Exhibit
UP&L__(MRT-1)

PacifiCorp
Exhibit UP&L _____(MRT-1)
Docket No. 03-2035-02
Witness: Mark R. Tallman

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman
Summary of Short-List Proposals

July 2003

RFP Code	Transaction Number	Project Name	MW Size	Structure Type	Optionality Call Daily, etc	Delivery Output	Generation Assets	Energy Price ($/MWh)	Fixed Charge ($/MWh)	Option Premium ($/MWh)	Capacity Charge ($/MWh)	Capacity Charge ($/KW-mo)	Option Delta	All-in Price ($/MWh)	Nom MWhs	PV MWhs	Delta VaR	POD	Start Date	End Date	Conditions	Firm or UNIT CONTINGENT	Comments	PAC Pays (PV$)	PAC Receives (PV$)	Net Value (PV$)	Net Value (PV$) per 100 MW of Capacity
Alias RFP23	Transaction B	Purchase Summer On-Peak Daily Call (June thru September)	100	Physical	Day-Ahead Call	7 x 16	No	$60.00		$23.00		$11.22	0.50		585,600	555,445	$9,969,722	Analyzed at 4Corners (Contingent on commercial operation of Redhawk Plant)	1/1/2002	12/31/2004	Analyzed at 4Corners (Contingent on commercial operation of Redhawk Plant)	Firm WSPP Schedule C with LD	June thru Sept Delivery	$12,775,228	$6,509,573	($6,571,091)	($6,571,091)
Alias RFP23	Transaction B2	Purchase Summer On-Peak Daily Call (June thru September)	100	Physical	Day-Ahead Call	7 x 16	No	$60.00		$28.00		$13.66	0.45		585,600	506,818	$8,270,111	Analyzed at 4Corners (Contingent on commercial operation of Redhawk Plant)	1/1/2004	12/31/2006	Analyzed at 4Corners (Contingent on commercial operation of Redhawk Plant)	Firm WSPP Schedule C with LD	June thru Sept Delivery	$14,190,891	$5,569,560	($8,621,332)	($8,621,332)
Alias RFP4	Transaction 2	Purchase Physical Day-ahead Call for all months of Term	100	Physical	Day-Ahead Call	6 x 16	No	$48.53		$14.75		$6.04	0.48		2,619,200	2,316,532	$32,302,913	Analyzed at MONA	6/1/2002	9/30/2007	Purchase Physical Day-ahead Call for all months of Term	Firm WSPP Schedule C with LD	Full year obligation	$34,168,846	$21,486,182	($12,682,664)	($12,682,664)
Alias RFP20	Transaction 3	Purchase Physical Day-ahead Call for each month of Term	100	Physical	Day-Ahead Call	6 x 16	No	$42.50		$11.60		$4.75	0.52		2,457,600	2,183,250	$29,076,125	Analyzed at MONA	7/1/2002	6/30/2007	Purchase Physical Day-ahead Call for each month of Term	Firm WSPP Schedule C with LD	Full year obligation	$25,317,415	$24,076,323	($1,241,092)	($1,241,092)
Alias RFP20	Transaction 4	Purchase Physical Day-ahead Call (June thru Sept)	100	Physical	Day-Ahead Call	6 x 16	No	$55.00		$18.20		$7.45	0.55		491,200	465,895	$8,382,890	Analyzed at MONA	6/1/2002	9/30/2004	Purchase Physical Day-ahead Call (June thru Sept)	Firm WSPP Schedule C with LD	June thru Sept Delivery	$8,480,281	$6,312,695	($2,167,586)	($2,167,586)
Alias RFP26	Transaction 1	Purchase Physical Energy HLH (June thru September)	25	Physical	None	6 x 16	No	$12.66	$37.97				1.00	$59.34	122,800	116,465	$4,146,648	Analyzed at Mona	6/1/2002	9/30/2004	Purchase Physical Energy HLH (June thru September)	WSPP Schedule C with LD	Must restrict POD to Mona	$6,911,081	$5,669,696	($1,241,385)	($4,965,540)
Alias RFP26	Transaction 2	Purchase Physical Energy HLH (June thru September)	100	Physical	None	6 x 16	No	$13.74	$41.22				1.00	$63.33	491,200	465,859	$17,701,610	Analyzed at Mona	6/1/2002	9/30/2004	Purchase Physical Energy HLH (June thru September)	WSPP Schedule C with LD	June thru Sept Delivery	$29,502,683	$22,678,783	($6,823,900)	($6,823,900)
Alias RFP26	Transaction 3	Purchase Physical Energy HLH (June thru September)	200	Physical	None	6 x 16	No	$13.95	$41.86				1.00	$64.27	982,400	931,719	$35,930,384	Analyzed at Mona	6/1/2002	9/30/2004	Purchase Physical Energy HLH (June thru September)	WSPP Schedule C with LD	June thru Sept Delivery	$59,883,974	$45,357,566	($14,526,408)	($7,263,204)
