Appendix B

AB.1 Demonstration of Transmission Benefit Calculation Using a 3-Node Prototype Model

AB.1.1 Introduction

This Appendix summarizes the applications of a three-node prototype model to calculate benefits resulting from a transmission expansion under the impact of long-term contract covering and strategic bidding. We use this 3-node prototype model to demonstrate how we simulate a power system, calculate and apply markup, calculate benefit, and how we conduct benefit tests.

Figure AB.1 shows the 3-node system. There are nine generation units connected to Node 1, three units to Node 2, and four units to Node 3. Table AB.1 summarizes the supply/demand balance of the system. Table AB.2 summarizes the characteristics of the generation units. Table AB.3 summarizes transmission line limits for both the without expansion and with expansion cases. We assume the transmission lines have equal impedance and, and for simplicity, the upgraded line had equal impedance with and without upgrade[1]. In the simulation, we modeled only the inter-nodal transmission lines (colored in blue). We construct this example with the three most important systems in the West in mind. Node 1 is the California area, Node 2 is the Northwest area, and Node 3 is the Southwest area. Generation capacity and load were proportionally scaled down by a factor of 1/10th.

[1] An increase in thermal capacity without a change in impedance could occur, for instance, if a transformer limitation is removed. In general, however, an increase in capacity due to re-conducting or addition of another circuit would lower impedance at the same time it increases capacity.

Figure AB.1 The 3-Node System

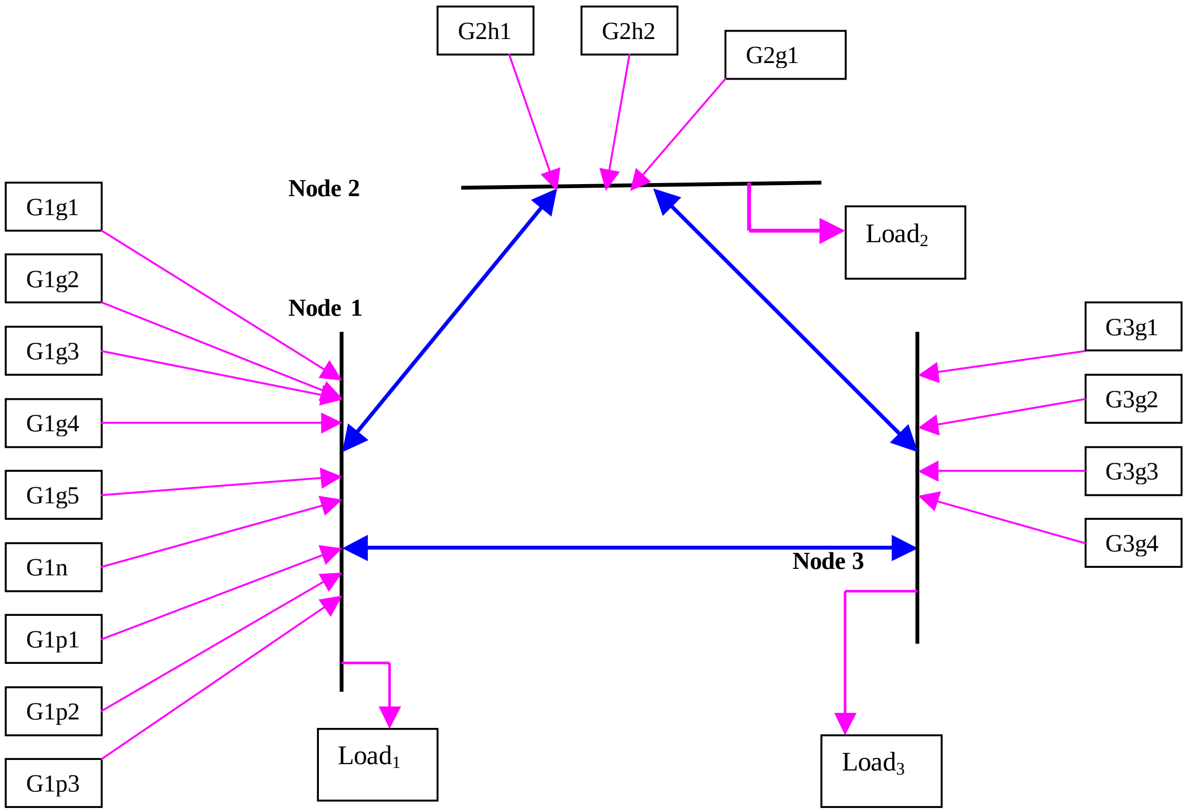

Table AB.1 Supply/Demand Balance in the 3-Node System

	Installed Capacity (MW)	Load (MW)
Node 1	5,000	6,000
Node 2	3,500	2,700
Node 3	2,000	1,500
System Total	**10,500**	**10,200**

