ahead and Real-Time example. This increase is expected to be small, including the cost of purchasing the URC / DRC and slight changes in the energy and AS cleared prices due to choosing more flexible units.

- Improved flexibility – Inclusion of URC / DRC in the Day-Ahead Market and RUC processes will reduce the chance of not having enough rampable capacity in the real-time process. As shown in the 4 days of simulation, more than 50% of the un-served reserves were eliminated with the same commitments as in production (except for July 6^{th} which was an exceptional day). If 50% of the reminder of un-served reserves could have been covered by inclusion of URC / DRC in Day-Ahead Market and RUC processes, the MISO could potentially achieve additional savings of $600k to $1M on annual basis for reductions in as offered costs plus the reserve scarcity costs.

- Reduction in CT commitments
  Another potential source of cost savings is reduce need for CT commitments close to RT as illustrated in the combined Day-Ahead and Real-Time example. A reduction of one or two CT commitments per day could provide additional savings of a few thousand dollars per day. These savings could amount to a couple of million dollars annually.
- Savings through changes in other mechanisms used to address flexibility
  Inclusion of the savings associated with reduction in RT UDS offset values and reductions in cleared headroom constraints (substituted by URC / DRC) will produce other levels of savings which are not fully studied in this analysis.
- Savings of reduced price spikes and associated costs
  the overall savings of as offered costs (production costs) plus the reductions in the unserved reserves, and fewer CT commitments close to real-time could be several times higher than the estimated real-time savings of $1.2M – 2.4M identified in this study.

The following Table summarizes these tangible combined savings:

	Annual Comb. Cost Savings
Impact of URC / DRC in RT with Original Commitment	$1.2 - 2.4 M
Additional Reduction of Scarcity Conditions by Inclusion of URC / DRC in DA (estimate)	$0.6 – 1.0 M$
Reduction of CT Commitments (estimate)	$2.0M
Total (DA to RT)	**$3.8 - 5.4M**

Included in the annual cost savings is the cost of URC / DRC. These constraints projected to be binding around 10% of the intervals in Real Time. The annual cost of URC / DRC is estimated in the range of $2.0 – 4.0M.

Cost-Benefit of Reduced RT-UDS Load Offset Magnitude

One of the ways that operators help guide the real-time disaptch is through adjustments of the RT-UDS offset which adjusts the anticipated load forecast. These adjustments provide the system response (e.g., early ramping for a change in load) needed by the operator. There are many factors influencing determination of the RT-UDS offset, one of which is anticipation of required movement in generation. The introduction of ramp products to provide ramp capability will allow operators to reduce their use of the offsets to manage ramping needs. At the same time, the ramp products will provide more transparency in the costs and value of the flexibility through market prices.

To exemplify the cost-benefit of a reduced RT-UDS load offset, the results of a series of simulations are compared. The simulation scenarios are the following:

- Base RT-UDS conditions including the historical RT-UDS load offset selected for that operating day without the new ramp products
- Base case with a reduced offset (e.g., an offset of 50% of the original offset) with the new ramp products

In these simulations, the production cost is calculated based on the dispatch solution. The extent to which there may be a change in production costs due to changes in deployed regulation is not included in the analysis. It is likely that if the UDS offset is more often used for pre-ramping resources when the load is going up, the offsetting regulation action would be to move regulating units down, reducing the production cost of regulating units. When these conditions occur, the movement of regulating units offsets some of the increase in production cost associated with dispatching generation to meet the higher level of load defined by the offset. This offsetting movement in regulating units is not directly accounted for the dispatch simulation, which does not account for changes in regulation instructions. When the daily average of the UDS offset values is not zero a rough adjustment can be made to account for the offsetting movement in regulating movements by valuing the excess energy at the average cleared MCP, to allow comparisons of production costs across cases with different UDS offsets For example if the average value of the UDS offset is positive, but lower in the ramp cast than the base case, the value of the difference in energy generation is added to the production cost for the simulated case.

The MISO production RT-UDS data for July 28, 2012 (one of the days from the price volatility study) was used to examine the impact of UDS load offset changes in conjunction with the ramp products. The simulation investigates only the real-time dispatch impacts of these changes since the offset is not used in the Day-Ahead Market.

RT As-Offered Cost	RT Product Paym'ts	RT RSG
DA As-Offered Cost	DA Product Paym'ts	DA RSG

The case with reduced RT-UDS offset and ramp products was run for 50% and 75% reductions in the original RT-UDS offset as shown in the table below.

UDS-Offset Reduction	**Adjusted Offer Cost**	**Un-served Products**	**Tx. Violation**	**Combined Costs**	**Total Load Payment**	
Base Case	**21395096**	**14947**	**4348**	**21414391**	**52207728**	
UDS-Offset Reduction	**Adjusted Offer Cost Savings**	**Un-served Products Savings**	**Tx. Violation Savings**	**Combined Costs Savings**	**URC/DRC Payment**	

$5 URC/DRC Demand Curve						
50%	22391	12874	912	36177	-10100	
75%	18605	13817	790	33211	-9914	

Comparing the results of this single day, reductions in the UDS load offset value cause

- Reduction in As-Offered Cost – As-offered cost has been adjusted to account for energy reduction due to positive average value for the UDS offset during the day
- Reduction in un-served reserves
- Reduction in transmission violation
- Reduction in load product payment
- Reduced combined savings with higher reductions in UDS offset
- The reductions are larger during price spike periods with reserve scarcity

Ramp Product Cost-Benefit Summary

The cost-benefit studies reported in this section show that the URC and DRC ramp products can provide the following:

- Reduced instances of short-term ramp-induced scarcity
  - Improved operational reliability
  - Reduce dependence on ad hoc operator actions to manage short-term variations in net load by using ramp products as operational shock absorbers
    - Reduce frequency CTs are started to meet ramp needs
    - Reduce need for RT UDS delta MW offsets
- Transparent market providing economic incentives for resources to provide additional ramp capability
  - Resources are paid a clearing price based on marginal opportunity cost so would not make more money by providing a different product
  - Improved long-term incentives for resources to offer and develop improved resource flexibility
- Maintenance of operational flexibility needed to manage increasing penetration of variable energy resources
  - Less expensive and effective alternative to increasing regulation requirements
  - Maximize ramp capability available from current fleet given online headroom
  - Cost benefit analysis is based on current level of net load variability, prospective increases in intermittent resource output may lead to greater variability and greater benefits
- Maintain ramp flexibility when resource mix changes
  - Changes in relative fuel prices and/or environmental laws can cause changes in operational resource mix (e.g., more gas generation online and priced to be loaded at max)

- Ramp products bias market commitment toward a more flexible resource available at slightly higher cost
- Dispatch to maintain ramp capability on fast responding resources when more ramp is needed