Alias RFP28	Transaction 1	Purchase Physical Energy HLH (July thru September)	50	Physical	None	6 x 16	No	$59.95					1.00	$67.83	615,200	490,569	$19,966,472	Analyzed at NUB	6/1/2002	5/31/2012	Purchase Physical Energy HLH (July thru September)	WSPP Schedule C with LD	Energy price escalates 3% annually	$33,277,454	$27,269,971	($6,007,483)	($12,014,966)
Alias RFP28	Transaction 2	Purchase Physical Day-ahead Tolling Option HLH (NUB and SoCal Gas) for 10 Years	50	Physical	Tolling Option Day-Ahead Call	6 x 16	Yes	$41.18		$19.20		$7.86	0.49		2,456,800	1,929,315	$23,562,797	Analyzed at NUB (Delivery on 95% of least expensive hours)	6/1/2002	5/31/2012	Purchase Physical Day-ahead Tolling Option HLH (NUB and SoCal Gas) for 10 Years	UC WSPP Schedule B	Heat Rate = 10,000. Physical tolling option. Seller wants bonus if annual availability is above minimum.	$37,049,099	$13,534,153	($23,514,946)	($47,029,892)
Alias RFP22	Transaction 1	Purchase Physical Day-ahead Tolling Option HLH (Mona and Rockies Gas) for 12 Years	200	Physical	Tolling Option Day-Ahead Call	6 x 16	New Construction	$37.58		$55.12		$22.60	0.78		3,920,000	3,019,728	$53,332,739	Analyzed at Mona (Delivery on 95% of least expensive hours)	6/1/2002	5/31/2014	Purchase Physical Day-ahead Tolling Option HLH (Mona and Rockies Gas) for 12 Years	UC WSPP Schedule B	HR = 10,000. Seller offer 4 hour minimum run to shape. Seller limits starts per year to 100. Capacity payment shaped for demand months of June thru September. Initial capital cost $164.4 million	$166,459,728	$60,235,023	($106,224,705)	($53,112,353)
Alias RFP22	Transaction 2	Purchase Physical Day-ahead Tolling Option HLH (Mona and Rockies Gas) for 3 Years	200	Physical	Tolling Option Day-Ahead Call	6 x 16	New Construction	$32.51		$60.92		$25.38	0.80		966,400	938,160	$14,619,936	Analyzed at Mona (Delivery on 95% of least expensive hours)	6/1/2002	5/31/2005	Purchase Physical Day-ahead Tolling Option HLH (Mona and Rockies Gas) for 3 Years	Analyzed at Mona (Delivery on 95% of least expensive hours)	HR = 10,000. Seller offer 4 hour minimum run to shape. Seller limits starts per year to 100. Capacity payment shaped for demand months of June thru September. Initial capital cost $164.4 million	$57,156,771	$15,900,210	($41,256,561)	($20,628,281)
Alias RFP22	WES Structure	Purchase Physical Day-ahead Tolling Option HLH (Mona and Rockies Gas) for 12 Years	200	Physical	Tolling Option Day-Ahead Call	7 x 24	New Construction	$38.01		$10.30		$7.52	0.56		17,808,000	13,299,252	$168,744,553	Analyzed at Mona (Delivery on 95% of least expensive hours)	6/1/2002	5/31/2014	Purchase Physical Day-ahead Tolling Option HLH (Mona and Rockies Gas) for 12 Years	UC WSPP Schedule B	HR = 10,000. Restructure Seller tolling offer. WES has call on an minimum of any four hours for 10 months per year. Increase number of starts to 300 per year and reduce start-up cost.	$136,931,029	$99,721,713	($37,209,316)	($18,604,658)
Alias RFP14	Transaction 1	Purchase Physical Day-ahead Tolling Option HLH (Gonder and Malin Gas) for 12 Years	100	Physical	Tolling Option Day-Ahead Call	6 x 16	Yes	$52.62		$60.92		$22.73	0.38		740,800	698,019	$8,406,736	Analyzed at Gonder (Delivery on 95% of least expensive hours)	6/1/2002	5/31/2005	Purchase Physical Day-ahead Tolling Option HLH (Gonder and Malin Gas) for 12 Years	UC WSPP Schedule C	HR = 13,838. Tolling structure on Gonder Malin spread. Wes sell provides gas on Tuscarora or Pauite P/L. Seller limits A/S to 240,000 MWh per year and starts at $1000 per start-up.	$42,526,188	$3,976,987	($38,549,201)	($38,549,201)