Table AB.2 Generation Characteristics in the 3-Node Example

Node	Generator	Type	Installed Capacity (MW)	Marginal Cost ($/MWh)	Is it a UDC generator?	Is it a strategic generator?[2]
1	G1g1	Gas	500	20	No	Yes
	G1g2	Gas	500	22	No	Yes
	G1g3	Gas	400	30	No	Yes
	G1g4	Gas	400	40	No	Yes
	G1g5	Gas	400	50	No	Yes
	G1p1	Gas	100	60	No	Yes
	G1p2	Gas	100	70	No	Yes
	G1p3*	Gas	600	40	No	Yes
	G1n	Nuclear	2000	10	Yes	No
2	G2h1	Hydro	1500	10	Yes	No
	G2h2	Hydro	1500	10	Yes	No
	G2g1*	Gas	500	20 (0 – 250 MW) 30 (250 – 500 MW)	No	No
3	G3g1	Gas	500	22 (0 – 250 MW) 30 (250 – 500 MW)	Yes	No
	G3g2	Gas	400	18	Yes	No
	G3g3*	Gas	600	20	No	No
	G3g4	Gas	500	20	No	No

Note: Generators colored in red are the largest non-UDC generators at each node.

Table AB.3 Transmission Line Limits in the 3-Node Example

Line	From Node	To Node	Bi-Directional OTC (MW)	
			Without Expansion	With Expansion
L1-2	**Node 1**	**Node 2**	600	650
L1-3	**Node 1**	**Node 3**	1000	1000
L2-3	**Node 2**	**Node 3**	9999	9999

AB.2 Transmission Expansion Benefit: No Markup and No Contract

Figure AB.2 and AB.3 depict the marginal cost simulation results for the non-expansion and expansion cases with a marginal cost bidding assumption.

[2] A non-UDC generator could be a strategic generator (i.e., often bidding above marginal cost) or a non-strategic generator (i.e., always bid marginal cost). In this example, we assume all non-UDC generators at Bus 1 are strategic. Furthermore due to lack of information on strategic bidding, we treat all generators other than those in the CAISO region as non-strategic in both this example and in our Path 26 study.

Figure AB.2 No Expansion, No Markup

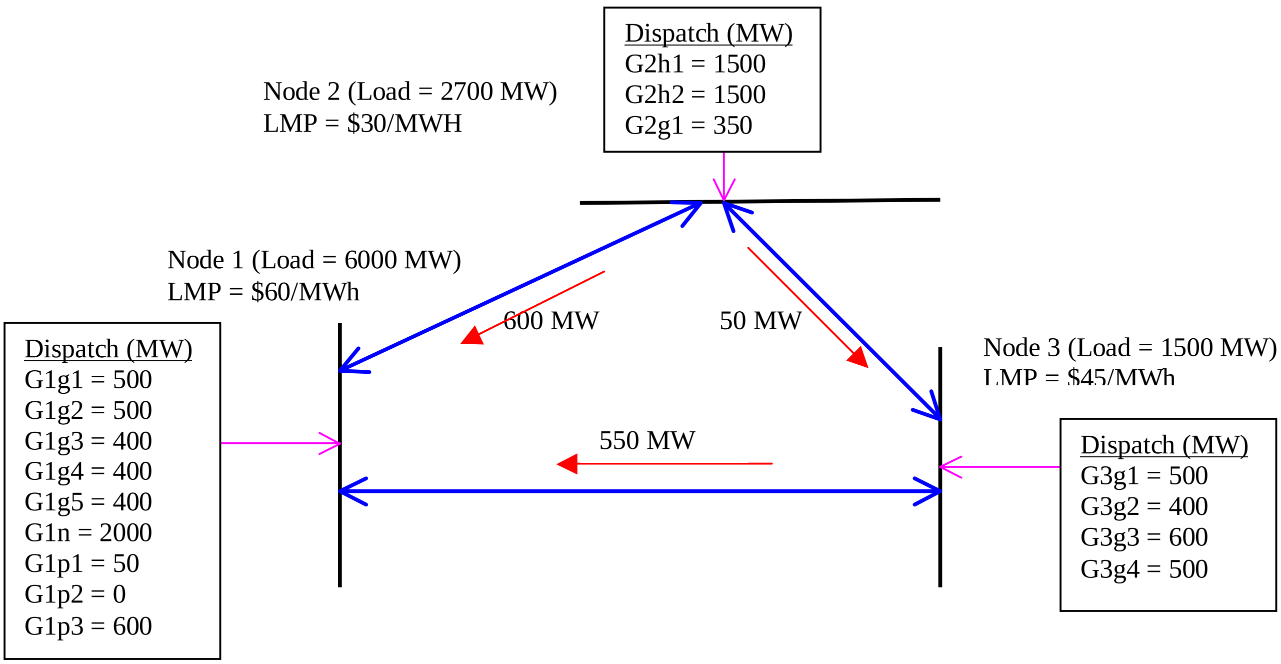

Figure AB.3 Expansion of L1-3, No Markup

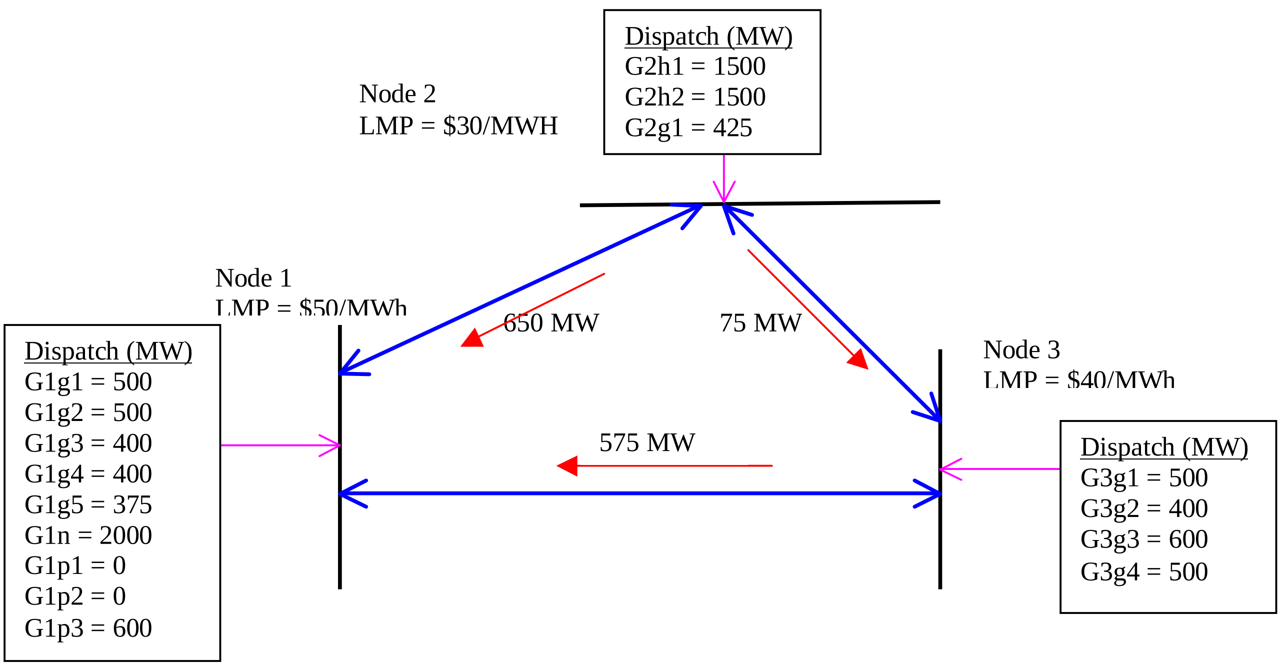

Table AB.4 compares the without and with case.

Table AB.4 Simulation Results: No Markup, No Contract Covering

			Without Expansion	With Expansion	Δ Change
LMP ($/MWh)		Node 1	$60	$50	-$10
		Node 2	$30	$30	$0
		Node 3	$45	$40	-$5
Line Flow (MW)		L1-2	600 MW (Node 2->1)	650 MW (Node 2->1)	+ 50 MW (Node 2->1)
		L1-3	550 MW (Node 3->1)	575 MW (Node 3->1)	+ 25 MW (Node 3->1)
		L2-3	50 MW (Node 2-> 3)	75 MW (Node 2->3)	+ 25 MW (Node 2->3)
Dispatch (MW)	Node 1	G1g1	500	500	0
		G1g2	500	500	0
		G1g3	400	400	0
		G1g4	400	400	0
		G1g5	400	375*	-25
		G1n	2,000	2,000	0
		G1p1	50*	0	-50
		G1p2	0	0	0
		G1p3	600	600	0
		Total	**4,850**	**4,775**	**-75**
	Node 2	G2h1	1500	1500	0
		G2h2	1500	1500	0
		G2g1	350*	425*	+75
		Total	**3,350**	**3,425**	**+75**
	Node 3	G3g1	500	500	0
		G3g2	400	400	0
		G3g3	600	600	0
		G3g4	500	500	0
		Total	**2,000**	**2,000**	**0**

Signifies the marginal generator that sets prices. In the absence of degeneracy, when one transmission constraint is binding, two generators will be marginal.

Table AB.5 and Table AB.6 show the benefits of upgrading the capacity of L1-3 from 600 MW to 650 MW.

Table AB.5 Surpluses without and with expansion: No Markup with No Contract Covering