Exhibit MRT-01 Summary

Transactions Completed

1) Alias RFP 20, Transaction 4
A physical day-ahead fixed price call for delivery of 100MW of firm on-peak energy and capacity to Mona. Energy price (strike price) of $55/MWh. PacifiCorp negotiated lower premium from $7.45/kW-mo to $6.85/kW-mo based on downward movement of forward power prices between Nov 21, 2001 to December 7, 2001.

2) Alias RFP 26, Transactions 1,2,3
Further analyses of these physical fixed price options for delivery of varying amounts of energy and capacity at Mona were dropped from additional consideration. Energy price (strike price) of the options were set so low ($12.66/MWh to $13.95/MWh) by the seller that offers were essentially physical take-or-pay swaps. The offers did not provide any real flexibility.

   There was extensive restructuring of this offer to a 100MW day-ahead tolling option for firm on-peak energy and capacity delivered to NUB. Term was set at 3-years and delivery was limited to the months of June thru September during 2002, 2003, and 2004. Contract heat rate was raised to 12,500 and capacity charges were reduced to $5.75/kW-mo, $6.35/kW-mo, and $6.65/kW-mo for 2002, 2003, and 2004 respectively. PacifiCorp also negotiated a financial natural gas delivery location of Malin, OR. The negotiated structure did not require PacifiCorp to make physical delivery of natural gas to the facility, which is located in Nevada. The capacity charges reflect the lower market curves on February 7, 2002, the higher contract heat rate, and the reduced spread between NUB power prices and Malin natural gas prices.

3) Alias RFP 22, Transactions 1 & 2
A physical day-ahead tolling option for delivery of 200MW of unit contingent energy and capacity in Utah delivered during the months of June thru September for either a 12-year or 3-year term. Both proposals were expensive and seller retained all plant optionality during the off-peak hours for June thru September and all optionality during the months November thru May. Fixed capacity charges of $22.60/kW-mo and $25.38/kW-mo would have allowed the seller to recover the majority of their capital cost at the expense of PacifiCorp.

   There was extensive restructuring of these offers to place the transaction at market and give PacifiCorp the entire optionality and flexibility of the plant. The final structure was a 15-year lease, with call options to purchase the plant at year 3 and year 6 and put options to terminate the lease at year 3 and year 6. In addition, PacifiCorp negotiated physical operation of the plant on a full year basis to capture: 1) day-of optionality; 2) the ability to shape the plant output each hour; 3) the ability to leverage existing gas transportation synergies with the existing Gadsby units; and 4) the ability to use the facility for Contingency Reserve (spin and non-spin) purposes. The final lease structure economics used the forward curves of January 29, 2002, for power and natural gas. The negotiated fixed capacity charge of $6.13/kW-mo was 18.4% lower than the offer of $7.52/kW-mo for a similar product on November 21, 2001.

Transactions Not Considered for Further Evaluation

1) Alias RFP 23, Transactions B and B2
Further analyses on these transactions were dropped from consideration. Seller made delivery contingent on commercial operation of the Redhawk plant, which put delivery of summer 2002 energy and capacity at risk.

2) Alias RFP 4, Transaction 2
Further analysis of this physical fixed price call option for delivery of 100MW of on-peak power at Mona was dropped from additional consideration. PacifiCorp would have been obligated to pay for the option for all months of the term commencing June 1, 2002 thru September 30, 2007.

3) Alias RFP 20, Transaction 3
Further analysis of this physical fixed price call option for delivery of 100MW of on-peak power at Mona was dropped from additional consideration. PacifiCorp would have been obligated to pay for the option for all months of the term commencing July 1, 2002 thru June 30, 2007.