			Without Expansion	With Expansion	Net Change
Cost-to-Load	Node 1		$60*6000 = $360,000	$50*6000 = $300,000	-$60,000
	Node 2		$30*2,700 = $81,000	$30*2,700 = $81,000	+$0
	Node 3		$45*1,500 = $67,500	$40*1,500 = $60,000	-$7,500
	Total		**$508,500**	**$441,000**	**-$67,500**
Producer Revenue	Node 1	Non-UDC Generators	$60*2850 = $171,000	$50*2775 = $138,750	-$32,250
		UDC Generator	$60*2,000 = $120,000	$50*2,000 = $100,000	-$20,000
		Total	$291,000	$238,750	-$52,250
	Node 2		$30*3,350 = $100,500	$30*3,425 = $102,750	+$2,250
	Node 3		$45*2,000 = $90,000	$40*2,000 = $80,000	-$10,000
	Total		**$481,500**	**$421,500**	**-$60,000**
Producer Cost	Node 1	Non-UDC generators	$96,000	$91,750	-$4,250
		UDC Generator	$20,000	$20,000	$0
		Total	$116,000	$111,750	-$4,250
	Node 2		$38,000	$40,250	+$2,250
	Node 3		$42,200	$42,200	$0
	Total		**+$196,200**	**+194,200**	**-$2,000**
Producer Surplus = PR - PC	Node 1	Non-UDC Generators	+$75,000	+$47,000	-$28,000
		UDC Generator	+ $100,000	+ $80,000	-$20,000
		Total	$175,000	$127,000	-$48,000
	Node 2		+ $62,500	$62,500	+$0
	Node 3		+$47,800	$37,800	-$10,000
	Total		**+285,300**	**+227,300**	**-$58,000**
Congestion Revenue	Total		$30*600 + $15*550 + $15*50 = $27,000	$20*650 + $10*575 + $10*75 = $19,500	-$7,500

Table AB.6 Expansion Benefit: No Markup and with No Contract Covering

Benefit		**Node 1**	**Node 2**	**Node 3**	**System Total**
ΔCS = -ΔCTL		+$60,000	+ $0	+$7,500	+$67,500
ΔPR	Non-UDC Generator	-$32,250			
	UDC Generator	-$20,000			
	Total	**-$52,250**	**+$2,250**	**-$10,000**	**-$60,000**
ΔPC	Non-UDC Generator	-$4,250			
	UDC Generator	$0			
	Total	**-$4,250**	**+$2,250**	**$0**	**-$2,000**
ΔPS = ΔPR – ΔPC	Non-UDC Generator	-$28,000			
	UDC Generator	-$20,000			
	Total	**-$48,000**	**+$0**	**-$10,000**	**-$58,000**
ΔCR					-$7,500
SB = ΔCS + ΔPS + ΔCR					**+$2,000**

In developing our CAISO Methodology, we stated that for any project, we would evaluate the project from different perspectives. We might evaluate the project using different criteria, depending on the extent of the project's impact on the system and what parties will be responsible for funding the project. We proposed four possible tests from various perspectives: Societal Test, Modified Societal Test, CAISO Ratepayers Test, and CAISO Participants Test. The Societal Test uses the perspective of the entire system (inter-connection). It evaluates a project based on how much total production cost saving it can bring to the entire system and compares the benefit with the project cost. If a project's cost (O&M cost and capital cost) is $500 for example and the total production cost saving to the entire system due to upgrade is $2,000, then the Societal Test would calculate a net benefit of $1,500 for the upgrade project ($2,000 - $500).

Some may argue that we should not include producers' monopoly rents in the producer surplus calculation, because we do not want to encourage generators to bid above their marginal costs. We proposed an alternative societal test – the Modified Societal Test, where monopoly rents are not included in the producer surplus calculation and any change in monopoly rents is not included in the producer benefit calculation. In a case where all generators bid their marginal costs (i.e., no markup), the Modified Societal Test will be the same as the Societal Test.

It is likely that a project approved by the CAISO will be paid by all ISO ratepayers through the PTO's revenue requirements. Because of this, we proposed a third evaluation criterion - the CAISO Ratepayers Test. In this test, we only include the benefit to the ISO ratepayers. This includes all LSEs and utility-retained generation. More specifically, this test includes the CAISO's consumer benefit, UDC generation's producer benefit, and PTOs' transmission owner benefit. In this particular example, Bus 1 is the ISO and the total consumer benefit at Bus 1 is $6,000, the total UDC-generation's producer benefit is -$2,000, and the ISO PTOs' transmission owner benefit (by owning L1-2 and L1-3) is -$7,500. The total CAISO ratepayers' benefit is $13,750.

AN argument can be made that when the CAISO approves a project it should consider all participants' benefit from the upgrade, not just the benefit to CAISO ratepayers. Therefore, we proposed a fourth test – the CAISO Participants Test. This test includes all CAISO participants' benefit (but not monopoly rent benefit), CAISO consumer's benefit, all generators' competitive rent benefit, and PTOs' transmission owner benefits. Table AB.7 shows the results for the four alternative tests:

Table AB.7 Four Proposed Tests: No Markup and With Contract

	Societal Test	Modified Societal Test	ISO Ratepayers Test	ISO Participants Test
Exp. Benefit	+$2,000	+$2,000	+$60,000 – $20,000 - $7,500 = +$32,500	+$60,000 - $48,000 - $7,500[3] = +$4,500
Cost	$500	$500	$500	$2,000
Net Benefit	+$1,500	+$1,500	+$32,000	+$2,500

The CAISO total participants' benefit is negative in this case because generators' more expensive resources at Bus 1 are replaced by cheaper imports when the line is upgraded. Thus both types of generators at Bus 1 are harmed by expansion in this example.

AB.3 Transmission Expansion: No Markup and With Contract Covering

Assume $Load_1$ is assigned long-term contracts with all non-UDC generators at Node 1 for 5 percent of their installed capacity at a fixed price **$59/MWh**. In other words, 1,500 MW of $Load_1$ is covered by long-term contract with non-UDC generators, and another 2,000 MW is covered by its own generation. Table AB.8 shows the contract amount for these generators. The last two columns of Table 8 show physical dispatch amounts for both the case without expansion and the one with expansion. If a generator dispatches less than its contract requirement, it has to purchase from the spot market to cover its position. In the case of expansion, G1p1 and G1p2 are not economic, thus their contract obligation of 50 MW each is purchased from the spot market. In addition we assume $Load_2$ and $Load_3$ didn't assign any long-term contract.

[3] Congestion revenue on L2-3 happens to be the same without and with upgrading of L1-2 in this example. Thus the CAISO's congestion revenue is the same as the total congestion revenue in this case. However this does not hold in general.

Table AB.8 Long-Term Contract Between Non-UDC Generators at Node 1 and $Load_1$

	Installed Capacity (MW)	Contract Amount with $Load_1$ (MW)	No Expansion Dispatch (MW)	With Expansion Dispatch (MW)
G1g1	500	250	500	500
G1g2	500	250	500	500
G1g3	400	200	400	400
G1g4	400	200	400	400
G1g5	400	200	400	300
G1p1	100	50	100	0
G1p2	100	50	100	0
G1p3	600	300	600	600
Non-UDC Total	3,000	1,500	3,000	2,700

We assumed that long-term contracting won't affect the dispatch of generation, nor the total transmission expansion benefit, but will affect the distribution of the benefit. Table AB.9 and Table AB.10 show the transmission expansion benefit with LTC.

Table AB.9 Surpluses without and with expansion: No Markup With Contract Covering

			Without Expansion	With Expansion	Net Change
Cost-to-Load	Node 1		CTL for un-covered load = \$60*4,500 = \$270,000 Fixed Contract Cost to Load = \$59*1,500 = \$88,500 Total CTL = \$358,500	CTL for un-covered load = \$50*4,500 = \$225,000 Fixed Contact Cost to Load = \$59*1,500 = \$88,500 Total CTL = \$313,500	-\$45,000
	Node 2		\$30*2,700 = \$81,000	\$30*2,700 = \$81,000	+\$0
	Node 3		\$45*1,500 = \$67,500	\$40*1,500 = \$60,000	-\$7,500
	Total		**\$507,000**	**\$454,500**	**-\$52,500**
Producer Revenue	Node 1	Non-UDC Generators	Gross Revenue from Spot Market = \$60*2,850 = \$171,000 Contract CFD = (\$59-\$60)*1,500 = -\$1,500 Total = \$169,500	Gross Revenue from Spot Market = \$50*2,775 = \$138,750 Contract CFD = (\$59-\$50)*1,500 = +\$13,500 Total = \$152,250	-\$17,250
		UDC Generator	\$60*2,000 = \$120,000	\$50*2,000 = \$100,000	-\$20,000
		Total	\$289,500	\$252,250	-\$37,250
	Node 2		\$30*3,350 = \$100,500	\$30*3,425 = \$102,750	+\$2,250
	Node 3		\$45*2,000 = \$90,000	\$40*2,000 = \$80,000	-\$10,000
	Total		**\$480,000**	**\$435,000**	**-\$45,000**
Producer Cost	Node 1	Non-UDC generators	\$96,000	\$91,750	-\$4,250
		UDC Generator	\$20,000	\$20,000	\$0
		Total	\$116,000	\$111,750	-\$4,250
	Node 2		\$38,000	\$40,250	+\$2,250
	Node 3		\$42,200	\$42,200	\$0
	Total		**+\$196,200**	**+194,200**	**-\$2,000**

Producer Surplus = PR - PC	Node 1	Non-UDC Generators	+ $73,500	$60,500	-$13,000
		UDC Generator	+ $100,000	$80,000	-$20,000
		Total	+$173,500	+$140,500	-$33,000
	Node 2		+$62,500	+$62,500	+$0
	Node 3		+$47,800	+$37,800	-$10,000
	Total		**+283,800**	**+240,800**	**-$43,000**
Congestion Revenue	Total		$30*600 + $15*550 + $15*50 = $27,000	$20*650 + $10*575 + $10*75 = $19,500	-$7,500

Table AB.10 Expansion Benefit: No Markup and With Contract Covering

Benefit		**Node 1**	**Node 2**	**Node 3**	**System Total**
ΔCS = -ΔCTL		+$45,000	+$0	+$7,500	+$52,500
ΔPR	Non-UDC Generator	-$17,250			
	UDC Generator	-$20,000			
	Total	**-$37,250**	**+$2,250**	**-$10,000**	**-$45,000**
ΔPC	Non-UDC Generator	-$4,250			
	UDC Generator	$0			
	Total	**-$4,250**	**+$2,250**	**$0**	**-$2,000**
ΔPS = ΔPR – ΔPC	Non-UDC Generator	-$13,000			
	UDC Generator	-$20,000			
	Total	**-$33,000**	**+$0**	**-$10,000**	**-$43,000**
ΔCR					-$7,500
SB = ΔCS + ΔPS + ΔCR					**+$2,000**