4) Alias RFP 28, Transaction 2
A physical day-ahead tolling option for delivery of 100MW of firm on-peak energy and capacity to Nevada-Utah border (NUB). Proposed offer included a heat rate of 10,000, capacity charge of $7.86/kW-mo, and an energy charge based on the daily Southern California border natural gas price. PacifiCorp would have been obligated to pay for capacity each month of the 10-year term (June 1, 2002 thru May 31, 2012).

5) Alias RFP 28, Transaction 1
Further analysis of this physical delivery of 50MW of on-peak power at Mona was dropped from consideration for two reasons: a) Term of 10-years and b) PacifiCorp had take-or-pay obligation of $59.95/MWh escalating @ 3% per year

6) Alias RFP14, Transaction 1
Further analysis of this physical 100MW day-ahead unit contingent tolling option was dropped from additional consideration. Product was unit contingent delivery at Gonder with a heat rate of 13,838. PacifiCorp was responsible for natural gas deliveries off the either the Tuscarora or Paiute pipelines. Seller limited ancillary service coverage to 240,000 MWh per year and capacity charge was completely out of market @ $22.73/kW-mo.

PacifiCorp
Exhibit UP&L _____(MRT-2)
Docket No. 03-2035-02
Witness: Mark R. Tallman

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark R. Tallman
Comparison of Gadsby Peakers with the West Valley, Sempra and Morgan Stanley Transactions

July 2003

	Analysis Results of Physical Options for Utah (2/11/2002)				Analysis Results of Physical Options for Utah (12/7/2001)	
	Gadsby Peakers	West Valley	Sempra	-	Morgan Stanley	
Delivery Mode	Physical	Physical	Physical	Physical	Physical	Physical
Delivery Pattern	7 x 24 On-peak Hourly Call	7 x 24 On-peak Hourly Call	6 x 16 On-peak DA Call	6 x 16 On-peak Firm	6 x 16 On-peak DA Call	6 x 16 On-peak
POD	PCEU	PCEU	NUB	Mona	Mona	Mona
Option Type	Tolling Option PCEU vs Rockies Gas	Tolling Option PCEU vs Rockies Gas	Tolling Option NUB vs Malin Gas	Physical Firm	Fixed Strike Option	Physical Firm
Term Start	6/1/2002	6/1/2002	6/1/2002	6/1/2002	6/1/2002	6/1/2002
Term End	9/30/2004	9/30/2004	9/30/2004	9/30/2004	9/30/2004	9/30/2004
Heat Rate	10,200	10,000	12,500	-	-	-
Delivery Months	June - Sept	June - Sept	June - Sept	June - Sept	June - Sept	June - Sept
Net Benefit (PV $)	6,940,631	6,314,391	263,074	(810,635)	(1,504,076)	(4,182,877)
Net Benefit (PV $) @100 MW	5,783,859	3,157,196	263,074	(810,635)	(1,504,076)	(4,182,877)
Premium Cost - $ (1 Year)	(5,333,333)	(14,983,000)	(2,500,000)	(2,502,400)	(2,740,000)	(9,715,936)
Premium Cost - $ (3 Year)	(16,000,000)	(44,949,000)	(7,500,000)	(7,507,200)	(8,220,000)	(29,147,808)
Premium Cost ($/MWh)	15.18	25.59	15.27	46.00	16.73	59.34
Premium Cost ($/KW-mo)	3.72	6.24	6.25	18.83	6.85	24.29
Average Strike Price ($/MWh)	25.74	25.70	30.16	46.00	55.00	59.34
Capacity - MW	120	200	100	100	100	100
Total Energy Possible - MWh	1,054,080	1,756,800	491,200	122,800	491,200	491,200
Energy Called Flat (MWh)	632,448	1,124,352	348,752	122,800	112,976	491,200
Energy Called Flat (aMW)	72	128	0	0	0	0
Energy Called HLH (aMW)	118	188	71	25	23	100
Delta (Flat) (note 2)	0.60	0.64	0.00	0.00	0.00	0.00
Delta (HLH) (note 2)	0.98	0.94	0.71	1.00	0.23	1.00
Net Benefit Change @ 100 MW (PV $)	6,594,494	3,967,831	1,073,709	0	2,678,801	
SD Reduction (note 1)	(433,425)	(561,284)	(373,884)		(257,061)	
RELATIVE RANKING	**1**	**2**	**3**	-	**4**	-

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS	))))))))	Docket No. 03-2035-02 DIRECT TESTIMONY OF J. RAND THURGOOD

JULY 2003

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is J. Rand Thurgood. My business address is 201 South Main Street, Suite 2200, Salt Lake City, Utah 84111. I am Managing Director of Resource Development.