This example shows the following:

1. Total societal benefit from transmission expansion, if measured as the sum of all market participants' benefit, stays the same even if Load$_1$ signs long-term contact with NGO generators. ***In other words, long-term contracting does not affect the total societal benefit from transmission expansion, because the total production cost saving remains the same regardless of contract covering.***

2. Contract covering has a significant impact on transmission benefit distribution among various market participants.

3. Non-UDC producers at Node 1 lose from transmission expansion, but they lose less if they are partially hedged comparing to having no contract at all. We assumed that if a long-term contract were already in place, it would be in place regardless whether the line is upgraded or not. Signing long-term contract with load prior to transmission upgrade may provide insurance to non-UDC generators against potential price decreases due to transmission expansion.

Table AB.11 shows the results for the four tests:

Table AB.11 Four Proposed Tests: No Markup and With Contract

	Societal Test	Modified Societal Test	ISO Ratepayers Test	ISO Participants Test
Exp. Benefit	+$2,000	+$2,000	+$45,000 – $20,000 - $7,500 = + $17,500	+$45,000 - $33,000 - $7,500 = +$4,500
Cost	$500	$500	$500	$500
Net Benefit	+$1,500	+$1,500	+$17,000	+$4,000

Again the CAISO Ratepayers' Test is affected significantly by contract position of the load. The CAISO Participants Test is not affected by the contract because we assumed the contract is between the CAISO load and the non-UDC generation in the same region thus the net effect is canceled out.

AB.4 Transmission Expansion: With Markup and Without Contract Covering

Generators may bid above their marginal costs to exercise market power or to recover their fixed cost. Our RSI regression analysis establishes a statistical relationship between regional price-cost markups and system conditions based on historical data. Using hourly data from November 1999 – October 2000 and January 2003 – December 2003, we estimated the following regression:[4]

Lerner-Index = 0.14 – 0.53***RSI** + 0.65***% of Load Un-hedged** + 0.086***Peak Hour Dummy** + 0.15***Summer Month Dummy.***

The definitions of the variables are:

(1) ***Lerner Index*** = $(P^m – P^c)/P^m$
Where P^m = Market Price,
P^c = Competitive Market Price if all generators bid their marginal costs.

(2) ***RSI*** = (A + B – C + D)/E
Where A = Total Regional Available Capacity
= Total Regional Capacity – Total Regional Capacity on Outages;

B = Maximum Importing Amount to the region in the Last 30 days;

C = The Largest Strategic Supplier's Available Capacity
= The Largest Strategic Supplier's Total Capacity – It's Capacity on Outages;

D = Long-Term-Contract Amount of the Largest Supplier;

E = Total Regional Load.

(3) ***Fraction of Load Un-Hedged*** = (E – F – G)/E

[4] Note that we have several alternative functional forms for regression analysis. Here I just listed one option.

Where F = Total UDC Available Generation Capacity;
G = Total State Long-Term-Contract in that region.

The relationship between Lerner Index and Price-Cost markup is
Price-Cost Markup = Lerner Index / (1 – Lerner Index),

where Price-Cost Markup = $(P^m - P^c)/P^c$. The purpose of applying the RSI regression prospectively is to predict price-cost markups for the importing region and use price-cost markups as generators' bid-cost markups where the internal supply cannot meet load and some of its internal generators are pivotal and have incentive to bid above marginal costs. Our historical experience suggests that a RSI value > 1.2 is usually a good indication of markup. Table AB.12 shows how we calculate regression variables required for predicting zonal price-cost markups.

Table AB.12 Calculation of Variables and Price-Cost Markups: the Case of No Contract

		Node 1	Node 2	Node 3
Largest Strategic Suppler and its capacity		G1p3 600 MW	G2g1 500 MW	G3g3 600 MW
Import Capability	**Without Expansion**	600 + 550 = 1,150 MW	500 + 9,999 = 10,499 MW	1,000 + 9,999 = 10,999 MW
	With Expansion	700 + 600 = 1,300 MW	700 + 9999 = 10,699 MW	1,000 + 9999 = 10,999 MW
Installed Capacity		5,000 MW	3,500 MW	2,000 MW
Load		6,000 MW	2,700 MW	1,500 MW
RSI Calculated	**Without Exp.**	=(5000 + 1150 – 600)/6000 = 0.925	>> 1.2	>> 1.2
	With Exp.	=(5000+1300 – 600)/6000 = 0.95	>> 1.2	>> 1.2
Fraction of Load Un-hedged		=(6000-2000)/6000 = 0.667	>> 100%	>> 100%
Predicted Lerner Index[5]	**Without Exp.**	0.3193		
	With Exp.	0.3061		
Predicted Price-cost Markup	**Without Exp.**	46.91%		
	With Exp.	44.10%		

We used the zonal RSI analysis-derived price-cost markup as the nodal bid-cost markup of strategic generators at Node 1. There are two approaches to apply the derived price-cost markup as bid-cost markup: apply to all strategic generators uniformly or apply to all strategic generators proportionally according to their capacity. We demonstrate here how the proportional approach works: each strategic generator's bid-cost markup is proportionally to its capacity according to its capacity share relative to the largest strategic supplier's capacity share. Table AB.13 shows how we derive bid-cost markups for each strategic generator at Node 1.