Q. How long have you been in your current role?

A. I have been in my current role since May of 2000.

Q. Please describe your educational history.

A. I have a BS degree and a Ph.D. degree in Chemical Engineering from Brigham Young University. Prior to my employment with PacifiCorp, I worked in research and development for Ireco Chemicals in Salt Lake City and for Oakridge National Laboratory in Oakridge, Tennessee. I have been employed by PacifiCorp for the past 23 years and have held a variety of positions in Research and Development, Power Supply Engineering and Resource Development. Since the summer of 2000, I have been responsible for the assessment, development, and optimization of both existing and new generation resources.

Q. Have you previously appeared in any proceedings before the Utah Public Utility Commission?

A. Yes. I presented testimony in Docket No. 01-035-37, the certificate proceeding for the Gadsby peaker project ("Gadsby Project").

Q. What is the purpose of your testimony?

A. I will provide the Commission with an update on the Gadsby Project.

Overview of the performance of the Gadsby Project

Q. When was the plant constructed and put into service?

A. The Gadsby Peaking Plant consists of thee units designated Unit 4, Unit 5 and Unit 6. Unit 4 was first synchronized to the grid on July 10, 2002. Unit 5 was synchronized on July 14, 2002 and Unit 6 was synchronized on July 29, 2002. During the period from July 10th to August 1, 2002, the units were tested at varying loads and the energy was supplied to the grid. On August 1, 2002 all three units were declared commercial and became available for dispatch.

Q. How does this compare with the schedule the Company presented at the Gadsby Project certificate proceeding?

A. During the certificate proceeding, the Company stated that the on-line commercial date would be sometime during the first week of September 2002 depending on the actual construction start date. The actual plant construction took just over five months and the Gadsby Project was, as I noted above, completed more than one month ahead of schedule.

Q. What is the cost of the Gadsby Project?

A. As of April 30, 2003, the actual cost of the Gadsby Project is $73.4 million.

Q. Do you consider the project to be completed or are there still outstanding action items to be completed?

A. The project is substantially complete. There are, however, a few outstanding items that remain to be completed. These include completion of a few equipment enclosures, some switchyard breaker replacements, miscellaneous small equipment changes and/or additions, purchase of some spare equipment, completion of the parking lot adjacent to the Jordan River and some landscaping work.

Q. What is the impact of these outstanding action items on the total cost of the Gadsby Project?

A. All of the remaining work is expected to be completed by the end of 2003, for a total cost of $2.4 million. Therefore, the total installed capital cost of the Gadsby Project is expected to be $75.8 million ($632 per kilowatt of installed capacity).

Q. How does this actual cost compare with the estimated cost of the Gadsby Project the Company presented at the certificate proceeding?

A. As the Commission noted in its January 31, 2002, Order in Docket No. 01-035-37, the Company's estimated total cost for the Gadsby Project was $80.4 million. Since the total installed cost of the project will be approximately $75.8 million, including all applicable overheads, sales taxes, and allowance for funds during construction, the actual cost of the Gadsby Project will be approximately $4.2 million, or 5.3 percent, less than the estimated cost.

Q. Please explain the design and operating assumptions of the Gadsby Project?

A. The Gadsby Project was designed to be operated as a peaking plant. The expected capacity factor for the plant was 33 percent. This capacity factor anticipated that the units would operate during the heavy load hours of the peak seasonal periods and would be off-line during light load hours.

Q. How is the Gadsby Plant performing against these assumptions?

A. The Gadsby Plant has met and continues to meet expectations. The equivalent availability of the plant from August 2002 through May 2003 on a rolling average basis is 88.94 percent. The capacity factors for each of the units during the same period on a rolling average basis are as follows: Unit 4 – 44.2 percent; Unit 5 – 39.5 percent; and Unit 6 – 41.6 percent. On a rolling average basis over this same period, the plant was connected to the grid 49.1 percent of the time. The difference between this number and the capacity factor numbers reflects the time the plant was used for operating reserves.

Q. What would you conclude regarding the construction and operation of the Gadsby Project?

A. The Gadsby Project was completed on time and within budget. It has been and continues to be used and useful in providing service to the Company's retail customers.

Q. Does this conclude your testimony?

A. Yes.