[5] We assume in this example that the time is the peak hour in a summer month.

Table AB.13 Calculation of Bid Prices: the Case of No Contract

Generator at Node 1	Capacity (MW)	Marginal Cost ($/MWh)	Capacity Share	Without Expansion		With Expansion	
				Markup Applied	Bid Price Derived ($/MWh)	Markup Applied	Bid Price Derived ($/MWh)
G1g1	500	20	16.7%	=(16.7%/20%)*46.91% = 39.1%	= 1.391*20 = 27.8	=(16.7%/20%)*44.1% = 36.8%	27.4
G1g2	500	22	16.7%	39.1%	30.6	36.8%	30.1
G1g3	400	30	13.3%	31.3%	39.4	29.4%	38.8
G1g4	400	40	13.3%	31.3%	52.5	29.4%	51.8
G1g5	400	50	13.3%	31.3%	65.6	29.4%	64.7
G1p1	100	60	3.3%	7.8%	64.7	7.4%	64.4
G1p2	100	70	3.3%	7.8%	75.5	7.4%	75.1
G1p3	600	40	20.0%	=(20.0%/20%)*46.91% = 46.91%	58.8	=(20%/20%)*44.1%= 44.1%	57.6
Total Strategic Generators	3000						

Table AB.14 shows the simulation results using the derived bid prices above. The only difference between Table AB.14 and Table AB.4 (competitive simulation results) is the nodal LMPs.[6]

[6] It is, however, true in generally that the dispatch might be different with markup than without markup, and likewise with the flows. (This can happen if a large company marks its bids up so far that one of its infra-marginal units becomes marginal or doesn't run at all. However, the flows might not change if the import constraints are binding in the base case; higher markups in the importing region in that situation cannot increase imports.) This example is just a special case.

Table AB.14 Simulation Results: With Markup and No Contract Covering

			Without Expansion	With Expansion	Δ Change
LMP ($/MWh)		Node 1	$65.64	$64.70	-$0.94
		Node 2	$30	$30	$0
		Node 3	$47.82	$47.35	-$0.47
Line Flow (MW)		L1-2	600 MW (Node 2->1)	650 MW (Node 2->1)	+ 50 MW (Node 2->1)
		L1-3	550 MW (Node 3->1)	575 MW (Node 3->1)	+ 25 MW (Node 3->1)
		L2-3	50 MW (Node 2->3)	75 MW (Node 2->3)	+ 25 MW (Node 2->3)
Dispatch (MW)	Node 1	G1g1	500	500	0
		G1g2	500	500	0
		G1g3	400	400	0
		G1g4	400	400	0
		G1g5	350*	275*	-75
		G1n	2,000	2,000	0
		G1p1	100	100	0
		G1p2	0	0	0
		G1p3	600	600	0
		Total	**4,850**	**4,775**	**-75**
	Node 2	G2h1	1500	1500	0
		G2h2	1500	1500	0
		G2g1	350*	425*	+75
		Total	**3,350**	**3,425**	**+75**
	Node 3	G3g1	500	500	0
		G3g2	400	400	0
		G3g3	600	600	0
		G3g4	500	500	0
		Total	**2,000**	**2,000**	**0**

Table AB.15 and AB.16 summarize the expansion benefit with markup to various market participants assuming no-contract covering. Table AB.16 confirms that the total societal benefit from transmission expansion equals the total production cost saving even when market is not perfectly competitive; this is necessarily true when there is no demand elasticity.

Table AB.15 Expansion Benefit: With Markup and Without Contract Covering

			Without Expansion	With Expansion	Net Change
Cost-to-Load	Node 1		$65.64*6000 = $393,840	$64.7*6000 = $388,200	-$5,640
	Node 2		$30*2,700 = $81,000	$30*2,700 = $81,000	+$0
	Node 3		$47.82*1,500 = $71,730	$47.35*1,500 = $71,025	-$705
	Total		**$546,570**	**$540,225**	**-$6,345**
Producer Revenue	Node 1	Non-UDC Generators	$65.64*2850 = $187,074	$64.7*2775 = $179,543	-$7,532
		UDC Generator	$65.64*2,000 = $131,280	$64.7*2,000 = $129,400	-$1,880
		Total	$318,354	$308,943	-$9,412
	Node 2		$30*3,350 = $100,500	$30*3,425 = $102,750	+$2,250
	Node 3		$47.82*2,000 = $95,640	$47.35*2,000 = $94,700	-$940
	Total		**$514,494**	**$506,393**	**-$8,102**
Producer Cost	Node 1	Non-UDC generators	$96,500	$92,750	-$3,750
		UDC Generator	$20,000	$20,000	$0
		Total	$116,500	$112,750	-$3,750
	Node 2		$38,000	$40,250	+$2,250
	Node 3		$42,200	$42,200	$0
	Total		**+$196,700**	**+195,200**	**-$1,500**
Producer Surplus = PR - PC	Node 1	Non-UDC Generators	+$90,574	+$86,793	-$3,781
		UDC Generator	+ $111,280	+ $109,400	-$1,880
		Total	$201,854	$196,193	-$5,661
	Node 2		+ $62,500	$62,500	+$0
	Node 3		+$53,440	$52,500	-$940
	Total		**+317,794**	**+311,193**	**-$6,601**
Monopoly Rent (MR)[7]	Node 1 Strategic Generators		($65.64 - $60)*2,850 = $16,074	($64.7 - $50)*2,775 = $40,793	$24,719
Competitive Rent (ComR)[8]	Node 1 Strategic Generators		$90,574 - $16,074 = $74,500	$86,793 - $40,793 = $46,000	-$28,500
Congestion Revenue	Total		$34.64*600 + $16.82*550 + $17.82*50 = $32,076	$34.7*650 + $17.35*575 + $17.35*75 = $33,833	+$1,757

7 Monopoly Rent is the excess profit strategic generators receive above what they would receive if they bid their marginal costs. We approximate monopoly rent with $MR \cong (p^m - p^c)*q^m$, where p^m is a (strategic) generator's locational marginal price if all strategic generators bid strategically (i.e., markup), and p^c is the generator's LMP if all generators bid marginal costs, and q^m is the generator's dispatch with markup. For non-strategic generators, we assume monopoly rent to be zero.

8 Competitive Rent is the difference between producer surplus and monopoly rent for a strategic generator. For non-strategic generators, competitive rent is the same as producer surplus.

Table AB.16 Benefits from Upgrade: Markup and No Contract Covering

Benefit		Node 1	Node 2	Node 3	System Total
ΔCS = -ΔCTL		+$5,640	$0	+$705	+$6,345
ΔPR	Non-UDC Generator	-$7,532			
	UDC Generator	-$1,880			
	Total	**-$9,412**	**+$2,250**	**-$940**	**-$8,102**
ΔPC	Non-UDC Generator	-$3,750			
	UDC Generator	$0			
	Total	**-$3,750**	**+$2,250**	**$0**	**-$1,500**
ΔPS = ΔPR – ΔPC	Non-UDC Generator	-$3,781			
	UDC Generator	-$1,880			
	Total	**-$5,661**	**+0**	**-$940**	**-$6,601**
ΔMR		**+$23,898**	**$0**	**$0**	**+$23,616**
ΔComR		-$28,500-$1,880 = **-$30,380**	**+$0**	**-$940**	**-$31,320**
ΔCR					+$1,757
SB = ΔCS + ΔPS + ΔCR					**+$1,500**

Comparing Table AB.16 and Table AB.6 (benefit under competitive case), we can see generators' ability to bid above their marginal costs change the distribution of total benefit among consumers, producers, and transmission owners.[9] Table AB.17 below shows the differences in participants' benefit between the competitive case and the markup case.

Table AB.17 Comparing Benefits Between Competitive and Markup: the Case of No Contract

	Competitive Case	Markup Case	Difference due to Markup
Consumer Benefit (ΔCS)	+$67,500	+$6,345	-$61,155
Producer Benefit (ΔPS)	**-$58,000**	-$6,601	+$51,399
Transmission Owner Benefit (ΔCR)	-$7,500	+$1,757	+$9,257
Total Societal Benefit (ΔSB)	+$2,000	+$1,500	-$500

Consumers could benefit a lot more from transmission upgrade if generators bid their marginal costs. (This, however, is not necessarily always the result; under other circumstances, consumers might benefit more in the noncompetitive solution.) Conversely, producers lose a lot less from transmission upgrade if they were able to bid above marginal costs. Transmission owners (or CRR holders) in this particular example, receive a benefit from transmission upgrade due to the generators' markup. Table AB.18 shows the results of the four proposed benefit tests with markup and without contract.

[9] It is very likely that the total societal benefit under markup case might be different than that under the competitive case. In this particular example, since dispatches under the competitive case and under the markup case stay the same, the total societal benefits are the same in either case.

Table AB.18 Four Proposed Tests: With Markup and Without Contract

	Societal Test	**Modified Societal Test**	**ISO Ratepayers Test**	**ISO Participants**
Exp. Benefit	+$1,500	+$6,345 – $31,320 + $1,757 = -$23,218	+$5,640 – $1,880 + $2,496 = +$6,256	+$5,640 - $30,380 + $2,496 = -$22,244
Cost	$500	$500	$500	$500
Net Benefit	+$1,000	-$23,718	+$5,756	-$22,744

AB.5 Summary

The calculations performed above demonstrated that both markup and contract covering have significant impacts on the individual market participant's benefit, as well as on benefit tests results. How contract covering and markups affect total benefit and its distribution should be studied on a case-to-case basis. We caution the readers to be very careful not to generalize the results from this particular example. It is critical to do a thorough calculation for any given market situation similar to what we demonstrated here.